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

June 10, 2009
(Amended September 2010)

Amendment, September 2010:
In June 2009, the CASA Board reviewed the non-consensus issues regarding gas-fired non-peaking units, as presented in this report. The board directed the Electricity Framework Review (EFR) project team to continue to work to resolve the issue of choice of BATEA and a corresponding source standard for non-peaking units, noting that all involved stakeholders need to participate, and all options will be on the table. Please refer to the Report on the First Five-Year Review of the Emissions Management Framework for the Alberta Electricity Sector, May 13, 2010 *for full details on the project team's discussions further to the information in this report. The project team reported back to the CASA board in March 2010 that they were unable to reach consensus on this issue. The board agreed to forward the issue to the appropriate Government of Alberta Ministers for a final decision. When finalized, the decision of the Minister/s will be available upon request from CASA and will be posted on the CASA website.*

Contents

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

As part of the five year review initiated in 2008, a multi-stakeholder Control Technologies and Reduction Strategies (CTRS) Task Group was established to:

- Collect and review relevant information on emissions as per recommendation 34 (Emissions Growth Review Trigger)
- Review technologies to identify the Best Available Technology Economically Achievable (BATEA) appropriate for Alberta's electricity sector, including aspects such as generation, combustion efficiency, control technology, monitoring methodologies and air emission characteristics.
- Identify the BATEA emission limit standards and corresponding deemed credit threshold for new electric power plants, which will be effective for plants approved after January 1, 2011. These standards are also expected to apply to existing facilities at the end of their design life as defined in the framework.
- Determine whether BATEA emission limit standards need to be set for other fuel types (including synthetic gas, bitumen etc.) and if so, what these standards will be.

The CTRS group retained two consultants to assist with its work. One consultant undertook an update of 2003 Emissions Forecast and the other provided a review of emission control technologies and advice on BATEA and related performance limits for certain generation and fuel types.

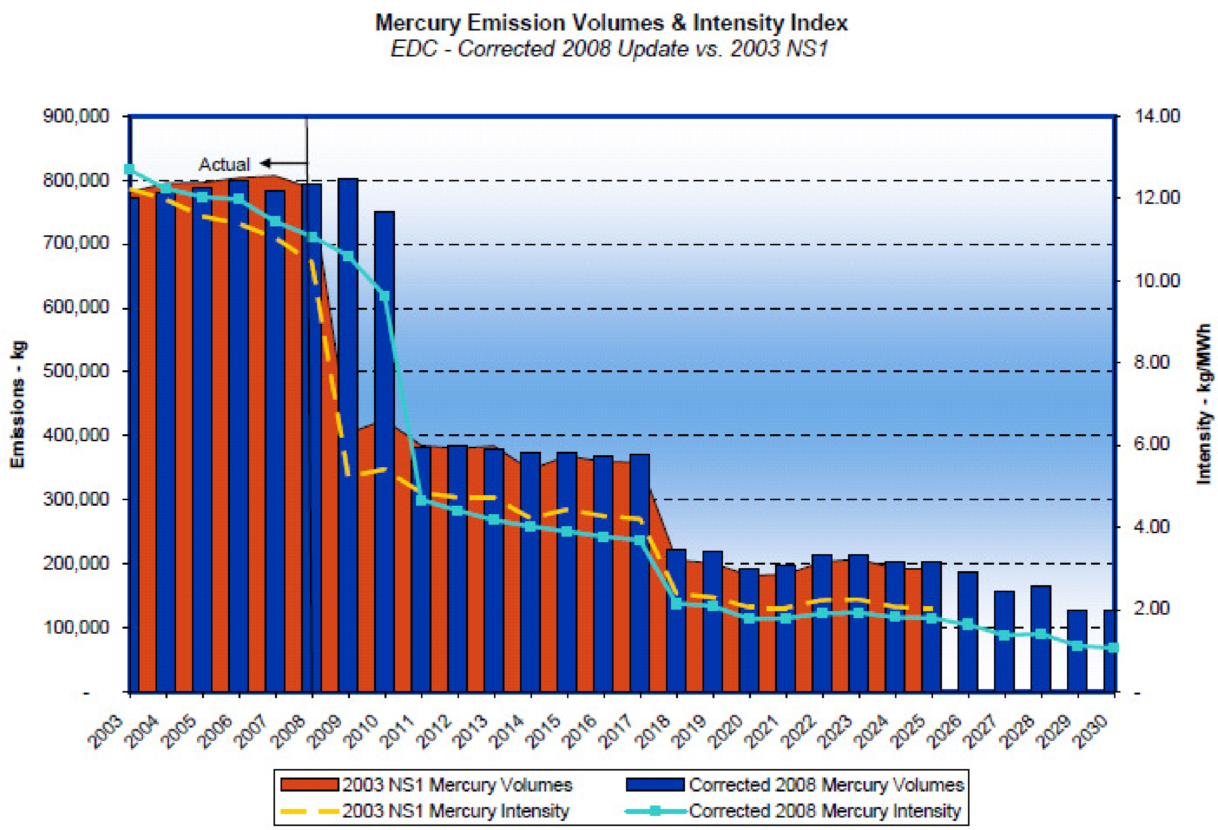
2 Summary of Generation and Emission Forecasts
The Emissions Forecast was an important tool in the development of the 2003 Framework, as it allowed the project team to project the impact of the framework on emission reductions over time (for Nitrogen Oxides, Sulphur Dioxide, Particulate Matter and Mercury).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

The emission forecast encompasses the next 20 + years, until 2030, as it was recognized that the majority of emission reduction actions will be taken within that timeframe.

Amendment, September 2010:
Several adjustments were made to the 2008 forecast results that were necessary to incorporate new information as well as correct for some formulaic errors that existed in the original 2008 emission level and intensity forecast results. These adjustments had a material effect on both historical and forecast emission levels and intensity calculations. CASA requested EDC attach an Appendix to their document entitled Electricity Framework 5 Year Review – Generation and Emissions Forecasts, July 9, 2009*, summarizing the corrections and showing the corrected 2008 data. The data presented in this report reflects the corrected 2008 data.*

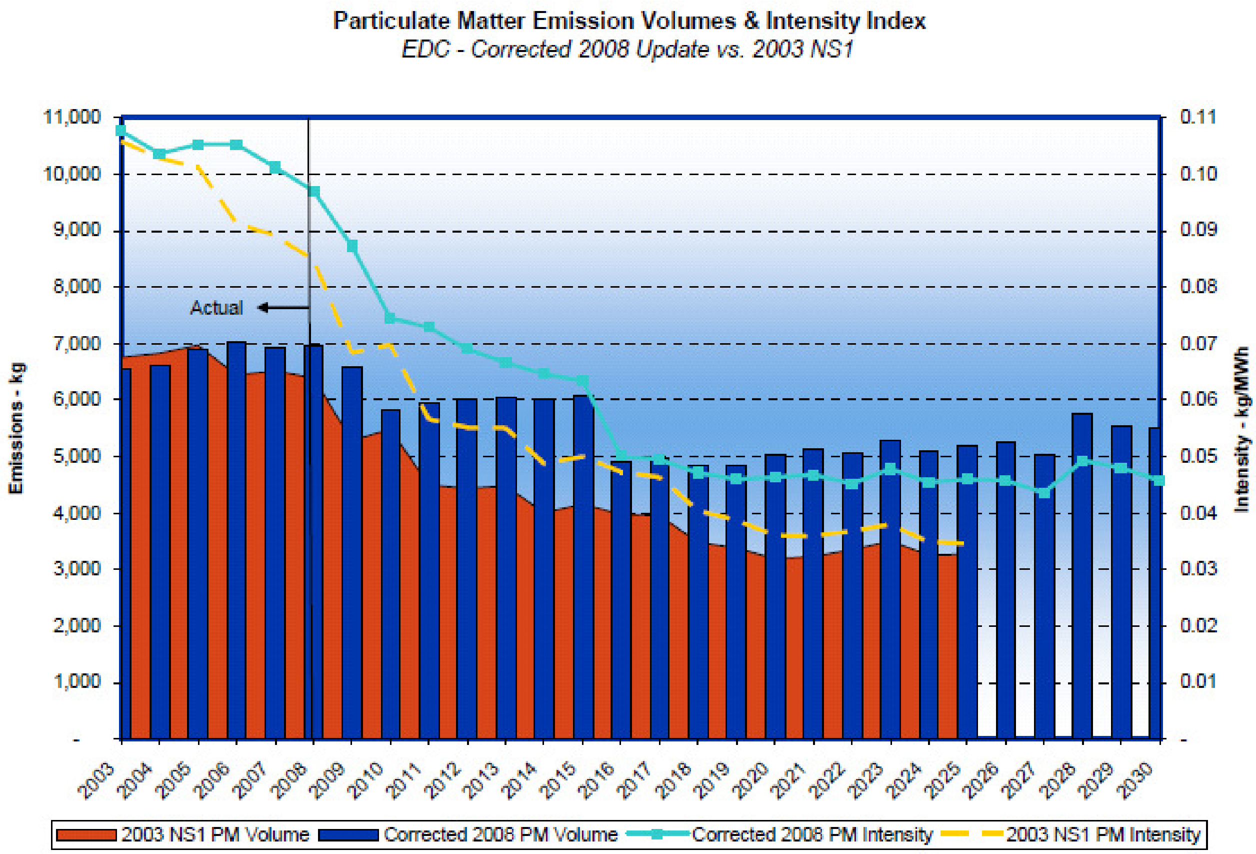
2.1. 2008 Generation and Emissions Forecast

2.1.1. Mercury Emissions



Overall, absolute mercury emissions levels have not changed significantly from the 2003 report, with the exception of a shift of the regulation implementation date from the end of 2009 to the beginning of 2011. Total mercury emissions and intensities are expected to decrease by an average of 4% each year from 2009 to 2030. These nominal changes in emissions result from changing retirement assumptions and some additional new coal-fired generation included in the updated forecast.

2.1.2. Particulate Matter Emissions

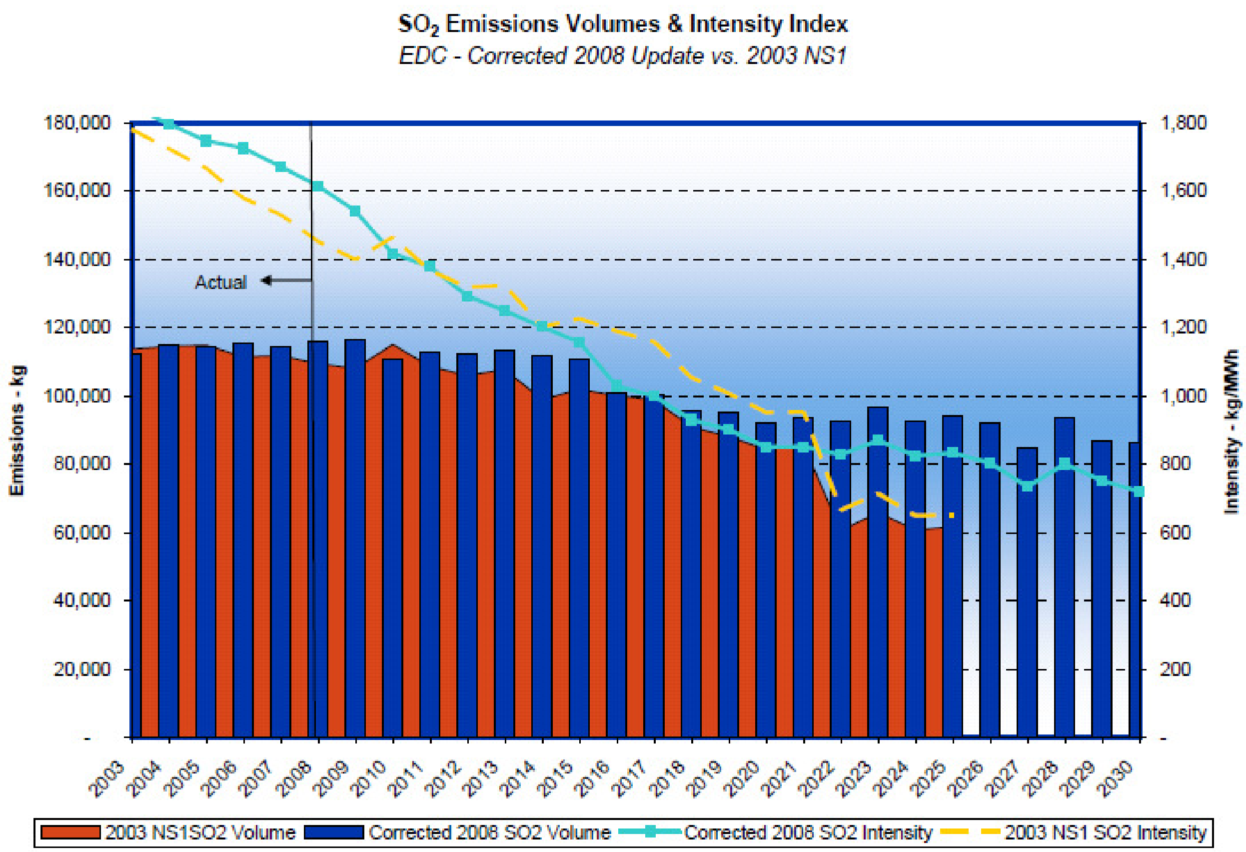


Absolute particulate matter emissions follow a similar trend as in the 2003 forecast but are considerably higher in the 2008 forecast. This is principally the result of the change in mercury control technology development from what was assumed in 2003. In 2003, it was anticipated that the application of mercury control technology would include activated carbon and compact bag houses (COHPAC), which was expected to have the co-benefit of reducing particulate matter emissions. However, the initial challenges with the development of COHPAC technology were not overcome and it was found that advanced sorbent technology can achieve the required mercury capture rate with existing particulate control technology (electrostatic precipitators). Therefore, the use of enhanced activated carbon sorbents and electrostatic precipitators became the preferred technology for mercury removal.

The 2008 forecast also indicated an increase in coal-fired generation compared to the 2003 forecast, particularly in the post 2017 period. The 2003 forecast assumed that coal production would be replaced by increased production using natural gas, but this is not the case in the 2008 forecast. The increase in coal capacity has added to the forecasted absolute increase in particulate emission levels in the current emissions forecast. Particulate matter intensity levels across the forecast period have remained relatively flat when compared to the 2003 forecast. The difference in trends in the emissions intensity versus absolute emissions is primarily a result of additional renewable energy included in the 2008 forecast which increases total generation without impacting absolute emissions. The result is that emission intensity does not increase to the same degree as absolute emissions.

Total PM emissions are expected to decrease by an average of 1% in each year from 2009 to 2030. By 2030, the PM emission intensity is forecast to decline by an average of 2% each year of the forecast.

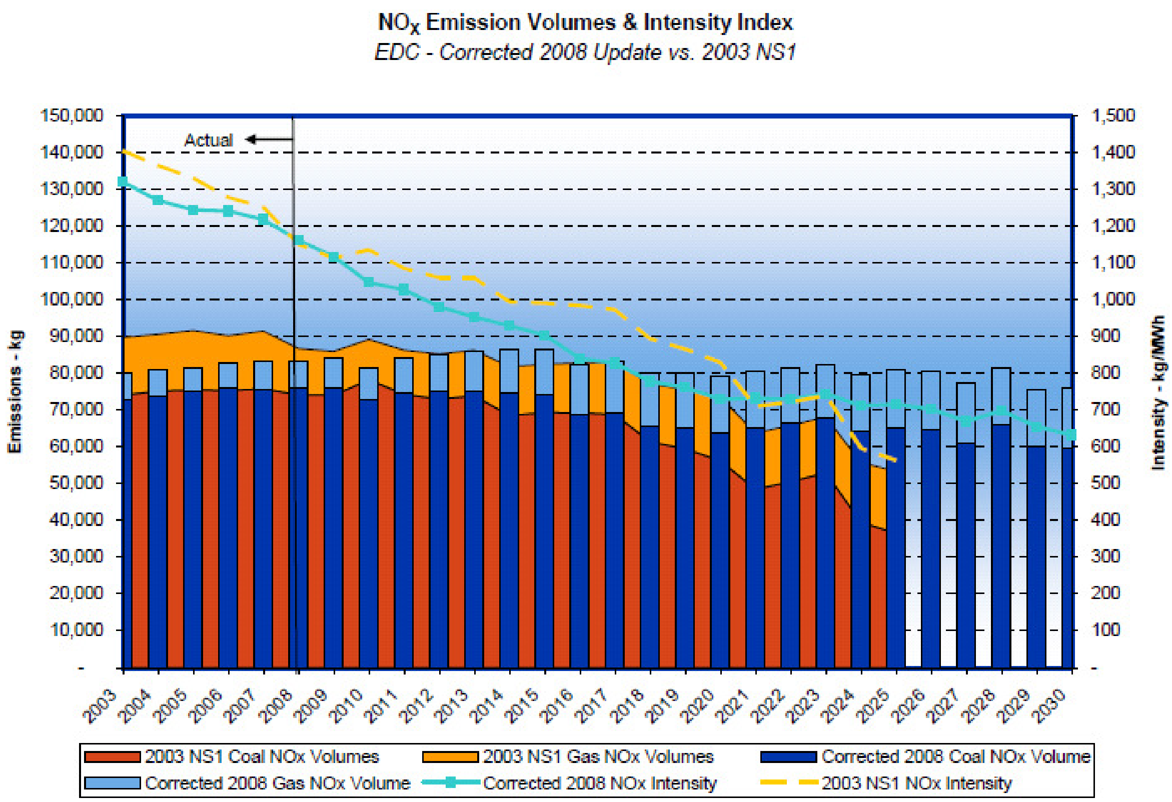
2.1.3. Sulphur Dioxide Emissions



Absolute SO_2 emissions in both the 2003 and 2008 forecasts are relatively similar. However, in the 2008 update, post 2017 absolute emissions are considerably higher than were previously forecast as a result of higher output from coal plants. This is primarily because the 2003 forecast assumed that coal production would be replaced by increased production using natural gas, but this is not the case in the 2008 forecast. The 2008 SO_2 emissions intensity levels are appreciably below the 2003 case (until 2022) because of increased renewable energy being included in the 2008 forecast. In the post 2022 period, the decrease in emissions intensity that results from increased renewable energy is offset by the increased emissions that result from additional new coal fired generation included in the 2008 forecast versus the 2003 forecast.

Total SO2 emissions are expected to decrease by an average of 1% in each year from 2009 to 2030. By 2030, the SO2 emission intensity is forecast to decline by and average of 2% each year of the forecast.

2.1.4. Nitrogen Oxides Emissions



NO_x emitted from coal generation is roughly unchanged from the 2003 forecast to the 2008 forecast until 2017. After 2017, the data shows a considerable increase in the 2008 predictions compared to the 2003 predictions. Emission intensity, as in the previous emission cases, is well below the 2003 projection prior to 2020 as a result of an increase in predicted proportion of renewable energy of the total generation. In the post-2020 period, the intensity in the 2008 forecast rises above the 2003 forecast due to an increase in coal-fired power in this period.

Total NO_x emissions are expected to decrease by an average of 0.5% in each year from 2009 to 2030. By 2030, the aggregate NO_x emission intensity is forecast to decline by an average of 2% per year.

3 Control Technologies Review

The objective of this review was to determine the Best Available Technology Economically Achievable (BATEA) for emission control technology that would be applicable to Alberta's electricity generating sector for units approved after January 1, 2011. A definition of BATEA is found in the 2003 Framework[1]:

> BATEA (Best Available Technology Economically Achievable) 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 analysis was conducted for control technologies used to reduce the emissions of four pollutants: nitrogen oxides (NO_x), sulphur dioxide (SO_2), particulate matter (PM), and mercury (Hg). Possible retrofit technologies for existing units were not assessed, as the review was entirely focused on new units.

Additionally, the energy requirements for any control technologies analyzed were identified, and the resulting greenhouse gas emissions were estimated. This analysis also reviewed future technologies, control techniques, and the use of alternative fuels applicable to electric generating units.

The BATEA determination was conducted for electrical utility boilers and combustion turbines of 25 megawatts (MW) or greater in size. The determination also considered different fuel types.

This study did not analyze BATEA for electrical utility boilers or turbines burning fuel oil. The decision to forgo such an analysis was made based on the cost of oil, which was considered to make it an unlikely source for fueling new power plants. In addition, permits reviewed in the U.S. indicate that no new construction of boilers or turbines burning fuel oil is currently planned. An analysis of gas fired boilers with steam turbines was not undertaken.

4 Recommendations for Updated Standards for New Thermal Generation Units

4.1. Best Technology Economically Achievable (BATEA)

Based on the results of this technology review, the CTRS task group reached consensus agreement on the following BATEA:

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

[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.

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

- New source standards for primary Particulate Matter for coal-fired units in Alberta will be based on the demonstrated performance of fabric filter baghouses.

- New source standards for Nitrogen Oxides for gas-fired peaking units in Alberta will be based on the demonstrated performance of dry low NO_x /dry low emissions (DLE/DLN) combustion technology subject to the definitions in this document. (Note: The new sources standards recognize that a peaking unit is not limited to a generating unit that has reached the end of its design life.)

- The CTRS task group did not reach consensus on what technology to base the new source standards for Nitrogen Oxides for non-peaking gas-fired units in Alberta. Consistent with the consultant's report, government, NGO, and some industry stakeholders agreed that selective catalytic reduction (SCR) is the best available technology economically achievable (BATEA). However, some industry stakeholders blocked the consensus agreement as they did not support the choice of BATEA and the corresponding source standard for non-peaking units.

4.2. 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.

4.2.1. Source Standards for New Coal-Fired Thermal Generation Units

Draft Recommendation 1: Source Standards for New Coal-Fired Thermal Generation Units

The CTRS task group recommends that the following standards apply to coal-fired boiler generating units without carbon capture technology that are approved on January 1, 2011 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[1])
  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.

4.2.2. NOx and SO_2 Credit Generation Thresholds

Draft Recommendation 2: NO_x **and SO_2 Credit Generation Thresholds**

The CTRS task group recommends that the following deemed credit thresholds for the 2011 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]

4.2.3. Credit for Early Action on Mercury Capture

Draft Recommendation 3: Credit for Early Action on Mercury Capture

The CTRS task group recommends that the initiative on Credit for Early Action on Mercury Capture be implemented as follows:

- The Credit for Early Action on Mercury initiative will enable operators to gain recognition for past and upcoming Mercury capture before the regulation deadline.
- Operators will earn credits for kilograms of Mercury captured (as a result of Mercury control activity demonstration, early installation of Mercury control equipment and other combustion process modifications).
- Credits can only be used on a site-basis (no trading) and only when plants experience upset conditions impacting their ability to achieve target removal requirements.
- The credits for early action recognition cannot be used to delay installation of Mercury control equipment.
- January 1, 2011 is the compliance date. Companies will earn credits for Mercury capture rates greater than 75% before January 1, 2011.

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

- Between January 1, 2011 and January 1, 2013, companies will earn credits for Mercury capture rates greater than 80%.
- All credits will be earned at a discount value of 50%.
- All credits will expire on December 31, 2015.

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

Amendment, September 2010:
In June 2009, the CASA Board reviewed the non-consensus issues regarding gas-fired non-peaking units, as presented in this report. The board directed the Electricity Framework Review (EFR) project team to continue to work to resolve the issue of choice of BATEA and a corresponding source standard for non-peaking units, noting that all involved stakeholders need to participate, and all options will be on the table. Please refer to the Report on the First Five-Year Review of the Emissions Management Framework for the Alberta Electricity Sector, May 13, 2010 *for full details on the project team's discussions further to the information in this report. The team reported back to the CASA board in March 2010 that they were unable to reach consensus on this issue. The board agreed to forward the issue to the appropriate Government of Alberta Ministers for a final decision. When finalized, the decision of the Minister/s will be available upon request from CASA and will be posted on the CASA website.*

<u>Description of Non-Consensus</u>

The task group could not agree on updated source standards for new gas-fired thermal generation units. The main blocks to consensus are:
A. the treatment of simple cycle units and peaking units and
B. the choice of BATEA and the corresponding source standard for non-peaking units.

A. Treatment of simple cycle units and peaking units

- Government, NGOs, and industry stakeholders agree that the BATEA for peaking units is DLN-DLE. However, determining the corresponding source standard has been a complicated task and through many discussions, government, NGOs, and some industry stakeholders were able to reach agreement on a standard they could live with. Although the proposal does not include a separate category for simple cycle units, participants feel that this option provides a peaking category that allows appropriate BATEA standards for simple cycle units.

- One industry stakeholder disagreed with the proposal because they feel the definition of peaking units in the proposal is too broad, potentially allowing units that may not be providing peaking service to benefit from the relaxed standard and less stringent emission control equipment requirement for peaker units.

B. Choice of BATEA and corresponding source standard for non-peaking units

- Consistent with the report prepared by the Eastern Research Group, government, NGO, and some industry stakeholders agree that selective catalytic reduction (SCR) is the best available technology economically achievable (BATEA). During the task group's discussions, some participants were able to reach agreement that, due to limited operating experience with SCRs in Alberta, the source standard should allow for some fluctuation during non-ideal operations, commissioning, and short-term, well-defined, transient periods. These stakeholders agree that SCRs are the BATEA because they are required to be installed and operated in a variety of applications, including co-generation, through the United States. Several of these facilities operate in cold weather. The consultant (Eastern Research Group) stated that ammonia slip/collateral emissions were only a concern at very low emission limits, well below those proposed for this new source standard.

- Some industry groups believe SCRs do not meet the definition of best available technology economically achievable (BATEA) compared to dry low NOx technology. They feel that SCR installations are not cost-effective based on the incremental reduction in NO_x emissions achieved in comparison to using dry-low NO_x burners. They also believe that negative collateral environmental impacts may outweigh the benefits of the incremental reduction in NO_x emissions. In addition, these industry representatives feel that that the proposed standard for gas turbines would be more stringent for cogeneration facilities (gas turbine and HRSG) than for combined cycle facilities (gas turbine, HRSG and steam turbine). They also believe that the recommended heat recovery allowance may be too stringent for cogeneration units, and should remain at a level consistent with the CCME standard until a technology review is completed.

Summary of Blocks to Consensus for Gas-Fired Units

Stakeholder Group/ Company	**A. Peaking Units**	**B. Non-Peaking Units**
Non-government organizations	✓	✓
Government	✓	✓
EPCOR, TransAlta, and TransCanada	✓	✓
ATCO Power	Block	✓
Oil and gas (incl. oil sands), petroleum products, and chemical manufacturers	✓*	Block

* CAPP has no position on simple cycle and peaking units because these units are not of concern to many of their facilties. Although they have indicated that they have not reviewed the proposals in detail, they will not block the consensus agreement.

Draft Recommendation 4: Source Standards for New Gas-Fired Thermal Generation Units (*non-consensus*)

It is recommended that the following NO_x BATEA standards apply to new gas-fired units that are approved on January 1, 2011 or later.

Non Peaking Standard Formula:

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

Net Power Output (per gas turbine train)	**Non Peaking ("A")** (kg NO_x /MWh net)	**Peaking Standard**
Greater than 100 MW	0.09	600 kg NO_x/MW annual maximum Design specification of 9 ppmv NO_x @15% O_2
25 to 100 MW		750 kg NO_x /MW annual maximum Design specification of 15 ppmv NO_x @15% O_2
Less than *25* MW	0.60	1512 kg NO_x/MW annual maximum

Heat Production Allowance "B": Natural Gas = 0.01 kg NO_x/GJ

(* Please see Appendix I for detailed explanation and examples.)

Areas of Non-Consensus

NGOs, government, and some industry stakeholders supported this recommendation as it is consistent with the advice received as part of the consultant's (Eastern Research Group) BATEA review. Other industry stakeholders blocked portions of this proposal because they could not agree with:

A. The treatment of simple cycle units and peaking units; or

B. The choice of BATEA and the corresponding source standard for non-peaking units. Two proposals were submitted to resolve these key areas of disagreement.

(Please see Appendix II to VIII for individual stakeholder statements.)

PROPOSAL A: ***Alternate Treatment of Simple Cycle Units and <u>Peaking Units</u>***

It is recommended that the releases of NO_x from a peaking unit into the atmosphere shall not exceed the following annual mass emission limit:

NO_x (kg) = "A" Kg/MWh * maximum net continuous rating in MW * 1500 hours

Unit Size	Peaking Units Emission Intensity "A" (kg/MWh net)
Greater than 100 MW	0.20
25 to 100 MW	0.25
Less than *25* MW	0.50

Notes:
- BATEA basis: DLN/DLE Burners or equivalent
- Service requested by the Alberta System Operator for system security is not included in the annual mass emission limit.
- Maximum Net Continuous Rating at ISO conditions as provided by the manufacturer

PROPOSAL B: ***Alternate Choice of BATEA and Corresponding Source Standard <u>Non-Peaking Units</u>***

For NO_x emissions from gas-fired turbines in cogeneration application, it is recommended that the emission limit standard for units approved after January 1, 2011 be based on the following:

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

Where:

Power Output Allowance "A": Natural Gas = No limit suggested but process and considerations for setting provided (See Appendices IV, VI and VII)

Heat Production Allowance "B": Natural Gas = 0.04 kg NO_x /GJ

Notes:
- The "A" factor to be based on dry-low NO_x technology as BATEA. A technology and performance study of the NO_x reduction capability of this technology on gas-fired cogeneration units operating under Alberta climatic conditions is proposed.
- The "B" factor (heat recovery allowance) for cogeneration units is consistent with the CCME Guideline of 0.04 kg NO_x /GJ. A BATEA review of heat recovery allowance for cogeneration units is proposed.

Alternate Fuels
The new source standard for NOx for gas-fired non-peaking units in Alberta was determined based on natural gas as the principal energy source. The team considered other forms of gaseous fuels, including produced-, synthetic- and refinery-gas, requesting input from relevant industry representatives. Due to limited availability of information and expected limited use of alternate gaseous fuels, the team did not complete a full assessment of the applicability of this standard in all cases. Therefore, the team advises that this natural-gas based NOx emission limit standard be applied to all natural gas-fired units. Units with a significant variation in fuel composition should be dealt with on an approval-by-approval basis, basing the emission limits on the capabilities of appropriate air pollution control technologies, as determined by applying the principles of Best Available Technology Economically Achievable (BATEA). It should be noted that the team did not reach agreement on the definition of a "significant variation" in fuel composition.

4.3. 15% Growth Trigger

In the 2003 Framework, Recommendation 34 directs each five-year review team to assess whether emissions from the previous five-year forecast have increased more than 15%. The 2008 Generation and Emissions Forecast indicated that emissions from the electricity sector would be higher than that projected in the original 2003 forecast and would likely exceed the 15% emissions growth trigger for PM, as well as for NO_x and SO_2 after 2020.

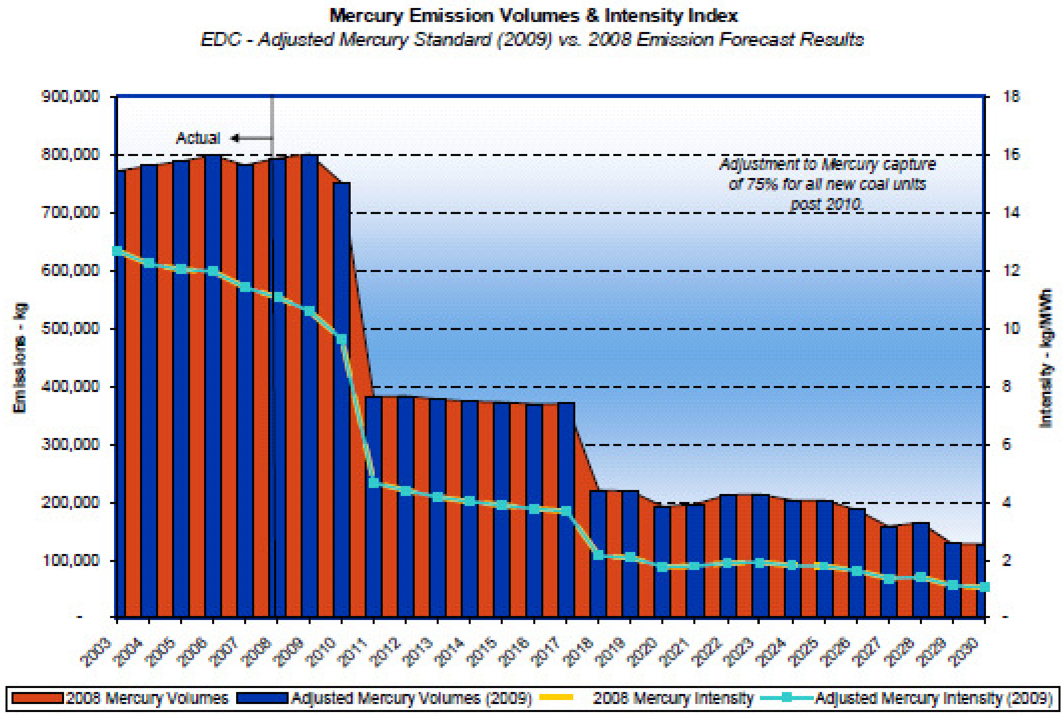
For PM emissions, the 2003 framework anticipated a potential issue, and Recommendation 22 indicates that if mercury control does not provide the anticipated co-reduction of PM, then the 2008 framework review should develop a primary particulate matter management system for existing units. Terms of Reference have been established for a task group to develop a PM Management System. The group will convene in September 2009.

For NO_x and SO_2, a key reason for the difference in these forecasts was the impact of the higher cost of natural gas in limiting the role of gas-fired facilities in replacing older coal plants as they reached their end-of-life.

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

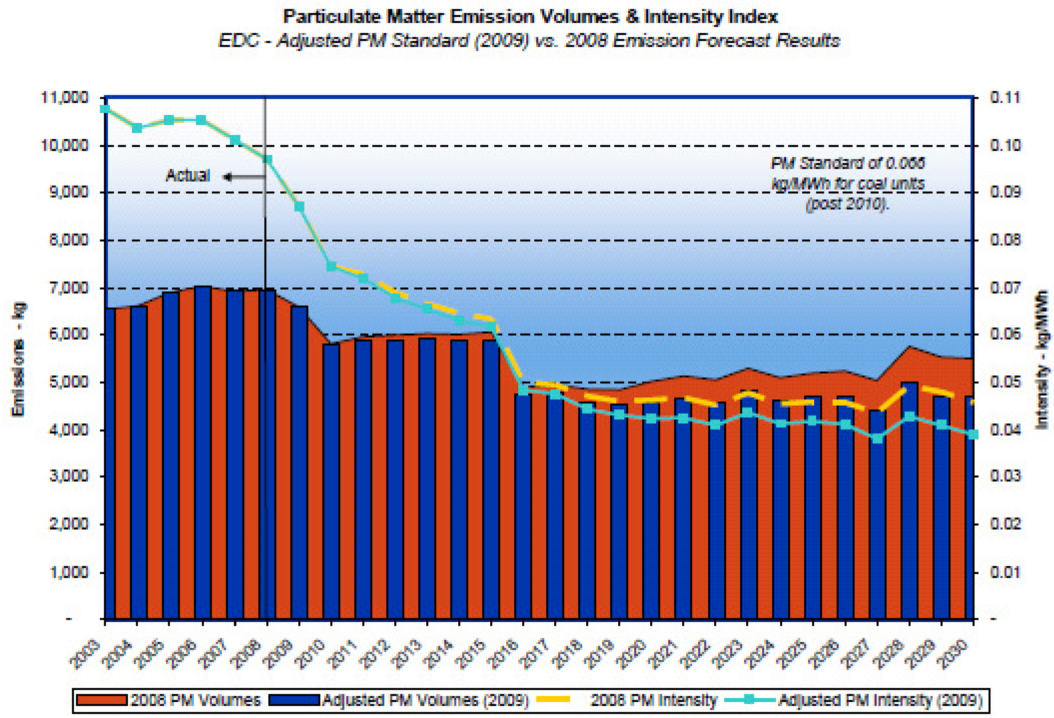
Concern about these projected exceedances was one of several important factors considered by the group during its discussions to set new emission limit standards. With the projected 15% emission growth trigger in mind, the team developed updated standards that would be adequate to bring long-term projected emissions back within the 15% trigger threshold. The team then arranged for the emissions forecast to be updated accordingly. However, in the process of preparing an updated forecast, the consultant discovered and corrected errors in the 2008 version that materially affected the emissions forecasts. In the corrected 2008 Forecast (completed April 2009), the level of projected NO_x and SO_2 emissions post-2020 is higher than first thought and greater than the 15% trigger value. Applying the proposed new emission standards does help to reduce the scale of emission increase, but the exceedances over the 2003 forecast could still be as high as 40-50% by 2025.

The following graphs show the impact of the proposed new BATEA standards on the projected future emissions[1].

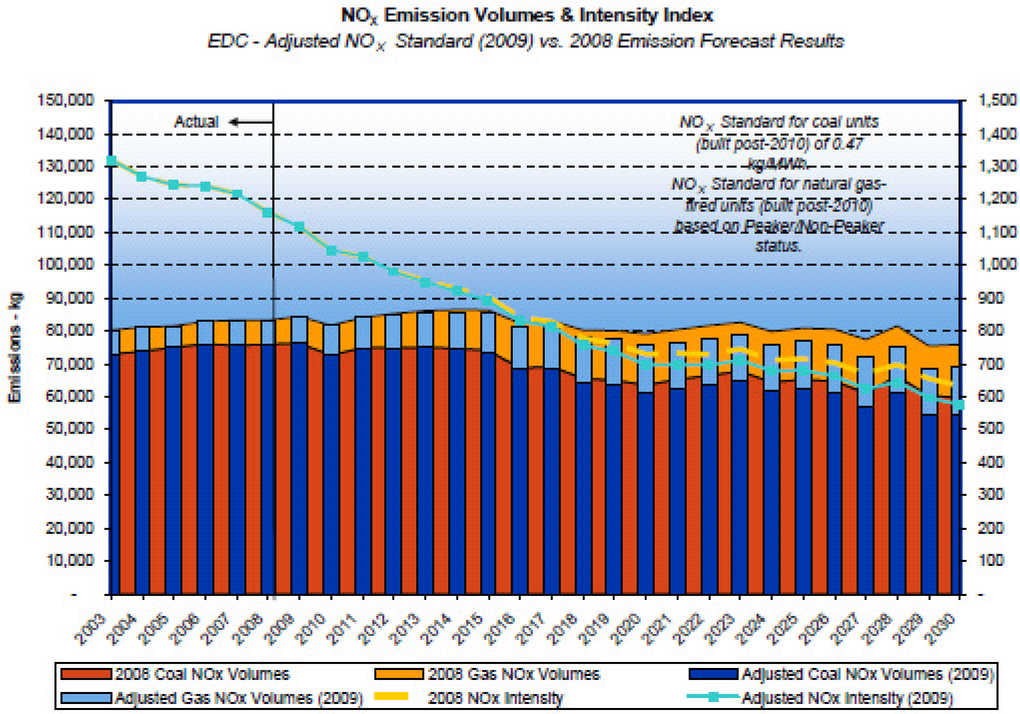


In general, absolute mercury emissions are forecast to decline significantly over time. There is a decrease from the end of 2009 to the beginning of 2011, due to a shift of the regulation implementation date. After 2011, the remainder of forecast decrease in emissions results from retirements of coal-fired facilities. The difference between 80% capture and 75% capture for mercury emissions on super-critical technology is relatively non-existent. Consequently, for new units the lower mercury standard proposed in the 2009 update has no impact on future absolute mercury emissions relative to the much larger impact created by the retirement of older units. The mercury emission intensity level is forecast to decline an average of 4.1% per year.

[1] Although the CTRS task group was not able to reach consensus on a NOx source standard for new gas-fired thermal generation, they agreed to use the draft, non-consensus source standard that appears in this report for the purposes of updating the emissions forecast.



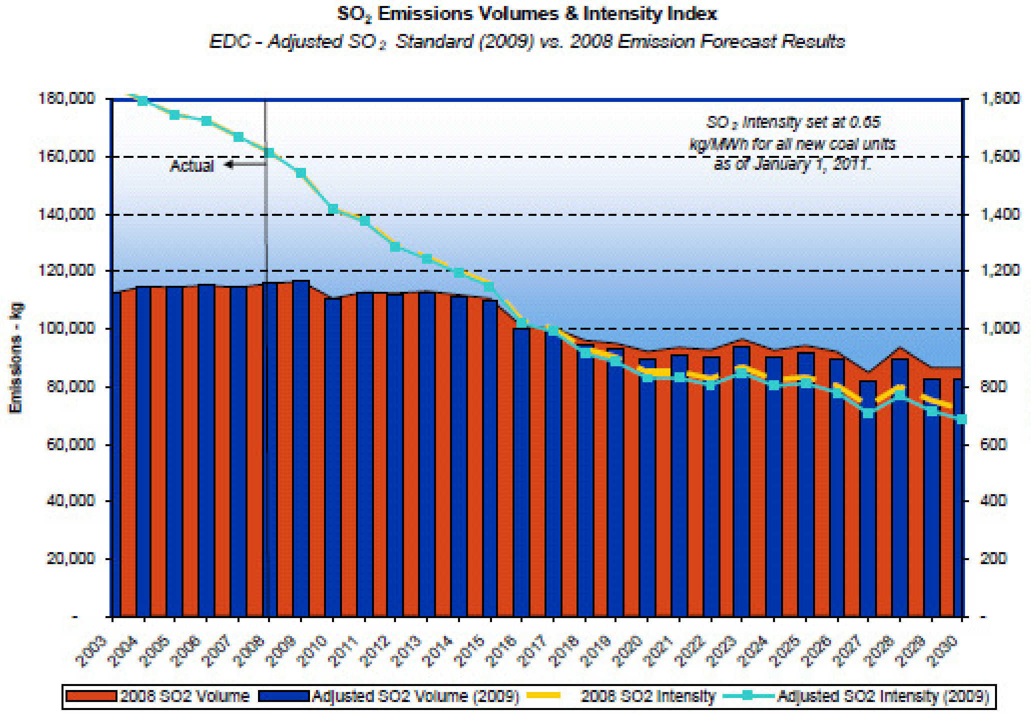
The 2009 update to the emissions forecast included an adjustment to the PM emissions target level. Consequently, absolute PM emissions are expected to be lower due to the 2009 adjustment to the PM emission standard relative to the absolute PM emissions in the 2008 forecast. With the updated emission standard, absolute PM emissions are expected to decrease by about 29% by 2030.



By 2030, absolute <u>natural gas</u> NO_x emission forecast for those units commissioned after January 1, 2011, and subject to the updated emission standard, were 35% lower than the absolute natural gas NO_x emissions in the 2008 forecast. Due to the assumption that natural gas-fired generation will make up a large share of the forecast generation fleet, natural gas NO_x emissions are expected to increase over the forecast period by about 79%.

By 2030, absolute <u>coal-fired</u> NO_x emission forecast for those units commissioned after January 1, 2011, and subject to the updated emission standard, were 28% lower than absolute coal-fired NO_x emission in the 2008 forecast. Coal-fired NO_x emissions are forecast to decline by about 29% over the forecast period.

Aggregate NO_x emissions are forecast to decline by about 18% from 2009 to 2030 in the 2009 forecast update. The NO_x emission intensity level is expected to decline by about 48% (2.2% per year).



For the period 2011 to 2030, absolute SO2 emission forecast for those units commissioned after January 1, 2011, and subject to the updated emission standard, were 19% lower than the absolute SO2 emissions in the 2008 forecast. Correspondingly, in aggregate SO2 emissions are expected to decline by about 29% in the 2009 forecast update. The SO2 emission intensity level is forecast to decline by about 56% by 2030 (2.5% per year).

The team feels that the proposed new emission standards are the best that can be agreed to at this time through the CASA consensus process. However, it is recommended that the next 5-year BATEA review team look closely at the need for further substantial reductions in emissions standards beginning with the 2016-2021 period with the aim of ensuring that emissions in the post- 2020 period do not exceed the 2003 forecast by more than15%. Additionally, other structural changes to the broader Emissions Management Framework may be necessary in order to ensure the fundamental objective of "meaningful reductions over time"[1]. It is also recommended that future teams take an active involvement with the development of the emissions forecasts to confirm their accuracy.

For consistency, the updated (2009) version of the 2008 Generation and Emissions forecast was revised only to demonstrate the impact of the proposed new emissions standards. This forecast does **not** reflect the potential impact of changes in respect to electricity market fundamentals related to the following four key issues:

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[1] An Emissions Management Framework for the Alberta Electricity Sector, November 2003, p25.

- As a result of the economic slowdown and recession in the world economy, there has been a reduction in the long-term expected development of Alberta's oil sands resource. The slowdown has resulted in lower electricity demand in the province and a reduction in some co-generation capacity additions associated with onsite generation requirements.
- The abundant supply of natural gas in the United States, as well as the economic slowdown, may also result in natural gas prices being lower in the future than what was assumed in the forecast. This could affect the relative economics of coal and natural gas-fired generation, potentially leading to new construction for gas-fired generation replacing the assumed new construction for coal-fired generation included in the forecast.
- The federal government's Greenhouse Gas (GHG) policy, released on March 2008, helped frame the incremental cost to Alberta's generation fleet to comply with the required emissions reductions. However, the political context influencing GHG policy continues to evolve, especially with the election of Barack Obama in the U.S. which has led the federal government to consider the potential implementation of a cap and trade system for the power generation sector. Implementation of a GHG policy is expected to have an impact on the expected generation resource mix over time, but it is difficult to project these impacts until the policy structure is clear.
- Implementation of a GHG policy is anticipated to impact electric energy pricing. Considering that consumer behaviour may shift in a way that advances increased levels of energy conservation, it is difficult to fully evaluate and model the likely market response, and the potential increased market penetration of demand side management tools and distributed generation that could result.

<u>APPENDIX I</u>: Interpretation of Proposed Gas Turbine NOx Standards in Recommendation 9 and Examples Under Different Scenarios

1. Standards

Non Peaking Standard Formula

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

- Values for Power Output Allowance "A" are provided in Standards Table.
- Useable Heat Output Allowance "B" (kg/GJ) = 0.01

Peaking Standards

Peaking standards are provided in Standards Table.

Standards Table

Net Power Output (per gas turbine train)	**Non Peaking ("A")** (kg NO_x /MWh net)	**Peaking Standard**
Greater than 100 MW	0.09	600 kg NO_x/MW annual maximum Design specification of 9 ppmv NOx @15% O_2
25 to 100 MW		750 kg NO_x/MW annual maximum Design specification of 15 ppmv NOx @15% O_2
Less than *25* MW	0.60	1512 kg NO_x/MW annual maximum

Heat Production Allowance "B": Natural Gas = 0.01 kg NO_x/GJ

Conditions

- A gas turbine may declare as a peaking unit if it meets the peaking standard and does not exceed a capacity factor of 40% in a calendar year unless required by the System Operator to operate to address a threat to system security.
- Emissions during the startups and shutdowns of SCRs or equivalent post combustion NOx reduction technology are excluded from the compliance measurement.
- The Non Peaking compliance measurement is based on existing Alberta Environment protocols subject to these conditions.

2. Basis

- The Non Peaking Standards are expressed as output standards in a similar format to the 1992 CCME Guidelines.
- BATEA basis: Non Peaking – LN Burners and SCR
Peaking – DLN / DLE Burners or equivalent
- Credit for useable heat output is based on the HRSG performance target in the AENV Approvals Program Interim Policy OSEMD-00-PP2 dated December 14, 2007.
- Peaking standards are based on the following consistent with Recommendation 11 of the 2003 Electricity Framework:

Greater than 100 MW: 0.40 kg/MWh x 1500 hours/year
25 to 100 MW: 0.50 kg/MWh x 1500 hours/year
Less than 25 MW: 1.008 kg/MWh x 1500 hours/year

3. Definitions

a. Capacity factor for the purposes of these standards means:
Net generation (MWh/year) / [Power Rating (net MW) x 8760 (hours/year)]
b. Concentrations of NOx (ppmv) are expressed in dry volume at 15 % oxygen and ISO conditions.
c. The Design Specification for peaking unit NOx emissions is consistent with vendor warranty under power rating conditions.
d. ISO conditions are International Standards Organization conditions that refer to a reference state of 288 degrees Kelvin (15 degrees C) temperature, 60 % relative humidity and 101.3 kilopascals barometric pressure.
e. Net Power Output means the power rating of the gas turbine plus an associated combined cycle steam turbine.
f. The Power Rating of the gas turbine means the normal maximum net continuous rating at ISO temperature conditions as provided by the manufacturer.
g. Thermal efficiencies are expressed as Lower Heating Value (LHV)
h. 1 ppmv NOx concentration as defined = 1.70 grams NOx as NO_2 per Gigajoule (GJ) of heat input, for natural gas combustion
i. 1 Megawatt-hour (MWh) = 3.6 Gigajoules (GJ)

4. Examples

4.1 A 110 MW gas turbine and 40 MW steam turbine in combined cycle, (a) at 55% efficiency and (b) at 45% efficiency.
NOx standard = 0.09 x 150 = 13.5 kg/h
(a) Implied NOx in flue gas = (0.09 x 1000 x 0.55) / (3.6 x 1.7) = 8.1 ppmv
(b) Implied NOx in flue gas = 6.6 ppmv

4.2 A 110 MW gas turbine and 40 MW steam turbine in combined cycle operating at 55 % efficiency, plus heat recovery boosting the overall efficiency to 80%.
Additional heat production = (0.8 – 0.55) x 3.6 x 150/0.55 = 245.5 GJ/h
NOx standard = (0.09 x 150) + (245.5 x 0.01) = 16.0 kg/h
Implied NOx in flue gas = 15.5/13.5 x 8.1 = 9.6 ppmv

4.3 A 90 MW gas turbine operating at 30 % electrical efficiency plus heat recovery boosting the overall efficiency.to an 80 %.
Additional heat production = (0.8 – 0.3) x 3.6 x 90/0.3 = 540 GJ/h
NOx standard = (0.09 x 90) + (540 x 0.01) = 13.5 kg/hr
Implied NOx in flue gas = (0.09 x 0.3 x 1000) / (1.7 x 3.6) x 13.5 / (0.09 x 90)
= 7.3 ppmv

4.4 A 15 MW non peaking gas turbine operating at 25 % efficiency:
NOx standard: 0.6 x 15 = 9 kg/h
Implied NOx in flue gas = 24.5 ppmv

4.5 A 30 MW non peaking gas turbine operating at 35 % efficiency
NOx standard = 0.09 x 30 = 2.7 kg/h
Implied NOx in flue gas = (0.09 x 1000 x 0.35) / (1.7 x 3.6) = 5.1 ppmv

4.6 A 30 MW peaking gas turbine

NOx standard = 750 x 30 = 22,500 kg/y

Also 15 ppmv design specification at full load and ISO conditions

Assuming annual average emissions intensity of 0.25 kg/MWh,

maximum capacity factor = (750 x 100) / (8760 x 0.25) = 34.2 %

If the unit is able to achieve an average emissions intensity of 0.2 kg/MWh, it could theoretically run at 42.8% capacity factor, but would be limited to 40 % capacity factor.

APPENDIX II: ATCO Power Concerns with Proposed Peaking Units Standards

May 10, 2009

Robyn-Leigh Jacobsen
Project Manager, Electricity Framework Review
Clean Air Strategic Alliance
10th Floor, 10035 – 108 St. N.W.
Edmonton, Alberta T5J 3E1

Dear Ms. Jacobsen:

RE: Natural Gas Turbine NOx Standards Proposed by Control Technology Subgroup
ATCO Power Concerns with Proposed Peaking Unit Standards

ATCO Power respectfully submits that it does not agree with the current industry proposal for the treatment of natural gas turbine peaking units. Our specific concerns with the proposed standards are as follows:

1. The proposed emission intensity target for peaker units does not represent the BATEA technology that was agreed upon for peaker units.
2. The proposed peaking standard annual capacity factor of 40% is substantially more than what is reasonably expected operating hours for peaking service.

Peaking units provide a valuable service to the electricity grid. These units are capable of responding quickly to electricity demand and thereby can reduce the need to operate base loaded generating units to provide contingency reserve energy. The ability to operate the Alberta Electricity Grid with a tighter reserve margin results in overall less emissions from generating units. Peaking unit operation typically entails several starts and stops with very short duration operating intervals. This results in low annual operating hours for peaking units. SCR technology does not work well with peaker units as the SCR requires a long start sequence before it is effective and does not respond well to varying unit load. DLE/DLN technology is better suited to peaker operation. The relaxed emission control for peaking units is considered acceptable because the operating hours are low and the overall annual emissions are a fraction of a base loaded gas unit.

Recommendation 11 of the 2003 CASA framework recognized the special consideration required for a peaking unit standard and recommended that an emissions cap be set for peakers to be consistent with the 1992 CCME guidelines. The 2003 CASA framework also suggested that the 2008 Five-Year Review should determine the BATEA emissions intensity limit to be applied after January 1, 2011. The current industry proposal is consistent with the methodology of the 2003 CASA framework and the CCME guidelines by setting a mass emission cap based on limited (1,500) hours, however the emission intensity limit is not consistent with BATEA for a modern gas turbine. Consider the following definitions:

- Peaking Combustion Turbine – A peaking combustion turbine is a unit which is ordinarily used to supply electric or motive power at periods of high demand or during unforeseen outages. Such a unit will not usually operate more than 7500 hours in any 5 year period and, in those years, a total of no more than 3000 hours during the months of May, June, July August and September. (CCME National Emission Guidelines for Stationary Combustion Turbines 1992)

- Peaking unit means:
  (1) A unit that has:
  (i) An average capacity factor of no more than 10.0 percent during the previous three calendar years, and
  (ii) A capacity factor of no more than 20.0 percent in each of those calendar years.
  (US EPA Code of Federal Regulation, Title 40, Part 72.2 Definitions)

Both of the above references have set a limitation on the operating hours for peaking service. The 2003 CASA framework did not set a limit on the operating hours, but rather used the 1500 hours multiplied by the BATEA limit to set an annual emissions cap. Peaking units were exempt from the annual average emissions intensity standard expected of other gas turbines. Instead an annual emissions cap was used to allow the starts, stops and higher partial load emissions intensities experienced by peaking service.

ATCO Power believes that limiting the operating hours is a critical aspect of the relaxed peaker emissions target. This can be accomplished through either setting an emissions cap or setting a maximum number of operating hours. If a new unit BATEA emissions intensity is used to calculate the emissions cap, then the CASA methodology will result in an appropriate annual emission cap target. If the new unit emissions intensity BATEA standard is not applied, then the operating hours must be strictly held to no more than 1500 annual operating hours to limit the annual mass emissions from the unit. This is consistent with the treatment of peaking service under the 2003 CASA framework, the CCME guidelines and that used in other jurisdictions.

The proposed natural gas turbine NOx standard for peaking units should not be adopted for the following reasons:

(1) The proposal allows a peaking unit to have a capacity factor of up to 40% that can result in 3,000 annual operating hours for a peaking unit at full load conditions equipped with current DLE technology. At partial load this same peaking unit could be allowed more than 6000 hours. This amount of operating hours is not consistent with peaking service. There is no justification for a relaxed emission standard for units that operate this many hours. [Capacity Factor is annual generation /(8760 hours * unit size rating)]

(2) The current standard would allow the same annual mass emissions from a base loaded combined cycle unit operating at 100% capacity factor and a similar size peaker unit

operating at 40% capacity factor. It is not reasonable to allow the same emissions for less than half of the generation.

(3) The proposed method is not consistent with the CASA approach used for coal and gas units as it does not apply a current BATEA emissions intensity standard to peaking units.

The emission intensity BATEA target for peaking units should be based on DLE technology as the working group has agreed. Based on what has been previously discussed as BATEA emission intensities for this technology, ATCO Power suggests the following treatment for natural gas peaking units:

Releases of NOx from a peaking unit into the atmosphere shall not exceed the following annual mass emission limit:

NOx (kg) = "A" Kg/MWh * maximum net continuous rating in MW * 1500 hours

Net Power Output	Peaking Units Emission Intensity "A" (Kg/MWh net)
> 100 MW	0.20
25 – 100 MW	0.25
< 25 MW	0.50

Notes:

- BATEA basis: DLN/DLE Burners or equivalent
- Service requested by the Alberta System Operator for system security is not included in the annual mass emission limit.
- Maximum Net Continuous Rating at ISO conditions as provided by the manufacturer

Please feel free to contact me at 403-209-6911 if you have any questions or require additional information.

Sincerely,

J.M. (Jim) Hackett, P. Eng.
Manager, Health, Safety and Environment
ATCO Power Canada Ltd.

APPENDIX III: EPCOR Position on Proposed Natural Gas Turbine NOx Standards

1. Statement of Position

EPCOR supports the non consensus standards proposal in the EFR Report to the CASA Board. This proposal is the product of a detailed consultative review and stakeholder examination over several months and is soundly based on BATEA.

2. Background

The proposal represents a compromise reached in March 2009 by the actively participating electric utility stakeholders and all contributed to its development. (ATCO Power, EPCOR, TransAlta Utilities and TransCanada.) An earlier proposal, which included separate intensity-based emission standards for combined cycle or cogeneration units and simple cycle units, was opposed by ATCO Power because it lacked a specific peaking unit category and because it disagreed with the inclusion of a separate simple cycle unit category. While the compromise proposal does not include a separate category for simple cycle units, it provides a peaking category that allows appropriate BATEA standards for simple cycle units at the lower capacity factors these are designed to operate.

After further consultation with other CASA stakeholders, it appeared at the end of April 2009 that the proposal had at least the tacit support of most of the government and environmental stakeholders involved. On May 1, 2009 ATCO Power suddenly withdrew its support.

3. Response to Option A – Alternative Peaking Proposal

In summary, EPCOR rejects Option A because it does not recognize that simple cycle units, which fall outside its much more restrictive definition of a peaking unit, should be subject to appropriate BATEA standards. As will be demonstrated below, this is counter to the BATEA principle for setting emission standards in both Alberta and the U.S.

(a) Peaking units are designed to supply power at short notice during peak demand periods, responding to either a spike in demand or coverage when a base load generating unit fails. As such the proposed capacity factor limitation of up to 40% is appropriate for maximum flexibility, as the constraints on duration of operation are a product of demand requirements from the system operator within Alberta. Simple cycle units are designed specifically to address this need with a fast response time. The units have the ability to be powered on and off in a matter of minutes to meet peak demand requirements, something which is less achievable with combined cycle units. The thermal efficiency of a simple cycle unit is typically much lower than a combined cycle unit and this impairs the economic value of running at capacity factors above 40%.

(b) The U.S. EPA clearly consider simple cycle gas turbine units and combined cycle units separate BATEA categories for the purpose of NOx emission standards setting and the EPA website on state permit standards is subdivided accordingly. An example is provided in the January 2009 ERG consultants report for CASA which shows separate Texas State emission standards for combined cycle units, simple cycle units and peaking units.

(c) Option A would result in simple cycle units outside its narrow peaking definition facing much more stringent emission requirements than combined cycle units. While both would be required to meet the same emissions intensity standards, simple cycle units would typically have to achieve a much lower emission rate (expressed as ppm NOx) due to their lower thermal efficiency. This means these simple cycle units would be subject to a more stringent BATEA than combined cycle units which is contrary to U.S. practice. For example, the Texas State simple cycle standards are 2.5 times less stringent in terms of emission rate than its combined cycle standards.

(d) Further information about recent U.S. BATEA standard permitting practice is available on the EPA website. This shows that during the past 10 years, state permit NOx standards for simple cycle units were on average far less stringent than for combined cycle units, and most were achievable with the use of dry low NOx burner technology. This is largely because additional NOx emission controls are much less cost-effective at the lower capacity factors simple cycle units are designed to operate.

(e) In Option A it is argued that the proposed standards should not allow the same annual mass emissions from a base-loaded combined cycle unit operating at 100% capacity factor as a similar sized peaker operating at 40% capacity factor. This comparison of annual emissions from different technologies at different loads is not relevant. Similar observations can be made about other emission standards in the U.S. and this is simply the result of the standards incorporating different BATEAs for different technologies. For example, the Texas State NOx standards in ERG's report for CASA allow a simple cycle unit operating at 30% capacity factor to annually emit nearly twice as much as a combined cycle unit of the same size operating at 60% capacity factor. The Texas standards also allow a peaking unit operating at only 10% capacity factor to emit nearly twice as much a combined cycle unit of the same size operating at 60 % capacity factor. Such comparisons are consequently meaningless.

(f) In Option A it is also argued that the proposed standards are not based on the current CASA BATEA emissions standard for peaking units. Both the proposed standards and Option A propose annual NOx emissions limits. The proposed standard differs in that it adequately takes into account the BATEA for simple cycle units by setting a larger annual limit based on 34.2% capacity factor and the same emission intensities of 0.20 kg/MWh for > 100MW and 0.25 kg/MWh for 25 - 100 MW capacity. (An overall capacity factor cap of 40 % for the peaking category was also agreed as part of the compromise). In addition, unlike Option A, the proposed standard ensures that units will not operate with excessive emissions at low capacity factors by ensuring that BATEA low NOx DLN/DLE burner technology or equivalent are installed on all peaker category units according to warranty-based design specifications of 9 ppm and 15 ppm NOx respectively.

4. Closing Word

If the proposed peaking category standards seem somewhat complicated, it is because these were based on a compromise. Although EPCOR supported the original less complicated electric utility proposal of intensity emission standards for all simple cycle units (0.20 kg/MWh for > 100 MW and 0.25 kg/MWh for 20 - 100 MW), it continues to favour the proposed standards because these gained considerable stakeholder support.

APPENDIX IV: CAPP Alternative Proposal to CASA NOx Performance Standards for Natural Gas-Fired Cogeneration

CANADIAN ASSOCIATION
OF PETROLEUM PRODUCERS

DATE May 26, 2009
TO CASA Electricity Framework Review Control Technology Review Subgroup, c/o Robyn Jacobsen, CASA Project Manager

FROM Krista Phillips, CAPP

SUBJECT **NOx Performance Standards for Natural Gas-Fired Cogeneration, CAPP Response**

The following is a memo to the CASA Electricity Framework Review Team's CTRS Subgroup in response to the proposed NOx performance standards for natural gas-fired turbines of`0.09 kg/MWh (equivalent to 5ppm at 35% efficiency), based on a Best Available Technology Economically Achievable (BATEA) as Selective Catalytic Reduction (SCR) technology, as proposed by some stakeholders on the CASA Electricity Framework Review Team. CAPP recommends that the NOx performance standard for new gas-fired cogeneration units used in the upstream oil and gas be set at a level based on dry low NOx technology that is achievable in Alberta's cold ambient conditions. This recommended standard, if adopted, will apply to new cogeneration units approved after January 1, 2011. The standard will also apply to existing cogeneration units at end of life which is defined as 30 years from date of commissioning (CASA 2003 Electricity Framework).

In summary CAPP's position is:

- The NOx emissions standard for gas-turbines should be set at a level consistent with Alberta Environment's definition of BATEA, which states that control technologies must be economically achievable and commercially viable in a variety of operating regions.
- SCR should not be considered BATEA for cogeneration units operating in Alberta because:
  - SCR is not economically achievable compared to the alternative dry low NOx combustion technology. SCR installed on planned cogeneration units in Fort McMurray region will cost $52 million compared to $1 million for dry low NOx, while offering a marginal improvement in NOx reductions of 2.1% from 2015 emissions forecast.
  - The performance of SCR has not demonstrated successful commercial application in a region with ambient conditions similar to Northern Alberta.
  - SCR introduces negative collateral environmental impacts that have not been balanced against the marginal environmental gains in NOx emissions reductions.

- CAPP's position on a performance standard is the following:
  - Gas-turbine NOx BATEA limits should be based on dry low NOx technology, as it is economically achievable and has been demonstrated to be effective and commercially viable in Alberta.
  - Heat recovery allowance for cogeneration units should remain consistent with the CCME Guideline of 0.04 kg NOx/GJ.
  - A technology and performance study of gas-fired cogeneration units in Alberta should be undertaken to determine a reduced performance standard for gas-fired turbines that is practical and achievable.

CAPP's rationale for proposing an alternative NOx performance standard is presented in the following discussion on SCR as BATEA for cogeneration units in the upstream oil and gas industry. We conclude with a recommended path forward on the BATEA review on gas-fired turbines as undertaken by the CTRS Subgroup.

SELECTIVE CATALYTIC REDUCTION AS BATEA

Some stakeholders on the Electricity Framework Review Team are recommending that emissions performance standards from gas-fired turbines be set at a level that is only achievable through the use of SCR, and is being considered as BATEA for control of NOx from gas-fired turbines in Alberta.

Alberta Environment (AENV) defines BATEA as "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"[1]. Based on this definition, CAPP does not consider SCR to be BATEA for NOx control for upstream oil and gas operations in Alberta, as the technology is not economically achievable, nor has it demonstrated successful commercial application in a region with a highly-variable climate similar to Northern Alberta.

Economic Feasibility & Cost-Effectiveness of SCR

Cost-effectiveness of NOx control technology is defined as the cost per tonne of NOx removed. In its report to CASA, the Eastern Research Group stated the cost-effectiveness of SCR to be approximately $4200/tonne (Table 3-4). In comparison, its 2007 report entitled "Technologies for Reduction NOx Emissions from Gas-Fired Stationary Combustion Sources", the Alberta Research Council (ARC) determined the cost-effectiveness of dry low NOx technology (9ppm to 25ppm) to be approximately $122 US/ton, or approximately $140 CDN/tonne.

Using a report on NOx control technology assessment undertaken by the Regional Issues Working Group in 2006[2] and the cost-effectiveness of SCR and dry low NOx technologies above, the cost-benefit of SCR and dry low NOx (~15ppm) can be evaluated[3]. Table 1 provides

[1] Alberta Environment (2005), *Alberta Air Emission Standards for Electricity Generation and Alberta Air Emission Guidelines for Electricity Generation*, Page 7: http://environment.gov.ab.ca/info/library/7837.pdf

[2] Golder Associates (2006), *Report on NOx Control Technology Assessment*. Submitted to the Regional Issues Working Group. Report No. 06-1331-018.

[3] Note: The RIWG Report considers two levels of dry low NOx technology: 1. Dry Low NOx as required by current CCME Guidelines of 25 ppm, and 2. Ultra-Dry Low NOx of 9-15ppm. "Dry Low NOx" technology for this analysis is assumed to reduce NOx performance limits from the baseline (25ppm) to 15ppm.

an overview of the environmental benefit and resulting costs of installing SCR versus dry low NOx technology at all planned cogeneration facilities in the Athabasca region.

Table 1 - Cost-Benefit Analysis

Case	**NOx Removed (t/d)**	**Cost per tonne NOx removed ($/tonne)**	**Total NOx Reduced (t/year)**	**Percentage Total NOx Emissions [a]**	**Total Annual Cost**
Dry low NOx (~15ppm)	23.60	140	8,495	4.3%	$1.3 million
SCR (5ppm)	34.96	4,200	12,587	6.4%	$53 million
Δ from dry low NOx to SCR	*+ 11.4*	*+4,060*	*+4,091*	*+2.1%*	*+$51.7 million*

[a] based on 2015 forecasted NOx emissions from oil sands sector (Cheminfo, 2007)

Table 1 shows the cost of removing total NOx removed and environmental benefit achieved by installing SCR or dry low NOx at all new cogeneration units. In summary, to achieve an additional 2.1% reduction in NOx emissions from the 2015 forecast, oil sands operators will be required to spend an additional $51.7 million.

Overall, this marginal 2.1% improvement beyond the proposed dry low NOx technology performance limit of 15ppm will have very little effect on ground level concentrations of NO_2 and PAI, as described in the RIWG report.

This basic analysis shows that the environmental benefit of installing SCR does not outweigh the costs of requiring the technology. **As such, SCR should not be considered the basis for BATEA on industrial cogeneration units under the premise that it is not economically achievable.**

Cogeneration versus Combined Cycle: Economics
In addition, CAPP notes that the ERG report, upon which the proposed BATEA for NOx performance standard for gas turbines was based, focused their review on combined cycle facilities with little consideration for cogeneration facilities. That cogeneration was omitted from the ERG report is important because there are inherent differences between cogeneration facilities that are operated at various oil sands facilities versus the combined cycle facilities that would be used for the sole purpose of providing power to the AB grid.

Cogeneration facilities at oil sands facilities are operated to meet the required steam demand. Oil sands operators have the ability to purchase power off the grid however an alternative source of steam is not available. As a result, the electricity that is generated must be sold to the grid regardless of price. Under these circumstances, cogeneration operators can not influence market prices or pass down additional costs to customers. This inherent difference between combined cycle units and cogeneration units will have an effect on the economics of installing SCR at oil sands facilities, which should be considered in developing a recommended performance standard for gas-fired turbines.

Performance Uncertainty

A central component to AENV's definition of BATEA is that the technology must have been demonstrated in successful commercial application across a range of regions. As there has been very limited operating experience with SCR in Alberta, there exists uncertainty regarding the operation, performance effectiveness and associated operating costs. Indeed, the ARC report suggested further studies should be completed to understand the costs and technology options appropriate for Alberta.

Although SCR has been demonstrated to be effective in many states throughout the US, the technology has not been demonstrated in commercial use within a climate as variable as Northern Alberta. Many studies, including those referenced above, indicate that very cold ambient temperatures (below -20°C) could affect the overall reduction performance of SCR. Environment Canada has submitted a similar conclusion in a letter submitted to Alberta Environment (addressed to Sandra McMillan) from Margaret Fairbairn at Environment Canada on November 7, 2006 regarding Alberta Environment's NOx BATEA Review for Stationary Sources North of Fort McMurray. In this letter, Environment Canada submits that SCR is not well-suited for operation in northern climate.

Since SCR has not been demonstrated through commercial application in northern climates, it should not be considered BATEA as defined by AENV.

Environmental Risk

The benefits of additional NOx emission reductions resulting from the use of SCR must be weighed with the associated environmental impacts of the technology. Both Environment Canada[1] and the US Environmental Protection Agency[2] (EPA) have raised concerns about the collateral environmental impacts associated with the use of SCR as BATEA or BACT. Some of the environmental impacts to be considered include:

- Ammonia slip emissions, which may contribute to increased ground-level concentrations of ammonia, acid deposition, and fine particulate matter.
- Handling and disposal of the spent catalyst, as the materials contained within the spent catalyst of SCR include heavy metal oxides such as vanadium and/or titanium.

The negative collateral environmental impacts must be considered along with the performance uncertainties listed above when assessing whether SCR is an appropriate control technology for NOx reductions in Alberta.

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[1] Letter from Margaret Fairbairn (Environment Canada) to Sandra McMillan (Alberta Environment), Re: Alberta Environment's NOx BATEA Review for Stationary Sources North of Fort McMurray (November 7, 2006)

[2] Letter from John Seitz (US EPA) to Air Division Directors (US EPA), Re: Consideration of Collateral Environmental Impacts Associated with the Use of SCR at Dry Low NOx Combined Cycle Natural Gas Turbines (Draft August 4, 2000)

CAPP'S POSITION ON NOX PERFORMANCE STANDARDS FOR COGENERATION SYSTEMS

To provide heat and power, cogeneration systems are composed of two units: a turbine and a heat recovery steam generator (HRSG). Waste heat from the gas turbine exhaust is used in the HRSG to produce steam, which ultimately imparts the environmental and economic benefit of a cogeneration system installation.

To credit the benefits of cogeneration systems, NOx performance standards for cogeneration systems must include a standard for each the turbine component and the HRSG component. In this section, we present CAPP's recommendation for each component of the cogeneration system, beginning with a recommended path forward for determining an appropriate standard for natural gas-fired turbines, followed by the heat recovery allowance for the HRSG unit.

Natural-gas Fired Turbines in Cogeneration Systems

CAPP is supportive of continuous improvement in control technology and emissions performance, and agrees that source performance standards should be based on BATEA as defined by AENV. As described above, CAPP is concerned with source performance standards based on SCR, as this technology may not be cost-effective, nor has successful commercial application been demonstrated in northern climates.

CAPP is concerned that the economics of SCR may unintentionally discourage companies from installing cogeneration units at oil sands facilities in the future. Cogeneration should be encouraged because it improves efficiency, reduces fuel use and GHG emissions, when compared to standalone electricity and steam generation.

That being said, CAPP does support the principle of continuous improvement in emissions performance from cogeneration units. We are proposing a path forward to develop a performance standard for new gas-fired turbines for cogeneration systems approved after January 1, 2011. The proposed standard will be based on the following criteria:

- A reduction from the existing CCME Guideline for gas-fired turbines of 0.50 kg/MWh (140 g/GJ).
- Set at a level achievable with dry low NOx combustion control technology.
    - Dry low NOx is a reliable, cost-effective control mechanism with minimal environmental risk,
    - Offers operators the flexibility to determine the most appropriate control technology (combustion or post-combustion) based on their facilities' unique operating characteristics; and
    - A standard that is equitable for simple cycle, cogeneration and combined cycle configurations.
- Achievable in Alberta's cold and dry ambient conditions.
    - The lower the NOx emissions desired, the tighter the operating conditions become. Research studies1 and oil sands industry experience with NOx control technologies

[1] Alberta Research Council (2007), *Technologies for Reducing NOx Emissions from Gas-Fired Stationary Combustion Sources*. Prepared for Alberta Environment; Staudt (2000), *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines – Technologies & Cost Effectiveness*, Prepared for the Northeast States for Coordinated Air Management.

suggests that ambient air temperatures can impact the effectiveness of control, with emissions increasing as temperatures decrease below -20°C.

- o The US EPA recognizes the challenges with meeting NOx emissions in cold climates, and has set a less stringent performance standard for natural gas-fired turbines installed in facilities located north of the 60th parallel. The NOx emissions standard set for turbines in this region is 96 ppm at 15% O2.

Although CAPP believes that SCR is inappropriate as a BATEA standard for gas-fired cogeneration units in Alberta, we acknowledge that end-of-pipe control technology, such as SCR, may be required in regions where air quality is a concern. However, such a technology recommendation remains outside the scope and mandate of the CASA Electricity Framework Review.

Path Forward

To determine an appropriate and achievable NOx performance standard based on the criteria listed above, CAPP recommends that a technology and performance review of cogeneration facilities operating in Alberta be undertaken. This study would consist of collecting NOx emissions performance data through CEMS and manual stack surveys and documenting the type of NOx controls used. This technology and performance review would provide stakeholders with the following:

- Performance of existing NOx control technologies used in cogeneration units.
- Seasonal variations in performance from changes in ambient temperature conditions.
- NOx control technology recommendations for new cogeneration facilities approved after 2011.

CAPP believes this approach is consistent with Alberta Environment's Oil Sands Environmental Management Division's Approval Program Interim Policy No. 2 ("Policy No. 2"), which states that "a technology review will be undertaken by AENV in conjunction with regional and industrial stakeholders to validate the performance of existing technologies and the applicability of additional technologies that could be used in the future". This study would accomplish the objective of *validating* performance of existing technologies, while providing more detail on the applicability of additional technologies, namely dry low NOx. Dry low NOx was disregarded in the ERG Report, upon which the proposed NOx standard was based[1].

CAPP proposes convening a multi-stakeholder committee to develop the project's terms of reference and proposal, to review the project's results, and to make a recommendation on a NOx performance standard based on the criteria listed above. Preferentially, this multi-stakeholder group would be convened by the CASA Board and managed through CASA Secretariat.

[1] The ERG report, upon which the CTRS Subgroup based the initial control standard for gas-fired turbines, considered the applicability of additional technologies but disregarded the potential for dry low NOx technology as a potential BATEA by dry low NOx offered only 25 ppm as standard. Studies show that dry low NOx technologies can achieve a standard as low as 9ppm (though this has yet to be proven achievable in Alberta's climate).

Heat Recovery Allowance for Cogeneration Systems
Both natural gas combined cycle (NGCC) units and cogeneration systems include a gas turbine generator and HRSG. However the NGCC unit also includes a steam turbine (ST).

Consistent with CCME and the CTRS subgroup, CAPP is supportive of proposing a NOx standard that is based on net power output (GTG and ST). This methodology provides credit to NGCC and cogeneration systems for the gains in efficiency over simple cycle units. The CTRS Subgroup's Recommendation 4 provides credit for NGCC systems, with an output NOx performance standard calculated based on net power output from the systems' gas and steam turbines. Given the stringency of the standard proposed by the CTRS Subgroup associated with electricity generation, combined cycle operators could have greater flexibility in achieving the required NOx emissions in comparison to cogeneration operators.

Furthermore for combined cycle and cogeneration units, the CTRS Subgroup has recommended a heat recovery allowance of 0.01 kg NOx/GJ, representing a 75% reduction from the current CCME Guidelines. According to Recommendation 4, the proposed heat recovery allowance of 0.01 kg NOx/GJ was based upon the performance target specified in Policy No. 2.

CAPP is concerned that the CTRS has stipulated a numerical value that was intended in Policy 2 as a performance target is now being considered as a compliance standard without the appropriate context described in Policy 2.

Furthermore, the recommended heat recovery allowance for NGCC and cogeneration units does not consider that the duct burners used in HRSGs, are considerably different with respect to burner configuration, efficiency and the associated emission performance standards in comparison to burners used in conventional boilers and once through steam generators (OTSGs). The existing heat recover allowance for HRSG units is 0.04 kg NOx/GJ, as indicated in the CCME Guidelines for Stationary Combustion Turbines[1] and recommended in the CASA 2003 Framework[2].

As recognized in Policy No.2, further review is required to understand the performance limitations and capability of duct burners prior to agreeing to an emission standard. In order for CASA to recommend a heat recovery allowance for HRSG units that differs from the CCME Standard and the CASA 2003 standard, a BATEA analysis on HRSG units must be completed. Until this time, **CAPP recommends that the heat recovery allowance for HRSG units remain at the existing standard of 0.04 kg NOx/GJ**.

[1] Canadian Council of Ministers of the Environment (CCME). 1992. National Emission Guidelines. PM 1072, CCME NOx/VOC Management Plan, Multistakeholders Working Group and Steering Committee.
[2] CASA (2003). An Emissions Management Framework for the Alberta Electricity Sector, Report to Stakeholders. Prepared by the Electricity Project Team. November 2003.

APPENDIX V: **NGO Comments on the CTRS Recommendations**

Section I. Comments on the BATEA recommendation for non-peaking gas-fired units:

NGOs support the recommendation that SCRs be designated as BATEA for non-peaking gas-fired units for the following reasons:

- According to the EPT definition of BATEA, BATEA technologies are those that have *been demonstrated to be economically feasible through successful commercial application across a range of regions and fuel types.* The ERG consultant's report clearly demonstrates that SCRs are applied widely across the U.S., the technology is increasingly being used in Canada and is used in both gaseous and non-gaseous fuel applications. As such the NGO members believe that SCRs clearly meet the EPT definition of BATEA which is the BATEA definition that should be applied.
- During discussions with the CTRS sub-group, ERG was specifically asked to comment on the application of SCRs in colder climates. ERG indicated that their research showed that SCRs were installed in applications in cold climates in the U.S. including in Alaska. The only associated inconvenience noted was that, in at least one such case, the system was housed indoors in order to avoid any cold weather impacts. It was noted that the increased cost of constructing a building to house the system was not considered to be significant in comparison to the total cost of the technology. An SCR unit has been operated at the Calgary Energy Centre (formerly the Calpine Energy Centre) and an SCR unit is part of EPCOR's new generation facilities at Cloverbar in Edmonton.
- While ERG did not specifically consider the application of SCRs at chemical facilities and other industrial facilities, a cursory review of information on the USEPA RBLC website http://cfpub1.epa.gov/rblc/htm/bl02.cfm indicates that SCRs are indeed in operation on several chemical facilities in the U.S.. The BP Amoco Co. Chocolate Bayou plant in Texas and the Shell Chemical Co. Geismar plant in Louisiana are examples.
- Ammonia slip was considered by ERG in its review. It was noted that ammonia slip was only expected to be of concern at NOx levels significantly more stringent than those recommended by the group. Where ammonia slip is an issue in the U.S. regulators have addressed the issue by putting in place regulations that limit the allowable ammonia emissions from associated facilities. It is noted that ammonia is already being used as a scrubbing agent in Syncrude's flue gas desulphurization system.

The NGO members of the team would like to note that while consensus was not reached on designating SCRs as the technology to be used in setting BATEA limits among all industry members of the team, the industry members that did agree to this recommendation include a number of companies such as TransAlta, TransCanada and ATCO Power that do own and operate gas-fired cogeneration units on industrial sites including sites in the oil sands region.

The NGO members of the sub-group would also like to note that many of the concerns raised by industry members with the application of SCRs, particularly those concerns raised with their application in specific industrial applications, for example as part of chemical facilities, were raised late in the CASA process. As such there was insufficient opportunity to discuss the issues and have them addressed by the experts hired to examine the control technologies and their application. The NGO members of the group feel that this inappropriate participation in the process has hampered the group's ability to fully address all concerns raised by industry but believes these concerns could have been largely addressed had they been raised in an appropriate timeframe. The NGO members would like to bring this concern to the attention of the CASA Board so that it might take steps to ensure similar issues are not encountered in other CASA-based processes, including future five-year reviews.

A. Background on SCRs as BATEA for Gas-fired Generation[1]

1. NOx Generation and Control Options:

Nitrogen oxides (NOx) are formed in high temperature combustion processes and are the result of the oxidation of the nitrogen in the combustion air (called thermal NOx) or in the fuel (called fuel NOx). In the combustion of natural gas, fuel NOx is negligible. The production of thermal NOx in gas turbines and boilers and furnaces is a function of temperature and fuel/oxygen ratios. By controlling temperature and/or fuel/oxygen ratios, NOx formation can be significantly reduced. This method of NOx reduction is termed *"combustion control"*. Reduction controls that remove NOx from the flue gas after the combustion stage are termed *"post-combustion controls"*. General information on NOx formation and control can be obtained from the United States Environmental Protection Agency (USEPA) website.[2,3]

Table 1 summarizes combustion and post-combustion NOx controls applicable to gas turbines, boilers and furnaces. The technologies in this table are well demonstrated and widely used. Where a high level of NOx control is required, a combination of low NOx "combustion" controls and "post combustion" control, e.g. SCR, are used. This approach reduces the capital and operating costs of the post-combustion control system.

[1] The following is based on a submission by the Fort McKay IRC to Alberta Environment on the application of BATEA to cogeneration facilities in the oil sands region.

[2] http://www.epa.gov/eogapti1/module6/nitrogen/formation/formation.htm

[3] Air Pollution Control Technology Fact Sheet. United States Environment Protection Agency. EPA-452/F-03-032 <http://www.epa.gov/ttncatc1/dir1/fscr.pdf>

Table 1: NOx Control Technologies [1,2,3,4]

NOx Control Technology	Description	Reductions achievable (compared to normal combustion)	Comment
Combustion			
▪ Low excess air (LEA)	Reduced airflow to combustion zone to minimize excess oxygen	25%	One or more of these combustion controls are built into the design of new gas turbines and boilers and furnaces so in general these reductions are already being realized with new units.
▪ Low NOx burners (LNB)	Involves staged combustion (either controlled fuel or controlled air) to reduce flame temperatures	25-50%	
▪ Low NOx burners plus overfire air (LNB + OFA)	Involves adding some of the combustion air after the burner stage	60%	
▪ Flue gas recirculation (FGR)	Involves recirculation of some of the combustion gas to lower flame temperature	25%	

[1] Nitrogen Dioxide in the United Kingdom Report (2004) http://www.defra.gov.uk/environment/airquality/aqeg/nitrogen-dioxide/nd-glossaryapp.pdf see page 317

[2] Emissions Trading For Alberta: Major Feasibility Study (INTERIM REPORT) to Alberta Environment: *Costs of Technologies to reduce NOx and SOx Emissions From Industrial and Electric Power Generation Sources in Alberta*, Cheminfo, December, 2002 DRAFT

[3] NOx Emissions Solutions for Gas Turbines by Kevin A. Carpenter, Siemens Westinghouse Power Corporation, 4400 Alafaya Trail, MC 250, Orlando, FL 32826-2399
http://www.netl.doe.gov/publications/proceedings/02/scr-sncr/carpentersummary.pdf

[4] Controlling NOx Emissions Part 1 and 2, Mike Bradford, Raive Grover, Peter Paul; www.cepamagazine.org , March 2002

[viii] An Emissions Management Framework for the Alberta Electivity Sector Report to Stakeholders. Clean Air Strategic Alliance. November 2003. ISBN 1-896250-25-4 http://casahome.org

Table 1 NOx Control Technologies [iv,v,vi,vii] (continued)

NOx Control Technology	Description	Reductions achievable (compared to normal combustion)	Comment
Combustion(cont)			
▪ Water-steam injection	Water or steam injected to control combustion temperature	60%	These and the other combustion technologies may be retrofitted on existing units depending on the combustion system characteristics.
▪ Natural gas reburning (NGR)	15-20% of natural gas is added after primary combustion zone	60%	
Post-combustion			
▪ Selective non-catalytic reduction (SNCR)	Involves injecting ammonia or urea into the hot flue gas (870-1,090°C)	20-60% beyond combustion controls	The process is difficult to control and is very temperature dependent. At higher temperatures the ammonia can form more NOx and at lower temperatures NOx reduction does not occur and ammonia releases occur (termed “ammonia slip”).
▪ Selective catalytic reduction (SCR)	Involves injecting ammonia or urea in the flue gas in the temperature range of 300-400 °C upstream of a catalyst e.g. vanadium pentoxide	75-90% beyond combustion controls	The catalyst helps ensure good (rapid) reaction between the NOx and NH_3 resulting in high NOx reduction and minimal ammonia slip

2. NOx Emission Limits and Best Available Demonstrated Technology (BADT):

In Alberta the current emission limits for gas turbines and boilers and heaters are based on the following guidelines:

a. Alberta Environment’s “Alberta Air Emission Standards For Electricity Generation” (Dec., 2005) which are the standards outlined in the CASA Emissions Management Framework for the Alberta Electricity Sector(2003)[1] (note: because in some circumstances the CCME National Emission Guidelines for Stationary Combustion Turbines(1992)[1] are more stringent than CASA limits they are still being used)

b. Alberta Environment's. Interim Emission Guidelines for Oxides of Nitrogen (NO,) for New Boilers, Heaters and Turbines using Gaseous Fuels for the Oil Sands Region in the Municipality of Wood Buffalo North of Fort McMurray based on a Review of Best Available Technology Economically Achievable (BATEA). Alberta Environment. Dec. 2007 (Policy 2)[2] and
c. CCME National Emission Guidelines for Commercial/Industrial Boilers and Heaters(1998).[3]

Table 2 outlines the emission limits in these documents. In general the CCME (1992)[4] and the CASA(2003)[5] limits reflect the use of good, but not the best, combustion-based NOx controls. A comparison of the CCME and CASA limits to those in the United States is complicated by the fact that, in the United States, emission limits for new major sources or major modifications at existing sources are reviewed and set on a case by case basis. Information on this standard setting approach is available on the USEPA website.[6,7]

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[1] National Emission Guidelines for Stationary Combustion Turbines. Canadian Council of Ministers of the Environment. December 1992.ISBN:0-919074-85-5

[2] Interim Emission Guidelines for Oxides of Nitrogen (NO,) for New Boilers, Heaters and Turbines using Gaseous Fuels for the Oil Sands Region in the Municipality of Wood Buffalo North of Fort McMurray based on a Review of Best Available Technology Economically Achievable (BATEA). Alberta Environment. Dec. 2007 (Policy 2)

[3] National Emission Guidelines for Commercial/Industrial Boilers and Heaters. Canadian Council of Ministers of the Environment. March 1998.ISBN:1-896997-16-3

[4] National Emission Guidelines for Stationary Combustion Turbines. Canadian Council of Ministers of the Environment. December 1992.ISBN:0-919074-85-5

[5] An Emissions Management Framework for the Alberta Electivity Sector Report to Stakeholders. Clean Air Strategic Alliance. November 2003. ISBN 1-896250-25-4 http://casahome.org

[6] New Source Review (NSR) < http://www.epa.gov/nsr/psd.html>

[7] USEPA RACT/BACT/LAER Clearinghouse (RBLC) http://cfpub1.epa.gov/rblc/htm/bl02.cfm

Table 2: A Summary of the NOx Emission Limits in Alberta for Gas-Fired Turbines and Gas-Fired Boilers

Unit Type and Size	Limits (these are on an output basis)				Comments
	AENV Policy 2[1]		CASA/AENV	CCME	
	Compliance	Target			
Gas Turbine >20MW	Based on CASA or CCME whichever more stringent	0.244 kg/MWh for electricity output and 0.035 kg/MWh for any steam/heat output from the unit	0.3 kg/MWh	0.504 kg/MWh for electricity output and 0.144 kg/MWh for any steam/heat output from the unit	The CCME limits are based on combustion controls but are dated and new units achieve much lower emissions. The CASA/AENV limits reflect advances in combustion-based NOx control but currently available units can achieve lower emissions and these limits are based on limited duct firing. The Policy 2 targets limits are based on newer combustion based NOx controls are what industry is to design to .

[1] The limits are based on input but for comparison purposes were converted to output using a turbine efficiency of 30% and a heat recovery efficiency of 80%.

3. NOx Emission Limits in the United States:

The following is a brief summary of the USEPA process for setting emission limits and the current NOx emission limits and controls being required on larger gas-fired turbines and boilers. This information is provided to supplement the information gathered by the ERG consultant in their work for the Control Technologies Sub-group of the CASA Electricity Framework Review Team.

a. A principle entitled: "*Prevention of Significant Deterioration (PSD)*" is applied in airsheds that are meeting National Ambient Air Quality Standards (NAAQS). These airsheds are called attainment areas.
b. New major sources for pollutant, or major modifications at existing sources for pollutants, must install Best Available Control Technology (BACT).
c. BACT is described as: "*… an emissions limitation which is based on the maximum degree of control that can be achieved. It is a case-by-case decision that considers energy, environmental, and economic impact. BACT can be add-on control equipment or*

modification of the production processes or methods. This includes fuel cleaning or treatment and innovative fuel combustion techniques. BACT may be a design, equipment, work practice, or operational standard if imposition of an emissions standard is infeasible."

d. A database of air permits is maintained to provide information on what has been required as BACT in air permits. The database is called the RACT/BACT/LAER Clearinghouse (RBLC).

This approach ensures that the most current information is used in setting limits and/or establishing control requirements. It also allows for consideration of economic factors which can vary from sector to sector, location to location and/or facility to facility.

The BACT process is distinct from the requirements for LAER (Least Achievable Emissions Rate) which "focuses on requiring the most stringent emissions limitation achieved in practice for such class or category of source...".[1] BACT is normally required in projects where air quality standards are not projected to be violated, and LAER is required for projects with impacts that may exacerbate existing or create new violations of air quality standards.

Searches of the RBLC database were done to determine the results of recent BACT decisions for large gas-fired turbines. The results of these searches are summarized in Table 3. It appears that BACT for co-generation units has, in the majority of recent approvals, been considered to include post-combustion NOx controls (generally SCR).

A more complete definition of BACT[2] is:

> *"an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant."*

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[1] *California Air Pollution Control Officers Association Best Available Control Technology Clearinghouse,* Section VIII. Control Technology Definitions, Sub-section B. LAER http://www.arb.ca.gov/bact/docs/controltech.htm

[2] USEPA New Source Review Workshop Manual –Prevention of Significant Deterioration and Nonattainment Area Permitting (Draft October, 1990) http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf

The definition of BADT[1] is:

> "emission control technology based on the maximum degree of emission reduction that has been shown to be practicably and economically achievable for a given source and type."

The experience and practice in the United States would indicate that SCR is generally considered to be BACT for co-generation units and in some circumstances for boilers. This requirement applies in areas meeting the NAAQOs which means it is the minimum requirement.

Table 3: Summary of NOx Emission Control Requirements for Large Gas Boilers, Furnaces and Boilers Approved in the United States since January 1, 1995[a]

Type of Unit	Number of Process Units Approved Since January 1995[b] with Noted Control & General NOx Limit[c]			
	Pollution Prevention (PP) (combustion controls)	Add on Controls	PP + Add on controls	PP + SCR
Large Natural Gas Combined Cycle and Cogeneration Combustion Turbines (>25 MW)	86 units (general range of NOx limits = 9 to 42 ppmdv @ 15 % O_2)	81 units (NOx limits = 2 to 9 @ 15 % O_2 –note it appears that SCR is the add-on technology at most of these units)	192 units (general range of NOx limits is less than 5 ppmdv @ 15 % O_2 – and add-on technology is generally SCR)	135 units (general range of NOx limits =2 to 7 ppmdv @ 15 % O_2 –note most less than 3.5 ppmdv) [1]

[1] Information obtained from USFPA RACT/BACT/LAER Clearinghouse (RBLC) which *"...contains case-specific information on the "Best Available" air pollution technologies that have been required to reduce the emission of air pollutants from stationary sources (e.g., power plants, steel mills, chemical plants, etc.). This information has been provided by State and local permitting agencies.*" http://cfpub1.epa.gov/rblc/htm/bl02.cfm

[b] It was noted that some units are listed under "add on controls" and under "PP + add on controls" so there is some data duplication/overlap

[c] These NOx limits were based on a review of the limits for 5 to 10 units selected randomly from the total list of units for that process and control type

4. Costs for SCR:

The cost for SCR control depends on the size of the unit, the flue gas NOx levels (which is a function of the NOx combustion-related controls) and on the total level of NOx reduction

[1] Sulphur dioxide management in Alberta. The report of the SO2 management project team, CASA 1997, p.19. See also Appendix 3. http://casahome.org

desired. The cost data on SCR provided by ERG is consistent with other NOx reduction cost data taken from USEPA reports.'[1]

A partial review of cost data from the USEPA RBLC database [xiii] indicates per ton NOx reduction costs ranging from approximately $1500 to $6500 per ton.

The research by Eastern Research Group stated the cost-effectiveness of SCR to be approximately $4200/tonne (Table 3-4). According to the modelling done by EDC for the CASA team the SCR based limits are expected to reduce emissions from gas-fired units by between 737 tonnes in 2015 rising to just over 1500 tonnes in 2030. This puts the cost per year of SCRs at $3M in 2015 rising to $6M in 2030 for the gas-fired sector as a whole. This modest cost will result in emissions reductions from gas-fired units in the sector of between 6% in 2015 to 9% in 2030. By 2030 the emissions reductions achieved by the sector would be equivalent to what a new 400MW coal-fired power plant would emit and would cost the sector just $6M annually.[2]

This limited cost data review would indicate that SCR control technology is not only expected to achieve significant reductions beyond combustions controls (75%-90% as indicated in Table 2) but is also economical and cost-effective.

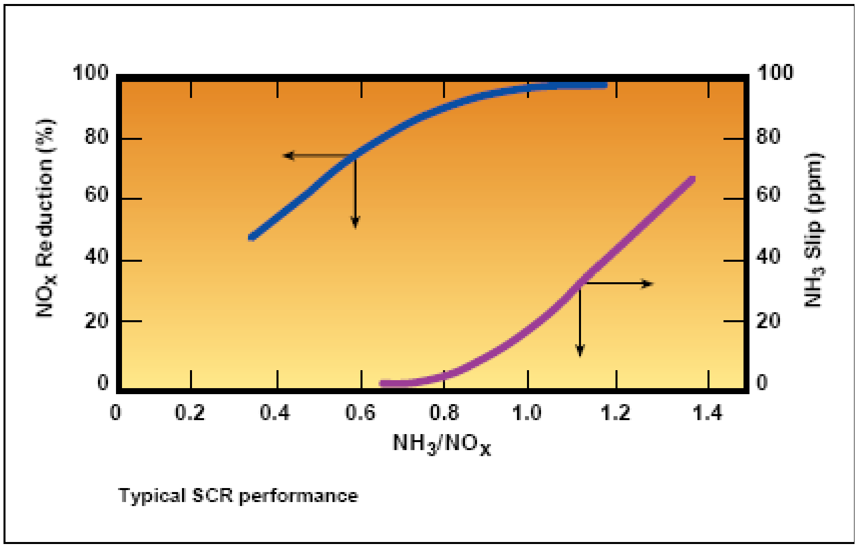
5. Ammonia Slip and the Relative Environmental Benefits of SCR:

One of the disadvantages associated with SCR control of NOx is "ammonia slip" which is the unreacted ammonia that remains after the catalyzed reaction between NOx and ammonia. This ammonia is emitted in the flue gas. A portion of the NOx emissions are therefore replaced by ammonia emissions and the environmental and health impacts of these emissions need to be considered.

[1] Analysis of Multi-Emissions Proposals for the U.S. Electricity Sector Requested by Senators Smith, Voinovich, and Brownback Prepared by: U.S. Environmental Protection Agency (2001) http://www.epa.gov/air/meproposalsanalysis.pdf.

[2] Assumes majority of emissions from gas-fired are from combined cycle and cogeneration facilities. A new coal fired power plant emitting at the new standards of 0.47kg/MWh and 80% capacity factor would emit 1,318 tonnes (=0.47 kg/MWh x 450MW x 0.8 x 8760 hours)

The following Figure from a clean coal technology SCR demonstration project report[1] shows that ammonia slip is a function of the NH_3 to NOx ratio entering the catalyst.



At NH_3 to NOx ratios of approximately 0.8, NOx removals of approximately 80% are achieved with minimal NH_3 slip (i.e. 2 ppmv).

Table 4 is a comparison of NOx versus NH_3 environmental and health issues and a qualitative evaluation of the overall benefits and disbenefits of SCR for NOx control.

Table 4: A Qualitative Comparison of the Relative Environmental and Health Issues of NOx versus Ammonia

Environmental and/or Health Issue	Comparison of Effects of NOx vs. NH_3		
	NOx	NH3	Comment
Ozone formation	yes	no	NOx appears to be the limiting precursor for O_3 formation in the Ft. McMurray region
Fine particulate formation	yes	yes	Since NH_3 is quite water soluble and reacts with nitrates and sulphates, it would likely contribute more to local fine particulate than NOx
Acid deposition	yes	yes	The acidification effects of NOx vs. NH_3 would be site specific but in general would likely be equivalent in most cases. Deposition of ammonia would likely occur faster which would affect the spatial distribution of deposition
Eutrophication	yes	yes	Same as for acid deposition
Direct Human health	yes	yes	The AAQOs[4] have a 1 hour limit for NH_3 of 1400 ug/m3 and 400 ug/m3 for NO_2
Direct Vegetation	yes	yes	European Guidelines recommend short term (24 hour)

[1] Control of Nitrogen Oxide Emissions: Selective Catalytic Reduction (SCR), TOPICAL REPORT NUMBER 9, The U.S. Department of Energy and Southern Company Services, Inc. JULY 1997

			limits of 270 ug/m3 for NH_3 and 70 ug/m3 for NOx and long term (1 year) limits of 8 ug/m3 for NH_3 and 30 ug/m3 for NOx
Climate Change	yes	?	Nitrate deposition that undergoes denitrification could contribute to N_2O releases. NH_3 could also contribute to N_2O releases but it would first have to go thru the nitrification cycle so it would seem less likely to contribute to climate change

If it is assumed that:

- the NOx emissions of new turbines and boilers are in the 15 to 20 ppmv range, and
- an 80% reduction in this rate is achievable with SCR at an ammonia slip rate of 2ppmv,

then 12 to16 ppmv of NOx emissions would be replaced with 2ppmv of NH3 emissions if SCR was employed. Based on the issues and criteria identified in Table 6, this removal rate of NOx and exchange rate of NH_3 for NOx would have net positive effect for all environmental and health issues associated with NOx and NH_3 (note: the issues of fine particulate formation and greenhouse gas require more analysis).

There are health and environmental issues associated with ammonia storage and transport however risk management strategies and controls are well established since ammonia is widely used in agricultural and industrial applications. There are also alternatives to reduce these risks such as onsite urea to ammonia conversion.[1]

6. Emissions Control Technology and Ambient Air Quality

The emissions limits recommended under recommendation #4 of the Electricity Framework Review Report assumes the installation of SCRs, but does not assume that SCRs will be applied in such a manner as to achieve the maximum emissions reduction potential from the technology. It is recognized that in many areas of the province concerns with ambient air quality are emerging. As such, NGO members of the team expect that, consistent with recommendations 32 and 33 of the original Electricity Project Team framework, where an air quality issue is identified further emissions reductions may be required from facilities in the "Hot spot" region.

Section II. Comments on Recommendations for Peaking Units

NGOs support the proposed peaking unit limits in recommendation 4 for the following reasons:

- The emissions levels that would be required by peaking units represent the application of technology that is consistent with the technology widely being applied on peaking units in the U.S..
- The emissions levels required under recommendation 4 are similar to the alternative recommendation presented in Option A. Recommendation 4 indicates that peaking units

[1] EC&C Technologies Inc. Risk Reduction through Urea – to – Ammonia Conversion. EM Air & Waste Management Association (Sept. 2005)

greater than 100 MW should be designed to meet a design specification of 9 ppmv. This would result in an emissions intensity that are in line with, but likely slightly less than, the 0.2kg/MWh intensity requirement expressed under the Option A alternative recommendation. Similarly, recommendation 4 indicates that units between 25MW and 100MW should be designed to meet a limit of 15 ppmv, which would also result in an emissions level that is similar to, but again likely slightly less than, the 0.25kg/MWh intensity recommended in Option A

NGOs recognize that it is important that Alberta have sufficient peaking capacity to accommodate intermittency issues associated with increased wind development in the province. As such NGOs believe it is appropriate that the recommendation provides a broader definition of peaking units (i.e. is established in a manner that allows peaking units to run up to 3000 hours per year as opposed to 1500 hours per year as indicated in Option A).

APPENDIX VI: Canada's Chemical Producers Association Issues with NOx Proposed Standard

CASA – Electricity Framework Review Project Team
Control Technologies and Reduction Strategies Task Team
June 3, 2009
Consensus Issues with suggested BATEA for Gas Fired Units

Key members of the Canadian Chemical Producers' Association (CCPA) have reviewed proposed standards for gas fired units, and want to reiterate concerns raised in the consideration of Selective Catalytic Reduction (SCR) control technology. CCPA supports the alternate proposal brought forward by CAPP.

CCPA issues with the NOx proposed standard for new gas-fired thermal generation units is based on the following:

- Potential process safety concerns –
  - It has been recognized, especially with pushing SCR efficiency, that ammonia slip will increasingly occur, and the implications of SCR installations, anhydrous ammonia storage and ammonia releases in a hydrocarbon environment such as a large petrochemical complex have not been assessed

- Cost / benefit associated with SCR technology and costs associated with addressing process safety concerns –
  - The additional and substantive cost increases associated with installation of a SCR in a hydrocarbon environment that required a Class 1, Division 1 Electrical Code rating were apparently not considered within the CASA cost assessment. Given that without the above additional cost consideration, the small incremental benefit from SCR over dry-low-NOx could not be justified on a cost basis this would further undermine the cost/benefit analysis.
  - On the environmental benefit side, while the need for continuous improvement is acknowledged, there appears to be is no demonstrated urgent need to address NOx emissions in the Alberta air-shed. The need or urgency of addressing future NOx emissions will be further clarified by other Alberta environment initiatives such as the cumulative effects, air quality modeling and regional planning. At that time the factual base for further emission reduction requirements will be much better established.
- CCPA's understanding of other industry non-consensus issues and proposed options for reducing NOx emissions from electricity generating facilities:
- CAPP Alternative Proposal to CASA with regard to NOx Performance Standards for Natural Gas-Fired Co-generation

- From CCPA's understanding of the CAPP Alternative Proposal, it also considers NOx emission reduction in the context of Air Quality Management in Alberta and its applicability to the upstream oil and gas sector in general and specifically oil sands development facilities. While acknowledging a commitment to continuous improvement CAPP questions the use of SCR technology as appropriate and cost effective BATEA. CAPP's cost analysis has shown that the incremental Total NOx removal by using SCR technology would be very expensive while providing only marginal control benefit. An alternate proposal by CAPP is to develop a performance standard for new natural gas fired turbines units approved after January 1, 2011. (by end of June 2009)

CCPA's review of the proposed NOx control standards and suggested BATEA by the CASA EFR-CTRS sub group

- Recognizing that the EFR has been reviewing the items as identified in Recommendation 28 of the original report for well over a year, but also that the consultant's report on the control technology was available in late January 2009, the assessment of the implications has been conducted by the CRTS sub group and the difference in the industry and NGO positions on Gas Fired Units was noted in a report dated March 10, 2009;
- Acknowledging the efforts by the industry co-chair of the EFR CTRS sub group to make CCPA aware of the proposed standards for gas fired co-generation, in March 2009; and
- Also recognizing the desire of the EFR to forward the final report to the CASA Board for its consideration on June 24, 2009, and the need to finalize documents expediently;
- Also recognizing that any non-consensus position should be documented and options considered for some future resolution, that the overall industry presentation of non-consensus should be kept as concise and combines as possible;
- Although the number of existing co-generation facilities at our petrochemical facilities is relatively small (Joffre and the Ft. Saskatchewan/Scotford area) and the units are owned and operated by joint ventures of independent companies, CCPA has not had adequate time to fully evaluate the safety and cost implications of implementing SCR control technology, but the review has been sufficient to raise considerable concern.
- NOx emissions result from a very broad range of combustion sources and the standards developed in one area are at times applied to broader emission sources without adequate assessment of implementation considerations. This may especially become an issue where cumulative effect considerations compel a look at retrofitting existing operations. Control technology implementation and implications needs to be considered to ensure the end result of a cleaner environment will in fact be achieved.

CCPA's position with regard to NOx Performance Standards for Natural Gas-Fired Co-generation

- CCPA's commitment to Responsible Care© includes continuous improvement and being proactive in reducing atmospheric emissions
- Especially in the current period of economic uncertainty, CCPA member companies are mindful of economic sustainability as well as the social and environmental aspects

- Having considered the CAPP non-consensus response and the options proposed by CAPP, CCPA agrees with most of the arguments advanced , although the petrochemical context has a number of differences

CCPA's position on the NOx standard for Gas Fire Units associated with co-gen facilities supports the CAPP alternate proposal (Option B as outlined in the CTRS – Source Standard for New Gas-Fired Thermal Generation Units – Alternate Proposals – May 11, 2009 (CASA document))

Submitted by:
Al Schulz,
Regional Director, Alberta
CCPA
June 3, 2009

APPENDIX VII: Canadian Petroleum Products Institute - Alternative Proposal to CASA NOx Performance Standards for Natural Gas-Fired Turbines

Canadian Petroleum Products Institute | Institut canadien des produits pétroliers

May 13, 2009

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Alternative Proposal to CASA
NOx Performance Standards for Natural Gas-Fired Turbines

The Canadian Petroleum Products Institute (CPPI) is pleased to provide the following comments to the CASA Electricity Framework Review Team's CTRS Subgroup in response to the proposed NOx performance standards for natural gas-fired turbines.

CPPI is the national association of major Canadian companies involved in the refining, distribution and/or marketing of petroleum products for transportation, home energy and industrial uses. Collectively, CPPI member companies operate 16 refineries (representing over 80 per cent of Canadian refining capacity) and supply over 7,000 branded retail outlets with transportation fuels across Canada. In Alberta, our petroleum refining members are Husky Energy, Imperial Oil, Petro-Canada, and Shell.

The CPPI recommends that the NOx performance standard for new gas-fired turbines be set at a level based on dry low NOx technology that is achievable in Alberta's cold ambient conditions, as outlined in the alternative proposal submitted by the Canadian Association of Petroleum Producers (CAPP).

The rationale for proposing an alternative NOx performance standard is based on the uncertain performance benefits associated with the prescribed Selective Catalytic Reduction (SCR) technology, the cost effectiveness of the prescribed SCR technology, and the environmental and safety concerns associated with the use of SCR technology. The option proposed by CAPP, and supported by CPPI, is consistent with a continuous improvement approach to the control of NOx emissions from gas-fired turbines. The need or urgency for additional measures is being evaluated by the initiatives such as Alberta's PM & Ozone Management Framework, CASA's recommendation for a Clean Air Strategy, Cumulative Effects Management, regional air quality modeling, and regional air shed planning.

The CPPI supports the review of emissions performance standards for gas-fired turbines as an element of Alberta's approach to reduce NOx emissions and prevent deterioration of air quality and overall environmental health. Multiple frameworks exist or are in development to manage air quality in face of potential growth in NOx emissions from industrial and area sources.
Many of these air quality frameworks establish or recommend multiple management response levels for managing the regional air quality based on existing and predicted regional ambient concentrations. If air quality in a region were to trigger a more rigorous response level, the air quality management framework would require more stringent actions depending upon on trends observed in source emission rates, and their projected impacts on regional ambient air quality. Implementation of the management frameworks will result in application of technological solutions appropriate to regional circumstances.

The CPPI is not opposed to reducing the NOx performance standard for new gas-fired turbines, however, the level should be set based on best available technology that is economically achievable, and that has been commercially demonstrated to operate effectively in Alberta’s climate. We observe, and concur that the recommendations of the CASA Electricity Framework Review Team do not include gas fired boilers.

Some stakeholders on the Electricity Framework Review Team are recommending that emissions performance standards for gas-fired turbines be set at a level that is only achievable through the use of SCR, and is being considered as BATEA for control of NOx from gas-fired turbines in Alberta.

Alberta Environment (AENV) defines BATEA as “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”[1]. Based on this definition, the CPPI does not consider SCR to be BATEA for NOx control for downstream refining operations in Alberta, as the technology is not economically achievable, nor has it demonstrated successful commercial application in a region with a highly-variable climate as Alberta experiences.

The *Economic Feasibility & Cost-Effectiveness of SCR* outlined in the submission by the CAPP alternative proposal forecast that the implementation of low NOx technology for the planned cogeneration facilities in the Athabasca region will result in a 4.3% reduction in NOx emissions at a cost of about $1.3 million. SCR will provide an additional 2.1% reduction at a cost of $51.7 million. As stated in the CAPP proposal, "The marginal 2.1% improvement beyond the proposed ultra-low NOx technology standard will have very little effect on ground level concentrations of NO_2 and PAI, as described in the RIWG report. This basic analysis shows that the environmental benefit of installing SCR does not outweigh the costs of requiring the technology."

[1] Alberta Environment (2005), *Alberta Air Emission Standards for Electricity Generation and Alberta Air Emission Guidelines for Electricity Generation*, Page 7: http://environment.gov.ab.ca/info/library/7837.pdf

Although SCR has been demonstrated to be effective in many states throughout the US, the technology has not been demonstrated in commercial use within a climate as variable as Alberta. In a communication to Alberta Environment (addressed to Sandra McMillan from Margaret Fairbairn at Environment Canada on November 7, 2006), Environment Canada submits that SCR is not well-suited for operation in northern climate. Since SCR has not been demonstrated through commercial application in northern climates, it should not be considered BATEA as defined by AENV.

The implementation of SCR, post-combustion control equipment adds complexity, introduces operability and reliability issues, and adds safety and environmental elements that may be reduced or even avoided by combustion controls.

In summary, SCR technology provides marginal improvements in emissions performance over low NOx burners. Its economic feasibility is questionable, and the technology has not been proven through successful commercial application across a range of regions and fuel types in Alberta's environment.

The additional cost of and operability concerns of mandated SCR versus low NOx technology may be sufficient to deter the implementation of new cogeneration units at refineries and other facilities in Alberta. Cogeneration should be encouraged because it improves efficiency, and reduces fuel use and GHG emissions, when compared to standalone heat and steam generation.

The **CPPI supports the CAPP's proposed development of a performance standard** based on the following criteria:

- A reduction from the existing CCME Standard for gas-fired turbines of 0.50 kg/MWh.
- Set at a level achievable with dry low NOx combustion control technology.
  - Dry low NOx is a reliable, cost-effective control mechanism with minimal environmental risk, and
  - Offers operators the flexibility to determine the most appropriate control technology (combustion or post-combustion) based on their facilities' unique operating characteristics.
- Achievable in Alberta's cold and dry ambient conditions.
  - The lower the NOx emissions desired, the tighter the operating conditions become. Research studies1 and oil sands industry experience with NOx control technologies suggests that ambient air temperatures can impact the effectiveness of control, with emissions increasing as temperatures decrease below -20°C.
  - The US EPA recognizes the challenges with meeting NOx emissions in cold climates, and has set a less stringent performance standard for natural gas-fired turbines installed in facilities located north of the 60^{th} parallel. The NOx emissions standard set for turbines in this region is 96 ppm at 15% O_2.

[1] Alberta Research Council (2007), *Technologies for Reducing NOx Emissions from Gas-Fired Stationary Combustion Sources*. Prepared for Alberta Environment; Staudt (2000), *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines – Technologies & Cost Effectiveness*, Prepared for the Northeast States for Coordinated Air Management.

The CAPP recommendation is for the gas turbine component of cogeneration units only and will not include a review or standard for heat recovery allowance, and does not include gas fired boilers.

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