Electricity Framework Review

Control Technologies and Reduction Strategies:
Recommendations to the Electricity Framework Review Project Team for their consideration

Prepared by the Control Technologies and Reduction Strategies Task Group of the CASA Electricity Framework Review Project Team

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Version 15

Contents

1. Introduction

Recommendation 29 of the 2003 Emissions Management Framework (the 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 Framework.

As part of the Five Year Review initiated in 2013, a multi-stakeholder Control Technologies and Reduction Strategies (CTRS) Task Group was established to:

- Determine emission standards and corresponding deemed credit threshold for new thermal generation units based on the application of Best Available Technology Economically Achievable (BATEA).
- Determine emission standards for new reciprocating engines and diesel engines for electrical generation, based on the application of Best Available Technology Economically Achievable (BATEA), with consideration to be given to the related work of the reciprocating engine BLIERs group.
- Review the electricity sector's Continuous Improvement Report relative to the previous continuous improvement goal statements and propose, and where appropriate make recommendations for modifications to the Framework that would result in improved opportunities for supporting continuous improvement efforts.

The CTRS task group retained a consultant to assist with its work. The consultant provided a review of emission control technologies for gas-fired generation and advice on BATEA and related performance limits.

Subsequent to receiving the above mandate from the Electricity Framework Review Project Team (EFR Project Team), the CTRS task group also undertook a task to review the need to develop emissions standards for biomass-fired generation.

Recommendation 30 in the Framework recommends that the effective date for the implementation of new standards is January 1, 2011 for the first 5-year review. The Government of Alberta recommends that the effective date for the BATEA of the 2013 Electricity Framework Review is January 1, 2016 to maintain the 5-year review cycle. However, industry would like the implementation date of the natural gas turbine standards to be January 1, 2017 to allow adequate time to discuss how the standards will address pending policy points such as start-up and shut-downs, and prepare new approval applications for the new projects.

Recommendations are given as advice to the EFR Project Team and may or may not be included in the EFR Project Team's final report which will be forwarded to CASA Board of Directors for their approval.

2. Control Technologies Review

The objective of this review was to determine the BATEA for emission control technology that would be applicable to Alberta's electricity generating sector for new units, effective January 1, 2016. A definition of BATEA is found in the 2003 Framework[1]:

> BATEA refers to technology that can achieve superior emissions performance and that has been demonstrated to be economically feasible through successful commercial application across a range of regions and fuel types. BATEA is used to establish emission control expectations or limits. Generally it is the emission limit that is specified and not the specific BATEA. Facilities can opt for other technologies or emission strategies as long as the emission limit is met.

The BATEA review was conducted for combustion turbines of 25 megawatts (MW) or greater in size and considered different fuel types. A consultant was hired to analyze BATEA for natural gas turbines with and without duct firing. For conventional coal, the CTRS task group agreed that there was no changes to the BATEA since the 2008 Five Year Review. The CTRS Task Group believes that it is unlikely that new coal fired-units will be built due to the *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations* (Federal GHG Regulations). Under the Federal GHG Regulations, any new coal units must meet carbon Dioxide (CO_2) emission performance of 420 kg/MWh, which is not achievable with conventional coal fired generation.

The control technologies analyzed reflected technologies currently being applied to new generating units and able to achieve superior emissions performance. The technologies also had to be demonstrated to be economically feasible through successful commercial application across a range of regions and fuel types. As such, the BATEA review included the following steps.

a. Eliminate Technically Infeasible Control Technologies: Eliminate potential control technologies that are either technically infeasible or not used at comparable facilities in North America.
b. Rank Feasible Control Technologies: For the technologies that are remaining, update maximum, minimum, and typical removal efficiencies for each of the applicable pollutants. Then, rank the remaining control technologies for each combination of fuel/combustion device on their effectiveness at removing each pollutant.
c. Determine Control Costs: Update the estimated costs and emission reductions from applying the control technologies to the types of units that are expected to be constructed in Alberta in the future.
d. Environmental/Safety Concerns: For each BATEA technology selected, provide information on water, waste, other environmental impacts, and GHG emissions.
e. Co-benefits: For each BATEA technology selected, evaluate the potential for the co-benefit of controlling substances other than the primary pollutant.

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[1] An Emissions Management Framework for the Alberta Electricity Sector: Report for Stakeholders, November 2003. Prepared by the Clean Air Strategic Alliance Electricity Project Team, p. 117.

In addition, the CTRS Task Group reviewed the United States Environmental Protection Agency (USEPA) Prevention of Significant Deterioration (PSD) permit program that requires new projects that emit 100 t/y or more of NOx emissions or 250 t/yr of New Source Review pollutants to conduct a Best Available Control Technology (BACT) analysis for the source, and Ontario's Best Available Control Technology Economically Achievable (BACTEA) process.

An analysis of gas-fired boilers with steam turbines was not undertaken because it was seen as an unlikely source of emissions.

Recommendation 1: The 2018 Five Year Review should review if the use of gas-fired boilers with turbines has changed and consider developing emissions standards, if warranted.

3. Recommendations for Updated Standards for New Thermal Generation Units

Emission standards and corresponding deemed credit threshold are determined based on the Best Available Technology Economically Achievable (BATEA). It should be noted that the installation of the selected control technology (i.e. the BATEA) is not prescribed; there is therefore some flexibility to achieve the BATEA based standards.

The CTRS Task Group confirmed with the Government of Alberta that the "credit thresholds/baseline emission intensities" should be aligned with the NOx and SO2 performance standards. For example, the thresholds – given the philosophy of CASA – should be below the emission limit set in the Air Emission Standard for Electricity Generators (2006). In May 2010 CASA recommended new emission limits. However, neither the Emissions Trading Regulation (2006) nor the Air Emission Standard for Electricity Generators (2005) were updated. Thus the credit thresholds have not been updated since 2006. The Standard is effectively updated because approval writers just point to the CASA 2010 report. So, the May 2010 CASA recommended baselines have not yet been "implemented". However the 2006 Regulation – based on the 2003 recommendations – are very much implemented.

3.1. Best Available Technology Economically Achievable (BATEA)

Based on the results of the BATEA review, the CTRS Task Group reached consensus agreement on the following BATEA:

Coal-Fired Units

- New source standards for <u>Nitrogen Oxides (NOx)</u> for coal-fired units in Alberta will be based on the demonstrated performance of selective catalytic reduction (SCR).

- New source standards for <u>Sulphur Dioxide (SOx)</u> for coal-fired units in Alberta will be based on the demonstrated performance of spray dryer adsorbers with fabric filter baghouses.

- New source standards for <u>Mercury</u> for coal-fired units in Alberta will be based on the demonstrated performance of sorbent injection.

- New source standards for <u>primary Particulate Matter (PM)</u> for coal-fired units in Alberta will be based on the demonstrated performance of fabric filter baghouses.

Reciprocating Engines

- New source standards for <u>Nitrogen Oxides (NOx)</u> for natural gas fired reciprocating engines in Alberta will be based on the demonstrated performance of lean burn engines (most without after treatment) or rich burn engines equipped with air-fuel ratio controllers and non-selective catalytic reduction technology.

- New source standards for <u>Nitrogen Oxides (NOx)</u> for regular use diesel compression ignition reciprocating engines in Alberta will be based on the demonstrated performance of selective catalytic reduction technology.

- New source standards for <u>Nitrogen Oxides(NOx)</u> for stand-by use diesel compression ignition reciprocating engines in Alberta will be based on the demonstrated performance of low NOx combustion control technology.

Gas-Fired Units

- The CTRS task group did not reach consensus on what technology to base the new source standards for Nitrogen Oxides for gas-fired units in Alberta. Standards will be based on either dry low-NOx (DLN), ultra-dry low NOx (UDLN), or selective catalytic reduction (SCR) depending on the size and type of unit but consensus could not be reached on when DLN, UDLN, or SCR should apply. The ENGO and industry proposals regarding NOx emission limits for gas-fired generation units are presented in Appendix C, D, and E respectively.

3.2. Draft Recommendations

These recommendations are given as advice to the project team and may or may not be included in the project team's final report which will be forwarded to CASA Board of Directors for their approval.

3.2.1. Source Standards and Credit Generation Thresholds for New Coal-Fired Thermal Generation Units

The standards that are recommended for new coal-fired thermal generation units are carried over from what was agreed to in 2010, as it was difficult to complete an analysis due to the uncertainty around a full review of the Framework. The EFR Project Team agreed that, in general, in terms of conventional coal-fired power plants, the 2010 recommended emission limits continued to reflect BATEA based limits. 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.

Draft Recommendation 1: Source Standards for Conventional New Coal-Fired Thermal Generation Units (Supercritcial)

It is recommended that the standards and credit limits in the *Report on the First Five Year Review of the Emissions Management Framework for the Alberta Electricity Sector, May 2010* be retained for conventional coal. (Please see Appendix I for full details.)

Draft Recommendation 2: Source Standards for Unconventional New Coal-Fired Thermal Generation Units

It is recommended that standards and credit limits for unconventional coal should be approved on a case-by-case review by regulator.

3.2.2. Credit for Early Action on Mercury Capture

In 2010, the EFR Project Team recommended an initiative on Credit for Early Action on Mercury. The current EFR Project Team reviewed the implementation of that recommendation and recorded the following conclusions:

- Between January 1, 2011 and January 1, 2013, companies were able to earn credits for Mercury capture rates greater than 80%.
- Some companies did initiate their Mercury control systems early, but credits generated by this early action have not been formally tracked, perhaps due to the fact that Alberta Environment and Sustainable Resource Development has not formalized this program in a standards document or any other mechanism.
- Although there may be additional work for industry and government to record credits generated, the EFR Project Team agreed by consensus that the recommendation has been implemented.

In addition, the 2014 Industry Continuous Improvement Report (received by the CTRS Task Group, see Appendix B) indicates that Mercury emissions have decreased by 43% since 2008.

Bearing in mind the foregoing information, the CTRS Task Group agreed that there was not a need to do any further work on Mercury for the current FiveYear Review.

3.2.3. Source Standards for New Gas-Fired Thermal Generation Units (Non-Consensus)

Description of Non-Consensus

The task group could not agree on updated source standards for new gas-fired thermal generation units. The group discussed standards based on either dry low-NOx (DLN), ultra-dry low NOx (UDLN) or selective catalytic reduction (SCR). The key area of disagreement is when DLN, UDLN or SCR should be applied, based on size and type of unit. The ENGO and industry proposals regarding NOx emission limits for gas-fired generation units are presented in Appendix C, D, and E.

Summary of Perspectives: Industry

The industry sector proposes an approach for gas turbines that recognizes the emissions performance capabilities of different generating unit sizes by setting appropriate standards based on dry low-NOx, ultra dry low-NOx or SCR technologies. Peaking units have separate standards to address the emissions aspects unique to peaking service. Emissions standards for cogeneration units include allowances for heat recovery in addition to electricity generation to account for the additional fuel consumed for heat production. A heat allowance of 0.034 kg NOx/GJ $_{input}$ is recommended which is a significant reduction from the CCME output based allowance and represents current good performance for duct firing. Gas turbine standards must be designed with flexibility to recognize the diversity of new and End of Design Life gas turbine units, encourage efficient choice in unit design and to achieve good environmental outcomes. Industry has outlined an approach for all gas turbines that produce electricity but suggests that further discussion is required to establish the actual gas turbine emission limits. An effective date of January 2017 should be considered to allow transition to the new requirements.

Summary of Perspectives: ENGO

The ENGO sector proposes an approach for gas turbines that reflects the application of BATEA based controls consistent with the intent of the Alberta Electricity Framework. A considerable amount of effort was spent by all sectors on this 2nd five year review of the electricity framework. The ENGOs feel that industry early in the process took the position; no SCR based limits for all but the very largest units. Three previous BATEA review reports all confirmed that SCR limits were a cost effective control technology for all but the smallest generation units e.g. less that 50-70 MW and represented BATEA. This industry position regarding SCR has made it very difficult to negotiate from a CASA interest-based discussions perspective. This position backslide on the part of the Utility Sector contravenes the principle of continuous improvement and the BATEA approach that underlies the CASA five-year review approach, which contemplates improved actions over time (Recommendation 29). Combined with the BATEA approach to standard setting, the overall framework posits the continuous improvement of BATEA-level technology over time. ENGOs are unable to square these overall Electricity Framework principles/concepts with this backslide in position and therefore could not reach consensus.

Summary of Perspectives: Government

Based on the direction outlined by Assistant Deputy Minister Rick Blackwood at the March CASA Board meeting, the Government of Alberta has indicated they will wait on the submissions of stakeholder statements and views on non-consensus recommendation for new gas-fired thermal generation and use these to make an informed decision regarding the source standards moving forward.

3.2.4. Source Standards for New Reciprocating Engines

Reciprocating Engines and the Framework

The possibility of emission limits for reciprocating engines used to generate electricity was addressed in the 2003 Framework. Recommendation 12 stated that:

> *"Emissions from reciprocating engines, excluding stand-by and emergency units, be addressed on an approval basis and compared to the BATEA level of the day.*
> *If there is a significant increase in the size or number of these units, they may be addressed as part of the Five Year Review"*

2008 Five Year Review

The Terms of Reference for the EFR Project Team undertaking the first Five Year Review of the Framework in 2008 included a task to:

> "*Review the use of reciprocating engines to determine if they should be considered as part of the framework (as per recommendation 12)*"

The issue was reviewed as part of the 2008 Five Year Review and action was deferred. The basis for deferral was that the provincial Government was in the process of developing NOx emission for reciprocating engines and therefore the issue was being addressed in another forum. It was also noted at that time that reciprocating engines were only a small part of the Alberta electricity industry. The final report from the 2008 Five Year Review EFR Project Team made no specific reference to, or recommendations related to, emission limits for reciprocating engines.

Reciprocating Engines and the 2013 Five Year Review

As part of second Five Year Review (initiated in 2013) of the Framework, the CTRS Task Group reviewed both the need for emission limits for reciprocating engines used for electricity generation and possible BATEA based limits for these types of engines.

Reciprocating engines include both natural gas-fired engines and compression ignition diesel engines. The CTRS Task Group reviewed information on the number, size and type of reciprocating engines currently in use for electricity generation in Alberta. The CTRS Task Group concluded that the potential existed for an increase in both the number of reciprocating engine electricity generation applications and the total amount of power generated by reciprocating engines. An example of this is the 65 MW natural gas reciprocating engine generator set installed by the Alberta Newsprint Company (ANC) in Whitecourt.

The CTRS Task Group also discussed issues such as design life, emergency use applications and size ranges.

- *Design Life:* On the issue of design life, the CTRS Task Group decided that it did not have enough information on the normal design life for reciprocating engines to determine if it should set a design life period as the Framework does for coal and gas fired units. As such, the recommendations will only apply to new units. The CTRS Task Group advises that this is issue be reviewed by a future Five Year Review EFR Project Team.

- *Emergency/Standby Units*: In terms of emergency or standby units the CTRS Task group decided that the focus should be on regular use units but a recommendation was provided for emission limits for new diesel-fired reciprocating engines used for stand-by power generation.
- *Size Ranges*: For size ranges the CTRS Task Group agreed that the proposed emission limits should only apply to reciprocating engine electricity generating units connected to the grid which generate greater than or equal to 75 kW.

The CTRS Task Group discussed the best approach for both evaluating BATEA for reciprocating engines and recommending BATEA based NOx emission limits for these types of units. The following is a summary of the approaches used.

Natural gas-fired reciprocating engines
For natural gas-fired reciprocating engines, the CTRS Task Group agreed that the recently conducted BATEA reviews for such engines under the National Air Quality Management System (AQMS) Base-Level Industrial Emissions Requirements (BLIERs) process could be used as the CTRS Task Group's BATEA review. The province was an active participant in the BLIERs process. After some clarification from the province regarding how BATEA controls were translated into the proposed BLIERs limits, the CTRS Task Group decided that it would recommend that emission limits for natural gas fired electricity generating reciprocating engines be the same as those being proposed under the AQMS BLIERs process.

Compression ignition diesel reciprocating engines
For compression ignition diesel reciprocating engines, the CTRS Task Group agreed that the U.S. Environmental Protection Agency "*Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuel*" (Federal Register / Vol. 69, No. 124 / Tuesday, June 29, 2004 / Rules and Regulations) could be used to determine BATEA and BATEA based emission limits. This rule established 2015 emission limits for generator sets based on post combustion NOx controls. The CTRS Task Group decided that it would recommend that emission limits for compression ignition reciprocating engines used for electricity generation have the same NOx emission limits as the Tier 4 limits for generator sets established by the USEPA for 2015+ model years.

Draft Recommendation 3: Source Standards for New Reciprocating Engines

It is recommended that the following standards apply to new reciprocating engines that are approved on January 1, 2016 or later.

- New Diesel-Fired Reciprocating Engines (regular use units)
  - Expressed in a similar format to the US EPA Tier 4 Compression Ignition New Source Performance Standards, which include diesel-powered generator sets.
  - Based on selective catalytic reduction (SCR).

> 75 kW1 (100 HP) (<30 L displacement per cylinder): 0.50 g/bhp-hr (approximately 0.67 g/kWh) > all units with ≥30 L displacement per cylinder: 1.8 g/kWh (approximately 1.34 g/bhp-hr)

Considerations:

- This policy applies to new reciprocating engines greater than 1 MW in size that are for the purpose of providing electricity into the provincial grid.
- An exemption applies to remote communities, defined as communities that do not have year-round road access.

▪ New Diesel-Fired Reciprocating Engines (stand-by units).

- Expressed in a similar format to the US EPA Tier 2 Compression Ignition New Source Performance Standards for generator sets.
- Based on combustion based controls i.e. no SCR.

≥75 kW and ≤ 560 kW (100 HP) 3.0 g (NMHC+NOx)/bhp-hr (approximately 4.0 g (NOx + NMHC)/kWh) >560 kW (750 HP) 4.8 g (NMHC+NOx)/bhp-hr (approximately 6.4 g (NOx + NMHC) /kWh)

▪ New Natural Gas-Fired Reciprocating Engine Standards

- Based on the BLIERs for NOx for natural gas-fired reciprocating spark ignition engines which are based on the USEPA requirements for these types of engines
- Based on either lean burn engines (most without after treatment) or rich burn engines (equipped with air-fuel ratio controllers and non-selective catalytic reduction technology).

>/= 75 kW (100HP is US size range): 2.7g/kWh (based on 2.01 g/bhp-hr)

3.2.5. Source Standards for New Biomass-Fired Generation

Biomass Generation and the Framework

The Framework does not specifically address biomass generating facilities other than to note that: "*…biomass and small "alternative" sources (e.g., small on-site generators using waste heat or gases) displace traditional fossil fuel-fired generation, emissions decrease.*" The 2008 Five Year Review did not review the issue of biomass generation and the Project Charter for this Five Year Review did not mention biomass generation. However the current EFR Project Team noted that biomass generation is increasing in the province and it is actively being promoted. Currently certain biomass generation facilities are subject to EPEA approval requirements in which case emission limits for these generation facilities are part of the facility's EPEA approval. There are currently no standalone standards specific to biomass generation and the CTRS considered whether or not such standards should be considered or were necessary for any or all types of biomass generation. As the following review and summary indicates the CTRS and EFR Team concluded that the current EPEA approval based approach for setting limits for biomass generation units is adequate but that the issue should be reviewed again during the next 5 year review.

The following is a summary of the EFR Project Team's findings and recommendations related to biomass generation.

Biomass Generation

Biomass generation is an important source of renewable use energy worldwide.
Biomass energy is any kind of energy that uses a biological organism (plant or animal) as its source. The definition of biomass is broad and fuels that can be considered "biomass" are wide and varied with new biomass energy sources continually being identified. Animal manure, landfill waste, wood pellets, vegetable oil, algae, crops like corn, sugar, switch grass and other plant material -- even paper and household garbage -- can be used as a biomass fuel source. (Plasco model[2])

An advantage of using biomass as a fuel source for power generation is that some biomass sources, like manure, sawdust and landfill garbage, could otherwise go to waste. These sources therefore reduce dependence on fossil fuels and nuclear energy while also reducing the negative impacts associated with the normal management of these biomass sources e.g. the noise, smell, vermin, and declines in property values that are associated with landfills.
Biomass fuel can be converted into heat energy directly through combustion, like the burning of a log in a fireplace or it can be converted into another fuel source; examples include ethanol gasoline made from corn, or methane gas derived from animal waste.

The main barriers to widespread use of biomass for power generation are cost, low conversion efficiency and feedstock availability[3].

Figures 1 shows the contribution of biomass generation to the Alberta electricity grid.

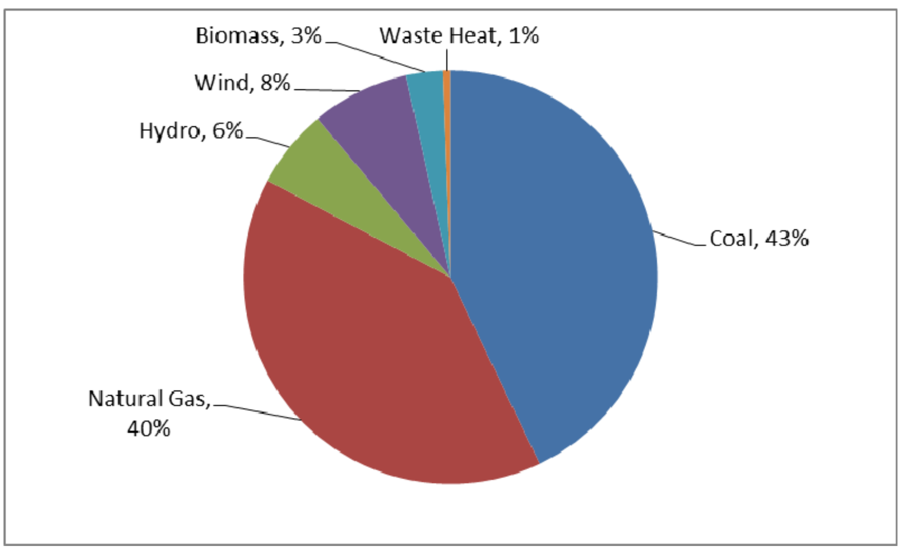


Figure 1: Alberta's Electric Energy Capacity by Source, 2014

[2]Plasco Energy Group http://www.plascoenergygroup.com/
[3] International Energy Agency 2007. *Biomass for Power Generation and CHP*. https://www.iea.org/techno/essentials3.pdf)

Biomass Energy and the Environment

The burning of biomass fuels, like the burning of fossil fuels, can produce pollutants such as volatile organic compounds (VOC's), particulate matter (PM), carbon monoxide (CO) and carbon dioxide (CO_2).

The renewable nature of biomass energy, however, has positive environmental implications and can greatly reduce this environmental impact. While burning biomass releases carbon monoxide and CO_2 into the atmosphere, trees and plants also *capture* carbon from the atmosphere during photosynthesis. This process is often called "carbon sequestering" or "carbon banking."

The Future of Biomass Energy

Biomass fuels include agricultural wastes, crop residues, wood and wood-wastes, etc. These types of biomass fuels do not add carbon dioxide to the atmosphere as the vegetation absorbs the same amount of carbon while growing. This biomass can be combusted directly, converted to other fuels and/or gasified.

Gasification[4] is the process of converting solid fuels such as wood, agricultural residues and coal into a more convenient combustible gas. This process is done in the gasifier[5], mainly comprised of a reactor where the combustible gas is generated and the gas is made available for power generation or thermal application after the required cleaning and cooling processes

Small and medium size biomass combined heat and power (CHP) plants (i.e., up to 5MW of electrical rated power) represent an attractive option to use locally available biomass resources at low cost, the corresponding investment per unit of rated power significantly rises when the installed power decreases. In these cases, secondary pollutant emissions control measures are most of the time not economically viable and primary emissions control must be used alone to minimize the formation of undesirable emissions such as NO_x and SO_x. Primary control measures require the careful optimization of fuel quality and combustion process.

Since biomass generation is increasing in the province and is actively being promoted, the CTRS task group agreed to the following recommendation:

Draft Recommendation 3: Biomass-Fired Generation

It is recommended that the 2018 Five Year Review team review the need to include biomass sources of electricity generation in the Alberta Electricity Framework.

Possible considerations for the next Five Year Review include:

- Definition of biomass
- Range of fuel sources that should/could be covered
- Priority pollutants from biomass
- End of design life requirements

[4] http://en.wikipedia.org/wiki/Gasification

[5] http://science.howstuffworks.com/environmental/green-tech/energy-production/gasification.htm

In terms of return on investment of time and effort, the next review team should consider:

- Is there a concern about equitable treatment across sectors? Would this work contribute to ensuring continued equitable treatment across sectors?
- Does biomass-fired generation contribute a significant amount of sector emissions?
- What's the growth potential for biomass related generation?
- Are operators meeting the same emissions standards as coal- and gas-fired generation?
- Does the framework need to manage for all fuel types? The CTRS task group agreed that the biomass industry reps on the team should be asked to provide input to the draft recommendation."[6]

[6] Committee notes from CASA-EFR, CTRS.

Appendix A - Source Standards and Credit Generation Thresholds for New Coal-Fired Thermal Generation Units

Excerpt from *Report on the First Five Year Review of the Emissions Management Framework for the Alberta Electricity Sector, May 2010*

The following standards apply to coal-fired boiler generating units without carbon capture technology that are approved on January 1, 2016 or later.

- Nitrogen Oxides (NO_x)
  - Emission standard: 0.47 kg/MWh net
  - Design specification: 0.40 kg/MWh net

(Note: In addition to requiring compliance with the NO_x emission standards, the environmental approval will include a condition that requires the proponent to design the NO_x control equipment with the capability to reduce emissions to 0.40 kg/MWh net, or less.)

- Sulphur Dioxide (SO2)
  - Emission standard: 0.65 kg/MWh net or 90% removal, whichever is less stringent.

- Particulate Matter (filterable[7])
  - 6.4 ng/J of heat input (~0.066 kg/MWh)

- Mercury
  - 75% capture design target
  - Optimization plans to meet 80% capture by 2013

The standards are conditional on emissions during startups and shutdowns (using best practices) excluded from compliance measurement and reasonable flexibility by Alberta Environment during commissioning periods for new technology.

The following deemed credit thresholds for the 2016 BATEA standards be applied to new coal-fired and gas-fired units:

A. NO_x (coal-fired) – 0.38 kg/MWh net

B. SO_2 – 0.55 kg/MWh net

C. NO_x (gas-fired) – “A” factor = 0.07 kg/MWh net and “B” factor = 0.008 kg/GJ

** NO_x (kg/h) = [Net Power Output (MW net) x A] + [Heat Output (GJ/h) x B]

[7] Alberta Environment ofStack Sampling Code or EPA Method 5 – front half particulate catch

Appendix B: 2014 Industry Continuous Improvement Report

CONTINUOUS IMPROVEMENT REPORT

2014 ELECTRICITY FRAMEWORK REVIEW CLEAN AIR STRATEGIC ALLIANCE

Alberta Electricity Sector

November 12, 2014

1. EXECUTIVE SUMMARY

The contribution of priority air emissions from Alberta's electricity sector has been decreasing for several years. Since 2008, the electricity sector emissions of nitrogen oxides have decreased by 14%, sulphur dioxide have decreased 14%, particulate matter have decreased 20%, mercury have decreased 43% and greenhouse gases are down 11%. These significant reductions have been accomplished while meeting the need for a 10% increase in electricity demand to accommodate Alberta's growing economy. Reduced operation of higher emitting units, retirement of older units, additions of new low-emitting generation, regulatory influences and the emissions reduction efforts taken by electricity sector participants have contributed to achieving the emissions reductions. Improvements to the provincial transmission system also contribute to emissions reductions by improving efficiency and reducing losses on the transmission system. The trend of reducing priority emissions while meeting new demands is expected to continue into the future as new lower emitting generation will continue to replace older facilities and governments introduce additional emission reduction initiatives.

2. INTRODUCTION

In 2003, the Alberta electricity generators agreed to prepare a continuous improvement report for the Clean Air Strategic Alliance (CASA) stakeholders during the scheduled five year review of the air management framework. The direction for the report is set out in Recommendation #29, item 6 of the CASA 2003 Electricity Framework report.

This report, the second Continuous Improvement Report (2009 to 2013), summarizes the electricity sector's air emissions profiles and highlights changes in the generation fuel mix during the past five years, and touches upon anticipated trends and continuous improvement opportunities for the future.
The report compares 2008 and 2013 installed capacity, generation and emissions data from the following publically available sources:

- Generation and installed capacity data is from the Alberta Utilities Commission (AUC) annual electricity data collection process. The data includes energy generation and installed capacity for Alberta power plants with a 0.5 Megawatts (MW) and greater installed capacity and includes "behind the fence" (electricity for on-site use) generation. Isolated plants generation and interchange energy is not included;
- Emission data for nitrogen oxides (NO_X), sulphur dioxide (SO_2), particulate matter (PM) and mercury (Hg) was obtained from Environment Canada's National Pollution Release Inventory online data search[i] of facility reported data. For SO_2, PM and Hg only coal-fired power plant emissions have been included; and
- Greenhouse gases (GHG) emission data was obtained from Environment Canada's Reported Facility GHG Emissions online data search[ii].

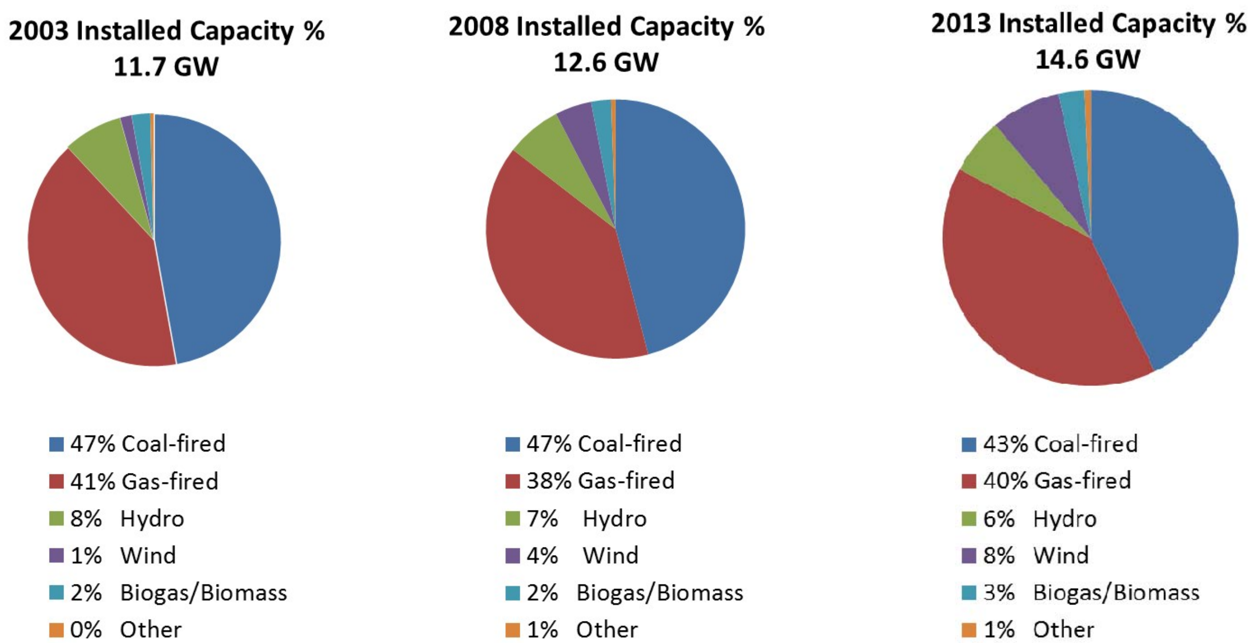
The emissions of some Alberta electricity generating units are not included in the electricity sector information as they report under other sectors (e.g. oil and gas, chemical, forestry). Information is not always publically available to separate the emissions for these units from their respective facility emissions so that they may be included with the electricity sector information in this report. Therefore, the emissions for these generating units are not included in this report whereas generation and installed capacity information is presented.

3. ALBERTA ELECTRICITY SECTOR

For nearly a century, the electricity sector has consistently delivered safe and reliable electricity to Albertans. Alberta is resource-rich and reliable electricity supply plays a significant role in maintaining a healthy economy. The province's electricity sector has seen substantial change including a shift to deregulation in 2001 and a growing demand for power that has put pressure to expand generation and transmission in anticipation of meeting future needs.

"Installed capacity" represents the total amount of electricity that theoretically could be produced if all the facilities in Alberta were generating power at their full output. Figure 1[iii] illustrates the Alberta electric energy installed capacity in Megawatts by resource. Information presented is net to electricity grid energy based on the maximum continuous rating (MCR) of each generating unit. The installed capacity has increased from 12.6 to 14.6 GW since 2008. Based on a percentage of total installed capacity in Alberta, natural gas-fired generation and renewables generation have increased installed capacity; whereas coal-fired capacity has less installed capacity. Wind generation in particular has seen a significant installed capacity growth over the past decade and share of total installed capacity.

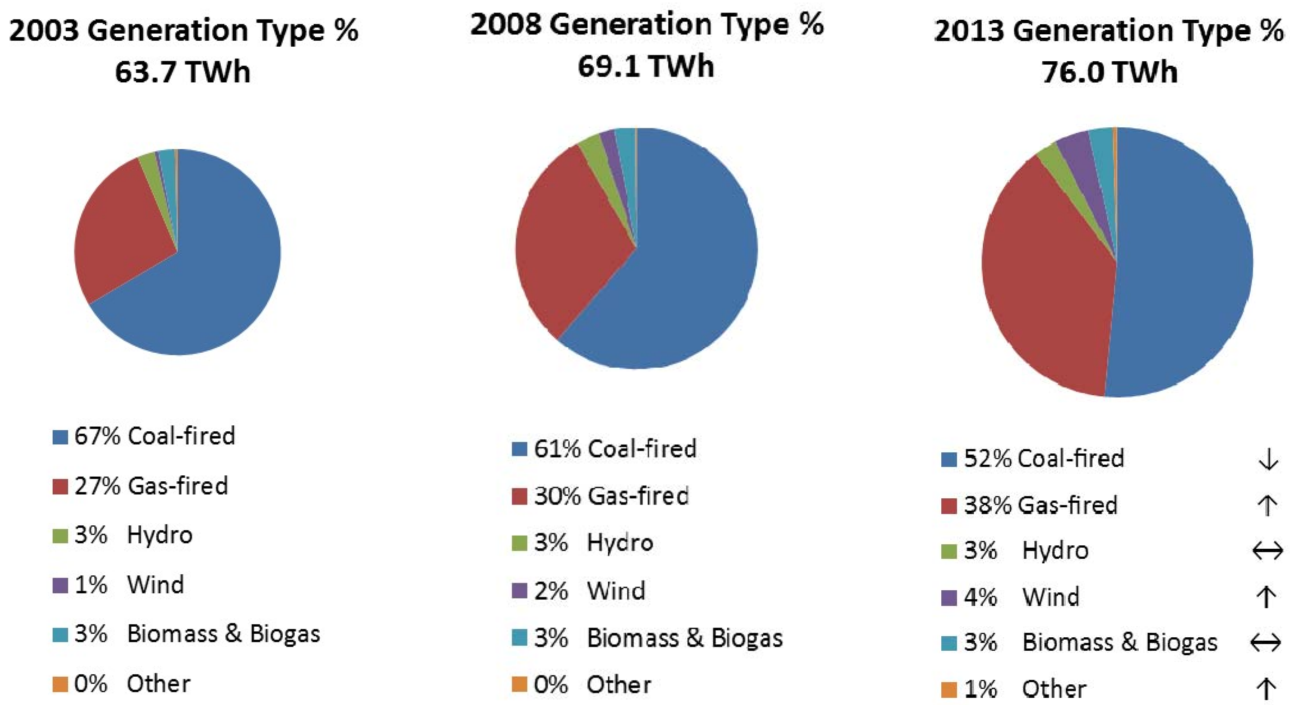
Figure 1 Alberta Electric Energy Net Installed Capacity by Resource (MCR MW)



The mix of the type of generating units actually providing energy is different than the mix of installed capacity. This is because generating units may not operate at their full capacity or may operate for shorter periods. An example of this would be a wind generator that may not operate all hours of the day depending on whether there is the required wind. Figure 2[iv] illustrates the generation mix for actual energy produced.

Since 2008, Alberta electricity generation has increased from 69.1 to 76.0 Terawatthour (TWh), a 10% increase, and the type of generating units providing that energy has changed. The energy contribution from renewables and natural gas generation during this period has increased, and coal-fired generation has decreased.

Figure 2 Alberta Electric Energy Generation by Resource (GWh)



The generation mix in Alberta continues to shift from a predominantly coal-based fleet to a natural gas-based fleet, with the majority of future generation additions expected to come from gas-fired combined cycle and cogeneration. Additional wind generation, small scale renewables and the potential for future hydro generation are also anticipated[v]. This different mix of generating types providing reliable energy to Albertans, and the replacement of retired units with more efficient generating technologies will result in lower electricity sector air emissions, even with expected increases in generation.

4. PRIORITY SUBSTANCE EMISSIONS

The emissions of the five priority substances (NO_X, SO_2, PM, Hg, GHG) from the Alberta electricity sector have reduced significantly over the past five years. The reduction in emissions is due to the change in generation mix, retirements of older units, new low-emitting generation, regulatory initiatives and emissions reduction efforts taken by electricity sector participants.

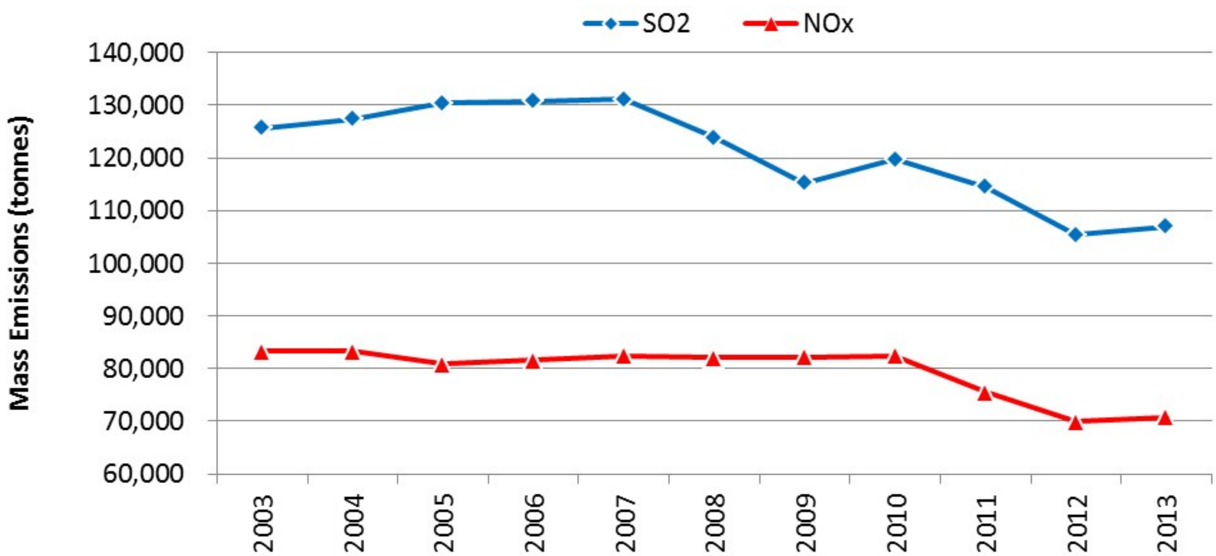
4.1. Nitrogen Oxides (NOx)

In 2008, the electricity sector made up 21% of NO_X mass emissions in Alberta. The electricity sector's NO_X emissions have decreased from 82,129 tonnes in 2008 to 70,790 tonnes in 2013, a 14% decrease (see Figure 3).

4.2. Sulphur Dioxide (SO_2)

In 2008, the electricity sector made up 34% of SO_2 mass emissions in Alberta. The electricity sector's SO_2 emissions have decreased from 123,777 tonnes in 2008 to 106,978 tonnes in 2013, a 14% decrease (see Figure 3).

Figure 3 NO_X and SO_2 Mass Emissions



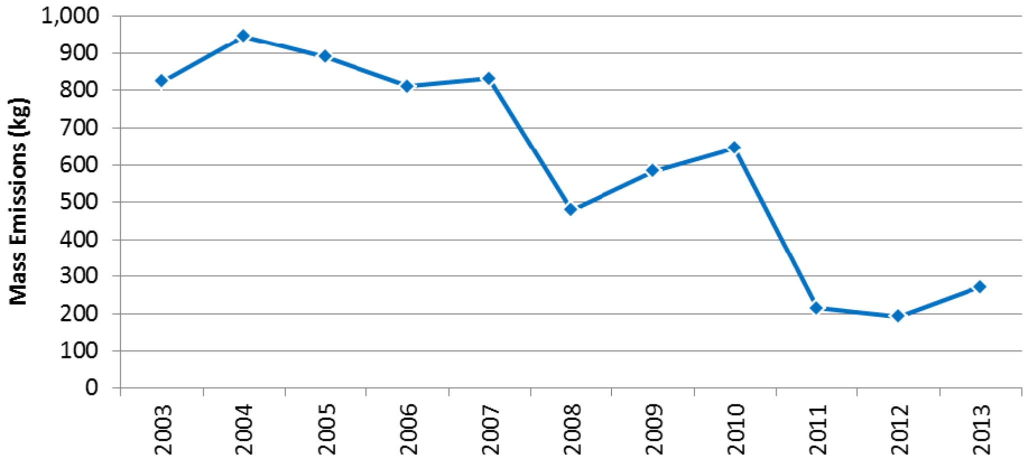
4.3. Mercury (Hg)

Trace amounts of Hg can be found in coal and when coal is burned, some Hg is released into the atmosphere. In 2008, the electricity sector made up 75% of Hg mass emissions in Alberta. In order to reduce Hg emissions, members of the Alberta electricity sector worked with Government and Environmental Non-Government Organizations through the CASA process to develop and recommend Hg standards for the electricity sector in Alberta. In 2006, the Government of Alberta passed the *Mercury Emissions from Coal-fired Power Plants Regulation* to comply with the CASA recommendations and the *Canada-wide Standards for Mercury Emissions from Coalfired Electric Power Generation Plants*. In 2011, as required in the regulation, Hg capture controls were installed at most coal-fired generation plants to reduce atmospheric Hg emissions (the H.R Milner plant was excluded due to the low level of mercury emissions).

The electricity sector's Hg emissions have decreased from 479 kilograms in 2008 to 273 kilograms in 2013, a 43% decrease (see Figure 4).

The method of measuring Hg emissions for most Alberta coal-fired plants changed from mass balance to Continuous Emissions Monitor System (CEMS) in 2011, a direct measurement system (the H.R. Milner power plant is excluded from this requirement).

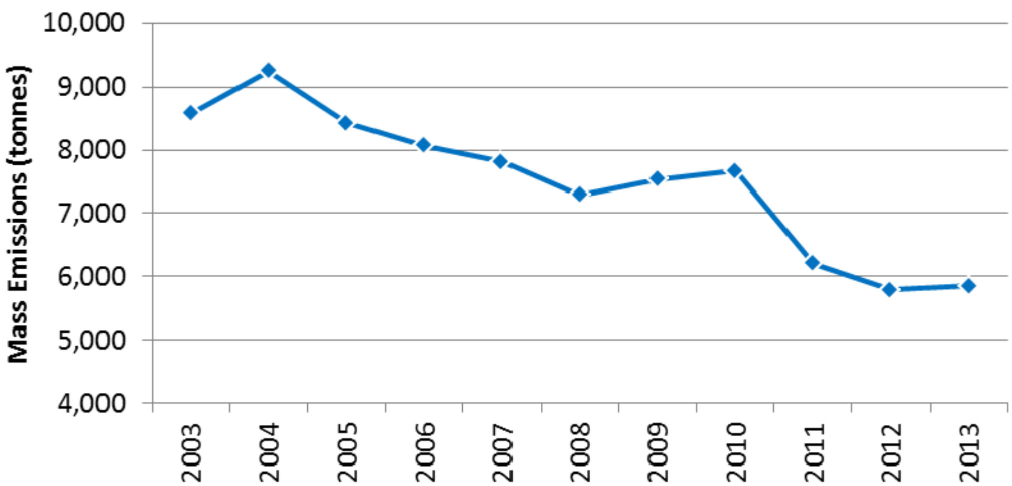
Figure 4 Mercury Mass Emissions



4.4. Particulate Matter

In 2008, the electricity sector made up 9% of primary PM mass emissions in Alberta. The electricity sector's primary PM emissions have decreased from 7,291 tonnes in 2008 to 5,847 tonnes in 2013, a 20% decrease (see Figure 5).

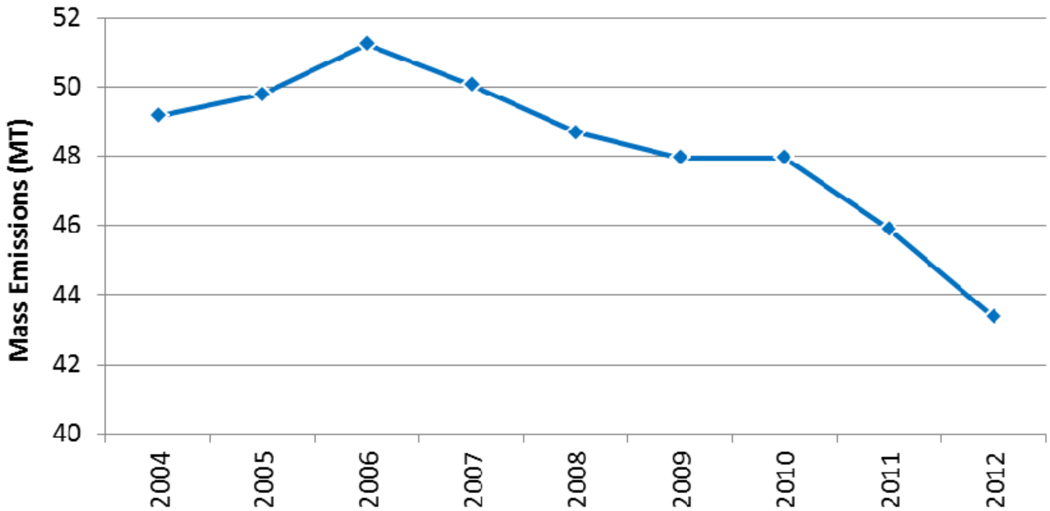
Figure 5 Primary Particulate Matter Mass Emissions



4.5. Greenhouse Gas (GHG)

In 2008, the electricity sector made up 44% of Greenhouse Gases mass emissions in Alberta. The electricity sector's Greenhouse Gases emissions have decreased from 48.7 megatonnes in 2008 to 43.4 megatonnes in 2012, an 11% decrease (data is not available for 2013, see Figure 6).

Figure 6 Greenhouse Gases Mass Emissions



Alberta Environment and Sustainable Resource Development (AESRD) is currently reviewing the Electricity Grid Displacement Factor (EGDF) and Electricity Grid Intensity Factor (EGIF). The EGDF is used for GHG offset projects that displaces other forms of grid electricity by supplying grid scale renewable/non-emitting electricity into the grid, while the EGIF is used when a GHG offset project results in an increase in on-site grid electricity use and reduce transmission losses. AESRD is expected to reduce the EGDF from 0.65 to 0.59 t CO_2e/MWh and EGIF from 0.88 to 0.64 t CO_2e/MWh by 2015. The expected reductions in EGDF and EGIF reflect the efficiency improvement in the grid emission intensity due to change in generation mix and transmission improvement.

5. EMISSIONS REDUCTIONS ACTIVITIES IN 2009 TO 2013

5.1. New Generation

Since 2008, a total of 2,348 MW of installed capacity was added to the Alberta electricity system and 552 MW was decommissioned (see Table 1[vi & vii] and Appendix 1). The retirement of older generating units and replacement with newer lower-emitting generating units has resulted in a net reduction in emissions, even though the actual generation produced has increased by 10%. The bulk of new generating capacity (70%) was made up of efficient natural gas-fired cogeneration and wind generation.

Table 1 New and Decommissioned Electricity Installed Capacity

Generation Type	Additions (MW)	Decommissioned (MW)	Net Change (MW)
Gas Cogeneration	657	0	657
Gas Conventional	448	240	208
Wind	595	0	595
Coal	541	279	262
Biomass Cogeneration	103	0	103
Biomass	4	33	-29
Total	**2,348**	**552**	**1,796**

Cogeneration (combined heat and power) units capture waste heat from electricity production and convert it to useful thermal energy (e.g. steam for use in industrial processes). The overall thermal efficiency of cogeneration units can be very efficient (more than 70%) which results in optimal use of the fuel and also lower emissions than if the electricity is produced by a simple cycle natural gas-fired turbine and heat is produced by a conventional boiler (80% efficiency). The 657 MW of gas cogeneration added since 2008 was primarily installed for steam-assisted gravity drainage (SAGD) bitumen recovery operations in north east Alberta. Most of these installations are able to provide electricity to the Alberta Interconnected Electrical System (AIES) as well as supply their own operations. Gas turbines with the cogeneration installations typically use dry low NO_X emissions (DLE) combustion technology.

Considerable wind generation has been added to the Alberta electrical system in recent years. The growth in this sector has been made possible by advances in wind technology and work to address integration issues to allow wind capacity to increase on the AIES. Wind provides renewable energy with no air emissions. Five-hundred and ninety-five megawatts of wind capacity has been added to the AIES in the past five years.

Conventional natural gas-fired generation often has the ability to startup and increase load quickly to respond to changing electricity needs on the AIES. Several units were added since 2008. Most units are equipped with DLE technology to provide low NO_x emissions. The Capital Power Clover Bar units are equipped with Selective Catalytic Reduction systems (SCR) to control NO_X emissions.
Keephills Unit 3, a 463 MW net coal-fired unit commissioned in September 2011, uses supercritical boiler technology with advanced air quality control systems that includes flue-gas desulphurization (SO_2 control); low NO_X staged burners (NO_X control), activated carbon injection (Hg control) and high (99.9%) efficiency fabric filters (PM control).

Biomass, biological materials usually from forestry residue, wood chips or municipal solid waste, can be combusted to produce electricity. Over the past five years there has been an increase in the installed capacity of biomass generation and cogeneration units operating in Alberta (313 MW in 2008 and 417 MW in 2013). For example, Canada's largest biogas cogeneration project began commercial operation in Lethbridge in December 2013. The facility is a 2.8 MW full-scale biogas cogeneration project fueled by organics comprised of agricultural manures and food processing wastes and generates electrical and thermal energy through the anaerobic digestion of organics. The facility is estimated to reduce greenhouse gas emissions by more than 224,000 tonnes CO_2e by 2020 and to reduce odors by up to 75%.

5.2. Emission Improvements

Members of the Alberta electricity sector have taken steps to reduce emissions over the past five years. Some examples are described below.

The *Alberta Mercury Emissions from Coal-Fired Power Plants Regulation* required operators of coal-fired units to install and operate Hg emission controls to capture at least 70% of the Hg from coal by January 2011. To respond to this requirement, some operators of the Alberta coal-fired generating facilities (ATCO Power, Capital Power, and Transalta) worked together to evaluate and test Hg control options. Based on the testing, the operators of the coal-fired units installed activated carbon injection systems (ACI) on their coal-fired units (except for H.R. Milner generating station which uses a baghouse to provide particulate and Hg capture). The ACI system pneumatically injects Powdered Activated Carbon (PAC) into the flue gases to adsorb the Hg and the PAC is collected with the fly ash. Implementation of these controls has resulted in a 70% capture rate in Hg emissions as required by the Regulation.
The Regulation also required the method of estimating Hg emissions from coal-fired generating station to change from mass balance (monitoring Hg concentration in the combusted coal and flyash, and calculating Hg emissions by the difference) in 2008 to Continuous Emissions Monitoring System (direct measurement of flue gas Hg concentration) in 2011 (except for H.R. Milner power plant).

The H.R. Milner generating station has made improvements to reduce emissions. Over the past five years, MAXIM changed operating practices to combust more natural gas thus reducing emissions. In 2009, a Selective Non Catalytic Reduction (SNCR) system was installed on the unit. Co-firing natural gas results in reduction in the emissions of all the priority substances and the SNCR system has resulted in a greater than 25% reduction in NO_X emissions from the station.

5.3. Emissions Control Research

The electricity sector and related associations continue to research emission control technologies. Some examples are presented below.

Between 2006 and 2010, the Canadian Clean Power Coalition performed a Front End Engineering Design (FEED) study for an approximately 240 MW net Integrated Gasification Combined Cycle facility with CO_2 capture. This study was aimed at discovering the true cost and viability of such a facility, which potentially would be built at the existing Genesee Generating Station in Alberta. The design target was to capture over 85% of the CO_2 from the unit and significantly reduce other criteria air emissions.

Project Pioneer investigated a fully integrated CO_2 capture and storage (CCS) project designed to capture one million tonnes annually of CO_2 from Keephills Unit 3 and transport the CO_2 by two pipelines: one for use in enhanced oil recovery, and the other to deep saline formations for permanent storage. The CCS process, including the chilled ammonia process, would cool and clean the flue gas, absorb and separate the CO_2 stream, compress the CO_2, cool it and convert the gas to a supercritical liquid phase suitable for pipeline transportation and storage. Following the conclusion of the FEED study, the industry partners determined that, although the technology works and capital costs were in-line with expectations, the market for carbon sales and the price of emissions reductions were insufficient to allow the project to precede.

The Canadian Clean Power Coalition considers biomass co-firing as potential way to reduce the CO_2 emissions from coal plants since biomass is generally considered a carbon neutral fuel. The Canadian Clean Power Coalition commissioned two studies related to biomass co-firing. The objective of the first study was to determine the maximum size of biomass particle that could be successfully combusted in a coal plant and to identify how co-firing with biomass will affect the operation of the plant including thermal efficiency, carbon burnout, slagging and fouling. The second study objective was to characterize several fuels and determine the operating consequences and capital cost of firing these fuels in six co-firing configurations. When used as a supplemental fuel in an existing coal-fired boiler, biomass can provide the following benefits: lower fuel costs, more fuel flexibility, reduced waste to landfills, reductions in NO_X, SO_2 and CO_2 emissions and a decrease in opacity. The study authors concluded that to comply with the end-of-useful-life greenhouse gas emission intensity standard in the Canada *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations*, 60% Biomass co-firing will be required; however marginal costs are prohibitive and firing at this rate is not possible for some of the biomass types tested.

6. PROPOSED ACTIVITIES 2014 TO 2018

6.1. Proposed New Generation

The Alberta Electric System Operator (AESO) has forecast that by 2023 electricity demand will increase by 39% above 2013 levels. To provide for the increased electricity demand, the generation developers have applied to the Alberta Utilities Commission for the following new generation projects:

- ATCO Power, Heartland Generating Station, a nominal 413 MW natural gas combined cycle plant equipped with SCR for NOx abatement
- Bowark Energy Ltd., Queenstown Power Plant, 92 MW simple cycle natural gasfired peaking power plant
- Capital Power, Genesee Units 4 and 5, a 1050 MW natural gas combined cycle plant equipped with SCR for NOx abatement
- City of Medicine Hat, Cousins West, 43 MW simple cycle natural gas-fired power plant
- E.on Climate and Renewables Canada Ltd., Grizzly Bear Creek Wind Power Project, 120 MW wind power plant SW of Vermilion

- Enbridge Inc., Whitetail Peaking Station, a 186 MW natural gas simple cycle peaking facility
- Enel Alberta Wind Inc. Riverview Wind Power Plant, 115 MW
- Imperial Oil, Strathcona Refinery cogeneration power plant, 41 MW
- Maxim Power Corp, Deerland Power Plant, a 190 MW simple cycle natural gaspeaking facility
- Maxim Power Corp, M2 Power Plant, a 520 MW natural gas combined cycle plant with SCR for NOx abatement
- Maxim Power Corp, M3 Power Plant, two natural gas-fired cogeneration units totaling 86 MW
- Renewable Energy Services Ltd. McLaughlin Wind Project, 60 MW
- Shell Canada Limited, Jackpine Mine Expansion, 115 MW cogeneration plant
- Shell Canada Limited, Pierre River Mine, 85 MW natural gas-fired cogeneration plant and 115 MW asphaltene-fired cogeneration plant
- Suncor Energy Products Inc., Hand Hills Wind Power Project, 80 MW
- Syncrude Canada Ltd., Mildred Lake, 92 MW cogeneration
- Taylor Processing Inc., Harmattan Gas Plant expansion to include a third 15 MW cogeneration unit
- Total E&P Joslyn Ltd., a 85 MW natural gas-fired cogeneration plant
- TransAlta Midamerican Partnership, Sundance 7, a 856 MW natural gas combined cycle plant with SCR for NOx abatement

The 800 MW Shepard Energy Centre, scheduled to be commissioned in early 2015, is a combined cycle facility that consists of two 240 MW state-of-the-art high efficiency Gclass natural gas-fired turbines and one 320 MW steam turbine. The facility will use an advanced emissions technology that includes a SCR unit that will reduce the concentration of NO_X to 3 parts per million and will generate less than half the CO_2 emission per megawatt than a conventional coal-fired plant.

6.2. Generation and Transmission Outlook

The Alberta Electric System Operator (AESO) publishes a Long-term Transmission Plan (LTP) annually. The Plan is the AESO's vision of how Alberta's electric transmission system needs to be developed to secure continued provincial economic growth over the next 20 years. The AESO uses a needs assessment process to identify projects over the near-term, medium term and long term. The 2013 LTP Plan forecasts generation and transmission needs to 2032.

Page 10, AESO 2013 LTP - *The projects identified in the 2013 LTP will help deliver the power Albertans need, facilitate the reliability of the provincial transmission system, and improve the efficiency of the transmission system. At the same time, transmission projects will remove existing transmission constraints on generation of all forms, including renewable sources such as wind, hydro and biomass, as well as intertie capacity.*

A more efficient transmission system delivers energy to consumers with less transmission line losses, and ultimately lower emissions.

The AESO 2014 Long Term Outlook (LTO) forecasts that the future generation mix in Alberta will shift, with baseload coal being replaced by natural gas, primarily combined cycle and cogenerations facilities, and renewable such as wind and biomass. The 2014 LTO forecasts that by 2034 Alberta's installed capacity will be 72% natural gas, 18% renewables and 10% coal-fired.

6.3. Regulatory Influences

Following are some examples of regulatory initiatives that could impact emissions in the foreseeable future.

The *Alberta Mercury Emissions from Coal-Fired Power Plants Regulation* required operators of coal-fired units to submit a proposal by January 2013 to optimize the Hg control programs. Implementation of the optimization programs will further decrease Hg emissions from Alberta coal-fired generating units.

The Government of Canada *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations*, that comes in to force on July 1, 2015, requires coal-fired generating units at or before 50 years of age to either meet a CO_2 emission performance standard of 420 tonnes CO_2/GWh, fuel switch, or close. It is anticipated that these regulations will result in substantial priority emission reductions due to the closure of coal-fired generating units.

Alberta's current GHG regulation is the Alberta Specified Gas Emitter Regulation (SGER) enacted in 2007. The Regulation expires at the end of 2014 and is currently under review. The regulation is expected to be renewed but any changes to it and alignment to federal policy initiatives are unknown at the time of writing. Changes could potentially impact priority emissions from the electricity sector.

The Government of Canada is currently contemplating development of standards for gas turbine CO_2 and NO_X emissions that may affect the emission levels of other priority substances or how the generating units operate. SO_2 and NO_X emissions reductions requirements for coal-fired generating units are also under consideration by Environment Canada.

The Government of Alberta is implementing the Water for Life Strategy as a vehicle for managing Alberta's water resources. One of the outcomes of the strategy is for all sectors to demonstrate best management practices to ensure the overall efficiency and productivity of water use in Alberta improves by 30% from 2005 levels by 2015. Potential future water constraints may impact the type of emission control technologies available to the electricity sector, as some emission control technologies can consume large quantities of water.

7. CONCLUSION

Since 2008, the Alberta electricity sector has seen a 10% increase in generation and emissions reduction in the five CASA priority substances (reductions: 14% NO_X, 14% SO_2, 43% Hg, 20% PM and 11% CO_2). Reduced operation of higher emitting units, retirements of older units, additions of new low emitting generation, regulatory influences and the emissions reduction efforts taken by electricity sector participants, have contributed to achieving the substantial emissions reductions. Improvements to the provincial transmission system also contribute to emissions reductions by improving efficiency and reducing losses on the transmission system. Going forward, the trend towards replacing older generation with new lower-emitting generation and planned regulatory initiatives are expected to continue and will result in lower emissions of priority substances, even with generation growth.

APPENDIX 1: GENERATING UNIT ADDITIONS AND RETIREMENTS

Table 4 Generation Additions Since 2009 [viii]

Developer/Project	Year Online	Capacity (MW)	Type
TransAlta Sundance #5 expansion	2009	53	Coal, conventional
MEG Christina Lake #1	2009	94	Cogen, natural gas
ATCO Power Scotford expansion	2009	15	Cogen, natural gas
ATCO Power Muskeg River upgrade	2009	2	Cogen, natural gas
EPCOR Clover Bar #2	2009	101	Natural Gas
EPCOR Clover Bar #3	2009	101	Natural Gas
City of Medicine Hat #15	2009	42	Natural Gas
Enmax Crossfield #1	2009	40	Natural Gas
Enmax Crossfield #2	2009	40	Natural Gas
Enmax Crossfield #3	2009	40	Natural Gas
TransAlta Blue Trail Wind Farm	2009	66	Wind
Nexen Long Lake expansion	2010	40	Cogen, natural gas
AltaGas Harmattan	2010	15	Cogen, natural gas
Connacher	2010	13	Cogen, natural gas
Finavera Ghost Pine Wind Farm	2010	82	Wind
TransAlta Summerview #2	2010	66	Wind
TransAlta Ardenville Wind Farm	2010	66	Wind
TransAlta/Capital Power Keephills #3	2011	450	Coal, supercritical
Weyerhaeuser Canada Grande Prairie Pulp Mill	2011	48	Cogen, biomass
Daishowa-Marubeni Peace River Pulp	2011	25	Cogen, biomass
University of Calgary	2011	15	Cogen, natural gas
BC Hydro Fort Nelson upgrade	2011	33	Natural Gas
Shell Canada Scotford Industrial Expansion	2011	18	Natural Gas
Suncor Wintering Hills	2011	88	Wind
TransAlta Keephills #2 Expansion	2012	19	Coal, conventional
TransAlta Keephills #1 Expansion	2012	19	Coal, conventional
Alberta Pacific Forest Industries Al-Pac Pulp Mill	2012	30	Cogen, biomass
Suncor Firebag Stage 3	2012	170	Cogen, natural gas
Suncor Firebag 4	2012	160	Cogen, natural gas
Southern Pacific McKay River	2012	17	Cogen, natural gas
AltaGas Harmattan	2012	15	Cogen, natural gas
BC Hydro Fort Nelson Expansion	2012	33	Natural Gas
Capital Power Halkirk	2012	150	Wind
Enel Castle Rock Wind Farm	2012	77	Wind
ECB Enviro Lethbridge	2013	4	Biomass
MEG Christina Lake 2B	2013	85	Cogen, natural gas
NRGreen Windfall Station	2013	16	Cogen, natural gas

Table 5 Generation Decommissioned Since 2009 [ix]

Facility	Gross Capacity (MW)	Type	Decommission Date
Rossdale Units 8, 9 & 10	203 37	Natural Gas	2009
City of Medicine Hat Units 5 & 8	279	Natural Gas	2009
Wabamun Unit 4	33	Coal	2010 2011
Grande Prairie Pulp Mill		Biomass	

APPENDIX 2: ABBREVIATIONS

AESO Alberta Electric System Operator
AESRD Alberta Environment and Sustainable Resource Development
AIES Alberta Integrated Electrical System
AUC Alberta Utilities Commission
CASA Alberta Clean Air Strategic Alliance
CCS Carbon capture and storage
CEMS Continuous emissions monitoring system
CH_4 Methane
CO_2 Carbon dioxide CO_2e Carbon
dioxide equivalent DLE Dry
low NO_X emissions
EGDF Electricity Grid Displacement Factor
EGIF Electricity Grid Intensity Factor
GHG Greenhouse gases GWh
Gigawatt-hour Hg Mercury
kg Kilogram
N_2O Nitrous oxide
NAICS North American Industry Classification System
NO_X Nitrogen oxides
NPRI National Pollution Release Inventory
MW Megawatt
MWe Megawatts electricity MWh
Megawatt-hour
MWnet Megawatts net
PAC Powdered activated carbon
PM Particulate matter
SAGD Steam-assisted gravity drainage
SCR Selective catalytic reduction
SNCR Selective non catalytic reduction
SO_2 Sulphur dioxide
TWh Terawatt-hour

References:

[i]Environment Canada; National Pollutant Release Inventory available at http://www.ec.gc.ca/inrpnpri/Default.asp?lang=En&n=4A577BB9-1.

The data was sorted by substance, Alberta, NAICS code Fossil-fuel Electric Power Generation (221112), and total releases to air.

ii Environment Canada; Greenhouse Gas Emissions in Canada available at http://www.ec.gc.ca/gesghg/default.asp?lang=En&n=1357A041-1.

GHG emissions data was obtained from Environment Canada's reported facility GHG emissions online data search by sorting for Alberta and NAICS code 221112.

iii AUC, Alberta Electric Energy Net Installed Capacity by Resource; available at http://www.auc.ab.ca/market-oversight/Annual-Electricity-Data-Collection/Pages/default.aspx.

iv AUC Alberta Electric Energy Generation (GWh) by Resource and Interchange; available at http://www.auc.ab.ca/market-oversight/Annual-Electricity-Data-Collection/Pages/default.aspx.

v AESO Long Term Outlook; available at http://www.aeso.ca/downloads/AESO_2014_Longterm_Outlook.pdf.

vi Alberta Energy, available at www.energy.alberta.ca/Electricity/pdfs/generation_since_1998.xlsx.pdf .

vii Alberta Energy; available at http://www.energy.alberta.ca/Electricity/682.asp

viii Alberta Energy; available at http://www.energy.alberta.ca/Electricity/pdfs/generation_since_1998.xlsx.pdf.

ix Alberta Energy; available at http://www.energy.alberta.ca/Electricity/682.asp.

Appendix C: ENGO Position and Proposal on NOx Emission Limits for Gas-Fired Generation Units, April 7, 2015

Background – A fundamental principle of the CASA Electricity Framework (EF) is that new generation units, and generation units at the end of a defined operating life period, will meet emission limits that are based on the application of best available technology economically achievable (BATEA). In the 1st 5-year of the EF there were two separate consultant reviews (ERG and Jacobs Consultancy) that looked at BATEA for gas-fired generation and both indicated that for larger gas fired units, i.e. greater than approximately 60-75MW, selective catalytic reduction (SCR) represented BATEA. Despite these findings consensus could not be reached in the 1st 5 year review that SCR-based limits should apply to co-generation units which are used in a number of industrial applications, particularly oil sands developments. SCR-based limits were proposed for combined cycle units.

The non-consensus on this issue resulted in the 1st 5-year review having two proposals for NOx limits for gas-fired units. One referred to as "Option A" was based on the application of SCR and was supported by the utility sector, NGOs and government. The other proposal was referred to as "Option B" was supported by CAPP and the Petroleum and Chemical sectors. These options were provided to government but no decision was made on what limits would apply to gas-fired units and a piecemeal approach to setting limits for gas-fired units currently exists. The ENGOs understand that the current absence of a "level playing field" with respect to regulatory requirements for gas-fired units has had some influence on the positions taken in the current 2nd 5-year review of the EF regarding emission limits for gas-fired units.

2nd (current) 5-year Control Technology Reduction Strategy (CTRS) Review - The ENGO's were an active participant on the 2nd 5-year CTRS Task Group. A contractor was again retained to determine BATEA limits for gas-fired generation units which confirmed that for all but the smallest gas-fired units (i.e. less than approximately 50 MW) BATEA was SCR. Early in the CTRS it became apparent that consensus on at least NOx limits for co-generation units would not be reached as CAPP was not prepared to consider SCR based controls for the types and sizes of co-generation units generally used in oil sands application (approximately 75 to 125 MW with 33-40+% duct firing for steam generation). One of the arguments given for this position was that co-generation units are very efficient and should be encouraged and SCR control requirements may discourage co-generation. Another argument was that the principle product of co-generation units is steam with electricity as a useful byproduct and therefore co-generation should be treated differently than combined cycle gas-fired generation units.

The ENGOs explored both of these issues and determined that:

- a combination of combined cycle (CC) power generation and boilers producing the same amount of power and heat as a co-generation unit are just as energy efficient; and
- such a combination produces approximately half the NOx emissions as a co-generation unit based on the application of dry low NOx controls.

This information was shared with the CTRS Task Group and no contrary information was provided by industry. Based on this information ENGOs concluded there is no inherent energy efficiency benefit to co-generation and, from a NOx emission perspective, there is a significant disadvantage to co-generation, unless SCR-based controls are applied.

In an attempt to achieve consensus, efforts were made to identify NOx emission management approaches and limits that addressed all interests. The ENGOs proposed a number of "straw-dog" options for NOx emissions controls for gas-fired units which allowed for some flexibility to use dry low NOx (DLN)/ultra dry low NOx (UDLN) controls in the 75-100 MW co-generation range. A major issue for CAPP was NOx limits for co-generation units in the 75 to 200 MW size range and consensus could not be reached on limits for this large size range of units. Co-generation units in this size range are major NOx emitters compared to single and combined cycle gas-fired units. For combined cycle units the utility sector also proposed NOx limits that did not reflect BATEA based controls.

Of particular concern to ENGOs was that the USEPA requires BACT (best available control technology) reviews for steam turbine, combined cycle and co-generation units greater than 250 MMBTU/h heat input in size (approx. 73 MW heat input) that emit greater than 100 t/y of NOx. These BACT reviews almost always result, as noted above, in units greater than 50 to 75 MW in size having SCR-based limits. However the emission proposal by industry for combined cycle and co-generation units would have NOx emissions ranging from 121 to 809 tonnes/y before SCR based NOx limits would apply. With SCR based limits these emission levels would be approximately 36.3 to 243 tonnes/yr. For other generation units, e.g. single cycle gas turbines, the USEPA has a 250 t/y NOx trigger for BACT reviews which results in less stringent requirements for these units on a power output basis but as noted below the ENGOs support the approach proposed to set limits for peaking unit.

These very significant levels of NOx emissions, without the application of BATEA level controls as determined by three independent consultants, were unacceptable to ENGOs and resulted in the inability to reach a consensus on NOx limits for gas-fired units. ENGOs would note that they offered options for units in the 75-175 MW size range involving caps or DLN performance targets in conjunction with industry-proposed compliance limits but industry indicated that its proposal was final. The final issue of concern for ENGOs was that the final 2015 industry proposal is much less stringent than the Option "A" proposal that the utility sector offered and agreed to (along with ENGOs and Government) in 2010.

These issues are discussed further as part of the following ENGO review of the industry proposal and ENGO proposal.

ENGO Commentary on Industry Proposal:

Non-peaking Units: Table 1 shows the industry proposal for non-peaking gas-fired units. These limits are not intensity based limits (see footnote to Table) and as such are not final limits but rather a means to final emission limits. Industry did not provide an indication of how it would convert these proposed input limits into output intensity based limits.

Table 1: Industry's Proposed NOx limits for Non Peaking Standard (Combined Cycle & Cogeneration)

NOx (kg/h) = [Net Electricity Generation (MWh net) x "A" + Heat output * "B"]

Power Rating (per gas turbine only)	**"A" Factor (kg/MWh)***	**"B" Factor [Heat recovery allowance] (g/GJin)**
Less or Equal 70 MW	based on dry low-NOx (25 ppm)	34
More than 70 MW and Less or Equal 100 MW	based on dry low-NOx (15 ppm)	34
More than 100 MW and Less or Equal 200 MW	based on ultra dry low-NOx (12 ppm)	34
More than 200 MW	based on SCR (7-9 ppm)	10 assuming that SCR removal efficiency is 70%

*Indicates level of emissions performance only. Determining Emissions Intensity (kg/MWh) requires further discussion by CASA working group

The final industry proposal for NOx limits for non-peaking gas-fired units could not be accepted by the ENGOs as they do not reflect the application of BATEA for a number of unit types and sizes. These proposed industry limits for combined cycle and co-generation units are also considerably less stringent than the Option "A" limits proposed in the 2010 "*Report on the First Five-Year Review of the Emissions Management Framework for the Alberta Electricity Sector*" which the NGO sectors, all government sectors, and the utilities sector agreed to. The chemical manufacturers sector, the petroleum products sector, and the oil and gas sector did not support Option "A" and proposed an alternate option (Option "B"). ENGOs would note that the 2010 Option "B" was slightly more stringent for combined cycle units in the 75-100 MW range than the 2015 industry proposal but is more stringent for co-generation units by about 25-30% but still much less stringent than the Option "A" limits. A comparison of the two 2010 emission limit proposals compared to the 2015 industry proposal is presented in Table 2.

Table 2: NOx emission (kg/h) comparison 2010 Option "A" and Option "B" Proposals vs 2015 Industry Proposal				
Unit size (MW)	Unit Type	Option "A" NOx emissions (kg/h) (2010 proposal agreed to by ENGOs, Gov't and Utility Sector)	2015 Industry Proposed NOx Emissions (kg/h)	Option "B" Proposal (CAPP, Petroleum and Chemical Sectors) from 2010 Review (kg/h)
75	Combined Cycle	6.8	13.8	13.5
100	Combined Cycle	9.0	18.4	18.0
150	Combined Cycle	13.5	22.0	27.0
200	Combined Cycle	18.0	29.4	36.0
250	Combined Cycle	22.5	24.5	45.0
300	Combined Cycle	27.0	29.4	54.0
75	Co-gen	14.9	34.6	45.9
100	Co-gen	19.8	46.2	61.2
150	Co-gen	29.7	69.3	91.8
200	Co-gen	39.6	92.4	122.4
250	Co-gen	49.5	50.6	153
300	Co-gen	59.4	60.7	183.6
Assumptions: Efficiency of a combined cycle unit is 50%. Duct firing in co-gen units accounts for 33% of total unit energy input. The efficiency of duct firing is 200% i.e. energy output of DB is 2x energy input (this appears to be a typical # and is the result of energy capture in the duct burner from the hot gas from the GT). 1 ppm of NOx in GT exhaust gas = 1.7 g NOx/GJin at 15% O2. "B" factor does not apply to combined cycle units as per CCME 1992 "National Emission Guidelines for Stationary Combustion Turbines". For 2015 industry proposal the GT NOX limit for units >200MW was specified at 7-9 ppm and for the emission comparison 8 ppm was used.				

The industry proposal therefore represents a "retrograde" step in terms of NOx management relative to the "Option A" proposal from the 2010 EFR review which the utility sector supported at the time. Industry did not provide any justification for this relaxation in proposed NOx limits for combined cycle units (as compared to 2010 proposed limits) nor did they provide any rationale as to why or how the proposed 2015 limits represented BATEA controls. This position backslide on the part of the Utility Sector contravenes the principle of continuous improvement and the BATEA approach that underlies the CASA five-year review approach, which contemplates improved actions over time (Recommendation 29). Combined with the BATEA approach to standard setting, the overall framework posits the continuous improvement of BATEA-level technology over time. ENGOs are unable to square these overall CASA EF principles/concepts with this backslide in positions.

Peaking Units: The industry proposal for NOx emission limits for peaking units are shown in Table 3.

Table 3: Industry's Proposed Peaking Unit NOx Standard

NOx (kg/h) = [Net Electricity Generation (MWh net) x "A"]

Power Rating (per gas turbine only)	**"A" Factor (kg/MWh)***	**Peaking Standard**[1]
Less or Equal 25 MW	based on dry low-NOx (25 ppm)	750 kg/MW
More than 25 and Less or Equal 100 MW	based on dry low-NOx (25 ppm)	600 kg/MW
More than 100 MW and Less or Equal 200 MW	based on ultra dry low-NOx (12 ppm)	300 kg/MW
More than 200 MW	based on SCR (7-9 ppm)	165 – 210 kg/MW

*Indicates level of emissions performance only. Determining Emissions Intensity (kg/MWh) requires further discussion by CASA working group

The current industry proposal for peaking units as noted above is considered reasonable for peaking units and has a cap on emissions which limits the hours a unit can run unless it performs better than its emission limit. The "A" factor is however considered too high for units > 200MW in size and should be based on NOx levels (input based) in the 4-6ppm range which is easily achieved with SCR however an allowance for start-up and shutdown conditions would need to be made.

ENGO Proposal:

Non-Peaking Units - The ENGO's are proposing emission limits for non-peaking gas-fired units be based on the 2010 Option "A" limits with three modifications. The first modification would be to align with the size ranges in the 2015 industry proposal for non-peaking units which is in part based on the recent CCME initiative related to Base Level Industrial Emission Requirements (BLIERs) for Gas Turbines. These draft BLIERs differentiated between 70MW and >70MW units and this is considered reasonable in terms of a size cut-off for establishing different NOx emission limits based on BATEA considerations, i.e. DLN for units of 70MW and smaller and SCR-based limits for units >70MW. The second modification would be to make the "A" factor for 70MW and small units 0.5 kg NOx/MWh net consistent with what the ENGOs' understand was a consensus BLIER for new non-peaking combustion turbine units. The final modification is to increase the heat allowance for 70MW and smaller units to reflect standard DLN duct burner NOx control technology which is the basis for the emission limits for units in this size range.

The ENGOs' proposed Option "A" limits with the above noted modifications are shown in Table 4.

[1] Under Recommendation 11 in the CASA Framework, the emissions cap for NOx for peaking gas-fired units is based on the following formula: (peaking unit BATEA intensity level of the day) * (Maximum Capacity Rating in MW) * (1500 hours).

It is the ENGOs' understanding that the Government also supports Option "A". There was some discussion on the basis for Option "A" factor of 0.09 kg NOx/MWh net. It is the ENGOs' understanding that this factor was based on SCR-based NOx emission limits which, depending on the NOx emission rate used (normally be in the 2-6 ppm range (energy input based)) and the unit's energy efficiency (say in the 40 to 50% range) would translate to a value in the general range of 0.09 kg NOx/MWh net. ENGOs would note that the "A" limit is not overly stringent in terms of an SCR-based limit in that for a 50% efficient CC unit the "A" factor translates to a ppm limit of 7.4 which is easily achievable with SCR technology. However an allowance needs to be made for start-up and shutdown of units.

The CTRS Task Group did not progress to the point of discussing design life and credit generation for new gas-fired units. The ENGO proposal is that the end of design life for gas units continue to be 30 years after which credits can be used to meet the BATEA NOx emission of the day for a maximum of an additional 10 years after which the unit must meet the BATEA NOx emission limits of the day. In terms of NOx credit generation it is recommended that the NOx credit emission intensity for new gas-fired units be 0.075 kg NOx/MWh net for the "A" factor for units >70MW and 0.3 kg NOx/MWh net for the "A" factor for units 70MW and smaller (this is based on a 15 ppm NOx gas turbine). It is recommended that the credit threshold for the "B" factor for heat recovery be 0.07 kg NOx/GJ out for units >70MW and 0.14 kg NOx/GJ out for the "B" factor for units 70MW and smaller. These credit thresholds are based on incenting better than normal/basic control technology selection and operation.

Table 4: Option "A" from 2010 EFR with Modifications (The ENGO Proposal for Non-Peaking Gas-fired Generation Units)

Non Peaking Standard Formula:
NOx (kg/h) = [Net Power Output (MW net) x A] + [Heat Output (GJ/h) x B]

Where:
A = Power Output Allowance – the total electricity and shaft power energy production
B = Heat Recovery Allowance – the total useful thermal energy recovered from the cogeneration / combined cycle facility
Power Output Allowance ("A")

Net Power Output (per gas turbine train)	**Non Peaking ("A")** (kg NO_x /MWh net)
Greater than 70 MW (2010 size was 25 MW)	0.09
Less than or equal to 70 MW (2010 size was 25 MW)	0.60

Heat Production Allowance "B": Natural Gas = 0.02 kg NO_x/GJ for units <=70 MW (in 2010 the limit was 0.01 kg NO_x/GJ for all units but this may have been too stringent for smaller units and may have dictated SCR controls when the application of SCR may not have been cost effective)
Heat Production Allowance "B": Natural Gas = 0.01 kg NO_x/GJ for units > 70 MW (in 2010 this applied to all units)

Peaking Units - Consensus within the utility sector could not be reached in 2010 on NOx limits for peaking units. The current industry proposal for peaking units as noted above ~~are~~ is considered reasonable. The ENGOs therefore support the industry proposal for peaking units except for units > 200MW. It is the ENGO position that an SCR limit for such units should be in the range of 4-6 ppm which is easily achievable with SCR technology.

Conclusion: The ENGO sector worked hard at finding a win-win solution on NOx limits for gas-fired generation units. Despite clear evidence that BATEA for combined cycle and co-generation units > 70MW in size was SCR, and despite ENGO efforts to give flexibility for the application of DLN technologies in the >70 to 150 MW size range, consensus could not be reached on these issues. From an ENGO perspective, its sector spent the last 2 years trying to reach consensus on NOx limits for new non-peaking gas-fired units only to have industry propose limits that, in some cases, were much less stringent than what they proposed in 2010. In particular the utility sector is now proposing limits that are much less stringent than they supported in 2010. Given how clear the objective information is on BATEA for gas-fired units at this time (and for at least five years now), this raises a concern regarding the utility sector's commitment to the intent of the Electricity Framework and the concept of BATEA based limits for new units.

The ENGO sector would note that Alberta presents itself as a leading jurisdiction in terms of pollution control requirements. Given the way in which BATEA is objectively determined, a credible statement on "leadership" requires that industry comply at least with BATEA control levels. Unless it requires the general application of SCR controls for larger i.e. >70MW combined cycle and co-generation units, Alberta cannot claim to be a leading jurisdiction in terms of NOx control for gas-fired generation units. ENGOs would also note that combined cycle and co-generation are growing forms of energy and heat production, and without good NOx controls these forms of energy production will result in unnecessary increases in provincial NOx emissions with associated air quality and health implications.

Appendix D: Industry Sector Comments on Electricity Framework Gas Turbine Standards, April 8, 2015

Industry members continue to support regulatory policy which drives additional reductions in emissions of Criteria Air Contaminants to protect health and the environment while supporting positive economic and social benefits. Good policy should be based on sound science, level of risk, cost effectiveness and should lead to air quality improvements for Albertans. In the spirit of the CASA consensus-based process, the industry members have agreed upon and put forward a proposal that will result in good emissions performance for new Gas Turbine installations while offering the required flexibility to allow efficient design.

Standards Needed for Expected Gas Turbine Growth

Gas Turbines generation is expected to grow considerably in the coming years to meet demand growth for energy and to replace coal facility retirements. The industry members believe that it is important to have standards in place to provide guidance and consistent requirements for anticipated new projects. It should also be recognized that projects already planned and seeking approvals may not be able to respond immediately to changes in new unit requirements so a transition period should be considered.

It is important to develop emission standards that recognize the unique aspects of Alberta's electricity market. Copying emission policies from other jurisdictions should be very limited because other jurisdiction may have different policy objectives or be responding to other pressures such as specific legal cases. The US EPA regulates air emissions from major sources (New Source Review "NSR") using the Prevention of Significant Deterioration (PSD) in attainment areas, and using the Lowest Achievable Emission Rate (LAER) in nonattainment areas. In order to trigger PSD permitting requirements, the proposed project must be a major stationary source or a major modification. A stationary source is any source type belonging to a list of 28 source categories that emits or has the potential to emit 100 tons per year or more of any pollutant regulated under the Federal Clean Air Act, or any other source type that emits or has the potential to emit 250 tons per year or more. If a source is determined to be major for any regulated pollutant, it is considered major for all. A stationary source generally includes all pollutant-emitting activities that belong to the same industrial grouping, are located on contiguous or adjacent properties, and are under common ownership or control[1].
In summary, peaking units will not trigger the PSD BACT assessment at 100t/y but will at 250 t/y. Regarding combined cycle units the rule seems odd, for example a peaking unit with 100 MW may not trigger the PSD because it emits less than 250 t/y; however, 100 MW combined cycle will trigger the PSD because it is above 250MMBTU/h heat input and has steam. It seems that the rule overlooks the efficiency gain of combined cycle over simple cycle. Adopting the

[1] http://www.ecfr.gov/cgi-bin/retrieveECFR?gp=&SID=f450ca152b854f3237c553df68992994&mc=true&n=pt40.3.52&r=PART&ty=HTML#se40.3.52_121

100 or 250 t/y cut off emission level needs further assessment since the EPA policy end points are not well understood.

Gas Turbine Flexibility Essential for Efficient and Low Emitting Electricity Generation

Gas turbines provide a significant benefit to the Alberta Interconnected Electrical System and to the environment. Gas Turbine configurations vary considerably and may include Simple Cycle Peaking units that can react quickly to electricity demand, augmenting base-loaded generation, Combined Cycle Gas Turbine units designed for high electrical energy efficiency, and Cogeneration units where electricity is a by-product of thermal generation yielding good overall efficiency for certain industrial applications. Equipment configurations and operating characteristics are diversified with different operating profiles (varying unit load versus steady load, frequent versus infrequent starts) and those units with heat output can produce a range of thermal energy quality from high pressure and temperature steam to hot water. These substantial differences must be recognized in standards that can embrace flexibility and allow efficient site specific design to optimize environmental performance (air pollutants, GHG and water impacts) while maximizing energy conservation and meeting economic considerations. Although standards are set for new units, consideration should also be given for End of Design Life units to ensure that emissions standards are achievable so as not to cause the premature closure of generating units because of small incremental emissions reductions. Because of the significant diversity in gas turbine applications, individual industry members can have different needs but all recognize the importance of flexible standards that promote efficient choices for all industry. This recognition has resulted in a united industry position in recommending a proposal that will result in good emissions performance while offering the flexibility to allow for the most appropriate application-specific design.

Industry Sector Recommends Flexible Standards Based on CCME Methodology

The industry proposal is consistent with current CCME requirements as well as the proposed BLIERs for NOx control from gas turbines and cogeneration units. The NOx emissions standards must have appropriate separate allowances for electricity generation and heat recovery to allow for flexible and efficient design. The industry proposal is considerably more stringent than the current gas turbine standards as recommended by CASA. The two non-consensus gas turbine standards proposed in the last electricity review improved on the original CASA standard by adopting a CCME methodology but one proposal (option A) set a heat allowance of 0.01 kg NOx/GJ_{output} that is not based on sound technical reasoning and forces SCR as the only control option. Industry members recommend that the heat allowance be set at 0.034 kg NOx/GJ_{input} which is appropriate for what current good performance can achieve for duct firing in a HRSG. The industry proposal also sets size categories for gas turbine emissions standards to recognize the different performance capabilities in the different size ranges. The gas turbine standards are based on dry low-NOx technology, ultra dry low-NOx or SCR depending on the unit size. The industry proposal recommends an approach and methodology for the gas turbine standards however, it is recognized that additional discussion is required to establish the actual gas turbine limits and how they would be applied.

Good environmental policy is more than just requiring the lowest NOx emitting technology into application at any cost. Regional Plans and hotspots provisions allow for more stringent standards as required. Under the Province's air quality management frameworks, the province can require higher levels of stringency in facility approvals if there are deteriorating air quality issues. In unstressed airsheds, focusing on the small incremental benefit of the lowest emitting NOx reduction technologies may increase costs, increase the unit heat rate (burn more fuel) and actually worsen the overall environmental impacts. Setting good performance standards that encourage efficient design and allow flexible operation will result in a better outcome.

Appendix E: Industry Proposal for Natural Gas Turbine NOx Standards, April 8, 2015

Basis

- Industry supports the 1992 CCME Guidelines.
- Separate categories are based on gas turbine capacity for non-peaking and peaking. "***peaking unit*** " means a generating unit that has an emissions cap based on 1500 hours of operation and has been declared as a peaking unit pursuant to the terms of its approval. Whether to cap actual operating hours at 1500 hours is under discussion and has not been resolved yet.
- The standards are conditional on emissions during the startups and shutdowns of SCRs or equivalent post combustion NOx reduction technology being excluded from the compliance measurement.
- Non Peaking compliance measurement based on existing Alberta Environment protocols subject to exclusions stated above.
- Standards apply to approvals for new units issued after January 1, 2017.

1. Peaking Standard

NOx (kg/h) = [Net Electricity Generation (MWh net) x A*]

Power Rating (per gas turbine only)	**Turbine Emission Limits***	**Peaking Standard**[1]
Less or Equal 25 MW	based on dry low-NOx (25 ppm)	750 kg/MW
More than 25 and Less or Equal 100 MW	based on dry low-NOx (25 ppm)	600 kg/MW
More than 100 MW and Less or Equal 200 MW	based on ultra dry low-NOx (12 ppm)	300 kg/MW
More than 200 MW	based on SCR (7 ppm)	165 kg/MW

* Converting the turbine Emission Limits to determine Emissions Intensity (kg/MWh) (A Factor) requires further discussion by CASA working group

[1] Under Recommendation 11 in the CASA Framework, the emissions cap for NOx for peaking gas-fired units is based on the following formula: (peaking unit BATEA intensity level of the day) * (Maximum Capacity Rating in MW) * (1500 hours).

2. Non Peaking Standard (Combined Cycle & Cogeneration)

NOx (kg/h) = [Net Electricity Generation (MWh net) x A* + Heat input * B]

Power Rating (per gas turbine only)	**Turbine Emission Limits***	**B Factor [Heat recovery allowance] (g/GJ_{input})**
Less or Equal 70 MW	based on dry low-NOx (25 ppm)	34
More than 70 MW and Less or Equal 100 MW	based on dry low-NOx (15 ppm)	34
More than 100 MW and Less or Equal 200 MW	based on ultra dry low-NOx (12 ppm)	34
More than 200 MW	based on SCR (7-9 ppm)	10 assuming that SCR removal efficiency is 70%

**Indicates level of emissions performance only. Converting the turbine Emission Limits to Determine Emissions Intensity (kg/MWh) (A Factor) requires further discussion by CASA working group.