2018 CASA Electricity Framework Review:

Perspectives on a NO_x Emission Standard for Natural Gas-Fired Turbines

Interim Report for the CASA Board from the Electricity Framework Review Project Team

December 13th, 2018

Acknowledgements

Project team members appreciated the opportunity to discuss and deepen their shared understanding of NOx emission standards for natural gas-fired electricity generating units in Alberta, and also appreciate the confidence placed in CASA by the Government of Alberta in requesting that this work be done. Project team members want to acknowledge the spirit of constructive collaboration that underpinned the process.

Members of the Electricity Framework Review Project Team:

Name	Stakeholder Group
Afrooz Farjoo	Alberta Energy
Ahmed Idriss	Capital Power
Ana Maria Radu	TransCanada
Colin Robb	Capital Power
Dan Moore	Alberta Newsprint Company
David Spink (Co-chair)	Prairie Acid Rain Coalition
Gabriel John	Alberta Energy
Garth Gettle	TransAlta
Jim Hackett (Co-chair)	ATCO
Katie Duffett (Project Manager)	Clean Air Strategic Alliance
Laurie Cheperdak	Alberta Health
Mark McGillivray	ENMAX
Matt Dance (Project Manager)	Clean Air Strategic Alliance
Mike Mellross	City of Edmonton
Natasha Rowden	MEG Energy (CAPP)
Randy Dobko (Co-chair)	Alberta Environment and Parks
Rekha Nambiar	Suncor (CAPP)
Saeed Kaddoura	Pembina Institute
Salima Loh	InterPipeline (CIAC)
Siobain Quinton	TransAlta
Sushmitha Gollapudi	Alberta Environment and Parks
Wayne Ungstad	Notinto Sipiy Conservation Authority

About CASA

The Clean Air Strategic Alliance (CASA) was established in March 1994 as a new way to manage air quality in Alberta. CASA is a multi-stakeholder partnership composed of representatives selected by industry, government, and non-government organizations. Every partner is committed to a comprehensive air quality management system for Alberta. CASA's mandate is to:

1. Implement the comprehensive Air Quality Management System for Alberta.
2. Conduct strategic air quality planning for Alberta through shared responsibility and use of a consensus-building, collaborative approach.
3. Prioritize concerns about air quality in Alberta and develop specific actions or action plans and activities to resolve those concerns.

Table of Contents

List of Appendices

List of Tables

Executive Summary

The Electricity Framework Review (EFR) Project Team was formed in June 2018 to address the tasks outlined in the project charter (Appendix 3). This interim report addresses the Phase 1 tasks, particularly updating the NOx air emission standards for new gas-fired generation units.

The project team was not able to reach consensus on a NOx emission standard for natural gas-fired continuously or intermittently operating combined cycle units or cogeneration units. Two approaches to managing NOx emissions were discussed, a Proposal “A” and a Proposal “B.”

Proposal “A” can be found in Appendix 1, including supporting perspectives from Capital Power, ENMAX, MAXIM Power, and the ENGO caucus.

Proposal “B” can be found in Appendix 2, including supporting perspectives from CAPP, CIAC, TransCanada, TransAlta, ATCO, and ANC. TransCanada, TransAlta, and ATCO have submitted a shared perspective.

1 Background

In January 2002, Alberta Environment asked the Clean Air Strategic Alliance (CASA) to develop a new way to manage air emissions from electricity generation in Alberta. Using a multi-stakeholder collaborate approach, CASA developed innovative solutions in the form of 71 recommendations comprising a management framework and presented it to the Government of Alberta in November 2003. This framework represented a set of consensus recommendations, agreed to as a package with all elements equally important and stakeholders noting that if the framework is fragmented in any way, the overall framework can no longer be regarded as a consensus package with full stakeholder support. The report, *An Emissions Management Framework for the Alberta Electricity Sector* (the Framework), was accepted by the Government of Alberta and implemented through regulations, standards, and facility approvals. The first emission standards were effective January 1, 2006.

To ensure continuous improvement and keep the Framework timely and relevant, a formal review of the Framework is to be undertaken every five years according to recommendation 29:

> **Recommendation 29 (2003)**
> This recommendation outlines the following elements of the Framework that must be reviewed by the project team:
> 1. A technology review to identify the Best Available Technology Economically Achievable (BATEA) emission standards,
> 2. The air emission substances subject to limits or formal management,
> 3. Co-benefits for priority substances and List 2 substances,
> 4. A review of economic and environmental triggers as set out in the framework in recommendations 34 and 35,
> 5. Additional information that illustrates potential health effects associated with emissions from the electricity sector; and
> 6. A report from the electricity sector on continuous improvement.

This review should include a multi-stakeholder group consisting of industry, government, non-government organizations, and communities with an interest in electricity generation in Alberta. The intent of the Five-Year Review is to assess new emission control technologies, update emission standards for new generation units, determine if emission standards for new substances need to be developed, review implementation progress, and determine if the Framework is achieving its emission management objectives.

The goal of the 2018 five-year review is to ensure the framework reflects the current circumstances of Alberta’s electricity sector. This report is a summary of the Phase 1 tasks that were completed on an accelerated timeline at the request of the Government of Alberta as they were deemed to be high priority to inform ongoing policy discussions.

2 Electricity Sector Context

2.1 Managing Air Emissions from Alberta's Electricity Sector

The emission requirements for Alberta's electricity sector are outlined in the 2005 *Alberta Air Emission Standards for Electricity Generation* and *Alberta Air Emission Guidelines for Electricity Generation* and the *Alberta Emission Trading Regulation.* The requirements are based upon recommendations from the 2003 *Electricity Emissions Management Framework* developed by CASA. The emission standards are implemented through inclusion in operating approvals issued under the *Environmental Protection and Enhancement Act*

NATURAL GAS-FIRED ELECTRICITY GENERATING UNITS

The annual NO_X emission intensity limits for new natural gas-fired continuously operating combined cycle units and cogeneration units were set based on the combustion capabilities of modern gas turbines at the time the standards were set. Table 1 presents an overview of these limits. In Alberta, electric power generation is responsible for 10% of NOx emissions (2015 data)[1] and is responsible for 16% of GHG emissions (2014 data)[2].

Alberta's electricity market is in transition from an energy-only market to capacity and energy markets. The electricity sector is also impacted by federal and provincial environmental policy such as the Alberta Climate Leadership Plan, the National Air Quality Management System including Base-level Industrial Emission Requirements (BLIERS), and the Federal *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*. The Alberta Climate Leadership Plan includes a phase out of coal-fired electricity generation and policy direction to have 30% of electricity in Alberta generated by renewables by 2030. The team discussed policies and information on each is available at:

- A presentation was provided to the project team on the Capacity Market in August, 2018 and be found here
- Information on Alberta's Climate Leadership Plan can be found here
- The BLIERS requirements can be found here

The coal phase-out may result in an increased number of gas-fired generation units in the province, some of which will be gas turbines. The Canadian Ambient Air Quality Standards (CAAQS)[3] for NO_2 will be put into place in 2020 and become more stringent in 2025. The project team received information on the CAAQS, available here.

1 http://www.casahome.org/attachments/CAAQS%20and%20NO2%202018-08-09.pdf
2 https://www.alberta.ca/climate-coal-electricity.aspx
3 https://open.alberta.ca/publications/9780778567592

Table 1: New Generating Units of a Natural Gas Fired or Cogeneration Power plant NOx Annual Emissions Intensity Limits, Effective January 1st, 2006 (current standards)

Electrical Power Generating Capacity of the Plant	**Unit Limit** (kg NO_X/MWh_{output})
0<20 MW	0.60
≥20 – 60 MW	0.40
>60 MW	0.30

*where MWh includes both the combined total thermal energy output and the net generation of electricity, excluding any electricity used to produce the electricity.
** These emission standards shall be used along with the maximum continuous rating of the installed equipment and any other relevant operational information about the installed generating unit to set hourly emission limits with the EPEA approval that is issue for the activity.
***The ENGO Caucus feels that the intent for gas-turbine units with heat recovery limits would represent continuous improvement from the 1992 CCME National Emission Guidelines for Stationary Combustion Turbines. This turned out not to be the case for cogeneration units and was subsequently recognized as an issue within the Framework.

3 Rationale for the 2018 Electricity Framework Review

As Alberta moves forward with its commitment to phase out coal emissions, increase the capacity of renewable energy in the province by 2030, and move to a capacity market, many electricity generators have expressed the intent to build new natural gas-fired turbines or coal to gas conversion units. Additionally, Alberta needs to continue to manage emissions in the provincial air zones to ensure that its principles of pollution prevention, continuous improvement, and keeping clean areas clean are being met and that the CAAQS are achieved, and to allow for future growth and development.

Stakeholders were interested in further dialogue on NOx emission standards for natural gas-fired electricity generation in the context of Alberta's changing electricity sector. Alberta Environment and Parks asked CASA to initiate a project team to allow a dialogue between stakeholders and to provide AEP with either a consensus recommendation or a perspectives document on the various views of the stakeholder groups.

4 Challenges

The project team discussions included the following issues:

- There is a desire for regulatory certainty for investment decisions as the province moves towards a capacity market.
- Stakeholders must be treated equitably so no one stakeholder group gains a competitive advantage.
- A new emission standard should be reflective of Best Available Technology Economically Achievable (BATEA).

- An open dialogue on the similarities and differences between industrial cogeneration and continuously operating natural gas turbines, both simple cycle and combined cycle, and the implications for any turbines that are operated intermittently.
- The aggressive project timeline in the face of a changing regulatory environment.

The stakeholder perspectives on these issues are included within the perspective documents (Appendix 1 and 2).

5 Status of Phase 1 Tasks

The project team did not reach consensus on the task of recommending a NOx air emission standard for new gas-fired electricity generation units. Stakeholders have submitted perspectives documents outlining their viewpoints on the various issues discussed by the project team (Appendix 1 and 2).

Dialogue at the project team was not limited to gas-fired generation. The project team received presentations and had discussions on issues scoping and a path forward for the other phase 1 tasks to ensure that these were not overlooked. The project team was not able to address all of these tasks in the time allocated in the project charter for phase 1. A summary of the tasks and their next steps is provided in Table 2.

Table 2: Status and next steps for the phase 1 tasks for the 2018 Electricity Management Framework Review

Task Description	**Status**	**Next Steps**
Review of Environmental and Economic Triggers (Recommendation 34 and 35)	Discussed by the working group and it was decided because it was unlikely the triggers have been met there was no value in allocating budget to have a consultant complete a trend assessment.	n/a
NOx air emission standards for new gas-fired generation units	Largely addressed during phase 1 and resulted in non-consensus and a perspectives document.	Subtasks to be discussed further in phase 2, see below.
NOx air emission standards for gas-fired reciprocating engines	Discussions initiated during phase 1, specifically on treatment of banked units.	Continued discussion in phase 2 with a recommendation to be included in either a second interim report or the final deliverable for the project in 2019.
NOx air emission standards for gas turbines fired by bio-gas	Discussions initiated during phase 1.	Continued discussion in phase 2 with a recommendation to be included in either a second interim report or the final

		deliverable for the project in 2019.
Design Life Considerations	Discussions initiated during phase 1.	Continued discussion in phase 2 with a recommendation to be included either in a second interim report or in the final deliverable for the project in 2019.
Determine Best Available Technology Economically Achievable (BATEA) for gas-fired generation	Completed. The project team reviewed the BATEA review completed during the 2013 EFR along with information obtained by industry representatives from manufacturers.	Full details to be provided in the final deliverable for the project in 2019.
Review lessons learned from industry using Selective Catalytic Reductions (SCR)	Industry representatives on the project team provided information on their experiences with SCR in their operations.	None, task complete.
Complete an assessment of the Emissions Trading System	The project team received information on the Emissions Trading System from the Government of Alberta and provided some feedback.	The Emissions Trading System will be reviewed again in phase 2 and any further feedback provided in the final deliverable for the project in 2019.
Develop and implement a communications strategy and actin plan	Discussed by the project team in phase I. Decided to postpone further discussion on details until phase 2.	A draft communications strategy for the project will be developed early in phase 2 of the project.

6 Conclusion

The project team is putting forward this interim report and appended stakeholder perspectives as advice to the Government of Alberta for use in their decision-making.

A more detailed final report including the results of the phase 1 and phase 2 tasks will be submitted following the completion of the project in 2019.

Appendix 1

Proposal A - NOx Standards for Peaking and Non-Peaking Gas Turbine Units and Supporting Stakeholder Perspectives

Includes perspectives from: Capital Power, ENMAX, MAXIM Power, and the ENGO Caucus

Proposal A - NOx Standards for Peaking and Non-Peaking Gas Turbine Units

The proposal is supported by Capital Power, ENMAX, Maxim Power and the ENGO caucus.

1. Proposal Basis

- The proposed NOx emission standards should align with the implementation of the capacity market and associated auctions, applying to gas turbine facilities commissioned on or after November 1, 2021.
- Non-Peaking Standards are expressed as output standards in a similar format to the *2017 Guidelines for the Reduction of Nitrogen Oxide Emissions from Natural Gas–fueled Stationary Combustion Turbines* by Environment and Climate Change Canada.
- Separate categories are based on gas turbine capacity for non-peaking and peaking.
- A gas turbine may declare as a peaking unit if it meets the peaking standard and, does not exceed a Total Potential Electrical Output of 33% in a calendar year [unless required by the System Operator to operate for system security.]
- The standards are conditional on emissions during the startups and shutdowns of Gas Turbines or post combustion NOx reduction technology being excluded from the compliance measurement.
- Non-Peaking compliance measurement would be based on existing Alberta Environment and Parks protocols subject to exclusions stated above.

2. Peaking Standard Formula[1]

- Peaking definition: 33% total potential output (MCR*8760*33%)
[Consistent with the proposed federal Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation]
- The “A” is based on 37% gas turbine efficiency

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

Power Rating (per gas turbine only)	**Natural Gas Turbine**	
	NOx concentration limit (ppm)	**Peaking Electricity Allowance (“A”)** (kg/MWh net)
More than 150 MW	6	0.1
More than 70 MW and Less or Equal 150 MW	15	0.25
Less than or Equal to 70 MW	25	0.41

1

- Normal maximum net continuous rating at ISO conditions as provided by the manufacturer
- Power rating for gas turbine plus an associated combined cycle steam turbine.
- All concentrations expressed in dry volume at 15 % oxygen and ISO conditions
- All thermal efficiencies expressed as Lower Heating Value (LHV)

3. **Non-Peaking Standard Formula**[1]

- Assumed ~8000 hours of operations at MCR
- 20% duct firing on combined cycle and 33% duct-firing on cogeneration
- HRSG – 34 g NOx/GJ_{in}
- SCR removal efficiency is 70%

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

Power Rating (per gas turbine only)	**Natural Gas Turbine/HRSG**		
	Reference NOx concentration limit (ppm) (Gas Turbine Only)	**Non-Peaking Electricity Allowance ("A")** (kg/MWh net)	**Heat Production Allowance ("B")** (kg/GJ net)
Equal or More than 70 MW	6	0.1	0.01 (based on SCR ~ 70% removal efficiency)
Less than 70 MW	15	0.25	0.025 (based on HRSG efficiency 34 g NOx/GJ_{in})

Capital Power Corporation
1200 – 10423 101 Street NW
Edmonton, AB T5H 0E9
www.capitalpower.com

December 3, 2018

Clean Air Strategic Alliance
1400, 9915 108 Street
Edmonton, Alberta
T5K 2G8

Re: Clean Air Strategic Alliance ("CASA") Emissions Management Framework for the Alberta Electricity Sector: 2018 Five-Year Review
Capital Power Corporation ("Capital Power") Perspective Document

Summary

Capital Power submits that Proposal A, which is supported by ENMAX, Maxim Power and the ENGO caucus, reflects the application of Best Available Technology Economically Achievable ("BATEA") based controls. Proposal A is consistent with the intent of the 2003 Alberta Electricity Emission Management Framework (the "Framework") and the Government of Alberta ("GOA") BATEA guidance. Proposal A demonstrates continuous improvements in environmental outcomes, provides regulatory certainty to investors, and maintains a level playing field between competitors in the Alberta electricity market. Based on the principles of BATEA, the economics of new gas turbines, and the expected areas of growth, Capital Power believes that cogeneration units between 70 MW and 100 MW would not cease to be economic if Selective Catalytic Reduction ("SCR") were used, as suggested under the alternate proposal.

As the leading developer of new power generation in Alberta's competitive market, Capital Power has added 1,500 MW and new generation capacity since 2004. With significant investments in the Alberta electricity market, Capital Power stands to be impacted by the renewed nitrogen oxide ("NOx") standards for new natural gas turbine facilities and natural gas turbines that reach end of design life ("gas turbine facilities"). As Alberta Environment and Parks ("AEP") moves forward with implementation of any new standards, Capital Power supports continued engagement and discussion of material details of the enclosed proposal.

1. Capital Power Interests

Capital Power is a growth-oriented power producer headquartered in Edmonton, Alberta. As the leading developer of new power generation in the province, Capital Power is engaged in the CASA 5-year review of the Framework to ensure the standards for gas turbine facilities are consistent with best practices in sustainability, provide certainty to support new investments, and maintain a level playing field between competitors in the Alberta electricity market.

Sustainability

The electricity industry is experiencing significant transformation, driven by low natural gas prices, a trend towards decarbonization, and technological advances. Capital Power sees opportunity in this change and is pursing strategies and objectives that will allow the company to protect and optimize existing assets, develop new generation, and evolve with the electricity markets to remain competitive.

A fundamental aspect of Capital Power's competitiveness is environmental sustainability. As a power producer with a diverse fleet of assets operating across North America, Capital Power is keenly aware of the environmental pressures that are accompanying the continuous evolution of electricity markets. To succeed in this environment, it is incumbent on power producers to adapt and seek opportunities to lead the industry in this transformation.

Regulatory Certainty

This is the third five-year review of the Framework and the industry continues to be faced with uncertainty over how the existing standards are applied. With the outdated NOx standards, inconsistent application of the requirements by approval writers and policy makers creates material risks to development and competitiveness of new assets. Capital Power submits that to this point, the process to update the standards does not reflect continuous improvement, and it should be the expectation that GOA will move to update the NOx standards for gas turbine facilities to be consistent with the application of BATEA.

Capital Power is the leading developer of new power generation in Alberta's competitive market. Since 2004, Capital Power has added 1,500 MW of new generation capacity, representing a total investment of $3.2 billion. These investments have included investments in two new supercritical coal units (Genesee 3 and Keephills 3), efficient natural gas peaking and Natural Gas Combined Cycle ("NGCC") units (Clover Bar Energy Centre "CBEC" and Shepard Energy Centre "SEC"), and wind generation (Halkirk Wind and Whitla Wind Facility, which is currently under construction).

Consistent with Capital Power's objectives for environmental sustainability, these investments have demonstrated a clear and consistent commitment to deploying the most efficient and advanced technologies that achieve superior competitiveness and environmental outcomes. As the first supercritical coal unit in North America, Genesee 3 was leading edge technology. Similarly, Capital Power's two LMS100s operating at the CBEC were leading edge peaking unit technology at the time they were deployed, and the SEC is the most efficient NGCC in Alberta. As Capital Power looks to develop additional generation in the province, the company will continue to pursue developments that are environmentally sustainable and competitive.

Despite a track record of development to meet extraordinary demand growth, uncertainty caused by the outdated standards for NOx would likely inhibit continued development by responsible parties without new measures to update the requirements. This uncertainty coincides with a critical time in the evolution of the electricity market as the GOA moves from an energy-only market to a capacity market.

Equity

A fundamental principle underlying competitive markets is equal treatment of all market participants. In the previous reviews of the Framework, stakeholders did not reach agreement on updated standards and the GOA failed to update the NOx emission standards. With outdated NOx standards, the application of the requirements by AEP has created materials issues with inequity.

As with previous non-consensus reviews, the consistent treatment of cogeneration and electricity sector projects is a major issue that remains unresolved. Though cogeneration is developed primarily to serve on-site steam requirements of oil sands and other industrial processes, the exported electricity competes directly in the electricity market. Despite being significant sources of NOx emissions, the clear majority of these projects are permitted by the Alberta Utilities Commission ("AUC") based on AEP policies to operate with no additional NOx abatement, while an equivalent electricity sector project is held to a higher standard. The inequity and disadvantages that this causes to electricity sector projects is an egregious breach of the principles of competitive markets, CASA, and best practices in emissions management.

2. <u>Proposed Standard</u>

Methodology

Consistent with the proposed methodology advanced by the Environmental Non-Government Organization ("ENGO") caucus, Capital Power developed proposed standards based on a 200 tonne per year ("t/y") threshold for NOx emissions. In establishing the thresholds and size cutoffs, turbine and Heat Recovery Steam Generators ("HRSG") performance were evaluated to reflect available technology. The proposed standards reflect the point at which advanced control options are required to maintain emissions below the 200 t/y threshold. While 200 t/y was used to establish size thresholds, it is not intended to form emission cap for unit-specific approvals.

Basis of the proposal

Capital Power submits that the following proposal should form the basis for a revised AEP NOx emission standard. The basis for the proposed standards should consider the following, which may require additional consultation with stakeholders should the Government proceed:

- The proposed NOx emission standards should align with the implementation of the capacity market and associated auctions, applying to gas turbine facilities commissioned on or after November 1, 2021.
- Non-Peaking Standards are expressed as output standards in a similar format to the 2017 Guidelines for the Reduction of Nitrogen Oxide Emissions from Natural Gas–fueled Stationary Combustion Turbines by Environment and Climate Change Canada.
- Separate categories are based on gas turbine capacity for non-peaking and peaking.
- A gas turbine may declare as a peaking unit if it meets the peaking standard and, does not exceed a Total Potential Electrical Output of 33% in a calendar year [unless required by the System Operator to operate for system security.]

- The standards are conditional on emissions during the startups and shutdowns of Gas Turbines or post combustion NOx reduction technology being excluded from the compliance measurement.
- Non-Peaking compliance measurement would be based on existing Alberta Environment and Parks protocols subject to exclusions stated above.

Peaking Standard[1]

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

Power Rating (per gas turbine only)	**Natural Gas Turbine**	
	NOx concentration limit (ppm)	**Peaking Electricity Allowance ("A")** (kg/MWh net)
More than 150 MW	6	0.1
More than 70 MW and Less or Equal 150 MW	15	0.25
Less than or Equal to 70 MW	25	0.41

Non-Peaking Standard[1]

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

Power Rating (per gas turbine only)	**Natural Gas Turbine/HRSG**		
	Reference NOx concentration limit (ppm) (Gas Turbine Only)	**Non-Peaking Electricity Allowance ("A")** (kg/MWh net)	**Heat Production Allowance ("B")** (kg/GJ net)
Equal or More than 70 MW	6	0.1	0.01 (based on SCR ~70% removal efficiency)
Less than 70 MW	15	0.25	0.025 (based on HRSG efficiency 34g NOx/GJ_{input})

1
- Normal maximum net continuous rating at ISO conditions as provided by the manufacturer
- Power rating for gas turbine plus an associated combined cycle steam turbine.
- All concentrations expressed in dry volume at 15 % oxygen and ISO conditions
- All thermal efficiencies expressed as Lower Heating Value (LHV)

3. <u>Capital Power Operating Perspectives</u>

Capital Power has operated electricity generation facilities in Alberta that employ SCR for NOx abatement since 2009. The CBEC is a simple cycle facility that consists of one 48 MW General Electric ("GE") LM6000 turbine commissioned in 2008, and two 101 MW GE LMS100 turbines commissioned in September and December 2009. SCR's are installed on the two LMS100 turbines.

Ammonia Handling and Slippage

The CBEC facility currently has storage facilities for Aqueous Ammonia (19%) on site as an input to the SCR operations. As an operation that is close in proximity to the City of Edmonton and other industrial facilities in the Clover Bar Industrial Area, Capital Power manages the operations and handling of ammonia to avoid any adverse effects to the surrounding community. To date there have been no material issues with ammonia slippage, an issue cited by several stakeholders as significant impediments to operating SCR. Capital Power respectfully disagrees with this perspective based on our history operating the equipment, and submits that this should not be considered to be a barrier to installing SCR in cogeneration facilities.

Capital and Operating Expenditures

As presented at the August 9th stakeholder meeting, Capital Power submits that the cost associated with installation and operation of SCR on turbines is not an impediment to the use of the technology. At the CBEC facility, the installation of the SCRs on two units had associated capital expenditures of roughly $5 million ($2009) per turbine. The ongoing operating expenditures of the facility associated with ammonia use ranges from $0.30-0.60/MWh.

These values are consistent with previous consultant reports commissioned by CASA. As specified in the 2014 Eastern Research Group report, the purchased equipment cost of SCR installed on a simple cycle turbine was estimated to be $45 per KW[2].

Based on the operating experience of Capital Power and other industry participants, it has been demonstrated that the cost is not prohibitive to the adoption of these technologies and should be considered BATEA technology for cogeneration and combined cycles with turbines greater than 70 MW, and large peaking units with turbines that exceed 150 MW.

4. <u>Alternative Proposals</u>

While the industry perspectives share many similar features, the critical differentiation between positions remains the cutoff for non-peaking generation, and the size at which advanced control technology is required. Based on the principles of BATEA, the economics of new gas turbines, and the expected areas of growth, Capital Power submits that the evidence clearly supports Capital Power's proposal that would require advanced control technology in non-peaking units greater than 70 MW.

---

[2] Eastern Research Group, Control Technologies Review for Gas Turbines in Simple Cycle, Combined Cycle and Cogeneration Installations (September 2014)

Best Available Technology Economically Achievable

In 2003 the Clean Air Strategic Alliance's Electricity Project Team developed Alberta-specific principles for *Best Available Technology Economically Achievable* ("BATEA"). BATEA was defined as "*technology that can achieve superior emissions performance and that has been demonstrated to be economically feasible through successful commercial application across a range of regions and fuel types*"[3]. In January 2011, AEP released the *Guidance for Assessing Best Available Technology (BATEA) and Developing Technology-Based Standards* guidance document ("Guidance Document"). The Guidance Document provides common approaches to assessing BATEA, developing technology-based standards, and applying standards as appropriate.

The intent of BATEA is to drive innovation and improve environmental performance through setting performance standards. According to Guidance Document, the approach that assesses demonstrated technology implicitly considers costs. The assumption is that if there is commercial application of abatement technology elsewhere (which may include other jurisdictions), then cost reasonableness of that technology is satisfied. The rationale for this assumption is that private industries minimize cost, so their choice of abatement technology would implicitly reflect reasonableness of technology cost.

As was demonstrated through industry presentations and discussion during the current 5-year review, SCRs have been used in Alberta since 2009 in peaking and non-peaking applications, including industrial cogeneration. Based on the experiences shared by industry, including Capital Power, it has been demonstrated that SCR should not be considered a novel technology and represents BATEA technology for non-peaking generators with turbines greater than 70 MW, and large peaking units with turbines that exceed 150 MW.

Cogeneration Economics

During the electricity framework review, there was considerable discussion regarding the economics of cogeneration and their inability to absorb additional costs related to emissions abatement for units between 70 MW and 100 MW. From the analysis that is publicly available, the arguments that suggest that units between 70 MW and 100 MW would cease to be economic from the requirement to install SCR is patently untrue.

The conclusions of the analysis completed and presented by the Alberta Climate Change Office clearly demonstrate that the projects have positive economics, and therefore, reasonable measures to install BATEA technology for NOx abatement would not be a disincentive to cogeneration development.

This position is supported by analysis published by the Canadian Energy Systems Analysis Research Initiative ("CESAR") in reports funded by parties including Suncor Energy, MEG Energy, and Alberta Innovates. Through the work of CESAR, the economics of cogeneration have been demonstrated to be favorable when looking at scenarios where 85 MW units are installed in the oil sands in various configurations. As the authors state, "*at the midpoint values for all parameters, all [net present values] were assessed to be positive*". In drawing this conclusion, the author looked at a range of assumptions for key variables to calculate the net present value of the investments in cogeneration, assuming a 10% annual return on investment. From the analysis presented, the

[3] An Emissions Management Framework for the Alberta Electricity Sector – Report to Stakeholders (November 2003)

"*median values for all simulations showed a positive NPV [Net Present Value] in the range of $90M to $190M when compared to the Base Case*"[4]. While the economics of each project are unique, the degree to which the economics of the simulated projects are positive would indicate that the requirement to install SCR would not be an impediment to further development of cogeneration.

Capital Power submits that this further supports Proposal A and a requirement to install advanced control technology in non-peaking turbines greater than 70 MW.

Growth in Non-Peaking Generation

Despite challenges facing the oil sands, provincial agencies, including the Alberta Electric System Operator ("AESO"), continue to forecast significant growth in cogeneration. In the most recent long-term outlook, the AESO identifies the significant benefits that may accrue to cogeneration operators in the oil sands from the Climate Leadership Plan. As a result, the growth in energy production expected from this form of generation is likely to exceed all other forms in the coming decades[5]. This view is supported by the most recent report of the Oil Sands Community Alliance ("OSCA") which canvassed member companies in 2016 and identified 57 cogeneration projects at various stages of development[6].

With the level of growth projected by both the AESO and the OSCA, the province is expected to see exceedances in the Canadian Ambient Air Quality Objectives. With a significant portion of the expected development coming from non-peaking units between 70 MW and 100 MW, it is incumbent on AEP to take appropriate measures to manage the associated growth in NOx emissions.

Closing Comments

For the reasons described above, Capital Power submits that the Proposal A reflects an appropriate BATEA-based standard that provides industry, government, and other stakeholders with regulatory certainty without compromising environmental outcomes. Capital Power strongly encourages the AEP to move forward with implementation of the proposed standards in a timely manner.

[4] CESAR Cogeneration Options for a 33,000 BPD SAGD Facility: Greenhouse Gas and Economic Implications (October 2016)
[5] AESO 2017 Long Term Outlook
[6] Oil Sands Community Alliance 2016 Oil Sands Co-generation and Connection Report (December 2017)

ENMAX Corporation
141 – 50 Avenue SE
Calgary, AB T2G 4S7
Tel (403) 514-3000
enmax.com

December 3, 2018

Clean Air Strategic Alliance ("CASA")
1400, 9915 108 Street
Edmonton, Alberta
T5K 2G8

RE: Comments on Clean Air Strategic Alliance ("CASA") Emissions Management Framework for the Alberta Electricity Sector: Phase 1 – NOx Standard for Gas Turbines

ENMAX Corporation ("ENMAX") is pleased to provide comments on the development an appropriate NOx Standard for natural gas fired turbines in Alberta. The development effort was the primary activity of the recent CASA Phase 1 process and was accomplished under strict deadlines provided by the Alberta Government. The result of the meetings was a non-consensus viewpoint among the attending members. ENMAX is providing this letter as a subset of our perspectives on the CASA facilitated process as part of the non-consensus report.

ENMAX has been an operator and developer of natural gas fired generation in Alberta since 2007 and has been an active participant in past CASA conversations for action on air emissions. The principles of Best Available Technology Economically Achievable ("BATEA") that were developed in the early years of CASA, are applied by our organization when developing new generation projects and have served as a valuable standard for our technology selection process. ENMAX has experience operating units with Selective Catalytic Reduction ("SCR") technology and have not experienced any major commercial or operational challenges with aqueous ammonia or the SCR equipment. ENMAX units with SCR operate well below the approved Alberta Environment NOx levels and reliably produce electricity for the competitive Alberta electricity market.

Support for "Proposal A"

ENMAX is generally supportive of the industry "Proposal A" which includes advanced emission controls on non-peaking gas turbines greater than 70 MW in size. The use of advanced emission controls is commonly thought to equate to the use of SCR as an add-on technology to the design of a gas turbine facility, however there is no specified technology that should be prescribed in any future standard. Proposal A also has the definition of a peaking unit having the total potential electrical output of 33% or lower for a gas turbine. Peaking units of smaller sizes are not well suited to SCR. ENMAX is only supportive of the entirety of Proposal A and has endorsed it with this understanding.

Summary

ENMAX encourages the Alberta Government to maintain a consultative approach in developing the language for the future NOx Standard to ensure the correct balance is achieved with substantive reductions in NOx for the province while maintaining reasonable flexibility for operators.

December 4, 2018

Clean Air Strategic Alliance ("CASA")
1400, 9915 108 Street
Edmonton, Alberta
T5K 2G8

RE: Comments on Clean Air Strategic Alliance ("CASA") Emissions Management Framework for the Alberta Electricity Sector: MAXIM Perspective on NO_X Standards for Gas Turbines

Maxim Power Corp ("MAXIM") appreciates the opportunity to provide perspective on updating the oxides of nitrogen (NO_X) standard for natural gas fired turbines.

MAXIM is generally supportive of the industry/ENGO "Proposal A" which embraces Selective Catalytic Reduction (SCR) equivalent performance on non-peaking gas turbines greater than 70 MW in size and peaking turbines greater than 150 MW in size. MAXIM notes that the values presented in Proposal A are estimates based on expected flue gas *concentrations* using SCR technology. It is expected that NO_X standards will need to be applied on a mass basis, and that these standards will be calculated carefully with all assumptions tested. In addition, standards should be flexible to allow for startup, shutdown, operational upsets, and other unexpected conditions, recognizing that investment in technology that achieves SCR equivalency meets the overall objective of significant NOx reduction.

Of key importance to MAXIM is that industry participants are able to make investment decisions with regulatory certainty. Research, engineering, and other significant resources are put into project development before an investment decision is made and are based on published regulatory criteria of the day, including environmental standards. Once the investment decision is made, it can take many years to acquire regulatory approvals, construct, and commission a facility as complex as a natural gas fired gas turbine. MAXIM believes that the new CASA air emissions standards should be implemented such they not negatively impact previously committed investment in Alberta based natural gas fired power generation. As such, MAXIM supports that the implementation timing of the new CASA standards not apply to facilities commissioned prior to November 1, 2021, coincidental with the upcoming transition to a capacity market in Alberta.

MAXIM encourages the Government of Alberta to continue a consultative approach to the development of new environmental standards for the electricity sector that respect the principals of a fair, efficient, and open competition.

Suite 1210, 715 – 5 Avenue S.W., Calgary, Alberta, Canada T2P 2X6
Tel: 403.263.3021 Fax: 403.263.9125 **www.maximpowercorp.com**

The ENGO Perspective Document on NOx Emission Limits for New Gas-Turbine Electricity Generation Units

(December 1, 2018)

Executive Summary: The ENGO community participated in this 3rd 5 year review of NOx emission limits peaking units for gas-turbine electricity generation units with the expectation that all stakeholders, who were part of the development of the CASA Electricity Framework, would honour one of the key intents of the Framework i.e. ensuring that the emission limits for new electricity generation units reflected BATEA based limits. Unfortunately this was not the case and proposals were presented by some of industry that clearly did not reflect BATEA. Fortunately there was a sector of industry that understood and honoured the intent of the Framework and the ENGOs are pleased to submit an ENGO/Industry proposal for different types and sizes of gas-turbine electricity generation that is consistent with that intent. ENGOs would note that this proposal is almost identical in terms of non-peaking units to what ENGOs, the entire utility sector and government supported in the 1st CASA Electricity Framework Review so it is interesting that approximately 8 years later some of the utility sector is not supporting what are clearly BATEA NOx limits for non-peaking units. It is the ENGO community's expectation that the government will adopt and implement this ENGO/Industry proposal immediately so that companies can plan projects accordingly. As noted in the joint proposal the proposed NOx emission standards should align with the implementation of the capacity market and associated auctions, applying to gas turbine facilities commissioned on or after November 1, 2021.

Introduction: The ENGO community participated in Phase 1 of the 2018 CASA Electricity Framework Review (EFR) Project Team. One objective of this Phase of the EFR was to develop new NOx emission limits that would apply to new gas-turbine power generation units. This was the third EFR and the two previous reviews failed to reach consensus on this issue in large part because of differing views on the limits that should apply to co-generation units in a certain size range. The two previous reviews resulted in non-consensus recommendations being provided to Government with no subsequent decision with the consequence that there is confusion as to what NOx limits should apply, or are to be applied, to different types and sizes of gas-fired power generation units and inconsistences in emission control requirements between combined cycle units and co-generations units. There is also an issue that one of the clear intents of the CASA Electricity Framework (EF) i.e. ensuring BATEA limits for electricity generating units are set and updated on a 5-year cycle, is not being met

Examples of current issues with respect to the lack of clear provincial direction on NOx emissions limits for gas fired simple cycle turbine units, combined cycle gas/steam turbine generation units and co-generation units (gas fired turbine electricity generation and gas fired heat recovery steam generation) include:

- Uncertainty on how or if the 2016 Federal "*Proposed Guidelines for the Reduction of Nitrogen Oxide Emissions from Natural Gas–fuelled Stationary Combustion Turbines*" (ECCC 2016) apply in Alberta;
- The current regulatory practice of requiring the application of selective catalytic reduction (SCR) based emission limits for combined cycle units but not co-generation units despite the fact that BATEA is (should be) the same for both of these unit types;

- Having different BATEA based performance targets for boilers, heaters and co-generation units for developments North of Fort McMurray that are not applied in the rest of the province and which are much lower than the compliance limits being applied i.e. the "*Interim Emission Guidelines for Oxides of Nitrogen (NOX) for New Boilers, Heaters and Turbines Using Gaseous Fuels Based on a Review of Best Available Technology Economically Achievable (BATEA).*"(AEP, 2007) when BATEA should be the same for all similar/like unit sizes and types;
- The lack of a clarity on what constitutes a peaking unit and the NOx emission limits that should apply to such units with the result that all stakeholders are confused on this issue; and
- Approval agencies/groups having no clear direction on NOx emission limit requirements and therefore each approval application is subject to debate and uncertainty regarding the appropriate NOx limits which should be applied.

The ENGO community therefore hoped that this third EFR review would be able to develop consensus NOx limit recommendations that would facilitate the government setting new NOx emission limits. New limits are needed to reflect advances in NOx control technology capability and lessons learned from the application of these technologies in Alberta and are also needed to provide consistency and certainty for all stakeholders in terms of the NOx emission limits that will apply to the different types and sizes of gas-turbine power generation units. Finally the government needs to apply the EF as intended and if it doesn't then the ENGO community will have to consider withdrawing its support for the Framework.

ENGO Interests: The overarching interest of the ENGO community is the protection and wise management of air quality in Alberta. Alberta has amongst the highest per capita NOx emissions in the developed world (Conference Board of Canada 2018) and information presented to the EFR Project Team by Alberta Environment and Parks (AEP) indicates that many of the air zones in Alberta will likely be in a NO_2 exceedance or management level when the first Canadian Ambient Air Quality Standards (CAAQS) NO_2 determination are made in 2021. NO_2 does not appear to have a threshold below which no adverse health effects occur. In addition to ambient NO_2, NOx emission contribute to fine particulate matter which also is a no-threshold air pollutant (CCME 2012). NOx emissions also contribute to ozone formation, acid deposition and nitrogen eutrophication deposition. Therefore eliminating/minimizing NOx emissions to the extent practical is an important air quality management imperative in terms of minimizing ambient NO_2 air quality levels and the associated adverse health and environmental effects associated with $NO_{2.}$ Effective NOx emission management is therefore a priority issue and BATEA NOx control limits need to be applied on a priority basis.

The general and specific NO_2 air quality and NOx emission management interest and approach that the ENGO community brought to the CASA EFR Project Team was therefore to encourage, and contribute to, the development of NOx emissions limit for gas-turbine generation units that reflected the provincial environmental principles (AEP 2012) of:

- pollution prevention through employment of best available technology economically achievable (BATEA),
- emission minimization through best management and control practices, and
- continuous improvement and keeping clean areas clean.

The focus was on developing NOx emission limits that reflect BATEA which is definitely not the case with the current NOx emission limits for gas-fired power and heat generation units although, as noted above, there is some confusion as to what the current limits actually are.

In support of the focus on BATEA controls it was noted that the Alberta Government has a policy that requires BATEA controls. This policy states:

> "*Industrial release limits will be established based on limits achievable using the most effective demonstrated pollution prevention/control technologies or the limits required to meet risk based and scientifically defensible ambient environmental quality guidelines, whichever are the more stringent.*" (AEP 2000)

The regular 5-year reviews of the Electricity Framework (EF) were intended to ensure that the emission limits for new electricity generation unit always reflected BATEA and the Government needs to ensure that this element of the EF is implemented otherwise a very key and important element of the Framework is irrelevant which raises the question of whether not the ENGO community should continue to support the EF.

In the previous 5 year review ENGOs raised a similar issue and noted:

> "*Given how clear the objective information is on BATEA for gas-fired units at this time (and for at least five years now), this raises a concern regarding the utility sector's commitment to the intent of the Electricity Framework and the concept of BATEA based limits for new units.*
>
> *The ENGO sector would note that Alberta presents itself as a leading jurisdiction in terms of pollution control requirements. Given the way in which BATEA is objectively determined, a credible statement on "leadership" requires that industry comply at least with BATEA control levels. Unless it requires the general application of SCR controls for larger i.e. >70MW combined cycle and co-generation units, Alberta cannot claim to be a leading jurisdiction in terms of NOx control for gas-fired generation units. ENGOs would also note that combined cycle and co-generation are growing forms of energy and heat production, and without good NOx controls these forms of energy production will result in unnecessary increases in provincial NOx emissions with associated air quality and health implications*."

This position and assertion remains valid based on the results of this 3rd 5-year BATEA review.

ENGO Approach: Early in the EFR process the ENGO community outlined the approaches that it was bringing to the review and which it hoped the Project Team could refine and would guide the development of BATEA based NOx emission limits:

- BATEA limits need to be applied to all sizes and types of units,
- Low NOx (LN) controls are preferred to selective catalytic reduction (SCR) controls but only when, and if, the LN controls can manage total NOx emissions to below certain annual levels and, when limits are based on LN controls, these controls need to reflect best LN controls i.e. LN BATEA for that size and type of unit,
- SCR is BATEA for units above a certain size and/or units that have a high number of annual operating hours which collectively translates into higher annual NOx emissions, and

- Both unit emission intensity (unit type and size) and total projected annual unit NOx emissions (operating hours) need to be considered in setting emission limits.

In terms of annual NOx emission levels that would require the transition from LN-based control limits to SCR-based control limits, the ENGO's initially considered 75 to 150 t/y of NOx emissions from a unit as an approximate cut-off for allowable annual NOx emissions using LN with annual emissions above this annual NOx emission level requiring SCR control. This annual emission yardstick is based on the United States Environmental Protection Agency (USEPA) Prevention of Significant Deterioration (PSD) permit program that requires new projects that emit 100 t/y or more of NOx emissions to conduct a Best Available Control Technology (BACT) analysis (USEPA 2018) for the source. These analyses generally results in the requirement for SCR controls. This program applies to gas turbine combined cycle or cogeneration units with a total heat input of more than 264 GJs and greater than 100 tons per year (91 tonnes/year (t/y)) of NOx emissions (USEPA 1993). Based on normal gas turbine combined cycle or cogeneration unit efficiencies this translate to unit sizes in the 35 to 55 MW total energy output range.

Selecting an emission level threshold as an emissions source management tool is being used by Alberta Environment and Parks to identify possible priority emission sources for further management (the "*Industrial Air Emissions Management Program for Red Deer North Saskatchewan Region Program Facilities*"). The criteria being used is that for sources with NOx emissions of 140 tonnes per year or greater located in the near impact zone being included in the initial stages of the program. It is recognized that this criteria applies to air zones that have triggered management actions under the CAAQS but it does provide an indication of what is considered a major NOx source.

The ENGO's, based on a number of considerations regarding the advantages of LN vs SCR, ultimately determined that a NOx emission limit of 200t/y represented a reasonable LN-SCR application demarcation criteria. Therefore unit sizes, types and design capacity factors that could stay below 200 t/y of NOx emissions with BATEA LN controls would get LN control based NOx limits and all others would get SCR-based NOx control limits. This was considered a very reasonable approach and accommodating to industry compared to the approach used by the USEPA.

Other Considerations: The ENGO approach to determining what represented BATEA based limits was informed by:

- Three previous CASA EFR BATEA review reports all confirming that SCR limits were a cost effective control technology for all but the smallest generation units e.g. less that 50-70 MW and represented BATEA for combined cycle and co-generation units greater that 50-70MW.
- LN control levels for different gas turbine sizes based on manufacturer specifications as outlined in the BATEA report that the Eastern Research Group (ERG) (Eastern Research Group 2015) did for the 2nd CASA EFR and as updated by industry as part of the 3rd EFR.
- Information provided by industry that BATEA controls for Heat Recovery Steam Generation (HRSG) units were 34 g NOx/ GJ_{in} to the HRSG unit.
- The operating experiences of companies that have SCR units which indicated that there were no significant operating challenges associated with SCR even at low temperatures except if a dirty fuel is used which is not the case with natural gas or mixed gas fuels.

- The uncertainty that the transition to a capacity electricity market creates and the influence that the increase in renewable generation may have of the types and sizes of future gas-turbine generating units.
- The current view that much of the future electricity generation in Alberta will come from co-generation units and therefore it is important to have BATEA based NOx control limits for these types of units.
- A brief review of the USEPA BACT Clearinghouse by Saeed Kaddoura of Pembina who was an ENGO member on the EFR Project Team but had to resign based on financial support issues. This review indicated that for units with SCR the NOx emission limit was 2 ppmv at 15% O_2.
- The economic analysis that has been conducted by the Alberta Government which indicates that, based on future scenario analyses, additional emission control costs will not be a disincentive for co-generation and that co-generation will be profitable.

(Note: From an ENGO perspective there was no information presented by industry that countered any of the above considerations. Some of the industry members on the EFR Team presented information related to the air quality benefits and absolute emission reductions and indicated that these needed to be considered. While the ENGO's believe that these are issues not directly related to setting BATEA-based NOx emission limits, it is clear that there will be definite air quality benefits and significant NOx emission reductions associated with the NOx limits proposed by the ENGO/Industry proposal. It is also noted that the industry presentation to the EFR Project Team on air quality impacts presented modelling data which had CAAQS comparison related predictions that were below current ambient NO_2 levels in the oil sands region. The presentation slides were subsequently corrected which showed that the actual measured levels of NO_2 in the region were high and while this is not relevant to setting BATEA based NOx emission limits it highlights the importance and air quality management value of setting such values. In terms of NOx emission reductions, the industry review misinterpreted the ENGO expectations for co-generation units. The ENGO/Industry proposal compared to the other industry proposal gives a difference in annual NOx emissions for an 85 MW co-gen unit with 33% duct firing between this proposal and the joint ENGO/industry proposal would be approximately 512 kg/d i.e. 834 kg/d versus 322 kg/d or approximately 278 t/yr versus 107 t/yr (based on 8000 operating hours per year). Based on the co-gen full buildout scenario of 4300 MW translated presented by CAPP this translates to an annual NOx emission difference of 9 kilotonnes which is very significant indicating the value of BATEA application in reducing NOx emissions.)

ENGO "Strawdog" Proposals for NOx Limits for Gas-fired Generation Units: Early in the EFR process the ENGOs proposed a "*strawdog*" proposal which was intended to initiate discussion which it did. Based on that discussion the "*strawdog*" was revised and presented back to the group. Based on some feedback this "*strawdog*" was refined. During this period (September to middle of October) no comprehensive and rationalized proposal was presented by industry. At the November 15th EFR meeting two industry proposals were received. These proposal were very different and it was explained that there would likely be two, or possibly more, final industry proposals with companies/sectors indicating which proposal it supported. The rationale/basis for one proposal was provided but for the other proposal the rationale for selecting the SCR vs LN based NOx limit categories was not provided and the justification for the high annual NOx emissions e.g. 350 t/y, for some unit types/sizes was not provided.

Based on the industry proposals presented on November 15th, and which based on the discussion at the meeting could be revised but It was however indicated by some of the industry that the issue of when SCR based controls should apply was unresolvable amongst the industry interests so there would be no one industry proposal.

The industry proposal put forward by Capital Power was consistent with the intent and direction of the final ENGO "strawdog" and based on this proposal discussions were held with Capital Power and an agreement was reached on a final ENGO/Capital Power proposal which Capital Power indicated that some other electricity sector generators would likely support. In this perspective document this proposal is being referred to as the ENGO/Industry proposal.

ENGO/Industry Proposal: The following 2 Tables summarize the limits as per the ENGO/industry proposal and provide some context around the basis for the NOx limits being proposed. ENGOs would note that the proposal is almost identical to the non-consensus proposals that were part of the 1st and 2nd EFRs and which clearly represented BATEA based limits and still represent BATEA based limits although it needs to be noted that the United States sets more stringent SCR based BATEA limits.

In putting this proposal forward this ENGO/Industry proposal it is recognized that in the application of the emission limits there will have to be qualifiers on when and how the limits are to be applied e.g. what constitutes start-up and shut-down etc. and the ENGOs are confident that the government will address these issues in a fair and appropriate way.

Summary: The ENGO sector in conjunction with some utility companies is proposing an approach for NOx limits for gas-turbine power generation units that reflects the application of BATEA based controls consistent with the intent of the Alberta Electricity Framework and Government Policy. Of particular importance in terms of establishing BATEA based NOx emission limits is for co-generation units in the greater than 70MW size range to have BATEA based limits as much of the new electricity generation in Alberta is likely to come from this type and size of unit. BATEA based emission limits for these type and sizes of units will result in significant NOx emission reductions over the business as usual case. Three previous CASA BATEA review reports all confirmed that SCR limits were a cost effective control technology for these types of generation units and SCR operating experience shows that there are no operational issues with this technology that justify concerns regarding its application.

The ENGO sector would again note that the CASA EF five-year review approach contemplated the application of the principle of continuous improvement which was the reason for the BATEA approach that underlies the CASA Recommendation 29. This is the 3rd five-year EFR and the gas-fired unit standards from 2003 are still being used. This does not reflect continuous improvement and it is expected that Government will move quickly to update the EF gas-turbine unit NOx limits consistent with the application of BATEA.

Table 1: Peaking Unit[1] NOx Emission Limits

Power Rating (per gas turbine only)	Natural Gas Turbines	
	NOx concentration limit (ppm)	Peaking Electricity Allowance ("A") (kg/MWh net) [4]
More than 150 MW	6[2]	.1 kg/MWh net
More than 70 MW and less or equal to 150 MW	15[3]	.25 kg/MWh net
Less than or equal to 70 MW	25[3]	.41 kg/MWh net

[1] Peaking unit is one that annually operates at no more than 33% of its total energy output i.e. MCR*8760*0.33

[2] Based on an assumed LN GT of 25 ppm (which is typical for larger units and the application of SCR to achieve ~75% NOx reduction. If this level of control can be achieved with LN controls that is acceptable

[3] These are considered to represent BATEA LN controls for these size of units and should not significantly limit equipment supplier options

[4] Based on an assumed 37% gas turbine efficiency. Higher efficiency units would be incented in that compliance would be easier and/or a unit could select/use a unit with a slightly higher NOx ppm rating. Note: "B" factor does not apply as there is no HRSG unit.

Table 2: Non-peaking Simple Cycle, Combined Cycle and Co-generation Unit[i] NOx Emission Limits

Power Rating (per gas turbine only)	Natural Gas Turbine/HRSG		
	NOx concentration limit (ppm)	Electricity Allowance ("A") (kg/MWh net) [4]	HRSG Heat Output Allowance ("B") (g/GJout) [5]
Equal or More than 70 MW	6[2]	.1 kg/MWh net	0.01[6]
Less than or equal to 70 MW	25[3]	.41 kg/MWh net	0.025[7]

[1] A combined cycle unit is a combination of a gas turbine and a steam turbine with the waste heat from the gas turbine providing heat energy for the steam turbine and a co-generation unit is one that generates electricity using a gas turbine and generates heat/steam using the exhaust heat from gas turbine often supplemented with additional fuel input.

[2] Based on an assumed LN GT of 25 ppm (which is typical for larger units) and the application of SCR to achieve ~75% NOx reduction. If this level of control can be achieved with LN controls that is acceptable

[3] These are considered to represent BATEA LN controls for these size of units and should not significantly limit equipment supplier options

[4] Based on an assumed 37% gas turbine efficiency. Higher efficiency units would be incented in that compliance would be easier and/or a unit could select/use a unit with a slightly higher NOx ppm rating.

[5] A heat output "B" factor is used because this is the factor preferred by industry but needs to be linked to the degree of NOx control being applied to the HRSG which is what determines BATEA in terms of LN

[6] Based on a LN duct burner of 34 g/Gjin, an assumed 150% heat recovery in the HRSG and an assumed SCR reduction of ~60%

[7] This is considered to be BATEA for LN HRSG burners and is based on an assumed 140% heat recovery in the HRSG

Summary: The ENGO sector in conjunction with some utility companies is proposing an approach for NOx limits for gas-fired power generation units that reflects the application of BATEA based controls consistent with the intent of the Alberta Electricity Framework and Government Policy. Of particular important in terms of establishing BATEA based NOx emission limits is for co-generation units in the greater than 70MW size range as much of the new electricity generation in Alberta is likely to come from this type and size of unit. BATEA based emission limits for these type and sizes of units will result in significant NOx emission reductions over the business as usual case. Three previous CASA BATEA review reports all confirmed that SCR limits were a cost effective control technology for these types of generation units and SCR operating experience shows that there are no operational issues with this technology that justify concerns regarding its application.

The ENGO sector would note that the CASA EF five-year review approach contemplated the application of the principle of continuous improvement which was the reason for the BATEA approach that underlies the CASA (Recommendation 29). This is the 3rd five-year EFR and the gas-fired unit standards from 2003 are still being used. This does not reflect continuous improvement and it is expected that Government will move quickly to update the EF gas-fired unit NOx limits consistent with the application of BATEA.

Appendix 2

Proposal B - NOx Standards for Peaking and Non-Peaking Gas Turbine Units and Supporting Stakeholder Perspectives

Includes perspectives from: CAPP, CIAC, TransCanada, TransAlta, ATCOȟÁÎÄ ! . #

Proposal B – NOx Emission Standards for Peaking and Non-Peaking Gas Turbine Units

The proposal is supported by CAPP, CIAC, TransCanada, TransAlta, ATCO, and ANC

Basis

- Output-based standards in format similar to *Guidelines for the Reduction of Nitrogen Oxide Emissions from Natural Gas-fueled Stationary Combustion Turbines, Environment and Climate Change Canada, November 2017*.
- Standards are NOx emission rates expressed in Kg/hr. Emissions intensities ("A" and "B" factors) are intended solely for determining mass emissions standards and are not suitable for own use in operating approvals.
- Separate categories are based on gas turbine capacity for non-peaking and peaking electricity generation.
- A gas turbine may declare as a peaking unit if it meets the peaking standard and, does not exceed a Total Potential Electrical Output of 33% in a calendar year [*unless required by the System Operator to operate for system security.]*
- These limits do not apply during start-up periods, shut-down periods, periods of part-load operation, upset conditions or when the ambient temperature at the point of air intake is less than -18^{0}C.
- Standard does not prescribe required technology. Current available equipment and BATEA technologies used to inform the basis for standard development were Dry Low Emissions (DLE) and Selective Catalytic Reduction (SCR).
- Implementation of Standards should align with the implementation of the capacity market and associated auctions, applying to gas turbine facilities commissioned on or after November 1, 2021.
- Compliance measurement based on existing Alberta Environment & Parks protocols subject to exclusions stated above.
- Standards do not apply to the following:
    - Emergency combustion turbines;
    - Combustion turbines used solely for purposes of research and development and field demonstration; and
    - Combustion turbines under repair, those being tested during their commissioning period or during verifications of repairs.

Definitions

"Natural gas" means a naturally occurring fluid mixture of hydrocarbons produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas is composed of at least 85% methane by volume, and it excludes landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas or any gaseous fuel produced in a process that might result in highly variable Sulphur content or heating value.
"Part-load operation" means the operation of the combustion turbine below 70% of its power rating.
"Peaking unit" means a unit that produces less than 33% of the quantity of electricity that would be generated in a calendar year if the unit were to operate at capacity at all time during that calendar year (unless required by the System Operator to operate for system security).
"Power rating" means normal maximum continuous rating (in megawatts – MW) at International Organization for Standardization (ISO) 3977-2 environmental design point conditions of ambient air 15^{0}C (288K), 60% relative humidity and 101.3 kilopascals barometric pressure.
"Shut-down period" means the period of time between the moment when the combustion turbine is operating at normal operating mode and the moment when it is non-operational.
"Electricity Output" is the total electricity and shaft power energy production expressed in MWh. May be referred to as unit nameplate capacity or maximum continuous rating (MCR).
"Heat Production" is the total useful heat energy recovered (GJ output)

Non-Peaking Standard Formula

Non-Peaking Unit NOx (kg/h) = [Electricity Output (MWh)[1] x A] + [Heat Output (GJ/h) x B]

where "A" and "B" factors are determined as follows:

Power Rating[2] (per gas turbine only)	**Natural Gas Turbine/HRSG**		
	NOx concentration (ppm)[3] (for illustrative purposes)	**Non-Peaking Electricity Output Allowance ("A") (kg/MWh)**	**Heat Production Allowance ("B") (kg/GJ net[4])**
More than 100 MW	7-9	**0.10**	**0.02**
40 to 100 MW	13-15	**0.20**	**0.034**
Less than 40 MW	25	**0.40**	**0.034**

Peaking Standard Formula

Peaking Unit NOx (kg/h) = [Electricity Output (MWh)[1] x A]

where "A" factor is determined as follows:

Power Rating[2] (per gas turbine only)	**Natural Gas Turbine**	
	NOx concentration (ppm)[3] (for illustrative purposes)	**Peaking Electricity Output Allowance ("A") (kg/MWh)**
More than 200 MW	7-9	**0.15**
More than 100 MW and Less or Equal 200 MW	12	**0.19**
Less than or Equal to 100 MW	25	**0.45**

Notes:
1. Normal maximum net continuous rating at ISO conditions as provided by the manufacturer
2. Power rating for gas turbine plus an associated combined cycle steam turbine.
3. All concentrations expressed in dry volume at 15 % oxygen and ISO conditions
4. All thermal efficiencies expressed as Lower Heating Value (LHV)

December 3, 2018

Katie Duffett via email: kduffett@awc-casa.ca
Project Manager
Clean Air Strategic Alliance
#1400, 9915 – 108th Street
Edmonton, AB T5K 2G8

Dear Ms. Duffett:

Re: CASA Electricity Framework Review 2018, CAPP Perspectives Document

The Canadian Association of Petroleum Producers (CAPP) represents companies, large and small, that explore for, develop and produce natural gas and oil throughout Canada. CAPP's member companies produce about 80 per cent of Canada's natural gas and oil. CAPP's associate members provide a wide range of services that support the upstream oil and natural gas industry. Together CAPP's members and associate members are an important part of a national industry with revenues from oil and natural gas production of about $101 billion a year.

CAPP appreciates the opportunity to provide our perspectives on the creation of a new Alberta baseline standard for NOx emissions for gas-fired electricity generation through the Clean Air Strategic Alliance's (CASA) multi-stakeholder process. Alberta Environment and Parks and Alberta Energy have indicated that the creation of a standard for NOx emissions from electricity generation that balances environmental, economic and social outcomes is a priority for Government.[1] We believe that our proposed standard achieves this goal and maintains industry competitiveness, demonstrates continuous improvement, and delivers a measureable benefit in air quality.

CAPP supports the Industry Proposal for New Natural Gas Turbine NO_X Standards (hereinafter referred to as "Proposal B") that was presented during the CASA process as one which delivers emissions reductions, sets an appropriate and progressive baseline standard across the province, and does not disincentivise the development of energy-efficient cogeneration in industrial applications. We specifically propose a new standard for non-peaking units as summarized in Table 1 below:

[1] July 15, 2018 Letter from Eric Denhoff, Deputy Minister of Alberta Environment and Park and Alberta Climate Change Office, addressed to Andre Asselin, Executive Director of CASA and shared with the CASA working group.

Table 1: Proposal B for New Non Peaking Standard Formula Based on Designed Emissions

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

Power Rating[1,2] (per gas turbine only)	Natural Gas Turbine/HRSG		
	Reference NOx concentration limit (ppm)[3] (Gas Turbine Only)	Non Peaking Electricity Allowance ("A") (kg/MWh net[2])	Heat Production Allowance ("B") (kg/GJ_{output} net[4])
More than 100 MW	7 - 9	0.1	0.02
40 to 100 MW	13 - 15	0.20	0.034
Less than 40 MW	25	0.40	0.034

1 Normal maximum net continuous rating at ISO conditions as provided by the manufacturer
2 Power rating for gas turbine plus an associated combined cycle steam turbine.
3 All concentrations expressed in dry volume at 15 % oxygen and ISO conditions
4 All thermal efficiencies expressed as Lower Heating Value (LHV)

Proposal B is founded on principles we believe to be vital for durable policy and which were shared during the CASA process. They include the following:

- Emissions standards should reflect a performance standard based on best available technology economically achievable (BATEA);
- Emissions standards should respect the competitive market and a level playing field while maintaining a balance between emissions control costs and emissions reductions;
- Standards should be intensity based and approval limits converted to mass based limits to allow operational flexibility. (Consideration for starts, stops, ancillary services, emergency dispatch and how equipment is operated);
- Greenhouse gas emissions and energy efficiency should be considered when setting NOx emission standards; and
- Emissions standards should be cost effective and complement the rigorous air quality management system already in place in Alberta.

Proposal B is consistent with these principles and the Government of Alberta's desire for an appropriate NOx standard for natural gas-fired electricity generation. This proposal relies on recent advancements in emissions control technologies and allows Alberta to remain a leading jurisdiction in NOx emissions standards for electricity generation. This approach delivers real emissions reductions beyond current regulation, shows the oil and gas industry's commitment to continued improvement, considers the unique operations of our sector, and balances emissions reductions and costs to industry.

Emissions control technologies form the basis for the CAPP-supported Industry Proposal

Proposal B takes into account recent advancements in emissions abatement technologies. The industry undertook a review of manufacturers' published literature on currently available equipment to determine the NOx emissions levels achievable with modern dry-low NOx burners. This review showed that there are reliable offerings of gas turbines in the sub 15 ppm category (for units greater than 40 MW) that would deliver reduced emissions from the current standard.

Based on the experience of member companies, vendors typically offer guarantees for emission levels which are higher than those published in vendor handbooks. This difference is recognition that the performance described in handbooks is specific to a narrow range of operating conditions in controlled environments. Therefore, in order to accommodate the variability (in fuel quality and temperature) common in oil sands operations, units must have the capability to remove more NOx than the suggested standard in order to achieve the recommended emissions levels. Additional discussions with vendors of heat recovery steam generators (HRSGs) indicated that NOx levels below 34 g/GJ_{output} could not be guaranteed for industrial cogeneration operators in the oil sands, due to limitations created by variation in fuel quality.

This work and the feedback received from vendors formed the basis for industry's proposed emissions standards below 100MW in order to ensure achievable emissions standards consistent with modern technology and a desire to progress beyond the current federal standard.[2]

The unique operational conditions of the oil and gas sector

Proposal B is also based on our sector's operations and application of cogeneration as an efficient source of electricity and steam. Both electricity and steam are vital for our industry with steam being particularly important for oil sands operations. On one hand, this makes cogeneration an energy efficient and favourable technology for our industry. On the other, distinct requirements as a result of different oil sands architecture contributes to a range of design specifications for electrical loading, steam demand, fuel quality and additional duct firing for heat/steam generation.

---

[2] See *Guidelines for the reduction of nitrogen oxide emissions from natural gas-fuelled stationary combustion turbines, Environment and Climate Change Canada*, 2017. Available at < https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/guidelines-objectives-codes-practice/reduction-nitrogen-oxide-combustion-turbines-guidelines.html >

To recognize the variability in the design and the efficiency of cogeneration, compared to other utility applications where fuel quality and duct firing requirement differ, CAPP recommends a standard that recognizes both power and heat in a clear, simple, and transparent manner. This approach avoids unnecessary complications in interpreting design requirements and allows compliance obligations to be clearly communicated. This form of a standard also accommodates translation into a mass based emission limit that can be reflected in operating approvals. Transparency in the calculation method further ensures equitable treatment for power and heat generation regardless of the end use (i.e. sale to the electrical grid or integrated industrial use). A clear limit provides design and compliance certainty as opposed to supplemental performance standards which we consider to be aspirational.

Proposal B recommends standards based on post-combustion control technology (for units greater than 100 MW) at levels that offer a reasonable NO_X removal rate. This approach gives recognition to the limited experience operating advanced controls in the oil sands sector where the impact of variable fuel quality and extreme cold is currently not well understood. Excessive post-combustion (such as Selective Catalytic Reduction (SCR)) removal rates could impose undue operational constraints (such as the need to flare off-spec fuel) and drive operators into non-compliance with requirements to conserve gas.

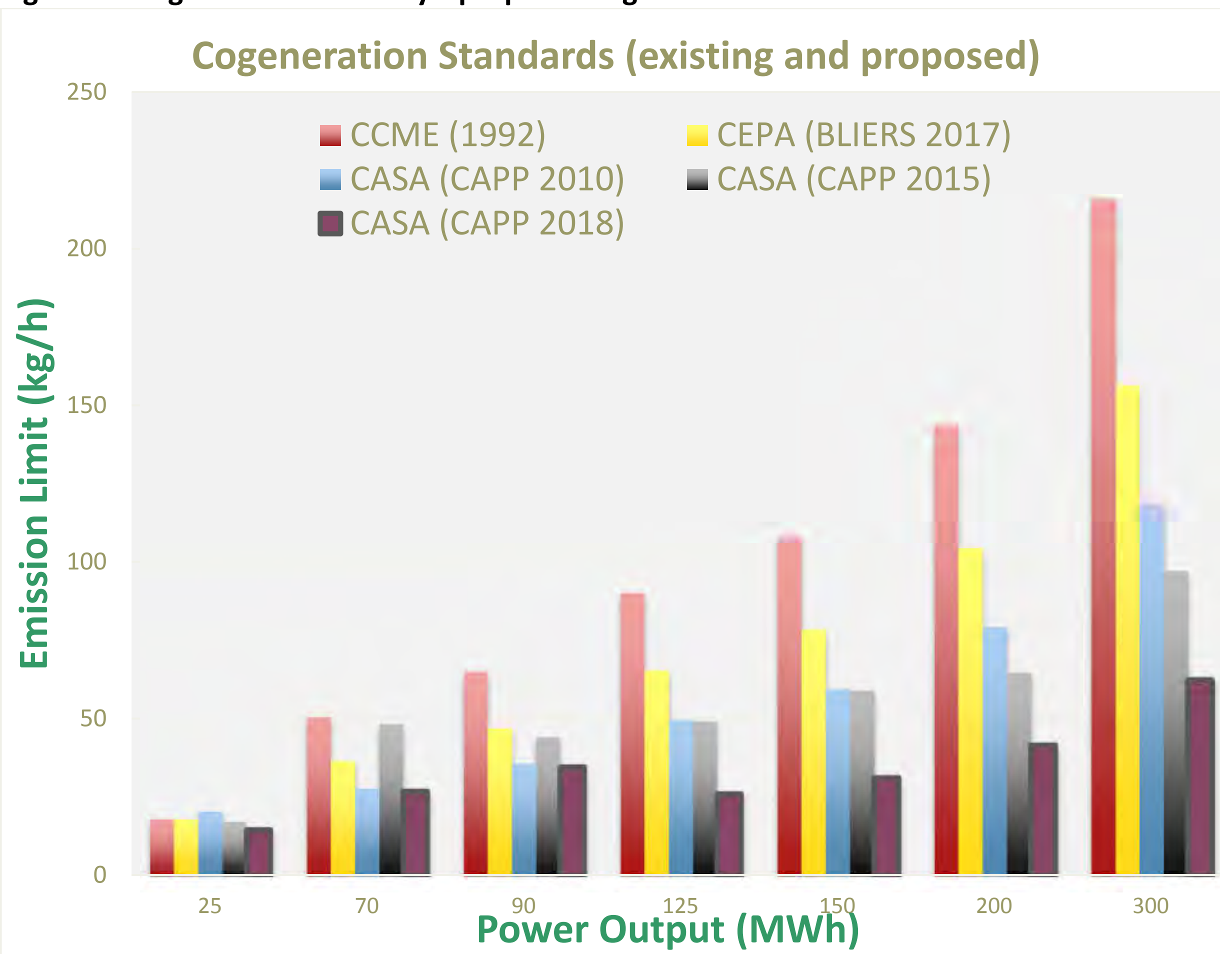
In addition, high NOx removal rates through aggressive use of SCR will necessitate increased reagent use and waste. It will also result in more frequent replacement of the catalyst bed associated with potential fouling from residual sulphur present in fuel. It is expected that the residual sulphur commonly present in produced/refinery gas used in the oil sands sector will be oxidized to SO_2 and SO_3 in the combustion process. SO_3 in contact with ammonia, can form ammonia salts (either ammonium sulfate or ammonium bi-sulfate) which can plug in the catalyst bed or foul the colder coils within the HRSG. Further research and operational experience of these complexities is required prior to any mandated application of SCR across a larger range of unit sizes. While SCR has been applied by utilities since 2009 in Alberta, SCR has not been tested for the range of operational conditions and fuel types typical of our sector.

It should be noted that the standards proposed are those only applicable under normal operating conditions. Further consideration for abnormal operational conditions and start up/shut down should also be considered in the implementation of the policy. To address these concerns, we would request that some accommodation be made for SCR is unavailable due to operational issues. In addition, as a change in policy will affect equipment that typically requires long lead procurement and design timelines we recommend provisions to permit a phase in for applicability.

Real emissions reductions and continued improvement

Proposal B represents the latest in a progression of CAPP proposals to decrease NOx emissions from cogeneration facilities (see Figure 1 below). Our latest proposal, represented at CASA (CAPP 2018) would deliver between 20 and 60% emissions reductions over the current federal standard, CEPA (BLIERS 2017)[3], across the various turbine sizes. Figure 1 also illustrates the progress our industry has made in terms of potential emissions reductions and genuine commitment to continual improvement and the CASA process.

Figure 1: Progression of industry's proposed cogeneration standards[4]



The cost of limiting emissions by focusing on cogeneration

[3] *Ibid.*
[4] See for "CCME (1992)" see Canadian Council of Ministers of the Environment, *National Emission Guidelines for Stationary Combustion Turbines*, 1992, at < https://www.ccme.ca/files/Resources/air/emissions/pn_1072_e.pdf >; for "CASA (CAPP 2010 and 2015)" see < http://www.casahome.org/current-initiatives/electricity-framework-review-55/ >; for "CEPA (BLIERS 2017)" see footnote 2 above.

CAPP members are committed to preserving air quality in the province and the principle of continuous improvement; however, increases in investment directed at emissions reductions should deliver commensurate improvements in air quality. This is considered to be one of the primary risks associated with mandating a stringent and costly standard for NOx emissions from cogeneration. In the absence of assessing an approach's overall impact to provincial NOx emissions, and achievement of the 2020/2025 CAAQS, there is a real risk that significant efforts and costs will be undertaken that will not actually help the province address its air quality concerns. To understand the potential impact on air quality of the proposed emissions standards discussed during CASA review, CAPP engaged Golder Associates to conduct regional modelling of oil sands development under various scenarios (see Appendix 2, herein "Golder report").

The Golder report looked at air dispersion modelling and the air quality changes in the Athabasca Oil Sands Region (AOSR), based on interim proposals presented by CAPP and the ENGO caucus during the CASA process. Ultimately these were not the final proposals tabled, but the two cases can still be used to provide a reasonable illustration of the difference in ground level NOx concentrations under the proposed standard. The Golder report shows that ground level NOx levels are minimally impacted by future cogeneration, and there would only be a nominal improvement in ambient air quality associated with the more stringent emission reductions modelled. It should also be noted that in all cases the Golder report is based on a "full development scenario" wherein all currently approved cogeneration facilities are commissioned. The full development scenario proposes aggressive oil sands growth where all proposed projects proceed. It is not clear that a full development scenario is realistic, but when modelled it reflects the highest potential emissions based on industry's current knowledge. Under these circumstances, the impact of cogeneration on ground-level NOx concentrations is low and the difference in emission between the CAPP proposal and the interim ENGO proposal is minor.[5]

In conjunction with the modelling undertaken by Golder, CAPP conducted internal analysis of the costs associated with applying SCR to new cogeneration facilities based on the interim CAPP and ENGO proposals. CAPP estimated the capital and operating costs of SCR based on the 2015 EFR study commissioned by CASA, a 30-year design life, and industry data on potential cogeneration. Using these inputs we calculated that the interim ENGO proposal could increase the cost of cogeneration in Alberta's oil sands operations by over $1 billion. In contrast, the interim CAPP proposal is expected to cost approximately $280 million. We acknowledge that these calculations are a rough estimation, but we are confident that a more comprehensive economic analysis based

---

[5] The total reductions between the two modelled scenarios were 18 tonnes/day in the AOSR. CAPP requested that Golder recalculate the total reductions based on an ENGO proposal more reflective of their final proposal; this resulted in a difference in emissions between the CAPP and ENGO proposal of 32 tonnes/day. Comprehensive modeling could not be revised in time to reflect final stakeholder proposals, however the minimal impact of cogeneration under the CAPP case on air quality illustrates that there are no emissions standards that could deliver significant improvements to overall air quality.

on final CASA proposals would only show a higher difference in cost between the two proposals. Fundamentally, we believe that the results of the Golder report in conjunction with our cost assessment clearly illustrate that the increase in cost between the proposals is not justified by the incremental reduction in emissions.

Industry proposed standards are complimentary to Air Quality Management within the Province

In conjunction with setting a new standard for NOx emissions for natural gas-fired electricity generation, it is clear that the Alberta Government is concerned about overall emissions management and achievement of the Canadian Ambient Air Quality Standards (CAAQS).[6] CAPP supports CAAQS achievement and we see our proposed emissions standard as part of the overall system designed to deliver and maintain good air quality in the province.

Established systems and management frameworks with proven processes currently exist (both provincially and federally) to apply more stringent emissions management in areas of special concerns. We continue to support the implementation of place-based solutions through regional frameworks, Alberta Ambient Air Quality Objectives (AAQOs), Canadian Ambient Air Quality Standards (CAAQS), EPEA application/renewals and other policies that provide targeted emissions reductions in Alberta. Under the province's air quality management frameworks, the province can apply higher levels of stringency to facility approvals if there are regional air quality issues or concerns. Setting an overly ambitious baseline standard that mandates high-cost emissions management in unstressed airsheds unnecessarily increases industry's operational costs. This is particularly concerning in regard to setting a NOx standard for cogeneration as the Golder report shows that emissions from cogeneration are unlikely to have a significant impact on overall air quality. We are very concerned that an overly stringent baseline standard for NOx emissions will significantly increase cost to industry while having a minimal impact on regional air quality and achievement of the 2020/2025 CAAQS.

As discussed in previous Electricity Framework Reviews, our industry is not supportive of adopting elements of policy from other jurisdictions (such as absolute emission thresholds of 200 T/yr) without considering the regulatory and policy context within which they are embedded. The absolute emission thresholds are difficult to justify as baseline standards as their thresholds cannot be linked to regional environmental circumstances. Alberta has a rigorous policy and regulatory system to address regional concerns and project-level impacts in a comprehensive and transparent manner. The application of absolute emission triggers sets a precedent that we believe erodes the efficacy of other existing, place-based provincial policy.

A more comprehensive review of provincial NOx emissions is necessary to determine the most cost effective opportunities for emission reduction and compliance with the CAAQS. The Golder report

[6] See footnote 1 above

illustrates that cogeneration cannot be a source of meaningful reduction of NOx emissions. As presented at Meeting 3 on September 5th, the oil and gas industry will make major reductions in NOx emissions and, through BLIERS, is making investment to achieve reductions of approximately 134 kT/yr. This change needs to be considered when discussing the future of Alberta's air quality.

Finally, we would like to acknowledge the compressed timeline in which the 2018 CASA Electricity Framework Review was completed and the associated constraints on the collection of technical information and robust stakeholder discussion. Specifically, we believe that there was insufficient information and discussion to make informed decisions on:

- The relationship between the proposed emissions limits and the achievement of the CAAQS.
- The potential for collateral environmental impacts associated with SCR including the transport, storage, handling, and disposal of ammonia as well as the potential odour caused by ammonia slippage at the stack.
- The technological feasibility of various stakeholder proposals under real world circumstances.
- The cumulative cost and environment impacts of installing SCR on units less than 100 MW versus units greater than 100 MW was not undertaken, or the associated constraints on the supply chain from increase ammonia use.

These concerns notwithstanding, we believe this proposal sets an appropriate province-wide baseline emission standard that balances environmental and economic interest. It is based on the adoption of next level technology to achieve emissions reductions, will deliver emissions reductions from the existing current standards and reflects a willingness to progress our position through the CASA process. If you have any questions or concerns regarding the above, please contact Rekha Nambiar at rnambiar@suncor.com, Natasha Rowden at Natasha.Rowden@megenergy.com with a cc to Don McCrimmon at don.mccrimmon@capp.ca.

Sincerely,

Sherry Sian

Sherry Sian
Manager, Environment, Health and Safety

Alberta Environment and Parks

Office of the Deputy Minister
11th Floor, South Petroleum Plaza
9915 - 108 Street
Edmonton, Alberta T5K 2G8
Telephone: 780-427-1799
www.alberta.ca

89733

JUL 5 2018

Andre Asselin, Executive Director
Clean Air Strategic Alliance
9915 - 108 Street, 1400
Edmonton AB T5K 2G8
a.asselin@awchome.ca

Dear Andre Asselin:

As Alberta moves forward with its commitment to phase out coal emissions, increase the capacity of renewable energy in the province by 2030, and move to a capacity market, many electricity generators have expressed the intent to build new natural gas-fired generation units, which will support this transition. Additionally, Alberta needs to continue to manage emissions in the provincial air zones to ensure Canadian Ambient Air Quality Standards (CAAQS) are achieved, and to allow for future growth and development.

As such, provincial nitrogen oxides (NO_X) emission standards for new continuously operating and intermittently operating natural gas-fired turbine plants are needed in order to enable generators to make business decisions on investment.

The Clean Air Strategic Alliance (CASA) has a long and successful history facilitating the development of an emissions management system for the electricity sector in Alberta. This process started in 2003 with the development of the *Emissions Management Framework for the Electricity Sector*, which continues to be implemented by government. Over the past 24 years, CASA has built its reputation on its ability to bring together diverse stakeholders to develop strategic air quality advice for the Province of Alberta. CASA is a neutral forum where stakeholders can come together, express their interests and develop innovative solutions to complex problems. I note with interest that CASA took on the task of developing a coal-to-gas NO_X emission standard last fall and was successful in recommending a consensus-based agreement on this standard.

I understand that CASA participants are interested in certainty around provincial NO_X emission standards for new natural gas-fired turbines that operate continuously and intermittently in an expedient manner. Government is also interested in certainty around this standard.

Government is supportive of the work on this standard that is outlined in the "Emissions Management Framework for the Alberta Electricity Sector: 2018 Five-Year Review" Project Charter that was recently approved by the CASA Board and the approach to discuss the standard as part of Phase 1 of the project.

I understand that discussions related to turbine emission standards have resulted in non-consensus recommendations during the preceding two five-year reviews. I would strongly urge the group to approach this discussion with an open, creative and collaborative attitude, and to strive for a consensus recommendation that balances environmental, economic and social outcomes.

This work is a high priority for both Environment and Parks and the Department of Energy. We are committed to working with CASA and all stakeholders to undertake this work and to an outcome that aligns with Alberta's vision for a healthy and clean province, where Albertans are leaders in environmental conservation and protection, and enjoy sustainable economic prosperity and a great quality of life.

I look forward to your response.

Sincerely,

for / Eric Denhoff
Deputy Minister
Alberta Environment and Parks and Alberta Climate Change Office

cc: Coleen Volk, Energy
Rick Blackwood, Environment and Parks
Ronda Goulden, Environment and Parks
Mike Fernandez, Climate Change Office
David James, Energy

REPORT

Air Emissions Analysis and Air Dispersion Modelling Study

in Support of CAPP's Impact Assessment of NO_X Emission Standards for Cogeneration

Submitted to:

Canadian Association of Petroleum Producers
2100, 350 - 7th Avenue S.W.
Calgary, AB T2P 3N9

Submitted by:

Golder Associates Ltd.
102, 2535 - 3rd Avenue S.E. Calgary, Alberta, T2A 7W5 Canada

+1 403 299 5600

18110920

November 26, 2018

Distribution List

1 Electronic Copy - Canadian Association of Petroleum Producers

1 Electronic Copy - Golder Associates Ltd.

Table of Contents

TABLES

FIGURES

APPENDICES

1.0 INTRODUCTION

Golder Associates Ltd. (Golder) was retained by the Canadian Association of Petroleum Producers (CAPP) to conduct an air emission analysis and air dispersion modelling study in support of CAPP's policy impact assessment of Alberta Environment and Park's (AEP) proposed nitrogen oxides (NO_X) emission standards for cogeneration plants. Cogeneration units considered for the study are those units that combine a gas-fired turbine with a heat recovery steam generator (HSRG) as a means of supplying electricity output and recoverable heat output. The dispersion modelling assessment evaluates three NO_X emission scenarios as defined by CAPP. The proposed cogeneration unit NO_X emission standards would only be applicable to new cogeneration units. The purpose of this assessment is to assess proposed NO_x emission standard scenarios and to evaluate a potential change in regionally predicted ground-level concentrations of nitrogen dioxide (NO_2). The current study includes NO_X emissions from point sources (e.g., stacks) at only those oil sands developments in operation, with the exception of planned cogeneration units.

This assessment evaluates the change in predicted ground-level NO_2 concentrations as they relate to their respective Alberta Ambient Air Quality Objectives (AAAQO) and Canadian Ambient Air Quality Standards (CAAQS) developed under the Air Quality Management System (AQMS).

2.0 COGENERATION UNIT NO_X EMISSIONS ANALYSIS

2.1 Air Dispersion Modelling Scenarios

Three separate air emission scenarios were modelled based on the request from CAPP. These three scenarios are described below.

Scenario 1 - Baseline Case: This scenario includes NO_X emissions from point sources within the Athabasca Oil Sands Region (AOSR) that are approved and currently in operation at the time of assessment. This scenario includes NO_X emissions from cogeneration units that are currently in operation, as approved in their respective Environmental Protection and Enhancement Act (EPEA) approvals.

Scenario 2 - CAPP Case: This scenario includes existing and approved point sources in addition to forecasted NO_X emissions with all planned cogeneration units installed with NO_X control equivalent to the CAPP Standard. The planned cogeneration units are those units that are approved but not in operation and those currently in regulatory application process.

Scenario 3 - ENGO Case: This scenario includes existing and approved point sources in addition to forecasted NO_X emissions with all planned cogeneration units installed with NO_X control equivalent to ENGO Standard. The planned cogeneration units are those units that are approved but not in operation and those currently in regulatory application process.

A summary of the emission source categories modelled in each of the scenarios is provided in Table 2-1. A more detailed description of CAPP and ENGO NO_X emission standards is provided in Section 2.3.

Table 2-1: NO_X Emission Source Categories Included in the Emission Scenarios

Emission Source Category	Scenario 1 (Baseline Case)	Scenario 2 (CAPP Case)	Scenario 3 (ENGO Case)
Cogen Sources			
Cogens in Operation	√	√	√
Approved Cogens not in Operation		√	√
Planned Cogens in Regulatory Application Process		√	√
Non-Cogen Oil Sands-related Sources			
Point Sources in Operation	√	√	√

2.2 Cogeneration Unit Inventory

A list of existing and planned cogeneration units in the AOSR was developed by Golder based on publicly available information, such as EPEA approvals, Environmental Impact Assessments, regulatory applications, as well as limited inputs provided by CAPP and a few individual operators (e.g., Suncor, Canadian Natural, MEG Energy, Cenovus Energy). Due to limited time to develop the cogeneration unit inventory, Golder was not able to confirm with the owner of each cogeneration unit whether the information is accurate. However, Golder is confident that the inventory is reasonably accurate for the purposes of this assessment.

Information gathered by Golder includes:

1) Owner/Operator of the Cogeneration Unit
2) Oil Sands Project the Cogeneration Unit Serves
3) Number of the Cogeneration Unit
4) Turbine Electricity Output: The turbine electricity output of a cogeneration unit is typically based on the nominal output. However, the approved NO_X emission rates for majority of the existing cogeneration units in the AOSR are derived based on the cogeneration units' maximum electricity output rather than nominal electricity output. Turbines operating in winter conditions when the ambient air temperature is low (e.g., -40°C as typically simulated for the extreme winter conditions) can produce more power than the nominal power output which is derived under standard ambient air temperature (e.g., 15°C). This is because turbine power output is dependent on mass flow of air through the compressor. As ambient temperature decreases and density of air increases, a higher mass of air can be sent through the compressor which increases the turbine power output. The turbine electricity outputs listed in the EPEA approvals were used for calculation purposes. Where turbine electricity outputs are not listed in EPEA approvals, the maximum electricity output ratings used for emissions estimations in publicly available application documents associated with specific oil sands projects were used.
5) HRSG Heat Output: Similar to turbine electricity output, HRSG heat outputs used to derived approved NO_X emission limits are assumed to be maximum output ratings. Where the HRSG heat outputs are not listed in EPEA approvals, the following methods are used to derive heat output ratings, in order of preference:
    a. Back-calculated using approved NO_X emission limit, known turbine electricity output, and known emissions estimation methodology for which the NO_X emission limit is based.
    b. If the size of cogeneration unit is similar other cogeneration units with known turbine electricity output, used the turbine electricity output to HRSG heat output ratio from the similarly sized cogeneration unit to determine the HRSG heat output.
    c. If the size of cogeneration unit is unique with no similar sized known cogeneration unit in the AOSR, used the average turbine electricity output to HRSG heat output ratio derived from all known cogeneration unit to determine the HRSG heat output.
6) Total Combined Energy Output: Turbine electricity output plus the HRSG heat output.
7) Approved NO_X Emissions: Obtained from publicly available EPEA approval documents.

It should be noted that typical NO_X emission standards for turbines, HRSG or cogeneration units are based on net rather gross power, heat or combined energy output. Information on the energy output on the cogeneration units found in the public domain almost never specifies whether the output value is gross or net output; therefore, all output values were assumed to be net output. This assumption can potentially result in marginal overestimation of the calculated NO_X emissions from the cogeneration units.

A list of the existing and planned cogeneration unit by operator for the AOSR is presented in Appendx A, Table A-1.

2.3 NO_X Emission Standards

This section describes the NO_X emission standards applied to Scenario 2 (CAPP Case) and Scenario 3 (ENGO Case). Nitrogen oxides emissions from cogeneration units are typically expressed in two ways, as a NO_X concentration in the exhaust gas expressed in parts per million by volume (ppmv) or as an emission intensity expressed in mass of NO_X per energy output such as grams per gigajoule (g/GJ) or kilograms per megawatt-hour (kg/MWh). Nitrogen oxides emission standards expressed in ppmv are typically used for compliance stack testing or monitoring and are based on the specific conditions of the exhaust gas (e.g., volumetric flow rate, ambient temperature, ambient pressure, moisture content and oxygen content). Since the exact conditions of the exhaust gas for each cogeneration unit are not known, the NO_X emission standards applied in Scenarios 2 and 3 are based on the standards expressed as an emission intensity.

Nitrogen oxide emission standard as an emission intensity can be applied by two methods as described below.

Method 1

$$NO_X = (Power\ Output \times A) + (Heat\ Output \times B)$$

Where;

NO_X = NO_X emission rate;

Power Output = Net power output (electricity and shaft power) of the turbine;

Heat Output = total useful thermal energy recovered from the cogeneration unit;

A = NO_X emission allowance applicable to power output; and

B = NO_X emission allowance applicable to heat recovery components.

Method 2

$$NO_X = (Combined\ Output \times C)$$

Where;

NO_X = NO_X emission rate;

Combined Output = Combination of the net power output (electricity and shaft power) and the total useful thermal energy recovered from the cogeneration unit;

C = NO_X emission allowance applicable to combined output.

A comparison of the proposed NO_X emission standards for cogeneration units, provided by CAPP, is provided in Table 2-2.

Table 2-2: Proposed NO_X Emission Standard Comparison

NO_X Emission Standard	Electricity Generating Power of Cogeneration Unit	"A" Factor ($g\ NO_X/GJ_{power\ output}$)	"B" Factor ($g\ NO_X/GJ_{heat\ output}$)	"C" Factor ($kg/MWh_{combined\ output}$)
CAPP	≤150 MW	85	34	N/A
	>150 MW	N/A	N/A	0.08 (equivalent to 9 ppmv)
ENGO	≤75 MW	85	34	N/A
	>75 to 100 MW	N/A	N/A	0.11 (equivalent to 13.3 ppmv)
	>100 MW	N/A	N/A	0.0375 (equivalent to 4.5 ppmv)

MW = g = gram; GJ = gigajoules; kg = kilogram; megawatt; MWh = megawatt-hour; N/A = not applicable.

2.4 NO_X Emissions Summary

A comparison of the total NO_X emissions modelled in each of the three scenarios is provided in Table 2-3.

Table 2-3: A Comparison of NO_X Emissions Modelled in the Scenarios

Category	NO_X Emissions (t/d)		
	Scenario 1 (Baseline Case)	Scenario 2 (CAPP Case)	Scenario 3 (ENGO Case)
Cogens	45.842	99.244	80.994
Non-Cogen Point Sources	144.636	144.636	144.636
Total	**190.478**	**243.880**	**225.630**

3.0 AIR DISPERSION MODELLING APPROACH

This section describes the air dispersion modelling approach. The modelling approach follows the recommendations in the Alberta Air Quality Model Guideline (AQMG, AEP 2013) unless specifically noted in this report.

3.1 Dispersion Model

The air dispersion modelling was completed using the CALPUFF model (Version 7). The modelling domain is approximately 290 kilometres (km) east-west and 417 km north south. The model's Group 2 Technical Option settings are outlined in Appendix B, Table B-1.

3.2 Meteorological Data

The CALPUFF model was run using a 3-dimensional 5-year (2002-2006) CALMET meteorological data set (Version 6.5) developed using AEP's MM5 data. The CALMET model requires the input of surface, upper air, and precipitation meteorological data. A hybrid approach that incorporated numerical weather prediction (NWP) model output and surface observation data was applied. CALMET meteorological data sets were generated using meteorological data from MM5 in combination with local meteorological observations at the air quality monitoring stations in the Wood Buffalo Environmental Association (WBEA) and the Lakeland Industry and Community Association (LICA) regions as listed in Appendix B, Table B-2.

The CALMET model settings are outlined in Appendix B, Table B-3. The same 5-year CALMET meteorological data set was also used in the recently submitted Canadian Natural Horizon North Pit Extension EIA (Canadian Natural 2018). Detailed information on the CALMET meteorological data can be found in 2018 Canadian Natural Horizon North Pit Extension EIA, Volume 3, Appendix 2B (2018 Canadian Natural).

3.3 Study Area

Based on the results of the dispersion modelling, the study area was selected to best represent the results in specific areas of interest. The study area is defined as a 186 km by 265 km area and includes all existing and approved large cogeneration units within the AOSR as shown in Figure 3-1.

3.4 Receptors

The modelling receptors were based on a Cartesian grid, concentrated over an approximate 224 km by 297 km area. The predicted ground-level concentrations at the gridded receptor locations are used in the generation of contour lines representing the red, orange and yellow CAAQS management levels for the 1-hour and annual averaging periods where applicable.

In addition to the gridded receptors, WBEA air monitoring stations (AMS) were included in the dispersion modelling. The WBEA AMS are listed below in Table 3-1. The WBEA AMS locations are presented graphically in Figure 3-1.

The receptor scheme is shown in Appendix B, Figure B-1.

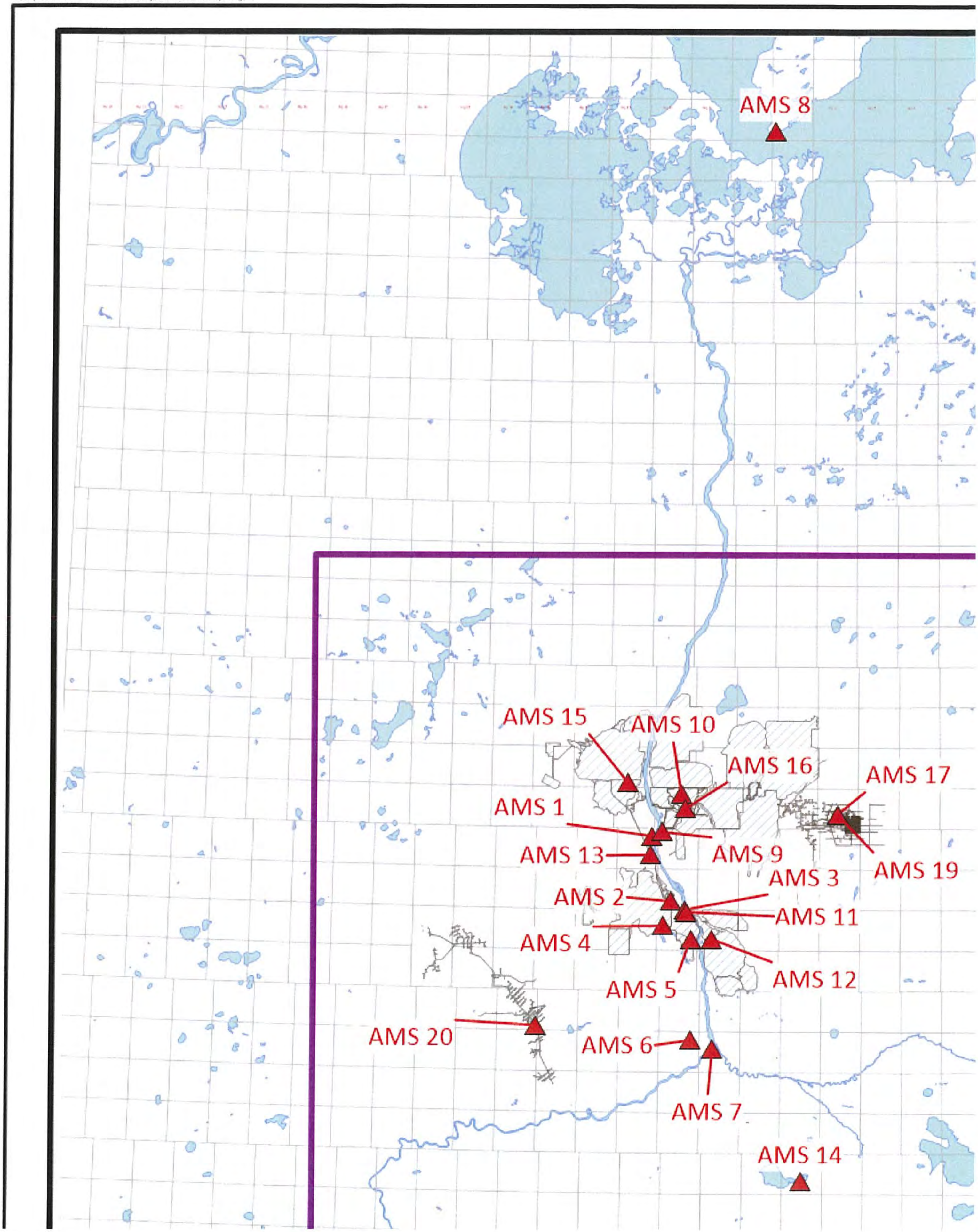

AMS 8
AMS 15
AMS 10
AMS 16
AMS 17
AMS 1
AMS 9
AMS 13
AMS 19
AMS 3
AMS 2
AMS 11
AMS 4
AMS 5
AMS 12
AMS 20
AMS 6
AMS 7
AMS 14

Table 3-1: Wood Buffalo Environmental Association Air Monitoring Stations

Station Name	WBEA AMS ID	Coordinates (NAD83 UTM Z12N)	
		Easting (m)	Northing (m)
Bertha Ganter - Fort McKay	AMS 1	461,292	6,338,657
Mildred Lake	AMS 2	465,795	6,323,069
Lower Camp B (Meteorology)	AMS 3	469,264	6,321,073
Buffalo Viewpoint	AMS 4	463,981	6,317,153
Mannix	AMS 5	470,697	6,313,920
Patricia McInnes	AMS 6	470,869	6,289,809
Athabasca Valley	AMS 7	476,127	6,287,698
Fort Chipewyan	AMS 8	489,780	6,507,597
Barge Landing	AMS 9	463,769	6,339,612
Albian Mine	AMS 10	468,312	6,348,777
Lower Camp (Air Quality)	AMS 11	469,598	6,320,483
Millennium Mine	AMS 12	475,641	6,314,037
Fort McKay South	AMS 13	461,119	6,334,165
Anzac	AMS 14	497,706	6,256,086
CNRL Horizon	AMS 15	455,437	6,351,437
CNUL Muskeg River	AMS 16	469,313	6,345,230
Wapasu	AMS 17	505,868	6,343,921
Stony Mountain	AMS 18	489,125	6,163,958
Firebag	AMS 19	506,034	6,343,808
Brion MacKay River	AMS 20	433,467	6,293,360
Conklin Community	AMS 21	495,036	6,165,163

NAD83 = North American Datum of 1983; UTM Z12N = Universal Transverse Mercator Zone12N; m = metres; AMS = Air Monitoring Station.

3.5 NO_X to NO_2 Conversion

Nitrogen Oxides are a by-product of fossil fuel combustion. When NO_X is emitted from a combustion source, it is in the form of nitric oxide (NO) and NO_2 with the majority of the NO_X being emitted as NO. It is assumed that NO_X from all combustion emission sources includes 90% NO and 10% NO_2 (BC MOE 2015). In the atmosphere, the highly unstable NO is typically converted to NO_2 over time.

In this assessment, the predicted NO_2 concentrations were derived from model-predicted NO_X concentrations using the Ozone Limiting Method (OLM). The OLM was selected because it is commonly used and accepted for NO_2 dispersion modelling assessments in the AOSR and is appropriate given the information available for dispersion modelling. The OLM assumes that the conversion of NO to NO_2 in the atmosphere is limited by the ambient ozone (O_3) concentration. If the ozone concentration is greater than 90% of the predicted NO_X concentration, the method assumes all NO_X is converted to NO_2. Otherwise, the NO_2 concentration in ppm is equal to the sum of the ozone and 10% of the predicted NO_X concentration, as shown in the following equation:

$$NO_2 = O_3 + 0.1 \times NO_X$$

Rural hourly ozone concentrations from Appendix E of the AQMG are used in the OLM calculations.

3.6 Background NO_2 Concentrations

Background concentrations are chosen to reflect concentrations from natural sources, nearby sources not included in the modelling and unidentified, possibly distant sources. These concentrations are to be added to model-predicted concentrations before comparison to applicable air quality standards per the AQMG. For this assessment, the WBEA stations were evaluated and the Fort Chipewyan station was chosen to be the most representative of background air quality conditions. The background values were derived from the 90th percentile hourly data from this station from 2016, per the guidance in the AQMG. The 1-hour and annual NO_2 values are presented in Table 3-2

Table 3-2: Background Concentrations for NO_2

Averaging Period	Background Concentration (µg/m³)
1-hour	4.5
Annual	0.9

µg/m³= micrograms per cubic meter.

3.7 Ambient Air Quality Criteria for NO_2

Two sets of criteria are applicable to the model predictions, the Alberta Ambient Air Quality Objectives and the Canadian Ambient Air Quality Standards, as described below.

3.7.1 Alberta Ambient Air Quality Objectives for NO_2

Alberta has developed air quality objectives under the Alberta Environmental Protection and Enhancement Act (EPEA) to protect air quality in Alberta. These objectives are in place for 1-hour and annual averaging periods for NO_2 and are applicable outside of developed areas, where public access is not restricted. The applicable Alberta Ambient Air Quality Objectives (AAAQOs) are presented in Table 3-3.

Table 3-3: Alberta Ambient Air Quality Objectives for NO_2

Compound	Averaging Period	Alberta Ambient Air Quality Objective (µg/m³)
NO_2	1-hour	300
	Annual	45

µg/m³= micrograms per cubic meter.

3.7.2 Canadian Ambient Air Quality Standards for NO_2

In 2012, the Canadian Council of Ministers of the Environment (CCME) finalized a framework to improve air quality management in Canada called the Air Quality Management System (AQMS). The AQMS is designed as:

- a comprehensive and collaborative approach by federal, provincial and territorial governments to reduce the emissions and ambient concentrations of various pollutants of concern; and
- a framework for collaborative action across Canada to further protect human health and the environment from harmful air pollutants through continuous improvement of air quality.

The driver of the AQMS is the development of Canadian Ambient Air Quality Standards (CAAQS) for the improvement of air quality across Canada.

Within the AQMS, provinces and territories are responsible for establishing air zones for the purposes of delineating air management jurisdictions. The Air Zone Management Framework (AZMF) provides a framework for achieving the CAAQS and implementing the national AQMS in Alberta (AEP 2015).

The AZMF uses four management levels which indicate actions to be taken based on the level an air zone is in. The levels are determined based on concentration thresholds. The AZMF Management Levels are as follows:

- Green Management Level – actions taken to keep clean areas clean
- Yellow Management Level – actions taken to prevent air quality deterioration
- Orange Management Level – actions taken to prevent CAAQS exceedance
- Red Management Level – actions taken to achieve CAAQS

Currently, 1-hour and annual CAAQS have been established for the year 2020 and 2025. The CAAQS values applicable in the year 2020 are considered for this assessment. A summary of the CAAQS management levels for NO_2 concentrations is provided in Table 3-4.

Table 3-4: 2020 Canadian Ambient Air Quality Standards Management Levels

Compound	Averaging Period	Management Level Concentrations (µg/m³)				Statistical Form
		Red	Orange	Yellow	Green	
NO_2	1-hour	>113 (>60 ppb)	>58 and ≤113 (>31 and ≤60 ppb)	>38 and ≤58 (>20 and ≤31 ppb)	≤38 (≤20 ppb)	The 3-year average of the annual 98th percentile of the daily maximum 1-hour average concentrations
	Annual	>32 (>17 ppb)	>13 and ≤32 (>7 and ≤17 ppb)	>3.8 and ≤13 (>2 and ≤7 ppb)	≤3.8 (≤2 ppb)	The average over a single calendar year of all 1-hour average concentrations

Reference: CCME 2017.

NO_2 = nitrogen dioxide; ppb = parts per billion; µg/m³ = microgram per cubic metre.

4.0 MODELLING PREDICTIONS

4.1 Ground-Level NO_2 Concentration Predictions

Each scenario was modelled separately, and the results are presented as maximum 1-hour and annual ground-level NO_2 concentrations. The predicted maximum 1-hour and annual NO_2 concentrations are shown graphically in Appendix C, Figures C-1 and C-2, respectively.

For Scenarios 1 to 3, all sources remain constant in the modelling except the altered cogeneration unit emissions, which allows for easy of comparison among these scenarios. The contour lines representing orange and yellow CAAQS management levels for Scenarios 1 to 3 are presented together graphically on a single contour plot for each averaging period (C-1 and C-2 for 1-hour and annual respectively). The red CAAQS level is not presented for Scenarios 1 to 3 as all predictions are below the threshold for the red CAAQS level in all scenarios. The green CAAQS level is represented by anything falling outside of the yellow CAAQS level.

The predicted maximum 1-hour and annual ground-level NO_2 concentrations at the WBEA AMS locations are presented in Tables 4-1 and 4-2 respectively, that allows for comparison among the predictions for each scenario. The most recent available continuous monitoring data is shown in Tables 4-1 and 4-2 for all stations that monitor NO_2 in the WBEA airshed. WBEA monitored concentrations are calculated based on the 3-year average of the 98th Percentile of daily maximum 1-hour values for the most recent available monitoring data for comparison to the 1-hour CAAQS (2015 to 2017) and the annual average of most recent year available monitoring data (2017) for comparison to the annual CAAQS. Annual averages may appear in Table 4-2 where there were no 1-hour CAAQS concentrations in Table 4-1, because at least one year of monitoring data was available at this location but there are not three years of data available.

CAAQS Management Level (µg/m³)	WBEA Monitored Concentration[(a)] (2015-2017) [µg/m³]	1-hour NO_2 Concentrations (Based on 3-year Average of 98th Percentile of Daily-Maximum)				
		Scenario 1	Scenario 2		Scenario 3	
		µg/m³	µg/m³	% Change	µg/m³	% Change
Red > 113, Orange > 58, Yellow > 38, Green ≤ 38	67.57	63.01	64.11	1.7%	63.68	1.1%
	—	96.14	96.26	0.1%	96.26	0.1%
	—	104.09	104.16	0.1%	104.13	0.0%
	—	73.60	74.51	1.2%	74.12	0.7%
	—	98.69	98.82	0.1%	98.77	0.1%
	69.21	51.12	52.24	2.2%	51.66	1.1%
	75.05	42.05	43.41	3.2%	42.84	1.9%
	28.86	18.15	20.42	12.5%	19.64	8.2%
	—	62.37	63.28	1.5%	63.10	1.2%
	—	82.45	82.62	0.2%	82.54	0.1%
	—	107.05	107.18	0.1%	107.12	0.1%
	—	77.26	77.65	0.5%	77.48	0.3%
	63.09	71.29	71.87	0.8%	71.64	0.5%
	39.85	35.83	37.08	3.5%	36.57	2.0%
	75.27	52.04	53.37	2.5%	52.72	1.3%
	83.39	68.84	68.97	0.2%	68.93	0.1%
	46.42	57.52	59.30	3.1%	58.41	1.5%
	17.33	26.78	27.87	4.0%	27.58	3.0%
	60.92	57.85	59.10	2.1%	58.33	0.8%
	—	56.61	59.13	4.5%	58.51	3.4%
	—	29.68	30.57	3.0%	30.29	2.1%

98th Percentile of daily maximum 1-hour values for the most recent available monitoring data (2015 to 2017).
there is insufficient data to calculate the statistical form specified for comparison to the CAAQS.

QS nt Level (^{3})	WBEA Monitored Concentration[a] (2017) [µg/m³]	Annual Average NO_2 Concentrations				
		Scenario 1	Scenario 2		Scenario 3	
		µg/m³	µg/m³	% Change	µg/m³	% Change
	13.51	4.33	4.67	8.0%	4.56	5.4%
	—	6.71	7.05	5.1%	6.94	3.5%
	—	7.84	8.16	4.2%	8.06	2.8%
	11.67	4.89	5.25	7.2%	5.14	5.0%
	—	7.95	8.42	5.9%	8.25	3.7%
	9.10	3.91	4.33	10.6%	4.19	7.1%
	13.86	3.12	3.47	11.3%	3.35	7.5%
	1.50	1.62	1.75	8.3%	1.71	5.5%
	—	4.43	4.76	7.4%	4.65	5.0%
32,	—	5.93	6.27	5.7%	6.16	3.9%
, Yellow >	—	8.14	8.47	4.0%	8.36	2.7%
n ≤ 3.8	—	4.44	4.84	8.8%	4.70	5.8%
	12.37	4.54	4.89	7.7%	4.78	5.3%
	3.80	3.27	3.74	14.4%	3.58	9.5%
	9.82	3.73	4.03	8.0%	3.93	5.4%
	18.81	6.25	6.60	5.7%	6.49	3.8%
	5.09	5.51	6.42	16.5%	6.10	10.7%
	2.19	2.20	2.49	13.3%	2.39	8.7%
	5.85	5.49	6.41	16.6%	6.08	10.7%
	3.29	4.23	4.63	9.6%	4.51	6.7%
	4.63	2.29	2.54	11.0%	2.45	7.3%

st recent year available monitoring data (2017). Annual averages may appear where there were no 1-hour CAAQS concentrations in Table 4-1, because at e years of data available.

there is insufficient data to calculate the statistical form specified for comparison to the CAAQS.

5.0 CLOSURE

We trust this information meets your current needs. Please contact the undersigned at your convenience with any questions or concerns.

Golder Associates Ltd.

Mackenzie Cator, EIT
Air Quality Specialist

Dennis Chang, P.Eng.
Senior Air Quality Consultant

Chris Madland, B.Sc.
Associate, Senior Air Quality Scientist

MC/DC/tt/al/jlb

\\golder.gds\calgary\complexdata\capp\18110920_capp_cogen_nox_oct2018\report\18110920_capp_cogen_nox_emissions_report_26nov2018_final.docx

6.0 REFERENCES

AEP (Alberta Environment and Parks). 2013. Air Quality Model Guideline. Prepared by the Air Policy Section of ESRD. Available at: http://aep.alberta.ca/air/air-quality-modelling/documents/AirQualityModelGuideline-Oct1-2013.pdf.

AEP. 2015. Alberta Implementation of the Air Zone Management Framework for Fine Particulate Matter and Ozone. ISBN 978-1-4601-2058-3. Available at http://aep.alberta.ca/air/management-frameworks/canadian-ambient-air-quality-standards/documents/ImplementationFramework-PM-Ozone-Sep2015.pdf.

B.C. MOE (British Columbia Ministry of Environment). British Columbia Air Quality Dispersion Modelling Guideline. Available at: https://www2.gov.bc.ca/gov/content/environment/air-land-water/air/air-quality-management/modelling.

Canadian Natural (Canadian Natural Resources Ltd.). 2018. Environmental Impact Assessment for Canadian Natural Horizon North Pit Extension, Volume 3. Available at ftp://ftp.gov.ab.ca/env/fs/EIA/.

APPENDIX A

Detailed Emissions Information

mber of Cogen Units	Regulatory and Operation Status	Modelled NO_x Emissions (t/d)		
		Scenario 1 (Baseline Case)	Scenario 2 (CAPP Case)	Scenario 3 (ENGO Case)
2	Approved and In Operation	4.253	4.253	4.253
2	Approved and In Operation	4.217	4.217	4.217
1	Approved but Not In Operation	-	1.030	0.483
2	Approved but Not In Operation	-	1.411	1.411
2	Approved and In Operation	2.016	2.016	2.016
2	Approved but Not In Operation	-	1.544	1.544
2	Approved and In Operation	1.834	1.834	1.834
2	Approved and In Operation	4.872	4.872	4.872
3	Approved but Not In Operation	-	5.342	3.630
1	Approved and In Operation	0.317	0.317	0.317
1	Approved but Not In Operation	-	0.210	0.210
6	Application in Progress	-	8.466	5.336
6	Approved and In Operation and Approved and Not in Operation	1.519	8.382	5.712
2	Application in Progress	-	2.677	1.653
3	Application in Progress	-	4.016	2.480
1	Application in Progress	-	0.828	0.408
2	Approved but Not In Operation	-	3.300	2.200
1	Approved but Not In Operation	-	1.650	1.100
2	Application in Progress	-	0.206	0.206
3	Approved but Not In Operation	-	0.234	0.234
2	Approved and In Operation	4.512	4.512	4.512
2	Application in Progress	-	2.259	1.059
5	Approved and In Operation	9.216	9.216	9.216
2	Approved and In Operation	3.682	3.682	3.682
2	Application in Progress	-	2.444	1.519
2	Application in Progress	-	2.451	1.522
1	Application in Progress	-	1.226	0.761
1	Application in Progress	-	0.130	0.130
2	Approved but Not In Operation	-	0.260	0.260
3	Approved and In Operation	0.425	0.425	0.425
2	Approved but Not In Operation	-	0.159	0.159
3	Approved and In Operation and Approved and Not In Operation	1.363	1.783	1.783
2	Approved and In Operation	4.018	4.018	4.018

roject Type	Point Sources In Operation NOx (t/d)	Note
ne & Upgrader	35.921	All sources in operation, no Voyageur South
Mine	4.454	Phase 1 and 2 only
ne & Upgrader	37.863	All sources in operation
Mine	1.032	All sources in operation
Mine	1.898	All sources in operation
ne & Upgrader	7.162	All sources in operation
In-Situ	5.974	Stage 1-4 only
In-Situ	0.204	All sources in operation
In-Situ	0.009	All sources in operation
In-situ	1.715	Kirby south, Phase 1, only 4 OTSGs
Mine	0.054	Only 1 OTSG in operation
In-Situ	0.670	All sources in operation, no expansion
Mine	1.949	All sources except solvent feed heaters
In-Situ	0.499	All sources in operation
itu & Upgrader	2.341	No upgrader sources, only steam gen & glycol heaters in operation
In-Situ	2.170	All sources in operation
In-Situ	2.170	All sources in operation
In-Situ	2.170	All sources in operation
In-Situ	0.115	All sources in operation
In-Situ	1.106	All sources in operation
In-Situ	5.162	19 of 22 approved steam gens in operation
In-Situ	0.580	All sources in operation
In-Situ	1.249	Only 4 OTSG currently constructed
In-Situ	6.165	Sources up to & including Phase F in operation
In-Situ	10.142	Sources up to & including Phase G in operation
In-Situ	2.280	Phase 1a and 1b only (10 steam gens)
In-Situ	1.516	All sources in operation
In-Situ	0.187	All sources in operation
In-Situ	0.407	All sources in operation
In-Situ	1.192	All sources in operation
In-Situ	0.453	All sources in operation, no expansion
In-situ	0.520	All sources in operation
In-Situ	1.319	Only 4 steam gens
In-Situ	0.227	All sources in operation
In-Situ	0.888	All sources in operation

APPENDIX B

CALPUFF and CALMET Modelling Options

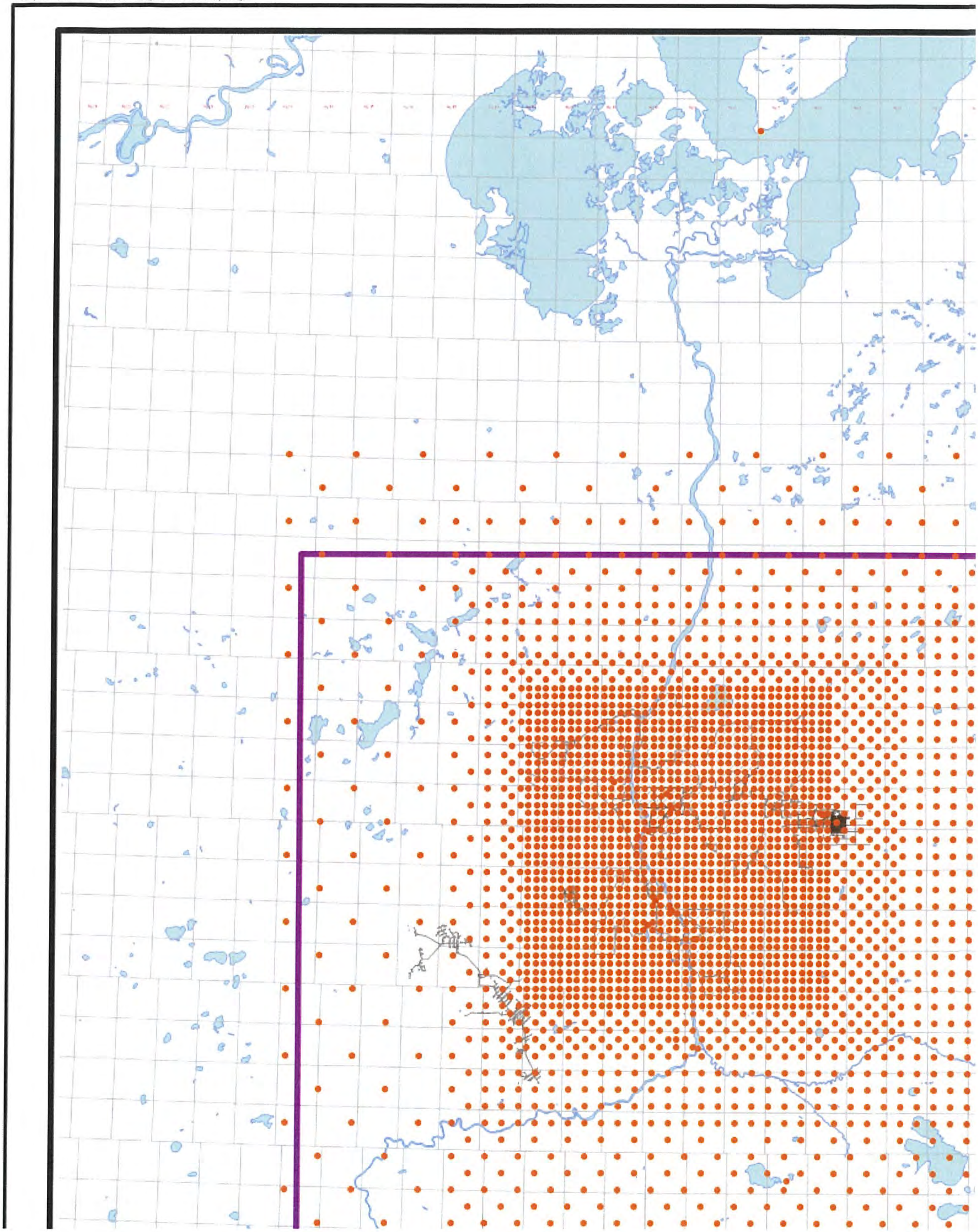


Table B-1: CALPUFF Model Group 2 Technical Options

Parameter	CALPUFF Default Value /AEP Recommended Value	Value Selected for This Study	Description
MGAUSS	1	1	Gaussian distribution used in near field
MCTADJ	3	3	partial plume path terrain adjustment
MCTSG	0	0	subgrid-scale complex terrain not modelled
MSLUG	0	0	near-field puffs not modelled as elongated
MTRANS	1	1	transitional plume rise modelled
MTIP	1	1	stack tip downwash used
MRISE	1	1	Briggs plume rise used
MTIP_FL	0	0	stack tip downwash for flare sources
MRISE_FL	2	2	plume rise module for flare sources
MBDW	2	2	Prime algorithm for building downwash was selected; however, no building downwash simulated.
MSHEAR	0	0	vertical wind shear not modelled
MSPLIT	0	0	puffs are not split
MCHEM	0	0	No chemical transformation modelled
MAQCHEM	0	0	aqueous phase transformation rates not modelled
MLWC	1	1	liquid Water Content flag (MLWC). (Used only if MAQCHEM = 1)
MWET	1	1	wet removal modelled
MDRY	1	1	dry deposition modelled
MTILT	0	0	Gravitational settling not modelled
MDISP	2	2	dispersion coefficients from internally calculated sigma v, sigma w using micrometeorological variables (u*, w*, L, etc.), , as specified in Appendix D of AQMG.
MTURBVW	3	3	use both sigma-(v/theta) and sigma-w from PROFILE.DAT to compute sigma-y and sigma-z (valid for METFM = 1,2,3,4,5)
MDISP2	3	3	PG dispersion coefficients for RURAL areas (computed using the ISCST multi-segment approximation) and MP coefficients in urban areas
MTAULY	0	0	Method used for Lagrangian timescale for Sigma-y (used only if MDISP=1,2 or MDISP2=1,2). Draxler default 617.284 (s).
MTAUADV	0	0	Method used for Advective-Decay timescale for Turbulence (used only if MDISP=2 or MDISP2=2). 0 = No turbulence advection.
MCTURB	1	1	Method used to compute turbulence sigma-v & sigma-w using micrometeorological variables (Used only if MDISP = 2 or MDISP2 = 2). Standard CALPUFF subroutines.
MROUGH	0	0	PG sigma-y and sigma-z not adjusted for roughness
MPARTL	1	1	partial plume penetration of elevated inversion
MPARTLBA	1	1	Partial plume penetration of elevated inversion modelled for buoyant area sources
MTINV	0	0	strength of temperature inversion not computed from measured/default gradients
MPDF	1	1	PDF used for dispersion under convective conditions, as specified in Appendix D of AQMG.
MSGTIBL	0	0	sub-grid TIBL module not used for shoreline
MBCON	0	0	boundary conditions not modelled
MSOURCE	0	0	Individual source contributions are not saved
MFOG	0	0	do not configure for FOG Model output
MREG	0	0	do not test options specified to see if they conform to regulatory values, as specified in Appendix D of AQMG.

Table B-2: Surface Meteorological Station Parameters

Station Name	Station ID	X Coordinate (km)[(a)]	Y Coordinate (km)[(a)]	Time Zone	Anemometer Height
Cold Lake	71120	547.587	6030.129	7	10
Fort Chipewyan (AMS 8)	71933	493.251	6514.076	7	10
Fort McMurray (AMS 6)	71932	486.715	6278.448	7	10
Mildred Lake (AMS 2)	71255	466.619	6321.230	7	10
Albian Mine (AMS 10)	99910	468.350	6349.048	7	10
Barge Landing (AMS 9)	99909	463.747	6339.809	7	10
Buffalo Viewpoint (AMS 4)	99904	464.000	6317.177	7	10
Fort McKay (AMS 1)	99901	461.287	6338.662	7	10
Lower Camp (AMS 11)	99903	469.597	6320.496	7	10
Mannix (AMS 5)	99905	470.695	6314.019	7	10
Millennium (AMS 12)	99912	475.640	6314.032	7	10

[(a)] Coordinates are in Universal Transverse Mercator (UTM) coordinates, Zone 12N.

Table B-3: CALMET Model Input Options

Input Group	Parameter	Default	Project	Description
Group 1 – General Run Control Parameters	IBYR	-	2002	starting year
	IBMO	-	1	starting month
	IBDY	-	1	starting day
	IBHR	-	0	starting hour
	IBSEC	-	0	starting second
	IEYR	-	2007	ending year
	IEMO	-	1	ending month
	IEDY	-	1	ending day
	IEHR	-	0	ending hour
	IESEC	-	0	ending second
	ABTZ	-	UTC-0700	UTC time zone (Mountain Standard Time)
	NSECDT	3600	3600	length of modelling time step (seconds)
	IRTYPE	1	1	run type – computes wind fields and micrometeorological variables
	LCALGRD	T	T	do not compute special data fields required by CALGRID
	ITEST	2	2	continues with execution of computational phase after setup
	MREG	-	0	no checks for conformance with US E.P.A. guidance

Table B-3: CALMET Model Input Options

Input Group	Parameter	Default	Project	Description
Group 2 – Map Projection and Grid Control Parameters	PMAP	UTM	UTM	map projection = Universal Transverse Mercator
	FEAST	0	-	false easting at the projection origin - not used when PMAP = UTM
	FNORTH	0	-	false northing at the projection origin - not used when PMAP = UTM
	IUTMZN	-	12	UTM zone
	UTMHEM	N	N	northern hemisphere projection
	RLAT0	-	40N	latitude of projection origin – not used when PMAP = UTM
	RLON0	-	90W	longitude of projection origin – not used when PMAP = UTM
	XLAT1	-	30N	matching parallel(s) of latitude for projection – not used when PMAP = UTM
	XLAT2	-	60N	matching parallel(s) of latitude for projection – not used when PMAP = UTM
	DATUM	WGS-84	NAR-C	datum region for output coordinates = NAR-C North American 1983 GRS 80 Spheroid
	NX	-	98	number of X grid cells
	NY	-	141	number of Y grid cells
	DGRIDKM	-	4.0	grid spacing (km)
	XORIGKM	-	304.177	X coordinate of southwest corner of domain (km)
	YORIGKM	-	5981.814	Y coordinate of southwest corner of domain (km)
	NZ	-	12	number of vertical layers
	ZFACE	-	0.,20.,40.,80.,120.,280.,520.,880., 1320.,1820.,2380.,3000.,4000	cell face heights in vertical grid (m)
Group 3 – Output Options	LSAVE	T	T	save meteorological fields in an unformatted output file
	IFORMO	1	1	CALPUFF/CALGRID type of unformatted output file
	LPRINT	F	F	do not print meteorological fields
	IPRINF	1	1	print interval (hours)
	IUVOUT	NZ*0	NZ*0	layers of U, V wind component to print (0=no, 1=yes)
	IWOUT	NZ*0	NZ*0	levels of W wind component to print (0=no, 1=yes)
	ITOUT	NZ*0	NZ*0	I (0=no, 1=yes)
	STABILITY	0	0	do not print PGT stability class
	USTAR	0	0	do not print friction velocity
	MONIN	0	0	do not print Monin-Obukhov length
	MIXHT	0	0	do not print mixing height
	WSTAR	0	0	do not print convective velocity scale
	PRECIP	0	0	do not print precipitation rate
	SENSHEAT	0	0	do not print sensible heat flux
	CONVZI	0	0	do not print convective mixing height
	LDB	F	F	do not print input meteorological data and internal variables
	NN1	1	1	first time step for which debug data are printed
	NN2	1	1	last time step for which debug data are printed
	LDBCST	F	F	do not print distance to land internal variables

CHEMISTRY INDUSTRY ASSOCIATION OF CANADA

Responsible Care® Our commitment to sustainability.

CASA Electricity Framework Review 2018 CIAC Statement on its Non-Consensus Position

The Chemistry Industry Association of Canada (CIAC) is grateful for the opportunity to participate meaningfully in the current process of defining new NO_x emission standards for gas-fired electricity generation in Alberta. The opportunity to engage in passionate discussions with interested stakeholders at the Clean Air Strategic Alliance (CASA) table created an appreciation for stakeholder perspectives and provided useful insight. Unfortunately, despite concerted efforts, stakeholders failed to agree upon an optimal power rating threshold for non-peaking new gas turbines (for post-combustion NO_x reduction technology). Consequently, industry and environmental non-governmental organizations (ENGOs) were not able to achieve consensus through this CASA-led process.

The CIAC is committed to preserving good air quality in Alberta and shares the Government of Alberta's goal of reducing Provincial NO_x emissions. For emissions management, the CIAC encourages a development approach rooted in the application of pragmatic standards and policies that work together instead of monolithic approaches. This is the CIAC's rationale for its non-consensus position. The CIAC requests that the Government of Alberta consider this position in the context of the Electricity Framework Review (EFR) working group's assessment of NO_x emissions standards for new gas turbine electricity generation units, which seeks to employ the Best Available Technology Economically Achievable (BATEA) and improve Alberta's ambient air quality.

Responsible Care® created in Canada in 1985 is the global chemical industry's unique performance initiative to improve health, environmental performance, enhance security, and to communicate with our stakeholders. This voluntary program has been implemented by 58 chemical associations in more than 60 countries around the globe.

Under Responsible Care, CIAC member-companies are expected to report all substance releases. Since reporting began in 1992, CIAC members have reduced their overall emissions by 228,500 tonnes (88 per cent). To achieve this, members have:

- Reduced discharges to water by 99 per cent;
- Reduced emissions of toxins targeted by the Canadian Environmental Protection Act by 90 per cent;
- Reduced emissions of air pollutants such as nitrogen oxides by 64 per cent and sulphur dioxide by 87 per cent;
- Reduced the global-warming potential of their operations by 69 per cent; and
- Reduced the production of hazardous waste for disposal by 64 per cent over 1995 levels.

CIAC member companies are significant energy consumers that produce large volumes of basic and intermediate organic chemicals and plastics. The petrochemical manufacturing sector imports sizable amounts of energy to supply power for required plant processes. Rising energy prices and compliance costs directly impact predictable earnings and global competitiveness, and motivate affected stakeholders to find cost-effective investments in energy efficient technologies. Energy efficient technologies (i.e., cogeneration that simultaneously produces electricity and useful heat from a single fuel consuming process) are ideal solutions for petrochemical manufacturing. Cogeneration is an attractive opportunity for the CIAC's value-added sector because it reduces emissions and operating costs. Recent Government of Alberta industry energy efficiency audits recognize cogeneration as the biggest operation efficiency opportunity for large industrial facilities.

The EFR work group agrees that standards for new gas turbines should reflect dry low NO_x (DLN). Industry acknowledges that selective catalytic reduction (SCR) is an appropriate post-combustion technology when considering:

- Environmental benefits;

- Availability of equipment emissions performance;
- Gas turbine operating characteristics;
- Service provided by gas turbine installations; and,
- The cost and value of incremental emissions reductions over current standards.

The CIAC endorses the views of the Canadian Association of Petroleum Producers (CAPP) and the Industry Proposal B (see Table 1). Furthermore, the CIAC supports post-combustion technology for new natural gas turbine unit sizes greater than 100 MW to be consistent with advanced control technology, such as SCR technology. Table 1 provides the Industry Proposal B for the *Non-Peaking NO_x Standard*. To credit the benefits of cogeneration systems, NO_x performance standards for these systems must include a standard for each turbine and heat recovery steam generator (HRSG) component. This ensures equitable treatment for power and heat generation, regardless of end use. Finally, the CIAC (like CAPP) does not support the application of alternate performance because it creates:

- An aspirational limit that is unachievable without technological advancement; and,
- Inconsistently in the application with other sectors.

Table 1: Industry Proposal B – Non-Peaking Standard Formula Based on Designed Emissions

New Natural Gas Turbine/HRSG			
Power Rating[1,2] (MW) Per Gas Turbine Only	**Reference NO_x Concentration Limit (ppm)[3] (Gas Turbine only)**	**Non-Peaking Electricity Allowance ("A") (kg/MWh net[2])**	**Heat Production Allowance ("B") (kg/GJ net[4])**
Greater than 100	7-9	0.10	0.020
40 to 100	13-15	0.20	0.034
Less than 40	25	0.40	0.034

Notes:
1. Normal maximum net continuous rating at independent system operator (ISO) conditions as provided by the manufacturer.
2. Power rating for gas turbine plus an associated combined cycle steam turbine.
3. All concentrations expressed in dry volume at 15% oxygen and ISO conditions.
4. All thermal efficiencies expressed as a lower heating value (LHV).

The formula shown next calculates emissions targets for various gas turbines by calculating allowable mass of NO_x per unit of useful electrical and thermal energy output.

Formula:
NO_x (kg/h) = [Net Electricity Generation (MWh net) x A] + [Heat Output (GJ/h) x B]

As with other industry perspective documents, the CIAC would like to present sector-specific rationale for CASA's consideration.

The CIAC understands that NO_x emission reductions and BATEA are inextricably linked by its effort to improve the air quality through the adoption of BATEA. Broadly, within Alberta Environment and Parks (AEP), air emissions management strategies include stationary sources and other sources, such as transportation (non-point) and municipalities. CIAC members like CAPP are uniquely positioned to reduce NO_x emissions from a broad range of combustion sources under several Federal regulatory and regional management initiatives. Examples of regulations that enforce NO_x reductions are:

- The *Federal Multi-Sector Air Pollutant Regulation (Boiler, Heater and Reciprocating Engines)*; and,

- *Guidelines for the Reduction of Nitrogen Oxide Emissions from Natural Gas-fuelled Stationary Combustion Gas Turbines (Nov 2017)*.

CAPP undertook a modelling exercise to evaluate potential NO_x emissions reductions from a new cogeneration development in Alberta to facilitate an evidence-based discussion (refer to Appendix 2 of *CAPP Position*). Under a fully-developed scenario (approved and announced), high-level model results indicate minimal changes in the predicted ground level air quality for NO_2 concentrations between the CAPP-Industry (greater than 100 MW threshold) and ENGO (greater than 70 MW threshold) proposals. However, the difference in the capital expenditures and operating expenditure for SCR technology installation, under a 70 MW scenario versus a 100 MW scenario, was quite substantial. As illustrated in the *CAPP Position*, the industry proposal B (see Table 1):

- Delivers emission reductions;
- Does not disincentivize cogeneration;
- Promotes a shift towards new technology; and,
- Has a significant and measurable benefit because it delivers a 20 to 60% reduction in emissions from existing applicable Federal and Provincial regulations and standards.

SCR use has unintended consequences that need recognition and require balancing when considering options for post-combustion emission reductions. First, the use of ammonia introduces transportation, storage and handling requirements, and necessary design Process safety factors. Second, SCR systems typically experience slippage ammonia emissions, a waste catalyst and replacement factors to maintain the SCR – all of which must be considered. Third, in certain conditions, unwanted and deleterious side reactions of sulphur dioxide (SO_2) oxidation (SO_3) may occur. The formation of SO_3 can damage downstream equipment – such as heat recovery steam generator (HRSG) cooler coils – due to corrosion, plugging or both, when combined with excessive ammonia slip. Lastly, poor system performance necessitates increased frequency of catalyst bed change outs because of the highly porous nature of a catalyst structure. Operational knowledge will be better understood and managed over time, and with experience. Similar to CAPP, CIAC encourages AEP to consider and evaluate the applications of SCR across a larger range of unit sizes before enforcing SCR Province-wide.

Like other CASA industry stakeholders, the CIAC does not support the concept of an absolute emissions threshold from other jurisdictions that may not be clearly understood or aligned with Alberta's overall policy direction. Alberta already has effective regional management plans that address regional concerns. These management response processes are evidence-based and comprehensively assess and address areas of concern. As stated by other stakeholders, embedding absolute emission triggers sets a precedent that undermines policy-making decisions of others.

The CIAC recognizes the Government of Alberta's desire to establish NO_x emissions standards for new gas turbine electricity generation and encourages it to consider a durable policy that reflects good emissions performance, respects the competitive market, and levels the playing field within energy industry sectors. The CIAC continues to be available for discussion, and resolute and committed to assisting the Government of Alberta reach its goal of establishing a durable NO_x Emissions Standard for New Natural Gas-Fired Electricity Generating Units.

TransCanada
450 – 1st Street SW, Calgary, Alberta, Canada T2P 5H1
Tel: 403.920.2819 Fax: 403. 920.2464
wendell_klassen@transcanada.com

December 6th, 2018

Katie Duffett
Project Manager
Clean Air Strategic Alliance
#1400, 9915 – 108th Street
Edmonton, AB, T5K2G8

Via: email: Katie Duffett <kduffett@awc-casa.ca>

Re: CASA Electricity Framework Review 2018, TransCanada's views

Dear Ms. Duffett,

Please allow me to begin this letter by expressing my appreciation for all the effort the CASA team has put into facilitating the 2018 Electricity Framework Review. TransCanada is a major North American energy infrastructure company with over $90 billion of total assets – primarily pipelines and power generation facilities – in Canada, the United States and Mexico. Our Energy business owns or has interests in 11 power generation facilities with a total capacity of over 6,600 megawatts.

TransCanada Energy welcomes the opportunity to submit this letter supporting the Industry Proposal for New Natural Gas Turbine NOx Standards (Proposal B) that was presented during the CASA process. We believe that Proposal B represents a balanced approach that demonstrates continuous and substantive improvement compared to previous proposals, achieves significant emissions reductions for natural gas generation and allows flexibility to adapt to future challenges.

Proposal B was developed based on Best Available Technology Economically Achievable (BATEA). During the 2018 Electricity Framework Review Phase 1 there was agreement among the review team members that BATEA for gas turbines should be based upon Dry Low Emissions (DLE) technology moving to Selective Catalytic Reduction (SCR) technology for larger gas turbines. When deciding the threshold for such stringency in NOx emissions performance, certain considerations need to be carefully balanced such as: environmental benefits, equipment availability, gas turbine operating characteristics, overall system needs due to intermittent generation, and a cost-benefit analysis. Equally important is to maintain an adequate perspective over the natural gas generation sector. While the Electricity sector made up 11% of provincial NOx emissions in 2016 (71 kT), natural gas generation represents only **0.7% of provincial NOx emissions**. Therefore, the measures contemplated to address the Natural Gas fired electricity NOx emissions must be proportional with their contribution to the overall provincial emissions as with the role Natural Gas generation will play in enabling more renewable, intermittent generation.

[Type here]

Therefore, TransCanada Energy is supporting Proposal B as it represents a significant reduction of allowable emissions from current provincial and federal emissions standards for gas turbines and aligns with the continuous improvement aspect of the Electricity Management Framework and allows for flexibility in adapting to future system needs.

Sincerely,

Wendell Klassen

Director, Market Services and Compliance
TransCanada Energy

Draft Gas Turbine Standards Perspective – TransCanada, TransAlta, and ATCO – December 6, 2018

The 2018 CASA Electricity Framework Review (EFR) discussions have had many areas of agreement and some different opinions on what represents the appropriate NOx emissions standards for gas turbine electricity generation. TransCanada, TransAlta and ATCO ("The Generators") share a similar perspective on the appropriate standards for new gas turbines generators and support Proposal B. The Generators represent a significant amount of electricity generation in Alberta and bring the combined experience as developers and operators of coal, coal to gas conversions, natural gas reciprocating, simple cycle gas turbine (both peaking and non-peaking operation), combined cycle gas turbine and cogeneration generating technologies.

Proposal B standards are based on Best Available Technology Economically Achievable (BATEA). Although the standard should not prescribe technology, there was agreement among the Electricity Framework Review team members that BATEA for gas turbines should be based upon Dry Low Emissions (DLE) technology moving to Selective Catalytic Reduction (SCR) technology for larger gas turbines. The Generators carefully considered and balanced environmental benefits (and co-benefits), currently available equipment emissions performance, gas turbine operating characteristics, service provided by gas turbine installations, and the value / cost (including cost to electricity consumers) of the incremental emissions reduction over current standards when assessing the proposals. Proposal B represents a significant reduction of allowable emissions from current provincial and federal emissions standards for gas turbines and supports the continuous improvement aspect of the Electricity Management Framework. There is a critical need to develop a standard that has flexibility to allow the best outcome as we phase out coal generation, increase the renewables portion of our electricity grid and implement a new capacity market. Recognizing that gas generation will play a very important role in making this vision a reality, Proposal B optimizes capital resources and allows innovative choices for the best overall environmental outcomes and reliable low-cost energy solutions. The CASA recommendation for coal to gas conversion standards is a great example of how policy direction can think outside of the box to offer flexibility but still seek the best overall outcome.

Electricity Generation in Alberta

Emissions from electricity generation in Alberta have reduced significantly in the past decade and will continue to decline in the future. The Electricity sector made up 11% of provincial NOx emissions in 2016 (71 kT[1]). While providing 43%[2] of actual electricity generation in Alberta, natural gas generation including behind-the-fence generation, has emitted 4.27 kT NOx[3] (0.7% of total NOx emissions) demonstrating that gas turbines are a low emitting form of electricity generation. Gas generation is expected to play an

[1] http://www.environment.alberta.ca/apps/etr/Documents.aspx
[2] http://www.auc.ab.ca/Pages/annual-electricity-data.aspx
[3] Results from National Pollutant Release Inventory database

important role in the years to come as it provides clean, flexible low-cost electricity and enables the transition to low emitting and renewable generation in the future.

Gas Turbine Emissions Standard Design

Emissions standards need to be flexible to realize the full environmental benefit that gas turbines can provide to the Alberta Interconnected Electrical System. Gas turbine peaking units can react quickly to electricity demand, augmenting base-loaded generation and support dispatch of non-emitting intermittent generation. The quick response and ramping of peaking units requires some flexibility in emissions standards to recognize the overall environmental benefits that they can provide. Proposal B sets NOx standards specific to peaking units to recognize this service.

Cogeneration gas turbine units provide high overall efficiency by utilizing turbine exhaust heat (that would otherwise be wasted) and may include supplemental duct firing to increase steam production for industrial processes. Emissions standards must recognize the value of the heat product and allocate appropriate emissions to both the electricity and heat products. The Proposal B standards for non-peaking units recognizes the two products (electricity and heat) with appropriate emissions factors representing BATEA, in determining the overall mass emission standard for the cogeneration unit.

Emissions standards for gas turbines must respect the principle of Fair Efficient Open Competition (FEOC) as required by the Alberta electricity market (capacity or energy). Standards for gas turbines should be fair, consistently applied and not create an unnecessary advantage for any market participant. Proposal B uses three generating unit size categories to allow a smooth transition between categories, consistently applies to all electricity generators to ensure electricity market fairness and recognizes the performance requirements of the various generating unit size ranges.

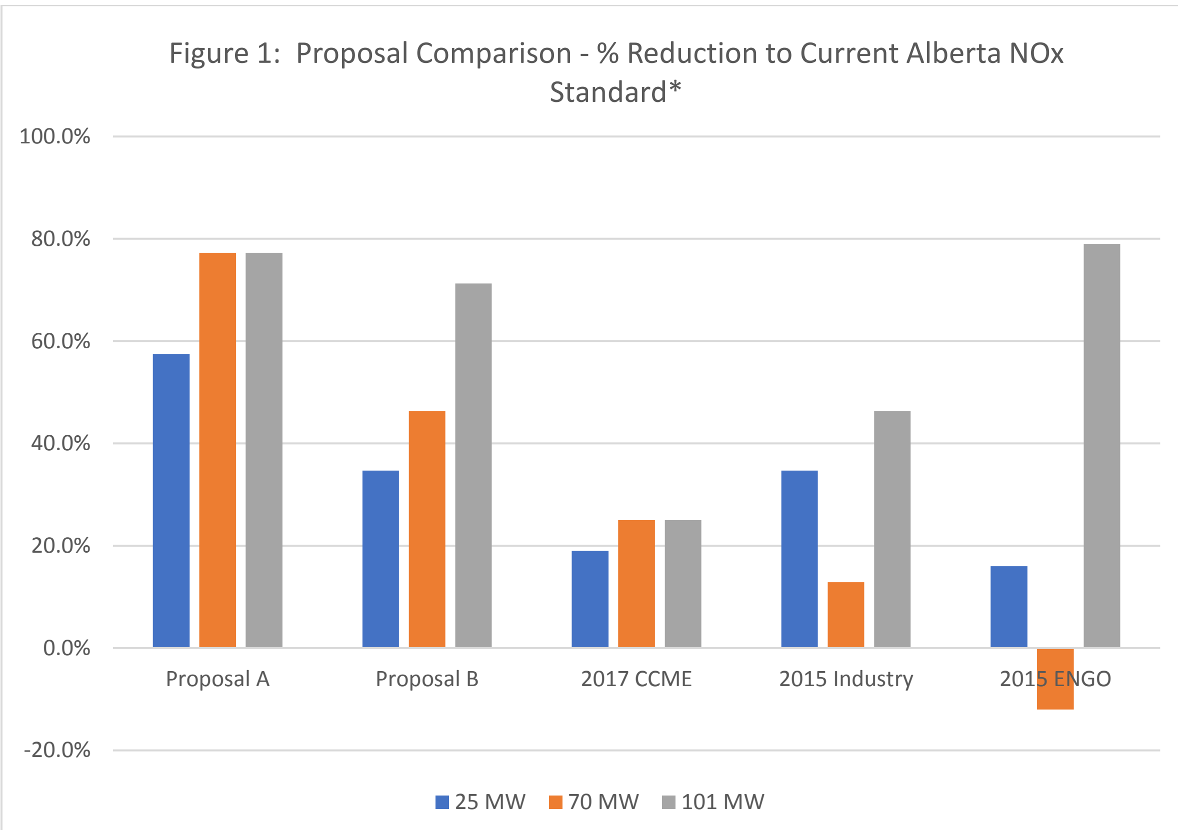
Standards must not result in unintended behavior or incent inefficient design. Size categories need to focus on equipment performance and avoid abrupt cliffs that could result in choices that avoid the most efficient facility design. An example would be a significant increase in emissions reduction stringency that would incent a change to different unit size to avoid the standard. Standards need to reflect good emissions performance with smooth transitions to more stringent requirements.

The role of small generating units in the future is not well understood. Small gas turbines may have opportunity to support distributed generation, combine with non-emitting generation or even support a local need for combined heat and power. Standards design must be careful not to inadvertently set a preference for less efficient (or higher emitting) small generation choices. Standards need to reflect good environmental performance but still allow some flexibility for these smaller installations.

Implementation of new emissions standards should allow sufficient time for electricity sector participants to plan and adjust to the new criteria. A minimum implementation date of one year after the final standard is announced is typically recommended however, due to the concurrent process to create a capacity market, aligning the implementation with the start of the capacity market would be an appropriate time to implement the new standards.

Standards may be expressed as intensity-based but the compliance limit used in the AEP approval must be a mass emissions limit based on generating unit Maximum Continuous Rating (MCR) and any corresponding heat allocation. An intensity-based standard set close to unit full load performance will restrict the flexible operation of a gas turbine and the system and environmental benefits it can provide.

The standards must provide real emissions reductions, demonstrate continuous improvement and balance incremental emissions reduction improvements with cost to equipment operators and electricity consumers. A comparison (Figure 1) of several gas turbine sizes illustrates that Proposal B is achieving considerable improvement over the current Alberta standard and aggressive reductions over the 2015 Industry Proposal in the over 70 MW cogeneration category.



*comparison assumes baseload cogeneration units with equal electricity and heat production ratios (energy output basis)

Although SCR technology can achieve low emissions levels of NOx, the technology has aspects related to storage of reactant, ammonia slip, catalyst disposal, additional capital costs and increased operating costs that need to be managed. Because of these operating issues, DLE is the preferred option for emissions control however, it is recognized that emissions performance beyond what current gas turbine equipment can achieve becomes necessary with larger equipment. Proposal B has set this threshold at equipment greater than 100 MW for non-peaking generating units and 200 MW for peaking units.

Standards should be consistent with other provincial and federal requirements and policy objectives where possible. Proposal B methodology is consistent with the Alberta 2006 standards and 2017 Federal guideline by using separate allowances for electricity generation and heat production. Proposal B also recognizes the role that natural gas generation will play under the Climate Leadership Plan objectives by allowing some flexibility to encourage the development of non-emitting renewables. The proposed federal regulation for natural gas generation will introduce GHG intensity standards that will create a conflict between NOx emissions concentration and generating unit's efficiency. A more efficient generating unit with lower mass emissions of NOx and GHG is the preferred outcome but this may not translate to the lowest NOx concentration in generating unit performance. Table 1 presents typical gas turbine performance data that illustrates that there can be choices and tradeoffs with efficiency, fuel consumption, NOx emission performance and GHG emissions performance. Flexibility in emissions standards is key to secure the best outcome.

Table 1 – Gas Turbine Performance – Illustrative Example

Turbine Option	Unit Size (MW)	Efficiency	NOx Emissions	CO2 Intensity (T/MWh)
1	90	34%	4 ppm	0.59
2	90	36%	15 ppm	0.55
3	75	41%	25 ppm	0.48

Other Considerations

The EFR team discussed the application of a mass emission threshold to trigger an SCR requirement. As was outlined by industry in the 2015 CASA EFR, copying specific emission policies from other jurisdictions may lose the intent of the policy and it also may not align with the Alberta overall policy direction. In the case of the US EPA annual mass emissions trigger for Prevention of Significant Deterioration (PSD) in attainment areas, the policy is designed to trigger a permitting review based on policy objectives of the EPA. The EPA process tends to jump to the conclusion that a BATEA technology must be economic and appropriate if it has been installed somewhere else. This process can misinterpret the success of an installation if the driver for the technology on the project was due to a policy direction, a specific concern in a region that requires additional abatement, a position a particular developer has taken (or negotiated) or the project circumstances may favour that particular technology. The EPA jurisdictions will also not have a Climate Leadership Plan targeting a phase-out of coal, the Pan-Canadian Framework on Clean Growth and Climate Change including a proposed Natural Gas Regulation for Generation of Electricity, a National Air Quality Management System including Base Level Industrial Emissions Requirements or an Alberta Electricity Management Framework. The trigger applied in the Alberta context is arbitrary and does not respect FEOC as the trigger methodology is not applied equally (or at all) to other forms of generation.

It is recognized that SCR technology can be installed on even the smallest of generating units depending on the circumstances. The 100 MW threshold was selected as an optimal level to balance cost, operating flexibility and environmental performance. Operators of equipment will make choices based on efficient design that could include SCR installation for a particular project when the BATEA target was set based on DLE. The economics, equipment choices or overall environmental objectives for a particular project may favour SCR installation, but this may not be the case for all generation projects of a similar size.

Conclusion

Proposal B is based on BATEA, smoothly and progressively increases emissions stringency as generating unit size increases and achieves significant emissions reductions beyond current standards. The electricity sector in Alberta is facing considerable regulatory change in the coming years as well as generating infrastructure transformation. Emissions standards must be designed to allow flexibility and create the opportunity for innovative generation solutions that provide real emissions reductions and reliable electricity at a reasonable cost to consumers.

The CASA framework is designed with a continuous improvement tool that triggers a review of the electricity framework every five years to ensure the framework meets current circumstances and to allow adjustments to be made. Regional Plans and other initiatives also allow improvements to be made when required. The difficult economic times demand the wise use of capital and a sensitive balance between incremental environmental benefit and cost. Proposal B offers an ideal outcome as it demonstrates continuous and substantive improvement compared to previous proposals, achieves significant emissions reductions for natural gas generation and allows flexibility to adapt to future challenges.

December 17, 2018

Katie Duffet
Clean Air Strategic Alliance
#1400, 9915 – 108th Street
Edmonton, AB T5K 2G8

Re: **CASA Electricity Framework Review 2018, Alberta Newsprint Company View**

Alberta Newsprint Company (ANC) takes this opportunity to submit this letter supporting the Industry Proposal for New Natural Gas Turbine NOx Standards (Proposal B).

ANC believes that Proposal B offers the best flexibility for producers and consumers in achieving electricity market certainty for Alberta while achieving significant NOx emission reductions.

ANC has reviewed and agrees with perspective of TransCanada, TransAlta, CAPP, CIAC and Atco.

Please contact me with any questions regarding the ANC support for Proposal B.

Yours truly,
ALBERTA NEWSPRINT COMPANY

Daniel Moore

Daniel Moore
Manager, Corporate Environmental Services

Attach. File 300-005-005

Appendix 3

Emissions Management Framework for the Alberta Electricity Sector: 2018 Five Year Review – Project Charter

Emissions Management Framework for the Alberta Electricity Sector: 2018 Five-Year Review

Project Charter

Approved by the CASA Board

September 2018

Project Charter

Contents

Background

In January 2002, Alberta Environment asked the Clean Air Strategic Alliance (CASA) to develop a new way to manage air emissions from electricity generation in Alberta. Using a multi-stakeholder collaborate approach, CASA developed 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* (the Framework), was accepted by the Government of Alberta and implemented through regulations, standards, and facility approvals. The first emission standards were effective January 1, 2006.

To ensure continuous improvement and keep the Framework timely and relevant, a formal review of the Framework is to be undertaken every five years according to recommendation 29. This review should include a multi-stakeholder group consisting of industry, government, non-government organizations, and communities with an interest in electricity generation in Alberta. The intent of the Five-Year Review is to assess new emission control technologies, update emission standards for new generation units, determine if emission standards for new substances need to be developed, review implementation progress, and determine if the Framework is achieving its emission management objectives.

A full review of the structure of the Framework itself would be triggered by the environmental and health factors noted in recommendation 34 (emission forecast is 15% higher than projected in the previous Five-Year Review) and the economic factors noted in recommendation 35 (economic assumptions are significantly different to adversely affect the viability of the electricity sector). A full structural review would consider changes to the Framework to reflect current circumstances.

First Five-Year Review

The first Five-Year Review started in 2008 and the Electricity Framework Review Team submitted their report and recommendations to the CASA Board in June 2009. The report contained ten consensus recommendations and one non-consensus item. The consensus items included revisions to the particulate matter (PM), nitrogen oxides (NOx), and sulphur dioxide (SO_2) emission standards for new coal-fired units based on improvements in emission control technologies, effective January 1, 2011. The non-consensus item pertained to NOx emission standards for new gas-fired generation for both peaking and non-peaking units. A final report, including the interests and rationale with respect to the non-consensus recommendation, was forwarded to the Government of Alberta in May 2010 for decision.

A subgroup-continued to meet to develop a particulate matter system for existing units, as per recommendation 22 of the Framework. In June 2010, the Federal Minister of Environment announced a proposed regulation for CO_2 emissions from coal-fired power plants. The specific details of the proposed federal coal regulation were not available until it was published in the Canada Gazette, making it difficult for the sub-group to reach agreement on a PM management system for existing coal units. As such, the Board put the sub-group into abeyance until the details of the proposed regulation were available.

Second Five-Year Review

The second Five-Year Review started in 2013. The project team reviewed greenhouse gas (GHG) regulations to identify potential implications and emissions management issues of the Framework created by the implementation of federal GHG regulations in addition to environmental and economic triggers (recommendation 34 and 35).

The group was unable to reach consensus on the need to review or adjust the Framework, given divergent views of the members as to what was required to allow changes to the Framework. An interim report identifying the key issues and differing perspectives was submitted to the CASA Board. The CASA Board asked the Government of Alberta to weigh in on the matter and to describe the path forward as appropriate. In August 2014, CASA was notified that the department of Environment and Parks was working on a cross-ministry plan with the departments of Energy and Health that would review the interim report and determine the next steps for the Framework. In June 2015, Environment and Parks notified CASA that in the absence of a decision on the interim report and Framework, the Government of Alberta would continue to make regulatory decisions in accordance with the existing 2003 Framework.

In March 2015 the project team provided 13 recommendations to the CASA Board, one of which was non-consensus (recommendation 3, emissions standards for gas-fired generation).

Project Goal

To ensure the *Emissions Management Framework for Alberta's Electricity Sector* reflects current circumstances, the project team will conduct the third Five-Year Review, as outlined in recommendation 29 of the Framework.

Project Scope

The requirements of the five-year review are reflected in the following recommendations:

Recommendation 29 (2003)

This recommendation outlines the following elements of the Framework that must be reviewed by the project team:

1. A technology review to identify the Best Available Technology Economically Achievable (BATEA) emission standards,
2. The air emission substances subject to limits or formal management,
3. Co-benefits for priority substances and List 2 substances,
4. A review of economic and environmental triggers as set out in the framework in recommendations 34 and 35,
5. Additional information that illustrates potential health effects associated with emissions from the electricity sector; and

6. A report from the electricity sector on continuous improvement.

Recommendation 22 (2003)
This recommendation states that if mercury control does not provide the anticipated co-reduction of primary particulate matter, the five-year review should develop a primary particulate matter management system for existing units.

Recommendation 9 (2010)
This was a non-consensus recommendation for source standards for new gas-fired non-peaking thermal generation units. The 2015 Five-Year Review was asked to revisit this issue.

Recommendation 3 (2015)
This was a non-consensus recommendation for emissions standards for gas-fired generation. The current Five-Year Review will revisit this issue.

Recommendation 4 (2015)
This recommendation states that the 2018 Five-Year Review should include review of the need to include biomass sources of electricity generation in the Framework.

Recommendation 8 (2015)
This recommendation states that the 2018 Five-Year Review should ensure that each substance listed in Category 2 (i.e. management actions need to be considered) of the Air Emissions Substance Review are evaluated, considering:

- The state of the science on the substance,
- Substance reduction potential including management and cost,
- Co-benefits to be managed, and
- Requirements for monitoring.

Recommendation 9 (2015)
This recommendation states that the group undertaking the health and ecological assessment in the 2018 five-year review should explicitly include substances listed in Category 3 (i.e. ongoing surveillance is recommended) in the search terms for the health and ecological literature reviews.

Recommendation 10 (2015)
This recommendation states the Health and Environmental Assessment Task (HEAT) Group should be convened as soon as possible in the 2018 Five-Year Review and should be provided with the terms of reference from the 2013 HEAT Group, to adjust as the new Group deems necessary.

Recommendation 11 (2015)
This recommendation states the implementation of the Emissions Trading System should be assessed as part of the 2018 Five-Year Review of the Framework.

Recommendation 13 (2015)
This recommendation states the 2018 Five-Year Review should consider the role of public consultation and develop a plan at the beginning of its process.

Key Task Areas

This project will be completed in two phases, with initial high-priority tasks to be completed on a shorter timeline ("short-term" or Phase 1) and delivered to the CASA Board no later than December 2018. The remaining tasks ("long-term" or Phase 2) will be completed by mid-2019.

It is likely the environmental and economic triggers (recommendation 34 and 35 of the Framework) have not been triggered.

Short-Term Tasks (Phase 1)

1. A technology review to identify the Best Available Technology Economically Achievable (BATEA) to update NOx air emission standards for new gas-fired generation units, including:
    - Continuous (non-peaking) and intermittent (peaking) natural gas-fired turbine units,
    - Industrial co-generation plants using gas-fired turbines,
    - Gas-fired reciprocating engines used for both industrial cogeneration and electricity generation when multiple units are banked,
    - Gas turbines fired by biogas, and
    - Design life considerations for gas-fired units.

2. Updates to consultant reports from the first and second five-year reviews to determine Best Available Technology Economically Achievable (BATEA)-based emission standards for gas-fired generation, if deemed appropriate.

3. Review lessons learned from industry using Selective Catalytic Reductions (SCR) in their operations.

4. As per recommendation 11 of the 2013 Five-Year review, complete an assessment of the implementation of the Emissions Trading System, with a focus on NOx emission credits. This assessment will include what the system is achieving and will continue to achieve, the intended objectives of providing incentives and rewards for better than required or expected performance, encouraging early shutdown of older units, and encouraging implementation of new emissions controls at existing units.

5. As per recommendation 13 of the 2013 Five-Year Review, develop and implement a strategy and action plan for communicating and engaging with stakeholders and the

public with a goal of informing and increasing the public's awareness and understanding of:

- The 2003 Framework and how it works to improve performance and reduce emissions,
- The 2013 Five-Year Review process and outcomes,
- The implications of the implementation of recommendations resulting from the 2013 Five-Year Review, and
- The 2018 Five-Year Review process.

Long-Term Tasks (Phase 2)

1. As per recommendation 4 in the 2013 five-year review, review the need to develop emission standards for biomass-fired electricity generation sources.

2. Review the draft federal stationary diesel engines regulations for electricity generation, for engines used both in continuous and standby service and consider implications for and alignment with the Framework.

3. As per recommendation 22 of the Framework, review primary PM management and develop a primary PM Management System for existing coal-fired units if deemed appropriate.

4. As per recommendation 8 of the 2013 Five-Year Review, review air emission substances emitted by electricity generation that are subject to formal control, including existing Category 2 substances and emergent substances and their impacts. This task should consider:
   - The state of the science on the substance,
   - The substance reduction potential including management and cost,
   - Co-benefits to be managed, and
   - Requirements for monitoring.

5. As per recommendation 10 of the 2013 Five-Year Review, convene a HEAT Group to oversee a review to identify any new and relevant studies or research findings regarding potential environmental or health effects from air emissions substances from electricity generation, including an independent peer review on results.

   As per recommendation 9 of the 2013 Five-Year Review, this task should explicitly include air emissions substances listed in Category 3 (i.e. on-going surveillance is recommended) in the search terms for the health and ecological assessment literature review.

6. Modernize the Framework document itself by consolidating the recommendations from the first and second Five-Year Reviews into the main Framework document, including adding information on implementation status of recommendations where applicable,

and reviewing the recommendations for relevancy in light of the changes to the electricity sector since the document was created.

7. As per recommendation 13 of the 2013 Five-Year Review, develop and implement a strategy and action plan for communicating and engaging with stakeholders and the public with a goal of informing and increasing the public's awareness and understanding of:
    - The 2003 Framework and how it works to improve performance and reduce emissions,
    - The 2013 Five-Year Review process and outcomes,
    - The implications of the implementation of recommendations resulting from the 2013 Five-year review, and
    - The 2018 five-year review process.

8. Review a report from the electricity sector on continuous improvement.

9. Make recommendations for future Five-Year Reviews.

Project Deliverables

The following deliverables will be developed by the project team and provided to the CASA Board:

- Interim report on short-term tasks to be provided no later than December 2018
- Final report including both the short and long-term tasks to be provided by mid-2019
- Communications plan

It should be noted that *CASA's Performance Measures Strategy: A "how-to" guide to performance measurement at CASA* indicates that each project team is required to generate one specific metric that will allow the success of the team to be evaluated 5 years in the future. More guidance on how this can be achieved can be found in the strategy.

Project Structure and Schedule

Project work should begin in June 2018. The entire project will take approximately 12 months, with a completion date of no later than December 2018 for the short-term tasks and mid-2019 for the long-term tasks.

Projected Resources and Costs

Table 1 outlines the potential external costs over the life of the project as anticipated by the project team. These figures are estimates only. As the work of the project team progresses, detailed work plans and associated budgets will need to be created.

Table 1: Estimated costs associated with the Five-Year Review of the Electricity Management Framework

Key Task	Estimated Budget
Environmental effects literature review (Phase 2, task 5)	$20,000
Health effects literature review (Phase 2, task 5)	$20,000
PM management system consideration (Phase 2, task 3)	$20,000
Communication/Consultation (Phase 1, task 5 and Phase 2, task 7)	$15,000
Total	$75,000

Risk Analysis

Identifying, analyzing and mitigating project risks is a key component of executing a successful project. The project team should incorporate proactive risk management into the project to mitigate risks that could undermine its success.

Table 2 lists the risks as well as possible mitigation strategies that the project team should consider as they undertake their work.

Table 2: Electricity Management Framework Review Risk Analysis including Possible Mitigation Strategies

Risks	Possible Mitigation Strategies
Process	
Timely funding not available for long-term (phase 2) tasks	• Identify who the "customers" of this work are. Who will find this valuable – seek funding there • Develop a strong value-proposition that includes: examples of sectors that may be involved or affected • Project Team members discuss the work and associated need for funding with their constituents early in the process
Recommended management actions are too broad or not specific to the project goal.	• Seek a balance between regional needs and provincial applicability in management actions chosen • Consider prioritizing cross-cutting actions that provide regional benefit and have the potential to be broadly applicable • Consider ways to align this work with existing management frameworks and plans
Can't reach agreement, e.g., management actions, or communications	• Determine in advance which pieces of work do and do not require consensus

	• Outline a clear decision-making process that includes what happens if the team can't agree – who will make the decision? • Have an explicit discussion around Interest-Based Negotiation, and get all the interests of the team members on the table
Project Team doesn't understand or follow the Project Charter	• Working group to create a project charter that is clear, especially with respect to the intent for sequencing of objectives • Board receives regular updates to ensure progress is monitored
CASA Board doesn't agree with management actions identified in Objective 4	• Project Team members liaise with their constituents and Board members on an ongoing basis • Project Team provides regular status reports for Board meetings
Recommendations of the project team are not implemented.	• This risk is outside the scope of the project team to mitigate; however, this risk will be reduced if i) the parties potentially involved in implementation are engaged, and ii) reference to implementation (who and how) is included in the report's recommendations
Information Collection	
Consultant is not available during the project timeline	• Engage the consultant as far in advance as possible to ensure availability
Lack of / limited information (accessibility)	• Ensure Project Team membership enables the team access to information • Use judgement where information is unavailable
Stakeholder Engagement	
During stakeholder engagement, "interested parties" don't agree with the list of management actions	• Try to develop the potential management actions collaboratively • If stakeholders disagree, seek to understand stakeholder reasons for disagreement • Identify non-consensus recommendations where appropriate
Lack of engagement/ownership on Project Team	• Identify and communicate with potential stakeholders early in the process • Create a clear value proposition • Be clear about what is being asked of stakeholders

Obtaining stakeholder feedback and refining management actions with interested parties takes longer than expected or causes scope creep.	• Set specific parameters for this piece of work:
	    o Purpose of soliciting feedback
	    o Scope of influence outcomes will have on overall process
	• Time available

Operating Terms of Reference

An Operating Terms of Reference describes how the project team agrees to work together. The project team should discuss and reach consensus on the following items:

- Requirements for quorum
- Governance
- Meeting protocols
- Roles and expectations of project team members
- How decisions will be made
- Ground Rules
- Frequency of project team meetings
- Frequency of updates and reports to the CASA Board
- Protocols for handling media requests
- Protocols for providing updates to interested parties
- Any other considerations for working together

Stakeholder Analysis and Engagement Plan

The project team would benefit from engaging different stakeholders for different purposes. Different stakeholders could be engaged in a variety of capacities and at different times throughout the project.

The working group identified the following categories of stakeholders that may be involved:

- Project Team: Stakeholders who are required at the table to reach consensus agreement.
- Corresponding members: Stakeholders who receive all correspondence but are not required at the table to reach consensus agreement.
- Task Groups or Technical Experts: Stakeholders who have a specific interest or expertise and can be engaged in a more focused way.
- Other:
    - Stakeholders from whom feedback on management actions is sought, which may include potential implementers or those potentially impacted
    - Members of the public who may be engaged