Acidifying Emissions Management Implementation Team

Final Report and Recommendations
to the
CASA Board of Directors

June 2002

Acidifying Emissions Management Implementation Team

Final Report and Recommendations to the CASA Board of Directors

June 2002

By consensus, the CASA Board of Directors approved this report and recommendations at its June 21, 2002 meeting. The Board of Directors amended recommendation three and that amendment is incorporated within this report.

Published by

Clean Air Strategic Alliance
10035 108 ST NW FLR 10
EDMONTON AB T5J 3E1
CANADA

Telephone:	(780) 427-9793
Fax:	(780) 422-3127
E-mail:	casa@casahome.org
Web site:	www.casahome.org

This report is available as an Adobe® Acrobat® PDF on the CASA web site.

ISBN 1-896250-17-3

Contents

1 Executive Summary

The original Clean Air Strategy for Alberta recognized the importance of effectively managing emissions of sulphur dioxide (SO_2) in Alberta. The Clean Air Strategic Alliance responded to this issue by establishing an SO_2 Management Project Team to review the system of managing SO_2 emissions in the province and develop recommendations for improvements. This team recommended a management system to the CASA board in 1997 that explicitly linked the day-to-day management of SO_2 emissions, goals and objectives for management, and the management tools with provision for periodic evaluation and improvement. A new multi-stakeholder team—the Acidifying Emissions Management Implementation Team, or AEMIT—was subsequently established to coordinate the implementation of these recommendations.

Among other things AEMIT was responsible for evaluating the SO_2 management system and recommending appropriate enhancements to ensure continuous improvement in its application. The system was assessed against the three broad air quality management goals contained in the 1997 report:

1. Protect the environment
2. Optimize economic performance and efficiency
3. Seek continuous improvement

After conducting three annual evaluations of the management system, the AEMIT believes that considerable progress has been made on goal 1, some progress on goal 2, and limited progress on goal 3. Therefore several of the recommendations in this report are made with the intent of advancing progress on goals 2 and 3. With the submission of this final report and recommendations to the CASA board, AEMIT has completed its work.

With respect to the management of acidifying emissions in Alberta, the AEMIT makes the following five recommendations:

Recommendation 1. When the Alberta Energy and Utilities Board and Alberta Environment identify a new acidifying emissions objective as a priority, they should also decide if it is appropriate to integrate the processes of setting the objective and developing a management framework. If the processes are integrated, the task should be referred to CASA. If integrated processes are not referred to CASA, an explanation will be provided.

Recommendation 2. Alberta Environment and the Alberta Energy and Utilities Board should establish the information systems listed below in support of acidifying emissions management:

- **i) provincial annual average concentration values for ambient NOx and SO_2 continuous monitoring stations;**
- **ii) number of SO_2 and NOx continuous monitoring stations removed from approval requirements based on long term records of low readings or because of participation in zonal management;**
- **iii) a comprehensive source and emission data capture and reporting system;**
- **iv) an electronic source emission inventory database for managing data collected as described in item (iii); and**
- **v) an SO_2 and NOx emissions forecasting system.**

Recommendation 3. Alberta Environment should lead an evaluation of the acidifying emissions management system every two to three years based on the evaluation process that has been established by AEMIT. Evaluation results should be reported to the CASA board and the next evaluation should be done in 2003. This task would require Alberta Environment to complete the forms that AEMIT has developed and used to conduct its evaluation; these are:

- **the goals, objectives and performance measures table, and**
- **the evaluation protocols table.**

Recommendation 4. If Alberta Environment determines that improvements should be made after the evaluation done in recommendation 3, Alberta Environment should make recommendations to the CASA board or forward a statement of opportunity if it is appropriate for a CASA project team to look at the issue.

Recommendation 5. The application of the management system framework developed by the SO_2 Management Project Team should be considered by Alberta Environment and the Alberta Energy and Utilities Board for the integrated management of air quality in Alberta.

The AEMIT also believes the three air quality goals should be more widely communicated and applied. Therefore, the team makes the following recommendation:

Recommendation 6. a) The CASA Communications Committee should increase the profile of the three air quality management goals in overall CASA documentation. These three goals are:

- **Protect the environment**
- **Optimize economic performance and efficiency**
- **Seek continuous improvement**

b) Other CASA project teams should consider incorporating the three air quality management goals in their terms of reference and reporting back to the CASA board on how the work of their team is consistent with the goals.

2 Background and History of the Acidifying Emissions Management Implementation Team

2.1 The SO_2 Management Project Team

The original Clean Air Strategy for Alberta recognized the importance of effectively managing emissions of sulphur dioxide (SO_2) in Alberta. The SO_2 management system, which was developed in the 1960s and '70s, focussed on regulating individual facilities and using technology to reduce SO_2 emissions and achieve emission requirements and ambient guidelines. While that system did lead to better control of SO_2 emissions, outstanding stakeholder issues remained. These issues and concerns were presented to the CASA board in 1994. The CASA board directed a working group to develop terms of reference and to prepare a budget and work plan for evaluating the way SO_2 was being managed in Alberta. In February 1995, the CASA board approved the terms of reference for the SO_2 Management Project Team, directing the team to determine:

- the issues and concerns with the current system of management,
- the management objectives for SO_2 in Alberta,
- the range of instruments available for the management of SO_2 emissions, and
- the most effective and efficient system for SO_2 management.[1]

Within the context of its review of the SO_2 management system and in anticipation of potential future needs, the project team established the Target Loading Subgroup in April 1995. Their main role was to evaluate and make recommendations to the project team on the feasibility and desirability of implementing critical and target loads within the SO_2 management system for Alberta. The subgroup's June 1996 report to the project team made detailed recommendations about the application of this approach, including interim critical loads for Alberta soils and aquatic systems. Following its acceptance by the project team and subsequently the CASA board in 1997, the recommendation was forwarded to the responsible provincial government department—Alberta Environment—for implementation. The CASA board approved the final report of the Target Loading Subgroup in June 1999; it included the framework for managing acidifying emissions and acid deposition in Alberta, based on the application of critical and target loads.[2]

The SO_2 Management Project Team presented its final report and recommendations to the CASA board in March 1997. The system that was recommended to the Board explicitly linked the day-to-day management of SO_2 emissions, goals and objectives for management, and the management tools with provision for periodic evaluation and improvement. In all, the project team made 20 recommendations in eight categories: Systems Approach; Management Goals; Management Objectives; Management Options; System Operation; System Evaluation; Information; and Future Opportunities.[*]

Recommendation 2 in the report of the SO_2 Management Project Team was for CASA to create a new multi-stakeholder implementation team, which eventually became the Acidifying Emissions Management Implementation Team.

[*] The extent to which these recommendations have been implemented is discussed in section 5 of this report.

2.2 The Acidifying Emissions Management Implementation Team

Terms of reference for the new implementation team were drafted and approved in principle by the CASA board in November 1996. The terms of reference were modified slightly after the team was established. The purpose of the team was to:

1. Coordinate the implementation of the recommendations in the report of SO_2 Management Project Team.
2. Evaluate and report on the implementation of the recommendations and the effectiveness of the enhanced management system.
3. Develop recommendations for managing acidifying emissions in Alberta.
4. Develop plans for (a) voluntary initiatives for enhanced performance, and (b) management of the differences between actual environmental conditions and environmental limits.
5. Review current emissions abatement strategies for NOx and SO_2 sources and make recommendations on the need for improvements.

The CASA board later approved a name change for the team to better reflect the overall mandate and work on emissions, deposition, and effects of nitrogen as well as sulphur compounds, making it the Acidifying Emissions Management Implementation Team. The new multi-stakeholder implementation team undertook a wide range of work in its first two years of activity.[†] The team identified four key priorities, and subsequently established subgroups to address them:

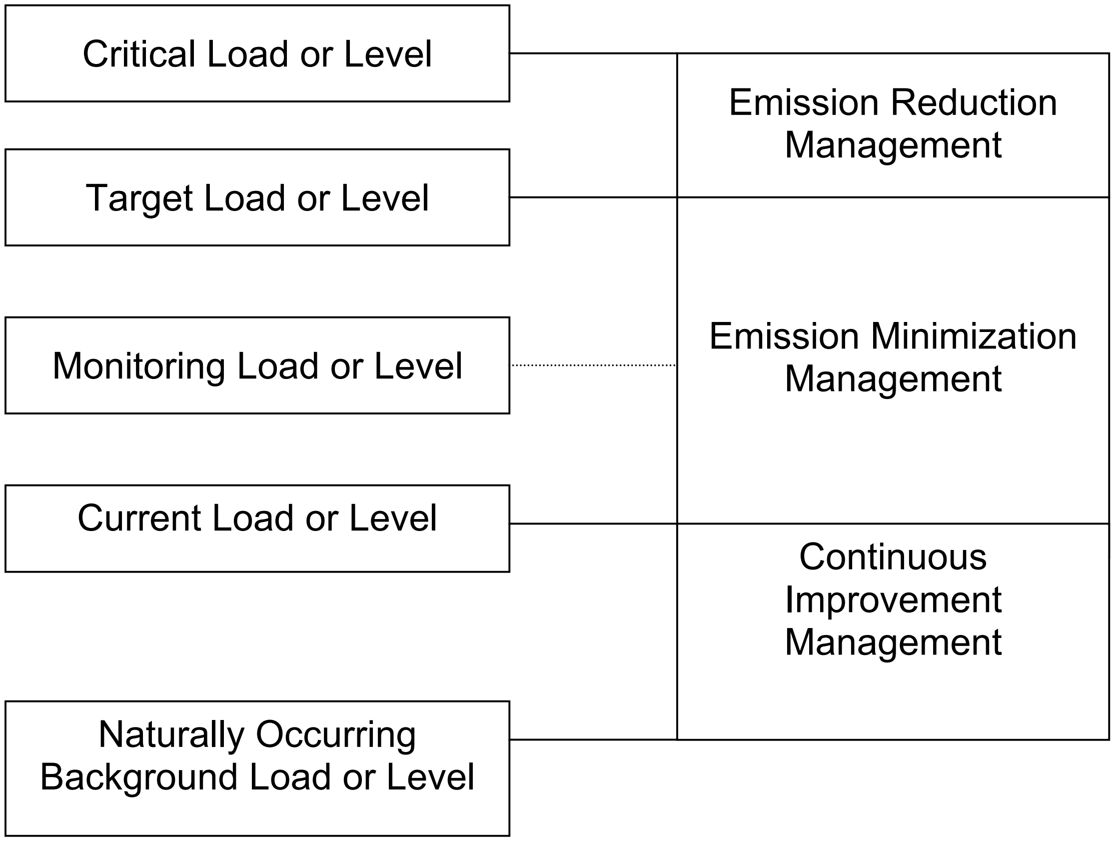
- critical and target loads for acid deposition in Alberta;
- enhanced performance, including ways to minimize the cost of managing emissions;
- evaluation of the SO_2 management system; and
- NOx/SOx abatement.

The AEMIT used a "managing the gap" approach for the management of acidifying emissions (see Figure 1 below). The gap to be managed is between current emissions and deposition, and the limits established for the protection of the environment and health. The gap applies to both emissions and concentrations of substances (SO_2 and NOx) in air, and to deposition of acidic compounds.

Using the RELAD model (the REgional Lagrangian Acid Deposition model), the Target Loading Subgroup estimated acid deposition then assessed sensitivity in Alberta and subsequently derived critical, target, and monitoring loads. In "managing the gap," the subgroup and the AEMIT developed management strategies and actions that are to be applied in three defined situations, with the management strategy becoming more rigorous as deposition loading rises.

[†] Appendix A of this report lists members of the Acidifying Emissions Management Implementation Team as well as those who participated in subgroups and on the SO_2 team. Appendix B lists the background documents prepared by and for the two teams and subgroups.

Figure 1. "Managing the Gap" Approach



The Enhanced Performance Subgroup was formed to explore ways to improve both the environmental and economic aspects of emissions management. This subgroup identified three elements it considered necessary for such improvements:

- Companies—within and across industries—need to take the initiative to propose and collaborate on innovative approaches to improving performance.
- There should be a means for regulatory/public recognition of any such industry initiative.
- In addition to site-specific criteria, regulators need to develop the administrative flexibility to evaluate such proposals in the context of broader social and environmental objectives.

Among other things, the subgroup also recommended continued research into the possible application of credit-based incentive programs to increase flexibility in reducing emissions. The CASA board accepted the report of this subgroup in June 1999, and the subgroup was disbanded with the formation of CASA's Pollution Prevention/Continuous Improvement Project Team, which was expected to address a number of these issues.

The Evaluation Subgroup did considerable work in support of recommendation 11 in the original SO_2 report, which directed AEMIT to evaluate the SO_2 management system and recommend any needed improvements. The evaluation framework developed by the subgroup was designed to answer two key questions: (a) are the goals of the management system being met (to protect the environment, optimize economic performance and efficiency, and seek continuous improvement)?

And (b) are the overall management system and the individual components operating as set out in the report of the SO_2 Management Project Team? The subgroup then used the evaluation protocol to assess the management system. The evaluation protocol and templates are provided in Appendix C.

In June 1999, AEMIT presented and the CASA board approved a comprehensive package, which included the final report and recommendations from the Target Loading Subgroup; the report from the Enhanced Performance Subgroup; and the proposed evaluation framework with goals, objectives and performance measures, and evaluation protocols. This represented the first of three evaluation reports to the CASA board, and was followed by similar reports in June 2000 and November 2001.

The NOx/SOx Subgroup was formed to review current emission abatement strategies for NOx and SO_2 sources and make recommendations on the need for improvements. The subgroup completed its deliverables in June 2001 and it was agreed that future work on this topic would be done by AEMIT as a whole. Section 4 of this report describes the work of this subgroup in more detail.

AEMIT held several workshops and commissioned various pieces of work. Workshop reports and other documents are listed in Appendix B.

The submission of this final report to the CASA board in June 2002 concludes the work of the Acidifying Emissions Management Implementation Team.

3 AEMIT Mandate

To provide a comprehensive final report to the CASA board, the Acidifying Emissions Management Implementation Team assessed its work in detail. AEMIT's purposes, as specified in the terms of reference, are noted below with the team's assessment and analysis of its work in each area.

1. *Coordinate the implementation of the recommendations of the SO_2 Management Project Team.*

   A substantial number of the recommendations have been implemented (see section 5) and, where further work is needed, it is best carried out by other CASA project teams.

2. *Evaluate and report on the implementation of the recommendations and the effectiveness of the enhanced management system.*

   Evaluations of the effectiveness of the enhanced management system were submitted to the CASA board in June 1999, June 2000, and November 2001. AEMIT has several recommendations to further improve the management system as a result of these evaluations. These recommendations are described in detail in section 6.

3. *Develop recommendations for managing acidifying emissions in Alberta.*

   The following recommendations have been developed:

   - A management framework for the application of critical, target, and monitoring loads for the evaluation and management of acid deposition was approved by the CASA board in June 1999 and has been implemented by Alberta Environment. Alberta Environment will complete a review of the framework in 2004.

- The Enhanced Performance report, which included recommendations for managing acidifying emissions, was approved by the CASA board in 1999.
- The findings of the NOx/SOx subgroup are discussed in section 4 of this report.

4. *Develop plans for (a) voluntary initiatives for enhanced performance, and (b) management of the differences between actual environmental conditions and environmental limits.*

With respect to (a), voluntary initiatives for enhanced performance:

- Although AEMIT has not developed plans *per se*, recommendations developed by AEMIT's Enhanced Performance Subgroup, were approved by the CASA board in June 1999, as to how the regulatory regime could provide industry with greater flexibility to achieve environmental objectives at lower cost, and
- Alberta Environment has developed a "LEAD" program that incorporates greater flexibility in the approval process to recognize and promote environmental performance by companies with a better than average compliance record.

With respect to (b), management of the differences between actual environmental conditions and environmental limits:

- AEMIT has not developed "plans," but the framework for the application of critical, target, and monitoring loads for the evaluation and management of acid deposition provides a mechanism to manage the gap between current conditions (deposition less than the critical load throughout Alberta) and environmental limits (the critical load), and
- The Pollution Prevention/Continuous Improvement Project Team is developing recommendations on pollution prevention.

5. *Review current emission abatement strategies for NOx and SO_2 sources and make recommendations on the need for improvements.*

AEMIT□s NOx/SOx Abatement Subgroup examined the quantity and characteristics of NOx and SO_2 emissions from all the major industrial sectors in Alberta and recommended development of a framework and targets for emission reductions from existing sources. AEMIT did not reach consensus on the recommendations from the subgroup, nor on the details for implementation of an emissions reduction target, but the team did agree that there is value in this type of provincial approach.

In summary, the team agreed that it has completed all of its mandated work with the exception of item 5. With changing priorities, AEMIT members agreed to request an opportunity to make a presentation to CASA's newly established Electricity Project Team on the findings of the NOx/SOx Subgroup and on the value of a provincial emissions reduction target approach for that team's consideration.

4 Findings of the NOx/SOx Subgroup

The AEMIT established the NOx/SOx Subgroup to "Review current emission abatement strategies for NOx and SO_2 sources and make recommendations on the need for improvements." The subgroup's terms of reference contained three deliverables:

1. A comparison of NOx/SOx emissions by sector type in Alberta that will include a summary of current regulatory and other emission management requirements by sector type. The summary will include a description of the rationale for current requirements.
2. An assessment of NOx/SOx emissions management improvement opportunities with supporting comparison of emissions reductions potential and costs by sector types. The assessment will include review of incentives and other mechanisms to facilitate emissions reductions.
3. Recommendations to AEMIT for further action by CASA and stakeholders.

The following three matrices were developed to complete the first two deliverables and these are provided in Appendices D-1 to D-3.

1. An "Emissions Management" matrix for both NOx and SOx that shows the 1995 NOx and SOx emissions for activities as defined in the Activities Designation Regulation, and the key regulatory tool for each activity (April 2000).
2. A "Summary of Control Technologies and Cost Information" for both NOx and SOx emissions, which lists the available technologies, emission reduction efficiency, and cost for each industrial sector (December 2000).
3. An "SO_2 /NOx Emissions Reduction and Cost" matrix, which combines the information from both of the above matrices and includes a summary of standards and guidelines for each industrial sector (May 2001).

AEMIT also undertook a project to upgrade the existing SO_2 and NOx emissions inventory information for five different sectors in Alberta:

- SO_2 emissions from batteries flaring solution gas;
- SO_2 emissions from well test flaring;
- NOx emissions from natural gas compressors;
- NOx emissions from heaters and boilers in industrial applications (including natural gas processing); and
- NOx emissions from heaters and boilers in commercial applications.

The team contracted Levelton Engineering to review existing available emissions inventory information and review potential sources of data for upgrading the existing available emission inventory for each sector. The contractor was also asked to develop a proposal for a second phase of the project to outline the information and a proposed methodology for upgrading the emissions information.

Based on results of phase 1 of the Levelton work (see Appendix E), it was agreed that the following three strategies would advance development of NOx/SO_2 inventories in the short term:

- *SO_2 emissions from solution gas flaring and well test flaring:* As done in previous federal/provincial inventory work, the EUB will supply estimates of SO_2 emissions from solution gas flaring and well test flaring to Alberta Environment, based on the best available information. Alberta Environment will use the information to work with Environment Canada in developing the inventory numbers for this sector.

- *NOx emissions derived from natural gas-fired compressors:* Inventory numbers for this sector will be derived from the Alberta Environment study that is currently underway.
- *NOx emissions from boilers and heaters in industrial and commercial applications*: As done before for federal/provincial inventory work, NOx emissions from boilers and heaters in industrial and commercial applications will be derived from work by Alberta Environment and Environment Canada.

The team also decided not to pursue phase 2 of the project as no new options for improving NOx and SO_2 inventories were identified in the consultant's proposal for phase 2.

At the end of its work, the subgroup concluded that:

1. There are many sources of SOx and NOx from many sectors.
2. Although new source performance standards are in place for all sectors that have significant emissions, penetration of technologies into existing facilities to meet these standards varies widely.
3. There is a diverse range of costs to increase penetration of best available control technology (BACT) in each sector.
4. There are no obvious low-cost reduction opportunities for NOx and SO_2 emissions.

The subgroup also made four recommendations to AEMIT regarding targets but AEMIT chose not to strive for consensus on these recommendations:

1. A provincial emission target for existing sources (on an acidifying basis) should be set. This target needs to include timelines, a number, and a regulatory backstop; all environmental objectives must be met and must address local concerns; must include mechanisms to recognize performance exceeding licensed levels; and target would be somewhere between full penetration of new source standards versus existing business as usual.
2. An economic efficiency target also must be set; e.g., 50% penetration of Best Available Technology (equivalent) should cost less than 50% of BAT.
3. AEMIT should establish the management option (unlike the sour gas sulphur recovery review).
4. Improved source emission inventory information should be gathered.

The team agreed there is value in pursuing a NOx/SOx emissions management approach involving province-wide reduction targets, but AEMIT chose not to strive for consensus on implementing this type of approach because of the establishment of CASA's new Electricity Project Team. With the formation in March 2002 of the Electricity Project Team, AEMIT agreed that this team's terms of reference are broad enough to allow for a discussion on the NOx/SOx target approach; however, AEMIT acknowledged that the Electricity Project Team is not planning to specifically address NOx and SOx targets. AEMIT concluded that if, after the Electricity Team finishes its work, there is still a need for the approach being considered by AEMIT for establishing province-wide reduction targets for NOx and SOx, a stakeholder could bring forward a statement of opportunity to CASA to address this need.

5 Assessment of Implementation of the 1997 Recommendations of the SO_2 Management Project Team

The terms of reference of the Acidifying Emissions Management Implementation Team included the preparation of a report on the implementation of the recommendations in the final report of the SO_2 Management Project Team. This section of AEMIT's report lists these recommendations and the progress that has been made in implementing them.‡

97-1.The SO_2 management framework (Figure 3 of the report) be adopted and used for the management of SO_2 in Alberta

AEMIT believes the conceptual framework has been adopted by CASA stakeholders, Alberta Environment, and the Alberta Energy and Utilities Board. However, the framework has been applied largely to goal one (protect the environment) with limited application to goals two and three (optimize economic performance and efficiency; continuous improvement).

The SO_2 management framework describes the "Objective Setting" and "Selection of Management Options" elements of the management framework as separate processes, with Alberta Environment and the AEUB responsible for setting management objectives, and CASA responsible for selecting management options. The processes have been combined with recent initiatives such as the Solution Gas Flaring Management Framework and the Sulphur Recovery Guideline Review. The Solution Gas Flaring Management Framework was developed through a CASA process, consistent with the framework. However, the Sulphur Recovery Guideline Review was done outside the CASA process. AEMIT's first recommendation attempts to address this situation.

97-2. A multi-stakeholder group be created to coordinate the implementation of these recommendations, provide ongoing evaluation of the management system, and report to the CASA board on progress

The AEMIT was created as a CASA project team and has coordinated implementation of these recommendations. Progress reports to the CASA board on the management system were submitted in June 1999, June 2000, and November 2001.

97-3. Organizations commit to their respective responsibilities (Table 3 of the report) for the implementation of the SO_2 management system

AEMIT is satisfied with the commitment shown by organizations identified in Table 3 as having responsibility for the implementation of the SO_2 management system.

97-4. The SO_2 management system apply the integrated air quality management goals adopted by the CASA board.

Goal #1. Protect the environment. Quantitative management objectives are in place for this goal. There has been strong commitment to this goal and a high degree of success in achieving it, based on data that assess performance against existing quantitative management objectives.

‡ Notes: (1) In this evaluation, references in recommendations 1, 3, 5, and 6 to pages, tables or figures in the report mean the final report of the SO_2 Management Project Team. (2) AEP and AEUB mean Alberta Environmental Protection, now Alberta Environment, and Alberta Energy and Utilities Board respectively.

Goal #2. Optimize economic performance and efficiency. Quantitative objectives do not exist for this goal. A key indicator of whether or not progress is being made against this goal is the degree to which management options that are implemented or proposed promote optimization of economic performance and efficiency. The Acidifying Emissions Management Implementation Team agrees that the frameworks for solution gas flaring and for critical and target loads for acid deposition are consistent with this goal. The management option selected stemming from the Sulphur Recovery Guideline Review was assessed against this goal and found to be consistent with it.

Goal #3. Seek continuous improvement. No quantitative management objectives have been set for this goal, which makes it difficult to assess whether the goal is being met. Some performance measures have been developed as part of the evaluation process to show performance trends over time. The AEMIT believes that only small steps have been taken to make progress on this goal.

97-5. The scope and form of the objectives outlined below (page 16 of the report) be adopted for establishment of numerical values or for future consideration. These objectives, including existing and new ones, cover environmental effect-based approaches, source emissions (performance) controls, and resource conservation.

In October 2000, Alberta Environment convened a workshop to get advice on priorities for ambient air quality guidelines. In preparation for the workshop, a Scientific Advisory Committee reviewed more than 128 substances that were nominated by stakeholders as possible candidates for ambient air quality guidelines and recommended substances it considered to be priorities for guideline development. Workshop participants reviewed these recommendations and concluded, among other things, that guidelines for nitrogen oxides and sulphur dioxide should be reviewed.[3]

The NOx/SOx Subgroup of the AEMIT reviewed current emission abatement strategies for sources of NOx and SO_2. The subgroup compared emissions by sector types in Alberta and assessed emissions management improvement opportunities. These activities and results were described in section 4 of this report.

Finally, not all objectives listed on page 16 in the 1997 SO_2 report have numerical values. There have been processes to establish new objectives against these items, but the team has not systematically gone through every one. Some examples are noted below.

Environmental Objectives

Ambient Air Quality Guidelines*:* In October 2000, Alberta Environment held a workshop to receive stakeholder input on the priority of 128 substances nominated for potential guideline development. In response to the outcomes of the workshop, the department prepared a three-year *Alberta Ambient Air Quality Guidelines Work Plan,* which outlines the steps in the development of new guidelines for three classes of substances, the review of four guidelines, and the adoption of six new guidelines (see Appendix F).

Deposition Guidelines: The report of the CASA Target Loading Subgroup has been implemented in the form of a provincial acid deposition management framework.

Odour: EUB Guide 60 prohibits off-lease odours from upstream petroleum industry operations. EUB guidelines and procedures also address enforcement for non-compliance with requirements.

Performance Objectives

Effects-based Regional Mass Emissions: Concern for acidifying emissions impacts in the oil sands region of north-eastern Alberta has led to the formation of the NOx-SO_2 Management Working Group (NSMWG) that will be making recommendations on:

- environmental capacity guidelines for the region,
- related management objectives, and
- a management system to implement the objectives.

The multi-stakeholder NSMWG process is modelled on CASA.

Target Regional Mass Emissions: There are no examples for this objective, but the use of local or regional mass emissions targets may be identified as tools within an oil sands regional NOx-SO_2 management framework.

Odour Complaint Handling: The EUB has procedures for use by its field surveillance staff to investigate and follow up on odour complaints.

Resource Objectives

Resource Conservation: EUB Guide 60 specifies methods and criteria for evaluating solution gas flares. If the specified criteria are met, the EUB requires that "economic" flare gas must be conserved and not flared. The EUB now requires applicants for oil sands projects to use the methods and criteria for evaluating conservation of solution gas that might otherwise be vented.

97-6. Alberta Environmental Protection and Alberta Energy and Utilities Board lead the development of a multi-stakeholder process which will result in the establishment of numerical values for the defined objectives (page 16 of the report).

There is an established process for identifying the need for new quantitative objectives that meet the criteria described in the report (acid deposition, particulate matter, ozone). The process has not been explicitly applied to the need for quantitative management objectives against the goals of "optimizing economic performance and efficiency" and "seeking continuous improvement." Following the multi-stakeholder workshop held in October 2000 (described above under recommendation 5), Alberta Environment prepared a work plan to address the top priorities,[4] having indicated at the workshop that guideline creation would be a higher priority than guideline review. Text describing the procedures for guideline development and the table noting priority substances for work between 2001 and 2004 have been excerpted from the work plan and are attached to this report as Appendix F.

97-7. Regulatory mechanisms continue to be used as the core management approach for achieving the objectives.

Execution of the regulatory management option by Alberta Environment and the AEUB continues to be effective, based on performance measures against environmental objectives.

97-8. The multi-stakeholder group design, evaluate and develop an implementation plan for the use of effective voluntary initiatives as supplements to encourage and promote enhanced performance.

AEMIT did not explicitly develop an implementation plan but this recommendation was addressed by the development of an enhanced performance plan (see Appendix G). The enhanced performance plan called on industry to develop proposals and initiatives that would improve environmental as well as economic performance. Credit for the management of grandfathered sulphur recovery gas plants and flexibility in reducing solution gas flaring are part of the legacy of this work.

An emissions credit component in the Sulphur Recovery Review has also been implemented, but this was not a CASA process. Part of the success of the CASA recommendations for reducing solution gas flaring was due to the fact that an industry-wide target was set, which facilitated voluntary action on the part of industry rather than having a specific approach prescribed.

Some of the work recommended by the Enhanced Performance Subgroup has been undertaken, although it is difficult to establish causal links. For example, Alberta Environment is looking broadly at the concept of emissions trading, Climate Change Central has been asked to develop a review on emissions trading specifically for greenhouse gases, and Alberta Environment has set up its “LEAD” program.

97-9. The AEP and AEUB approvals process be applied as the central mechanisms to ensure objectives are achieved, and be modified to incorporate new objectives.

The approvals process continues to be the central mechanism to ensure objectives are met and is modified as required.

97-10. The differences between existing environmental conditions and environmental limits be managed to ensure a preventative approach is taken to ongoing management. The multi-stakeholder group investigate, evaluate, and recommend mechanisms to manage this difference.

AEMIT conducted a “managing the gap” workshop to develop and refine the approach to managing and reducing emissions. This approach was the cornerstone of the work by the Target Loading Subgroup and identified three situations that require a different management approach. In the first situation, between pre-industrial background and current deposition levels, emissions are to be managed on a continuous improvement basis. In the second case, where emissions from plant expansions or a new facility would cause deposition to increase above the current level of deposition but would remain below the target load, emissions would be managed on an emission minimization basis. In the third case where emissions are expected to result in deposition exceeding the target load, emissions would need to be managed on an emission reduction basis to reduce them to below the target load.

The Target Loading Subgroup developed recommendations on critical loads (environmental limits) as well as lesser acid deposition levels—the target and monitoring loads. Management actions triggered by exceedance of target and monitoring loads will act as mechanisms to ensure that the gap between environmental conditions and limits is never closed.

The revised sulphur recovery guideline, although not a CASA initiative, will contribute to managing the gap. The Pollution Prevention/Continuous Improvement Project Team is also expected to recommend initiatives that will help manage the gap. Ongoing evaluation of new source performance standards to ensure the correct balance between economic development and environmental protection will be another key element in managing the gap.

97-11. The SO_2 management system be evaluated and enhanced, if necessary, by the multi-stakeholder group on the implementation of these recommendations and on the performance of the management system against the defined management goals and objectives of the system.

AEMIT has submitted three evaluation reports: June 1999, June 2000 and November 2001. The system has the potential to effectively manage SO_2 and NOx emissions in Alberta. As noted earlier, performance assessment against the economic efficiency and continuous improvement goals is difficult, since no numerical objectives have been set.

97-12. The multi-stakeholder group report to the CASA board at least annually for the first three years on implementation and evaluation, and once every five years on system evaluation.

Reports were submitted in 1999, 2000, and 2001. For the future, AEMIT recommends reports every two to three years (recommendation 3).

97-13. AEP and AEUB establish a comprehensive, reliable and integrated SO_2 atmospheric source and emission capture and reporting system. The system should use an acceptable electronic data information exchange standard that is compatible and can be integrated with collected ambient monitoring data.[§]

AEMIT agreed that an electronic database and concomitant electronic reporting are very important for establishing inventories, and that forecasting work (recommendation 14 below) needs to be made a priority because: (a) CASA project teams need this information and having timely access to it prevents each group from having to start at the beginning to assemble what they need, and (b) the information provides solid support for the development of innovative and creative air quality management systems and the assessment of cumulative effects.

SO_2 and NOx ambient air quality data are available in the online CASA data warehouse, but AEMIT believes that further effort is required. Emissions inventories are incomplete because there is no way to capture and pull together information from all sources and, for many sources, especially those that are not licensed, information is not being captured at all. The current system is paper-based and is difficult to access and consolidate. It is not clear what compatibility and integration with ambient monitoring data means. This situation and the limited progress on recommendation 97-14 resulted in AEMIT's recommendation 2 to the CASA board.

97-14. AEUB and AEP establish an SO_2 emission forecasting system that provides emission forecasts on an ongoing and timely basis.

Little progress has been made to date due to resource constraints at Alberta Environment and the AEUB. (See discussion under recommendation 97-13 above.)

97-15. CASA institute mechanisms, such as Internet, symposium/workshop, etc., for ongoing information sharing among stakeholders.

There has been substantial progress in developing information-sharing mechanisms. The CASA website has been substantially upgraded and enhancement of the CASA data warehouse is done on an ongoing basis. However, there is room for improvement. For example, the six years between CASA science symposia is too long.

[§] Recommendations 97-13 and 97-14 are regarded as applying to both SO_2 and NOx.

97-16. CASA assess and examine the potential application of the management system framework, recommended above, for the integrated management of air quality in Alberta.

No formal assessment has been done, but the management system framework is being used on an *ad hoc* basis by other organizations.

97-17. CASA support stakeholder activities related to the examination and implementation of other management instruments, such as economic instruments, which could be applied to the management of SO_2 emissions.

Some examples of economic instruments applied through other projects include:

- flaring (royalty relief, industry targets rather than site targets)
- sulphur recovery credits and sulphur emission control assistance program, expanded as a complement to Sulphur Recovery Guidelines

97-18. Using the recommendations put forth by the Target Loading Task Group, AEP establish deposition guidelines for the province using the multi-stakeholder process identified in recommendation 97-6.

These guidelines are in place.

97-19. Stakeholders work to ensure local, provincial, and national SO_2 management approaches and outcomes are complementary.

Participation of some stakeholders in multi-stakeholder processes at all three levels has been useful in accomplishing this.

97-20. The CASA board develop a strategy for communicating the results of this project to the stakeholders and the general public.

CASA communications in general have improved, but CASA has not specifically communicated the results of the SO_2 project to the general public.

6 Evaluation of the SO_2 Management System and Recommendations

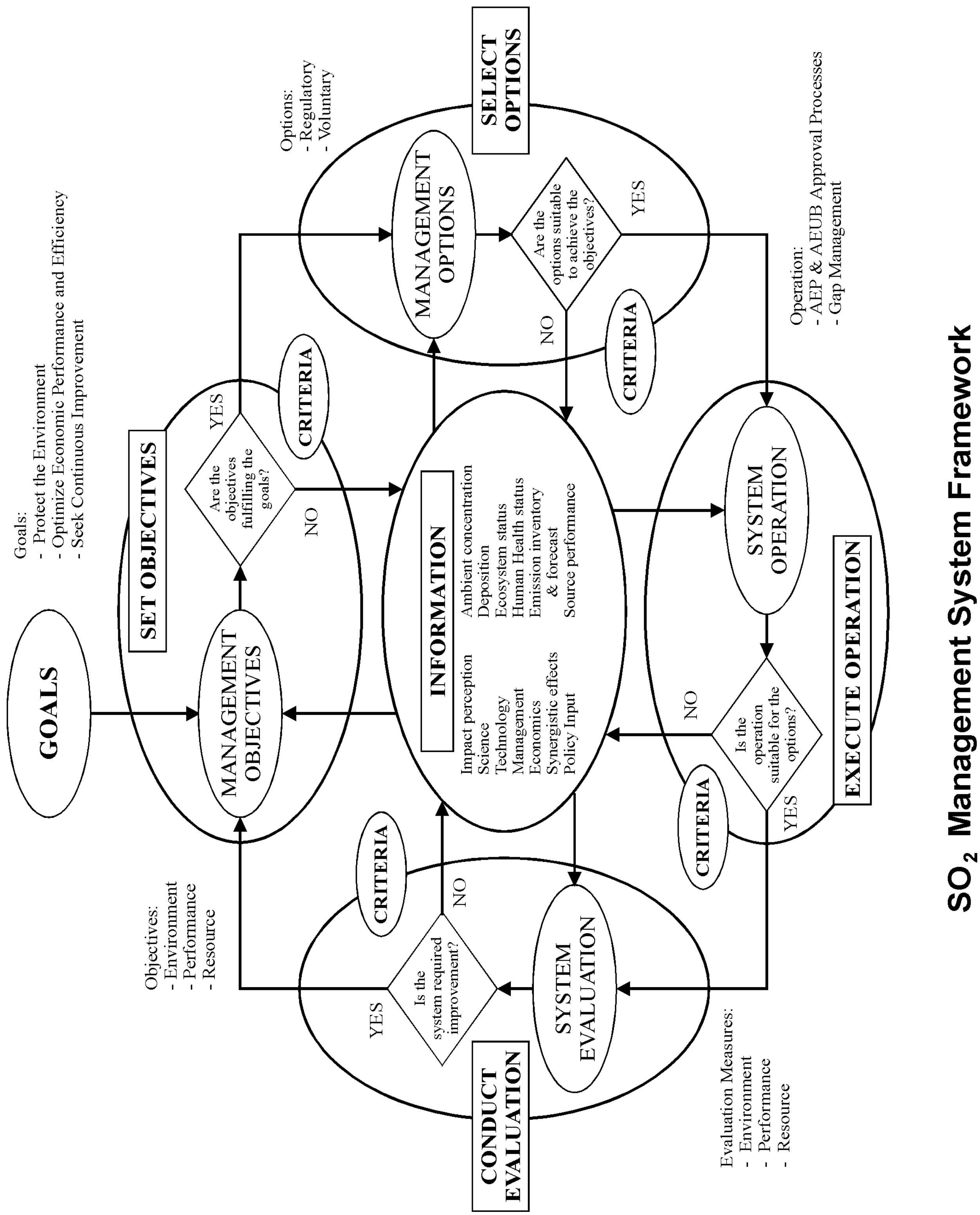
"The SO_2 Management System Framework explicitly links management options and implementation to goals and objectives, with feedback loops to information and evaluation."[5] The framework is illustrated graphically in Figure 2.

AEMIT was given responsibility for evaluating the SO_2 management system and, if necessary, enhancing the implementation of the recommendations and the performance of the management system against the management goals and objectives of the system. AEMIT has completed three annual evaluation reports to the CASA board. Based on this experience and additional work undertaken by the team, AEMIT has five recommendations for enhancing the SO_2 management system and one recommendation to help advance the overall goals of CASA.

Recommendation 1. When the Alberta Energy and Utilities Board and Alberta Environment identify a new acidifying emissions objective as a priority, they should also decide if it is appropriate to integrate the processes of setting the objective and developing a management framework. If the processes are integrated, the task should be referred to CASA. If integrated processes are not referred to CASA, an explanation will be provided.

This recommendation is an upgrade to the SO_2 management system described in the original report, which set out the "Objective Setting" and "Selection of Management Options" of the management system as separate tasks. The original SO_2 report identified Alberta Environmental Protection and the Alberta Energy and Utilities Board/Alberta Energy as responsible for management objectives, and CASA as responsible for developing management options. These processes have been combined in some recent initiatives such as the Solution Gas Flaring Management Framework, which was a CASA process, and the Sulphur Recovery Guideline Review, which was not. Table 3, "Responsibilities and Roles for the SO_2 Management System" from the original SO_2 report has been updated to reflect this recommendation and is attached as Appendix H.

Figure 2. SO_2 Management System Framework



Recommendation 2. Alberta Environment and the Alberta Energy and Utilities Board should establish the information systems listed below in support of acidifying emissions management:

- **i) provincial annual average concentration values for ambient NOx and SO_2 continuous monitoring stations;**
- **ii) the number of SO_2 and NOx continuous monitoring stations removed from approval requirements based on long term records of low readings or because of participation in zonal management;**
- **iii) a comprehensive source and emission data capture and reporting system;**
- **iv) an electronic source emission inventory database for managing data collected as described in item (iii); and**
- **v) an SO_2 and NOx emissions forecasting system.**

This recommendation stems from the less than stellar implementation of recommendations 13 and 14 in the 1997 report from the SO_2 Management Project Team, as described earlier in section 5. The information collection processes related to source and ambient monitoring were set up to provide information for the regulatory management option. Resource constraints and priorities in Alberta Environment and the Alberta Energy and Utilities Board have slowed the development of non-regulatory management information such as emission inventories and forecasts but AEMIT is optimistic that some of these gaps will soon begin to be addressed. CASA project teams, and others, need timely access to reliable inventory and forecast information to support the development of innovative and creative air quality management systems and the assessment of cumulative effects.

Recommendation 3. Alberta Environment should lead an evaluation of the acidifying emissions management system every two to three years based on the evaluation process that has been established by AEMIT. Evaluation results should be reported to the CASA board and the next evaluation should be done in 2003. This task would require Alberta Environment to complete the forms that AEMIT has developed and used to conduct its evaluation; these are:

- **the goals, objectives and performance measures table, and**
- **the evaluation protocols table.**

In its 1997 report, the SO_2 Management Project Team recommended that a system evaluation be done every five years (recommendation 12). The AEMIT reported in 1999, 2000 and 2001 and is of the view that five-year intervals are too long. Regular assessments are important to determine if the system is functioning properly. A CASA team does not necessarily need to do the assessment, but results should be reported to the CASA board. A description of the process and templates for evaluating the SO_2 Management System are included in Appendix C.

Recommendation 4. If Alberta Environment determines that improvements should be made after the evaluation done in recommendation 3, Alberta Environment should make recommendations to the CASA board or forward a statement of opportunity if it is appropriate for a CASA project team to look at the issue.

This new step, following from recommendation 3 above, would occur following the "evaluation process" and is indicated in the revised Table 3 in Appendix H.

Recommendation 5. The application of the management system framework developed by the SO_2 Management Project Team should be considered by Alberta Environment and the Alberta Energy and Utilities Board for the integrated management of air quality in Alberta.

AEMIT believes the management system framework developed for SO_2 could be extended to the management of other air emissions.

Recommendation 6. a) The CASA Communications Committee should increase the profile of the three air quality management goals in overall CASA documentation. These three goals are:

- **Protect the environment**
- **Optimize economic performance and efficiency**
- **Seek continuous improvement**

b) Other CASA project teams should consider incorporating the three air quality management goals in their terms of reference and reporting back to the CASA board on how the work of their team is consistent with the goals.

These goals have been used and adopted by Alberta Environment and by CASA's Electricity Project Team. They encompass protection of the environment while recognizing both the economic costs of impacts on the environment and human health, and the economic impact of environmental protection.

Endnotes

[1] *Sulphur Dioxide Management in Alberta: The Report of the SO_2 Management Project Team*, February 1997. p. 3. Available online at the CASA website, www.casahome.org/uploads/AEMIT_SO2_Management_final_report.pdf

[2] *Application of Critical, Target, and Monitoring Loads for the Evaluation and Management of Acid Deposition,* published in November 1999 by Alberta Environment and the Clean Air Strategic Alliance and available online at www.gov.ab.ca/env/protenf/standards or at www.casahome.org.

[3] *Priority-Setting Workshop Report for Alberta Ambient Air Quality Guidelines, Proceedings*. October 23, 2000. Available online at http://www.casahome.org/uploads/CASA_PrioritySetting4ABambientAQguidelinesOCT-23-2000.pdf

[4] *Alberta Ambient Air Quality Guidelines Work Plan*, April 2001. Alberta Environment. Available online at http://www3.gov.ab.ca/env/protenf/publications/AlbertaAmbientAirQualityGuidelinesWorkPlan.pdf

[5] *Sulphur Dioxide Management in Alberta: The Report of the SO_2 Management Project Team*. February 1997. p.11

Appendix A Members of the Acidifying Emissions Management Implementation Team, Subgroups and SO_2 Management Project Team

Acidifying Emissions Management Implementation Team

Randy Angle	Alberta Environment (co-chair)
Kerra Chomlak	Clean Air Strategic Alliance
Kim Eastlick	Alberta Energy and Utilities Board
Martha Kostuch	Prairie Acid Rain Coalition
Mike Leaist	TransAlta Corporation
Chris Severson-Baker	Pembina Institute for Appropriate Development
John Squarek	Small Explorers and Producers of Canada
Ron Pauls	Syncrude Canada Ltd. (co-chair)
Ron Schmitz	Canadian Association of Petroleum Producers
Darcy Walberg	Agrium/Fertilizer Manufacturers

Corresponding Member:

Dermot Lane	Fording Coal Limited

Past Members:

Kim Johnson	Canadian Petroleum Products Institute
Christine Macken	Clean Air Strategic Alliance
David McCoy	Husky Oil Limited

Note: The subgroup members' affiliation and organization names are listed as they were at the time the subgroup was active.

Enhanced Performance Subgroup

Randy Dobko	Alberta Environmental Protection
Kim Eastlick	Alberta Energy and Utilities Board
Grant Hilsenteger	Alberta Resource Development
Kevin Johnston	Alberta Energy and Utilities Board
Kim Johnson	Canadian Petroleum Products Institute
Martha Kostuch	Prairie Acid Rain Coalition
Brent Lakeman	Alberta Resource Development
Dermot Lane	Fording Coal Limited
Christine Macken	Clean Air Strategic Alliance
Ron Schmitz	Canadian Association of Petroleum Producers
Dan Smith	Pembina Institute for Appropriate Development

Evaluation Subgroup

Mike Leaist	TransAlta Corporation
Chow-Seng Liu	Alberta Environmental Protection (past member)

NOx/SOx Subgroup

Randy Dobko	Alberta Environment
Kim Eastlick	Alberta Energy and Utilities Board
Martha Kostuch	Prairie Acid Rain Coalition
Mike Leaist	TransAlta Corporation
Ron Pauls	Syncrude Canada Limited
Ron Schmitz	Husky Oil Limited
John Squarek	Canadian Association of Petroleum Producers

Past Member:

Kim Johnson	Canadian Petroleum Products Institute

Target Loading Subgroups

Dave Ballagh	Saskatchewan Environment and Resource Management
Kim Eastlick	Alberta Energy and Utilities Board
Kenneth Foster	Alberta Environmental Protection
Les Johnston	EPCOR
Martha Kostuch	Prairie Acid Rain Coalition
David McCoy	Husky Oil Limited
Karen McDonald	Environment Canada
Ron Pauls	Syncrude Canada Limited

SO_2 Management Project Team

Randy Angle	Alberta Environmental Protection
Lawrence Cheng	Alberta Environmental Protection
Ian Dowsett	Alberta Energy and Utilities Board
Murray Ellis	Clean Air Strategic Alliance
Bill Hunter	Canadian Petroleum Products Institute
Kim Johnson	Shell Canada Limited
Martha Kostuch	Prairie Acid Rain Coalition
Jerry Lack	Alberta Environmental Protection
Brent Lakeman	Alberta Environmental Protection
Gord Lambert	TransAlta Utilities Corporation
Dermot Lane	Fording Coal Limited
Garry Mann	Canadian Occidental Petroleum Limited
Karen McDonald	Environment Canada
Dave Nixon	Syncrude Canada Limited
David Pryce	Canadian Association of Petroleum Producers
Gary Sargent	Alberta Cattle Commission
Dan Smith	Pembina Institute for Appropriate Development
Darcy Walberg	Viridian Inc.

Appendix B Background Documents

Various reports were prepared by or for the Acidifying Emissions Management Implementation Team and the SO_2 Management Project Team before it. These are listed below. Most documents are available through the Clean Air Strategic Alliance.

SO_2 and NOx Emissions Inventories Upgrades for Alberta, Phase I. Prepared by Levelton Engineering Ltd. November 2001.

Application of Critical, Target, and Monitoring Loads for the Evaluation and Management of Acid Deposition. Target Loading Subgroup, Clean Air Strategic Alliance and Alberta Environment. November 1999.

Enhanced Performance Subgroup Report: Suggestions for Managing Acidifying Emissions in Alberta. Enhanced Performance Subgroup, Clean Air Strategic Alliance. June 1999.

SO_2 Management Implementation Team Objectives Setting Workshop, Final Report. Centre for Learning, Ghost River, Alberta. March 3 and 4, 1999.

"Managing the Gap" Workshop. CASA SO_2 Implementation Team, Rafter 6 Ranch, Seebe, Alberta. January 15-16, 1998.

Sulphur Dioxide Management in Alberta: The Report of the SO_2 Management Project Team. Clean Air Strategic Alliance, Edmonton. February 13, 1997.

Final Report of the Target Loading Subgroup on Critical and Target Loading in Alberta. Target Loading Subgroup, Clean Air Strategic Alliance, Edmonton. 1996.

Scientific Appendix to the Final Report of the Target Loading Subgroup on Critical and Target Loading in Alberta. May 1996. Clean Air Strategic Alliance.

Appendix C Process and Templates for Evaluation of the SO_2 Management System

Appendix C-1. Acidifying Emissions Management System Evaluation Process

The recommendation

> **11. The SO_2 management system be evaluated and enhanced, if necessary, by the multi-stakeholder group on the implementation of these recommendations and on the performance of the management system against defined management goals and objectives of the system.**

calls for evaluation or the performance of the management system. The evaluation process has been designed to answer two questions:

1. Are the goals of the management system being met (to protect the environment, to optimize economic performance and efficiency, to seek continuous improvement)?

2. Are the overall management system and the individual components (set objectives, management options), operating as set out in the 'Report of the SO_2 Management Project Team'?

Are the Goals of the Management System Being Met?

Process:

1. Identify management objectives that currently exist and organize against goals (see Goals, Objectives, Performance Measures table).

2. Develop performance measures against existing management objectives.

3. Develop other performance measures that relate to goals for which no management objective currently exists.

4. Review performance measures proposed through steps 2 and 3 with the AEMIT and reach agreement on ones that will be pursued.

5. Where it exists, collect data to calculate performance measures and develop assessments against management system objectives.

6. Where data doesn't currently exist, put process in place to obtain on ongoing basis.

Are the overall management system and the individual components (set objectives, management options), operating as set out in the 'Report of the SO_2 Management Project Team'?

Process:

1. Prepare evaluation protocols for each management system component containing a description of how the element is intended to operate and questions to determine whether the operation is as per description in the 'Report of the SO_2 Management Project Team.'

2. Complete evaluation templates by developing answers to questions with the AEMIT.

3. Summarize key points from reviews of individual system components and develop assessment of overall management system operation.

Appendix C-2. Acidifying Emissions Management System Evaluation Protocols

SET OBJECTIVES

Evaluation Questions	Assessment/Action
Are the various groups carrying out their roles as identified in the 'set objectives' component of the management system (from table 3 in Feb 1997 report)?	
Is there a process for identifying where new objectives and performance measures may be needed?	
Is there a consistent, clearly defined, multi-stakeholder process lead by AENV and AEUB for developing the new objectives once the need has been identified?	
Do the current objectives and performance measures provide a quantitative expression of the goals and are they explicitly linked to the goals?	
Is the identification of the need for new objectives responsive to new issues and information?	

SELECT MANAGEMENT OPTIONS

Evaluation Questions	Assessment/Action
Are the various groups carrying out their roles as identified in the 'select option' component of the management system?	
Are the AENV/AEUB approvals achieving the goals and objectives and are they providing for flexibility and innovation?	
Is there a process in place to develop alternate management options/instruments?	
Have other management instruments been implemented to meet the objectives (e.g. emissions trading)?	

EXECUTE OPERATION

Evaluation Questions	Assessment/Action
Are the various groups carrying out their roles as identified in the 'execute operation' component of the management system?	
Is the regulatory system operating effectively as the central mechanism to achieve objectives?	
Are any other management options in the 'execute operation' stage and if so are they operating effectively?	

CONDUCT EVALUATION

Evaluation Questions	Assessment/Action
Are the various groups carrying out their roles as identified in the 'conduct evaluation' component of the management system?	
Has the evaluation process been defined and is the process consistent with the characteristics set out (transparent, documented, objective, open, responsive to the needs of stakeholders)?	
Is the process implemented?	
Does the process include performance measures of system efficiency?	

INFORMATION

Evaluation Questions	Assessment/Action
Are the various groups carrying out their roles as identified in the 'information' component of the management system?	
Were resources available to generate or locate information needed to properly execute the four other components of the management system?	
Is the current information available on ambient concentrations, mass loadings and environmental monitoring adequate and responsive to management system needs (timely, accessible)?	
Is the information collection and management system efficient and cost effective?	
What mechanisms are in place for ongoing information sharing among stakeholders?	

Appendix C-3. Goals, Objectives and Performance Measures for the SO_2 Management System Evaluation, May 2001

GOAL	MANAGEMENT OBJECTIVE	PERFORMANCE MEASURES	RESULTS	SOURCE OF DATA

To Protect the Environment
• Minimize adverse effects (short- and long-term)
  • People
  • Animals
  • Environment
	Compliance with ambient concentration guidelines
	• Hourly SO_2<0.17 ppm
	• Hourly NOx<0.21 ppm
	• Daily SO_2<0.06
	• Daily NOx<0.11
		% Exceedences =
		\# Exceedences x 100%
		# Hours monitored		

		% Compliance = (#Hours mon. - # exceedences) x 100% # Hours monitored		
	Compliance with ambient concentration guidelines • Hourly SO_2<0.17 ppm • Hourly NOx<0.21 ppm • Daily SO_2<0.06 • Daily NOx<0.11	Average annual ambient concentration for industrial compliance stations (SO_2, NO_2)		
	Compliance with deposition guidelines -Monthly sulphation • <0.5 SO_3 equiv mg/day/100cm2	Number of sulphation exceedences		
	-Interim critical loads for acid deposition for high, moderate, low sensitivity soils • High < .25 H+/ha/yr • Moderate< .50 H+/ha/yr • Low< 1.0 H+/ha/yr	# Gridcells>limit (Based on modeling data)		
	Compliance with source emission and sulphur recovery requirements	# Exceedences of source emission approval limits		
To Optimize Economic Performance and Efficiency • Minimize adverse economic impacts • Ensure best use of resources (technological, human, financial, etc.) • Facilities, goods, services		number of SO_2/NOx continuous monitoring stations removed from approval requirements based on long term record of low readings or thru participation in zonal management		
		Economic performance and efficiency goal can be achieved by the means (management option) used to achieve		

GOAL	MANAGEMENT OBJECTIVE	PERFORMANCE MEASURES	RESULTS	SOURCE OF DATA
		environmental objectives. Performance measure is the assessment of whether or not the management option selected to meet objectives meets the criteria set out in the SO_2 Project Team Report and the Enhanced Performance Subgroup Report. For each management option that has been selected since the beginning of 1999, each main stakeholder group represented on AEMIT makes this (yes/no) assessment.		
		Number of ambient monitoring stations (NOx/SOx)		
Pursue economic enhancements on a full life-cycle basis		No Proposed Measures		
• Meet societal expectations • Ensure that the integrity of the economy is maintained • Ensure the needs of future generations are not compromised		No Proposed Measures		
To Seek Continuous Improvement (Eco-Efficiency) • Minimize wastes (e.g., per unit of output) • Waste minimization and pollution reduction/prevention		Total SO_2 and NOx emissions (kilotonnes)		
		SO_2 and NOx emissions per unit GDP (tonnes/$M)		
• Minimize resource inputs and use (e.g., per unit of output) • Resource conservation and energy efficiency				
• Enhance competitiveness				

Appendix D NOx/SOx Matrices Prepared by the NOx/SOx Subgroup

Appendix D-1a. Alberta SO_2 Emissions – 1995 (tonnes/year)

		No. of Facilities	Source Type	1995 Emissions	Key Regulatory Tool	Comments
Division 2: Substance Release						
Part 1:	Agriculture					
Part 2:	Chemical					
	Fertilizer	2		1,505	Fertilizer Guidelines	sulphuric acid plants
	Chemical Manufacturing	5	point	357	unknown	H2S manufacturing plant accounts for 267 t
			area	28		
	Coke/Carbon Manufacturing	1		2,419	uncontrolled	Alcan
	Petrochemical Manufacturing	4		271	unknown	one source accounts for 251 t
Part 3:	Construction					
	Cement	2		3,090	uncontrolled	feedstock related
				4	uncontrolled	
Part 4:	Food or Animal By Products					
Part 5:	Metals	unknown	area	81	unknown	
Part 6:	Mineral Processing	unknown	area	447	unknown	
Part 7:	Wastewater and Storm Drainage					
Part 8:	Oil & Gas					
	Oil Refinery	6		8,741	IL88-13	3 sources uncontrolled - 325 t
	Oil Sands Processing	2		160,948	IL88-13 and National Power Guidelines	
	Sour Gas Processing	234		193,877	IL88-13	
	Sour Gas Well Testing			30,400	uncontrolled	
	Solution Gas Flaring			52,200	uncontrolled	
	Oilfield Salt Water Disposal			6,492	uncontrolled	

		No. of Facilities	Source Type	1995 Emissions	Key Regulatory Tool	Comments
Part 9:	Power Plants	7		130,400	National Power Plant Guidelines	coal-fired power plants
		17		19	uncontrolled	all other plants; uncontrolled due to nature of feedstock (i.e., low sulphur coal)
Part 10:	Services					
Part 11:	Wood Products					
	Pulp and Paper (Kraft)	4	point	3,818	controlled for odor abatement	
			area	22		
	Wood Industry	2		1	unknown	
	Wood Waste Incineration	unknown	area	10	unknown	
Part 12:	Biotechnology					
Part 13:	Manufacturing					
Division 1 - Waste Management						
	Ind./Comm. Incineration	unknown	area	7	unknown	
Division 3 - Conservation and Reclamation						
	Coal Processing	5	point	1,907	uncontrolled	
			area	429		
Other Sources						
	Industry	unknown	area	234	unknown	
	Forest Fires	unknown	area	32	uncontrolled	
	Prescribed Burning	unknown	area	43	unknown	
Transportation Sector						
	Air	unknown		527	Fuel Formulation	National Standard
	Gasoline Powered Vehicles	unknown		1,419	Fuel Formulation	National Standard
	Diesel Powered Vehicles	unknown		7,509	Fuel Formulation	National Standard
Fuel Combustion						
	Commercial	unknown		389	Fuel Formulation	
	Residential	unknown		317	Fuel Formulation	
	Residential Wood	unknown		108	None	

Appendix D-1b. Alberta NOx Emissions – 1995 (tonnes/year)

		No. of Facilities	Source Type	1995 Emissions	Key Regulatory Tool	Comments
Division 2: Substance Release						
Part 1:	Agriculture					
Part 2:	Chemical					
	Fertilizer	6	point	6,518	CCME Heater and Boiler Guideline; Fertilizer Guidelines;	Approval Process (nitric acid and ammonia plants);
	Chemical Manufacturing	10	point	4,431	CCME Heater and Boiler Guideline	
	Fertil./Chemical Manufacturing		area	4,872		
	Coke/Carbon Manufacturing	2		227		Alcan
				506		Cancarb
	Petrochemical Manufacturing	9		7,545	CCME Heater and Boiler Guideline	
Part 3:	Construction					
	Cement	4		7,638	CCME Cement Kiln Guideline	
	Insulation Manufacturing	2		297	CCME Heater and Boiler Guideline	
	Building Products	1		30	CCME Heater and Boiler Guideline	
	Miscellaneous	unknown	area	237		
Part 4:	Food or Animal By Products					
Part 5:	Metals	unknown	area	92		
	Foundries	unknown	area	1		
Part 6:	Mineral Processing					
Part 7:	Wastewater and Storm Drainage					
Part 8:	Oil & Gas					
	Oil Refinery	5		3,924	CCME Heater and Boiler Guideline	
	Oil Sands Processing	2		16,542	CCME Heater and Boiler Guideline; CCME National Turbine Guideline	
	Sour Gas Processing	1219	point	218,321	IL88-5; CCME National Turbine Guideline	all upstream oil/gas; sweet gas plants and compressor stations
			area	37,391		
	Oilfield Salt Water Disposal	1		32		multiple sources

		No. of Facilities	Source Type	1995 Emissions	Key Regulatory Tool	Comments
Part 9:	Power Plants	34	point	86,582	National Power Plant Guideline; National Turbine Guidelines	coal fired facilities (7) - 79321 t; gas fired facilities (5) - 5627 t
			area	4,152		
Part 10:	Services					
Part 11:	Wood Products					
	Pulp and Paper	6	point	4,425		
			area	5		
	Wood Industry	33		4,857		
	Industrial Fuelwood Combustion	unknown	area	582		
	Residential Fuelwood Comb.	unknown	area	667		
Part 12:	Biotechnology					
Part 13:	Manufacturing					
Division 1 - Waste Management						
	Indust./Commercial Incineration	unknown		13		
	Crematorium	unknown	area	2		
Division 3 - Conservation and Reclamation						
	Coal Processing	5	point	1,106		
			area	231		
	Mining/Rock Quarrying	unknown	area	620		
Other Sources						
	Industrial Fuel Combustion	unknown	area	788		
	Commercial Fuel Combustion	unknown	area	5,444		
	Residential Fuel Combustion	unknown	area	6,365		
	Forest Fires	unknown	area	14,252		
	Prescribed Burning	unknown	area	2,070		
Transportation Sector						
	Air	unknown		8,215	unknown	
	Gasoline Powered Vehicles	unknown		61,054	Vehicle Emission Standards	
	Diesel Powered Vehicles	unknown		137,183	Vehicle Emission Standards	

Appendix D-2a. Summary of SO_2 Emission Control Technologies and Cost Information

Industrial Sectors	Available Technologies	Emission Reduction Efficiency	Cost*
Utilities (coal fired and coke fired)	Non- Regenerative FGD: Ammonium Sulphate Flue Gas Desulphurization	91% (Syncrude, 2000)	(see oilsands sector)
	Wet Flue Gas Desulphurization	95% - 95.4% (TransAlta, 2000; EmtrolCorp, 2000)	Capital: $90 -147 M (M = million) Operating and Maintenance (O&M): $6 - 14.5 M/year (TransAlta, 2000) Cost-effectiveness (Smith, et al., 1998): £260-460/tonne SO_2 removed ($572-1012/tonne SO_2 removed)
	Spray-drying Flue Gas Desulphurization (application of the process is limited to unit sizes up to 150 MW_e) (Smith, et al., 1998)	70% - 90% (Schmitz, 2000; Smith, et al., 1998)	Cost-effectiveness (Smith, et al., 1998): £200-330/tonne SO_2 removed ($440-726/tonne SO_2 removed)
	Limestone Injection Multistage Burner or Furnace Sorbent Injection (LIMB FDG)	50% (TransAlta, 2000), 55% to 70% (Schmitz, 2000)	Capital: $24 - 40 M (TransAlta, 2000) O&M: $4 -7.5 M/year (TransAlta, 2000) Or To reduce SO_2 emissions by 77 to 97 tonnes per day from coal-fired power plants in Alberta (Schmitz, 2000): Capital: $240 M O&M: $50 M/year Cost-effectiveness (Smith, et al., 1998): £420-490/tonne SO_2 removed ($924-1078/tonne SO_2 removed)
	LIFAC (Dry injection FGD?) (TransAlta, 2000)	75%	Capital: (information to come) O&M: (information to come)
	Current control methods: a) 5% to 10% of SO_2 is removal by particulate control device, b) by reducing production (TransAlta, 2000)		

Industrial Sectors	Available Technologies	Emission Reduction Efficiency	Cost*
	Regenerative FGD (no recorded commercial applications) (CH2M Hill Engineering Ltd., 1993; Cooper at al., 1997): - Wellman-Lord process - Cansolv™ process - SCOSOx® (Goal Line Environmental Technologies LLC, 2000) http://www.glet.com)	~ 98% - 99.8% (CH2M Hill Engineering Ltd., 1993; Goal Line Environmental Technologies LLC, 2000)	Cost estimation for Cansolv™ process (Syncrude Canada, 1991; CH2M Hill Engineering Ltd., 1993): Capital cost: $104 M for one CO boiler Operating cost: $34 M/year/boiler has requested price information of the SCOSOx system from the manufacturer
	Combined SOx/NOx control systems (Smith et al., 1998):		
	- The SNOx process	> 95% SO_2 reduction and about 95% NOx reduction	N/A
	- The DESONOx process	94% SO_2 reduction and about 80% NOx reduction	N/A
	- The SOx-NOx-ROX BOX (SNRB) process	80% SO_2 reduction and > 90% NOx reduction	N/A
	- The Lurgi CFB process	up to 97% SO_2 reduction and 88% NOx reduction	N/A
	- The E-beam process	94% SO_2 reduction and up to 80% NOx reduction	N/A
Sour Gas Processing: Sulphur recovery plants (Schmitz, 2000)	Conventional Claus process	92.0% to 97.0% (in Alberta: 87.3% to 98.3%)	N/A
	Claus process + tail gas clean-up unit: Claus process + Sulfreen	98.0% to 98.7% (in Alberta: 98.1% to 99.0%)	Capital: $88 M O&M: $5 M/year Annualized cost: 1381 $/ tonne S

Industrial Sectors	Available Technologies	Emission Reduction Efficiency	Cost*
	Claus process + SCOT	99.9% to 99.98%	Capital: $215 M O&M: $38.7 M/year Annualized cost: $2763/tonne S
Acid gas flaring plants (Schmitz, 2000)	Acid gas injection system	~ 100%	Capital cost varies with acid gas capacity (see Figure 1) Operating costs: 1) maintenance and repair costs = 3% of capital costs 2) other operating costs = $138.92 per million standard cubic feet of acid gas (1999$) Cost-effectiveness: $400 to $1600/tonne of sulphur injected (85% acid gas quality, in 2000 dollars) $600 to $2300/tonne of sulphur injected (15% acid gas quality, in 2000 dollars)
Well Test Flaring (Schmitz, 2000)	Information is unavailable (emission reduction mainly achieved by meeting the requirements of the "Upstream Petroleum Industry Flaring Requirement, Guide-60" (EUB, 1999), i.e. reduction in well flow test volume or limiting duration of test)	N/A	N/A
Oilsands Operation (Acid gas portion)	Amine, Claus process + Sulfreen+ Ammonium Sulphate Flue Gas Desulphurization (Syncrude, 2000)	99.9%	Cost for ~ 600 tonnes/day S recovery Amine, Claus and Sulfreen plants: a) Total installed Cost (including indirect cost): $0.10 M/tonne S /day b) Direct Field Cost (equipment and installation only): $0.06M/tonne S /day c) Operating cost (including running maintenance = 1.730, shutdown maintenance = 0.400, chemicals/lube = 0.017, workforce = 0.046): 2.193 M/year Cost for FGD: a) Total installed cost: $1.49 million (M)

Industrial Sectors	Available Technologies	Emission Reduction Efficiency	Cost*
			/tonne S /day b) Direct field cost: $0.88 M/tonne S /day c) Operating cost (including running maintenance = 0.810, shutdown maintenance = 2.000): 2.810 M/year
Salt Water Disposal	Waste gas injection system (part of the salt water disposal system) (Redwater Water Disposal Company Limited, 2000)	~ 100%	Capital cost (control equipment, piping and electrical wiring): $5000 Operating cost: ~ 0
Coke Calcining	No information available, however, FGD technologies might be applied to this industry with certain process modification.	(see FGD technologies in Utility sector)	(see FGD technologies in Utility sector)
Cement Manufacturing (Greer, 1989)	*Efficient kiln system with low fuel input*	N/A	N/A
	Absorption in the particulate control device	N/A	N/A
	Gas scrubbing in the raw mill (absorption of SO_2 in roller mills)	N/A	N/A
	Internal absorption systems (calcium or sodium-based SO_2 scrubbing systems located within the cement-making process)	N/A	N/A
	Tail gas scrubbers	N/A	N/A
	Selective quarrying (high sulphur areas can be by-passed and/or blended with low-sulphur materials from the same source)	N/A	N/A
	Raw material beneficiation (screening out of sulphur-containing components)	N/A	N/A
		N/A	N/A
	Alternate raw materials	N/A	N/A
	Low sulphur/clean coal	N/A	N/A
	Alternative fuels		
Pulp & Paper mills	In-process controls: use low sulphur heavy oil fuels; firing high percent solids black liquor (H.A. Simons Ltd., 1995)	75% (by contact with black liquor in direct contact evaporator type recovery boiler)	Cost estimation for upgrading a low odor boiler to high solids firing: Capital cost: $4 M (an additional $1.8 –

Industrial Sectors	Available Technologies	Emission Reduction Efficiency	Cost*
		removal efficiency depends on the solid content in the black liquor fired in the low odour type recovery boilers	2.7 M for conversion to ultra high solids firing) (H.A. Simons Ltd., 1995)
	Scrubbing (H.A. Simons Ltd., 1995) Wet – scrubbers	75% with weak wash (SO_2 emission originating from oxidation of Total Reduced Sulphur in smelt dissolving tanks) 80 - 95% (from wood fired power boiler)	Wet Scrubbers (used in): 1. smelt dissolving tank Capital cost: $0.5 M (H.A. Simons Ltd., 1995) 2. wood fired power boiler Capital cost: $5.6 M (H.A. Simons Ltd., 1995)
	Dry – scrubbers	70 – 80% (from wood fired power boiler)	N/A
	Wet-dry scrubbers	N/A	N/A
	Stand alone incinerator (thermal oxidizers, to burn off non-condensable gases) (Tarpey, 2000)	N/A	Capital cost: ~ $1 M (Tarpey, 2000)
Coal Processing	Coal Washing (conventional) (Smith et al., 1998)	25%	N/A
	TRW Gravimelt or Molten Caustic Leaching (MCL) process (developed in US, currently in pilot-plant stage) (Smith et al., 1998)	removes almost all the pyritic sulphur (but not the organic sulphur)	N/A
	A process similar to TRW Gravimelt or Molten Caustic Leaching (MCL) was developed by CSIRO institute (Australia) (Smith et al., 1998)	removes almost all the pyritic sulphur	Operating cost: ~ £50/tonne of coal ($110/tonne)
	Biodesulphurisation (no full scale application) (Smith et al., 1998)	N/A	Operating cost (estimated): ~ £30/tonne of coal ($66/tonne)

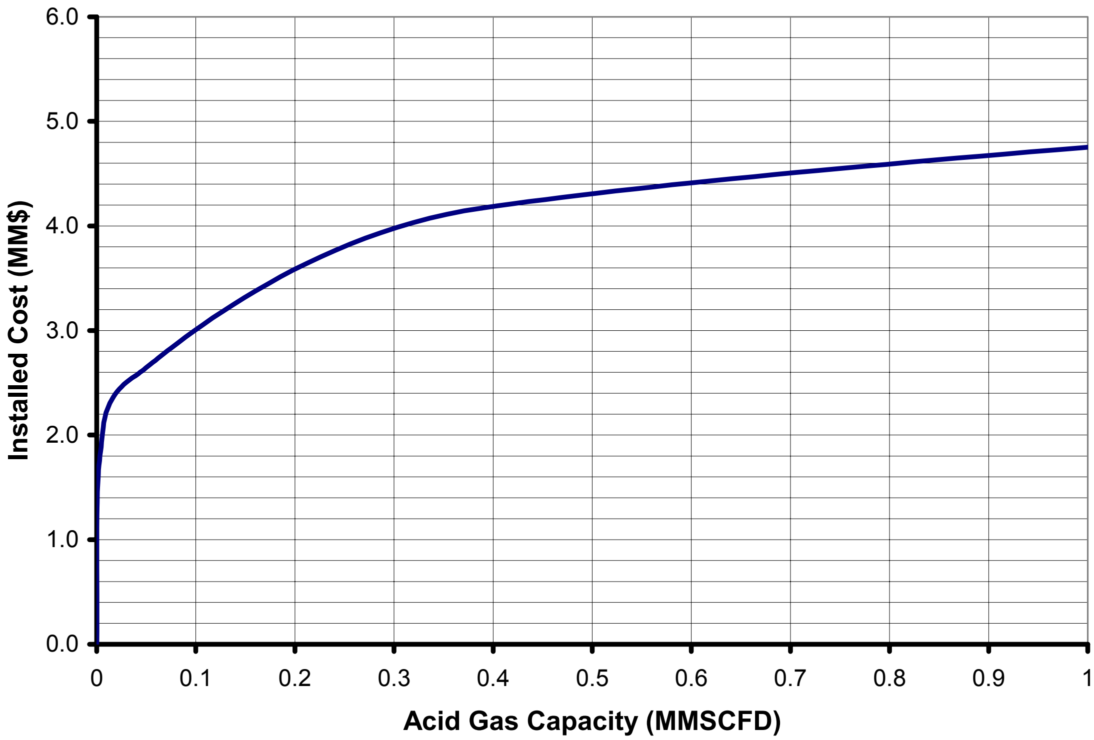
Industrial Sectors	Available Technologies	Emission Reduction Efficiency	Cost*
	Self-scrubbing coal (a mix of conventionally washed coal and limestone, developed in US) (Smith et al., 1998)	N/A	N/A
Transportation (gasoline and diesel-powered vehicles and engines)	Fuel modification: reduction of sulphur in gasoline and diesel (Environment Canada, 2000; Smith et al., 1998)	N/A	Diesel (Environment Canada, 2000) 1. To reduce sulphur level in on-road diesel from current 320 ppm (average) to 50 ppm: Capital cost: $1.2 billion Operating cost: $80 M/year Annualized unit cost: ¢1.56/liter 2. To reduce sulphur level in regular (off-road) diesel from current 2630 ppm (average) to 400 ppm: Capital cost: $420 M Operating cost: $43 M/year Annualized unit cost: ¢1.41/liter Gasoline To reduce sulphur level in gasoline from 350 ppm to 30 ppm: Capital cost: ~ $200 M ? (Shell Canada Ltd., Calgary Herald, Nov. 7, 2000 news) Operating cost: N/A
	Alternative fuels (Smith et al., 1998)		N/A

* The cost information is reported in various formats based on the source information provided.
N/A = information is unavailable

Figure 1 (for Appendix D-2a)

Capital Costs - Acid Gas Compression, Dehydration, Pipeline and Injection

Wells (1997$) (Schmitz, 2000)



References (for Appendix D-2a)

CH2M Hill Engineering Ltd., 1993. *Evaluation of Option to Reduce Sulphur Dioxide Emissions from the Natural Gas Processing and Tar Sands Industries* (A report prepared for Environmental Canada). Report EPS 2/PN/2. Minister of Supply and Services Canada, Catalogue No. En 49-11/2-2E.

Cooper, J.R.; Collins, R.; Massey, T.H.; Venkatesaran, N. and Westaway, S. 1997. “Sulphur removal from flue gases in utility sector: practicalities and economics,” in Proceedings of the Institution of Mechanical Engineering. Part A – *Journal of Power and Energy*, 211(1): 11-26.

EmtrolCorp, 2000. FGD System Controls SO_2 Emissions. http://www.EmtrolCorp.com.

Environment Canada, 2000. “Future Canadian emission standards for vehicles and engines and standards for reformulation of petroleum-based fuels.” A discussion paper in advance of a Notice of Intent by the Federal Minister of Environment. April, 2000.

Goal Line Environmental Technologies LLC, 2000. The SCOSOx Catalytic Sorption System for Flue Gas Desulfurization http://www.glet.com.

Greer, W.L. 1989. “SO_2/NOx control compliance with environmental regulations.” *IEEE Transactions On Industry Applications*, 25(3): 475-485.

H.A. Simons Ltd. 1995. *Emissions and Control Options for Wood and Wood Derived Fuel Fired Industrial Boiler Systems.*

Redwater Water Disposal Company Limited. 2000. *Salt water disposal system description.*

Schmitz, R. 2000. *Acidifying Emissions in Alberta – Managing the Gap*. Master of Engineering Thesis, University of Calgary.

Smith, A.; Chakraborty, R.; Goode, A.; Marlowe, I.; Marsh, G.; Maunder, D; Sharman, P; Stewart, I. 1998. *Technical Innovation to Reduce the Adverse Environmental Impacts of Existing Energy Sources.* AEA Technology, Culhom D5, Abingdon, UK (http://www.aeat.co.uk).

Syncrude, 2000. Emission reduction technologies and cost information.

Tarpey, T. (Daishowa Marubeni) 2000. Telephone conversation.

TransAlta, 2000. Emission reduction technologies and cost information.

Appendix D-2b. Summary of NOx Emission Control Technologies and Cost Information

Industrial Sectors	Available Technologies	Emission Reduction Efficiency/Effluent Concentration	Cost*
Agriculture (NOx are primarily emitted from): Farm vehicles Fertilizers (Alberta Agriculture website: agric.gov.ab.ca)	No information is available for the agriculture sector (however, the information on the available technologies and related cost for the vehicles/transportation sector can be used as a reference for farm vehicles)	N/A	N/A
Heaters & Boilers	Combustion Control (CCME, 1998):		
	Low Excess Air	16% - 20%	N/A
	Low NOx Burners		Capital Cost ($K): 54.5 (for new boiler/heater) 329.4 (for retrofit) Cost effectiveness ($/tonne of NOx reduced): 309 (for new boiler/heater) 3,821 (for retrofit)
	- Air–staged	37% - 50%	N/A
	- Fuel –staged	37% - 60%	N/A
	- Ultra-low NOx burners	73% - 75%	Capital Cost ($K): 92.0 (for new boiler/heater) 366.9 (for retrofit) Cost effectiveness ($/tonne of NOx reduced): 418 (for new boiler/heater) 3298 (for retrofit)
	- Radiant	85% (natural gas fired)	N/A
	Flue Gas Recirculation	35% - 57%	Capital Cost ($K): 64.0 (for new boiler/heater) 243.4 (for retrofit) Cost effectiveness ($/tonne of NOx reduced): 557 (for new boiler/heater) 3,006 (for retrofit)

Industrial Sectors	Available Technologies	Emission Reduction Efficiency/Effluent Concentration	Cost*
	Flue Gas Recirculation and Low NOx Burners	45% - 70%	N/A
	Reduction of Combustion Air Temperature	N/A	N/A
	Water or Steam Injection	N/A	N/A
	Staged Combustion	N/A	N/A
	Reburning	N/A	N/A
	Post-combustion Control: *Selective Non-catalytic Reduction*	50%	Capital Cost ($K): 363.6 (for new boiler/heater) 424.3 (for retrofit) Cost effectiveness ($/tonne of NOx reduced): 5,451 (for new boiler/heater) 7,168 (for retrofit)
	Selective Catalytic Reduction	80% - 90%	Capital Cost ($K): 708.1 (for new boiler/heater) 1,365.8 (for retrofit) Cost effectiveness ($/tonne of NOx reduced): 3,993 (for new boiler/heater) 9,219 (for retrofit)
	Combined sulphur oxides/nitrogen oxides (SOx/NOx) Control (CCME, 1998):		
	- Wet Scrubbing	N/A	N/A
	- Irradiation	N/A	N/A
	- Adsorption	N/A	N/A
	- Alkali Injection	N/A	N/A
	- Catalytic Methods	N/A	N/A
	The following combined SOx/NOx control technologies are applicable to both power and heat generation industries (Smith et al., 1998):		

Industrial Sectors	Available Technologies	Emission Reduction Efficiency/Effluent Concentration	Cost*
	- The SNOx process	> 95% SO_2 reduction and about 95% NOx reduction	N/A
	- The DESONOx process	94% SO_2 reduction and about 80% NOx reduction	N/A
	- The SOx-NOx-ROX BOX (SNRB) process	80% SO_2 reduction and > 90% NOx reduction	N/A
	- The Lurgi CFB process	up to 97% SO_2 reduction and 88% NOx reduction	N/A
	- The E-beam process	94% SO_2 reduction and up to 80% NOx reduction	N/A
	Fuel switching	N/A	N/A
	Energy Conservation	N/A	N/A
	SCONOx TM (Goalline Env Technologies, LLC., 2000; ABB Alstom, 2000)	< 2 ppm	Information to come
Engines - Turbine (Klein, 1996, 1999)	*Water Injection*	70-80% (water/fuel mass ratio 1:1)	Annualized cost ($/year): (a) 29,600 (3-20 MW, Cogeneration) (b) 34,000 (3-20 MW, Simple cycle) Cost effectiveness ($/tonne of NOx removed): (a) 492 (3-20 MW, Cogeneration) (b) 2,850 (-20 MW, Simple cycle)
	Steam Injection	70-80%	Annualized cost ($/year): (a) 851,600 (>20 MW, Cogeneration) (b) 721,000 (> 20 MW, Combined cycle) Cost effectiveness ($/tonne of NOx removed):

Industrial Sectors	Available Technologies	Emission Reduction Efficiency/Effluent Concentration	Cost*
			(a) 847 (>20 MW, Cogeneration) (b) 1,730 (> 20 MW, Combined cycle)
	Dry Low NOx	25-30 ppmv (for small to medium-sized units), 7 ppmv (for large units)	Annualized cost ($/year): (a) 321,600 (>20 MW, Cogeneration) (b) 73,000 (3-20 MW, Simple cycle) (c) 400,000 (>20 MW, Simple cycle) Cost effectiveness ($/tonne of NOx removed): (a) 77 (>20 MW, Cogeneration) (b) 450 (3-20 MW, Simple cycle) (c) 1020 (>20 MW, Simple cycle)
	Selective Catalytic Reduction (SCR) (used on large units)	~ 80%	Capital cost: $50/KW installed (for large units)
	SCONOx ™ (Goalline Env Technologies, LLC., 2000; ABB Alstom, 2000)	<2 ppm	(see heater and boiler sector)
- Reciprocating	*Improved combustion controls* Reducing peak temperature (US EPA, 1999) 1. air/fuel ratio 2. timing of ignition/type of ignition 3. pre-stratified combustion (pre-combustion)	20-97%	NOx emission could be reduced by about 66% at no cost by the improved combustion controls (Schmitz, 2000) The estimated cost for the pre-combustion technology (Karell, et al., 1991): Capital cost: $2 M O&M cost: $20,000/year
	Reducing residence time at peak temperature (US EPA, 1999): valve timing	N/A	N/A
	Low NOx combustion retrofits (Schmitz, 2000)	33-79%	Cost effectiveness ($/tonne of NOx removed): 453 to 3423

Industrial Sectors	Available Technologies	Emission Reduction Efficiency/Effluent Concentration	Cost*
	Chemical reduction of NOx (catalytic converters)	80-90% (US EPA, 1999)	
	Selective catalytic reduction (SCR)		Capital and operating cost: varies with compressor size (see Figures 1 and 2, Schmitz, 2000) For SCR units designed for 80% NOx control (Karell, et al., 1991): Capital cost: $2 - 4 M O&M cost: $140,000/year Cost effectiveness ($/ton of NOx removed) (US EPA, 1999): 500 – 2,800
	Non-Selective Catalytic Reduction (NSCR)		Capital cost: N/A O&M cost: N/A Cost effectiveness ($/ton of NOx removed) (US EPA, 1999): 700 – 1300
	Oxidation of NOx with subsequent absorption (US EPA, 1999): Non-thermal Plasma Reactor (NTPR)	80-95%	N/A
	Removal of nitrogen (US EPA, 1999): Ultra-Low Nitrogen Fuel	N/A	N/A
	Using a sorbent (US EPA, 1999): Sorbent In Exhaust Ducts Adsorber In Fixed Bed	60-90%	N/A
	SCONOx ™ (Goalline Env Technologies, LLC., 2000; ABB Alstom, 2000)	<2 ppm	(see heater and boiler sector)
Cement Kilns (CCME, 1998)	*Combustion Operation Modifications (COM)* (all types of kilns)	15-30% (SOx, CO, THC may increase)	N/A
	Low NOx Burners (LNB) (indirect-fired, direct-fired kilns)	15-30% (CO, THC may increase)	Annualized cost (K$/year): (a) 110-160 (indirect-fired kilns)

Industrial Sectors	Available Technologies	Emission Reduction Efficiency/Effluent Concentration	Cost*
			(b) 370-590 (direct-fired kilns) Cost effectiveness ($/tonne of NOx removed): (a) 340-570 (indirect-fired kilns) (b) 1,280-2,050 (direct-fired kilns)
	Staged Air Combustion (SAC) (precalciner, preheater, and long kilns)	20-50% (CO, THC may increase)	Annualized cost (K$/year): (a) 120-160 (precalciner, preheater) (b) 180-220(long kilns) Cost effectiveness ($/tonne of NOx removed): (a) 250-400 (precalciner, preheater) (b) 660-940 (long kilns)
	Selective Non-catalytic Reduction (SNCR) (precalciner kilns)	40-70% (potential for NH_3, PM_{10} emissions)	Annualized cost (K$/year): 610-1,250 (precalciner kilns) Cost effectiveness ($/tonne of NOx removed): 1,220-1,690
	Selective Catalytic Reduction (SCR) (all types of kilns)	70-90% (potential for NH_3, PM_{10} emissions, SO_3 may increase)	Annualized cost (K$/year): 3,510-10,050 Cost effectiveness ($/tonne of NOx removed): 4,840-7,500
Utilities (TransAlta, 2000)	*Separated Overfire Air (SOFA)/Low NOx Burners (LNB)* (SOFA systems installed in combination with LNB) *Advanced Coal Reburning (ACR)* *Selective Catalytic Reduction (SCR)*	50% 65% 90%	Capital cost ($ millions): 5-7 Annual O&M cost ($ millions): negligible Capital cost (($ millions): 8-14 Annual O&M cost ($ millions): 1.5-3.5 Capital cost (($ millions): 26-44 Annual O&M cost ($ millions): 2-3.5 Cost effectiveness (($/tonne of NOx removed): 1700 to 3000 (Schmitz, 2000)

Industrial Sectors	Available Technologies	Emission Reduction Efficiency/Effluent Concentration	Cost*
	SCONOx ™ (Goalline Env Technologies, LLC., 2000; ABB Alstom, 2000)	< 2 ppm	(see heater and boiler sector)
Vehicles/Transportation (California Air Resources Board, 1997) On-Road Vehicles: a) Light-duty vehicles passenger cars (gasoline and diesel)	Model year		
	Retrofit NOx devices (ignition timing retard and exhaust gas recirculation (EGR)) — 1966-1970	N/A	N/A
	Ignition timing retard *EGR* — *1972-1974*	N/A	N/A
	Ignition timing retard *Enriched air fuel mixture* *EGR* — 1975-1979	N/A	N/A
	Three-way catalyst (TWC) *Oxygen Sensor* *EGR* *Fuel Injection* *Engine Modification* *On-board diagnostics I (1988)* — *1980-1988*	> 90% (engine-out)	N/A
	TWC/increased catalyst loading *Oxygen sensor* *EGR* *Improved fuel injection* *On-board diagnostics I* — *1989-1993*		
	TWC/increased catalyst loading *Dual oxygen sensors* *EGR* *Sequential fuel injection* *On-board diagnostics II* — 1994-1997	Meet "low emission vehicles" standards	Cost effectiveness of *On-board diagnostics II* technology (for THC+NOx reduction, 1994 model year): $0.87-1.09/lb reduced ($1.91-2.40/kg reduced)

Industrial Sectors	**Available Technologies**	**Emission Reduction Efficiency/Effluent Concentration**	**Cost***
	TWC/increased catalyst loading 1998+ *Dual oxygen sensors* *EGR* *Sequential fuel injection* *On-board diagnostics II* *Palladium-only catalysts* *Individual cylinder air/fuel control*	Meet "low emission vehicles" standards	Cost effectiveness for implementing Low Emission Vehicle (LEV) program (for THC+NOx reduction, 1994-2003 model year): TLEV $1.83/lb reduced ($4.02/kg reduced) LEV $1.03/lb reduced ($2.27/kg reduced) ULEV $1.80/lb reduced ($3.96/kg reduced) ZEV $5.21-19.08/lb reduced ($11.46-41.98/kg reduced)
b) Medium-duty and heavy-duty vehicles	*Engine modification* *Timing retard* *EGR*	N/A	N/A
Other Mobile: a) Heavy-duty off-road mobile equipment	*Injection timing retard* *Turbocharging* (may be used) *Aftercooling (*may be used)	Meet the standards equivalent in stringency to the on-road heavy- duty equipment standards	Cost effectiveness: $ 0.21/lb reduced ($ 0.46/kg reduced) (175-750 hp engines, 1996 model year) $0.18/lb reduced ($0.40/kg reduced) (> 750 hp engines, 2000 model year) $0.65/lb reduced ($1.43/kg reduced) (175- 750 hp engines, 2001 model year)
b) Utility equipment (hand-held and non hand-held equipment engines)	*Modifying the engine and cooling system* (*e.g., retard timing*) *Improving the ignition system and carburetor* *More effective quality control along the production line*	N/A	Cost effectiveness for THC+NOx reduction: a) 1994 model year: $0.09-1.17/lb reduced ($0.2-2.57/kg reduced) b) 1999 model year: $0.56-6.60/lb reduced ($1.23-14.5/kg reduced)

Industrial Sectors	Available Technologies	Emission Reduction Efficiency/Effluent Concentration	Cost*
c) Off-highway vehicles (off-highway recreational vehicles, farm and construction equipment (<175 hp), off-highway industrial equipment)	(NOx emission from the vehicles in this category is low; emission reduction is achieved through the adoption of regulations similar to those applicable to on-road and other off-road vehicles)		N/A
	Fuel modification: reduction of olefins in gasoline (Smith et al., 1998)	N/A	N/A
	Alternative fuels (Smith et al., 1998)	N/A	N/A

- TLEV = transitional low emission vehicle; LEV = low emission vehicle; ULEV = ultra-low emission vehicle
- ZEV = zero emission vehicle
- N/A = information unavailable

* The cost information is reported in various formats based on the source information provided.

Figure 1 (for Appendix D-2b, reciprocating engines)
Capital Cost Sensitivity of SCR to Compressor Size (1992$)

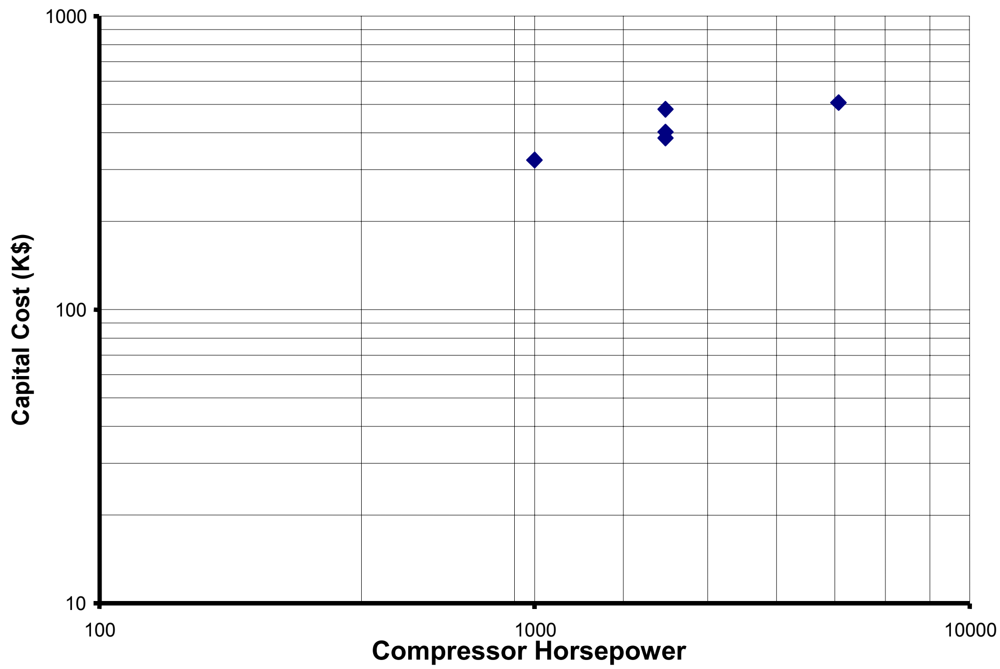
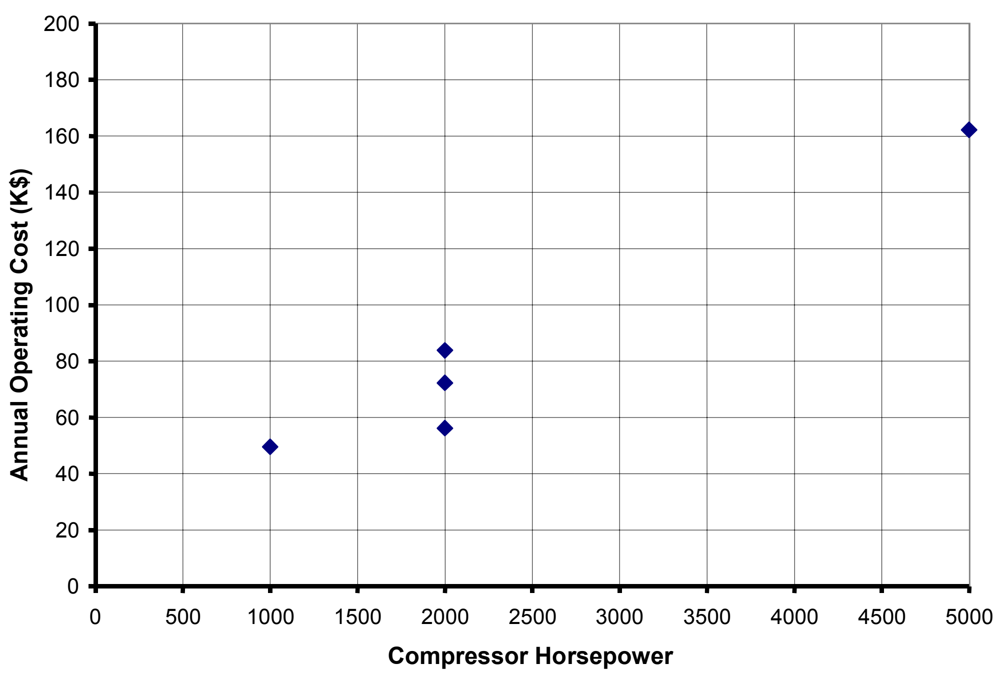


Figure 2. (for Appendix D-2b, reciprocating engines)
Operating Cost Sensitivity of SCR to Compressor Size (1992$)



References (for Appendix D-2b)

ABB Alstom Power, 2000. http://www.apcnoxcontrol.com/index.html

Alberta Agriculture, 2000. http://www.agric.gov.ab.ca/navigation/sustain/about/index.html

California Air Resources Board, 1997. Sources and Control of Oxides of Nitrogen Emissions.

CCME, 1998. National Emission Guidelines for Commercial/Industrial Boilers and Heaters.

Environment Canada. 2000. *Future Canadian emission standards for vehicles and engines and standards for reformulation of petroleum-based fuels.* A discussion paper in advance of a Notice of Intent by the Federal Minister of Environment. April 2000.

Goal Line Environmental Technologies LLC, 2000. http://www.glet.com.

Karell, M.A.; Moffatt, M.H. and Li, R. 1991. *Comparison of Alternative Technologies for the Control of NOx Emissions from Diesel and Dual Fuel Reciprocating Engines.* Malcolm Pirnie, Inc., P.O. Box 751, White Plans, NY 10602.

Klein, M. 1996. "Description of low-NOx combustion systems for gas turbines." Combustion '96 Conference, Ottawa, ON, June 1996.

Klein, M. 1999. "The need for standards to promote low emission, high efficiency gas turbine facilities." Paper presented at the International Gas Turbine & Aeroengine Congress & Exhibition, Indianapolis, Indiana, June 7-10, 1999, ASME paper #99-GT-405.

Schmitz, R. 2000. *Acidifying Emissions in Alberta – Managing the Gap*. Master of Engineering Thesis, University of Calgary.

Smith, A.; Chakraborty, R.; Goode, A.; Marlowe, I.; Marsh, G.; Maunder, D; Sharman, P; Stewart, I. 1998. Technical Innovation to Reduce the Adverse Environmental Impacts of Existing Energy Sources. AEA Technology, Culhom D5, Abingdon, UK (http://www.aeat.co.uk).

TransAlta, 2000. Emission reduction technologies and cost information.

US EPA, 1999. Technical Bulletin: Nitrogen Oxides (NOx), Why and How They are Controlled. EPA 456/F-99-006, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711, U.S.

Appendix D-3a. SO_2 and NOx Standards and Guidelines for Industrial Sectors

Industrial Sector	SO_2 Standards/Guidelines	
	Title	Emission Limits
Utilities	Thermal Power Generation Emissions - National Guidelines for New Stationary Sources (Environment Canada, 1993)	The hourly mean rate of SO_2 emission over successive 720 operating hours from new fossil fuel-fired utility steam generating units should not exceed the following: Generating units emitting more than 258 ng/J of heat input, when uncontrolled: (**a**) Those units emitting between 258 ng/J and 2580 ng/J of heat input should be controlled such that the final emission does not exceed 258 ng/J of heat input; (**b**) Units emitting more than 2580 ng/J of heat input should be controlled so that a minimum of 90% of the uncontrolled emission is captured before release to the atmosphere.
Sour Gas Plants	IL88-13 (The Sulfur Recovery Guidelines - Gas Processing Operations) (Alberta Energy and Utilities Board, 1988)	Sulfur recovery requirements: (**a**) 70% for plants with sulfur inlet rate in the 1 to 5 tonnes/day range; (**b**) 90% for plants with sulfur inlet rate between 5 to 10 tonnes/day; (**c**) 96.2% for plants with sulfur inlet rate of 10 to 50 tonnes/day; (**d**) 98.5 to 98.8% for plants with sulfur inlet rate of 50 to 2000 tonnes/day; (**e**) 99.8% for plants with inlet rate greater than 2000 tonnes/day.
Well Test Flaring	Upstream Petroleum Industry Flaring Requirement, Guide-60 (Alberta Energy and Utilities Board, 1999)	Flare gas volume and H_2S content dependent
Oil Sands	**1**) IL88-13 (The Sulfur Recovery Guidelines - Gas Processing Operations) (Alberta Energy and Utilities Board, 1988) **2**) Thermal Power Generation Emissions - National Guidelines for New Stationary Sources (Environment Canada, 1993)	
Heavy Oil In Situ	Upstream Petroleum Industry Flaring Requirement, Guide-60 (Alberta Energy and Utilities Board, 1999)	Flare gas volume and H_2S content dependent
Salt Water Disposal	no standards/guidelines	
Solution Gas Flaring	Upstream Petroleum Industry Flaring Requirement, Guide-60 (Alberta Energy and Utilities Board, 1999)	Flare gas volume and H_2S content dependent
Coke Calcining	no standards/guidelines	
Cement Manufacturing	National Emission Guideline for Cement Kilns (CCME, 1998)	Site specific
Pulp & Paper	no standards/guidelines	
Coal Processing	no standards/guidelines	
Transportation	**1**) Sulfur in Gasoline Regulations (Government of Canada, 1999) **2**) Diesel Fuel Regulations (Government of Canada, 1999)	

Industrial Sector	NOx Standards/Guidelines	
	Title	Emission Limits
Agriculture	no standards/guidelines	
Heaters & Boilers	National Emission Guideline for Commercial/Industrial Boilers and Heaters (CCME, 1998)	Application: Capacity - The guideline applies to all new and modified fossil fuel-fired boilers and heaters with a capacity equal to or greater than 10.5 GJ/hr (10 M Mbtu/hr). The unit capacity to which wood/biomass limits apply is to be determined. Fuel - The Guideline applies where a fossil fuel-fired boiler or heater is fired with a primary fuel and does not apply where a boiler or heater is fired with a standby fuel. Application according to fuel for wood/biomass units is to be determined. Modified boilers and heaters - The application of this Guideline to modified sources will be determined by the implementing province. Emissions of NOx as nitrogen dioxide, in units of g/Gj_i from new boilers and heaters, according to primary fuel should not exceed the following (see Table 1).
Engines - turbines	National Emission Guidelines for Stationary Combustion Turbines (CCME, 1992)	The emission targets for various types of combustion turbines are determined by calculation of the allowable mass of NOx (grams) per unit output of shaft or electrical energy (Gigajoules), as well as an allowance for an additional quantity of NOx emitted if useful energy is demonstrated to be recovered from the facility's exhaust thermal energy during normal operation. Allowable emissions over the relevant time period equal: (Power Output x A)+(Heat Output x B) = grams of NO_2 equivalent (see Table 2 for A and B rates)
Engines - recip	Code of Practice for Compressor and Pumping Stations and Sweet Gas Processing Plants (Alberta Environment, 1996)	6 grams NOx/kW/h for natural gas-driven reciprocating engines of a size greater than 600 kW at full load
Cement Kilns	National Emission Guideline for Cement Kilns (CCME, 1998)	For large new cement kilns with a permitted capacity greater than 1500 tonnes per day, which receive final regulatory approval for construction after January 1, 1998: the emissions should not exceed 2.3 kg of NOx per tonne of clinker production, based on a monthly average time period.
Utilities - Coal	Thermal Power Generation Emissions - National Guidelines for New Stationary Sources (Environment Canada, 1993)	The hourly mean rate of nitrogen oxides (expressed as NO_2) emission over successive 720 operating hours from new fossil fuel-fired utility steam generating units should not exceed the following: (**a**) for new units which the original projected data of first commercial operation is prior to January 1, 1995: (i) 258 ng/J of heat input, when fired with solid fossil fuel, (ii) 129 ng/J of heat input, when fired with liquid fossil fuel, (iii) 86 ng/J of heat input, when fired with gaseous fuel; (**b**) new units for which the original projected date of first commercial operation is January 1, 1995, or later, should meet a tonne/hour emission limit, calculated for each unit based on the following emission rates at maximum continuous rating: (i) 170 ng/J of heat input, when fired with solid fossil fuel, (ii) 110 ng/J of heat input, when fired with liquid fossil fuel, (iii) 50 ng/J of heat input, when fired with gaseous fuel.
Transportation	no standards/guidelines	

Table 1. (Appendix D-3a) Emission Limits for New Fossil Fuel-Fired Boilers and Heaters

Capacity		NOx Emission Limits (g/GJ)			
GJ/hour	MMBtu/hr	Gaseous Fuel	Distillate Oil	Residual Oil < 0.35% Nitrogen	Residual Oil ≥ 0.35% Nitrogen
10.5 – 105	(10 - 100)	26	40	90	110
> 105	(> 100)	40	50	90	125

Source: National Emission Guideline for Commercial/Industrial Boilers and Heaters (CCME, 1998)

Table 2. (Appendix D-3a) Power Output Allowance and Heat Recovery Allowance

Power output allowance “A" (g/GJ)		
Non-peaking turbines	Natural gas	Liquid fuel
< 3 MW	500	1250
3 - 20 MW	240	460
> 20 MW	140	380
Peaking turbines		
< 3 MW	Exempt	Exempt
> 3 MW	280	530
Heat recovery allowance "B" (g/GJ)		
For all units:	Natural gas	40
	Liquid	60
	Solid-derived	120

* Power output is the total electricity and shaft power energy production expressed in Gigajoules (3.6 GJ per MW-hour).
* Heat output is the total useful heat energy recovered from the combustion turbine facility.
Source: National Emission Guidelines for Stationary Combustion Turbines (CCME, 1992)

Appendix D-3b. SO_2 and NOx Emission Reduction and Cost

	Total quantity of emission (tonnes/year)	Number of emission sources	Geographic concentration of emission sources (3)	Existing level of control relative to BACT	Elevation above ground of point of release (5)	Availability of control technology	Cost	Likelihood of increase/decrease of emission	Other Processes Addressing Sector	Potential Emission Reduction (tonnes/year)
SO_2										
Utilities	130000	7		Low (compliance)	High	Yes	\$4000 to \$6000 per tonne SO2, for retrofit, 95% removal	increasing activity, volume of emissions may be reducing from shutdown of older plants	CASA PM & O3, National MERS, unclear what will be developed.	assume an average of 95% emission reduction efficiency for *Wet FGD (TransAlta, 2000; EmtrolCorp, 2000)*: **1**)[a] 123500 **2**)[b] 61750 **3**)[c] 37050
Sour Gas Plants	194000	234	dispersed	varies	medium to high	Yes	\$300 to \$2300 per tonne SO2	increased activity, ? emissions	Yes	emission reduction from degrandfathering 61 grandfathered plants: 33215 (23360 or 36% of 1998 emissions from 33 sulpher recovery plants and 9855 or 62% of 1998 emissions from 28 acid gas flaring plants) (Alberta Environment et al., 2000)
Well Test Flaring	30000	> 300 tests/yr	dispersed	none	medium to high	some (in line or shorter testing)	?	Increased activity	Yes	
Oilsands	160000[3]	2	concentrated	Acid gas - high Flue gas - varies	High	Yes	Acid gas - already at BACT Flue gas - ?	increased activity, acid gas emissions decreasing, flue gas emissions decreasing (from 1995 levels)	Yes	assume 91% emission reduction efficiency for *ammonium sulphate FGD* (Syncrude, 2000): 49504[4]
Heavy Oil In Situ	2000	2	dispersed	none	medium to high	Yes	?	increased activity, increased emissions unless controls	Guide 60 and Sulphur Recovery	
Salt Water Disposal	6500	30 to 40	1 area	none in 1995 some now	low	Yes	low cost for suitable sites	level emissions	Being addressed already	assume using waste gas injection system, 100% emission reduction efficiency (Redwater Water Disposal Company Limited, 2000): **1**) 6500 **2**) 3250 **3**) 1950
Solution Gas Flaring	52000	5000++ (sour & sweet)	dispersed	none in 1995, now Guide 60	medium	Yes	varies	decreasing emissions	CASA Flaring/Venting	
Coke Calcining	2400	1	1	none	high	?	?, probably high	level emissions	AENV dealing with single source through approval	
Cement Manufacturing	3100	2	2	none	high	?	?, probably high	level emissions or increasing if switch to coal	issues around coal use dealt with through approvals, EIA, hearings	

	Total quantity of emission (tonnes/year)	Number of emission sources	Geographic concentration of emission sources (3)	Existing level of control relative to BACT	Elevation above ground of point of release (5)	Availability of control technology	Cost	Likelihood of increase/decrease of emission	Other Processes Addressing Sector	Potential Emission Reduction (tonnes/year)
Pulp & Paper	3800	4[5]	dispersed	none	high	yes	?	level emissions	CASA PM & O3,National MERS,unclear what will be developed.	assume an average of 75% emission reduction efficiency for *In-process control* and *Scrubbers* technologies (H.A. Simons Ltd., 1995): **1**) 2850 **2**) 1425 **3**) 855
Coal Processing	2300	5	dispersed	none	medium	?	?	decreasing emissions		assuming 25% emission reduction by conventional coal washing (Smith et al., 1998): **1**) 575 **2**) 289 **3**) 173
Transportation	9500	many	dispersed	some	low	yes	$51000/tonne SO2	increased activity but decreasing emissions as a result of future controls	Yes	emission reduction efficiency data are unavailable

	Total quantity of emission (tonnes/year)	Number of emission sources	Geographic concentration of emission sources (3)	Existing level of control relative to BACT	Elevation above ground of point of release (5)	Availability of control technology	Cost	Likelihood of increase/decrease of emission	Other Processes Addressing Sector	Potential Emission Reduction (tonnes/year)
NOx										
Agriculture	?	many	dispersed	?	low	?	?	?		
Heaters & Boilers	?, lots	many	dispersed	low for most	medium	yes	$300 to $4000/tonne NOx ($300 for new)	increasing emissions		(**A**) assume an average of 55% emission reduction efficiency for *low excess air, low NOx burners, and flue gas recirculation technologies* (CCME, 1998): **1**) 55% reduction of current emissions **2**) 27.5% reduction of current emissions **3**) 16.5% reduction of current emissions (**B**) assume an average of 75% emission reduction efficiency for *SCR and SNCR technologies* (CCME, 1998): **1**) 75% reduction of current emissions **2**) 37.5% reduction of current emissions **3**) 22.5% reduction of current emissions (**C**) assume an average of 90% emission reduction efficiency for *combined SOx/NOx control technologies* (Smith et al., 1998): **1**) 90% reduction of current emissions **2**) 45% reduction of current emissions **3**) 27% reduction of current emissions

	Total quantity of emission (tonnes/year)	Number of emission sources	Geographic concentration of emission sources (3)	Existing level of control relative to BACT	Elevation above ground of point of release (5)	Availability of control technology	Cost	Likelihood of increase/decrease of emission	Other Processes Addressing Sector	Potential Emission Reduction (tonnes/year)
Engines - turbines	?, lots	many	dispersed	~30%	low	yes	\$500 to \$3000/tonne NOx	increasing emissions		assume an average of 78% emission reduction efficiency for *Water injection, Steam injection and SCR technologies (Klein, 1996, 1999*) and 30% of the industry has already applied certain types of control technologies: **1**) 55% reduction of the current emissions if the control technologies are applied to the remaining turbines **2**) 27% reduction of the current emissions if the control technologies are applied to 50% of the remaining turbines **3**) 16% reduction of the current emissions if the control technologies are applied to 30% of the remaining turbines
Engines - recip	?	many	dispersed	~30%	low	yes	\$500 to \$3500/tonne NOx	increasing emissions		(**A**) assume an average of 66% emission reduction efficiency for *Improved combustion controls* (Schmitz, 2000) and 30% of the industry has already applied certain types of control technologies: **1**) 46% reduction of the current emissions if the control technologies are applied to the remaining reciprocating engines **2**) 23% reduction of the current emissions if the control technologies are applied to 50% of the remaining reciprocating engines **3**) 14% reduction of the current emissions if the control technologies are applied to 30% of the remaining reciprocating engines (**B**) assume an average of 85% emission reduction efficiency for *SCR, SNCR and oxidation of NOx (with subsequent absorption, using a sorbent)* technologies (US EPA, 1999): **1**) 60% reduction of the current emissions if the control technologies are applied to the remaining engines **2**) 30% reduction of the current emissions if the control technologies are applied to 50% of the remaining engines **3**) 18% reduction of the current emissions if the control technologies are applied to 30% of the remaining engines

	Total quantity of emission (tonnes/year)	Number of emission sources	Geographic concentration of emission sources (3)	Existing level of control relative to BACT	Elevation above ground of point of release (5)	Availability of control technology	Cost	Likelihood of increase/decrease of emission	Other Processes Addressing Sector	Potential Emission Reduction (tonnes/year)
Cement Kilns	7600	2	2 sites	?	high	yes	$350 to $7500/tonne NOx	level emissions		(**A**) assume an average of 25% emission reduction efficiency for L*ow NOx burners* and *combustion operation modification* (CCME, 1998): **1**) 1900 **2**) 950 (**B**) assume an average of 55% emission reduction efficiency for *SNCR technology* (CCME, 1998): **1**) 4180 **2**) 2090 (**C**) assume an average of 80% emission reduction efficiency for *SCR technology* (CCME, 1998): **1**) 6080 **2**) 3040
Utilities - Coal	79300	7	7 sites	part way	high	yes	$1700 to $3000/tonne NOx	increasing activity and emissions?	MERS, CASA PM & O3	(**A**) assume an average of 50% emission reduction efficiency for *Separated overfire air/low NOx burners* (TransAlta, 2000): **1**) 39650 **2**) 19825 **3**) 11895 (**B**) assume an average of 65% emission reduction efficiency for *Advanced coal reburning* (TransAlta, 2000): **1**) 51545 **2**) 25773 **3**) 15464 (**C**) assume an average of 90% emission reduction for *SCR* technology (TransAlta, 2000): **1**) 71370 **2**) 35685 **3**) 21411
Transportation	198000	many	dispersed	medium (~50%)	low	yes	$400 to $4000/tonne NOx	decreasing emissions	CASA VET, Federal rules, O3 annex	emission reduction efficiency data are unavailable

Explanations and Summaries (Appendix D-3b)

1. Amount of emissions that can be reduced for an industrial sector was calculated by using an average removal efficiency if there were several technologies available or an efficiency of a specific technology. The technology(s) that was used in the calculation was listed in the column 10 (Potential Emission Reduction, tonnes/year).

2. Assumptions were made in current level (in %) of application of the technologies in an industrial sector where the information was not available:

> [a)] assuming currently there is no (i.e. 0%) emission control technology applications in the industrial sector
>
> [b)] assuming emission control technology application in 50% of the industrial sector
>
> [c)] assuming emission control technology application in 70% of the industrial sector

3. 1995 emission estimation

4. The amount of emissions is evenly divided between two operations, and 68% of the emissions from one operation (based on Syncrude estimation) was used to calculate potential reduction by using FGD

5. Kraft mills only

References

Alberta Energy and Utilities Board, 1988. *Informational Letter IL 88-13: Sulfur Recovery Guidelines - Gas Processing Operations.*

Alberta Environment, Alberta Department of Resource Development, and Alberta Energy and Utilities Board, 2001. Staff Report on the Review of the Sulfur Recovery Guidelines.

CCME, 1998. *National Emission Guidelines for Commercial/Industrial Boilers and Heaters*.

CCME, 1998. *National Emission Guideline for Cement Kilns*.

CCME, 1992. *National Emission Guidelines for Stationary Combustion Turbines*.

EmtrolCorp, 2000. FGD System Controls SO_2 Emissions. http://www.EmtrolCorp.com.

Environment Canada, 1993. *Thermal Power Generation Emissions - National Guidelines for New Stationary Sources*.

Government of Canada, 1997. *Diesel Fuel Regulations*, SOR/97-110, February 1997.

Government of Canada, 1999. *Sulfur in Gasoline Regulations*, SOR/99-236, June 1999.

H.A. Simons Ltd. 1995. *Emissions and Control Options for Wood and Wood Derived Fuel Fired Industrial Boiler Systems.*

Klein, M. 1996. "Description of low-NOx combustion systems for gas turbines." Combustion '96 Conference, Ottawa, ON, June 1996.

Klein, M. 1999. "The need for standards to promote low emission, high efficiency gas turbine facilities." Paper presented at the International Gas Turbine & Aeroengine Congress & Exhibition, Indianapolis, Indiana, June 7-10, 1999, ASME paper #99-GT-405.

Redwater Water Disposal Company Limited. 2000. Salt water disposal system description.

Smith, A.; Chakraborty, R.; Goode, A.; Marlowe, I.; Marsh, G.; Maunder, D; Sharman, P; Stewart, I. 1998. *Technical Innovation to Reduce the Adverse Environmental Impacts of Existing Energy Sources*. AEA Technology, Culhom D5, Abingdon, UK (http://www.aeat.co.uk).

Syncrude, 2000. Emission reduction technologies and cost information.

TransAlta, 2000. Emission reduction technologies and cost information.

US EPA, 1999. Technical Bulletin: *Nitrogen Oxides (NOx), Why and How They are Controlled*. EPA 456/F-99-006, Office of Air Quality Planning and Standards, Research Triangle park, NC 27711, US.

DRAFT

PHASE I
SO_2 AND NO_X
EMISSIONS INVENTORIES
UPGRADES FOR ALBERTA

Prepared for:

Clean Air Strategic Alliance

9940 106 St NW FLR 9
Edmonton, Alberta
T5K 2N2

Attention: Kerra Chomlak

Prepared by:

Levelton Engineering Ltd.
515-808, 4th Avenue S.W.
Calgary, Alberta
T2P 3E8

Richmond Tel: 604-278-1411
Calgary Tel: 604-269-4141
Email: aschutte@levelton.com

November 2001

TABLE OF CONTENTS

Note: Project management details have been removed from the original report for this appendix.

1. INTRODUCTION

The Clean Air Strategic Alliance (CASA) Acidifying Emissions Management Implementation Team (AEMIT) is in the process of preparing information to upgrade the existing SO_2 and NO_X air emissions inventories in Alberta. The objective of the work is to establish a firmer baseline for provincial emission reduction targets. As part of the upgrade, CASA outlined a request for proposal to upgrade emissions for specific sectors in Alberta.

Two phases were outlined for the project. Phase I involved reviewing existing data, potential sources of data, and preparing a proposal, while Phase II will focus on the calculation, results and reporting. Levelton was retained by CASA to conduct Phase I of the project, and has prepared the following report and accompanying proposal to complete Phase II. This report outlines the existing background information and data, reviews current approaches used to calculate emissions and develop input data, and ends with a detailed methodology and estimated cost to complete the inventory.

2. PROJECT DESCRIPTION

The first step identified to establish an upgrade for the NO_X and SO_2 emissions inventory for the five sectors outlined below was to review the existing available emissions inventories. This review gave information on emissions calculations and estimations. Once these inventories were examined, a review of the sources of data that could potentially be used for upgrading the existing emissions inventories was completed. These reviews assist to develop the most appropriate methodology for upgrading the emissions information.

The specific sectors that require upgrading are:

- SO_2 emissions from batteries flaring solution gas;
- SO_2 emissions from well test flaring;
- NO_X emissions from natural gas compressors;
- NO_X emissions from heaters and boilers in industrial applications (including natural gas processing); and
- NO_X emissions from heaters and boilers in commercial applications.

This report outlines the existing SO_2 and NO_X emissions inventory information for the identified sectors in the Province of Alberta, provides a review of the potential sources of data for upgrading the inventories for each sector, and outlines a methodology and proposal in order to establish a firmer baseline in Phase II of the project.

3. REVIEW OF EXISTING AVAILABLE INVENTORY INFORMATION AND CALCULATION METHODS

3.1 INTRODUCTION

There are many inventories of SO_2 and NO_X emissions in Alberta, dating as far back as the early 1960's. Although useful in their time, most of the eldest inventories are outdated and are not useful to this study. The detailed information regarding some of the older emission inventories is therefore not presented in this report; for information on the survey methods and calculation techniques used in older material, the reader is redirected to the document entitled: "Emission Inventories of Sulphur Dioxide, Nitrogen Oxides, and Ammonia in Alberta 1963 to 1995: A Review."

3.2 INFORMATION FROM INVENTORIES

The inventories of most importance to complete Phase II of the project are:

- The 1984 Acid Deposition Research Program (ADRP);
- The 1995 National Criteria Air Contaminant (CAC) Inventory;
- Determination of NO_X Technologies and Emission Factors in the Alberta Upstream Oil and Gas Industry (2002); and
- A Detailed Inventory of CH_4 and VOC Emissions from Upstream Oil and Gas Operations in Canada.

The ADRP inventory was initially developed to investigate the effects of acidifying emissions in Alberta. This inventory was designed for use with dispersion modelling by the inclusion of detailed emission, geographical, and temporal parameters. It includes emissions from transportation, urban, and point sources for both NO_X and SO_2. Of particular note is that it contains information on commercial heaters and boilers**.** In consideration that it was completed in 1984, the emissions cannot currently be considered accurate. At the time, information on commercial heaters and boilers was not readily available. The method used for emissions calculations for commercial heaters and boilers used the gas consumption in commercial areas and AP-42 emission factors. The information for gas consumption in commercial areas was provided from gas utility reports. These reports gather the fuel use for commercial sectors where fuel is mostly used for heating.

Currently, information on commercial boilers and heaters is not readily available. The method that was used for the ADRP inventory in 1984 could still be considered the best available method. Further details on the methodology are described in section 3.6.

The CAC inventory is the most recently completed inventory of Criteria Contaminants (SO_2, NO_X, CO, and hydrocarbons). This inventory is done every 5 years by Environment Canada. The CAC inventory accesses a database called the National Residual Discharge System (RDIS). There are plans to combine the CAC Inventory with the National Pollutant Release Inventory (NPRI), which, in the future, will provide annual estimates of NO_X and SO_2, but this information will not be available for this study.

RDIS classifies sources with a SCC code, which allows individual components, such as a certain type of boiler, to be identified. Although RDIS serves the CAC inventory well, it does not contain details of the calculation techniques and there are potential discrepancies that exist with respect to source identification compared to other databases. The source identification in the CAC cannot easily be reconciled with other AENV inventories, because the Facility Identifiers are different. Without careful examination of the inventories, reconciling ID's could lead to double counting or omission of sources.

For Alberta, The RDIS data is based on information originally acquired by AENV. AENV is currently in the process of updating this database, and it could be very useful for improving the estimates of emissions of SO_2 and NO_X in the industrial sector. For RDIS, it should be noted that industry has indicated that "the process data …is not representative of the industry as it exists today" (EPWG-2000). Environment Canada still relies on the original data supplied by AENV and will continue to do so until a future update becomes available. The project entitled the "*Determination of*

NO_X technologies and Emission Factors in the Alberta Upstream Oil and Gas Industry" directed by AENV is intended to upgrade emissions from all upstream oil and gas industry. This database is not yet available to update related emissions inventories, but it is planned to be complete by the spring of 2002.

In 1999, CAPP published an emissions inventory as part of the upstream petroleum industries efforts to develop appropriate environmental action plans. The inventory contained emissions of CH_4, VOCs, CO_2, N_2O, H_2S, CO, and NO_X from Conventional gas production and processing operations. The inventory is the most recent information available. Although there are no direct estimates that are required for the sections to be updated in Phase II of the project, base information, such as the number of wells, provide a useful basis for making estimations.

3.3 CALCULATION METHODS AND EMISSION FACTORS

3.3.1 Sulphur Dioxide

When SO_2 emissions are not readily available from monitoring, the preferred method for calculation of SO_2 emissions from fuel combustion is to assume all of the sulphur in the fuel gas is converted to SO_2. The mass of sulphur in the fuel is then calculated from the volume of gas burned and its average sulphur content (mass/volume). When the actual sulphur content of the gas is not available, the average gas composition in the vicinity of the area is usually used.

3.3.2 Nitrogen Oxides

NO_X emissions are usually estimated using emission factors. Several emissions factors are available, some more accurate than others, depending on the source and on the application and unit operated. The first reference for emissions factors is the US EPA report AP-42.

For natural gas emission factors from AP-42 from pipeline compressors and storage stations and for gas processing plants, the Chapter 3.2 entitled *Natural Gas-Fired Reciprocating Engines* is usually used. The emission factors are based on an extensive set of monitored data from various sectors and for sources having various power ratings. Although conservative, they give a reasonable estimate of air emissions. The emissions factors for NO_X are rated "A" or "B", which qualifies them as:

> A = Tests are performed by a sound methodology and are reported in enough detail for adequate validation.
>
> B = Tests are performed by a generally sound methodology, but lacking enough detail for adequate validation.

Emissions from heaters and boilers in the commercial sectors are best estimated using average emission factors by fuel type. There are a variety of fuel types considered for these estimates including natural gas, propane, kerosene and stove oil, light fuel oil, heavy fuel oil, Canadian bituminous coal, sub-bituminous coal, lignite coal, anthracite coal and imported coals. Using the emission factors outlined in the latest AP-42 document for these sources can be considered the best available method. Almost all of the heaters and boilers for the commercial sector in Alberta use natural gas or petroleum products.

A second reference for emissions factors is Environment Canada, more specifically, the Emissions and Projections Working Group (EPWG), which until recently, was referred to as the National Emissions Inventory and Projections Task Group (NEIPTG). This group operates under the direction of the National Air Issues Coordinating Committee (NAICC-A) and has developed the Canada's criteria air contaminants (CAC) emission inventory (most recently developed for 1995 CAC emissions) previously discussed in section 3.2.

Finally, a third reference is the NO_X emission factors developed in the "Energy-Related Nitrogen Oxide Emissions in Alberta 1988 – 2005" report from the Energy Resource Conservation Board and Alberta Energy published in 1990. Although the main source of the emission factors used in that document were Environment Canada and US EPA AP-42, emission factors were developed for the Alberta gas processing industry using estimated fuel use fractions and type of equipment used. In consideration that these emission factors were developed using data from 1987 and 1988, more recent emission factors are available and should be used to develop a more accurate estimate of emissions.

4. REVIEW OF SOURCES OF DATA AND PROPOSED METHODOLOGY

4.1 INTRODUCTION

Part of the work in updating the air emissions information in Alberta was to identify potential data sources for the following emission sources. Data concerning these sources are discussed in the following subsections.

4.2 SO_2 EMISSIONS FROM BATTERIES FLARING SOLUTION GAS

Information on battery flaring of solution gas is maintained by the Energy and Utilities Board (EUB). The EUB appears to have the best available information to calculate emissions from activities in this sector. The following sources were identified:

EUB ST60A: This statistical publication covers information on flaring from crude oil and bitumen batteries. It contains the total volumes of gas flared and vented for each battery. However, it does not contain the H_2S content of the gas. This data is filed in MS Excel™ data files.

EUB ST60B: This statistical publication provides information on the total aggregate flared volumes of batteries and well-test flaring for Alberta. It is presented in a MS Word™ document.

EUB Guide 56 – Schedule 1: In this type of approval form, the industry provides the sulphur content of the flared gas. Each individual form is submitted as a MS Word™ document and information is subsequently compiled from all forms and transferred to MS Excel™ data files.

To update the SO_2 emissions inventory for batteries flaring solution gas, a mass balance calculation using the volume of gas flared reported in the ST 60A EUB and the H_2S content of the flared gases reported by the industry in the Guide 56 - Schedule 1 could be utilized. This information can be cross-referenced with data from the CAPP emission inventory.

4.3 SO_2 Emissions from Well Test Flaring

Information from well test flaring is maintained by both the EUB and AENV. AENV does not license and approve as many wells as the EUB. Upon examining sources of data, the EUB appears to have the best available information. The following sources were identified:

- Well Test Flaring Reports: Although the information contained in these reports is proprietary, the well test flaring reports provide volumes of gas flared during well tests. In addition, actual measurements of the sulphur content of the well are often reported. Each form is submitted as a MS Word™ document and the information is subsequently transferred to MS Excel™ data files.

- Well Test Application Forms: The industry must submit an application form for well testing when the H_2S content of the gas is equal or greater than 5% of the gas volume. When reported, the H_2S content is usually not known until the well is flared, but outside estimates are usually determined from sulphur content of gas from nearby wells in the same geological formation. This information is transferred side by side to the well test flaring report MS Excel™ database.

The SO_2 emissions from well test flaring can be calculated using a mass balance based on the volumes of flared gas provided in the well test reports and either the H_2S content of the gas from the well test application forms or the measured H_2S content from well test reports. The total flared volumes could be compared to the aggregate totals published in the ST60B flaring report. With this method, only emissions from wells with an H_2S content of $\geq$ 5% would be inventoried. Emissions from wells having less sulphur content could be estimated with the information on the statistics for the H_2S content of gas, taking the percentile of wells with less than 5% of sulphur and apply that percentile to the total volumes of gas flared.

An alternative method using public rather than proprietary information to estimate SO_2 emissions from well test flaring would be to use the provincial totals and percentiles of volumes of gas flared during well tests and the totals and percentiles of H_2S content of gas flared during well tests. However, a significant uncertainty would exist in joining these two pieces of information since they are recorded separately. In other words, there is no link in between the percentiles of H_2S content of the gas and the percentiles of the volumes of gas flared. Figures 3.1 and 3.2 present an example of these percentiles. This is intended to illustrate that H_2S content and volume are not linked, as some wells may have large volumes with low H_2S, and vice versa. The best estimate would be obtained from the total volume of gas flared with the average H_2S content for each well test.

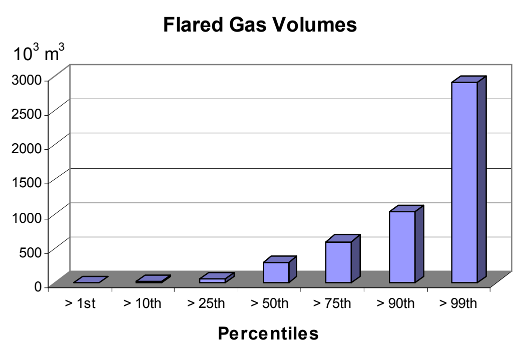


Figure 1 Example of public information on Volumes of Flared Gas during Well Tests in 2000

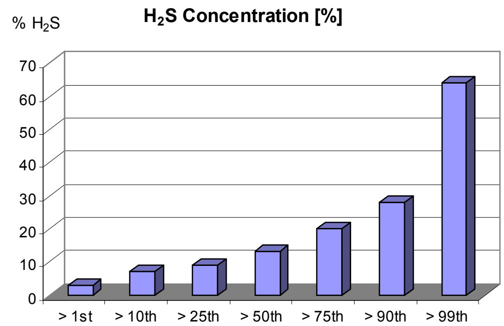


Figure 2 Example of public information on H_2S content of Flared Gas during Well Tests in 2000

At this point in time, it is still uncertain whether or not the information from well tests flaring reports that can be aggregated or arranged so that the data is no longer proprietary and could be used for preparation of the emission inventory. The EUB personnel are not fully aware of the implications of this approach. Using more refined information would be possible if clarity is obtained on what is proprietary and the length of time that data remains proprietary. A review of the method used in British Columbia to do a similar emission inventory revealed that average H_2S content for general areas of the province were used, combined with the total volume of gas flared.

4.4 NO_X EMISSIONS FROM NATURAL GAS COMPRESSORS

Alberta Environment is currently in the process of doing an inventory of NO_X emissions from natural gas compressors, which is anticipated to be completed in the second quarter of 2002. AENV has identified four data sources that are going to be examined:

- Acid Deposition Research Program;
- Data from the EUB;
- CAPP's Inventory of CH_4 and VOC Emissions from the Canadian Upstream Oil and Gas Industry report (Includes emissions of NO_X);
- The1995 Alberta CAC Inventory.

Because AENV is currently in the process of upgrading this inventory as described in Section 2.1, Levelton has not included updating emissions from natural gas compressors in the accompanying proposal. This avoids duplication of the work that is desired by CASA for these sources. However, for consolidation purposes, the results of the AENV inventory for Natural Gas Compressors can be formatted to be included in the final MS Excel™ data sheet, if it is desired by CASA.

4.5 NO_X EMISSIONS FROM HEATERS AND BOILERS IN INDUSTRIAL APPLICATIONS

Most industrial boilers and heaters are included in operational permit applications to AENV. The permits issued for these sources by AENV usually identify the different emission sources and their respective design capacity, and sometimes NO_X emission rates limits. Use of Low-NO_X combustion technology could also be determined from the permits. Using US EPA AP-42 emissions factors or the CCME *National Emission Guideline for Commercial/Industrial Boilers and Heaters, the NO_X Emissions from Heaters and Boilers* for units equal to, or greater than 10.5 GJ/hr of energy input, inventory could be done by looking at all industrial permits and calculating the NO_X emissions from the information in the permits.

Conversely, to ease the time consuming task of going through all AENV industrial permits; the AENV surveys for the CAC can be used. These surveys reference the same permit holders for units emitting greater than or equal to 10 tonnes of NO_X per year. Survey data are gathered on a list to show the operators of heaters and boilers units, SCC codes, NO_X emissions rates and calculation methods. Even though responses to this survey are noteworthy, gaps may be found, as it is not mandatory to the industry to reply. Verification with the permits should remain and be closely done to assure that all sources are being recorded. The next survey is planned to be issued in the first part of 2002. Information on industrial operations emitting less than 10 tonnes per year of NO_X is not likely to be reported at this point in time.

The data from this survey contains SCC codes, while the Guidance Document that will accompany the survey will contain SCC codes that include heaters and boilers for the following industrial sectors:

Electric Generation
Chemical Manufacturing
Food & Agricultural
Primary Metals
Secondary Metals
Mineral Products
Coal Processing
Petroleum Refining
Pulp & Paper
Wood Products
Rubber & Misc. Plastic Products
Fabricated Metal Products
Oil & Gas Production
In-process Fuel Use
Product Storage & Marketing
Waste Disposal

Since emission estimates will strongly depend on the information in the permits, which varies from permit to permit and industry to industry, various calculation methods will need to be used. The standard hierarchy of estimating methods to be used, starting with the most reliable for large industry sources, would adhere to the following approach:

1) Monitoring Data;
2) Permitted emission limits;
3) Fuel use or power rating and emission factor (with examination for whether or not Low-NO_X burners are applied or not);
4) Power rating and CCME emission guidelines (with attention to adjust results if Low-NO_X burners are installed);
5) Engineering estimates based on energy output capacity data*assumed load factor*hour/year/thermal efficiency*emission factor; or
6) Generic production rate and emission factor.

In consideration that information on the expected average load is not always available; several options are possible for estimating the average annual emissions. When needed, the load factor could be estimated with:

1) Ratio of the plant production to plant capacity;
2) Contact with licensee;
3) Selection of a nominal load factor for each industry sector based on trade information on production; or
4) Nominal judgmental estimate.

The calculation of NO_X emissions from industrial heaters and boilers will need to be done on a case-by-case basis. Each source will have to be examined following the approach presented above. It depends on the information available in the permits and the AENV survey.

4.6 NO_X EMISSIONS FROM HEATERS AND BOILERS IN COMMERCIAL APPLICATIONS

The ADRP inventory utilized gas consumption reports in commercial sectors, and applied emission factors. It is anticipated that utility companies in Alberta have this type of data available, and the largest sectors, if not all of them, could be identified and emission estimates can be made. These reports gather the fuel use for commercial sectors where fuel is mostly used for heating. This method has been used effectively in the ADRP and other inventories in Canada.

The standard method for calculating emissions for this sector is by obtaining the total Statistics Canada fuel numbers for the province and applying the appropriate emission factor, the total emission estimate for the province could easily be calculated. This could be broken down further by obtaining fuel estimates for major urban areas, and taking the difference. If the desire is to further disaggregate the commercial sources, then a more refined approach must be utilized.

Commercial heaters and boilers must usually apply for permits through their respective municipal governments as well. The permit data generally does not contain enough information to calculate emissions but could give an estimate of the numbers of systems per commercial sector. Therefore, to ensure that data gaps are reduced, and the most accurate data is obtained, a few of the largest municipal governments could be contacted for further information to estimate emissions from heaters and boilers.

A typical list of Commercial Heaters and Boilers includes:

Laundry, Drycleaning, and Pressing Machines Construction Activities Plastics and Fabrication of Materials Commercial Printing Commercial Fuel Combustion Gas Distribution Paint and Body Repair Shops Department Stores Savings Credit Institutions Insurance, Real Estate Agencies Other Scientific and Technical Services Elementary and Secondary Schools Universities and Colleges Education related Services Correctional Services Public Administration Health Services, Other Research Administration Religious Organizations General Administrative Services	Post-Secondary Non-University Education Other Recreational Facilities General Hospitals Medical Laboratories Other Business Managing Services Hotels, Restaurants and Taverns Other Miscellaneous Services Defense Services Hotels and Motor Hotels Other Recreation & Vacation Camps Local Administration Sports and Recreation Clubs, and Services Sports and Recreation Clubs Other Amusement & Recreational Services Other Government Offices Electric Motor Repair Other Repair Services

Commercial/institutional external combustion sources are classified by the boiler/furnace design or type of fuel. Past inventories have shown that natural gas and petroleum products represent almost 100% of the energy consumption for commercial units. It is unclear at this time whether non-industrial sources that may not directly classify under “commercial” are of interest to CASA. For the purposes of the rest of this document, it is assumed that all non-industrial and commercial heaters and boilers are of interest.

In order to refine and/or review the emissions calculation, total gas consumption for industry sectors and commercial sources by region can also be obtained by contacting provincial utilities. Statistics Canada information could be used to verify provincial estimates for a commercial sector that could then be disaggregated using surrogate parameters. The surrogate parameters would relate to the fuel use and would be different for many of the sectors. For example, the “population” could be used to derive emissions per industry and obtain factors in [kW/capita] for sectors such as dry cleaning, paint department stores, schools, health centers, etc.; “industry economic activity” could be used for large commercial operations and factors in [kW/production] could be obtained.

This approach obtains reasonable estimates and could be used to compare with the previous estimates in the earlier ADRP report (based on gas consumption reports). However, discussion with CASA should follow to determine the preferred approach since the ADRP method can be time-consuming if all municipal permits and utility reports must be examined.

5. METHODOLOGY AND PROPOSAL FOR PHASE II

The request for proposal detailed the content that should be included in the report:

- A general description of the existing inventory information for the sectors, including the sources of data, the calculation methods used, and the strengths and weaknesses. This has been discussed earlier in this report, and will be expanded upon to produce more detailed and pertinent information if required.
- A detailed description of the methodology that was utilized to update the inventory. The sources of data, calculations that were used, and the strengths and weaknesses of the current information will be included. The calculations will all be included in the formulas in the MS Excel™ sheets and a sample calculation of each type will be supplied in the report.
- The inventory results, including both licensed (where applicable) and actual emissions.
- A description of the accuracy of the results/range of possible error in the inventory estimates.

The methodology to conduct the project successfully was discussed in section 4 and is broken down into specific tasks in the following section.

5.1 OUTLINE OF TASKS

The following tasks are outlined for completing Phase II of the project:

1) The first task would be to gather the most current and appropriate emission factors potentially usable for calculating the emissions from sources in five sectors, and incorporate them into a spreadsheet.
2) Batteries: In consideration that the EUB has the most valuable information for updating the SO_2 emissions inventory for batteries and well test flares, the second step of the project would be to complete a detailed review of the EUB information and extract the required data:
    a. ST 60A EUB and insert all volumes (actual and licensed) of gas flared and sulphur content of the gas, if available, per battery, including their location (SO_2 for batteries);
    b. Guide 56 – Schedule 1 database would be scrutinized to export information on the sulphur content of gas flared per batteries and match them to the volumes of gas previously exported in the spreadsheet;
    c. Highlight missing data and sulphur contents for each respective battery;
    d. If batteries are missing sulphur content data, step 4 should be conducted.
    e. The report ST 60B EUB should be considered to verify that the totals of volumes of gas flared matches what was recorded in the spreadsheet. This could help if some batteries are missing information on flaring volumes.
    f. A mass balance calculation should be calculated based on the information recorded in the previous steps.

3) The methodology for calculating SO_2 emissions from well tests will depend on whether proprietary or public information is used. If so:
    a. The spreadsheets recording data from the flaring application reports and well tests flaring report will be obtained.
    b. The transfer of information from this latter database to the main project's spreadsheet will follow, making sure that the identification and location of the well are included with the volumes (actual and approved) and sulphur content of the well. Both the

applied and approved H_2S content for the SO_2 emissions calculations will be incorporated where available.

If only public information is to be used:

c. The total of the flared gas volume would be applied to the average H_2S content of the gas in Alberta. This estimate would not be as precise, but could be refined by AENV regions and potentially by county when a better idea of the level of detailed information becomes freely available. Estimates by region would be developed by determining the volume of flowed gas and the average gas H_2S content by region.

4) In the case where batteries are missing sulphur content data, values will be estimated from the nearest well producing from the same formation, or failing this an Alberta average value.
5) The following step concentrates on commercial heaters and boilers and constitutes:
   a. The commercial/institutional fuel use will be obtained from the Statistics Canada summary of fuel use for Alberta.
   b. The emission factor recorded in the spreadsheet in step 1 for commercial boilers and heaters would be used to calculate NO_X emissions.
   c. Acquired fuel usage reports from utility companies will be used to crosscheck data for regions or sectors where possible. Other possibilities for this section require further discussion with CASA if they desire a greater breakdown of sources.
6) The next step focuses on industrial heaters and boilers and oil and gas compressors. These sectors would be surveyed at the end since the most accurate information will be made available starting in spring 2002. For industrial boilers and heaters:
   a. A reduced list of all SCC codes pertaining to boilers and heaters in Alberta will be generated and incorporated into the spreadsheet;
   b. The latest AENV survey data concerning the identification and location of units, their power rating, emission rates and calculation method would be extracted and imported in the project's spreadsheet.
   c. An overview of the municipal permits would be completed to QA/QC any discrepancies and/ or double counting of the units.
   d. Appropriate statistics from the AENV survey will be used along with emission factors to calculate emissions.
7) Finally, the inventory and database elaborated by AENV on NO_X emissions from oil and gas compressors will be analysed and data such as: identification, location of the compressors, emissions, emissions factors, power rating and calculation method will be extracted.

These steps cover all the sectors targeted for updating the SO_2 and NO_X emissions inventories in Alberta. Upon notice of contract award, Levelton will proceed with completing the gathering of all the identified data required to carry out the calculations. Much of the base inventory data has already been obtained. Subsequently, it will be initially QA/QCd, and if revisions are necessary, or data gaps exist, the appropriate source will be contacted for clarification. Project communications will be maintained at regular intervals via telephone and/or email.

The steps outlined above for the various sectors will then proceed. As requested, this will be done in MS Excel™ format. The MS Excel™ spreadsheet(s) will contain all of the base quantities, methods, emission factors, and emission estimates for both the actual and licensed (where applicable) emissions. Furthermore, a DRAFT report will be generated. This latter document and the MS Excel™

spreadsheet(s) will be circulated amongst AEMIT members. Once the report has been reviewed and feedback is obtained, either a second draft will be issued, or a final report will be produced.

Levelton has extensive experience with both government and private sector projects. Levelton has an excellent track record of ensuring that projects are completed to the specified scope and on budget. Levelton will provide a detailed breakdown of all costs associated with the work, and can provide backup timecards and receipts, etc. if it is desired.

5.2 ANALYSIS AND QUALITY CONTROL

As discussed in previous sections, annual emissions of the sectors will be prepared. The specific time period (e.g. 2000) will be determined by discussion with CASA. Input data for emissions estimation and output results will be compiled in a MS Excel™ workbook with separate worksheets for each worksheet and associated reference data.

Proposed Levelton project members are very experienced in the preparation of computerized emission inventories and are therefore familiar with potential sources of errors. This first-hand experience has allowed for the development of internal procedures and methods of checking inventory results to identify and correct any errors. The QA/QC measures that are applied will be documented in the final report to assure inventory users of the accuracy of the results and identify sources of error that are beyond Levelton's control. The QA/QC program could include the following elements:

- On-line code lookup displays to avoid coding errors;
- Comparison of like emission sources to identify anomalies for checking and correction;
- Order of magnitude checks for groups of emission sources e.g. past inventories
- Cross-comparison of emission totals;
- Printouts of fields for visual inspection for omissions and miscoding;
- Calculation checks using test data;
- Original calculations from the bottom-up for select examples.
- Others

Data gaps will be documented in the final report, together with recommendations for future work to fill these gaps.

5.3 REPORTS AND DELIVERABLES

In developing the work plan for the project, priority has been given to preparation of an improved and more reliable inventory. The proposed documentation will provide an easily read description of the results of the inventory. The following Table of Contents is a tentative illustration of the anticipated organization and content of the final report for Phase II:

1. Executive Summary
2. Introduction
3. Existing Inventories
   - Description
   - Calculation Methods Used
   - Strengths and Weaknesses
4. Methodology and Sources of Data for Inventory Upgrades
5. Emission Inventory – Overall Emissions (Licensed and Actual)
   - SO_2 emissions from batteries flaring gas solutions

- SO_2 emissions from well test flaring
- NO_X emissions from natural gas compressors
- NO_X emissions from heaters and boilers in industrial applications (including natural gas processing)
- NO_X emissions from heaters and boilers in commercial applications1995 Calgary

6. Data QA/QC, Sources of Error, Gaps and Uncertainties
7. Conclusions and Recommendations
8. References

6. REFERENCES

AEE_1990: Energy Resources Conservation Board, Energy-Related Nitrogen Oxide Emissions in Alberta 1988 – 2005, Alberta Energy, 1990

AENV, 1987, Acid Deposition Research Program (ADRP) Inventory

AEP_1996: David Slubik, Emission Inventories of Sulphur Dioxide, Nitrogen Oxides, and Ammonia in Alberta 1963 to 1995: A Review, Alberta Environmental Protection, February 1996.

AEP_EUB: W.S.Macdonald and B.F. Bietz, Management of Industrial Sulphur Dioxide and Nitrogen Oxides Emissions in Alberta – Description of the Existing System, Air and Water Approvals Division – Alberta Environmental Protection and Alberta Energy Utilities Board

B.C.MELP_1998: Clearstone Engineering and Levelton Engineering, 1995 Provincial Emission Inventory Update Upstream and Downstream Oil and Gas Emission Estimation, B.C. Ministry of Environment, Land and Parks – Environmental Protection Department – Air Resources Branch, January 1998.

CAPP 1999: A Detailed Emission Inventory of CH4 and VOC Emissions from Upstream Oil and Gas Operations in Canada, Volumes 1-4

Environment Canada, 1995 Criteria are Contaminant Inventory

EPWG-2000: Emissions and Projections Working Group, Summary Report of the Third EPWG-Stakeholder Workshop – Final Report, Hull-Quebec, September, 2000.

EUB_Guide56: Alberta Energy Utilities Board, Energy Development Application Guide and Schedules, October 2000.

EUB_Guide60_1999: Alberta Energy Utilities Board, Upstream Petroleum Industry Flaring Guide, July 1999.

EUB_Guide60_2001: Alberta Energy Utilities Board, Updates and Clarifications to Guide 60, February 2001.

EUB_Guide7: Alberta Energy Utilities Board, Production Accounting Handbook, May 2001.

US EPA_AP42: U.S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources, Triangle Park, NC, January 1995.

Summary of Air Emissions (Inventory) Reporting in the Oil and Gas Industry in Alberta

Activity	Description	NAICS (educated guess)	Reporting Emissions to AENV	Number Reporting to AENV	Currently Reporting to NPRI	Report Under Proposed Changes CAC's/Exemption
Regulated by Alberta Environment						
1. Sulphur manufacturing or processing plant	sulphur manufacturing or processing plant means a plant that manufactures or processes compounds containing elemental sulphur in quantities greater than 1.0 tonne per day	211113	Some NO_x	1	Yes	Not likely. NO_x emissions are less than 10 t/yr.
2. Sulphur storage facility	sulphur storage facility means a facility that has a storage capacity for sulphur of greater than 100 tonnes	211113	None	0	None	No
3. Oil sands processing plant	oil sands processing plant means a plant for (i) the recovery from oil sands of crude bitumen, sand and other substances, or (ii) the extraction from crude bitumen of crude oil, natural gas and other substances	211114	SO_2, NO_x	5	Yes	Yes – all CAC's
4. Enhanced recovery in-situ oil sands or heavy oil processing plant	enhanced recovery in-situ oil sands or heavy oil processing plant means a plant that processes or recovers heavy oil or crude bitumen by thermal or solvent in-situ recovery methods, but does not include any production facilities that are connected by pipeline to the plant	211114	SO_2, NO_x	14	Yes	Yes – all CAC's
5. Sour gas processing plant	sour gas processing plant means a plant that processes raw gas and separates and removes sulphur compounds from the raw gas stream	211113	SO_2, NO_x	240	Yes	Yes – all CAC's
6. Sweet gas processing plant (approval)	sweet gas processing plant means a plant that (i) processes raw gas, (ii) does not separate any sulphur compounds from the raw gas stream, and (iii) releases industrial wastewater to the environment other than by evaporation, by injection into an approved deep well facility, or by directing the industrial wastewater to a wastewater treatment plant	211113	NO_x	3	Unsure	Yes – all CAC's
7. Sweet gas processing plant (registration)	sweet gas processing plant means a plant that processes raw gas and(i) that does not separate any sulphur compounds from the raw gas stream, (ii) emits more than 16 kg per hour of oxides of nitrogen, and (iii) does not release industrial wastewater to the environment other than by evaporation, by injection into an approved deep well facility, or by directing the industrial wastewater to a wastewater treatment plant	211113	NO_x for only largest facilities Estimates can be made from Registration forms (~200)	3	Unsure	Yes – all CAC's
8. Bulk petroleum storage facility	bulk petroleum storage facility means a facility that has the capacity to store 10 000 m3 or more of petroleum products	412110	SO_2, NO_x Less than 10 t/yr	1	No – exempt activity	Will remain exempt

SUMMARY OF AIR EMISSIONS (INVENTORY) REPORTING IN THE OIL AND GAS INDUSTRY IN ALBERTA

Activity	Description	NAICS (educated guess)	Reporting Emissions to AENV	Number Reporting to AENV	Currently Reporting to NPRI	Report Under Proposed Changes CAC's/Exemption
9. Brine storage pond	brine storage pond means a pond that is used for the storage of water that contains more than 5000 mg per litre of chlorides	211113	None	0	No	No
10. compressor and pumping station (registration)	compressor and pumping station means a facility for the movement of a fluid by means of compression and pumping of the fluid and that has a total oxides of nitrogen emission rate of greater than 16 kilograms per hour	211113	None – But Estimates can be made from Registration forms (~200)	0	No	Unsure. 20,000 hour threshold would likely not be reached.
Regulated by Alberta Energy and Utilities Board						
11. Oil/Bitumen and Gas Batteries	Oil/bitumen battery - A system or arrangement of tanks or other surface equipment or devices receiving the effluent of one or more wells for the purpose of separation and measurement prior to the delivery to market or other disposition, but not including a custom treating plant, tank farm, oil loading and unloading terminal, or oil sands processing plant. Detailed description of Battery types can be found in Guide 7, Appendix 3.		Separate volumes for flared, vented, and fuel gas are reported monthly on S2. Fuel gas also reported. (some info available electronically).	Operating in yr 2000 Oil Bats = 6843 Bit Bats = 712 Gas Bats = 5435 Grand Total = 12990		
12. Satellite Batteries	Satellite or satellite battery - A small group of surface equipment (not including storage tanks) located between a number of wells and the main battery that is intended to separate and measure the production from each well, after which the fluids are recombined and piped to the main battery for treating and storage or delivery.		All numbers reported as oil, bit or gas bats.	Approx 3630 including suspended		
13. Gas Processing Facilities	Gas processing plant - A system or arrangement of equipment used for the extraction of hydrogen sulphide, helium, ethane, natural gas liquids, or other substances from raw gas; does not include a well head separator, treater, dehydrator, or production facility that recovers less than 2 m3/day of hydrocarbon liquids without using a liquid extraction process (e.g., refrigeration, desiccant). In addition, this does not include an arrangement of equipment that removes small amounts of sulphur (less than 0.1 tonne/day) through the use of nonregenerative scavenging chemicals that generate no hydrogen sulphide or sulphur dioxide.		Combined flared and vented numbers reported on S20 in addition to fuel gas (info available electronically). S essns reported on S30's where s inlet gt 1 t/d.	Approx 612-8= 604 operating plants.		

SUMMARY OF AIR EMISSIONS (INVENTORY) REPORTING IN THE OIL AND GAS INDUSTRY IN ALBERTA

Activity	Description	NAICS (educated guess)	Reporting Emissions to AENV	Number Reporting to AENV	Currently Reporting to NPRI	Report Under Proposed Changes CAC's/Exemption
14. Straddle Gas Plants	This is a plant whose purpose is recovering liquids (C2 and/or C3 and C4) from sales quality gas.		Combined flared and vented numbers reported on S20 in addition to fuel gas (info available electronically).	8 plants		
15. Compressor Stations	Compressor station/site - Service equipment intended to maintain or increase the flowing pressure of the gas that it receives from a well, battery, or gathering system prior to delivery to market or other disposition.		Combined flared and vented numbers reported on S8 in addition to fuel gas (info available electronically).	2001 gas gathering systems		
16. Custom Treating Plants	Custom treating plant - A system or arrangement of tanks and other surface equipment receiving oil/water emulsion exclusively by truck for separation prior to delivery to market or other disposition.		Reports (S24) – paper copies only available. Flared/Vented and Fuel Gas. Not sure to what extent these numbers are currently reported. No electronic info available.	Approx. 60 to 80 plants.		
17. Injection/Disposal Wells	Injection/disposal wells - A system or arrangement of surface equipment associated with the injection or disposal of any substance through a well.		Reports (S18) Flared/Vented and Lease Fuel Gas. Electronic info not readily available.	7636		
18. Pump Stations	Pumping station - A system of equipment located at intervals along a main pipeline to maintain flow to the terminal point.					

Summary of Air Emissions (Inventory) Reporting in the Oil and Gas Industry in Alberta

Activity	Description	NAICS (educated guess)	Reporting Emissions to AENV	Number Reporting to AENV	Currently Reporting to NPRI	Report Under Proposed Changes CAC's/Exemption
19. Tank Farm/Oil Loading and Unloading Terminal	Tank farm - A system or arrangement of tanks or other surface equipment associated with the operation of a pipeline and that may include measurement equipment and line heaters, but does not include separation equipment or storage vessels at a battery approved under the Oil and Gas Conservation Act. Oil loading and unloading facility - A system or arrangement of tanks and other surface equipment receiving crude oil by truck for the purpose of delivering crude oil into a pipeline.					
20. Pipelines	Companies transporting sales gas in the province to a distributor are required to report on transporter statements.		Transporter statements Flared, Vent and Fuel Gas.	10		
21. Wells			Any emissions from wells are reported on batteries. Both vented and flared gas is reported.	116 199 –7 636 = 108 563		
22. Waste Facilities	No emissions information – any emissions likely small. Reporting info related to crude oil recovery		No emission info.	40		
23. Industrial Development Permits	Any industrial or manufacturing operation using more than 100 terajoules of energy resource as feedstock or one petajoules of fuel and raw material must report annually fuel use and flared and wasted (see IL 80-22). These reports are confidential but aggregate info could be published.		Flared and wasted, and fuel use are reported.			

211113 – Conventional Oil and Gas Extraction. This Canadian industry comprises establishments primarily engaged in the exploration for, and/or production of, petroleum or natural gas from wells in which the hydrocarbons will initially flow or can be produced using normal pumping techniques.

211114 – Non-Conventional Oil and Gas Extraction. This Canadian industry comprises establishments primarily engaged in producing crude oil from surface shales or tar sands or from reservoirs in which the hydrocarbons are semisolids and conventional production methods are not possible.

Other notes – The EUB requires other information relating to emissions at the time of application (since April 1996). This information includes Nox emission ratings (g/kW-h) for compression and total continuous emissions for all facilities for CO2 (t/d) and Nox (t/hr). Further details on this information are contained in Guide 56, Schedule 2, page 2 (item 7).

Flared, vented and fuel gas numbers are reported as gas volumes corrected to 101 kPa, 15 deg C and reported to nearest 0.1 E3m3.

Appendix F Procedures for Guideline Development[**]

Four procedures for guideline development have been identified: *reviewing, updating, adopting, and creating*. The route that will be followed for guideline development depends on two factors: whether a guideline exists in Alberta, and whether it is a stakeholder priority or a department need. The matrix found in Table 4 identifies the process to be followed for each set of criteria.

Table 4 Procedures for Alberta Ambient Air Quality Guideline Development

	No Guideline	**Existing Guideline**
Stakeholder Priorities	Create	Review
AENV Needs	Adopt	Update

A guideline *creation* procedure is followed where no Alberta guideline exists and the substance is a stakeholder priority. Guideline creation begins with a 'scoping' phase. During the scoping phase approaches to guideline development are researched, and recommendations on possible approaches to guideline development are made. When the scoping phase is completed, the information gathering stage can begin. During the information gathering stage, information relevant to the guideline creation process is compiled and reviewed. The assessment phase is conducted by stakeholders to synthesize and evaluate information gathered. Reports and recommendations are then made to Alberta Environment by the working group involved in the guideline creation procedure. A guideline is then proposed. A public review is conducted; results are taken under consideration, and a new guideline is announced.

Guideline *review* takes place where an Alberta guideline is currently in place and the guideline is a stakeholder priority. The review procedure is the equivalent of the guideline creation procedure, with two exceptions: the scoping phase is eliminated, and the final output is a revised guideline instead of a new guideline.

Guidelines are to be adopted where no Alberta guideline exists and Alberta Environment needs the guideline. A survey of the guidelines in other jurisdictions is the first phase in guideline adoption. Guidelines surveyed are examined and evaluated. Reports are generated to provide the basis and background for the guideline. A guideline is proposed and released for public review. Finally, a new guideline is adopted.

Guideline updates take place where an Alberta guideline is currently in place and Alberta Environment needs the guideline to be revisited. A guideline update begins by incorporating the latest literature into current guideline documentation. Reports are generated to provide the basis and background for the guideline. A guideline is proposed and released for public review. Then the updated guideline is established. Stakeholders may request participation in the guideline update procedure, although there is no formal stakeholder consultation phase.

The Table of Contents for assessment reports can be found in Appendix B [of the original work plan]. The development of a guideline through the creating, reviewing, adopting, or updating procedures will be followed by a minimum 60-day public comment period.

[**] Source: *Alberta Ambient Air Quality Guidelines Work Plan*, April 2001. Alberta Environment. online at http://www3.gov.ab.ca/env/protenf/publications/AlbertaAmbientAirQualityGuidelinesWorkPlan.pdf Several figures that illustrate the text are included in the work plan but not reproduced in this appendix.

SUBSTANCE CLASSIFICATION

The following groups of substances were identified as being areas of high stakeholder concern: heavy metals, Volatile Organic Compounds, and Reduced Sulphur Compounds. Reduced Sulphur Compounds include all compounds contained in Total Reduced Sulphur (hydrogen sulphide, dimethyl sulphide, dimethyl disulphide, and methyl mercaptan), in addition to carbon disulphide and carbonyl sulphide. These three substance groups were identified as priorities for guideline development because they responded to a large number of stakeholder-identified priorities. Creating guidelines for these groupings instead of for individual substances is an effective use of limited resources, and results in the creation of guidelines that address a greater number of substances overall.

Substances and groups of substances were classed *review, adopt, update or create.* The classification of each substance or group of substances can be found in Table 5.

During the Ambient Air Quality Guidelines Priority Setting Workshop, Randy Angle of Alberta Environment indicated to participants that Alberta Environment would place priority on guideline creation over guideline review. As such, substances for which no guidelines exist in Alberta are the priority for guideline development. Guidelines that were identified by stakeholders as priority for review have been ranked using factors such as research requirements, potential timeframes, and ties to other processes. Because of resource limitations, work will not begin on the substances in the grey box in Table 5: Chlorine, Chlorine dioxide and Nitrogen dioxide, at this time. All substances in the grey box are currently supported by Alberta Ambient Air Quality Guidelines.

Table 5 Alberta Ambient Air Quality Guidelines: Development Procedure, by Substance

Create	Review	Adopt
- Heavy Metals - Reduced Sulphur Compounds (RSC) *(including Hydrogen sulphide, Carbon disulphide)* - Volatile Organic Compounds (VOCs) *(including Benzene, Toluene, and Xylenes)*	- Ammonia - Ozone - Particulate Matter - Sulphur dioxide No action at this time: - Chlorine - Chlorine dioxide - Nitrogen dioxide	- Acrylic acid - Acrylonitrile - Cumene acetone - 2-Ethyl hexanol - Pentachlorophenol - Propylene oxide

Appendix G Enhanced Performance Subgroup Draft Report

Suggestions for Managing Acidifying Emissions in Alberta

The Enhanced Performance Subgroup believes that there may be some potential to improve the management of acidifying emissions in Alberta, including opportunities for improving both environmental and economic aspects of emissions management. Three elements are considered essential for such improvements:

- companies – within and across industries – need to take the initiative to propose and collaborate on innovative approaches to improving performance;
- there should be a means for regulatory/public recognition of any such industry initiatives; and
- in addition to site-specific criteria, regulators need to develop the administrative flexibility to evaluate such proposals in the context of broader social and environmental objectives.

The first element reflects the view that if the regulatory regime provides the opportunity to consider alternative approaches to meeting environmental objectives, then it is incumbent on industry to initiate such proposals. It also reflects a view that, although there are likely to be initiatives that could be undertaken by individual companies, significant improvements in the efficiency of emissions management is likely to require the cooperation of several companies, perhaps from different industries. The subgroup believes that since competitive factors are not generally conducive to such cooperation, a conscious effort on the part of industry is likely to be a prerequisite for new approaches to emerge.

The second provision stems from the likelihood that significant additional SO_2 abatement will be achieved only at a net cost to industry and, consequently, there should be some form of "official" recognition of industry's efforts.

The third element suggests that rigidity in the regulatory process could stymie some attempts at innovation, such as a proposed technological change that involves tradeoffs between competing regulatory objectives. It also reflects the need for flexibility in regulatory administrative processes (e.g., application processes and reporting procedures) to accommodate industry proposals that may involve emissions from two or more facilities. Subject to certain constraints discussed below, it may serve the public interest better to concede some site-specific objectives in order to achieve a broader set of goals.

The subgroup recommends that the following guidelines be considered by both industry when developing proposals for enhanced performance, and by regulators when evaluating such proposals:

- proposals must result in improved or equivalent environmental quality;
- the public must be consulted and local concerns addressed; and
- ambient air quality and target loading guidelines must be met.

Additional Discussion

Regulatory Flexibility

The subgroup's idea of the kind of regulatory flexibility that could be desirable is reasonably summarized by the following two situations.

Suppose that sulphur recovery guidelines require that two facilities have their processes upgraded. Then suppose that two operators agree to share the costs of upgrading only one of the facilities, which would have the effect of achieving a larger combined impact on emissions than would occur if both plants were upgraded separately, perhaps by implementing acid gas injection at one of them. [††] Under the enhanced performance concept, the operators could apply to offset emissions greater than guidelines at the second facility with the incremental recovery achieved above guidelines at the zero emissions facility. With appropriate public consultation and consideration of local concerns, regulators would process the proposal in the spirit of the enhanced performance concept. If approved, the offset proposal would be accepted as meeting upgrading requirements at both facilities.

Another example could be where a relatively small volume of sour gas is being routinely flared - in compliance with the Alberta Ambient Air Quality Guidelines - but which could be processed at a nearby plant. However, a different set of guidelines might require the plant operator to upgrade the gas plant in order for it to process the new source of gas, and such costs might well be prohibitive. Consequently the gas might continue to be flared even though a reduction in emissions could be achieved by processing it in the existing plant. In cases such as these, environmental and economic efficiencies could be realized by relaxing requirements for improved sulphur recovery. Where the proposed emissions meet the equivalency requirement as well as the other criteria (i.e. ambient air quality and public input), regulators should be prepared to be flexible.

Implement Recognition-based Incentive Programs

Consideration should be given to designing a process that recognizes the efforts of companies to improve environmental performance. The nature of the recognition could be as simple as a "goodwill" certificate or mention in a newsletter. It could also respect the future applicability of emissions trading and allow 'banking' of any voluntary improvements for credit, as discussed below.

Continued Research into Credit-based Incentive Programs

If events warrant a regulatory process that requires emissions reductions (rather than the voluntary approach employed when emissions are well below critical targets), thought should be given to innovative approaches to achieving the desired results. For instance, credit-based systems would give firms increased flexibility in achieving emissions reductions. However, since this would be a new concept in environmental regulation in Alberta, there are several areas that warrant further investigation. These would include:

- the process for determining the extent and timing of desired emissions reductions,
- whether or not a voluntary process is likely to work,
- the roles for credits or allowances,
- verification processes, and
- the roles for banking and trading.

[††] The idea here is that the costs of upgrading the facilities separately could be greater – and the combined reduction in emissions smaller – than if the operators combined their efforts to upgrade only one of the facilities. With a cooperative approach there would be improvements to both environmental management and economic efficiency.

Recommendations

The Enhanced Performance Subgroup believes that improving the economics of environmental protection is important to meeting environmental objectives. Further, the subgroup believes that the current regulatory regime could provide industry with greater flexibility to achieve environmental objectives at a lower cost. The Enhanced Performance Subgroup recommends the following:

1. Industry operators should be responsible for proposing enhanced performance initiatives suited to specific circumstances.
2. Industry associations should promote collaboration among companies to encourage evaluation of joint performance enhancement initiatives.
3. Proposals for enhanced performance should incorporate the following criteria:
   a) the proposals result in improved or equivalent environmental quality;
   b) the public be consulted and local concerns addressed; and,
   c) ambient air quality and target loading guidelines be met.
4. Alberta Environmental Protection (AEP) and the Alberta Energy and Utilities Board (EUB) should consider industry's proposals, including concepts involving emissions off-sets, in the broader context of environmental objectives and the public interest.
5. AEP and the EUB should provide flexibility in regulatory administrative processes, including applications approvals and compliance reporting; to accommodate consideration and implementation of enhanced performance initiatives.
6. Additional work should be done to identify appropriate means of acknowledging enhanced performance by industry.
7. AEP, the EUB and the SO_2 Management Implementation Team should review the nature and success of enhanced performance initiatives to determine the opportunity for creating a broader program for emissions off-sets or credit trading.

Appendix H Responsibility and Roles for the SO_2 Management System

(revised Table 3 from 1997 report)

	AENV	AEUB /AE	EC	CASA	MSG	IND	ENGOs
GOALS	S	S	S	A/R	N/A	S	S
MANAGEMENT OBJECTIVES							
Environment	A/R	S	S	I	N/A	S	S
Performance							
environment-related	A/R	S	S	I	N/A	S	S
resource-related	S	A/R	I	I	N/A	S	S
Resource	S	A/R	I	I	N/A	S	S
MANAGEMENT OPTIONS	S	S	S	A/R	N/A	S	S
INTEGRATE DEVELOPMENT OF MANAGEMENT OBJECTIVES AND OPTIONS (for acidifying emissions)	S	S	S	A/R	N/A	S	S
SYSTEM OPERATION							
Environment objectives	A/R	S	S	I	N/A	S	S
Performance objectives							
environment-related	A/R	S	S	I	N/A	S	S
resource-related	S	A/R	I	I	N/A	S	S
Resource objectives	S	A/R	I	I	N/A	S	S
SYSTEM EVALUATION	R	S	S	A	N/A	S	S
DEVELOPMENT OF RECOMMENDATIONS FOR IMPROVEMENT	R	S	S	A	N/A	S	S
INFORMATION	S	S	S	A	N/A	S	S

AENV = Alberta Environment; AEUB/AE = Alberta Energy and Utilities Board / Alberta Energy; EC = Environment Canada; CASA = CASA Board of Directors; MSG = Multi-stakeholder Group recommended in 2 of the original SO_2 report; IND = Industry; ENGOs = Environmental Non-government Organizations; N/A = Not Applicable

A = Accountable, final approval; R = Responsible (only one per task); I = Inform; S = Support.