Report on the First Five-Year Review of the Emissions Management Framework for the Alberta Electricity Sector

Prepared by the CASA
Electricity Framework Review Project Team

For the CASA Board of Directors

May 13, 2010

Acknowledgements

Members of the Electricity Framework Five-Year Review Project Team showed remarkable dedication and commitment to the challenges presented by their tasks. The volunteer time given to this project by individuals and organizations was significant.

About CASA

The Clean Air Strategic Alliance (CASA) is a multi-stakeholder partnership composed of representatives selected by industry, government and non-government organizations. Stakeholders are committed to developing and applying a comprehensive air quality management system for all Albertans.

All CASA groups and teams, including the board of directors, make decisions and recommendations by consensus. Recommendations are likely to be more effective and long lasting than those reached through adversarial processes.

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Executive Summary and Recommendations

In January 2002, Alberta Environment asked CASA to develop a new way to manage air emissions from the electricity sector. Using a multi-stakeholder collaborative approach, CASA came up with innovative solutions in the form of 71 recommendations comprising a management framework, and presented it to the Government of Alberta in November 2003. The report, *An Emissions Management Framework for the Alberta Electricity Sector*, was promptly accepted by the Government, which, along with the electricity generation industry, is now implementing the recommendations for reducing emissions.

To ensure continuous improvement and to keep the Framework timely and relevant, a key recommendation (#29) was that a multi-stakeholder review be done every five years. The intent of the five-year review is to assess new emission control technologies, update emission limits for new generation units, determine if emission limits for new substances need to be developed, review implementation progress and determine if the Framework is achieving its emission management objectives.

At the request of Alberta Environment, CASA established the Electricity Framework Review Project Team, which began its work in the fall of 2007. To maintain consistency and continuity, the project team used the same definitions as in the 2003 Framework, which was adopted by the Government of Alberta. This includes the understanding that the Framework and review activities apply to all electricity generation units in Alberta. These definitions appear in section 1.2 and in the glossary.

To ensure a thorough review, the team established several task groups to consider specific aspects of its terms of reference in more detail. These were:

- The Implementation Task Group
- The Health and Environmental Assessment Task Group
- The Control Technologies and Reduction Strategies Task Group
- The Public Consultation Task Group
- The Particulate Matter Management System Task Group

Another important element of the review was the preparation by the electricity generation industry of a continuous improvement report. Greenhouse gases, although included in the original Framework, were not part of the mandate for the five-year review.

The CASA Board approved ten (10) consensus recommendations from the Electricity Framework Review Project Team in June 2009. The team was given additional time to investigate the non-consensus issues regarding source standards for new gas-fired generation. This report presents the results of the first five-year review, including recommendations (consensus and non-consensus) consistent with the intent and purpose of the five-year review recommendations in the 2003 Framework.

Implementation

In general, non-government organizations (NGOs) and industry stakeholders were of the view that the 2003 Framework recommendations have been implemented satisfactorily. Several areas where more work is needed are the focus of recommendations 1 through 3 below. The team has also prepared terms of reference for a new task group to develop a Particulate Matter Management Plan, which is required under Recommendation 22 in the Framework.

Recommendation 1: Implementation Status of Emissions Trading Recommendations

The Electricity Framework Review Project Team recommends that:

> In 2013, the next five-year review team should complete a detailed evaluation of the implementation of recommendations 8 and 9 of the 2003 Framework, regarding the Emissions Trading System.

Recommendation 2: Public Availability of Monitoring, Reporting and Compliance Data

The Electricity Framework Review Project Team recommends that:

> Alberta Environment ensure that monitoring, reporting, and compliance data is made available to the public in an easily accessible manner, and that this be considered a high priority in Alberta Environment's Integrated Monitoring and Reporting Framework expected to be completed by March 31, 2010.

Recommendation 3: Recommendations from CASA Renewable and Alternative Energy Project Team and Electrical Efficiency and Conservation Project Team

The Electricity Framework Review Project Team recommends that:

> The CASA board review the status of implementation of the recommendations made by the Renewable and Alternative Energy project team and the Electrical Efficiency and Conservation project team by the end of 2009.

Health and Environmental Assessment

Based on the two literature reviews conducted as part of the health and environmental assessment, the team concluded that: a) no new air emission substances were identified that should be of concern to regulators; and b) no new environmental and health effects information was identified that would warrant a detailed review of the Framework. Recommendations 4 and 5 address the results of this health and environmental assessment.

Recommendation 4: Health and Environmental Effects Information

The Electricity Framework Review Project Team recommends that:

> No additional work or revisions to the Framework are required at this time based on new or additional health and environmental effects information.

Recommendation 5: Analysis of Health and Environmental Effects Research

The Electricity Framework Review Project Team recommends that:

> For future five-year reviews, a multi-stakeholder group with appropriate representation be struck to oversee a study to identify any new and relevant studies or research findings regarding potential environmental or health effects from air emissions from electricity generation, and that an independent peer review be completed on the results.

Control Technologies and Reduction Strategies

Based on the results of an independent technology review, the project team reached consensus agreement on the Best Available Technology Economically Achievable (BATEA) for new coal-fired units. They also reached agreement on BATEA for new gas-fired peaking units, but were unable to agree on the BATEA for new gas-fired non-peaking units.

Recommendations 6, 7, and 8 were agreed to by consensus and address reduction strategies for new coal-fired generation. Recommendation 9 is a non-consensus recommendation; the CASA Board agreed to forward this issue to the appropriate Government of Alberta Ministers for a final decision.

Recommendation 6: Source Standards for New Coal-Fired Thermal Generation Units

The Electricity Framework Review Project Team 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 (NOx)**
>
> > Emission standard: 0.47 kg/MWh net
> > Design specification: 0.40 kg/MWh net
> >
> > (Note: In addition to requiring compliance with the NOx emission standards, the environmental approval will include a condition that requires the proponent to design the NOx control equipment with the capability to reduce emissions to 0.40 kg/MWh net, or less.)
>
> **Sulphur Dioxide (SO_2)**
>
> > 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 new technology commissioning period.

Recommendation 7: NOx and SO_2 Credit Generation Thresholds

The Electricity Framework Review Project Team recommends that:

The following deemed credit thresholds for the 2011 BATEA standards be applied to new coal-fired and gas-fired units:

A. NOx (coal-fired) – 0.38 kg/MWh net
B. SO_2 – 0.55 kg/MWh net
C. NOx (gas-fired) – "A" factor = 0.07 kg/MWh net and "B" factor = 0.008 kg/GJ
   Non-Peaking Standard Formula:
   NOx (kg/h) = [Net Power Output (MW net) x A] + [Heat Output (GJ/h) x B]

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

Recommendation 8: Credit for Early Action on Mercury Capture
The Electricity Framework Review Project Team 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.
- 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.

Recommendation 9: Source Standards for New Gas-Fired Non-Peaking Thermal Generation Units
No consensus. Details of non-consensus recommendation are available in section 5.4

Future Five-Year Reviews

The lessons learned for this project team that can be applied to future Framework reviews center around: (a) ensuring appropriate participation from all potential stakeholders with a vested interest in electricity generation in Alberta, and (b) developing a realistic and appropriate timeline for the work of the team. The next five-year review is scheduled to occur in 2013. The 2003 Framework recommends that the review and recommendations be completed within 12 months of the formation of the project team. Pre-planning should position the project team to complete its work by December 2013. A suggested schedule for the completion of major milestones appears in section 7.

Recommendation 10: Pre-consultation Phase for Next Five-Year Review
The Electricity Framework Review Project Team recommends that:

The working group formed to develop terms of reference and timelines for the next five-year review build in a pre-consultation phase, which would involve focused public outreach about CASA as well as the Electricity Framework and progress in its implementation.

Public Consultation

Input from consultation participants suggests that the 2003 Framework is focused on the right priorities. Concerns were expressed about emissions trading, and recommendation 1 should help to address those concerns. Participants also wanted to see: more focus on developing clean, renewable electricity sources; increasing efficiency at generation units; and more effort to improve conservation. These concerns were recognized, but were outside the scope for this review. There is an ongoing need to share information, both in concerned communities and across Alberta, about what is being done to reduce emissions from electricity generation. This need is partly addressed by recommendation 10 for a pre-consultation phase in the next five-year review, and by recommendation 11 below.

Recommendation 11: Higher Profile for the Electricity Emissions Management Framework
The Electricity Framework Review Project Team recommends that:

> CASA maintain a website that is updated twice a year with information about the Framework and its implementation.

Continuous Improvement in the Electricity Sector

In line with the Framework's direction, electricity generators prepared a continuous improvement report as information. The report examined Alberta's load history and forecast, looked at the changes in generation (both added and retired) between 2003 and 2008, and described the continuous improvement initiatives undertaken between 2003 and 2008 in the sector. It also identified goals for further continuous improvement between 2008 and 2013. Progress against these goals will be assessed at the next five-year review.

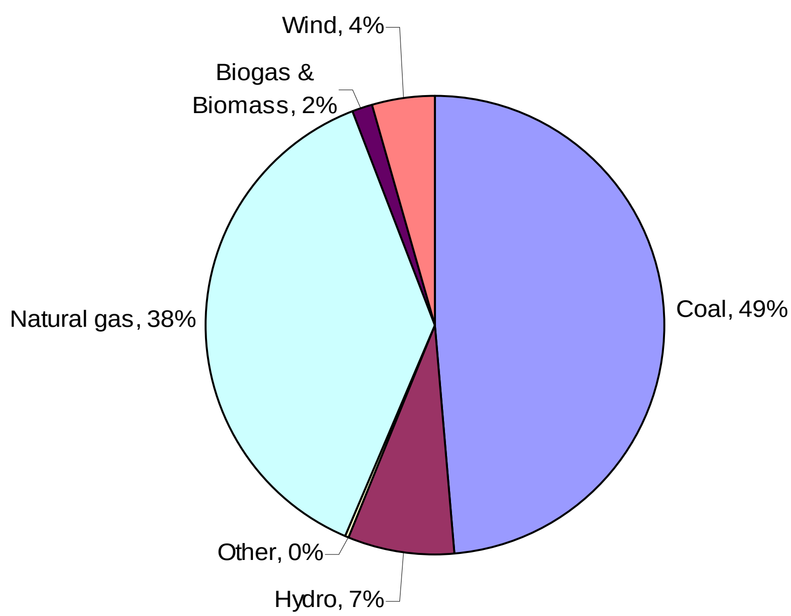
1 Alberta's Emissions Management Framework for the Electricity Sector

1.1 Electricity Generation in Alberta

Albertans count on having a reliable support of electricity – an important commodity in our everyday lives. Alberta's electricity sector has seen many significant changes in the last ten years, including deregulation and a growing demand for power due to rapid industrial development and population growth. At the same time, concerns have been raised about the health and environmental impacts of air emissions due to electricity generated from fossil fuels, mainly coal.

Figure 1 shows the installed capacity in the province, by source for 2007. "Installed capacity" is the total amount of electricity that theoretically could be produced if all the facilities in Alberta were generating power.

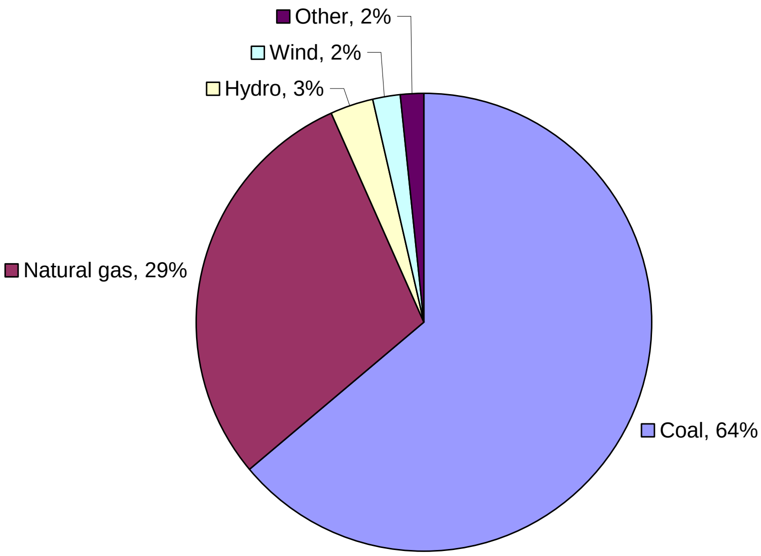
Figure 1. Alberta's Electric Energy Capacity by Source, 2007



Total installed capacity = 12,142.6 MW.
Source: Alberta Utilities Commission. "Other" includes oil, diesel, geothermal and solar.

In 2007, Alberta produced 69,212 gigawatt-hours (GWh) of electricity; sources of this generation are shown in Figure 2.

Figure 2. Alberta's Electric Energy Generation by Source, 2007



Source: Alberta Electric System Operator. "Other" sources are biomass and waste heat.

Electric power generation is a significant emitter of several major air pollutants: sulphur dioxide (SO_2), nitrogen oxides (NOx), and mercury (Hg).[2] As well, coal-fired units produce primary particulate matter, and electricity generated by the burning of fossil fuels also creates greenhouse gas emissions. In 2006, this sector produced 30% of Alberta's total SO_2 and 10% of its total NOx emissions.[3] Coal-fired power plants emit about 90% of Alberta's total reported annual mercury emissions.

1.2 The Emissions Management Framework

In January 2002, Alberta Environment asked CASA to develop a new way to manage air emissions from the electricity sector. Using a multi-stakeholder collaborative approach, CASA came up with innovative solutions in the form of 71 recommendations comprising a management framework, which it presented to the Government of Alberta in November 2003. The report – *An Emissions Management Framework for the Alberta Electricity Sector: Report to Stakeholders*[4] – and its recommendations focused on:

- new emission limits for new electricity generation units,
- an emissions trading and credit generation system,
- design life limits for existing units, after which new emission limits would apply,

[2] See the Glossary in Appendix A for more information on these substances.
[3] Source: www.ec.gc.ca/pdb/cac/Emissions1990-2015/2006/2006_AB_e.cfm. Natural and open sources are included in the total Alberta emissions.
[4] The Framework is available online at www.casahome.org/?cat=73 or www.environment.alberta.ca/642.html or on request to CASA or Alberta Environment.

- stakeholder review at five-year intervals,
- monitoring transparency and accountability,
- continuous improvement,
- renewable and alternative energy,
- energy efficiency and conservation, and
- response to potential hot spots.

The Framework was promptly accepted by the Government of Alberta, which, along with the electricity generation industry, is now implementing the recommendations.

Although CASA considered a wide range of factors in developing the Framework, it was based on certain economic assumptions and emissions forecasts of the day, as well as best available technology economically achievable (BATEA) at the time. CASA also identified five priority substances that were the focus of the Framework (nitrogen oxides, sulphur dioxide, mercury, primary particulate matter, and greenhouse gases[5]), knowing that new priority substances could emerge in the future.

To ensure continuous improvement and to keep the Framework timely and relevant, a key recommendation was that a multi-stakeholder review be done every five years. The intent of the five-year review is not to re-do the original Framework, but rather to assess new emission control technologies, update emission limits for new generation units, determine if emission limits for new substances need to be developed, review implementation progress and determine if the Framework is achieving its emission management objectives.

To maintain consistency and continuity, the project team used the same definitions as in the 2003 Framework, which was adopted by the Government of Alberta. This includes the understanding that the Framework and review activities apply to all electricity generation units in Alberta. These definitions are noted below.

Generation Unit
For the purposes of the 2003 Emissions Framework, a “generation unit” refers to separate components of a power plant facility that result in the production of electricity energy and, where relevant, the combustion of fossil fuel (e.g., a boiler-generator pair or a gas turbine-generator pair).

Existing Units
For the purposes of this management framework, an “existing” thermal generation unit be defined as follows:

An existing coal or gas unit is one that, prior to the most recent review and update of the BATEA emission limits,

1) has valid EUB and Alberta Environment approvals in place for the eventual unit start-up dates contemplated in the approvals, or planned by the project proponent, AND

[5] Greenhouse gases are being addressed through various climate change initiatives, including Alberta’s Climate Change Strategy and were not considered in the five-year review.

2) in addition to any conditions of EUB and Alberta Environment approvals regarding dates for commencement of construction or formal commissioning of the units, has
   a) within three years of receiving its Alberta Environment approval
      - continuous and substantive onsite construction, or
      - boiler foundation in place.

   AND
   b) has received formal commissioning and is available for commercial service within eight years of receiving its Alberta Environment approval for coal-fired units, or within five years of receiving its Alberta Environment approval for gas-fired units.

New units
For the purposes of the 2003 Framework, a "new" thermal generation unit, be defined as any unit that does not meet the criteria for an "existing" unit and will therefore be required to comply with the BATEA or other emissions limits in effect at the time.

Design Life
The Design Life for coal-fired units, except for the Wabamun generating facility, is defined as the date of expiry of the PPA term or 40 years from the date of commissioning, whichever is greater. The end of Design Life for Wabamun units 1, 2, and 4 is December 31, 2010, according to their EPEA approval (Approval 10323-02-00), which states that, "a decision must be made by December 2005 whether to modify the unit to meet applicable environmental standards or to commence decommissioning by 2010."
Design Life for gas-fired units is the date of expiry of the PPA term or 30 years from the date of commissioning, whichever is greater.
Design Life for peaking gas-fired units is the date of expiry of the PPA term or 60 years from the date of commissioning, whichever is greater.

2 The Five-Year Review of the Framework

Recommendation 29 in the 2003 Framework committed the government to a five-year review of certain Framework elements, with the first review to have begun no later than April 2008. In March 2007, Alberta Environment asked CASA to establish a multi-stakeholder project team to lead the first review, focusing on the following elements as described in recommendation 29:

1. A technology review to identify the BATEA emission limit standards,
2. The air emission substances subject to limits or formal management,
3. Co-benefits of possible emission management strategies for priority and other substances,
4. A review of economic and environmental triggers as set out in the Framework,
5. Additional information that illustrates potential health effects associated with emissions from the electricity sector, and
6. Reports from electricity companies on continuous improvement.

The CASA Electricity Framework Review Project Team[6] began its work in the fall of 2007, guided by the terms of reference noted in Appendix C. The review also looked at progress to date in implementing the Framework. Public consultations were an important part of the review and are described in more detail in Section 8 of this report.

[6] Team members and their affiliations along with the composition of the task groups are noted in Appendix B.

To ensure a thorough review, the team established several task groups to consider specific aspects of its terms of reference in more detail. These were:

- The Implementation Task Group
- The Health and Environmental Assessment Task Group
- The Control Technologies and Reduction Strategies Task Group
- The Public Consultation Task Group

Each task group produced a report with its analysis and recommendations, which were adopted by the team and appear in the body of this report. These and other documents prepared by and for the team are listed in Appendix D.

3 Managing Emissions from the Electricity Sector in Alberta

3.1 Progress in Implementing the 2003 Framework

With the assistance of Alberta Energy and Alberta Health and Wellness, Alberta Environment took the lead in implementing most of the recommendations contained in the 2003 Electricity Framework. Implementation products included two new regulations (Emissions Trading Regulation, Mercury Regulation), new *Air Emission Standards for Electricity Generation*, approvals clauses, and a document outlining the protocol for implementing the recommendations on "hot spots."

Throughout the implementation process, stakeholders were kept informed of the work and had many opportunities to give advice and confirm that implementation met the intent of the recommendations in the Framework. The following sections examine implementation progress and make recommendations where appropriate. In general, non-government organizations (NGOs) and industry stakeholders agree that the Framework recommendations have been implemented satisfactorily. However, in some areas, specifically the management approaches for mercury and greenhouse gases, and energy efficiency and conservation, stakeholders differed on the extent to which Framework recommendations had been implemented; those views are noted in the full report of the Implementation Task Group, which is online at www.casahome.org/?page_id=3196.

3.1.1 Management Approach for NOx and SO_2

Framework recommendations 6 through 12 and 37 through 41 address a management approach for NOx and SO_2.

Recommendations 8 and 9 pertain to an emissions trading system and are intended to provide incentives and rewards for better than required or expected performance, encourage early shutdown of older units, encourage implementation of new emissions controls at existing units, and allow companies some flexibility in meeting new emission limits at the end of a unit's design life. Alberta Environment has implemented these recommendations through the Emissions Trading Regulation and electronic data submission of monitoring information. Since the Emissions Trading System has only been in place for two years, it may be too early to assess whether it is achieving the desired objectives, and no trades have yet occurred.

Recommendation 9 also included: a) the possibility of expanding the Emissions Trading System to other industries, and b) consideration of a cap and trade system for the electricity sector. The EFR team does not believe this recommendation should be considered as fully implemented and the multi-stakeholder committee to Alberta Environment should continue to advise on any adjustments that may be needed to achieve the original intent of the recommendation.

Recommendation 1: Implementation Status of Emissions Trading Recommendations
The Electricity Framework Review Project Team recommends that:

> In 2013, the next five-year review team should complete a detailed evaluation of the implementation of recommendations 8 and 9 of the 2003 Framework, regarding the Emissions Trading System.

3.1.2 Management Approach for Mercury

Framework recommendations 13 through 18, 43 and 44 address a management approach for mercury.

These recommendations were intended to reduce mercury emissions from coal-fired power plants, and to inform the Canadian Council of Ministers of the Environment (CCME) in developing standards and a monitoring protocol for mercury. The mercury control technology on which the 2003 recommendations were based was carbon injection and compact hybrid fabric filters (COHPAC). To implement these recommendations, Alberta Environment introduced:

- A mercury regulation, which was developed through consultation and input from a multi-stakeholder advisory group.
- The mercury control program, which is being implemented through Regulation 34/2006.[7] It required the operators of coal-fired power plants to submit plans for mercury reduction to Alberta Environment by March 31, 2007. These plans had to be based on capture of at least 70% of the mercury in the coal being combusted, and are subject to ongoing review and refinement, with the goal of capturing at least 80% by 2013.
- The mercury monitoring protocol, which was completed in 2007. Alberta will use the CCME monitoring protocol to ensure the CCME requirements will be met.

3.1.3 Management Approach for Primary Particulate Matter

Framework recommendations 19 through 22, 42 and 45 address a management approach for particulate matter (PM). Alberta Environment responded to these recommendations by implementing the following policies in the approvals process:

- Air Emissions Standards for Electricity Generation, and
- Electronic data submission of monitoring information.

In 2003, the technology expected to be applied for mercury control included activated carbon and compact bag houses (COHPAC); this was expected to have the co-benefit of reducing particulate matter emissions. The initial challenges with the development of COHPAC technology were not overcome and it was found that advanced sorbent technology allowed a sufficiently high mercury capture rate with existing particulate control technology (i.e., electrostatic precipitators). Enhanced activated carbon sorbents and electrostatic precipitators, in conjunction with existing electrostatic precipitators became the preferred technology for mercury removal; thus the expected co-benefits of mercury control for PM will not be realized.

The Framework described potential issues with achieving the co-benefits of mercury control, and recommendation 22 indicates that if mercury control does not provide a co-reduction of PM, then the

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[7] See the *Alberta Gazette* of March 15, 2006, online at www.qp.alberta.ca/alberta_gazette.cfm?page=gazette_2006_pt2.cfm.

2008 framework review should develop a primary particulate matter management system for existing units. The team has developed terms of reference to guide the work of the task group that will develop a PM management system.

3.1.4 Greenhouse Gases

Framework recommendations 23 through 28, 46 and 47 address the management of greenhouse gases.

In July 2007, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year were required to reduce their greenhouse gas emissions intensity by 12% under the *Climate Change and Emissions Management Act*. Facilities can make their reductions through improvements to their operations, by purchasing Alberta-based credits, or by contributing to the Climate Change and Emissions Management Fund. Clean fuel technologies, energy efficiency and increased conservation and development of renewable energy have also been emphasized. Alberta is committed to alignment with evolving federal policy and to being in line with the rest of North America as an integrated carbon market advances.

The federal government is developing the domestic framework for industrial greenhouse gas emissions and intends to put the regulatory framework into law in the near future. The federal government has set an objective that 90% of Canada's electricity needs be provided by non-emitting sources, such as hydro, nuclear, clean coal or wind power by 2020, and will continue to provide support for biofuels, wind and other energy alternatives in support of this goal.

With these other activities underway, greenhouse gases were considered to be outside the scope of this five-year review.

3.1.5 Five-Year Review

Framework recommendations 29 through 31, 34, 35, 70, and 71 address the five-year reviews.

At the request of Alberta Environment, CASA established the EFR project team to lead the first five-year multi-stakeholder review of the Framework, as described previously in section 2. This report is the result of the review.

3.1.6 Identifying and Addressing Hot Spots

Framework recommendations 32 and 33 address the issue of hot spots.

With advice from a multi-stakeholder group, Alberta Environment developed and published a *Guide for Responding to Potential "Hot Spots" Resulting from Air Emissions from the Thermal Electric Power Generation Sector* (November 2005). The guide outlines both internal and external processes for identifying and managing potential hot spots caused or potentially caused by air emissions from thermal electrical generation facilities. The guide specifies key stakeholders and agencies, including Alberta Health and Wellness, Alberta Sustainable Resource Development, the (Alberta) Energy and Utilities Board (now the Alberta Utilities Commission), regional health authorities,[8] local airshed zones, municipalities, environmental non-government organizations, stakeholder groups, and federal government departments. The team considers the Guide to be thorough and appropriate, but because

[8] Regional health authorities were in place when the guide was developed but were disbanded with recent changes to Alberta's health system.

no hot spot has yet been identified, the Guide has not been tested and thus it is difficult to assess its effectiveness at this time.

3.1.7 Public Availability of Monitoring, Reporting, and Compliance Data

Framework recommendations 36 through 47 address the issue of public availability of monitoring, reporting and compliance data.

Some stakeholders believe that this data is not easily accessible to the public and that these recommendations should be fully implemented as soon as possible.

Recommendation 2: Public Availability of Monitoring, Reporting and Compliance Data

The Electricity Framework Review Project Team recommends that:

> Alberta Environment ensure that monitoring, reporting, and compliance data is made available to the public in an easily accessible manner, and that this be considered a high priority in Alberta Environment's Integrated Monitoring and Reporting Framework expected to be completed by March 31, 2010.

3.1.8 Enhancing Transparency, Accountability and Public Participation

Framework recommendations 48 through 54 address enhancing transparency, accountability and public participation.

While implementing the Framework's recommendations, the Government of Alberta worked closely with stakeholders and provided a number of opportunities for the public to learn about the Framework and comment on the implementation plans. In addition to meetings with implementation and advisory groups, the following opportunities for public information and input were provided:

- Meeting with community members in the Wabamun area
- Overall implementation meetings held in Stony Plain and Calgary
- Meeting on emissions trading in Calgary
- Meeting on mercury in Edmonton
- Baseline workshops for industry in Edmonton and Calgary.

Public involvement is reflected in specific elements of the Framework as described below.

Public Involvement in Developing an Emissions Trading System

The Emission Trading Regulation was developed under the *Environmental Protection and Enhancement Act (EPEA).* Alberta Environment has established a public registry to track the creation, transfer, and retirement of credits. Companies and individuals can buy and sell credits privately and the registry records the transfer of credits between companies and individuals. Clauses are inserted into approvals, authorizing the use of credits to meet the new emissions limits in Alberta.

The Framework gives industry flexibility to meet new standards for nitrogen oxides and sulphur dioxide emissions, and encourages early emissions reductions and early shutdown of older units. For more information, see *An A to Z Guide to Emissions Trading* published by Alberta Environment.[9]

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[9] This document is online at http://www.environment.alberta.ca/1376.html.

Emissions Trading Technical Advisory Group
This small group consisted of stakeholders and government staff, as well as people with expertise in market design and emissions trading systems. They examined the possible expansion of the emissions trading system and its conversion to a cap and trade system. The overall system was designed in conjunction with this stakeholder advisory group.

3.1.9 Renewable and Alternative Energy
Framework recommendations 55 through 64 address renewable and alternative energy.

Net Metering and Net Billing
On February 1, 2008, the Government of Alberta enacted the *Micro-Generation Regulation* allowing Albertans to generate their own electricity and receive credit for any excess power they don't use and which is sent into the electricity grid. Micro-generation options include producing power via solar panels, small-scale hydro, wind, biomass, micro-cogeneration and fuel cells. The Alberta Utilities Commission (AUC) is overseeing the implementation of the regulation, and has developed processes to simplify approvals and interconnection with the grid.

Renewable and Alternative Energy Project Team
Following the recommendations made in the 2003 Framework, CASA's Renewable and Alternative Energy (R&A) Project Team explored potential options to increase Alberta's supply of renewable and alternative electrical energy. In the end, members decided to recommend that the Government of Alberta develop a renewable and alternative electrical energy policy framework, and to forward the results of the team's work to the Government for consideration.[10] Alberta Energy subsequently led the development of a Provincial Energy Strategy that was announced on December 11, 2008.[11] Recommendations from the R&A project team were considered in the development of the Energy Strategy. The EFR team is of the view that the recommendations of the 2003 Framework were addressed by the work of the R&A project team, but implementation of recommendations 55 through 64 in the Framework depend on successful implementation of the R&A team's recommendations.

3.1.10 Energy Efficiency and Conservation
Framework recommendations 65 through 68 address energy efficiency and conservation.

Electrical Efficiency and Conservation Project Team
The Electrical Efficiency and Conservation (EEC) Project Team was formed in January 2004 with the goal of implementing the Framework's energy efficiency and conservation recommendations by increasing electrical efficiency and expanding conservation efforts in Alberta. A significant task was to develop an energy efficiency target for the province. The team was also asked to identify the resources required to implement the various programs recommended to meet the provincial target.

The team agreed that an overarching energy efficiency framework was needed within government to make progress on its tasks. In its final report, the team made five recommendations related to establishing an energy conservation and efficiency framework for Alberta.[12] Alberta Energy subsequently led the development of a Provincial Energy Strategy, announced on December 11,

[10] The team's report, *Recommendations for a Renewable and Alternative Electrical Energy Framework for Alberta*, was released in March 2007, and is available online at http://www.casahome.org/?page_id=114.
[11] The Provincial Energy Strategy is available online at http://www.energy.gov.ab.ca/Initiatives/strategy.asp.
[12] This report, entitled *The Need for an Overarching Energy Conservation and Efficiency Framework in Alberta*, was released in November 2006 and is available online at http://www.casahome.org/?page_id=109.

2008. Recommendations from the EEC Project Team were considered in the development of the Energy Strategy.

Some stakeholders believe that recommendations 67 and 68 need more work and should be referred to the appropriate implementing agency. Implementation of the rest of the Framework recommendations in this area relies on the successful implementation of the EEC team's recommendations.

Recommendation 3: Recommendations from CASA Renewable and Alternative Energy Project Team and Electrical Efficiency and Conservation Project Team

The Electricity Framework Review Project Team recommends that:

> The CASA board review the status of implementation of the recommendations made by the Renewable and Alternative Energy project team and the Electrical Efficiency and Conservation project team by the end of 2009.

3.1.11 Information Gathering

Framework recommendation 69 addresses the gathering and availability of information.

The materials developed by and for the original CASA Electricity Project Team are on file with Alberta Environment, in both electronic and print format.

3.2 Continuous Improvement in the Alberta Electricity Sector

Recommendation 29, which is the basis for the five-year review of the Electricity Framework, specified six elements that were to be addressed in the review, one of which was continuous improvement. The expectation was that electricity generators would prepare a continuous improvement report as part of each five-year review. The report would summarize emission control initiatives taken during the previous five years and identify goals for further continuous improvement during the next five-year period. Progress against these goals would then be assessed at each subsequent review, starting in 2013. If appropriate, the multi-stakeholder review team could recommend modifications to the Framework that improve opportunities for supporting continuous improvement efforts.

The electricity generation industry prepared a continuous improvement report as part of this first five-year review,[13] which it presented to the team as information. The report examines Alberta's load history and forecast, looks at the changes in generation (both added and retired) between 2003 and 2008, and describes the continuous improvement initiatives undertaken between 2003 and 2008 in the electricity sector, which include:

- An IGCC development project
- Clover Bar Landfill gas generating station
- Genesee Units 1 and 2 combustion optimization
- Turbine efficiency improvement
- Sundance upgrades
- Mercury monitoring programs
- Mercury capture tests

[13] The industry continuous improvement report appears in Appendix E.

- Transmission upgrades. Specifically, improvements have been made to the transmission infrastructure to reduce line losses and to connect new generation in different regions of the province.

Initiatives planned for 2009 to 2013 include:
- Continuation of the IGCC project. The future of the project depends on technical and economic factors and on the availability of a CO_2 pipeline and storage infrastructure.
- Development of carbon capture and storage (CCS)
- Clean coal development
- Micro-Generation. The Micro-Generation Regulation was enacted on February 1, 2008 and was fully implemented on January 1, 2009. It allows Albertans to generate their own electricity and receive credit for any excess electricity that is delivered to the grid. Companies have supported this initiative and are accepting the electricity from micro-generators.
- Coal-fired generators will continue with their mercury control program to complete the technology test program; engineer, install and commission the control equipment by the January 1, 2011 regulatory deadline; evaluate the control technology during longer-term commercial operations; and review possible optimization measures.
- Several projects are planned in various parts of Alberta to improve transmission reliability and efficiency and to connect new sources of renewable generation.

The industry noted that confidentiality issues limit what goals or predictions can be included in the continuous improvement report, but the stated planned initiatives reflect commitments the industry is making. Some are not efficiency gains (e.g., CCS), but will contribute to an overall improvement in environmental performance. The plans focus mainly on “big ticket” items and many of the smaller improvements cannot be identified in a public document. The continuous improvement report done for the 2013 review is expected to describe all the significant continuous improvement activities that were implemented between 2009 and 2013.

4 Health and Environmental Assessment

As part of this five-year review, the project team established a multi-stakeholder Health and Environmental Assessment Task Group to:
- Assess new information related to possible new substances not yet regulated, but which should be considered based on potential impacts;
- Compile and review any new or additional information that illustrates potential health effects associated with emissions from the electricity sector and determine how any new information impacts the framework; and
- Make recommendations for future five-year reviews.

In addition, consultants were hired to review recently published research or reports (2002-2007) and provide reports pertaining to any new information on the magnitude and/or nature of: 1) health effects or impacts, and 2) environmental effects or impacts of air emissions associated with fossil fuel-based electrical generation. The recommendations arising from the health and environmental assessment are based on research and reports published up to December 31, 2007.

The consultants prepared annotated bibliographies[14] that surveyed and documented any new information, studies and reports related to the direct or indirect health and environmental effects of air emissions from fossil fuel fired electrical generation facilities, with a focus on:

- Direct and indirect health and environmental effects that could be associated with air emissions from fossil fuel fired electrical generation facilities, and
- New information related to emissions from fossil fuel fired electrical generation facilities.

4.1 Environmental Effects Literature Review

The objective of this review was to report on recent research that addresses: 1) atmospheric emissions from thermal electricity generation, and 2) the direct and indirect environmental effects of these emissions. Although all of the abstracts presented in the report were screened for relevance, no attempt was made to critically evaluate the quality of the science. Some of the papers included in the report are quite broad in scope (e.g., they include pollutant sources other than thermal electricity).

The vast majority of papers published on thermal electricity generation since 2002 have focused on pollutant reduction, pollutant monitoring and regulatory evaluations. There has been considerable emphasis on research related to mercury emissions and abatement. Recent studies on direct and indirect environmental effects of air emissions from thermal electricity generation were primarily limited to local and regional studies (especially in Eastern Europe and Greece) and to toxicity research on some List 2 substances. For certain pollutants, especially for particulate matter and polycyclic aromatic hydrocarbons (PAHs), recent research was primarily directed toward human health effects; these abstracts were screened out of this report. Further investigation revealed that the bulk of research projects relating to environmental effects of thermal electricity generation were published between 1985 and 1999, and that these findings appear to be so well-documented that focus has now shifted to pollutant reduction. As such, part of this review is focused on technology and standard/guideline changes that have evolved since 2002. Many researchers are now conducting "life cycle" emissions studies, where the total emissions of electricity generation (including upstream processes such as mining and fuel transport) are accounted for and evaluated in economic and environmental terms.

No attempt was made to search for new or "emerging" pollutants from thermal electricity generation. Despite this, a number of studies on radionuclide emissions were encountered during the course of the review; these are included in the section that presents results for List 2 substances. Research continues to advance in the field of PAH speciation.

4.2 Health Effects Literature Review

The objective of this review was to report on recent "white" and "grey" literature articles[15] assessing the health effects of electrical generation emissions. The search was limited to studies published between 2002 and 2007 that examined the relationship between electrical generation from fossil fuel combustion and adverse health effects. For the white literature, articles were identified and collected using the databases *ISI Web of Science*, *Ovid EMBASE*, *Toxnet*, and *Pubmed*. For the grey literature, reports and other scientific articles were obtained through searches of individual websites of government agencies and environmental groups. In total, 37 white literature and 19 grey literature articles were found. Most studies evaluated at least one of the five priority substances (Hg, SO_2,

[14] The documents prepared by consultants as part of the review are available online at www.casahome.org/?page_id=3196.

[15] "White" articles have been peer-reviewed and published in the scientific literature. "Grey" articles are not peer-reviewed and appear in other sources, such as government and industry publications.

NO_X, particulate matter, and greenhouse gases (primarily CO_2)). A few studies assessed one or more of the List 2 substances, and no health effects studies were found assessing any new "emerging chemicals." A vast amount of research continues to be done on the potential health impacts of particulate matter, especially $PM_{2.5}$.This report offers the findings of the literature searches and provides a compilation of suitable abstracts.

4.3 Other Considerations

Information on projects and initiatives related to emissions from the electricity sector was provided through presentations from government and industry. Of specific note, TransAlta and EPCOR made a presentation to the task group on their environmental monitoring programs at the Genesee, Wabamun, Sundance, and Keephills generating stations.

4.4 Health and Environmental Effects Conclusions and Recommendations

Conclusions based on the two literature reviews are that:

- No new emission substances from fossil fuel combustion were identified that should be of concern to regulators; and
- No new environmental and health effects information was identified that would warrant a detailed review of the Framework.

Recommendation 4: Health and Environmental Effects Information

The Electricity Framework Review Project Team recommends that:

> No additional work or revisions to the Framework are required at this time based on new or additional health and environmental effects information.

Recommendation 5: Analysis of Research

The Electricity Framework Review Project Team recommends that:

> For future five-year reviews, a multi-stakeholder group with appropriate representation be struck to oversee a study to identify any new and relevant studies or research findings regarding potential environmental or health effects from air emissions from electricity generation, and that an independent peer review be completed on the results.

5 Control Technologies and Reduction Strategies

As part of this five-year review, the team established a multi-stakeholder Control Technologies and Reduction Strategies Task Group 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 end of their design life as defined in the framework; and
- 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.

To assist with this work, consultants were hired to: 1) update the 2003 Emissions Forecast, and 2) review technologies and advise on BATEA and related performance limits for certain generation and fuel types. The results are summarized below and the full consultants' reports along with the final report of the Control Technologies and Reduction Strategies Task Group are available from CASA upon request and on the CASA website.

5.1 Summary of Generation and Emissions Forecasts

The emission forecast was an important tool in the development of the 2003 Framework as it allowed the original CASA 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 had been significant changes since 2003, an update of the forecast was completed in 2008, as part of the five-year review. The emission forecast encompasses the next 20+ years, until 2030, as it was recognized that most emission reduction actions identified in the 2003 Framework would occur in that timeframe.[16]

- 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.
- Absolute particulate matter emissions follow a similar trend as in the 2003 forecast but are considerably higher in the 2008 forecast. This is mainly due to differences in the technology applied, which is described in section 3.1.3 of this document. Particulate matter intensity levels across the forecast period have remained relatively flat when compared with the 2003 forecast.
- 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 due to higher output from coal plants. 2008 SO_2 emissions intensity levels are appreciably below the 2003 case until 2022.
- NOx emitted from coal-fired 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.

5.2 Control Technologies Review

The objective of the control technologies review was to determine the BATEA for emission control technology that would apply to Alberta electricity generating units approved after January 1, 2011.[17] To assist with this work, two consultants were hired. The Eastern Research Group conducted a broad analysis for control technologies to reduce emissions of NOx, SO_2, PM, and mercury. Possible retrofit technologies for existing units were not assessed as the review was entirely focused on new units. The energy requirements for any control technologies analyzed were also identified, and the resulting greenhouse gas emissions were estimated. The study also reviewed future technologies, control techniques, and the use of alternative fuels applicable to electric generating units. Later, Jacobs Consulting was hired to conduct specific research on control technologies for co-generation units in non-peaking service.

[16] The full report of the CTRS Subgroup illustrates the emissions forecasts graphically for each substance.
[17] BATEA is defined in the glossary, using the same definition as in the 2003 Framework.

Based on the results of this technology review, the project team reached consensus agreement on the following:

Coal-Fired Units

- New source standards for Nitrogen Oxides for coal-fired units in Alberta will be based on the demonstrated performance of selective catalytic reduction (SCR).
- New source standards for Sulphur Dioxide for coal-fired units in Alberta will be based on the demonstrated performance of spray dryer adsorbers with fabric filter baghouses.
- New source standards for 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.

Gas-Fired Units

- New source standards for Nitrogen Oxides for gas-fired peaking units in Alberta will be based on the demonstrated performance of dry low NOx/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.)
- Consensus could not be reached on the BATEA for new source standards for Nitrogen Oxides for gas-fired non-peaking units in Alberta.

5.3 Source Standards for New Coal-Fired Thermal Generation Units

Recommendation 6: Source Standards for New Coal-Fired Thermal Generation Units
The Electricity Framework Review Project Team 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 (NOx)

Emission standard: 0.47 kg/MWh net
Design specification: 0.40 kg/MWh net

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

Sulphur Dioxide (SO_2)

Emission standard: 0.65 kg/MWh net or 90% removal, whichever is less stringent.

Particulate Matter (filterable[18])

6.4 ng/J of heat input (~0.066 kg/MWh)

[18] Alberta Environment Stack Sampling Code or EPA Method 5 – front half particulate catch

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 new technology commissioning period.

Recommendation 7: NOx and SO_2 Credit Generation Thresholds

The Electricity Framework Review Project Team recommends that:

The following deemed credit thresholds for the 2011 BATEA standards be applied to new coal-fired units:

A. NOx (coal-fired) – 0.38 kg/MWh net

B. SO_2 – 0.55 kg/MWh net

[C. NOx (gas-fired) – this credit threshold should be determined once the BATEA and corresponding NOx emission standard has been determined.]

Recommendation 8: Credit for Early Action on Mercury Capture

The Electricity Framework Review Project Team 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.
- 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.

5.4 Source Standards for New Gas-Fired Generation Units (Non-consensus)

The EFR project team 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.

5.4.1 Treatment of simple cycle units and peaking units

All stakeholders agree that the BATEA for peaking units is a Dry Low NOx/Dry Low Emission (DLN/DLE) combustion system. However, determining the corresponding source standard has been a complicated task. Through many discussions, some stakeholders reached agreement on a standard. However, one stakeholder was concerned that the classification of peaking units is too broad and could potentially capture units that are not actually providing peaking service.

The CASA Board discussed the treatment of simple cycle and peaking units in June 2009. The board agreed that Alberta Environment and industry participants should work together to resolve the issue related to peaking units. When finalized, the results of this work will be available upon request from CASA and will be posted on the CASA website.

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

In June 2009, the CASA Board reviewed the non-consensus issues regarding gas-fired non-peaking units. The board directed the 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. 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.

Recommendation 9: Source Standards for New Gas-Fired Non-Peaking Thermal Generation Units *(non-consensus)*

The main block to consensus is the choice of BATEA and the corresponding source standard. All NGO sectors, all government sectors, and the utilities sector were able to reach agreement on a source standard for new gas-fired non-peaking units (Option A). The chemical manufacturers sector, the petroleum products sector, and the oil and gas sector did not agree with the original proposal and offered an alternate solution (Option B). The disagreeing parties’ positions and rationale for supporting each proposal are summarized below; details can be found in Appendix F. In addition, Appendix G includes individual submissions from interested stakeholders.

The EFR project team had already completed a broader emissions control technology review with Eastern Research Group (ERG). However, some stakeholders felt that the ERG review did not consider the unique economic and operational issues surrounding cogeneration facilities. To further assist with this particular issue, Jacobs Consultancy was hired to undertake a review of natural gas and alternate fuel combustion and control technologies, in order to establish the best available technology economically achievable (BATEA) for NOx emissions control for cogeneration units. Both the ERG report and the Jacobs Consultancy report are available upon request and on the CASA website.

Although the EFR project team could not agree on updated source standards for new gas-fired non-peaking thermal generation units, stakeholders generally agreed that they had similar interests in the following areas:

- The emission standard should be based on the performance of a technology that is considered BATEA. Stakeholders could not reach agreement on what technology constituted BATEA.
- Cost-effectiveness and economic achievability are important factors to consider.
- Alberta should set standards to reduce emissions that are comparable to leading jurisdictions in attainment areas (i.e. areas of good air quality).
- The emission standard is not intended to create disincentives for cogeneration development.
- There should be flexibility to meet the emission standard with any processes and/or technology that make sense to each operator.

OPTION A:

It is recommended that, effective January 1, 2011, the NOx BATEA standard for new gas-fired non-peaking units will be:

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

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

Power Output Allowance (“A”)

Net Power Output (per gas turbine train)	**Non Peaking (“A”)** (kg NO_x /MWh net)
Greater than 25 MW	0.09
Less than *25* MW	0.60

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

Based on the reports prepared by the Eastern Research Group and Jacobs Consultancy, the government, NGO, and utilities sectors support Option A, and agree that Selective Catalytic Reduction (SCR) is the best available technology economically achievable (BATEA). These sectors agree that SCR is a proven technology used in jurisdictions with climate conditions similar to Alberta. SCR technology is installed and operated in a variety of applications, including co-generation, in the United States. Several of these facilities operate in cold weather and there are SCR units operating in Alberta. These sectors also agree that the use of SCRs can be cost effective in larger installations and that ammonia slip/collateral emissions are only a concern at very low emission limits (far below the emission limits being recommended in Option A). There are a large number of SCR systems in operation that safely handle NH_3 (ammonia).

During the team's discussions, these sectors reached 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.

Those stakeholders supporting Option A felt that Dry Low NOx technology was not the BATEA because, according to the definition of BATEA in the Emissions Management Framework, BATEA technologies are those that have "been demonstrated to be economically feasible through successful commercial application across a range of regions and fuel types"19. The reports from the Eastern Research Group and Jacobs Consultancy clearly demonstrate 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. There are two simple cycle peaking units equipped with SCRs currently operated in Edmonton – the operator (Capital Power Corporation) believes that they are economical and do not have any outstanding environmental or safety concerns. The stakeholders note that while there is the potential for new developments in DLN technology, this equipment has yet to be installed and operated in Alberta. In addition, turbine manufacturers will not provide a performance guarantee for DLN units that achieve very low emissions limits where these units are operating below a certain ambient temperature (this would be a concern in Alberta's climate conditions).

OPTION B:

It is recommended that, effective January 1, 2011, the NOx BATEA standard for new gas-fired non-peaking units will be:

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

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

Power Output Allowance ("A")

Power Rating (per gas turbine only)	**Natural Gas Non-Peaking** (kg/MWh)
Greater than 25 MW	0.18[20]
Less than 25 MW	0.60

Heat Recovery Allowance ("B")
For All Units: 0.04 kg/GJ

[19] An Emissions Management Framework for the Alberta Electricity Sector – Report to Stakeholders. November 2003. p. 117.
[20] To be applied on an annual average basis

Applicability

- Effective for units approved after January 1, 2011 for new and for end of life installations
- Natural gas fired systems
  - Dry low NOx burners – on which this BATEA standard is based – are designed and engineered for natural gas as fuel
  - Systems fueled by alternate gaseous fuels to be handled on a permitting, case-by-case basis (e.g., systems fired with a mix of natural gas with syngas, off-gas or refinery fuel gas)
- Start-up and shut-down and upset conditions are exempted from the standard

Basis

- Non-peaking standards expressed as output standards
  - Consistent with CCME's National Emission Guidelines for Stationary Combustion Turbines (December 1992)
  - Considers the environmental benefits afforded by energy efficiency gains of cogeneration and combined cycle installations
- The BATEA basis for the power output standard ("A") is Dry Low NOx (DLN) burners
  - The standard is applied on an annual basis to the large turbines (>25 MW) to account for cold ambient weather conditions where denser air causes combustion instability in DLN burners
- The BATEA basis for the heat recovery allowance ("B") is consistent with manufacturers' standard burner configuration
  - Captures the efficiency gains from cogeneration and combined cycle systems.

Based on the report prepared by Jacobs Consultancy, the oil and gas sector, the petroleum products sector, and the chemical manufacturers sector support Option B, and believe that proven Dry Low NOx (DLN) burners meet the definition of BATEA. These sectors agreed that DLN technology is proven reliable in Alberta. The latest proven DLN burner technology achieves a significant reduction in NOx emissions without requiring significant capital and operating costs. Recognizing DLN technology as BATEA incents and accelerates technology development and deployment in new DLN technology. This technology may result in NOx performance levels approaching those attainable with SCR for a fraction of the cost and without environmental and safety liabilities of SCRs. The timeline for this forecasted technological development is unknown. These sectors assert that DLN technology does not present a risk of disincenting further installations of cogeneration systems, whereas a requirement for SCR might.

The sectors supporting Option B believe that SCR does not meet the definition of BATEA. They have concluded that the incremental benefit in NOx reductions from SCR technology do not outweigh the additional safety and environmental liabilities, costs, and reliability issues associated with SCR. In addition, the sectors conclude that Option A may be more stringent for cogeneration facilities than for combined cycle facilities.

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.

5.5 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 those projected in the original 2003 forecast and would likely exceed the 15% emissions growth trigger for PM, as well as for NOx 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 NOx 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.

5.6 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 team 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 NOx 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 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 five-year 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 will not be more than 15% above the 2003 forecast. Additionally, other structural changes to the broader Framework may be necessary to ensure that the fundamental objective of "meaningful reductions over time"[21] will be realized. It is also recommended that future teams be actively involved with the development of such forecasts to confirm their accuracy.

[21] An Emissions Management Framework for the Alberta Electricity Sector, November 2003, p. 25.

6 Particulate Matter Management

The 2003 Electricity Framework envisioned that primary particulate matter would be addressed through the installation of mercury controls. Recommendation 22 on the Co-Benefits of Mercury Control stated:

> "For existing and transitional coal-fired units, where mercury controls include fabric filters, the primary particulate matter target of 0.095 kg/MWh shall apply. If mercury control identified in the 2005 review does not provide this co-reduction of primary particulate matter, then the 2008 system review should develop a primary particulate matter management system for existing units."

When the Framework was developed, the applied mercury control technology was expected to include activated carbon and compact bag houses (COHPAC); this technology was expected to have the co-benefit of significantly reducing particulate matter (PM) emissions. The potential co-benefit of improved primary PM capture was not realized due to several factors. The initial challenges with the development of COHPAC technology were not overcome and it was found that advanced sorbent technology allows a higher mercury capture rate with existing particulate control technology (electrostatic precipitators). Enhanced activated carbon sorbents and electrostatic precipitators, in conjunction with existing electrostatic precipitators became the preferred technology for mercury removal, and thus the expected co-benefits of mercury control for PM will not be realized.

With no further action, emissions for PM after 2010 are projected to be more than 15% higher than forecast in 2003. The 2003 Framework anticipated this issue, as reflected in Recommendation 22. Because the mercury reduction technology that is being implemented does not result in the expected co-reduction of primary particulate matter, the Electricity Framework Review Project Team needed to propose a specific plan to manage primary particulate matter. The team has drafted terms of reference for a new CASA task group to develop a management plan for primary particulate matter. The team intends that the new task group will report to the current EFR team, which will not be disbanded until the PM Management Plan has been prepared and approved by the CASA board.

7 Future Five-Year Reviews

The Electricity Framework Review (EFR) project team began work in 2007 on the first five-year review of *An Emissions Management Framework for the Alberta Electricity Sector*. This review was a learning experience and the purpose of this section is to help the secretariat and the CASA Board apply these lessons to future Electricity Framework Review project teams. The lessons learned for this project team center around: (a) ensuring appropriate participation from all potential stakeholders with a vested interest in electricity generation in Alberta, and (b) developing a realistic and appropriate timeline for the work of the team.

The EFR project team believes that all parties with a vital interest in electricity generation in Alberta should be involved in the five-year reviews. In this review, the team endeavored to make the process as inclusive as possible by specifically requesting the participation of those organizations that would have an interest in the work. Despite these efforts, not all interested parties actively participated in the process from the beginning, when much of the team's time together was spent building the foundation for its work and establishing a common understanding of the issues and the responsibilities of the team. In the CASA process, establishing this common understanding is essential to developing consensus. The lack of involvement from all interested parties at the start of the review made it more challenging for the team to complete its work. The team's experience has confirmed the importance of ensuring that all parties are informed to enable *active* participation in the process and meetings from the start. The team advises that for future five-year reviews, the CASA Board should provide assistance to ensure active participation from all interested parties.

The next five-year review is scheduled to occur in 2013. The 2003 Framework recommends that the review and recommendations be completed within 12 months of the formation of the project team. Pre-planning should position the project team to complete its work by December 2013. This groundwork should include:

- Securing funding and hiring consultants and to commence:
    - An updated emissions and generation forecast.
    - A technology review to identify the BATEA emission limit standards.
    - A review of any new information (January 2008 - December 2012) that examines potential health and environmental effects associated with emissions from electricity generation.
    - A pre-consultation phase.
- Securing any additional funding.
- Developing a realistic and detailed timeline for the project team's work.

Based on the experience and learnings of the EFR project team, the following timeline has been drafted to ensure that the appropriate steps are taken in a timely manner to build a solid foundation for the work of the 2013 EFR project team.

2013 Electricity Framework Review Project Team

Date	Milestone
September 2011	Alberta Environment, in consultation with Alberta Energy and other regulatory agencies, presents a Statement of Opportunity to the CASA Board to initiate the 2013 Five-Year Electricity Framework Review (EFR).
September to December 2011 (1 meeting)	A working group develops Terms of Reference for the 2013 EFR.
December 2011	CASA Board approves the Terms of Reference for the project team to begin work in January 2012.
January to February 2012 (1 meeting)	EFR Project Team develops a work plan and budget, and establishes scope of work for sub-groups. • 2008 Project Team Expenses: $270,000
March 2012 (1 meeting)	EFR Project Team develops Request for Proposals (RFPs) for the: • Technology Review (hired June 2012) • Emissions Forecast (hired July 2012) • Health and Environmental Effects Review (hired October 2012)
April to June 2012	EFR Project Team retains a consultant to conduct the Technology Review • RFP issued April 2012 • Consultant hired June 2012 • Final report March 2013 • 2008 budget: $160,000
June to July 2012	EFR Project Team retains a consultant to conduct the Emissions Forecast • RFP issued June 2012 • Consultant hired July 2012 • Final report April 2013 • 2008 budget: $35,000

Date	Milestone
September to October 2012	EFR Project Team retains a consultant to conduct the Health and Environmental Effects Review • RFP issued September 2012 • Consultant(s) hired October 2012 • Final report(s) January 2013 • 2008 budget: $20,000
April 2012 to January 2013	Multi-stakeholder representatives from the team monitor the progress of the consultants.
January to June 2013	Sub-Group reviews the Emissions Forecast and Technology Review and develops recommendations.
January 2013	Sub-Group prepares and implements 2013 EFR public consultation process.
February to June 2013	Sub-Group reviews the Health and Environmental Effects review and develops recommendations.
May to June 2013	Pre-consultation phase. This phase of consultation serves to: • Educate the public on the Electricity Framework and the Five-Year Review. • Gather information about public issues and concerns related to emissions from electricity generation. • 2008 budget: $50,000
June 30, 2013	Sub-Group reports and recommendations finalized and forwarded to EFR Project Team.
September 2013	Public Consultation occurs. • 2008 budget: ? (Example: 2008 Clean Air Strategy consultation cost $210,000)
October 2013	EFR report is finalized for the December CASA Board meeting. • 2008 budget for team report: $10,000
December 2013	EFR Project Team presents to the CASA Board.

The team is of the view that additional effort is needed to raise awareness about the Electricity Framework specifically, and CASA generally, and that consultations for future five-year reviews would benefit by a pre-consultation phase with focused public outreach.

Recommendation 10: Pre-consultation Phase for Next Five-Year Review
The Electricity Framework Review Project Team recommends that:

> The working group formed to develop terms of reference and timelines for the next five-year review build in a pre-consultation phase, which would involve focused public outreach about CASA as well as the Electricity Framework and progress in its implementation.

8 The CASA Electricity Framework Review Consultations

The project team gathered public input via two town hall meetings, one in Hanna and one at Keephills, and through a survey that was available in both print and electronic format. Approximately 50 people attended the two town hall meetings, most of them at the Keephills event, and 90 completed surveys were received by the February 28, 2009 deadline. One written submission was also received and was incorporated into the survey results. No responses were received from First Nations or Métis organizations.

Respondents and participants were not a representative sample of Albertans, thus results cannot be generalized to the population as a whole.[22]

More than half the survey respondents spontaneously identified air pollution and/or air quality as the issue that concerned them most about electricity production in Alberta and in their region. This concern was named more than twice as often as the one(s) immediately following, which were lack of alternatives to fossil fuels (particularly coal), and environmental and health damage related to production and transmission activities. At the regional scale, respondents were concerned about increased pressure for expansion of existing generation. Although respondents also regarded greenhouse gas emissions from the burning of fossil fuel as a serious concern, greenhouse gases and climate change are not part of the mandate for this Framework review.

More than 90% of respondents felt that air toxins and acid deposition are at least a medium priority. Both of these important issues are addressed in detail in the 2003 Framework. Each five-year review of the Framework will provide an opportunity to consider new technology and approaches to respond to these issues.

With respect to solutions, 80% of survey respondents said that increasing the amount of power derived from clean and renewable power sources was a high priority. Approximately 60% thought tougher standards on emitters, and reducing electricity use through more efficient technologies or conservation were high priorities, and 53% said increasing the efficiency of generation was a high priority.

Town hall attendees, like the survey respondents, noted:

1. The overall need to reduce emissions from power plants, including the use of stronger regulations and application of better technology requirements.
2. The need to encourage, through incentives and other means:
    - The development of renewable and alternative energy to reduce reliance on fossil fuels, and
    - Conservation to reduce electricity demand.
3. Concerns about the adequacy of monitoring downwind of major facilities. The need for better access to data and information was also mentioned in town hall meetings.

Overall, comments from the public consultations can be summarized as follows:

1. The 2003 *Emissions Management Framework for the Alberta Electricity Sector* is focused on the right priorities as expressed by those who participated in the consultations for the first five-year Framework review. Specifically, participants identified air toxins (such as mercury, heavy metals and fine particulates) and acidifying emissions as priorities. These issues were

[22] The full report of the Consultation Task Group is available online at http://www.casahome.org/?page_id=3196.

addressed in the 2003 Framework and solutions are being implemented. Only a few years have passed since appropriate regulations and other mechanisms were put in place to deal with these issues, and more time is needed to determine their impact on emissions from the electricity sector. Participants also voiced concerns about emissions trading and how the system now being implemented will affect communities that have power generation facilities. Again, the 2003 Framework envisioned how emissions trading should proceed and more time will be needed to see the impacts and determine if any adjustments are needed.

2. There is a need to focus more on developing clean, renewable sources of electricity and on increasing efficiency at generation units. Both of these approaches would reduce the generation of emissions in the first place.

3. The Framework requires best available technology economically achievable (BATEA) on new plants, so the cost of generation from new facilities using conventional fuels is likely to increase. This is expected to make investment in renewables and alternatives more attractive, thereby increasing the expansion of this sector. Survey respondents indicated they would pay more for their power to achieve significant reductions in emissions, and this attitude supports both the increased development of renewable and alternative energy and the use of BATEA for new facilities. Incentives to encourage retrofits and the adoption of new technology to reduce pollution were suggested as approaches to be considered.

4. There is a need to improve conservation efforts and identify other solutions to reduce electricity demand and consumption. Participants in the consultations strongly supported such solutions, both through the adoption of more efficient technologies and through efforts to change consumer behaviour.

5. There is an ongoing need to share information, both in concerned communities and across Alberta, about what is being done to reduce emissions from electricity generation. This could entail a stronger role for a number of players, including airshed zones that have members from the power generation sector, CASA, Alberta Environment, and individual companies that generate electricity.

The team is of the view that additional effort is needed to provide ongoing updates to the public about the Electricity Framework and its implementation. This would assist the interested public in staying abreast of developments and would facilitate the public consultations for the next five-year review (see also recommendation 10 on a pre-consultation phase).

Recommendation 11: Higher Profile for the Electricity Emissions Management Framework
The Electricity Framework Review Project Team recommends that:

> CASA maintain a website that is regularly updated with information about the Electricity Framework and its implementation.

Appendix A: Glossary

AESO (Alberta Electric System Operator)
The AESO is responsible for the safe, reliable and economic operation and planning of Alberta's interconnected power system and the facilitation of Alberta's real-time wholesale electricity market.

Atmospheric emissions
Pollutants emitted into the atmosphere. These are onsite air releases from sources at a facility and include: stack (or point source) emissions; emissions from storage and handling; fugitive emissions; and emissions from other sources such as spills.

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

Cap and trade
A type of emission trading system. In a "cap and trade" system, the regulatory authority sets a cap on total emissions from the participants (or sector) in the trading system. The regulator then creates and allocates allowances to each participant, the total of which is equal to the overall cap. The allowances held by each participant must balance with their emissions at the end of each compliance period; the allocation is typically done annually, and thus the compliance period is also one year. Allowances are based on an absolute amount of emissions produced (that is, tonnes or kilograms) per year. If a participant can reduce emissions below their allocated allowances, the surplus amounts can be traded or banked.

CO_2 (carbon dioxide)
A greenhouse gas that is produced in the burning of fossil fuels

Co-benefits
When a technology to reduce a specific emission also has the benefit of reducing other emissions

Co-generation
Co-generation is the combined production of electricity and heat for use in manufacturing processes; in general, the energy remaining after electricity generation is used in the production of process heat or steam. These types of units are often part of industrial complexes with the electricity not used within the complex offered into the competitive electricity market.

Cumulative impact
The impact of multiple emissions sources and/or developments in a given region.

Design life
The Design Life for coal-fired units, except for the Wabamun generating facility, is defined as the date of expiry of the PPA term or 40 years from the date of commissioning, whichever is greater. The end of Design Life for Wabamun units 1, 2, and 4 is December 31, 2010, according to their EPEA approval (Approval 10323-02-00), which states that, "a decision must be made by December 2005 whether to modify the unit to meet applicable environmental standards or to commence decommissioning by 2010."
Design Life for gas-fired units is the date of expiry of the PPA term or 30 years from the date of commissioning, whichever is greater.
Design Life for peaking gas-fired units is the date of expiry of the PPA term or 60 years from the date of commissioning, whichever is greater.

Emissions trading
The use of allowances or credits to motivate improved performance while allowing some flexibility for facilities to achieve emission controls in the least cost manner. The experience has been that emissions trading encourages greater reductions earlier. This system was highly successful in reducing lead in gasoline, and has also been used to manage and reduce SO_2 and NO_x in the U.S.

Existing units
For the purposes of this management framework, an "existing" thermal generation unit be defined as follows:

An existing coal or gas unit is one that, prior to the most recent review and update of the BATEA emission limits,

1) has valid EUB and Alberta Environment approvals in place for the eventual unit start-up dates contemplated in the approvals, or planned by the project proponent, AND
2) in addition to any conditions of EUB and Alberta Environment approvals regarding dates for commencement of construction or formal commissioning of the units, has

   a) within three years of receiving its Alberta Environment approval

   - continuous and substantive onsite construction, or
   - boiler foundation in place.

   AND

   b) has received formal commissioning and is available for commercial service within eight years of receiving its Alberta Environment approval for coal-fired units, or within five years of receiving its Alberta Environment approval for gas-fired units.

Fossil fuels
Fuels such as coal and natural gas that are derived from the Earth's fossilization process.

Generation unit
For the purposes of the 2003 Emissions Framework, a "generation unit" refers to separate components of a power plant facility that result in the production of electricity energy and, where relevant, the combustion of fossil fuel (e.g., a boiler-generator pair or a gas turbine-generator pair).

GHG (greenhouse gas(es)
These gases enhance the Earth's natural greenhouse effect and are major contributors to global climate change. GHGs covered by federal and provincial legislation include carbon dioxide, methane, nitrous oxide, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulphur hexafluoride.

GWh (Gigawatt-hour)
A Gigawatt-hour equals 1000 megawatt-hours or 1,000,000 kilowatt-hours. A kilowatt-hour is the number of kilowatts used in one hour.

Hg (mercury)
A natural element that is widespread in the environment. It is toxic and bioaccumulates. It is present in coal and therefore the burning of coal results in mercury releases to the environment.

MW (Megawatt)
A megawatt equals 1,000,000 watts or 1000 kilowatts); it is a unit of capacity.

New units
For the purposes of the 2003 Framework, a "new" thermal generation unit, be defined as any unit that does not meet the criteria for an "existing" unit and will therefore be required to comply with the BATEA or other emissions limits in effect at the time.

NGCC (Natural Gas Combined Cycle)
With NGCC, gas is combusted in a gas turbine and the expanding gas drives a generating turbine and the hot exit gases are used in a heat recovery steam generator to produce high-pressure steam, which drives a steam turbine generator that also produces electricity (sometimes supplementary gas is used in the steam generation cycle).

NGO (Non-government organization)
NGOs are usually non-profit or community groups. ENGOs are environmental non-government organizations.

NOx (nitrogen oxides, also called oxides of nitrogen)
Emissions produced in the burning of fossil fuels, arising largely from the oxidation of the nitrogen present in air that is used to support fuel combustion. NOx includes NO (nitrogen oxide) and NO_2 (nitrogen dioxide) but not N_2O (nitrous oxide).

PAHs (polycyclic aromatic hydrocarbons)
PAHs are a group of more than 100 chemicals formed during the incomplete combustion of fossil fuels and other organic substances. They are usually found as a mixture of several compounds. Some PAHs are manufactured.

Primary PM (particulate matter)
Small particles produced in the burning of fossil fuels that are emitted into the atmosphere

SCR (Selective Catalytic Reduction)
SCR is a control technology for nitrogen oxides (NOx) that uses ammonia and a catalyst to convert NOx to N_2.

SO_2 (sulphur dioxide)
An emission produced in the burning of fuels containing sulphur. All coals contain some sulphur.

Appendix B: Project Team Members and Task Group Members

Jack Davis	Alberta Utilities Commission
Jim Hackett*	ATCO Power
Randy Dobko*	Alberta Environment
Terry Dumonceau	EnCana Power and Processing
Ahmed Idriss	Capital Power
Robyn Jacobsen	Clean Air Strategic Alliance
Bob Jones	Alberta Association of Municipal Districts and Counties
Bevan Laing	Alberta Energy
Tom Marr-Laing*	Pembina Institute
Ken Omotani	TransAlta
Krista Phillips	Canadian Association of Petroleum Producers
Al Schulz	Canadian Chemical Producers Association
Nashina Shariff	Toxics Watch Society
Rahul Shrivastava	ENMAX Energy
David Spink	Prairie Acid Rain Coalition
John Squarek	Small Explorers and Producers Association of Canada
Carolyn Tester	Imperial Oil
Trevor Thain	Alberta Urban Municipalities Association
Harry Tyrrell	Mewassin Community Council
Wayne Ungstad	Ponoka Fish and Game
Srikanth Venugopal	TransCanada
Bev Yee	Alberta Environment

Alternate Members, Corresponding Members and Former Project Team Members

Michael Brown	Energy Resources Conservation Board
Casey Chan	Capital Power
Kerra Chomlak	Clean Air Strategic Alliance
Linda Duncan	Lake Wabamun Enhancement and Protection Association
Tim Goos	Environment Canada
Debra Hopkins	Alberta Health and Wellness
Les Johnston	EPCOR
Chris Joy	ENMAX Energy
Mark Kavanagh	Alberta Utilities Commission
Gary Keay	Nexen
Carolyn Kolebaba	Alberta Association of Municipal Districts and Counties
Christine Macken	Clean Air Strategic Alliance
Alex MacKenzie	Alberta Health and Wellness
Greg Moffatt	TransCanada
Julie Mondoux	EPCOR
Jeff Sansom	EPCOR
John Skowronski	Canadian Petroleum Products Institute
Michael Smith	Capital Power
Tracy Smith	Shell Canada
Randy Stubbings	ENMAX Energy
Joan Tingley	ATCO Power
Susan Valentine	Alberta Association of Municipal Districts and Counties
Corey Wilson	ENMAX Energy
Ruth Yanor	Mewassin Community Council

N.B. The affiliations of some former team members and task group members may have changed. The affiliation shown for each person was accurate at the time the individual was active with the team or task group.

** designates a chair or co-chair of the group*

Task Groups listed below include current, former and corresponding members.

Consultation Task Group

Renata Bothwell	Alberta Environment
Chris Dickson	Alberta Environment
Linda Duncan	Lake Wabamun Enhancement and Protection Association
Jim Hackett	ATCO Power
Sharon Hawrelak	Clean Air Strategic Alliance
Ogo Ikhalo	Alberta Environment
Ahmed Idriss	Alberta Environment
Robyn Jacobsen	Clean Air Strategic Alliance
Joan Tingley	ATCO Power
Aynsley Toews	Alberta Environment
Harry Tyrrell	Mewassin Community Action Council
Wayne Ungstad	Ponoka Fish and Game

Control Technologies and Reduction Strategies Task Group

Angela Ball	TransAlta
Michael Brown	Energy Resources Conservation Board
Jack Davis	Alberta Utilities Commission
Randy Dobko	Alberta Environment
Jim Hackett	ATCO Power
Hasan Imran	TCPL
Rick Hyndman	Canadian Association of Petroleum Producers
Robyn Jacobsen	Clean Air Strategic Alliance
Les Johnston	EPCOR
Chris Joy	ENMAX
Mark Kavanagh	Alberta Utilities Commission
Bevan Laing	Alberta Energy
Christine Macken	Clean Air Strategic Alliance
Tom Marr-Laing	Pembina Institute
Greg Moffatt	TransCanada
Julie Mondoux	EPCOR
Ken Omotani*	TransAlta
Krista Phillips	Canadian Association of Petroleum Producers
Anita Sartori	CNRL / Canadian Association of Petroleum Producers
Nashina Shariff	Toxics Watch Society
David Spink	Prairie Acid Rain Coalition
Randy Stubbings	ENMAX Energy
Joan Tingley	ATCO Power
Srikanth Venugopal	TransCanada
Colleen West	Suncor Energy Inc. Oil Sands

Health and Environmental Assessment Task Group

Angela Ball	TransAlta
Linda Duncan	Lake Wabamun Enhancement and Protection Association
Debra Hopkins	Alberta Health and Wellness
Ahmed Idriss	Alberta Environment
Robyn Jacobsen	Clean Air Strategic Alliance
Les Johnston	EPCOR
Timothy Lambert	Calgary Health Region
Christine Macken	Clean Air Strategic Alliance
Ken Omotani	TransAlta
Jagtar Sandhu	Health Canada
Jeff Sansom	EPCOR
Joan Tingley	ATCO Power

Implementation Task Group

Jim Hackett*	ATCO Power
Ahmed Idriss	Alberta Environment
Robyn Jacobsen	Clean Air Strategic Alliance
Nashina Shariff	Toxics Watch Society

PM Management System Task Group

Jim Hackett	ATCO Power
Ahmed Idriss	Alberta Environment
Robyn Jacobsen	Clean Air Strategic Alliance
Les Johnston	EPCOR
Bevan Laing	Alberta Energy
Greg Moffatt	TransCanada (corresponding member)
Julie Mondoux	EPCOR
Ken Omotani	TransAlta
Krista Phillips	Canadian Association of Petroleum Producers (corresponding member)
Srikanth Venugopal	TransCanada (corresponding member)

Appendix C: EFR Project Team Terms of Reference

June 2007

Background

At the March 2007 Board meeting, the CASA Board of Directors approved a Statement of Opportunity brought forward by Alberta Environment to begin a five year review of the *Emissions Management Framework for the Alberta Electricity Sector* as outlined in the Electricity Project Team (EPT) Report to Stakeholders (Nov 2003). The Framework includes recommendations related to:

- stakeholder review at 5 year intervals,
- emissions standards for new units,
- emission requirements for existing units,
- monitoring transparency and accountability,
- continuous improvement,
- renewable and alternative energy
- energy efficiency and conservation and
- response to potential hot spots

The Framework recommends that government undertake a multi-stakeholder review of Best Available Technology Economically Achievable and other related elements within the Framework during 2008. This includes a number of specific tasks set out in the recommendations.

As part of this review, it will be necessary to consider and document what has already been done to implement the Framework recommendations (e.g., recommendation 25)

Based on the importance of taking an integrated approach and recognizing the interconnection of air and greenhouse gas emissions, the project team should consider as appropriate and relevant, GHG issues in the 5 year review. The team should also be aware of the linkages of the review to GHG and other policy initiatives however, the review should not duplicate these other policy efforts, in particular for GHG, where existing processes are in place.

It will also be helpful to conduct a preliminary scoping of the information required to undertake the review to identify issues that require further information to be compiled and a more detailed analysis as part of the review.

Goal

Initial Scoping

The project team will conduct an initial scoping to determine which, if any of the below mentioned key task areas warrant a detailed review, and either recommend that no further work is necessary or undertake a detailed review of those areas and make recommendations on them. Related but out of scope issues will be identified as appropriate for awareness.

Review and update, if necessary, elements of the *Emissions Management Framework for the Alberta Electricity Sector Report to Stakeholders* as described in recommendation 29 and associated recommendations in the above report.

Key Task Areas

- Update specific air emissions standards for new electric power plants constructed after 2010. This includes emissions of nitrogen oxides, sulfur dioxide, mercury, particulate matter and GHG (on a unit specific basis)
    - Recommendation 25 should be included in relation to its application for new units post 2011.
    - This should consider the implications and requirements from other policies such as GHG regulation and the Canada-wide standards.
    - The review of GHG does NOT include:
      - a review of offsets,
      - targets for existing units,
      - sectoral reduction targets or
      - allocation of emissions between electricity and steam for cogeneration
- Review new information related to:
    - air emission substances subject to limits or formal management in Alberta or other jurisdictions and
    - possible new substances not yet regulated, but which should be considered based on potential impacts.

  Identify if further action is needed.
- Compile and review any new or additional information that illustrates potential health effects associated with emissions from the electricity sector and determine how any new information impacts the framework
- Review technologies to identify BATEA for the electricity sector including such aspects as generation, combustion efficiency, control technology, monitoring methodologies and air emission characteristics.
- Determine whether BATEA standards should prescribe emission limits or the installation of a particular technology.
- Review the source characterization exercise completed for the original Electricity Project Team and identify what, if any further action is needed. This will include completing the future substances review described in recommendation 71 to assess whether additional substances should be formally controlled based on new or emerging information.
- Review particulate matter management as per recommendation 22
- Review the use of reciprocating engines to determine if they should be considered as part of the framework (as per recommendation 12)
- Determine whether BATEA standards need to be set for other fuel types (including synthetic gas, bitumen etc.) and if so, what these standards will be.
- Collect and review relevant information on economic issues as per recommendation 35
- Collect and review relevant information on emissions as per recommendation 34
- Review continuous improvement reports submitted by industry and identify goals for further continuous improvement pursuant to recommendation 29.
- Review the proposed federal regulatory agenda for air emissions as it related to the Framework and make recommendations as appropriate.
- Make recommendations for future five year reviews.

Timelines
As set out in the EPT consensus report it was agreed that the Framework be reviewed at five year intervals by a multi-stakeholder group. The following timeline reflects that determined by the report and the CASA board. It is agreed that the review should be initiated in a timely fashion to enable completion by the agreed completion date for reporting. It was agreed that since this was a review of previous work done by a CASA team (i.e., not a new initiative) and that there is strong support by all the stakeholders to proceed, it can proceed in an efficient fashion.

June 2007	Report to CASA Board on terms of reference
Nov 2008	Final report to CASA board on findings of review

Membership
Membership on the project team will include all effected stakeholders. A notice will be provided to all previous Electricity Project Team members and their respective sectors to provide them with opportunity to participate in the project team and identify representatives.

It is suggested that the most efficient process may be to mirror the approach adopted by the EPT and establish a core team with potential for smaller task groups to tackle key topics.

The following are suggested project team members:

- Alberta Energy
- Alberta Energy and Utilities Board
- Alberta Environment
- Alberta Health and Wellness
- Canadian Chemical Producers Association
- Climate Change Central
- Electricity generators (including cogeneration)
- Environment Canada
- NGO from environmental groups, health groups and representatives of local communities concerned with electricity emissions, to be selected by AEN delegate selection process. It is anticipated that a minimum of 6 delegates from the three sectors will be selected.
- Oil and gas sector (reflecting any direct interest in emissions from the electricity sector)
- Power Purchase Arrangement Buyers

Budget
It is anticipated that consultants will be needed to gather background information on the following areas:

- review of emissions standards in other jurisdictions,
- source characterization,
- review of environmental effects (including a literature review, scientific review and discussions with people working in the field),
- literature review of health effects,
- emission forecasts,
- review of generation, combustion efficiency, emissions control and monitoring technology, and
- review of co-benefits in relation to PM and the additional substances list.

The information gathered may consist of new information and updated information on matters considered during the original Electricity Project Team report.

It is anticipated that the cost for consultants could be approximately $200,000. This estimate is roughly one half of the amount spent during the original Electricity Project Team report.

In addition to consultants there will be costs associated with writing and printing the report and per diems.

Appendix D: Documents Prepared by or for the Electricity Framework Five-Year Review

The following documents were prepared during the course of the work of the Electricity Framework Review (EFR) Project Team, either by the team or commissioned for them. These reports are available online at http://www.casahome.org/?cat=128, and are also available on request to the CASA Secretariat.

Terms of Reference
Electricity Framework Review Project Team Terms of Reference, June 21, 2007

Documents related to Progress in Implementing the 2003 Framework

- Implementation of Recommendations made in the *Emissions Management Framework for the Alberta Electricity Sector, November 2003,* April 2009
- Implementation Assessment Report, Alberta Environment
- Continuous Improvement Report, Air Emission Control 2004-2008, Alberta Electricity Sector, April 2009

Documents related to Health and Environmental Effects

- EFR Literature Review on Environmental Effects, March 2008
- EFR Abstracts - Health Effects 2002-2007
- Recommendations from the Health and Environmental Assessment Task Group, October 2008

Documents related to Control Technologies and Reduction Strategies

- Electricity Framework 5-Year Review – Control Technologies Review, Co-Generation Units, February 2010
- Electricity Framework 5-Year Review - Generation and Emissions Forecasts, September 2008 and April 2009
- Electricity Framework 5-Year Review - Control Technologies Review Final Report, January 2009
- Control Technologies and Reduction Strategies Recommendations

Documents related to Consultations

- Electricity Framework Review – Discussion Guide and Survey 2009, December 2008
- Electricity Framework Review Consultation News Release, January 2009
- *What We Heard* Report, April 2009

Appendix E: Continuous Improvement Report

Continuous Improvement Report
Air Emission Control, 2004-2008
Alberta Electricity Sector

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1 Introduction

Reliable supplies of electricity are an essential commodity for Albertans. The province's electricity sector has seen substantial change in recent years, including a shift to deregulation (effective January 1, 2001) and a growing demand for power, which has put pressure on utility companies to expand generation in anticipation of meeting future needs. At the same time, concerns are being raised about the health and environmental impacts of air emissions, particularly from coal-fired generation plants, which remain the primary source of Alberta's electricity.

Power generated in Alberta is exchanged through a power pool operated by the Independent System Operator (ISO), providing an open-access competitive market for electric energy. Power can also be exchanged through forward markets or direct sales arrangements. The ISO co-ordinates all electricity sales and purchases in the province, as well as all energy imports and exports; it also provides real-time control of the provincial electricity grid.

In 2003 the Alberta electricity generators consented to prepare a continuous improvement report to Clean Air Strategic Alliance (CASA) stakeholders during the scheduled five year reviews of the air management framework. The report summarizes emission control initiatives taken during the past five years and identifies goals for further continuous improvement. This is in accordance with Recommendation 29 of, *An Emissions Framework for the Alberta Electricity Sector Report to Stakeholders* (November 2003), which is:

Recommendation 29: Five-Year Review

The EPT 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 the following elements of the emissions management framework:
>
> 1. a technology review to identify the BATEA emission limit standards and corresponding deemed credit threshold for new thermal generation units, including new peaking units;
> 2. the air emission substances subject to limits or formal management, including looking at existing List 2 and possible new substances;
> 3. co-benefits for priority substances and List 2 substances;
> 4. economic and environmental triggers as defined by recommendations 34 and 35;
> 5. additional information that illustrates potential health effects associated with emissions from the electricity sector; and
> 6. continuous improvement. With each Five-Year Review, the electricity sector will provide a continuous improvement report that summarizes action taken during the past five years. The report will also identify goals for further continuous improvement during the next five-year period, in particular with respect to the priority substances emitted by existing units. This report will be reviewed and discussed as part of the Five-Year Review process. Beginning with the second Five-Year Review (2013), upon reviewing system performance relative to the previous continuous improvement goal statements, the multi-stakeholder team can propose, where appropriate, recommendations for modifications to the framework that result in improved opportunities for supporting continuous improvement efforts.

This review should involve a multi-stakeholder group that:

a) consists of representatives from industry, government, non-government organizations and communities with an interest in the electricity sector;

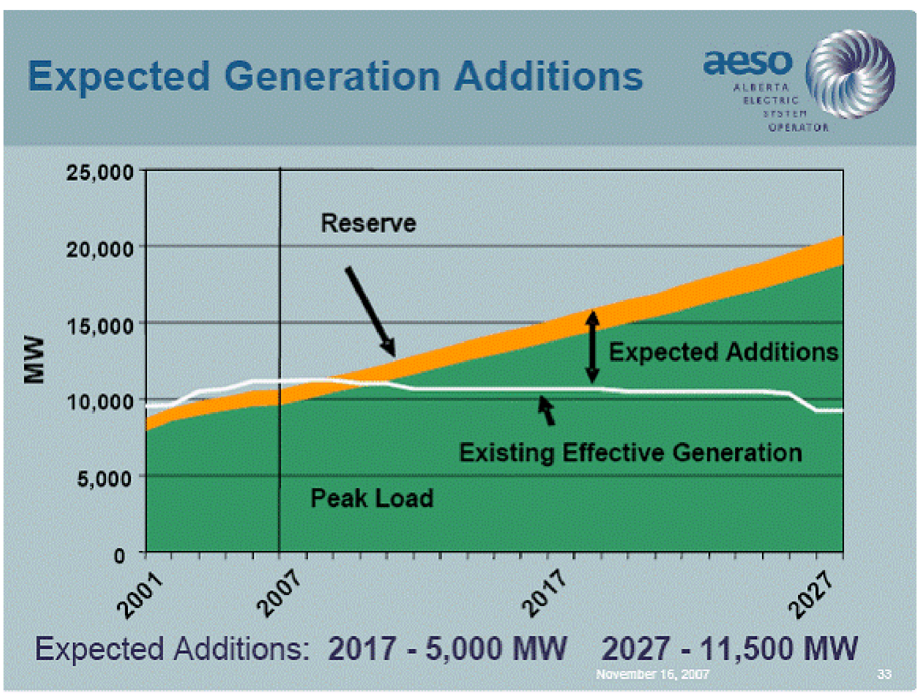
b) conducts an initial scoping to determine which if any of the elements identified in the review process described in the above recommendation warrant a detailed review, and either recommends that no further work is necessary or undertakes a detailed review of those elements and makes recommendations on them;
c) has access to the resources necessary to obtain the information and technical advice needed to complete its review;
d) uses a consensus decision-making process; and
e) completes its review and provides its recommendations to Alberta Environment within 12 months of the group being formed.

2 Alberta Load History and Forecast

Table 1. Customer Usage Estimates GWH[23]

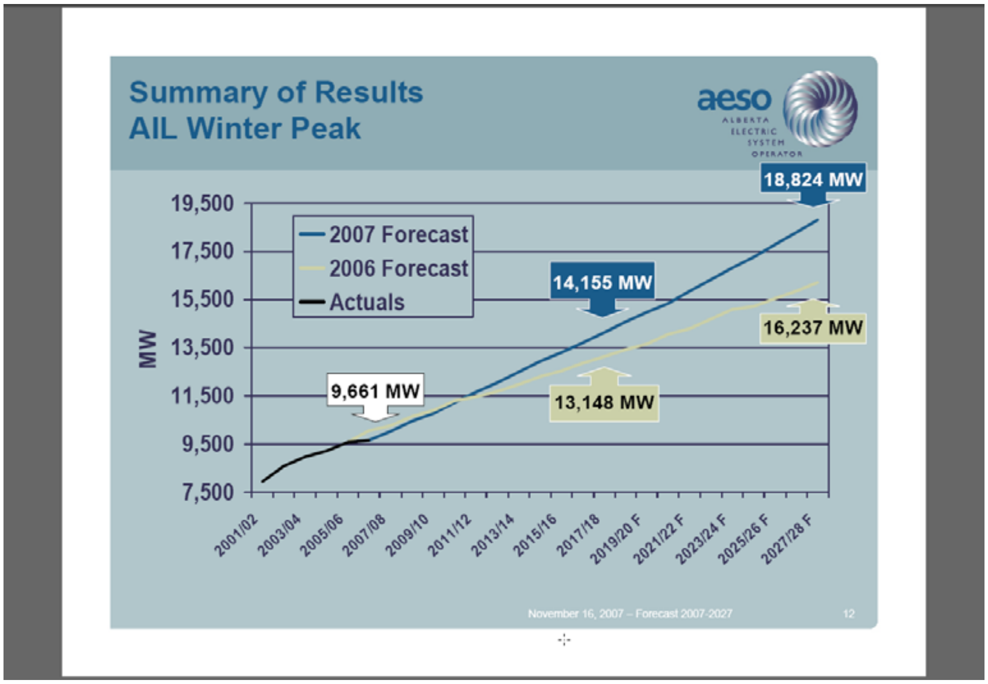
	2002	2003	2004	2005	2006	2007
Residential	7,226.3	7,581.0	7,580.5	7,769.1	8,253.5	8,561.1
Farm	1,702.5	1,776.1	1,734.6	1,705.1	1,768.5	1,806.8
Commercial	11,190.1	11,117.8	11,689.6	12,080.5	12,733.2	13,132.2
Industrial	28,738.0	27,869.7	28,530.6	29,054.6	29,225.0	28,427.0
Total	**48,449.2**	**48,345**	**49,535**	**50,609**	**51,980**	**51,927**

Figure 1. Alberta Energy Forecast[24]



[23] Alberta Energy, Electricity Statistics, Customer Usage Estimated, was compiled from AUC information, available at http://www.energy.gov.ab.ca/Electricity/682.asp
[24] Alberta Electric System Operator, 2006 October, Future Demand and Energy Requirements (Period 2006- 2027), Document FC2006-1, available at http://www.aeso.ca/files/2006_Long-term_Load_Forecast_(November_2006).pdf

Figure 2. Alberta Winter Peak Demand Forecast[25]



3 Generation Changes

3.1 Additional Generation Since 2003

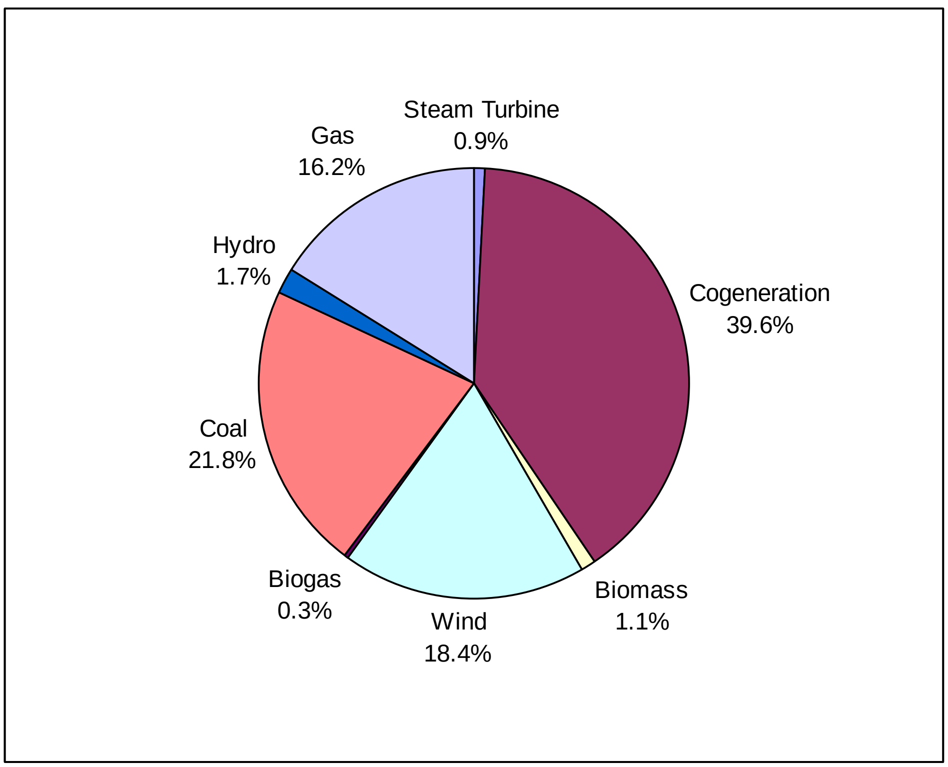
- Wind
  - McBride Lake 2003, (76 MW)
  - Summerview 2004, (70 MW)
  - Taylor Wind Farm 2004, (3.4 MW)
  - Soderglen 2007, (70 MW)
  - Taber Wind Farm 2007,(80 MW)
  - Oldman River Wind Energy 2007, (3.5 MW)

- Coal
  - Genesee 3 2005, (450 MW)
- Gas
  - Clover Bar (landfill gas generator, 2005, 4.8 MW)
  - Clover Bar (simple cycle, 2008, 43.4 MW)
  - Muskeg (co-gen, 2002,170 MW)
  - Scotford (combined cycle, 2003 170 MW)
  - Calgary Energy Centre (combined cycle, 2005, 300 MW)
  - Valleyview (simple cycle, 2008, 45 MW)

[25] Alberta Electric System Operator, 2006 October, Future Demand and Energy Requirements (Period 2006- 2027), Document FC2006-1, available at http://www.aeso.ca/files/2006_Long-term_Load_Forecast_(November_2006).pdf

- In 2003, a new 32 MW hydro-electricity generating station was commissioned at the Oldman River Dam site. Hydro-electricity generation has near-zero air emissions and, by using an existing reservoir, land disturbance has been minimized.
- The 450 MW Genesee Unit 3 started commercial operation in 2005 and incorporated the first high efficiency supercritical boiler in Canada and advanced emissions control technology. The unit is demonstrating NOx, SO_2, and PM emissions a step change lower than previous units.
- A new 43.4 MW simple cycle aero-derivative fast start gas turbine was installed at the Clover Bar site in Edmonton in 2008. The old steam turbine generating station at the site was retired.
- In 2008, a new 45 MW natural gas-fired generating unit is being commission at Valleyview. The unit was designed with NOx controls that will allow it to meet the emission standard in the Emission Trading Regulation credit threshold generation value of 0.3 kg/MWh_{output} which is 25% better than the 0.4 kg/MWh_{output} NOx emission standard for this type and size of unit (Alberta Air Emission Standards For Electricity Generation, 2005).
- Two additional simple cycle aero-derivative fast start natural gas turbines are scheduled for installation at Clover Bar before the end of 2010 adding a further 200 MW of capacity at the site. NOx control will be achieved with water injection and SCRs at both units.

Figure 3. Alberta New Generation 2003-2008[26]



[26] Extracted from Alberta Energy, Electricity Statistics, Generation Additions 1998-2008, which was compiled from AUC, AESO and industry information, available at http://www.energy.gov.ab.ca/Electricity/682.asp

3.2 Retired Generation Since 2003

Table 2. Generation Decommissioned[27]

Location	Installed Capacity (MW)	Type	Decommission Date
Wabamun 3	140	Coal	2003
Wabamun 1 & 2	128	Coal	2005
Clover Bar	629	Gas	2005
Total	897		

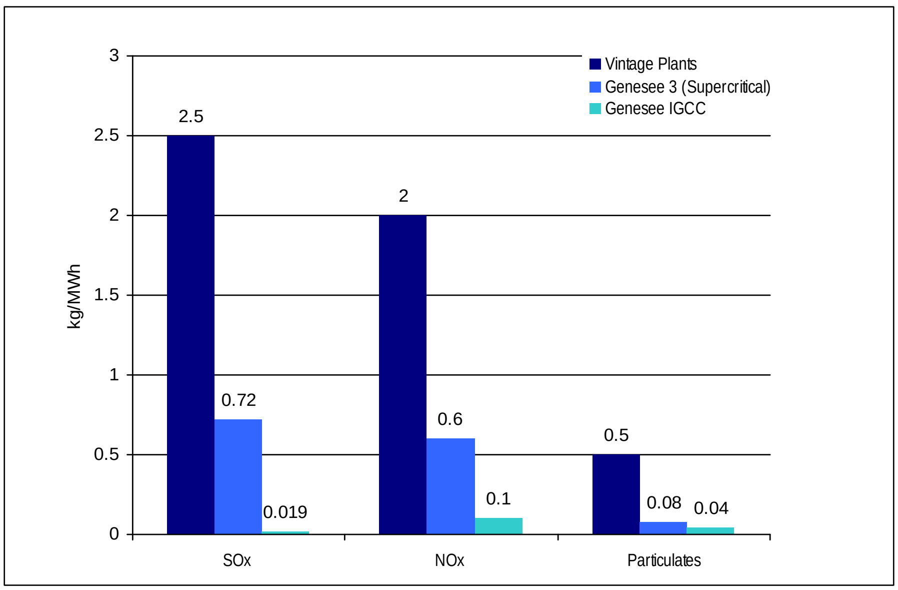
4 Initiatives 2003 to 2008

4.1 IGCC (Clean Coal) Development Project

Supercritical technology such as that in use at Genesee 3 has already achieved a step-change reduction in emissions compared to vintage plants by improving the energy efficiency of coal-fired units by approximately 10% Gasification is the next significant step. Emissions from gasification are not only much less, but have a fundamentally different profile, than those associated with vintage or supercritical coal-fired plants. The technology can be designed to take advantage of opportunities for carbon capture and storage, which will reduce greenhouse gas emissions to near zero.

Compared to supercritical coal-fired facilities, Integrated Gasification Combined Cycle (IGCC) technology has the potential to further lower NOx, particulate matter (PM), and SO_2 emissions by a considerable amount.

Figure 4. IGCC Air Pollutant Emission Reduction Potential



[27] Alberta Energy, retrieved August 22, 2008, Electricity Statistics, available on http://www.energy.gov.ab.ca/Electricity/682.asp

An IGCC plant could allow for the capture of a relatively pure CO_2 stream which would be suitable for Enhanced Oil Recovery, perhaps in the Pembina Oil Fields. However investment in pipeline infrastructure to accommodate carbon capture and storage would be needed.

The clean coal process also creates hydrogen – a potential fuel for the future. Gasification may give us a continuous and affordable source of hydrogen to power tomorrow's hybrid and electric cars.

The technology is known, but has not yet been proven at a utility-sized facility or with Alberta's low sulphur mid-rank coal.

- Demonstration plants built in other countries have experienced high capital and operating costs (at least 1/3 higher than conventional plants) and there continue to be issues with operating reliability.
- Experience on a utility-sized (500+MW) IGCC facility is needed to better understand and manage construction and operation costs in a northern climate.
- To develop this facility, engineering and design work is required, focused on:
    - adapting the technology to work with the type of coal found in Alberta,
    - removing emissions of concern,
    - investigating commercial-scale geological storage of CO_2,
    - ensuring cost competitiveness and cost certainty, related to both capital and operating costs, and
    - ensuring successful construction and operation in a northern climate

The Canadian Clean Power Coalition is an association of responsible, leading Canadian coal and coal-fired electricity producers. Its aim is to secure a future for coal-fired electricity generation, leading Canadian coal and coal-fired electricity within the context of Canada's multi-fuelled electricity industry, by proactively addressing environmental issues with governments and stakeholders.
Basin Electric Power Cooperative (North Dakota), EPCOR, Sherritt International, Nova Scotia Power, SaskPower, TransAlta, Electric Power Research Institute (California).

CANADIAN CLEAN POWER COALITION

In October 2006 the Province of Alberta agreed to partner with EPCOR Utilities Incorporated and the Canadian Clean Power Coalition (CCPC) in a $33 million research and development project that promises to make Canada a world leader in clean coal technology. The federal government joined this partnership in October 2007. The application of this technology, on this scale, with this type of coal, is a first in the world. This front-end engineering design project is an important step before construction of a full-scale coal gasification power plant that will demonstrate this advanced clean coal technology to Canadians and the world. The Government of Canada is investing $11 million in the project through ecoENERGY Technology, and both EPCOR and AERI will contribute equal amounts.

The project will be located at the Genesee Generating Station site west of Edmonton. Researchers will conduct front-end engineering design work for a power plant that would turn sub-bituminous coal into synthesis gas (mostly hydrogen and carbon monoxide). The work is scheduled for completion in 2009, and if subsequent investment and construction decisions go as planned, a 500-megawatt generating station using the new technology could be in operation as early as 2015.

Commercialization is expected to take place over three phases following which a consortium of investors would be in a position to make a decision on building a utility-scale pilot plant.

Phase I	Technology Selection and Project Definition
Phase II	Front-End Engineering Design, 2008 – 2009 (Genesee site)
Phase III	Regulatory Environmental Permitting for Construction leads to a decision to build an IGCC facility in Alberta, 2010-2015

In summary, IGCC gives coal-fired generation an environmental footprint that will take us into a GHG constrained future.

- Production of clean power with 90% CO_2 capture and removal of all emissions of concern is technically feasible and can become economically viable at certain locations.
- Gasification costs and reliability depend on feed quality. There is little experience with low rank lignites, sub-bitumous coal, and coal-coke mixtures in Canada.
- IGCC technology offers investors the flexibility to change feed stocks and even potential products. This provides a sense of certainty in light of tougher emission and GHG standards, and a changing regulatory regime.
- IGCC taps into Alberta's vast coal reserves to provide a secure supply of electrical energy in a more environmentally acceptable way.
- A CO_2 pipeline and storage infrastructure will need to be built.

4.2 Clover Bar Landfill Gas Generating Station

EPCOR's 4.8 megawatt (MW) Clover Bar Landfill Gas Generating Station commenced operation on February, 2005 at the Edmonton Waste Management Centre. The facility is powered by methane gas produced by decomposing organic material and produces enough energy to power 4,600 homes.

The City of Edmonton has purchased the power output from the Clover Bar facility – an investment that ensures a significant portion of its energy requirements come from a renewable resource.

Methane is 21 times more powerful a greenhouse gas than carbon dioxide. Using it for electricity exploits a resource that would otherwise pollute the atmosphere, transforming it into useful energy. When landfill gas is collected and used for power generation, it displaces conventional, non-renewable fuels such as coal and natural gas, preventing more greenhouse gases from entering the atmosphere.

Figure 5. Clover Bar Landfill Gas Generating Units

4.3 Genesee Units 1 & 2 Combustion Optimization

The 2005 Tri-Utility Mercury Test Program showed that combustion optimization using Genesee coal could result in the following improvements:

- an increase the efficiency of coal combustion in the boiler
- a decrease in NOx emissions (by up to 30%)
- an increase the inherent mercury removal in the electrostatic precipitators from about 27% to as much as 45%.

Consequently, EPCOR has completed installation of the equipment. . It is expected that the effect of this equipment will be a more precise control/balancing of coal combustion in the boiler, a higher efficiency of coal combustion resulting in decreases in stack emissions such as NOx, CO_2, and particulate matter, and a decrease in Hg emissions.

The reduction in mercury emissions will be well ahead of the January 1, 2011 deadline. The expected NOx emissions reduction will contribute to improved air quality in the area by slightly lowering ground-level NO_2, ozone and $PM_{2.5}$ concentrations.

4.4 Turbine Efficiency Improvement

The efficiency of the existing steam turbines at a number of coal fired generating stations has been improved by installing Dense Pack and upgrading the turbine seals. Current turbine designs using advanced computer modeling result in a higher efficiency steam path which allows for more useful energy to be extracted from the same steam flow. This efficiency improvement allows for additional generation with no increase in fuel consumption and, thereby, no increase in emissions. The efficiency improvements range from an increase of 2 to 3 % and vary by unit.

The units upgraded in the 2003 to 2007 period include Battle River Unit 5, Sheerness Units 1 and 2. It has been estimated that these upgrades have resulted in an additional 24 MW of non-emitting generating capacity in Alberta.

4.5 Sundance Upgrades

Uprates have been completed at TransAlta's Sundance plant. The uprates have been done to reduce process bottlenecks and have resulted in improved production efficiencies and have reduced emission intensities.

In 2007, an uprate was completed on Sundance Unit 4, which has resulted in emission intensity reductions from 1-2.5% for the overall facility. The uprate for Sundance Unit 5 is scheduled to be completed in 2009. Uprates for other TransAlta units are being reviewed.

4.6 Mercury Monitoring Programs

As required in the Mercury Emissions from Coal-Fired Power Plants Regulation, all the coal-generating stations have initiated source mercury monitoring programs starting in January 2008. The programs include annual mercury stack surveys, weekly monitoring of the concentration of mercury in coal and ash, and the calculation of the annual mass of mercury emitted to the atmosphere. The monitoring programs will allow baseline monitoring of mercury prior to the installation of mercury capture equipment by 2011.

4.7 Mercury Capture Tests

In preparation for the installation of mercury capture equipment on the coal-fired generating units by January 1, 2011, a number of bench-scale and pilot projects have been conducted.

- EERC (Energy & Environmental Research Center)
- GE Energy
- Sundance
- Keephills
- Battle River - activated carbon injection system is being tested on one half of unit 5 in the last half of 2008. Test results are not available at the time of the writing of this report.
- EPCOR conducted a full-scale test of activated carbon on Genesee Unit 3 in 2008. Test results are not yet available.

Mercury continuous emission monitoring systems (CEMS) were tested during the various pilot projects and, generally, the analyzer reliability was disappointing and of concern.

4.8 Transmission Upgrades

A number of transmission lines have been constructed. Improvements to the transmission infrastructure help to minimize line loss[28] and meet generation needs in different regions of the province. New and upgraded transmission lines include:

- Third 240 kV line from Dover (Fort McMurray area) to Heart Lake.
- Second 240 kV line from Battle River to Hansman Lake (Metiskow area).
- Re-energize 1203L and 1209L to 500 kV operation.
- New 240 kV underground line from Castle Downs to Victoria.

In addition, the following projects are planned for the next five years to improve transmission reliability and efficiency as well as interconnect new sources of renewable generation:

- Re-energize 1202L to 500 kV operation.
- Increase capacity from the Edmonton/Wabamun Lake areas to the Calgary/southern Alberta areas.

[28] While each of these projects might contribute to loss reductions, absolute system losses may fluctuate from year to year depending on load growth and generation dispatch patterns.

- Two 500 kV AC lines from the Edmonton area to the Heartland area, one of which will be operated at 240 kV.
- Increase capacity from the Edmonton area to the Fort McMurray area.
- Rebuild of the existing 240 kV line 904L in the Edmonton area.
- Two 144 kV lines from Wesley Creek to Hotchkiss.
- Two 240 kV lines from Goose Lake (Pincher Creek area) to Peigan to Lethbridge, for interconnection of wind.
- South Alberta 240 kV development; for interconnection of wind.
- Transmission development in the Hanna area for interconnection of wind.
- New inter-ties to neighbouring jurisdictions.

5 Planned Initiatives 2009 to 2013

- The IGCC Project will continue according to the schedule outlined in Section 2.1. As previously stated, the project is dependent on not only technical and economic factors but the availability of a CO_2 pipeline and storage infrastructure.
- Development of CCS (carbon capture and storage)
- Clean coal development
- Micro-Generation
    - Effective Jan 1, 2009, the Micro-Generation Regulation passed into law and allows Albertans to generate their own electricity and receive credit for any excess electricity that is delivered to the grid.
    - Companies such as Enmax have supported this initiative and are getting ready to accept the electricity from the micro-generators.
    - ENMAX will be launching a suite of solar powered, wind and combined heat and power technologies their customers will be able to install for a competitive rate.
- Calgary Downtown District Energy
  Construction was started in September 2008 for a heat generating facility located at 9th Ave and 4th Street SE. This multi phase project will provide heating for up to 10 million square feet of new and existing downtown buildings through a network of underground insulated pipes that run along the industrial corridor of downtown Calgary. The use of underground heat will reduce fuel consumption and GHGs and is strategically located to service current muni-owned and selected future downtown buildings.
- The coal-fired generators will continue with their mercury control program:
    - complete the technology test program,
    - engineer, install and commission the control equipment by the January 1, 2011 regulatory deadline,
    - evaluate the control technology during longer term commercial operations
    - review possible optimization measures.
- Enmax has proposed a new generation facility near Calgary, about 2 km northeast of the community of Shepard, the Shepard Energy Centre. The new natural gas-fired generating facility will be built using the best gas technology and meet about two thirds of Calgary's electricity requirements and emit up to 50% less CO_2 per MW than current coal plants in Alberta.

Continued activities related to improving combustion, generation and/or transmission efficiency with the existing generation and transmission system will also be undertaken the results of which will be reported during the next 5 year review.

Appendix F: Source Standards for New Gas-Fired Non-Peaking Generation Units

In June 2009, the Electricity Framework Review (EFR) project team forwarded a report to the CASA Board that contained ten consensus and one non-consensus recommendation. The one non-consensus recommendation pertains to NOx emissions for new gas-fired generation units, including non-peaking and peaking units. One of the outstanding issues is the choice of BATEA and the corresponding source standard for non-peaking units. The Board directed the 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.

The EFR project team has already completed a broader emissions control technology review with Eastern Research Group (ERG). However, some stakeholders felt that the ERG review did not consider the unique economic and operational issues surrounding cogeneration facilities. To further assist with this particular issue, Jacobs Consultancy was hired to undertake a review of natural gas and alternate fuel combustion and control technologies, in order to establish the best available technology economically achievable (BATEA) for NOx emissions control for cogeneration units.

Control Technologies Review – Cogeneration Units

Jacobs Consultancy carried out the following activities to achieve study objectives:

- Control Technology Review – Capital and operating cost estimates were made for various NOx control technologies and the cost effectiveness of the technologies were calculated.
- Alternate Fuels Review –Information was gathered about the impact of firing with fuels other than natural gas on the effectiveness of NOx control technology.
- Heat Recovery Allowance – Commentary was provided on the types of duct burner available, associated NOx emissions, and industry experience with newer low NOx technology. Sensitivity analyses were performed on the heat recovery and NOx generation with duct firing, and a methodology was suggested to calculate an output based heat recovery allowance assuming a control technology of choice.
- Jurisdictional Review –Legislation was researched for allowable NOx emissions outside Alberta and the data was compiled for comparison with local regulations.

The following consultants' reports are available on the CASA website at: http://www.casahome.org/?page_id=3196:

- "Control Technologies Review: Cogeneration Units", February 2010, Jacobs Consultancy
- "Electricity Framework 5-Year Reveiw – Control Technologies Review", January 2009, Eastern Research Group

It should be noted that these reports were prepared by third party consultants to provide advice to the team only. They are not consensus reports of the team.

Source Standards for New Gas-Fired Non-Peaking Generation Units

The EFR project team could not agree on updated source standards for new gas-fired non-peaking thermal generation units. However, stakeholders generally agreed that they had similar interests in the following areas:

- The emission standard should be based on the performance of a technology that is considered BATEA. Stakeholders could not reach agreement on what technology constituted BATEA.

- Cost-effectiveness and economic achievability are important factor to consider.
- Alberta should set standards to reduce emissions that are comparable to leading jurisdictions in attainment areas (i.e. areas of good air quality).
- The emission standard is not intended to create disincentives for cogeneration development.
- There should be flexibility to meet the emission standard with any processes and/or technology that make sense to each operator.

Summary of Blocks to Consensus

The main block to consensus is the choice of BATEA and the corresponding source standard. The disagreeing parties' positions and rationale are as follows.

1. Support for Proposal A

Based on the reports prepared by the Eastern Research Group and Jacobs Consultancy, government, NGO, and some industry stakeholders support **Proposal A**, and agree that Selective catalytic reduction (SCR) is the best available technology economically achievable (BATEA).

- SCR technology is a proven technology used in jurisdictions with climate conditions similar to Alberta. SCR technology is installed and operated in a variety of applications, including co-generation, in some locations in the United States. Several of these facilities operate in cold weather and there are SCR units operating in Alberta.
- Although there is the potential for new developments in DLN technology, this equipment has yet to be installed and operated in Alberta. The Jacobs report indicates that, even for DLN units that can achieve very low emissions levels, turbine manufacturers will not provide a performance guarantee for units operating below a certain ambient temperature.
- Based on the report from Jacobs Consultancy, these stakeholders also agree that the use of selective catalytic reduction (SCR) to further reduce NOx can be cost effective in larger installations.
  - Specifically, for facilities greater than approximately 40MW, the incremental cost effectiveness is less than 0.4 cents per kWh on the electricity portion, and less then 42 cents per tonne of steam. When compared with stand-alone steam generation and electricity imported from the grid, installation of SCRs would result in a cost of $6.21 per tonne of steam compared to $9.87 per tonne for stand-alone steam generators. On the electricity side, the cost of SCRs would be 9.1 cents/kWh compared to 9.0 cents per kWh for the stand-alone options.
  - Where duct burning is employed, the incremental cost effectiveness of applying SCRs for installations greater than 70MW is between $5,000 and $6,800 per tonne of NOx removed. For installations with duct burning greater than 40 MW, cost effectiveness is between $5,000 and $8,600 per tonne of NOx removed.
- The Jacobs report indicates that the use of SCR adds 0.2 cents/kwh to the electricity price which is within the variation of the average electricity pool price.
- The report from the 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. Ammonia slip from SCRs is well-documented and it is potential impact is limited to areas that have PM issues – this is not the case in Alberta. The Jacobs report reiterates that there are a large number of SCR systems in operation that safely handle NH3 (ammonia).

- During the team's discussions, participants reached 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.

2. Support for Proposal B

Based on the report prepared by Jacobs Consultancy, other industry groups support **Proposal B,** and believe that proven Dry Low NOx (DLN) burners meet the definition of best available technology economically achievable (BATEA).

- DLN technology is proven reliable in Alberta. The latest proven DLN burner technology achieves a significant reduction in NOx emissions without requiring significant capital and operating costs. The incremental cost-effectiveness for DLN is less than $100 per tonne, whereas SCR[29]'s incremental cost-effectiveness is between $5,000 and $12,000 per tonne on diffusion burner systems.
- Proven DLN technology meets the BACTEA criteria set in the CASA June, 2009 control technology assessment (ERG report): it provides emission reductions within 15% of the best control technology (of SCR).
- The "standard" duct burner technology (38 g/GJ) is BATEA. Lower emission duct burners are not proven in Alberta.
- The groups supporting Proposal B concluded that the incremental benefit in NOx reductions from SCR technology do not outweigh the additional safety and environmental liabilities, costs, reliability issues, and associated with SCR.
- The stakeholders supporting Proposal B assert that DLN technology does not present a risk of disincenting further installations of cogeneration systems, whereas a requirement for SCR might.
- Recognizing the latest proven DLN technology as BATEA incents and accelerates technology development and deployment in new DLN technology. This technology may result in NOx performance levels approaching those attainable with SCR for a fraction of the cost and without liability. The timeline for this forecasted technological development is unknown.
- An output-based standard that recognizes all energy generated from the cogeneration installation is important to continue incenting cogeneration installation. The Jacobs report's jurisdictional review shows that Texas, California, Norway and Germany give credit to the entire steam output (from waste heat and supplemental firing) of combined heat and power systems.
- Lastly, the industry groups supporting Proposal B conclude that the alternative proposed recommendation for non-peaking thermal units is more stringent for cogeneration facilities than for combined cycle facilities. For combined cycle units, recovery of waste heat receives a NOx emissions allowance based on the power output allowance factor. For cogeneration systems, recovery of waste heat receives a NOx emissions allowance based on the smaller heat recovery allowance.

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

[29] The incremental cost-effectiveness quoted is for the DLN+SCR case in the Jacobs report, which is the configuration required to meet the June 2009 proposal.

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.

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

It is recommended that, effective January 1, 2011, the NOx BATEA standard for new gas-fired units will be:

PROPOSAL A:

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

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

Power Output Allowance ("A")

Net Power Output (per gas turbine train)	**Non Peaking ("A")** (kg NO_x /MWh net)
Greater than 25 MW	0.09
Less than *25* MW	0.60

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

PROPOSAL B:

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

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

Power Output Allowance ("A")

Power Rating (per gas turbine only)	**Natural Gas Non-Peaking** (kg/MWh)
Greater than 25 MW	0.18[30]
Less than 25 MW	0.60

Heat Recovery Allowance ("B")
For All Units: 0.04 kg/GJ

Applicability

- Effective for units approved after January 1, 2011 for new and for end of life installations
- Natural gas fired systems
  - Dry low NOx burners – on which this BATEA standard is based – are designed and engineered for natural gas as fuel
  - Systems fueled by alternate gaseous fuels to be handled on a permitting, case-by-case basis (e.g., systems fired with a mix of natural gas with syngas, off-gas or refinery fuel gas)
- Start-up and shut-down and upset conditions are exempted from the standard

Basis

- Non-peaking standards expressed as output standards
  - Consistent with CCME's National Emission Guidelines for Stationary Combustion Turbines (December 1992)
  - Considers the environmental benefits afforded by energy efficiency gains of cogeneration and combined cycle installations
- The BATEA basis for the power output standard ("A") is Dry Low NOx (DLN) burners
  - The standard is applied on an annual basis to the large turbines (>25 MW) to account for cold ambient weather conditions where denser air causes combustion instability in DLN burners
- The BATEA basis for the heat recovery allowance ("B") is consistent with manufacturers' standard burner configuration
  - Captures the efficiency gains from cogeneration and combined cycle systems.

[30] To be applied on an annual average basis

Appendix G: Stakeholder Statements on Non-Consensus Recommendation

Source Standards for New Gas-Fired Non-Peaking Units
Stakeholder statements on non-consensus recommendation

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A. Capital Power Corporation

1. Statement of Position

CPC supports the non consensus standards that are based on:

- Non Peaking Standards expressed as output standards in a similar format to the 1992 CCME Guidelines.
- Separate categories based on gas turbine capacity for non peaking and peaking / mid-merit
- BATEA basis: Non Peaking – LN Burners and SCR
Peaking / Mid-Merit – DLN / DLE Burners or alternative
- Operation required by the System Operator for system security exempt from the standard and not included in the emission allowance.
- Non peaking standards conditional on emissions during startups and shutdowns (using best practices) being excluded from the compliance measurement.
- Credit for heat produced is based on the HRSG performance target in the AENV Approvals Program Interim Policy OSEMD-00-PP2 dated December 14, 2007.
- Non Peaking compliance measurement based on existing Alberta Environment protocols subject to exclusions stated above.
- Consideration of appropriate relaxation of emission standards during the approval process where a project can demonstrate a significant additional NOx reduction.

Non Peaking Standard Formula

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

Power Rating (per gas turbine only)	**Natural Gas** **Non Peaking ("A")** (kg/MWh net[31])	**Peaking / Mid-Merit Standard**
More than 100 MW	0.09	750 kg/MW annual maximum[32,33] Design specification of 9 ppmv[4,5]
25 to 100 MW		750 kg/MW annual maximum[2,3] Design specification of 15 ppmv[34,35]
Less than 25 MW	0.60	750 kg/MW annual maximum

Heat Production Allowance "B factor" for Natural Gas = 0.01 kg/GJ

[31] Net power rating for gas turbine plus an associated combined cycle steam turbine.
[32] Normal maximum net continuous rating at ISO conditions as provided by the manufacturer
[33] Based on 0.25 kg/MWh x 3000 hours/year
[34] Normal maximum net continuous rating at ISO conditions as provided by the manufacturer
[35] Based on 0.25 kg/MWh x 3000 hours/year

This proposal is the product of a detailed consultative review and stakeholder examination over several months and is soundly based on BATEA. Industry (CPC, ATCO Power, TransAlta Utilities and TransCanada) and AENV have agreed to a concept for addressing peaking units, but this concept cannot yet be tabled or included in the team's report. The standard for peaking units will depend on the standard reached for non-peaking units because the peaking units cannot have more stringent standards than non peaking. Ideally, the proposal for peaking units will be presented by AENV to the board in March 2010. If there is no update in March, AENV could provide an update to the board in June 2010 about how it plans to proceed.

2. Background

The proposal represents a compromise reached in March 2009 (non peaking) and November 2009 (peaking) by the actively participating electric utility stakeholders and all contributed to its development. (CPC, ATCO Power, TransAlta Utilities and TransCanada.) 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.

CPC views Jacobs study a comprehensive one, the study provided sufficient information and details about the technology capabilities, environmental impacts, costs and heat recovery allowance. In our opinion, the study supports our position about the technology of choice for non peaking gas fired facilities (Non Peaking – LN Burners and SCR).

B. Canadian Association of Petroleum Producers

CAPP
CANADIAN ASSOCIATION
OF PETROLEUM PRODUCERS

March 5, 2010

Ms. Kerra Chomlak, Executive Director
Clean Air Strategic Alliance
10035 – 108 Street
Edmonton, AB T5J 3E1

Dear Ms. Chomlak:

Re: NOx Performance Standards for Non-Peaking Natural Gas-Fired Gas Turbines

CAPP submits the following discussion and rationale in support of the CAPP-CPPI-CIAC recommendation ("CCC proposal") on NOx standards for natural gas-fired non-peaking units as submitted in February 2010.

In general, CAPP supports Alberta Environment's definition of Best Available Technology Economically Achievable (BATEA), which is defined as control technology that can achieve superior emissions performance that has been demonstrated to be economically achievable and commercially viable in a variety of operating regions and fuel types. CAPP also supports the CASA Electricity Framework Review Team's development of a NOx standard for gas-fired turbines that are based on BATEA.

CAPP supports Alberta's efforts to integrate and ensure consistency in policy development. In the context of the Alberta's Land Use Framework and of airshed zone management, whether under the proposed national Comprehensive Air Management System or under Alberta's Clean Air Strategy, CAPP supports the development of NOx performance standards that will provide a level of performance consistent with standards in leading jurisdictions in attainment areas.

As the CASA Team agreed, the standard for non-peaking units will be an output based standard. As such there are two components to the standard: a power output allowance and a heat recovery allowance. The proposal put forth by CAPP, CPPI and CIAC, is set based upon a BATEA of the best available dry low-NOx (DLN) combustion technology[36] for the power output allowance of 0.18 kg/MWh. The heat recovery allowance is set at 40g NOx/GJ to account for the energy efficiency gains and environmental benefits obtained from installing a turbine in a cogeneration or combined cycle configuration.

The following discussion explores CAPP's interests in environmental performance standards and demonstrates why CAPP supports the CCC proposed recommendation NOx standard for natural gas-fired turbines.

[36] With a 20ppm or lower NOx emissions guarantee from turbine vendor

CAPP INTERESTS AND RATIONALE

The following six points frame CAPP's interests in the NOx standard-setting process and how the recommended standards meet these interests. Where applicable, the Control Technologies Review, Cogeneration Units report, as undertaken by Jacobs Consultancy on behalf of the CASA Electricity Framework Review Team ("Jacobs report") is referenced.

1. **CAPP is interested in standards based on best available and demonstrated technology that provides the greatest opportunity for NOx reductions recognizing the efficient use of capital and operating costs.**

   - The analysis in the Jacobs report (Table B.5) shows that DLN technology is the technology that best meets this interest, as it offers the greatest opportunity for NOx reductions at a reasonable cost.
     - As reported in the Jacobs report, the cost-effectiveness of DLN technology compared to SCR technology differs by a factor of 100. The cost-effectiveness of cogeneration systems with DLN and SCR installations are approximately $60/tonne and $6000/tonne NOx reduced, respectively.
     - Applying the two recommended standards to a representative cogeneration system installed in in-situ oil sands service would result in a maximum of emissions 484 tonnes/year of NOx under the CCC proposal and 155 tonnes/year NOx in the June 2009 non-consensus proposal (maximum emissions limits shown in Appendix B). For a representative cogeneration unit with an 85MW turbine, the difference provides a maximum reduction in NOx emissions of 329 tonnes per year, but with an annual cost increase of approximately $2.4 million. In perspective, the total NOx emissions from all sources in Alberta in 2007 was 813,523 tonnes[37]. Thus the June 2009 standard would provide a reduction equivalent to 0.04% of provincial emissions at a significant annual cost relative to the CCC proposal.
     - Another illustration of the cost-achievability of DLN is shown in Table 1 below, which is an update of the table presented in CAPP's non-consensus submission to the CASA Board in June 2009 (also labeled Table 1). This table compares the cost of NOx removed and the environmental benefits gained from installing SCR or DLN technology at all planned cogeneration facilities in the Athabasca region[38]. The cost-effectiveness has been updated to reflect the results of the Jacobs report, and the comparison shows that:
       - If DLN technology were installed at all planned cogeneration facilities in the Athabasca region, the total cost would be $0.5 million for DLN, as opposed to $83 million for SCR installations. To achieve an additional 2.1% reduction in Alberta's total forecasted NOx emissions in 2015, cogeneration operators are required to spend an additional $82.5 million.
   - For heat recovery, the Jacobs report concludes that the standard duct burner technology is the only technology available that is demonstrated to be operable over a wide variety of regions and fuel types with guaranteed emissions performance levels. Standard duct burners thus meet the definition of BATEA. The alternative technology, dual-stage duct burners, is not considered BATEA, as performance been not demonstrated in a wide variety of operating regions and ambient conditions, or over a range of fuel types. In addition, the dual-stage duct burners are currently only offered by one vendor, do not have guaranteed emission levels (the 22g/GJ quoted

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[37] Environment Canada, CAC Emissions Inventory (2007). Total emissions reported does not include open and natural sources.
[38] Golder Associates (2006), *Report on NOx Control Technology Assessment*. Submitted to the Regional Issues Working Group. Report No. 06-1331-018.

by Jacobs approximate) and cannot be used with fuels other than natural gas due to susceptibility to coking and fuels with high hydrogen content.

Table 1 - Cost-Benefit Analysis of DLN and SCR Technologies

Case	NOx Removed (t/d)	Cost-Effectivness ($/tonne)	Total NOx Reduced (t/year)	Percentage Total NOx Emissions[a]	Total Annual Cost
DLN (~9-15ppm)	23.60	57	8,495	4.3%	$0.51 million
SCR (5ppm)	34.96	6,300 [b]	12,587	6.4%	$83 million
Δ from UDLN to SCR	*+ 11.4*	*+20,166*	*+4,091*	*+2.1%*	*+$82.5 million*

[a] Based on 2015 forecasted NOx emissions from oil sands sector (Cheminfo, 2007)
[b] As indicated in the Jacobs report, the quoted incremental cost-effectiveness is for turbines rated at 20ppm for an 85 MW turbine with 32% duct firing, fired to 840C to turbines rated at 5ppm (SCR).

This Table was developed using a report on NOx control technology assessment undertaken by the Regional Issues Working Group in 2006 and the cost-effectiveness of SCR and DLN technologies[39] as reported by Jacobs.

2. **CAPP is interested in minimizing the risk of disincenting or preventing future installations of cogeneration systems.**

- DLN technologies have been proven operational in variable and cold climates, as opposed to SCR technology, which has not yet been fully demonstrated in Alberta. The lack of demonstration and certainty of reliable operation increases this risk in disincenting cogeneration.
- Combined cycle and cogeneration systems are encouraged by governments and industry because of the energy efficiency gains, fuel savings and reductions in greenhouse gas emissions through the use of the turbine waste heat for power or steam.
  - Output based standards are designed to recognize the benefits of lower emissions and fuel use achieved by cogeneration systems, as compared to stand alone power and steam production[40]. The output based standard formula credits the additional investment made for these gains in efficiencies, thereby providing additional incentive to install such systems.
  - The proposed NOx allocation to the steam output should be sufficient to account for the efficiency gains obtained from the use of the turbine waste heat as steam and should be based on best available technology that would otherwise be required to generate this steam output.

[39] 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 ultra-DLN.
[40] US EPA (2004) *Output-based Regulations: A Handbook for Air Regulators*. Available at: http://www.epa.gov/chp/documents/obr_final_9105.pdf

- The proposed heat recovery allowance of 40g NOx/GJ was originally developed by the CCME and is applied to the total steam output of the cogeneration facility, including the steam produced from the turbine's waste heat. The allowance is based on the current CCME standards for large boilers as applied in Canada and most of Alberta. Applying the boiler standard to the waste heat from the turbine credits operators for the steam production of the cogeneration facility that would otherwise have to be generated using a once through steam generator (boiler).
- The 40g NOx/ GJ heat recovery allowance is also consistent with the BATEA for duct burner technology (rounded up from 38 g/GJ), as indicated above.

3. CAPP is interested in ensuring operators are offered the flexibility to meet the standard using multiple technologies

- Although the proposed standard can be met using the latest proven DLN technology, the CCC proposed standard does not preclude companies from installing SCR, or other low emissions, technology, if appropriate.
- The June 2009 non-consensus recommendation limits companies to installing SCR only, and excludes the opportunity to rely on DLN technology for NOx reduction, which is contrary to this interest.
- The limitation of NOx control equipment to SCR only could disincent developers from installing cogeneration units.

4. CAPP is interested in continuous improvement in NOx reduction and encouraging technology development and deployment

- The CCC recommended standard for the power output allowance (A factor) is consistent with the evolution in DLN technology. As the Jacob report shows, there are currently two turbine frames that have vendor guarantees equivalent to the proposed power output allowance of 0.18kg/MWh. However, also indicated in the report, turbine frames of smaller power ratings are being currently being developed and tested with emerging DLN technology[41]. The CCC proposal will motivate turbine vendors into developing the latest proven DLN for a wider range of turbine sizes.
- Limiting companies to choosing SCR technology will prevent companies from engaging in the broad development and deployment of the more cost-effective and emerging DLN technology.
- The proposed power output allowance (A factor) of 0.18 kg/MWh is a 64% decrease from the current power output allowance indicated in the existing CCME regulatory standard for cogeneration systems[42], and a 40% decrease from the CASA 2003 Electricity Framework standard.
- Appendix A offers a comparison of the regulated maximum emissions limit for a representative cogeneration system installed in a SAGD facility. The CCC proposed standard represents a reduction from the current regulation (CCME) and the CASA 2003 Electricity Framework of 33% and 49%, respectively.

[41] As indicated in the Jacobs report, some turbine vendors are supplying a limited number of turbines with vendor guarantees of 9ppm. GE has informed CAPP that they are planning to cold weather test turbines rated for 5ppm in late 2010, early 2011

[42] The Canadian Council of Ministers of the Environment's National Emissions Guidelines for Stationary Combustion Turbines

5. **CAPP is interested in standards that are aligned with what other leading jurisdictions would require as base-level source performance standards**

   - Appendix A provides a comparison of the regulated maximum emissions limit for a representative cogeneration system installed at a SAGD facility. Shown in the Appendix's table are current standards regulated by the US EPA, Germany, Norway, Texas and California, as summarized in the Jacobs report. Texas and California are presented for information only; the colder winter climate in Alberta makes achieving NOx levels similar to Texas and California unattainable using DLN only.
   - The maximum emissions limits for the hypothetical SAGD facility under the proposed standards sit between what would be required if the facility were installed and regulated in Germany and Norway, and in Texas. If the US EPA's standard is applied, there is a significant increase in the maximum NOx emissions limit from the limit that would be imposed under the CCC proposal.
   - Given that the Electricity Framework Review BATEA-based standards are to be considered base-level performance, it is appropriate that the proposed standard be equivalent to leading jurisdictions in attainment areas (areas with no air quality issues). As Texas and California are considered to be non-attainment jurisdictions, they required higher standards than are necessary for a province-wide BATEA standard in Alberta.

6. **CAPP supports standards that minimize collateral environmental impacts**

   - DLN technology is a pre-combustion technology that controls NOx by pre-mixing air and fuel prior to combustion. SCR technology, on the other hand, is a post-combustion technology that scrubs NOx emissions from the turbine's flue gas by combining it with ammonia and injecting it across a catalyst bed. As opposed to DLN, SCR is an add-on technology that requires additional space and raw material handling (catalyst and ammonia), which increases the collateral impacts of NOx control.
   - Although the environmental and safety risks due to operation of SCR units are manageable, as demonstrated by the successful use of SCR in many applications in other jurisdictions, the absolute risk of an ammonia-related environmental or safety incident is higher with SCR than without. Inherent safety considerations lead to a preference to avoid the installation of SCR units unless they are strictly necessary. Risks inherent to the use of SCR include:
     - Safety concerns associated with ammonia, which is explosive, flammable and toxic. Facilities that use ammonia must be designed and operated to manage risks associated with the transport, storage and handling of ammonia; the potential for ammonia leaks and spills and the potential for public and occupational exposure.
     - Environmental impacts in the form of collateral NH_3, NOx, GHG and secondary $PM_{2.5}$ emissions, incremental water consumption, and additional waste solids for landfill. Table 2 provides a comparison of the collateral environmental impacts of SCR technology, which are also described in the eight points below.

Table 2 - Collateral Impacts of DLN versus SCR Technologies

Environmental Considerations	Dry Low-NOx	Selective Catalytic Reduction
Water Use	–	+ 212,000 gallons / year [a]
Ammonia Emissions	–	+ 25 tonnes / year
$PM_{2.5}$ Emissions	–	+ 170 tonnes / year
GHG Emissions	–	+ 2700 tonnes / year from ammonia production, transport and vapourization, and de-mineralized water production
NOx Emissions	–	+ from ammonia production, transport and vapourization, and de-mineralized water production
Waste	–	+ 200 tonnes catalyst every 5 to 10 years

[a] Based on Jacobs report and 19% aqueous ammonia density of 0.262 and 176 g NH3/L of solution

This table was developed using the results provided in the Jacobs report on collateral environmental impacts of NOx control technology. Additional references were used, as

Collateral Environmental Impacts of SCR

1. The use of SCRs will result in ~ 25 tonnes/year of ammonia emissions (for a typical oil sands cogeneration unit) because not all ammonia is reacted in the catalyst bed.
2. Ammonia emissions readily convert to fine particulate matter, $PM_{2.5}$. Ammonia will react with SO_3 to form ammonium bi-sulfate which forms $PM_{2.5}$. Elevated concentrations of fine particulate matter can be a public health concern. A typical oil sands cogeneration unit with SCR could produce 170 tonnes of $PM_{2.5}$ in a year.
3. Ammonia production is energy intensive and creates both GHG emissions. Based on the Jacobs report ammonia consumption estimate for a typical oil sands cogeneration unit and on a an average CO_2 emission rate for Canadian ammonia producers of 1.07 tonnes CO_2 per tonne NH_3[43], incremental GHG emissions of about 200 tonnes per year would be required for operation of a typical cogeneration unit.
4. Because of the safety concerns associated with anhydrous ammonia, industries prefer to use the aqueous form. A typical oil sands cogeneration unit will use 212,000 imperial gallons of fresh water each year in their use of 19% aqueous ammonia. In addition, de-mineralized water must be used to produce this ammonia because solids in the ammonia will create plugging issues in the SCR system. De-mineralized water is created through distillation which also creates GHG and NOx emissions.
5. Cogeneration operators can source ammonia in Fort Saskatchewan, Alberta, where it is produced. The transport of ammonia to operators creates GHG and NOx emissions. A typical oil sands cogeneration unit will require one truck of ammonia per week from Fort Saskatchewan to Fort McMurray, which will increase GHG emissions by 50 tonnes per year. NOx emissions will also increase from fuel combustion.

[43] Natural Resources Canada (2007) "Canadian Ammonia Producers: Benchmarking energy efficiency and carbon dioxide emissions"

6. Cogeneration units with SCRs typically experience a 0.45% energy loss which will create around 2,000 tonnes/year of GHG for a typical oils ands cogeneration unit. The energy loss comes from the pressure drop that occurs across the SCR in the HRSG. Additional firing, requiring more fuel and resulting in increased emissions is required to replace the efficiency loss. Jacobs reported that one HRSG vendor had recently installed new equipment that was built (larger) to compensate for the pressure drop normally found across an SCR – however, the vendor that installs many of the HRSGs in Alberta was not consulted to determine if their HRSGs are also designed to compensate for pressure loss. Some industry members were not able to satisfactorily conclude that this practice is widely adopted and, if widely adopted, that it would result in zero power loss across the turbine.
7. The vapourization of ammonia associated with SCR use creates GHGs: a typical oil sands cogeneration unit equipped with an SCR will create 250 tonnes of GHG emissions during ammonia vaporization each year. In addition, this will also cause incremental NOx emissions.
8. SCRs will generate waste – SCR catalyst has a life of between 5 and 10 years. About 200 tonnes of catalyst must be land-filled when it reaches end of life. The US EPA does not consider the catalyst hazardous material, however, Jacobs did not identify if the categorization of the catalyst would be similar in Alberta. The catalyst contains vanadium, a heavy metal.

Sincerely,

Krista Phillips (*sent via e-mail*)
Manager, National Air Issues
Canadian Association of Petroleum Producers

Appendix A - Maximum NOx Emissions Limits Comparisons
Canadian & International

The following table shows the maximum emissions limits a representative SAGD Cogeneration Facility would have to meet when applying Canadian and International standards. The representative cogeneration unit in this comparison is comprised of an 85MW turbine and has 1000 GJ/h steam load.

Standard	Regulatory Components	Maximum Emissions Limit
US EPA	0.150 kg/GJ (includes useful electrical, kinetic and thermal energy)	128 kg/h [44]
CASA 2003	0.3 kg/MWh (MWh includes steam output)	108.9 kg/h
CCME	A = 26ppm (0.50 g/MWh) B = 0.04 kg/GJ (0.144 kg/MWh)	82.5 kg/h
Jacobs analysis [a]	A = 20ppm (0.38 kg/MWh) B = 0.04 kg/GJ (0.144 kg/MWh)	72.3 kg/h
Germany & Norway	0.76 kg/MWh (40ppmv)	64.6 kg/h
CAPP-CPPI-CIAC Proposal	A = 9ppm (0.18 kg/MWh) B = 0.04 kg/GJ (0.144 kg/MWh)	55.3 kg/h
Texas	0.09 kg/MWh (5ppm) with 1MW credit for every 3.6 GJ of heat recovered	32.7 kg/h
June 2009 Non-Consensus Proposal	A = 5ppm (0.09 kg/MWh) B = 0.01 kg/GJ (0.036 kg/MWh)	17.7 kg/h
California	0.0317 kg/MWh with 1MW credit for every 3.6 GJ of heat recovered	11.5 kg/h

[a] "Jacobs analysis" in this context refers to the power output allowance set based on the DLN technology used for the Technology and Economic Analysis section of the Jacobs report.

[44] To be confirmed

C. Non-Government Organizations

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 reports from the Eastern Research Group and Jacobs Consultancy clearly demonstrate 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. The Jacob's Consultancy clearly confirms that cold weather operation is not an issue.
- 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 indicated 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 Jacob's Consultancy report addressed the issue of ammonia slip and ammonia handling safety in detail and no significant issues/concerns were identified.

The NGO members of the team would like to note that the Jacob's Consultancy report addressed all the of the concerns raised by some of the industry sectors and clearly indicated that for larger co-generation units i.e. greater than approximately 40 to 60 MW gas turbine size, are cost-effective from generally accepted cost per tonne reduction costs, incremental increase in cost of commodities and relative to power purchase and steam generation. 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 industry sectors that continue to be opposed to the SCR based limit appear to be fundamentally opposed to SCR and the NGO members are unsure how to address such a position.

The NGO members of the sub-group would like to reiterate that every concern raised by industry members with the application of SCRs have been addressed by the consultant (Jacob's Consultancy) that has international experience with the design and operation of SCR systems and has indicated that for certain size units represent BATEA.

The following information on SCR was part of the NGO's original position and the NGO believes that the Jacob's Consultancy report confirms/supports this information so it is reiterated again.

A. Background on SCRs as BATEA for Gas-fired Generation[45]

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.[46,47]

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.

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[45] 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.

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

[47] 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 [48,49,50,51]

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%	

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

[49] 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

[50] 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

[51] 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) (note: because in some circumstances the CCME National Emission Guidelines for Stationary Combustion Turbines(1992)[52] are more stringent than CASA limits they are still being used)

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

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)[53] and
c. CCME National Emission Guidelines for Commercial/Industrial Boilers and Heaters(1998).[54]

Table 2 outlines the emission limits in these documents. In general the CCME (1992)[55] and the CASA(2003)[56] 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.[57,58]

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%.

[53] 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)
[54] National Emission Guidelines for Commercial/Industrial Boilers and Heaters. Canadian Council of Ministers of the Environment. March 1998.ISBN:1-896997-16-3
[55] National Emission Guidelines for Stationary Combustion Turbines. Canadian Council of Ministers of the Environment. December 1992.ISBN:0-919074-85-5
[56] 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
[57] New Source Review (NSR) < http://www.epa.gov/nsr/psd.html>
[58] USEPA RACT/BACT/LAER Clearinghouse (RBLC**)** http://cfpub1.epa.gov/rblc/htm/bl02.cfm

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...".[59] 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[60] 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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[59] *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

[60] 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[61] 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) [c]

[a] 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 desired. The cost data on SCR provided by ERG is consistent with other NOx reduction cost data taken from USEPA reports.'[62]

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

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

[62] 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.

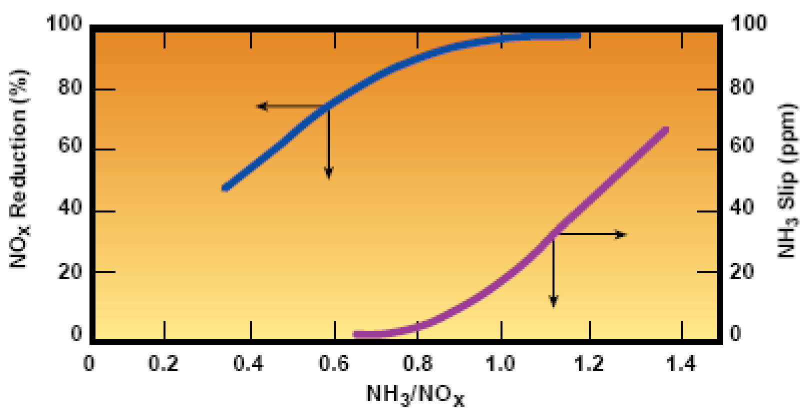
$6M in 2030 for the gas-fired sector as a whole. This modest cost will result in emissions reductions from gas-fired units in the sector of between 6% in 2015 to 9% in 2030. By 2030 the emissions reductions achieved by the sector would be equivalent to what a new 400MW coal-fired power plant would emit and would cost the sector just $6M annually.[63]

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.

The following Figure from a clean coal technology SCR demonstration project report[64] shows that ammonia slip is a function of the NH_3 to NOx ratio entering the catalyst.



Typical SCR performance

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.

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[63] 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)

[64] 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

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) 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.[65]

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.

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

D. Chemistry Industry Association of Canada

Chemistry Industry Association of Canada
canadianchemistry.ca

Association canadienne de l'industrie de la chimie
chimiecanadienne.ca

March 4, 2010

Ms. Kerra Chomlak, Executive Director
Clean Air Strategic Alliance
10035 – 108 St.
Edmonton, Alberta, T5J 3E1

Dear Ms. Chomlak,

Re: CASA EFR review – NO_x Performance Standards for Non-Peaking Natural Gas Fired Turbines

On behalf of the Chemistry Industry Association of Canada (CIAC), and further to our May 14, 2009 non-consensus position with regard to NO_x performance standards for natural gas fired co-gen facilities, I would like to make the following points:

1. CIAC appreciates the time and effort put in by NGOs, Alberta Environment and CASA staff, as well as other industry sectors to develop more clarity on the BACTEA for NO_x emission control from gas fired turbines. Our understanding of the implications of SCR and DLN NO_x emission control is significantly enhanced from May 2009, and the extensive dialogue that has happened since then has given us a better appreciation of the environmental, technological and implementation concerns of all parties around the table.

2. CIAC acknowledges the Alberta Environment commitment to sustain the high quality of Alberta's environment and through our CIAC member commitment to Responsible Care®are committed to continuous improvement and being proactive in preventing and reducing atmospheric emissions.

3. CIAC member companies are a significant manufacturing and exporting sector in Alberta, and the manufacturing processes requires significant amounts of steam and electric power. Generating the steam and electricity on site through co-generation (co-gen) facilities, not only is a most efficient way to maximize the available energy from fuel combustion, but also provides competitive benefits to the company through increased reliability and very low electricity transmission costs. While excess power generated is provided to the Alberta Interconnected System, and total capacity ratings may be quite significant, the reality is that the CIAC associated co-gen facilities are sized and operated primarily to steam demands and over the last decade have rarely been shown to run at capacity. Further, due to very low utilization rates, the required plant steam may be generated by high pressure boilers instead.

4. While co-gen facilities provide a highly efficient way of extracting maximum usable energy from natural gas to generate steam and electricity, a significant increase (order of magnitude) in the cost of NO_x control has the potential to further dis-incent the

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potential utilization of co-gen units in Alberta. For example, the work conducted by Jacobs Consultancy showed that SCR technology applied to an 85 MW turbine with ~ 30% duct burning achieved incremental NOX reductions using SCR versus DLN at a cost of $13,000 per tonne NOx reduced. DLN accomplished 92% of the SCR reduction at $60 per tonne.

5. A concern raised in May 2009 was the potential risks with implementing SCR control technology in a chemical manufacturing facility complex. It is acknowleged that the chemistry industry is more than capable of handling hazardous chemicals, including ammonia, safely and with appropriate process safety controls. Choosing to introduce a highly toxic, flammable and corrosive gas into a high risk environment (e.g., Class 1, Div. 1. Electrical code classified areas) is an extremely expensive scenario that may tip the cost balance to traditional purchased electricity and boiler use – loosing the many benefits of localized power generation. In addition the Jacobs report outlines collateral impacts of SCR technology, that collectively have a significant negative impact on the environment.

6. CIAC is committed to continuous improvement, which includes emission avoidance and control, and this commitment has been demonstrated over the National Emissions Reduction Masterplan as outlined over the last 15 years in our annual 'Reducing Emissions' reports. The proposed CAPP/CPPI/CIAC standard uses proven technology to achieve a 33% reduction in NOx emissions (for an 85 MW turbine with ~ 30% duct firing) over the current CCME standard. Our members have significant concern that the SCR technology is a very dramatic step-change both in control effectiveness, which is not argued, but also in control costs, associated collateral impacts and has not been proven in Alberta's climate. Other NOx control technologies, such as DLN+, or ultraDLN remain an area of significant research and development and may offer effective NOx emission reduction with fewer negative environmental collateral impacts.Traditionally Alberta Environment has selected an appropriate control standard based primarily on environmental considerations, but also recognizing technical achievability and to a lesser extent maintaining the industry competitiveness by comparing our standards to other jurisdictions.

7. CIAC supports the proposed CAPP/CPPI/CIAC standard as outlined in the attached document and believes it is consistent with the points outlined above and is environmentally, socially, technically and economically achievable and sustainable.

8. CIAC appreciates and remains a very strong supporter of the CASA process, and the opportunity to dialogue on important air quality strategies with the Alberta government departments, NGOs and other industry sectors.

Sincerely,

Al Schulz, Regional Director, Alberta
Chemistry Industry Association of Canada

E. Canadian Petroleum Products Institute

Canadian Petroleum Products Institute | Institut canadien des produits pétroliers

March 4, 2010

Ms. Robyn Jacobsen, Project Manager
CASA Electricity Framework Review Team
Clean Air Strategic Alliance
10th Floor, 10035-108 Street N.W.
Edmonton, AB
T5J 3E1
Email: rjacobsen@casahome.org

Dear Ms. Jacobsen:

Re: **Alternative Proposal to CASA**
<u>NOx Performance Standards for Non-Peaking Natural Gas-Fired Turbines</u>

The Canadian Petroleum Products Institute (CPPI)[66] is pleased to provide the following comments to the CASA Electricity Framework Review Team's CTRS Subgroup (Subgroup) in response to the proposed NOx performance standards for natural gas-fired turbines. These comments supplement those in CPPI's letter to the Subgroup of May 13, 2009, benefiting from the *Control Technologies Review, Cogeneration Units* study completed by Jacobs Consultancy in February, 2010.

CPPI supports a regulatory policy driving additional reductions in emissions of Criteria Air Contaminants to meet health and environmental standards. The supporting standards should protect health and the environment while supporting positive economic and social benefits. The resulting actions should be based on sound science, risk assessment, be cost effective and lead to air quality improvements under Alberta circumstances.

CPPI is a strong supporter of CASA, which provides the opportunity to develop solutions that best meet the balance of Alberta's varied needs. We are grateful for the additional time and work by the CTRS subgroup to further study this issue.

The CPPI, joins the Chemistry Industry Association of Canada (CIAC), and the Canadian Association of Petroleum Producers (CAPP) in supporting BACTEA which reflects proven dry low

[66] CPPI members: Bitumar Inc., Chevron Canada Limited, Husky Energy Inc., Imperial Oil Limited (Products and Chemicals Division), North Atlantic Refining Limited, NOVA Chemicals (Canada) Ltd., Parkland Income Fund, Shell Canada Products, Suncor Energy Products Inc., and Ultramar Ltd .

NOx (DLN) combustion systems for cogeneration turbine systems, along with “standard” low NOx duct burners in the heat recovery steam generator (HRSG).

This recommendation:

- drives a 33% reduction in NOx emissions over the current CCME standard.
- is consistent with the practice in Alberta, and other jurisdictions, of setting BACTEA standards that are within 15% of the technology with the highest control efficiency.
- is consistent with the Alberta Land Use Framework approach of addressing cumulative effects of air emissions on a regional air shed basis and seeking more strict standards when required to ensure health-based ambient air quality standards are always met.
- is consistent with finding cost effective solutions with NOx removal at <$100 per tonne versus costs up to $12,000 per tonne for the highest control technology.
- is consistent with an overall risk management approach protecting the public from potential exposure to dangerous goods and controlled substances (ammonia), minimizing emissions of all air pollutants and utilizing cost effective technology sufficiently proven to work well in our Canadian environment.

In addition, this recommendation supports the government policy of incenting energy efficiency and the reduction of greenhouse gas emissions.

The specific recommendation and supporting rationale are outlined in the attached documents.

In summary, the CPPI recommends the adoption of the following equipment as Turbine/HRSG (cogeneration) NOx BACTEA (the application and basis are in Appendix A of the discussion enclosed.): **Dry Low NOx (DLN) turbine combustion systems that are guaranteed for NOx (as NO2) emissions of 20 ppm or lower (at 15% O2) and that are currently installed and proven in Alberta, and “standard” low NOx duct burners (LNDB) that are typically guaranteed to emit 38 g/GJ input and that are also installed and proven in Alberta. This recommendation is for turbines larger than 25 MW.**

This BACTEA supports the proposed NOx Standard for turbines 25MW and larger using the following formula:
NOx (kg/h) = (Power Output (MWh net) x 0.18 kg/MWh net) + (Heat Output (GJ/h) x 0.04 kg/GJ)

We appreciate the opportunity to exchange information and ideas on important air quality issues with Alberta government, NGO and other industry representatives through the CASA process.

Yours truly,

CPPI - Western Division

John Skowronski
Director, Environmental Affairs
email: johnskowronski@cppi.ca
JS:/cfk (Enclosures)

cc Cindy Christopher, Imperial Oil Ltd.; email: cindy.l.christopher@esso.ca Ted Stoner, CPPI – Western Division; email: tedstoner@cppi.ca
Krista Phillips, CAPP; email: krista.phillips@capp.ca
Al Schulz, CIAC; email:aschulz@ccpa.ca

Enclosure

1. CPPI Alternative Proposal to CASA NOx Performance Standards for Non-Peaking Natural Gas-Fired Turbines – Discussion
2. Appendix A - Proposed Non-Peaking NOx Standards For Natural Gas Fired Systems - February 16, 2010
3. Alternative Proposal to CASA NOx Performance Standards for Natural Gas-Fired Turbines – May 13, 2009 letter

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

Discussion:

The following points are provided as support for the CPPI BACTEA and NOx emission standard recommendations. The Jacobs February, 2010 Control Technologies Review, Cogeneration Units report is the base reference unless otherwise stated.

- **The CPPI proposed standard will result in turbine system NOx reductions.**

  1. As noted in Table 2 below, for an 85MW turbine, with 32% duct burning, hereinafter referred to as "the 85MW case", both the CCME and 2003 CASA EFR standards currently allow natural gas turbine systems to generate higher NOx emissions versus the proposed CPPI standard. The CPPI proposed power output allowance represents a 64% decrease from the current CCME guideline power output allowance. In addition, adoption of the proposed standard versus the CCME and CASA 2003 Electricity Framework would decrease allowable emissions for the 85MW cogen case by 33% and 49%, respectively.

- **The CPPI believes that the above recommended equipment meets the intent of BACTEA based on the following points:**

  1. The recommendation meets the BACTEA standard used in the January, 2009 Electricity Framework 5 Year Control Technologies Review[67]. The "Guideline for Identification of Best Available Control Technology - Economically Achievable (BACTEA) for Ontario Regulation 194/05 Industry Emissions – Nitrogen Dioxides and Sulphur Dioxide"[68] was applied by Eastern Research Group in its development of the January, 2009 BACTEA recommendations. This guideline states "In determining BACTEA, the applicant can select any technology that has a removal efficiency that is within 15% of the control technology with the highest control efficiency." Turbines with the latest, proven DLN technology (with 20 ppm or lower NOx emissions) provide an 88% removal efficiency versus a DLN+SCR efficiency of 99%. Low NOx duct burners that generate NOx emissions of 38 g/GJ are the lowest emitting, proven low NOx burners for HRSGs. Based on data presented in the Jacobs report, all of the turbine sizes reviewed with duct burning at 840°C (~30% of total cogen fuel firing in the HRSG duct burners) are within 15% of the control technology with the highest control efficiency (DLN+SCR).

     Note that CPPI believes that duct firing in cogeneration applications will be limited by a maximum HRSG bulk temperature of 840°C, consistent with the Jacobs report. The Jacobs report notes that this level of firing is typical of double-walled insulated units, and that these units are most prevalent. In addition, Jacobs did not provide any examples of when duct firing limitations of up to 1070°C would be applied and how common this would be for potential future cogeneration facilities in Alberta.

[67] http://www.casahome.org/wp-content/uploads/2009/03/efr-control-technologies-review-finalreport1.pdf, p 1-1
[68] http://www.ene.gov.on.ca/envision/AIR/regulations/5169e.pdf, p6

2. BACTEA requires the use of proven technology: DLN technology is proven in Alberta, while SCR use is not.

3. DLN combustion systems provide a cost-effective approach for emission reduction compared to SCR control technology. Jacobs identified that capital costs for SCR control technology are significantly higher than DLN combustion systems, for example, for the 85MW case, capital costs are 12 M$ vs 1 M$, respectively). In addition, for the same case, annual operating costs for SCR applications were identified by Jacobs as an incremental 1 M$ per year over the cost of DLN combustion technology. In terms of cost-effectiveness, SCRs are between 110 and 150 times more costly as shown in Table 1 below.

Table 1: Cost-Effectiveness

	42 MW	42 MW	70 MW	70 MW	85 MW	85 MW
	without DB	with DB	without DB	with DB	without DB	with DB
	$/tonne NOx reduction					
DLN	80	80	69	69	57	57
DLN+SCR	12,000	8,600	10,000	6,800	8,900	6,300
Note: Duct Burning case - 32% of total fuel, fired to 840 deg C						

Note that DLN+SCR cost effectiveness is associated with the incremental NOx reduction achieved with an SCR

4. DLN combustion systems and low NOx duct burners (LNDBs) are a low complexity control option versus SCR controls. SCRs require significantly more plant equipment and controls to operate versus DLN combustion systems. In addition, SCRs cause HRSG fouling and corrosion issues because of ammonium sulfate salt fouling – this will increase maintenance costs and downtime (costs not included in the Jacobs report).

5. Retrofit with DLN type technology will likely present fewer challenges than retrofit with SCRs. The cost effectiveness data presented in the Jacobs report does not represent retrofit costs. It is expected that the cost-effectiveness numbers for retrofit of SCR equipment may be significantly higher because the SCR must be installed in the HRSG. This will likely require significant onsite demolition and construction. Depending on unique plant configurations, other issues such as spacing, may create significant challenges for SCR retrofits.

- **Standards developed for all areas of Alberta should provide base level emission reduction requirements.**

  1. The Land Use Framework and Regional Air Shed Management standards, which incorporate effects-based approaches, will increase regulation stringency if required.

- **SCR operation presents risks to both the public and industry.**

  1. Ammonia use in an SCR presents safety concerns. Ammonia is explosive, flammable and toxic. Facilities that use ammonia must be designed and operated to manage risks associated with:
     a. the transport, storage and handling of ammonia
     b. the potential for ammonia leaks and spills
     c. the potential for public and occupational exposure.

  On site storage of the quantities of ammonia required for an SCR application add a liability. The 85MW case requires ammonia storage for at least 6,000 gallons (based on one week's storage) and the delivery and off-loading of at least one truck per week.

While refiners are capable of managing such risks, unnecessary safety risks are best avoided.

- **The use of ammonia in a SCR introduces collateral environmental impacts.**

1. The use of an SCRs on the 85MW case cogeneration unit will result in ~ 25 tonnes per year of ammonia emissions (slip) because not all ammonia is reacted in the catalyst bed. In addition, ammonia slip may convert to fine particulate matter, $PM_{2.5.}$ Ammonia will react with SO3 to form ammonium bi-sulfate which forms $PM_{2.5.}$ Elevated concentrations of fine particulate matter are recognized as a public health concern. The 85MW case cogeneration unit could produce 170 tonnes of $PM_{2.5}$ in a year.

2. Ammonia production is energy intensive and will produce on average 200 tonnes of CO2 in a year to produce the ammonia required for the 85MW case cogeneration[69]. The ammonia production will also create additional NOx emissions. In addition, to minimize safety risks associated with ammonia, industries prefer to use the aqueous form of this chemical. The 85MW case cogeneration will use 210,000 imperial gallons of fresh water each year in their use of 19% aqueous ammonia. In addition, de-mineralized water must be used to produce this ammonia because solids in the ammonia will create plugging issues in the SCR system. De-mineralized water is created through distillation which also creates GHG and NOx emissions. Cogeneration operators can source ammonia from 7 plants in Alberta, 3 are in the Fort Saskatchewan area and 3 are in southern Alberta.

3. The vaporization of ammonia associated with SCR use creates GHGs: the 85MW case cogeneration unit equipped with an SCR will create 250 tonnes of GHG during ammonia vaporization each year. In addition, this will also cause incremental NOx emissions.

4. Cogeneration units with SCRs typically experience a 0.5% energy loss which will create around 2,000 tonnes/year of GHG for the 85MW case cogeneration unit. The energy loss comes from the pressure drop that occurs across the SCR in the HRSG. Additional firing, requiring more fuel and resulting in increased emissions, is required to replace the efficiency loss. Jacobs reported that one HRSG vendor had recently installed new equipment that was built (larger) to compensate for the pressure drop normally found across an SCR – however, the vendor that installs many of the HRSGs in Alberta was not consulted to determine if their HRSGs are also designed to compensate for pressure loss. The ERG Technology review also indicated that it is typical for a turbine to experience a 0.5% efficiency loss due to an SCR installation.[70] Some industry members were not able to satisfactorily conclude that the practice of building larger HRSGs widely adopted and, if widely adopted, that it would result in zero power loss across the turbine.

5. SCRs generate waste because the catalyst has a life of between 5 and 10 years. About 200 tonnes of catalyst must be land-filled at end of life. The catalyst contains vanadium, a heavy metal.

[69] http://oee.nrcan.gc.ca/industrial/technical-info/benchmarking/ammonia/pdf/ammonia-study.pdf (based on Jacobs report NH3 use 85 MW, 840 deg C duct burning case and an average of 1.07 tonnes CO2/tonne of NH3 produce

[70] http://www.casahome.org/wp-content/uploads/2009/03/efr-control-technologies-review-finalreport1.pdf, p 3-30

- **The CPPI proposed standard is in line with leading jurisdictions.**

1. Standards and SCR implementation in US jurisdictions are typically driven by non-attainment in NOx and/or Ozone. It is not appropriate for the base level Alberta standard to be more stringent than the Texas standard.

Table 2: Standard Comparisons (85MW turbine with 1000 GJ/h steam output)

Standard	Regulatory Components	Emissions Limit
Alberta Air Emission Standards for Electricity Generation, 2005	Greater than 60MW 0.3 kg/MWh output	108.8 kg/h
CCME (1992)	A = 26ppm (0.50 g/MWh) B = 0.04 kg/GJ	82.5 kg/h
CAPP/CPPI/CIAC Proposal	**A = 9ppm (0.18 kg/MWh) B = 0.04 kg/GJ**	**55.3 kg/h**
June 2009 Non-Consensus Proposal	**A = 5ppm (0.09 kg/MWh) B = 0.01 kg/GJ**	**17.65 kg/h**
Jurisdictional Scan		
US EPA (2006)	For turbines, greater than 3.5MW and less than or equal to 110MW 150 g/GJ of useful output	128.4 kg/h
Germany & Norway	0.76 kg/MWh (40ppmv)	64.6 kg/h
Texas	0.09 kg/MWh (5ppm) with 1MWcredit for every 3.6 GJ of heat recovered	32.7 kg/h
California	0.0317 kg/MWh with 1MW credit for every 3.6 GJ of heat recovered	11.5 kg/h

- **The CAPP/CPPI/CIAC (CCC) proposed BATEA and standard promotes efficient use of energy.**

1. The use of the 40 g/GJ heat recovery NOx allowance (HRA) remains relevant. The 40 g/GJ (output) for the energy recovered in a HRSG, was originally developed in the CCME Turbine standards[71]. The allowance was to incent the use of turbine waste heat for steam production. Typical combined cycle electricity generation can recover around 55% of energy – the remaining 45% of energy is lost to either to air or water. Recovery of waste heat for steam generation can push the efficiency of cogen units to over 80%. HRSG duct firing also promotes energy efficiency by using the excess (heated) combustion air that was not used in during fuel combustion in the turbine. The CCME standard assumption was that steam production from turbine waste heat would back out steam production that would otherwise be produced in a once through steam generator. This provides both energy and NOx savings. The CCME guideline for boilers and heaters[72], which is still in use today across most of Canada and in Alberta, has a NOx emissions limit of 40 g/GJ input for large boilers and heaters. The turbine heat allowance factor

[71] http://www.ccme.ca/assets/pdf/pn_1072_e.pdf
[72] http://www.ccme.ca/assets/pdf/pn_1286_e.pdf

was set to be in line with the CCME boiler NOx emission limit (setting the NOx Heat Recovery Allowance (HRA) lower than the current boiler NOx limit may disincent new cogeneration applications).

- **To summarize, the proposed CCC standard minimizes the risk of disincenting the installation of cogeneration systems.**

    1. Companies that consider the installation of cogeneration equipment will look at many factors when making a decision to invest or not to invest. Project economics will be very important – if the new turbine (cogen) standard requires an SCR to meet NOx emission limits, the SCR capital and operating costs and the incremental costs associated with managing the safety and environmental risks associated with ammonia, may impact the bottom line sufficiently to impede investment. (Note that the Jacobs report suggests that the economics between cogeneration applications and stand alone boilers plus purchased electricity will favor cogeneration. This conclusion was not accepted by all "cogen" team members. The team was not given the opportunity to challenge the assumptions associated with the Jacobs analysis because the information was received in the final draft of the report and there was insufficient time to question what was presented. In addition to project economics and risk management concerns, companies will also consider the increased operational complexity that an SCR would bring to their facility. The generation of electricity is not a core business for CAPP/CPPI/CIAC members and careful consideration will be given to all of the benefits and all of the downsides associated with building and operating a cogeneration facility.

Appendix A

Proposed Non-Peaking NOx Standards For Natural Gas Fired Systems, February 16, 2010

Non Peaking Standard Formula

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

Where:

A = Power Output Allowance – the total electricity and shaft power energy production

B = Heat Recovery Allowance – the total useful thermal energy recovered from the cogeneration / combined cycle facility

Power Output Allowance ("A")

Power Rating (per gas turbine only)	Natural Gas Non-Peaking (kg/MWh)
< 25 MW	0.60
> 25 MW	0.18[73]

Heat Recovery Allowance ("B")

For All Units: 0.04 kg/GJ

Applicability

- Effective for units approved after January 1, 2011 for new and for end of life installations
- Natural gas fired systems
  - o Dry low NOx burners – on which this BATEA standard is based – are designed and engineered for natural gas as fuel
  - o Systems fueled by alternate gaseous fuels to be handled on a permitting, case-by-case basis (eg., systems fired with a mix of natural gas with syngas, off-gas or refinery fuel gas)
- Start-up and shut-down and upset conditions are exempted from the standard

Basis

- Non-peaking standards expressed as output standards
  - o Consistent with CCME's National Emission Guidelines for Stationary Combustion Turbines (December 1992)
  - o Considers the environmental benefits afforded by energy efficiency gains of cogeneration and combined cycle installations
- The BATEA basis for the power output standard ("A") is Dry Low NOx (DLN) burners
  - o The standard is applied on an annual basis to the large turbines (>25 MW) to account for cold ambient weather conditions where denser air causes combustion instability in DLN burners
- The BATEA basis for the heat recovery allowance ("B") is consistent with manufacturers' standard burner configuration
  - o Captures the efficiency gains from cogeneration and combined cycle systems

[73] To be applied on an annual average basis

F. 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

Standards Table

<table>
<tr><th>Net Power Output
(per gas turbine train)</th><th>Non Peaking ("A")
(kg NO_x /MWh net)</th></tr>
<tr><td>Greater than 100 MW</td><td rowspan="2">0.09</td></tr>
<tr><td>25 to 100 MW</td></tr>
<tr><td>Less than 25 MW</td><td>0.60</td></tr>
</table>

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.

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. 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.
d. Net Power Output means the power rating of the gas turbine plus an associated combined cycle steam turbine.

e. The Power Rating of the gas turbine means the normal maximum net continuous rating at ISO temperature conditions as provided by the manufacturer.
f. Thermal efficiencies are expressed as Lower Heating Value (LHV)
g. 1 ppmv NOx concentration as defined = 1.70 grams NOx as NO_2 per Gigajoule (GJ) of heat input, for natural gas combustion
h. 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