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Directive 060

Revised edition November 16, 2006
(Formerly Guide 60)

Upstream Petroleum Industry Flaring, Incinerating, and Venting

The Alberta Energy and Utilities Board (EUB/Board) has approved this directive on November 16, 2006.

<original signed by>

M. N. McCrank, Q.C., P.Eng.
Chairman

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1 Introduction

1.1 Purpose of This Directive

The Alberta Energy and Utilities Board (EUB) *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting* provides regulatory requirements and guidelines for flaring, incinerating, and venting in Alberta, as well as procedural information for flare permit requests, dispersion modelling, and the measuring and reporting of flared, incinerated, and vented gas. In addition to upstream petroleum industry facilities, the directive also applies to gas transmission facilities licensed by the EUB.

For the purpose of this directive, the term "operator" is used to designate the responsible duty holder (e.g., operator, licensee, company, applicant, approval holder, or permit holder) as specified in legislation.

Effective January 31, 2007, this revised directive supersedes the previous edition of *Guide 60* (1999) and all editions of *Guide 60: Updates and Clarifications* (1999 and 2001). As a result, *Interim Directive (ID) 99-06*, which introduced *Guide 60* (1999), is also rescinded.

Until April 30, 2007, the EUB will work with operators by providing education in cases where noncompliance with these new requirements is identified and corrective actions are taken.

After April 30, 2007, in cases where operators are in the process of implementing changes to comply with the new requirements in *Directive 060* but have not yet achieved compliance, operators must have the following material available for audit if requested by the EUB:

- a detailed plan and schedule for complying with new *Directive 060* requirements before June 30, 2007, and
- justification for not complying with new *Directive 060* requirements by April 30, 2007.

After April 30, 2007, if no effort has been made to achieve compliance with the new requirements in *Directive 060* or the material described above is not available for audit, enforcement will apply.

After June 30, 2007, enforcement of all requirements will take place.

Requirements that are unchanged from previous versions of *Directive 060* (formerly *Guide 60*) must be complied with immediately.

1.2 What's New in This Edition

A summary of key revisions in this edition is contained in Appendix 1.

This directive incorporates new requirements for the evaluation of solution gas venting and the reporting of economic evaluation data on solution gas flares and vents as described in *General Bulletin (GB) 2002-05: EUB Requirements for Evaluation of Solution Gas Vent Gas Conservation*.

Some of the most significant changes are as follow:

- The economic evaluation criterion for solution gas conservation is no longer a net present value (NPV) greater than zero. Conservation is now required if the evaluation yields an NPV greater than -$50 000Cdn. See Section 2.8.1.
- Applying the decision tree and conducting an economic evaluation is no longer required for solution gas flares and vents less than 900 m^3/day unless specifically requested by the EUB. See Section 2.3.
- The decision tree process that was originally developed for solution gas flaring has now been extended to solution gas venting and nonassociated gas flaring and venting. See Sections 2.3, 3.1, 4.1, 5.1, 6.1, and 8.1.
- Time limits have been developed for well test flaring and venting. There are time limits specific to each type of well. For conventional oil and gas wells, for example, the time limit is 72 hours. The time limits were developed based on data gathered by the EUB and reviewed by the CASA FVPT. See Section 3.2.
- Upon completion of testing, conventional oil and gas wells and dry coalbed methane wells must be shut in until conservation is in place (unless it is demonstrated that conservation is not required or is not required to be evaluated). See Section 3.2(6).
- Additional gas plant flaring requirements have been developed. These include reduced flare volume limits on larger gas plants and a requirement to not exceed six major nonroutine flaring events in any consecutive six-month period. See Sections 5.2 and 5.3.
- It is now a requirement that programs be developed and implemented to address fugitive emissions. See Section 8.7.

1.3 Flaring, Incinerating, and Venting Management Hierarchy and Framework

Flaring, incinerating, and venting are associated with a wide range of energy development activities and operations, including disposal of gas associated with

- oil, bitumen, and gas well drilling,
- oil, bitumen, and gas well completion or well servicing (well “cleanup”),
- gas well testing to estimate reserves and determine productivity,
- routine oil or bitumen production (solution gas),
- planned nonroutine depressuring of processing equipment and gas pipelines for maintenance,
- unplanned nonroutine depressuring of process equipment and gas pipelines due to process upsets or emergency, and
- upstream petroleum industry waste management facilities.

Two multistakeholder teams from the Clean Air Strategic Alliance (CASA – see www.casahome.org) have made recommendations on flaring, incinerating, and venting for the upstream petroleum industry upon which the EUB has based this directive (see Appendix 2 for background on *Directive 060*).

In particular, the EUB has adopted CASA’s objective hierarchy and its framework for the management of routine solution gas flares (Figure 1) and has extended its application to include flaring, incinerating, and venting of gas in general (see also CASA’s 1998 *Management of Routine Solution Gas Flaring in Alberta: Report and Recommendations of the Flaring Project Team*).

In accordance with the objective hierarchy, operators must evaluate the following three options:

- Can flaring, incinerating, and venting be eliminated?
- Can flaring, incinerating, and venting be reduced?
- Will flaring, incinerating, and venting meet performance standards?

1.4 Access to Production Flaring, Incinerating, and Venting Data

The EUB makes flaring, incinerating, and venting information available to operators in order to facilitate solution gas conservation and clustering opportunities, as described in Section 2.13.

1.5 How to Use This Directive

EUB requirements and recommended practices are numbered sequentially within each section and subsection throughout *Directive 060*. "Must" indicates a requirement for which compliance is required and is subject to EUB enforcement, while "recommends" indicates a best practice that can be used by the applicable party but is not an EUB requirement and does not carry an enforcement consequence.

To assist the reader, Appendix 3 lists references and contacts cited, Appendix 4 lists definitions of terms used, and Appendix 5 lists acronyms and abbreviations used throughout the text.

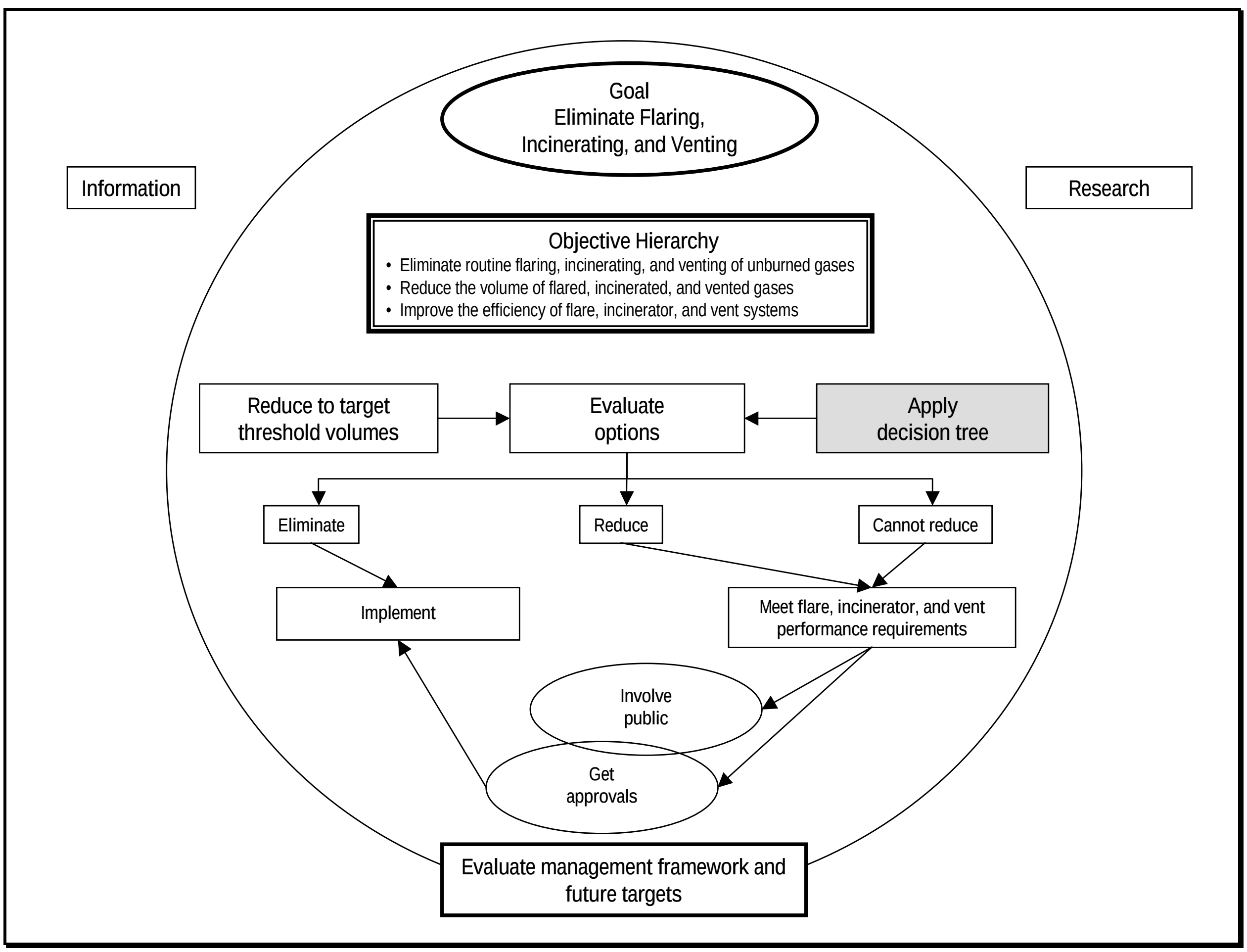

Figure 1. Solution Gas Flaring/Venting Management Framework (adapted from CASA)

2 Solution Gas Management (Crude Oil/Bitumen Battery Flaring, Incinerating, and Venting)

The EUB's goal is to have the upstream petroleum industry continue to reduce the volume of solution gas routinely flared, incinerated, and vented. The EUB expects that the upstream petroleum industry will pursue continuous improvement in reducing solution gas flaring, incinerating, and venting in Alberta. The EUB, in consultation with stakeholders, will monitor progress to determine the need for additional requirements to facilitate increased solution gas conservation.

Combustion of solution gas in incinerators is not considered an alternative to conservation.

For the purposes of solution gas management and disposition reporting, incinerated gas must be reported as flared.

Conservation is defined as the recovery of solution gas for sale, for use as fuel for production facilities, for other useful purposes (e.g., power generation), or for beneficial injection into an oil or gas pool (e.g., pressure maintenance, enhanced oil recovery). Conservation opportunities are evaluated as economic or uneconomic based on the criteria listed in Section 2.8.

2.1 Solution Gas Flaring Reduction Targets

Significant reduction in flaring has been accomplished by the upstream petroleum industry. Relative to the 1996 baseline, solution gas flaring was reduced by 72% in 2005.[1] Consistent with its goal, this directive incorporates recommendations made by CASA in 2002, 2004, and 2005 to ensure that reductions in flaring continue by setting out the following limits:

1) **The Alberta solution gas flaring limit is 670 million cubic metres (10^6 m^3) per year** (50% of the revised 1996 baseline of 1340 10^6 m^3/year) effective immediately.

2) If solution gas flaring exceeds the 670 10^6 m^3 limit in any year, the EUB will impose reductions that will stipulate maximum solution gas flaring limits for individual operating sites based on analysis of the most current annual data so as to reduce flaring to less than 670 10^6 m^3/year. For example, solution gas flaring could be limited to a maximum of 500 thousand (10^3) m^3/year at any one site.

2.2 Solution Gas Venting Reduction

The EUB does not consider venting as an acceptable alternative to flaring. If gas volumes are sufficient to sustain stable combustion, the gas must be burned (or conserved) (see Section 8.1). If venting is the only feasible alternative, it must meet the requirements in Section 8.

Solution gas venting for 2005 was 59% less than the 2000 venting baseline. The CASA Flaring and Venting Project Team considered solution gas venting in the 2004 *Gas*

[1] The EUB reports solution gas flaring and venting volumes annually. Further data on flaring and venting can be found in the report EUB *ST60B-2006: Upstream Petroleum Industry Flaring and Venting Report* available on the EUB Web site at http://www.eub.ca/docs/products/STs/st60b_current.pdf.

Flaring and Venting in Alberta: Report and Recommendations for the Upstream Petroleum Industry by the Flaring and Venting Project Team.[2] The EUB accepts these recommendations and has incorporated them into *Directive 060*.

2.3 Solution Gas Flaring and Venting Decision Tree

The EUB adopted the Solution Gas Flaring/Venting Management Framework (Figure 1) and endorses the Solution Gas Flaring and Venting Decision Tree Process (Figure 2), as recommended by CASA. Operators must apply the decision tree to all flares and vents greater than 900 m^3/day and be able to demonstrate how each element of the decision tree was considered and, where appropriate, implemented.

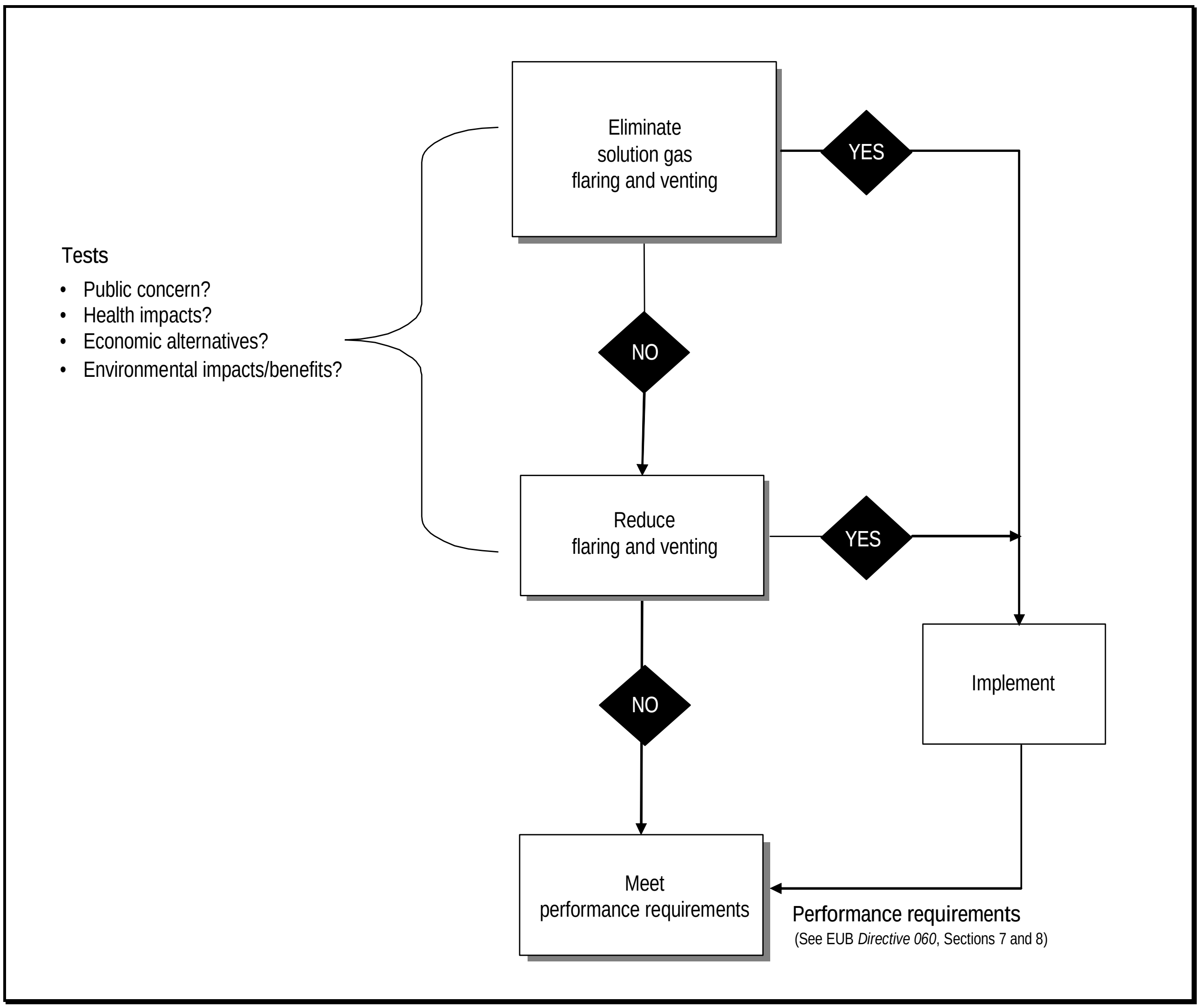

Figure 2. Solution Gas Flaring/Venting Decision Tree (adapted from CASA)

[2] This and other reports from this team are available on the CASA Web site at www.casahome.org. Go to CASA Library, and then click on Flaring Venting Project Team.

2.4 Conservation at New Oil and Bitumen Batteries

For the sole purposes of interpreting well test duration limits, conservation timing, and conservation prebuild requirements, crude oil sites within the geographic area defined by the boundary Township (TWP) 45, Range (RGE) 1W4 to RGE 8W4, and TWP 52, RGE 1W4 to RGE 8W4, and producing from the Mannville Group of formations will be regulated as bitumen sites.

1) Crude Oil: In general, for new oil sites[3] the solution gas flaring during the test period must not extend beyond the time required to obtain data for the economic evaluation and for sizing conservation equipment. Any flaring for testing, cleanup, and completions must not exceed a total of 72 hours (see Section 3.2 for further details and extensions to time limits).

   a) Upon completion of the testing period, if testing shows that combined flaring and venting volumes will exceed 900 m^3/day, solution gas conservation must be evaluated as described in Section 2.8. The site must be shut in at the conclusion of the test period and remain shut in pending the results of the solution gas conservation evaluation process.

      i) If the results of the solution gas conservation evaluation process indicate that conservation is required, the well(s) must remain shut in until conservation is implemented.

      ii) If the results of the solution gas conservation evaluation process indicate that conservation is not required, the well may proceed to produce without conserving the solution gas.

   b) If testing shows that combined flaring and venting volumes do not exceed 900 m^3/day, economic evaluation of solution gas conservation is not required and the well may proceed to produce without conserving the solution gas. The EUB still recommends economic evaluation of gas conservation, even in cases of less than 900 m^3/day.

2) Bitumen:

   a) Operators of multiwell bitumen sites must prebuild solution gas conservation lines to one common point on the lease as part of initial construction.

   b) For new bitumen sites, the test period is limited to the lesser of 6 months or until combined flared and vented volumes exceed a rolling average of 900 m^3/day for any consecutive 3-month period.

      i) As soon as testing shows that combined flaring and venting volumes exceed 900 m^3/day,[4] conservation must be evaluated as described in Section 2.8.

      ii) If conservation is required, it must occur as quickly as possible and must not exceed a maximum of 6 months after flow rate

[3] A site is defined as a single surface lease (pads counted as one lease) where gas is flared or vented.
[4] Volumes are calculated based on a 3-month rolling average.

determination. Shorter tie-in times must be pursued wherever possible. Wells must be shut in if required conservation is not operational within the timelines noted above.

c) If testing shows that combined flaring and venting volumes do not exceed 900 m^3/day, economic evaluation of solution gas conservation is not required and the well may proceed to produce without conserving the solution gas. The EUB still recommends economic evaluation of gas conservation, even in cases of less than 900 m^3/day.

2.5 Conservation at Existing Oil and Bitumen Batteries

These requirements apply to all oil and bitumen batteries unless otherwise specified.

1) Operators must conserve solution gas at all sites[5] where

   a) combined flaring and venting volumes are greater than 900 m^3/day per site[6] and the decision tree process and economic evaluation (Section 2.8) result in a net present value (NPV) of greater than –$50 000Cdn;

   b) the gas:oil ratio (GOR) is greater than 3000 m^3/m^3; all wells producing with a GOR greater than 3000 m^3/m^3 at any time during the life of the well must be shut in until the gas is conserved; or

   c) flared volumes are greater than 900 m^3/day per site and the flare is within 500 m of an existing residence, regardless of economics.

      i) If a new residence is constructed or relocated within 500 m of an existing solution gas flare after the effective date of this directive, operators must consult with the new residents for the purpose of providing information about the flaring operation.

2) For any sites flaring or venting combined volumes greater than 900 m^3 per day and not conserving, a review of conservation economics must be done at least once per year using the criteria in Section 2.8.

3) The EUB may still require economic evaluations for sites flaring or venting combined volumes less than 900 m^3 per day and not conserving on a case-by-case basis if it is believed that conservation may be feasible.

4) Conserving facilities must be designed for 95% conservation with a minimum operating level of 90%.

5) Operators may apply to discontinue conservation if annual operating expenses exceed annual revenue. See Section 2.5(6).

6) Operators must obtain approval from the EUB Operations Group to discontinue conservation once it has been implemented at any facility and

   a) complete a decision tree to evaluate alternatives to discontinuing conservation,

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[5] A site is defined as a single-surface lease (pads counted as one lease) where gas is flared or vented.
[6] Volumes are calculated based on a 3-month rolling average.

b) provide information on actual annual operating expenses and revenues,

c) notify the appropriate EUB Field Centre and residents within 500 m of their intentions to discontinue conservation and initiate flaring or venting at a site, and

d) comply with Table 1 in the event conservation facilities are not operational until such time as approval from the EUB Operations Group to discontinue conservation is granted.

2.6 Clustering

Solution gas is economic to conserve in some areas if operators coordinate their efforts in an efficient, cooperative process to take advantage of combined gas volumes and economies of scale. Furthermore, solution gas conservation economics (see Section 2.8) will be enhanced if conservation is incorporated into the initial planning of larger multiwell projects.

1) Operators of production facilities operating within 3 kilometres (km) of each other or other appropriate oil and gas facilities (including pipelines) must jointly consider "clustering" when evaluating solution gas conservation economics.

   The EUB may suspend production in the area under consideration until the economic assessment is complete.

   The EUB recommends that

   a) operators exchange production data and jointly consider clustering of solution gas production or regional gas conservation systems, and

   b) the operator with the largest flare and vent volumes would take the lead in coordinating the evaluation of conservation economics for the area.

2) Operators of multiwell oil or bitumen developments must assess conservation on a project or development area basis regardless of distance. Evaluations must address all potential gas vent and flare sources associated with the multiwell development.

   a) Operators must incorporate provision for conservation at all stages of project development to optimize the opportunity for economic conservation of solution gas.

   b) Applications under *Directive 056: Energy Development Applications and Schedules* for multiwell oil or bitumen developments must include a summary of the gas conservation evaluation and a description of the operator's related project plans.

2.7 Power Generation Using Otherwise-Flared/Vented Gas

Power generation is an alternative for conserving solution gas.

1) Approval of electrical power plants by the EUB is required under the *Hydro and Electric Energy Act*.

a) EUB *Directive 028: Applications for Power Plants, Substations, Transmission Lines, and Industrial System Designations* provides application requirements for power plant applications and includes a simplified application form for electric power generating projects smaller than or equal to 1.0 megawatt (MW).

2) Power plants with a generation capacity of greater than 1.0 MW at peak load require approval from Alberta Environment issued under the *Environmental Protection and Enhancement Act*.

2.8 Economic Evaluation of Gas Conservation

1) **If conservation is determined to be economic by any method using the economic decision tree process, the gas must be conserved.**

   a) Methods of conservation include pipeline to sales, fuel, power generation, pressure maintenance, or any other alternative method that may become available.

   b) For any sites flaring or venting combined volumes greater than 900 m^3/day and not conserving, conservation economics must be updated every 12 months. This information, with the responsible individual named and the document dated, is to be kept on file by the operator and must be provided to the EUB upon request. Evaluation information may be stored at a central location rather than being stored on site.

   c) Operators are not required to provide copies of evaluations to the EUB unless requested. Upon request, operators must provide the evaluation to the EUB within 5 working days.

   d) If the EUB Operations Group determines that the economic evaluation process has not been completed in accordance with *Directive 060* requirements, the operator will be subject to enforcement action, which may include suspension of facility operations.

2.8.1 Economic Evaluation Criteria

Economic evaluations of gas conservation must use the following criteria. The operator must consider the most economically feasible option in providing detailed economics. Specific EUB economic evaluation submission requirements are listed in Section 2.8.2.

1) Evaluations must be completed on a before-tax basis.

2) Price forecasts used in the evaluation of solution gas conservation projects (gas gathered, processed, and sold to market) must use the most recent GLJ Petroleum Consultants' *Product Price and Market Forecasts for the Canadian Oil and Gas. Industry*. Gas prices must be obtained from the "Natural Gas and Sulphur Price Forecast Table" in the "Alberta Plant Gate – Aggregator" column ($Cdn/MMBtu)." Condensate prices must be obtained from the "Crude Oil and Natural Gas Liquids Table" in the "Alberta Natural Gas Liquids Section – Edmonton Pentanes Plus" column ($Cdn/MMBtu)."

3) Price forecasts for power generation projects must reflect the most recent 12-month rolling average of the Pool Monthly Summary price as published by the

Alberta Electric System Operator (AESO). This information can be obtained from the AESO Web site http://ets.powerpool.ab.ca. The power price must be escalated at the long-term inflation rate (see item 8). Alternatively, the cost of the power displaced at the site may be used.

4) Operators must have information to support the remaining reserves calculation and the production forecast (including planned drilling programs and pressure maintenance schemes).

5) Operators must have a detailed breakdown of capital costs showing equipment, material, installation, and engineering costs. Capital costs must be approved-for-expenditure quality numbers and must be based on selection of appropriate technology. Any capital costs incurred prior to the initiation of the solution gas project (sunk costs) must not be included in the analysis; only future capital costs related to solution gas conservation may be included.

   a) For new flares, if there are capital cost savings resulting from implementing gas conservation, such as any equipment that would otherwise be required, they must be considered in the conservation economic evaluation and subtracted from the overall cost of the conservation infrastructure in evaluating the economics of solution gas tie-in.

   b) Salvage value of gas conservation infrastructure must be included as project revenue in the year the value would be realized (e.g., transfer of a gas compressor from one conservation project at the end of that project's life to another conservation project). The salvage value must be a reasonable market value estimate of the equipment and not a depreciated value from a taxation perspective.

6) The incremental annual operating costs for the gas conservation project, including gas gathering and processing fees, are to be assumed as up to 10% of the initial capital cost of installing the conservation facilities. If the gas contains 10 moles per kilomole (mol/kmol) hydrogen sulphide (H_2S) or more, the incremental annual operating costs for the solution gas project may be assumed to be up to 20% of the capital cost to initially install the conservation facilities.

   a) The economic evaluation must account for any cost savings, such as reduced trucking, equipment rental, and operator costs, that may result from the conservation project.

7) The incremental annual operating costs for power generation projects are to be assumed as up to 10% of the initial capital cost of installing the generation facilities. Standby fees may be calculated in addition to this 10% allowance.

8) The most recent long-term inflation rate must be based on the Consumer Price Index forecast as published on the Government of Alberta, Department of Finance Web site at www.finance.gov.ab.ca/aboutalberta/economic_bulletins/current_economic_indicators.pdf. The CPI for Alberta should be chosen.

9) The discount rate must be equal to the prime lending rate of ATB Financial on loans payable in Canadian dollars plus 3%, based on the month preceding the month during which the evaluation is conducted. This rate is reviewed periodically by the EUB and will be revised if the cost of capital for the oil and gas industry changes significantly.

10) The conservation economics must be evaluated on a royalties-in basis (paying royalties) for incremental gas and gas by-products that would otherwise be flared or vented. If the economic evaluation results in an NPV less than –$50 000Cdn, operators must re-evaluate the gas conservation project on a royalties-out basis (not paying royalties). If this evaluation results in an NPV equal to or greater than –$50 000Cdn, the operator must proceed with the conservation project and may then apply to Alberta Energy for an Otherwise Flared Solution Gas royalty waiver.

11) A solution gas conservation project is considered economic, and the gas must be conserved, if the economics of gas conservation generates an NPV before-tax greater than –$50 000Cdn.

   a) The NPV is defined as the sum of discounted, annual, before-tax cash flows for the economic life of the solution gas conservation project, where each annual before-tax cash flow is net of that year's conserving project capital investment, if any.

   b) The economic life of a conservation project is defined as the period from the start of the project to the time when annual expenses exceed annual revenue. Note that Section 2.5(6) provides a process whereby operators may apply to discontinue conservation if annual expenses exceed annual revenue.

12) If a solution gas conservation project has an NPV less than –$50 000Cdn and is therefore considered uneconomic on its initial evaluation, the project economics must be re-evaluated annually (within 12 months after the latest evaluation) using updated prices, costs, and forecasts.

2.8.2 EUB Economic Evaluation Audit Requirements

1) Economic evaluation audit packages submitted to the EUB Operations Group upon request must contain the following information in International System of Units (SI):

   a) detailed capital and operating cost schedules as set out in Sections 2.8.1(5) and 2.8.1(6);

   b) oil and gas reserves calculations and supporting information (including a discussion of planned drilling programs and pressure maintenance schemes);

   c) a production forecast for both the oil and gas streams and the economic limit (date and production rates) of the project based on the oil production rate (including planned drilling programs and pressure maintenance schemes);

   d) a copy of the gas analysis from the project or a representative analog complete with gas heating value and gas liquid yields;

   e) documentation of alternatives that were considered in order to eliminate or reduce flaring, incinerating, or venting, how they were evaluated, and the outcome of the evaluation; and

   f) documentation of compliance with the requirements listed in Sections 7 and 8.

2.9 Consultation and Notification

Public consultation and notification requirements for facility applications are specified in *Directive 056*.

Operators with continuous solution gas flares, incinerators, or vents must consult or notify the public as required by *Directive 056* of activities related to the flaring, incinerating, and venting of solution gas at upstream petroleum industry facilities, in accordance with this section.

1) Applicants for new wells and facilities must include information specific to flaring, incinerating, and venting as part of the public notification process (see Section 2.9.1).

2) Applicants must consult with residents (in accordance with *Directive 056* consultation requirements) prior to licensing if the proposed site may flare natural gas.

3) Operators must consult annually with residents within 500 m of a solution gas flare and address their concerns. Residents may inform operators if they wish to be exempt from consultation in subsequent years or if they wish to be consulted on an annual or bi-annual basis. Operators must recommence annual consultations when new residents move into the existing residence.

4) Applicants must consult with residents (in accordance with *Directive 056* consultation requirements) prior to licensing if the proposed site may vent natural gas. Residents may inform operators if they wish to be consulted on an annual or bi-annual basis.

5) Residents within 500 m of a facility's solution gas flare must be notified by the operator of the results of the decision tree evaluation.

   a) An information package specific to flaring, incinerating, and venting, including the material listed in Section 2.9.1, must be provided to residents as part of public notification.

6) Operators must notify residents, the appropriate EUB Field Centre, and Alberta Environment of nonroutine flaring, incinerating, and venting at production and processing facilities, as described in Section 2.11, Table 1.

2.9.1 Public Information Package

As a minimum, public information packages **must include the following:**

1) the definition of solution gas and information on its conservation and use;

2) an explanation of solution gas flaring, incinerating, and venting management options and the decision tree process;

3) results of the decision tree analysis for the site in question;

4) information on general flare/vent performance requirements and reduction targets;

5) a description of specific actions the operator will take to eliminate or reduce the flaring, incinerating, or venting or improve the efficiency of the flare, incinerator, or vent source based on the evaluation;

6) a description of the EUB process for facility applications and approvals (see *Directive 056*);

7) information about an individual's right to object to the application for the facility and the process for doing so; and

8) a list of industry, EUB, and government contacts related to public consultation and relevant to the individual project.

2.10 Dealing with Public Concerns/Objections

1) Operators must address public concerns/objections about solution gas flaring, incinerating, and venting that arise from notification (Section 2.9).

2.11 Nonroutine Flaring, Incinerating, and Venting at Solution Gas Conserving Facilities

Operators must minimize nonroutine flaring, incinerating, and venting during upsets and outages of solution gas conserving facilities.

In addition to these requirements, the EUB recommends that operators contact the appropriate EUB Field Centre for recommendations on approaches to minimize solution gas flaring during conserving facility outages.

2.11.1 Limitations on Nonroutine Flaring, Incinerating, and Venting During Solution Gas Conserving Facility Outages

1) Production operations must be managed to control nonroutine flaring, incinerating, and venting of normally conserved solution gas in accordance with Table 1, below.

2) Table 1 does not apply to nonassociated gas (the percentage cutbacks listed in Table 1 apply to solution gas only). All nonassociated gas must be shut in during facility outages.

3) Operators must notify as required in Table 1.

4) If there is a restriction to plant inlet, the EUB recommends that solution gas be processed on a priority basis in relation to nonassociated gas in order to minimize unnecessary flaring of solution gas.

5) The EUB recommends that wells with the highest GOR be shut in first during facility outages and cutbacks.

6) Provided the overall required percentage reduction in solution gas production is achieved, it is not necessary to implement equal reductions at all locations upstream of the conserving facility outage.

    a) When multiple operators are involved, they may determine how to best implement the overall required production reductions. If agreement cannot be reached, each operator must implement production reductions as specified in Table 1.

Table 1. Limitations and notification requirements for nonroutine flaring, incinerating, and venting during solution gas conserving facility[1] outages

Shutdown category	Duration	Operational requirements
Partial equipment outages	< 5 days	Shut-in of production is not required for equipment outages lasting less than 5 days that involve small volumes of gas (e.g., storage tank vapour recovery unit repair). This allowance is limited to a maximum of 2 10^3 m^3 per day, subject to limitations on venting, as defined in Section 8.
Planned	< 4 hours	Operators must make all reasonable efforts[2] to reduce battery or solution gas plant inlet gas volumes by 50% of average daily solution gas production over the preceding 30-day period.
	> 4 hours	Operators must reduce battery or solution gas plant inlet gas volumes by 75% of average daily solution gas production over the preceding 30-day period and meet the following requirements: • Solution gas must not be flared from wells that have an H_2S content greater than 10%. • Production may be sustained at rates to provide sufficient throughput to keep equipment operating safely and within minimum design turndown range. If this volume is greater than 25% of the average daily solution gas production, a variance must be obtained from the appropriate EUB Field Centre (see Section 2.11.3). • Residents within 500 m must be notified at least 24 hours before the planned flaring event. • The EUB also recommends that operators notify individuals that have identified themselves to the operator as being sensitive or interested regarding emissions from the facility. • The appropriate EUB Field Centre must be notified[3] if the event meets reporting requirements identified in *IL 98-01*,[4] Section 4.4.
Emergency[5] or plant upset	< 4 hours	No reduction in plant inlet is required.
	> 4 hours	Operators must reduce battery or solution gas plant inlet gas volumes by 75% of average daily solution gas production over the preceding 30-day period and must meet the following requirements: • Solution gas must not be flared from wells that have an H_2S content greater than 10%. • Production may be sustained at rates to provide sufficient throughput to keep equipment operating safely and within minimum design turndown range. If this volume is greater than 25% of the average daily production, a variance must be obtained from the appropriate EUB Field Centre (see Section 2.11.3). • Residents within 500 m must be notified without delay about the flaring event. • The EUB also recommends that operators notify individuals that have identified themselves to the operator as being sensitive or interested regarding emissions from the facility. • The appropriate EUB Field Centre[3] must be notified if the event meets reporting requirements identified in *IL 98-01*,[4] Section 4.4.
Repeat nonroutine flaring[6]		Operators must investigate causes of repeat nonroutine flaring or venting and take steps necessary to eliminate or reduce the frequency of such incidents.

[1] For definition of conserving facility, see Appendix 4.
[2] Notwithstanding solution gas reduction requirements listed in Table 1, if a sour or acid gas flare or incinerator stack is not designed to meet the one-hour *Alberta Ambient Air Quality Objectives* for sulphur dioxide (SO_2) under high flow rate conditions, action must be taken immediately to reduce gas to a rate compliant with *Alberta Ambient Air Quality Objectives* (see Section 7).
[3] The appropriate EUB Field Centre must be notified through the EUB Field Inspection System (FIS), in the Digital Data Submission (DDS) System. In situations where limits have been exceeded the appropriate EUB Field Centre must be contacted by telephone prior to DDS notification.
[4] *IL 98-01: A Memorandum of Understanding Between Alberta Environmental Protection and the Alberta Energy and Utilities Board Regarding Coordination of Release Notification Requirements and Subsequent Regulatory Response*.
[5] Emergency shutdowns or plant upsets are unplanned events at the battery site or at facilities downstream of the battery that cause nonroutine flaring at the battery.
[6] Repeat nonroutine flares are defined as recurring events of similar cause at a conserving facility during a 30-day period.

2.11.2 Planned Shutdown (Turnaround) Considerations

1) Operators must evaluate and implement appropriate measures to reduce solution gas flaring, incinerating, and venting during a gas plant turnaround or planned shutdown. Alternatives that minimize impacts of planned shutdowns include

   a) delivering solution gas to a nearby gas plant that is not on turnaround;

   b) scheduling maintenance at related oil facilities to coincide with the gas plant turnaround;

   c) injecting solution gas into the gas cap of an oil pool or into a gas reservoir and producing it back when the gas plant is back on stream (see *Directive 065: Resources Applications for Conventional Oil and Gas Reservoirs*); and

   d) communicating with well, battery, and gas plant operators to ensure that nonroutine solution gas flaring, incinerating, and venting are minimized.

2.11.3 Alternatives to Solution Gas Shut-in Requirements

The appropriate EUB Field Centre will consider alternatives to the shut-in requirements listed in this directive for solution gas. This will be done only if the operator can demonstrate that shutting in a well or a group of wells may cause damage to well equipment or permanent reduction in productivity or if shutting in is impractical due to the remoteness of facilities. In these special cases, the operator must consult with the EUB Field Centre about alternatives to shut-in for a particular gas plant or battery.

1) Operators must plan for outages. If an alternative to Table 1 is justified, operators must submit a written request to the EUB Field Centre explaining the alternative requested and giving supporting reasons for the request. Contact with the EUB Field Centre must not be deferred until an actual outage occurs. Operators must submit the written request to the EUB Field Centre a minimum of 30 days prior to a planned shutdown.

2.12 Royalty Treatment of Flared and Vented Gas

In December 1998 the Alberta Government created the Otherwise Flared Solution Gas Royalty Waiver Program to encourage the productive use of solution gas currently being flared. For more information, see the Alberta Energy *Information Letter (IL) 99-19: Otherwise Flared Solution Gas Royalty Waiver Program* available on the Web at http://www.energy.gov.ab.ca.

The program is summarized as follows:

- The Alberta Department of Energy has developed criteria to ensure that when gas can be economically conserved, it does not receive a royalty waiver.
- The program covers all methods of conserving solution gas.

2.13 Solution Gas Reporting Requirements and Data Access

2.13.1 Solution Gas Reporting Requirements

1) Flared, incinerated, and vented solution gas must be reported monthly through the Petroleum Registry of Alberta as described in Section 10.

a) Operators must report all new oil well production, including the test period, and obtain a battery code for any new oil wells before production, including flaring, can be reported.

2.13.2 Data Access

The EUB Operations Group makes available production data related to the disposition of oil, gas, and water for all crude oil and bitumen batteries, except information associated with wells that are part of an approved EUB experimental scheme. Confidential information is respected using existing confidentiality protocols.

Electronic copies of the data identified as *ST60* and *ST60A* are available on a monthly and annual basis. Data are provided for oil batteries and bitumen batteries. It is the responsibility of the interested party to determine if the data represent a physical battery or a collection of single wells that are reported on a common report.

2.13.3 Cooperating with Third Parties

The EUB recommends that operators cooperate with qualified third parties attempting to conserve solution gas through open market or clustering efforts by providing nonconfidential information, such as gas analyses, flared and vented volumes, pressures, and other relevant data, on a timely basis (also see Section 2.6).

In cases where conservation is determined by the company to be uneconomic (as per Section 2.8) but a third party is able to conserve the gas, the EUB recommends that operators either conserve the gas or make the gas available at the lease boundary at no charge within 3 months of a request for the gas. It would be understood that this gas may be provided without processing or compression, and the third-party organization must not have an impact on the upstream operations.

Any third party making data requests to operators must be technically qualified and have a reasonable expectation of proceeding with the gas conservation project. Third parties must also comply with all relevant EUB requirements.

3 Temporary and Well Test Flaring and Incinerating

This section applies to temporary flaring and incinerating activities. These activities include well testing, well cleanup, well servicing, sour gas pipeline (as defined in *Directive 056*) blowdown, coalbed methane well testing, underbalanced drilling, maintenance blowdowns, and emergency blowdowns through temporary or permanent flare or incinerator equipment.

Note that unplanned nonroutine flaring and incinerating (e.g., process upsets, emergencies) do not require a temporary permit. Planned nonroutine flaring and incinerating events (e.g., maintenance blowdowns, pipeline depressuring, turnarounds) do require a temporary flaring or incinerating permit, as stated in Section 3.3.

See Section 8 for temporary venting requirements. The EUB does not consider venting as an acceptable alternative to flaring or incinerating. If gas volumes are sufficient to sustain stable combustion, the gas must be burned or conserved (see Section 8.1(5) for specifics on well test venting). If venting is the only feasible alternative, it must meet the requirements in Section 8.

3.1 Temporary Flaring and Incinerating Decision Tree

1) Operators must use the Temporary Flaring and Incinerating Decision Tree Process (Figure 3) to evaluate all opportunities to eliminate or reduce flaring and incinerating, regardless of volume.

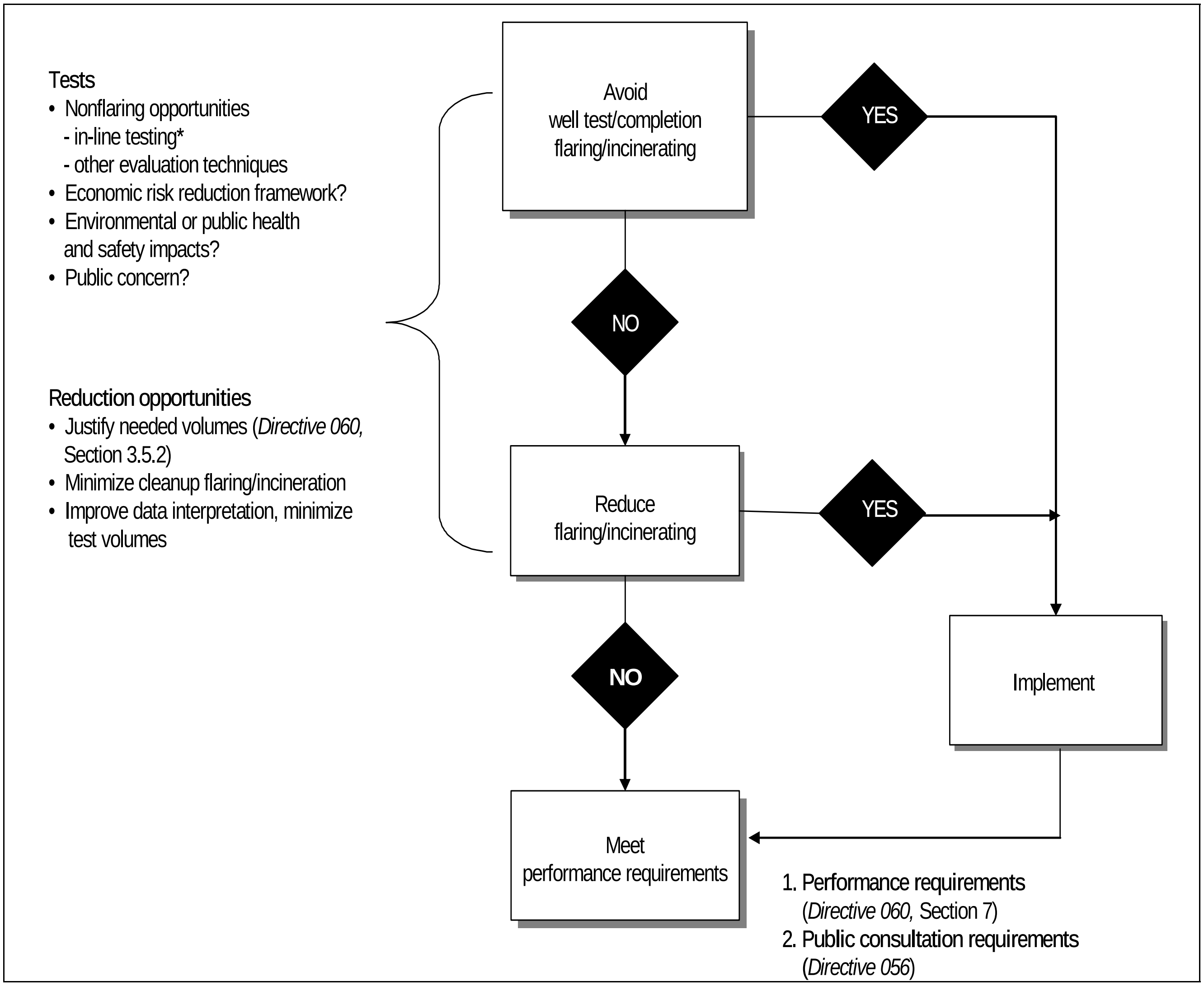
2) Operators must evaluate opportunities to use existing gas gathering systems prior to commencing temporary maintenance, well cleanup, or testing operations (i.e., "in-line testing"). In-line testing must be used when economic and feasible to do so. Information on the evaluation of the most feasible option (e.g., closest potential tie-in location) must be provided with permit requests (Section 3.5.1). Further, the EUB recommends that in-line testing be used in situations where

   a) suitable infrastructure exists in proximity to the well and can be connected at moderate cost and where use of the infrastructure does not compromise integrity, or

   b) sufficient productivity information is known about a development well such that connecting pipelines can be constructed with minimal financial risk prior to testing.

3) If in-line testing is not possible, operators must design completions and well testing programs to minimize emissions, while ensuring a technically sound well completion and acquisition of sufficient reservoir and productivity information for future development decisions. *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells* must be consulted for details on the minimum pressure and deliverability requirements for well testing and the recommended practices to ensure that the appropriate information is obtained for conservation and pool management purposes in addition to the requirements of this directive.

   a) Operators must use appropriate equipment and design temporary (maintenance, well completion, or test) programs to comply with performance requirements in Section 7 and the *Alberta Ambient Air Quality Objectives*.



*In-line testing may still involve very small quantities of gas flared or incinerated.

Figure 3. Temporary Flaring and Incinerating Decision Tree (adapted from CASA)

3.2 Oil and Gas Well Test Flaring, Incinerating, and Venting Duration Limits

For the sole purposes of interpreting well test duration limits, conservation timing, and conservation prebuild requirements, crude oil sites within the geographic area defined by the boundary TWP 45, RGE 1W4 to RGE 8W4, and TWP 52, RGE 1W4 to RGE 8W4, and producing from the Mannville Group of formations will be regulated as bitumen sites.

1) These time limits are per zone and nonconsecutive and they do not include shut-in time. These time periods include cleanup, completion, and testing operations.

   a) crude oil wells/sites[7]: 72 hours

[7] A site is defined as a single-surface lease (pads counted as one lease) where gas is flared or vented.

b) bitumen wells/sites: As soon as flow rates exceed an average of 900 m^3/day for any consecutive 3-month period, not to exceed 6 months (see Section 2.4[2])

c) gas (nonassociated, non-coalbed methane): 72 hours

d) dry coalbed methane development wells (producing less than 1 m^3 of water per operating day): 120 hours

e) dry coalbed methane nondevelopment wells (producing less than 1 m^3 of water per operating day): 336 hours

f) wet coalbed methane wells (producing more than 1 m^3 of water per operating day): see Section 3.2(7) below

2) Extensions to the time limits listed in 1 (a), (c), (d), and (e) above will be allowed only in the following unique situations:

   a) cleanup of the wellbore is not complete;

   b) stabilized flow has not been reached; or

   c) there have been mechanical problems with the well.

   For extensions to the time limits stated in 1 (b) and (f), operators must request approval from the appropriate EUB Field Centre as described in 4 below.

3) The operator must document these reasons for extension and keep the information on file for audit by the EUB Field Centre when requested. The operator is not required to request permission to extend the flaring/venting beyond the specified time limit listed in 1 (a), (c), (d) or (e) if the reason matches those listed in 2 (a), (b) or (c), but must provide advance notification to the appropriate EUB Field Centre via the Digital Data Submission (DDS) system as soon as the operator recognizes that the time limit will be exceeded.

   a) If an audited operator fails to justify the need to exceed the time limitation to the EUB Field Centre's satisfaction, enforcement action will apply.

4) If additional time for well test flaring/incinerating or venting is needed for reasons other than those listed above, the appropriate EUB Field Centre must be contacted for approval to continue as soon as possible, and no later than the end of the specified time period.

5) If a temporary flaring/incinerating permit has been issued, the volume allowed in the permit will take precedence over the time limit described above.

6) When well test information indicates that cleanup is complete and the well flow is stabilized and all other EUB requirements (e.g., EUB *Directive 040*) are met, flaring/incinerating/venting must be discontinued, even if the time limit or the flaring/incinerating permit volume has not been reached. This requirement does not apply to bitumen or wet coalbed methane wells. Timing requirements for bitumen are in Section 2.4 (2). Timing requirements for wet coalbed methane wells are in 7 below.

7) For wet coalbed methane wells (producing more than 1 m^3 of water per operating day), flaring/incinerating or venting must cease (gas must be conserved) within 6 months of gas production for an individual well exceeding a cumulative total of 100 $10^3 m^3$ for any consecutive 3-month period (about 1100 m^3/day). Shorter tie-in periods must be pursued wherever possible.

   a) Operators must notify the EUB Operations Group as soon as the cumulative total gas production exceeds 100 $10^3 m^3$ for any consecutive 3-month period at a wet coalbed methane well that is flaring/incinerating or venting.

   b) For wet coalbed methane wells that do not trigger the requirement above (100 $10^3 m^3$ in 3 months), flaring/incinerating and venting are limited to the lesser of

      i) a total period of 18 months, including the time to tie in the well, or

      ii) a total cumulative volume of 400 $10^3 m^3$ for Tier 2 (development) wells or 600 $10^3 m^3$ for Tier 1 (other) wells per zone tested (see Section 3.3.1[2]). Wells already tied in are treated as Tier 3 and allowed a maximum cumulative flare/incineration and vent volume of 200 $10^3 m^3$.

   c) If additional flaring/incinerating or venting durations or volumes are needed to test a coalbed methane well producing more than 1 m^3 of water per operating day, the operator must make a written request to the EUB Operations Group as early as possible and in no case later than the end of the 18-month or volume allowance flare/incineration or vent period. Any request must include the reasons for the extension. Extensions may be granted to allow for additional flaring/incineration/vent duration or volume for reservoir evaluations or if other special circumstances warrant.

3.3 Temporary Flaring/Incinerating Permits

Figure 4 depicts the temporary flaring/incinerating permit process.

1) Any representative of the EUB may suspend well flaring or incineration operations for noncompliance with conditions of the permit (see Section 12).

3.3.1 Conditions That Require a Temporary Flaring/Incinerating Permit

Note that an exemption for flaring small volumes of sour gas is found in Section 3.3.2(2).

1) Operators must obtain a permit to flare or incinerate sour gas containing more than 50 mol/kmol H_2S (5%) or sour gas from any well classified as a critical sour well.

   a) If operations result in higher concentrations of H_2S than that of the well (e.g., flaring gas from tanks), the composition of the gas to be burned must be determined and used for establishing whether a permit is required. This composition must also be used in any required dispersion modelling.

   b) If supplemental fuel gas is used, the resulting composition must be used for dispersion modelling. However, the gas composition from the source is still used as the basis for determining whether a permit is required.

2) Operators must obtain a permit for temporary flaring or incinerating of natural gas if gas well test volumes exceed the volume allowance threshold. This is based on the volume of gas flowed back from the well (i.e., does not include fuel gas added), regardless of composition.

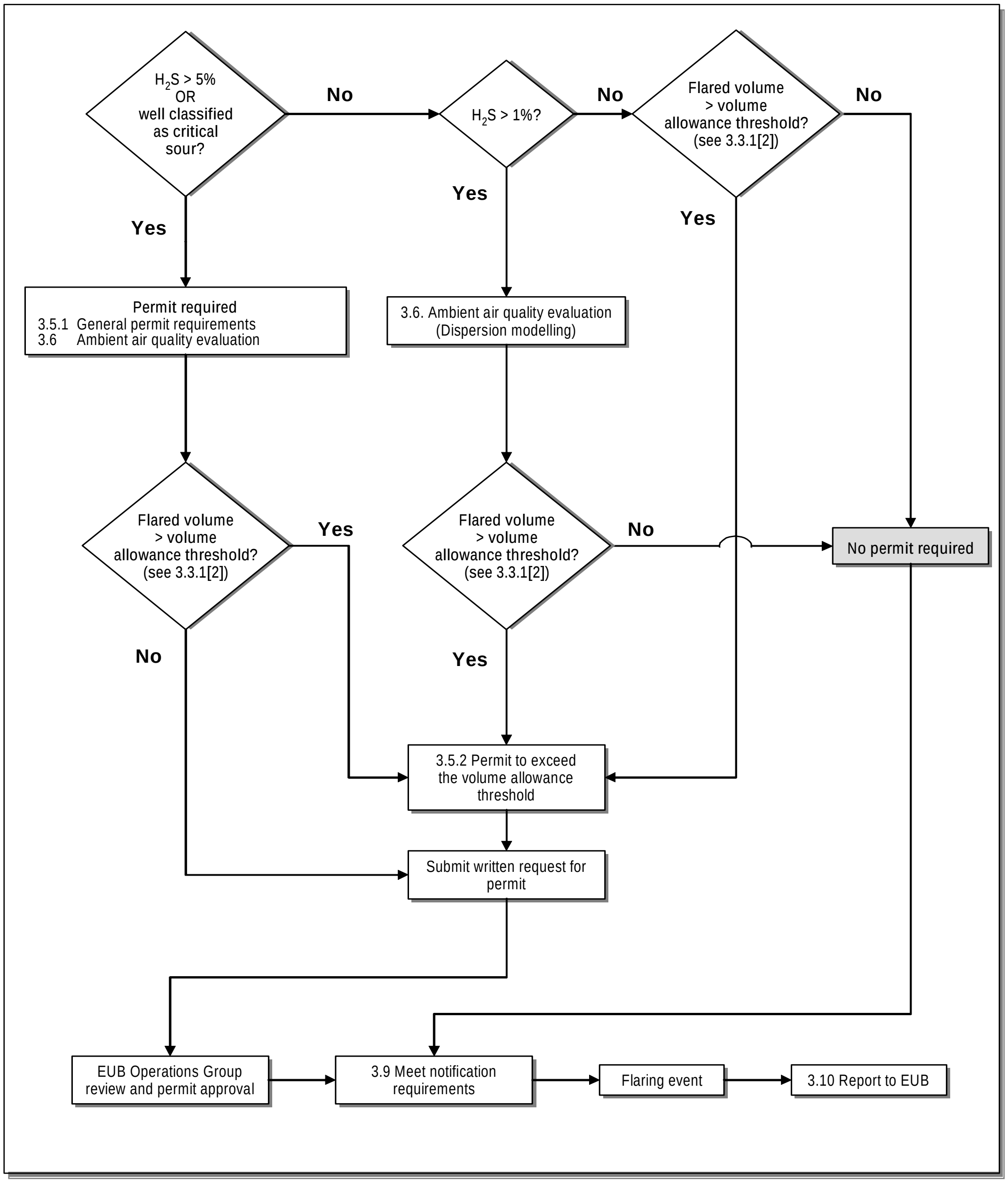


Figure 4. Temporary flaring/incinerating permit process

a) The volume allowance threshold is defined in three tiers. This is based on the volume of gas flowed back from the well (i.e., does not include fuel gas added), regardless of composition. These volumes apply to gas well tests only:

i) **Tier 1 ≤ 600 10^3 m^3**: applies to wells that have not been tied in and have a Lahee classification of New Field Wildcat (NFW), New Pool Wildcat (NPW), Deeper Pool Test (DPT), or Outpost (OUT).

ii) **Tier 2 ≤ 400 10^3 m^3**: applies to wells that have not been tied in and have been assigned a Lahee classification (including Development) not listed in the Tier 1 allowance (excluding Re-entry [REN] and Experimental [EX] wells. See (b) and (c) below).

iii) **Tier 3 ≤ 200 10^3 m^3**: applies to any well that has been tied into facilities appropriately designed to handle production from the formation being tested (e.g., sweet versus sour service).

All requested volumes must be justified and may be questioned by the EUB.

b) The volume allowance threshold for a Re-entry well is the same tier allowance (1, 2, or 3) that applied to the well before it was reclassified as re-entry.

c) For wells with a Lahee classification of Experimental, the volume allowance threshold is the same tier allowance (1, 2, or 3) that applied to the well before it was reclassified as Experimental or that normally would have applied to the well had it not been classified as Experimental.

d) An incremental volume of 200 10^3 m^3 may be added to the volume allowance threshold defined above for each additional zone being tested during continuous operations on a well (with continuous operations meaning that servicing equipment and personnel are not demobilized between tests on each zone) subject to the following limitations:

i) The volume flared from any zone during multiple-zone tests must not exceed the volume allowance threshold for a single zone unless a larger volume is specifically approved by the EUB Operations Group.

ii) The incremental allowance does not apply to single tests over multiple commingled zones. Each zone to be tested must be identified and fully accounted for in the related flare permit request.

3.3.2 Conditions That Do Not Require a Temporary Flaring/Incinerating Permit

1) A permit is not required if the gas contains less than or equal to 50 mol/kmol H_2S (5%) and total volume (for gas well tests) is less than the volume allowance threshold (see section above). However, operators must meet the requirements set out in Section 3 and Section 7, as well as the notification and consultation requirements set out in Section 3.9.

a) Operators must evaluate compliance with the one-hour *Alberta Ambient Air Quality Objectives* for sulphur dioxide (SO_2) if the gas contains more than

10 mol/kmol H_2S (1%). Related dispersion modelling results must be provided to the EUB Operations Group upon request.

2) Flaring or incinerating small volumes of sour gas containing more than 50 mol/kmol H_2S (5%) are exempt from EUB permit requirements provided that the following conditions are met:

   a) Total sulphur emission rates do not exceed 1.0 tonne per day.

   b) Gas flow rates do not exceed 10 10^3 m^3/day, nor does total volume exceed 50 10^3 m^3 over the duration of the event.

   c) Equipment is designed to ensure compliance with the one-hour *Alberta Ambient Air Quality Objectives* for SO_2 and/or operating procedures are in place to ensure compliance with the Objectives. Related dispersion modelling evaluations and design information are documented and available to the EUB Operations Group upon request.

   d) Rates and volumes are measured and reported as defined in Section 10.

   e) Written notification is provided to the EUB Operations Group. The notification includes the total expected gas volumes and sulphur emissions. If applicable, the notification provides an explanation of any air quality management plans needed to ensure compliance with the *Alberta Ambient Air Quality Objectives*.

3) The EUB does not require temporary permits for the use of permanent flares or incinerators installed in EUB-licensed facilities, including batteries, compressor stations, and gas plants provided that operators can show, on request of EUB Operations Group or Field Centre staff, that

   a) the flaring or incinerating volumes, rates, and gas composition are within the limits of the facility licence;

   b) the flares or incinerators are designed to operate safely under the intended conditions in compliance with the *Alberta Ambient Air Quality Objectives*; and

   c) the total volumes are less than the volume allowance threshold.

4) Similarly, the EUB does not require temporary permits for unplanned nonroutine events such as emergencies. Operators must ensure that temporary nonroutine systems are adequately designed to operate safely under anticipated emergency and upset conditions and must meet the requirements set out in Section 7.

   a) For planned nonroutine events, including maintenance blowdowns, pipeline depressuring, and turnarounds, operators must obtain a temporary permit unless exempted in (2) or (3) above.

3.4 Flaring and Incinerating Permits for Underbalanced Drilling

Permit requirements (Section 3.3) and notification and consultation requirements (Section 3.9) for temporary flaring and incinerating also apply to underbalanced drilling.

For more detail on underbalanced drilling requirements, see *EUB Interim Directive (ID) 94-03: Underbalanced Drilling, ID 97-06: Sour Well Licensing and Drilling Requirements*, and Appendix 6.

3.5 Permit Requirements for Temporary Flares and Incinerators

Figure 4 summarizes the temporary permit process.

3.5.1 General Permit Requirements

1) Requests for temporary permits must be submitted to the EUB Operations Group and must include complete information on the proposed activity, as requested in the *EUBflare.xls* and *EUBincin.xls* spreadsheets (available on the EUB Web site) and summarized as follows:

    a) a cover letter requesting a permit and informing the EUB Operations Group of any public objections and/or concerns to the proposed flaring/incineration activities;

    b) information about the site where flaring/incinerating will occur, including location, Lahee classification, and related maps;

    c) an evaluation of the most feasible option for in-line testing;

    d) information on planned flaring/incinerating, including reasons for the activity (e.g., well testing, completions, pipeline depressuring), H_2S content, flow rates, total volumes, and type of combustion device to be used (i.e., flare or incinerator);

    e) information on the operator's assessment of impacts on ambient air quality, including results of dispersion modelling for SO_2;

    f) in situations where there is potential to exceed the EUB low-risk criteria (see Section 3.6[5] for low-risk criteria) for SO_2, information on the operator's proposed air quality management plan to prevent exceedances.

2) Any inconsistencies in the request or modelling will result in the request being rejected and returned to the operator.

3) The temporary permit request can be submitted electronically by the operator. The permit will be in the name of the operator.

3.5.2 Requests to Exceed the Volume Allowance Threshold

Information requirements apply to all requests to exceed the volume allowance threshold. However, any volume of gas flared or incinerated must be defensible.

1) Operators must provide specific engineering, economic, and operational information to justify reasons for flaring or incinerating gas volumes in excess of the volume allowance threshold.

2) All requests for volumes greater than the volume allowance threshold regardless of H_2S content must be submitted to the EUB Operations Group and must include the following, in addition to information specified in Section 3.5.1 (note that items 1 [e] and [f] of that section do not apply to sweet gas wells).

a) Requests relating to tests to determine if sufficient gas supply exists to justify related investments must include information on the scope of development required to produce the well and necessary threshold reserves. See Appendix 6.

b) Requests relating to tests to determine the relationship between absolute open flow (AOF) and deliverability of the well must include justification of the volume being requested as it pertains to obtaining an accurate deliverability relationship, in accordance with EUB *Directive 040*.

c) Requests relating to tests to establish the stabilized flow rate of the well must include justification of the flare volume request as it pertains to obtaining a stabilized flow rate, including the identification of any analogous well(s) being used for comparison purposes.

3) Should the information described above not be available or applicable, operators must include discussion on why the material is not included with the exceedance request.

4) For underbalanced drilling, follow the guidelines in Appendix 6.

3.5.3 Blanket Flaring/Incinerating Permits

Sour oil and gas well operations such as well servicing may result in flaring of relatively small volumes of gas at several sites in a local area. In order to simplify temporary permit request requirements, the EUB Operations Group may issue a single "blanket" permit to cover several flaring events at different sites in an area if so requested by the operator. Blanket permit request requirements and limitations are as follows:

1) Blanket permits are issued on a fixed-term basis for periods not to exceed one calendar year. Operators must complete and submit a new flare permit request to renew blanket permits for additional periods of time.

2) Blanket permits are limited to specific stack heights, locations, rates, maximum volumes per event, maximum H_2S concentrations, and maximum sulphur emissions per event as listed in the permit request.

3) All wells must be licensed before they can be considered for a blanket permit.

4) For every well under consideration for a blanket permit request, operators must use the *EUBflare.xls* or *EUBincin.xls* spreadsheet (available on the EUB Web site) to evaluate the temporary flaring or incinerating parameters during the period when flaring/incinerating is planned.

   a) The spreadsheets provide screening modelling. Refined modelling may be required and must meet the low-risk criteria.

   b) Any inconsistencies in the request or modelling will result in the request being rejected and returned to the operators.

5) A blanket permit will not be considered if

   a) projected volumes are over 100 10^3 m^3 per site or flaring event;

   b) total sulphur emissions will exceed 10 tonnes per event;

c) an air quality management plan is necessary for compliance with the EUB low risk criteria for SO_2; or

d) complex terrain modelling is required for specific locations.

Exceptions may be made only after consultation with the EUB Operations Group.

6) A list of wells, their bottomhole and surface locations, and licence numbers must be submitted to the EUB Operations Group before a blanket permit request will be considered.

7) A Sour Gas Flaring/Incineration Data Summary Report (see Appendix 7) for each well event must be completed and submitted within 30 days of the end of each calendar quarter-year to the EUB Operations Group.

If no flaring or incinerating was conducted over the previous calendar quarter-year, a Sour Gas Flaring/Incineration Data Summary Report must be submitted reflecting the lack of flaring or incinerating.

8) Operators must comply with public and EUB Field Centre notification requirements for each flare event covered by the blanket permit as described in Section 3.9.

3.5.4 EUB Review of Permit Requests (Operations Group)

Requested volumes, rates, and/or conditions may not be granted by the EUB Operations Group. Consideration will be given to total volumes, total sulphur emissions, local land uses, proximity of residences, and potential for exceedance of the *Alberta Ambient Air Quality Objectives* before a permit is granted. EUB Operations Group staff will consult with operators in such situations.

1) Operators must avoid temporary flaring or incinerating in situations where existing infrastructure can be reasonably used for in-line disposition of the gas, especially in populated areas.

2) Operators must limit requested volumes for gas, especially gas with high H_2S contents. Situations involving sulphur emissions of 50 tonnes or more are subject to closer scrutiny by the EUB Operations Group. The EUB Operations Group typically will not approve permits where total sulphur emissions exceed 300 tonnes.

3.6 Ambient Air Quality Evaluation (Dispersion Modelling)

1) Operators must evaluate impacts of sour gas flaring, incinerating, or enclosed burning on ambient air quality if it is proposed to burn sour gas containing more than 10 mol/kmol H_2S (1% H_2S) or 1 tonne per day of sulphur.

2) Either the flaring (*EUBflare.xls*) or incinerator (*EUBincin.xls*) spreadsheet must be completed.

3) Information on ambient air quality impact evaluations must be included in requests to burn sour gas or, if no permit is required, must be provided to the EUB upon request. The dispersion modelling within *EUBflare.xls* or *EUBincin.xls* may be sufficient if a screening assessment is adequate.

4) Sour gas flares and incinerators must be designed for the gas composition and flow rates for the specific situation involved in the temporary permit (see Section 7 for further information).

5) Equipment design and/or operating procedures must address all modelled predictions that exceed the *Alberta Ambient Air Quality Objectives*, excluding predicted values meeting the EUB's low-risk criteria. The low-risk criteria only apply to temporary events.

   a) EUB low-risk criteria for temporary events allow limited exclusion of predicted ambient air quality results, provided that

      i) the meteorological conditions that cause predicted exceedances occur less than 1% of the time, and

      ii) the values do not exceed a predicted one-hour SO_2 ambient concentration of 900 micrograms (µg) per m^3.

   Note that while model predictions up to 900 $\mu g/m^3$ will be considered, actual exceedances of the *Alberta Ambient Air Quality Objectives* are never permitted.

   b) EUB low-risk criteria for parallel airflow are incorporated in the flaring (*EUBflare.xls*) spreadsheet. For incinerators, refined modelling may be required to demonstrate that the EUB low-risk criteria are met for parallel airflow.

   c) EUB low-risk criteria may be used when refined and complex terrain modelling is conducted for temporary events.

   d) The EUB Operations Group will also consider operator use of the low-risk criteria in situations where air quality management plans (see Appendix 8) are necessary to ensure compliance with the *Alberta Ambient Air Quality Objectives*.

      i) Air quality management plan decision criteria must be based on meteorological or ambient air quality monitoring data.

6) Operators must evaluate cumulative effects on ambient air quality if there are continuous SO_2 emissions sources (e.g., sour gas plants, sour flaring batteries) within 7 km or within the isopleth of one-third of the *Alberta Ambient Air Quality Objective* for SO_2 (as described in Section 7.12.3), whichever distance is less. Sour gas burning operations must be planned so that *Alberta Ambient Air Quality Objective* exceedances due to the **combined** effect of all sources in the area do not occur.

   a) Other sources can be modelled at maximum expected operating emission rates at the time of the temporary event.

7) Concurrent temporary sour gas burning (i.e., multiple well test flaring/incinerating) must not occur within 14 km of each other, unless an operator can demonstrate that the cumulative emissions resulting from concurrent flaring can meet *Alberta Ambient Air Quality Objectives*.

8) Dispersion modelling assessments must be done using methodologies acceptable to the EUB Operations Group as described in Sections 3.6 and 7.12 and in Appendix 9.

9) Operators must retain for one year after the flaring/incinerating event information on dispersion assessments for flares or incinerators that require dispersion modelling but do not require a flaring permit (see Section 3.3.2). This information must be provided to the EUB Operations Group upon request.

3.7 Site-Specific Requirements Related to Well Flaring and Incinerating

The following requirements apply to the use of temporary flares and incinerators.

1) Temporary flares and incinerators must comply with design and operation requirements defined in Section 7.

    a) Flares and incinerators must not be operated outside design operating ranges as specified by the designing or reviewing professional engineer, certified technician, or certified technologist.[8]

2) Operators must determine the H_2S content of flared or incinerated gas using Tutweiller or gas chromatography methods as soon as practical after commencement of operation if gas analysis has not been obtained within the preceding 12 months.

3) If the H_2S content in the gas is found to exceed 50 mol/kmol H_2S and no flaring or incinerating permit has been issued by the EUB Operations Group or if the H_2S content of the gas exceeds the maximum value listed in the related permit, operations must be suspended and the appropriate EUB Field Centre notified. Operations must not resume until a permit or permit amendment is issued by the EUB Operations Group in response to a written request.

4) Both high- and low-pressure gas-liquid separation stages must be used for sour gas to minimize vapour released from produced hydrocarbon liquid and sour water storage.

5) Liquid storage must be designed to prevent the escape of sour gas to the environment. (For additional detail see Canadian Petroleum Safety Council, Industry Recommended Practice (IRP) Volume 4-2000/02: Well Testing and Fluid Handling.)

6) Tanks and equipment used for temporary flaring/incineration operations must be provided with secondary containment, when required, as specified in EUB *Directive 055: Storage Requirements for the Upstream Petroleum Industry*. Storage tanks must be provided with secondary containment unless the following conditions are met:

    a) The operation is staffed 24 hours per day, or

[8] The titles Professional Engineer, Certified Technician, and Certified Technologist refer to designations as granted by APEGGA, ASET, or the equivalent.

b) The tanks are equipped with a high-level device that will shut down operations (a high-level shutdown [HLSD]).

3.8 Temporary Facilities for In-Line Tests

To facilitate conservation, the operator may install a temporary compressor and pipeline connections. For temporary compressor installation, see *Directive 056*.

This section of this directive does not apply to oil batteries. However, *Directive 056* application requirements apply to both temporary and permanent oil batteries.

1) Details on application requirements and exceptions for temporary well test facilities and pipeline connections are provided in *Directive 056*. In the case of a discrepancy between this directive and *Directive 056*, *Directive 056* application requirements apply.

2) Exceptions to EUB applications requirements for temporary facilities, such as temporary connection to existing gathering systems, are intended to encourage conservation of gas associated with well testing. The provisions do not apply to testing situations where gas will be flared.

3) Only one test period will be approved at each site. If there are multiple events, an application is required (see *Directive 056*).

4) In the case of extended tests or multiple tests that require temporary facilities to operate for more than 21 days, operators must complete an application (see *Directive 056*).

5) Proposals to install temporary compressors and other facilities for reasons other than testing new wells must comply with *Directive 056* application requirements.

6) Operators intending to use temporary production, compression, and/or pipeline facilities must notify the appropriate EUB Field Centre and obtain approval for a variance from *Directive 056* application requirements.

   a) The notification must include a description of the proposed equipment (including relevant capacities), driver type, and layout. (For example, provide a description of the compressor power rating and note whether the driver type is gas, diesel, or electric.)

   b) Operators intending to install and use temporary pipelines for well testing purposes must complete and submit to the appropriate EUB Field Centre the Checklist for 21-Day Temporary Surface Pipelines for Well Testing Purposes.[9]

   c) EUB Field Centre approvals for temporary facilities are valid for 21 days from the start date and include the dismantling and removal of the temporary facilities (including pipelines) from the lease. Any exceptions, including allowances for downtime during testing, must be referred to the appropriate EUB Field Centre for further review.

[9] Available on the EUB Web site www.eub.ca.

7) Temporary facilities, including pipelines, must comply with relevant EUB requirements.

   a) Temporary facilities must meet noise control requirements defined in *Directive 038: Noise Control Directive User Guide.*

   b) Operators must meet emergency response plan requirements for sour wells. The plan must incorporate provisions for the temporary equipment as appropriate. (See *Directive 071: Emergency Preparedness and Response Requirements for the Upstream Petroleum Industry*.)

8) Temporary sweetening processes, if used, must be of the zero-sulphur-emissions type. Operators must submit a facility application, as described in *Directive 056* for temporary installation of regenerative sweetening processes with acid gas.

   a) All temporary or permanent regenerative sweetening facilities require an Alberta Environment sour gas processing plant approval.

9) Temporary pipelines and batteries must comply with *Directive 056* public consultation requirements.

3.9 Notification and Consultation Requirements

Operators must notify all residents located within the notification radius as defined in Table 2 that flaring, incinerating, or venting will occur. The EUB does not require operators to obtain the consent of the residents within the notification radius.

1) Operators must notify all residents of flaring, incinerating, and venting events as defined in Table 2 (see also *Oil and Gas Conservation Regulations* 7.060). The notification distances in Table 2 represent *minimum* requirements.

2) Notice must be given to the appropriate EUB Field Centre via the DDS system of any planned flaring, incinerating, or venting activity at least 24 hours in advance.

   a) The notice to the appropriate EUB Field Centre must provide a contact name and telephone number in case of complaints or emergencies (see Appendix 10).

3) Upon EUB Field Centre request, operators must provide a list of notified residents within the specified notification radius, as well as a sample of the information provided to residents.

4) Operators must notify residents in writing (see Appendix 11) and provide them with basic information regarding the flaring, incinerating, or venting event as follows:

   a) operator name, contact persons, and telephone numbers,

   b) location of the flaring, incinerating, or venting,

   c) duration of the event (start date and latest expected completion date),

   d) expected event volume and rates,

e) information on the type of well (oil, gas, or coalbed methane) and, if applicable, information on the H_2S content of the flared or incinerated gas, and

f) EUB Field Centre contact telephone number.

Table 2. Temporary flaring, venting, and incinerating notification requirements[1,2]

Type of operation (applies to sweet and sour streams)	Duration of event (hrs in 24-hr period)		Gas volume (10^3 m^3 in a 24-hr period)	Notification[3]
Temporary (i.e., for well cleanup, testing, or maintenance)	< 4	and	< 30	No notification[4]
Temporary (i.e., for well cleanup, testing, or maintenance) if gas contains ≤ 10 mol/kmol H_2S	> 4	or	> 30	Residents, 1.5 km radius; EUB Field Centre
Temporary (i.e., for well cleanup, testing, or maintenance) if gas contains >10 mol/kmol H_2S	> 4	or	> 30	Residents, 3 km radius; EUB Field Centre
Temporary (i.e., for well cleanup, testing, or maintenance) through permanent battery or plant flare or incinerator	< 4		--	No public notification;[4] Notify EUB[5] if flaring >30 10^3 m^3
Temporary (i.e., for well cleanup, testing, or maintenance) through permanent battery or plant flare or incinerator	> 4		--	Residents, 0.5 km radius;[5] EUB Field Centre

[1] Temporary venting is not permitted within 500 m of a residence unless consented to by the resident and approved by the EUB Field Centre (Section 8.1(6)).

[2] See Appendix 10 for further information on EUB Field Centre notification reporting procedure.

[3] 24 to 72 hours in advance of planned flaring, venting, or incinerating operations, operators must notify the appropriate EUB Field Centre via the DDS system, all rural residents outside of incorporated centres and hamlets and within the specified radius, and administrators of any incorporated centres and hamlets within the specified radius. Note that in the case of incorporated centres and hamlets, it is sufficient to contact only the appropriate administrator. Advance notification of more than 72 hours (not longer than 90 days) must also offer the option for renotification within the 24- to 72-hour period prior to operations. After 90 days, renotification is mandatory.

[4] The EUB recommends additional "good neighbour" notification for short-duration events to be conducted with residents who have identified themselves to the operator as being sensitive or interested regarding emissions from the facility within the same notification radius as specified for events more than 4 hours.

[5] The EUB recommends additional "good neighbour" notification for longer duration events (more than four hours) to be conducted with residents who have identified themselves to the operator as being sensitive or interested regarding emissions from the facility.

5) Operators may conduct a one-time notification program for multiple-well projects in an area. In addition to the information noted above, the related multiple-well project notification must provide

a) the locations where flaring, incinerating, or venting will occur,

b) the period during which the project will be carried out, and

c) the expected duration and volume of temporary flaring, venting, or incinerating operations.

6) Operators may limit the number of repeat notifications to individual residents if

a) the resident requests that the number of notifications be reduced,

b) the operator provides the resident with an outline of expected flaring and incinerating activities in the area, and

c) the operator documents the agreement to reduced notifications in writing and obtains the signature of the resident(s) to ratify the agreement. A copy of this letter agreement must be provided to the EUB upon request.

7) Operators may conduct a single notification to each resident within the notification area and the appropriate EUB Field Centre, rather than a separate notification for each flaring, venting, or incinerating period throughout the program, if this is acceptable to the potentially affected parties. The method of notification must be discussed during the initial notification process.

8) The EUB recommends that operators consider placing signage on public roads surrounding the temporary flaring or incinerating operations indicating the operation type and contact phone number for inquiries.

3.9.1 Addressing Resident Concerns

1) The EUB recommends that operators work with residents prior to commencing well test or temporary flaring or incinerating for the purpose of addressing resident concerns about those proposed activities.

2) Operators must disclose any unresolved resident concerns about the proposed flaring or incinerating activities to the appropriate EUB Field Centre without delay. The resident may also make a complaint to the appropriate EUB Field Centre.

3) EUB Field Centre staff will then review the proposed flaring or incinerating activities. If the operator is in compliance with *Directive 060,* the operations will be allowed to proceed.

3.9.2 EUB Flaring/Incinerating/Venting Notice Form

1) In order to comply with the requirements in Section 3.9 above, operators must complete the EUB Flaring/Incinerating/Venting Notice Form on line using the EUB's DDS system and submit it electronically to the appropriate EUB Field Centre, as described in Appendix 10.

3.10 Reporting Gas Well Test Data

1) Well test results and information required by flaring and incinerating permits must be submitted in accordance with the requirements of *Directive 040, Bulletin 2004-15: New Well Test Capture (WTC) System Implementation Date Reminder: Changes to Final WTC Pressure ASCII Standard (PAS) Formats and Version 4.0 PAS File Business Rules Implications,* the applicable permit, and Section 10.

a) All well test reports must be submitted within three months of completing the fieldwork. This information must include the volume of gas produced to flare, vent, or pipeline, as well as all gas analyses from samples gathered at the wellhead and must be submitted to the EUB Production/Well Data Services Group.

2) All well tests that require permits must submit a Sour Gas Flaring/Incineration Data Summary Report to the EUB Operations Group within three weeks of the completion of flaring or incinerating activities (see Section 10.4, Appendix 7, and *EUBflare.xls* or *EUBincin.xls* spreadsheet).

3) All flaring, incinerating, and venting at a well site (including well tests) must be reported on the appropriate production reporting submissions, including the Petroleum Registry of Alberta. (See *Directive 007: Production Accounting Handbook*).

   a) In order to be able to report to the EUB, the operator must obtain a battery code. Any produced volumes, including those flared, incinerated, or vented, must be reported (see *Directive 007*).

   b) Fluid volumes and fuel consumption must be recorded and reported on the monthly production submissions (see Section 10).

3.11 Zero Flaring Agreements

Flaring is allowed by the EUB when conducted in accordance with *Directive 060*. However, parties may agree to zero flaring, as set out in a Zero Flaring Agreement (see Appendix 12). The agreement must be signed by both parties and filed by the applicant with the well application. Once filed, the Zero Flaring Agreement is deemed to be a condition of the well licence. **Should the operator fail to meet this agreement, operations at the well may be suspended.** This agreement, including the condition, expires at the commencement of production operations.

Once the well or facility is licensed, if the operator needs to change this Zero Flaring Agreement, the operator must file an Application to Change a Zero Flaring Agreement with the EUB Operations Group, with a copy to the co-signers.

1) An Application to Change a Zero Flaring Agreement must include

   a) the reasons that the agreement needs to be changed,

   b) a copy of the original application and approval,

   c) a copy of the original and revised Zero Flaring Agreement, and

   d) a summary of the consultation and notification that have been done, including confirmation of any agreements reached with the parties affected by this agreement.

Until a decision on this application has been made by the EUB, flaring may only occur as set out in the Zero Flaring Agreement. **With respect to oil wells, agreement not to flare during well testing means that the operator has agreed to initially conserve the gas.** If it later becomes uneconomic to conserve the gas, operators must follow the process in *Directive 060*, Section 2.5(6), to discontinue conservation.

The operator is required to make an effort to address the landowner or occupant concerns and may make use of the EUB's Appropriate Dispute Resolution (ADR) process if that becomes necessary prior to filing an application with the EUB to change this Zero Flaring Agreement.

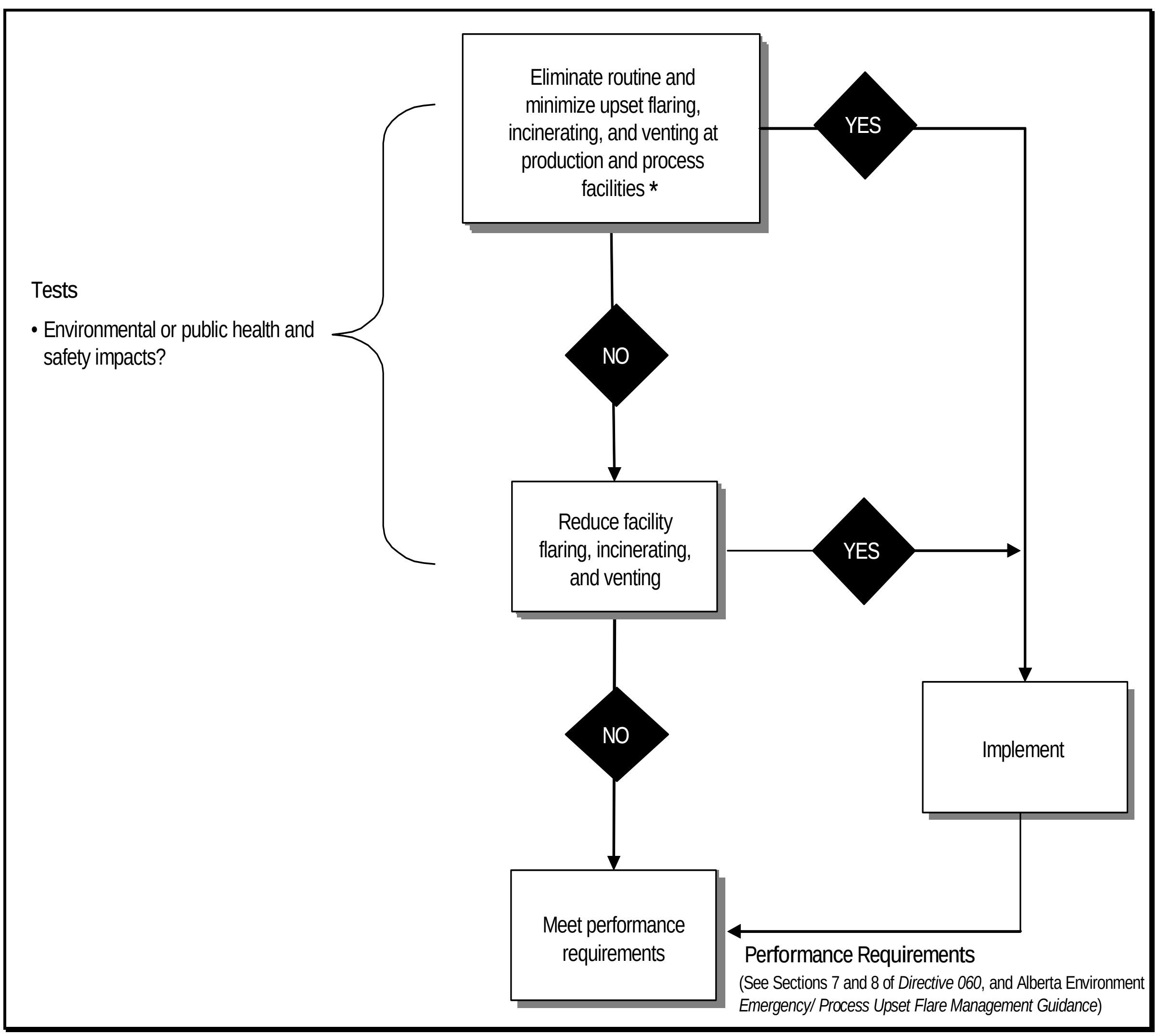
4 Gas Battery, Dehydrator, and Compressor Station Flaring, Incinerating, and Venting

This section addresses gas battery, dehydrator, and compressor station flaring, incinerating, and venting and includes

- routine flaring and incinerating, and
- nonroutine flaring, incinerating, and venting for equipment depressuring for maintenance, process upsets, and emergency depressuring for safety reasons.

4.1 Gas Battery, Dehydrator, and Compressor Station Flaring, Incinerating, and Venting Decision Tree

1) Operators must use the decision tree analysis shown in Figure 5 to evaluate all new and existing gas battery, dehydrator, and compressor station flares, incinerators, and vents regardless of volume except for intermittent small sources (less than 100 m^3 per month), such as pig trap depressuring.



* This does not apply to emergency situations.

Figure 5. Facility Flaring, Incinerating, and Venting Decision Tree (adapted from CASA)

2) Operators must document alternatives that were considered in order to eliminate or reduce flaring, incinerating, and/or venting, how they were evaluated, and the outcome of the evaluation.

3) New batteries proposing routine flaring, venting, or incinerating must be evaluated prior to application as part of the facility design. All existing batteries with routine sources were required to have been evaluated by December 31, 2004.

4) Operators must assess opportunities to eliminate or reduce nonroutine flaring, incinerating, and venting of gas due to frequent (i.e., one event per month) maintenance or facility outages.

   a) Operators must investigate and correct frequent nonroutine events at gas batteries.

   b) Operators must address concerns or objections of residents related to nonroutine gas battery flaring.

5) Flare, incinerator, and vent systems must be designed and operated in compliance with Sections 7 and 8, good engineering practice, and relevant safety codes and regulations. All permanent flare stacks installed prior to January 1, 2000, were required to have implemented the results of the decision tree evaluation by December 31, 2004.

4.2 Notification

1) Operators must notify residents and the appropriate EUB Field Centre of nonroutine flaring at gas batteries as follows:

   a) If gas battery flaring exceeds 4 hours in duration, operators must conduct resident notification as described in Section 3.9 and Table 2.

   b) If a gas battery flaring event exceeds 30 10^3 m^3 and/or 4 hours in duration or is likely to cause resident concern, the appropriate EUB Field Centre must be notified (see Table 2). If different notification requirements are in *Directive 060* and in *IL 98-01*, operators must comply with the more stringent requirement.

2) Operators must provide the EUB Field Centre with a minimum of 24 hours' advance notice of planned gas battery outages and turnarounds that will result in flaring greater than 30 10^3 m^3 and/or 4 hours' duration.

4.3 Reporting

1) All monthly flared, incinerated, and vented volumes must be reported separately on the Petroleum Registry of Alberta in accordance with Section 10 and *Directive 007*.

2) Gas burned in an incinerator must be reported as flared. Fuel gas burned in an incinerator must be reported as fuel gas.

3) Gas flared or vented at gas batteries must be reported at the location where the flaring or venting took place. For facilities that do not require a licence (such as small booster compressors), the flared and vented volumes must be reported at the nearest upstream reporting well, battery, or pipeline facility.

5 Gas Plant Flaring, Incinerating, and Venting

This section addresses disposal of gas from gas processing plants by flaring, incinerating, and venting. Sources of natural gas flaring, incinerating, and venting at gas production facilities include

- routine flaring, incinerating, and venting of low-pressure flash-gas and other gas streams, and
- nonroutine flaring, incinerating, and venting for equipment depressuring for maintenance process upsets, and emergency depressuring for safety reasons.

5.1 Gas Plant Flaring, Incinerating, and Venting Decision Tree

Operators must use the decision tree analysis shown in Figure 6 to evaluate all new and existing gas plant flares, incinerators, and vents regardless of volume except for intermittent small sources (less than 100 m^3 per month), such as pig trap depressuring. Furthermore, these evaluations must be updated annually or upon changes at the plant that materially change plant operation.

1) Licensees must document alternatives that were considered in order to eliminate or reduce flaring, incinerating, and/or venting, how they were evaluated, and the outcome of the evaluation.

2) Operators must assess opportunities to eliminate or reduce nonroutine flaring, incinerating, and venting of gas due to frequent maintenance or facility reliability outages, as well as

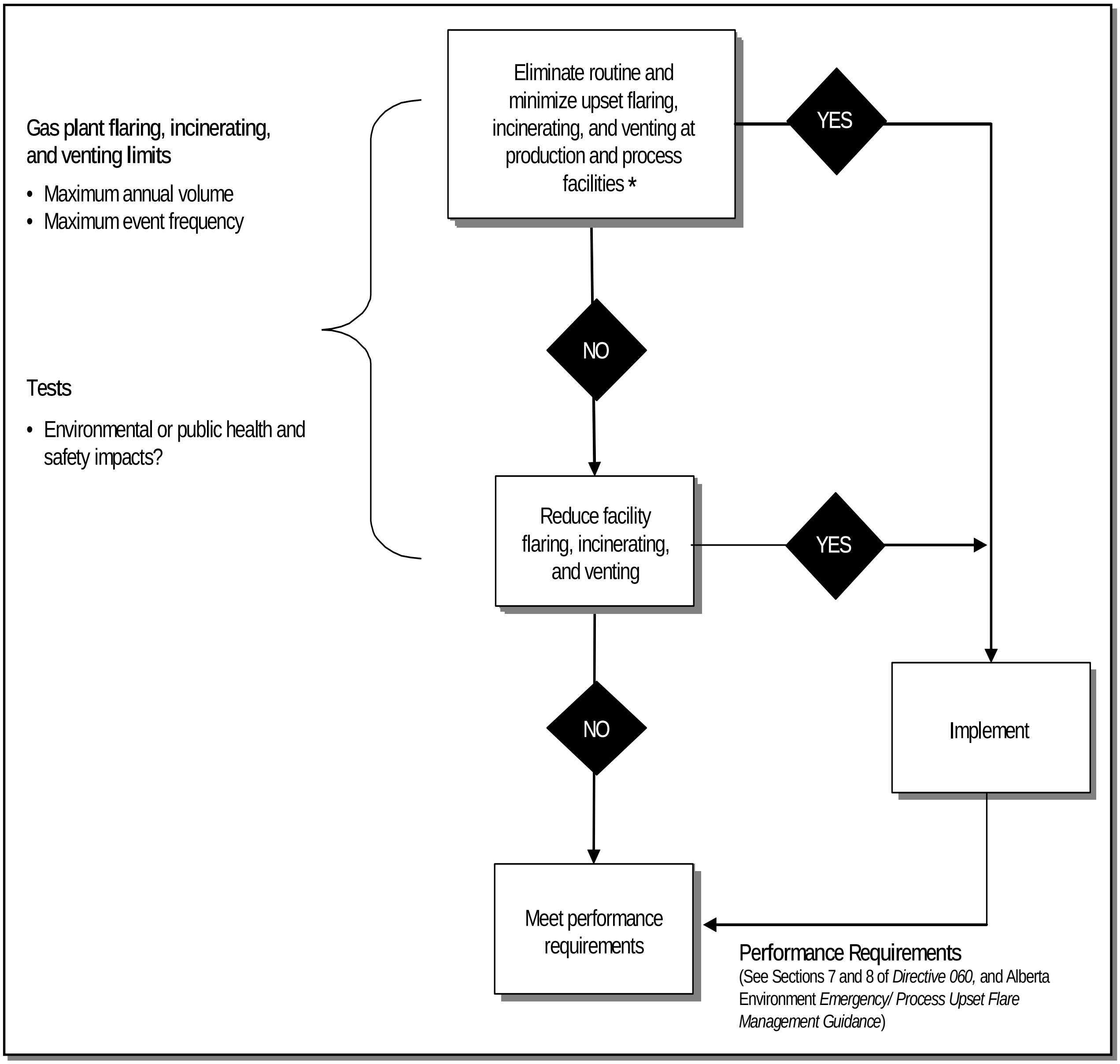
   a) address concerns and objections of residents notified in accordance with Table 2 related to nonroutine flaring, and

   b) comply with the limitations on total flared, incinerated, and vented volumes and number of repeat events defined in Sections 5.2 and 5.3.

3) Flare, incinerator, and vent systems must be designed and operated in compliance with Sections 7 and 8, good engineering practice, and any other safety codes and regulations required by other agencies.

   a) Gas streams directed to continuous gas plant flares must have a minimum heating value as defined in Section 7.1.1.

   b) All existing plants were required to have performance evaluations completed by December 31, 2004.



* This does not apply to emergency situations.

Figure 6. Facility Flaring, Incinerating, and Venting Decision Tree (adapted from CASA)

5.2 Gas Plant Flaring/Incinerating/Venting Volume Limits

The EUB limits the total annual volume of gas disposed of by nonroutine flaring, incinerating, and venting at gas processing plants. Fuel gas used for pilots or flare system purge, as well as acid gas volumes from gas sweetening (which are normally continuously flared) are excluded from the following limits:

1) For gas plants processing less than 1.0 billion (10^9) m^3 per year (raw gas inlet volume), flaring, incinerating, and venting must not exceed 1% of raw gas receipts in the first year of operation and must not exceed 0.5% of receipts in any year thereafter.

2) For gas plants processing more than 1.0 10^9 m^3 per year, flaring, incinerating, and venting must not exceed the greater of 0.2% of receipts or 5.0 10^6 m^3 per year.

3) If multiple flare stacks are available in gas production, gathering, and processing systems, operators must use the flare stack that is the most efficient and capable of providing the best dispersion. In most cases this would be the gas plant flare stack.

   a) Operators can deduct solution gas flared at gas plants during plant shutdowns lasting more than seven days in calculating the annual flared volumes applicable to items (1) and (2) above. These solution gas volumes must be documented and provided to the EUB upon request.

4) Operators must comply with the solution gas reduction limitations in Section 2.11 during facility outages.

5) All nonassociated gas must be shut in during facility outages.

6) The EUB recommends that solution gas be processed on a priority basis in relation to nonassociated gas.

5.3 Frequent Nonroutine Flaring/Incinerating/Venting Events

Information on enforcement actions related to not meeting the criteria below is provided in Section 12.

1) Operators must investigate and correct causes of repeat nonroutine flaring, incinerating, and venting.

2) Gas plants must not exceed six major nonroutine flaring events in any consecutive (rolling) six-month period (6-in-6). Major flaring events are defined in Table 3.

Table 3. Major flaring event definition

Approved plant inlet capacity	Major flaring event definition*
> 500 10^3 m^3/d	100 10^3 m^3 or more
150 - 500 10^3 m^3/d	20% of plant design daily inlet or more
< 150 10^3 m^3/d	30 10^3 m^3 or more

* The definition of a flaring event includes situations where
1) volumes greater than or equal to those specified in the table are flared in any single day; each day that specified flared volumes are exceeded is considered to be a separate, individual event; or
2) volumes greater than or equal to those specified in the table are flared in one contiguous period spanning more than one day (for example, flaring for four days at a continuous rate of 25 10^3 m^3/d is considered one event).

3) Operators must log and monitor nonroutine flaring events, as required in Section 10.4. Major flaring events must be flagged. Should a sixth major flaring event occur within any consecutive (rolling) six-month period:

   a) Operators must submit a written “exceedance” report to the appropriate EUB Field Centre and copy this report to the EUB Operations Group within 30 days of the occurrence of the sixth flaring event.

      i) The exceedance report must provide data on all flaring events (volume and duration) for the consecutive (rolling) six-month period in question and their possible causes.

ii) The report must also propose a plan and corresponding timeline for implementing corrective actions to ensure that frequent major nonroutine flaring does not recur.

b) Operators must obtain EUB Field Centre approval of the proposed plan referred to in 3(a)(ii) above.

i) If facility modifications are proposed in the plan and approvals are required by *Directive 056*, EUB Applications Group approval must be obtained prior to implementing any such actions.

ii) Upon EUB Field Centre approval of the plan including facility modifications, operators are expected to expedite schedules for implementing the plan.

c) After the plan implementation date, the EUB will take enforcement action if another exceedance of the 6-in-6 criterion occurs within 24 months.

5.4 Notification

1) Operators must notify residents and the appropriate EUB Field Centre of nonroutine flaring at gas plants (see Table 2).

a) The appropriate EUB Field Centre must be notified if a nonroutine flaring event exceeds 30 10^3 m^3, exceeds 4 hours' duration, or is likely to cause public concern (see Appendix 10 for notification procedure).

b) If more stringent notification requirements than required by this directive have been put in place through *IL 98-01*, operators must comply with the more stringent requirements.

c) Operators must provide the appropriate EUB Field Centre with a minimum of 24 hours' advance notice of a plant turnaround.

d) The appropriate EUB Field Centre must be notified 24 to 72 hours in advance of planned flaring and within 24 hours of unplanned flaring when notification is required.

5.5 Measurement and Reporting

Measurement and reporting requirements for gas plants include the following:

1) All monthly flared and vented volumes must be reported separately on the Petroleum Registry of Alberta (see Section 10) in accordance with *Directive 007*. This information is then summarized in EUB *ST13* and *ST13A*.

2) Flaring of sour gas must also be reported on the Sulphur Balance Report in *Directive 007*.

3) When measurement is not required, engineering estimates must be used to report any flared gas not measured (see Section 10).

4) Operators must provide a documented system for measurement and/or estimation of flared and vented gas volumes (as defined in Section 10) upon EUB Operations Group request. All flare events both minor and major must be logged (as per Section 10.4) and provided upon request.

5) Fuel gas that is flared, incinerated, or vented (e.g., flare pilot gas, header purge gas, storage tank blanket gas) must be reported as fuel gas, not flared gas.

6) Operators must monitor and minimize fuel gas use for flare header purge, flare, and incinerator pilots.

   a) Operators must be able to justify fuel gas usage volumes.

   b) The EUB may require evidence of this justification on the basis of case-specific audits and inspections.

6 Pipeline Flaring, Incinerating, and Venting

This section addresses disposal of gases from gas gathering and transmission lines by flaring, incinerating, and venting. Sources of natural gas flaring, incinerating, or venting include

- routine flaring, incinerating, and venting of low-pressure flash-gas and other gas streams at pipeline system compressor and dehydration facilities, and
- nonroutine flaring, incinerating, and venting for pipeline depressuring for maintenance, process upsets, or emergency depressuring for safety reasons.

6.1 Pipeline Systems Flaring, Incinerating, and Venting Decision Tree

Licensees must use the decision tree analysis shown in Figure 7 to evaluate all new and existing pipeline systems, including compression station flares, incinerators, and vents, except for intermittent small sources (less than 100 m^3 per month), such as pig trap depressuring. These evaluations must be updated prior to any planned flare/incinerator/ vent events.

1) Licensees must document alternatives considered in order to eliminate or reduce flaring, incinerating, and/or venting, how they were evaluated, and the outcome of the evaluation.

2) Operators must assess opportunities to eliminate or reduce flaring, incinerating, and venting of gas due to frequent maintenance or facility outages.

   a) Operators must investigate and correct repeat events at gas pipelines and related facilities (e.g., compressor stations).

   b) Operators must address public complaints and concerns related to pipeline facility flaring, incinerating, or venting.

   c) Operators must investigate and implement feasible measures to conserve gas from depressuring of pipeline systems.

3) Operators of gas pipeline systems must ensure that flares, incinerators, and vents are designed and operated in compliance with Sections 7 and 8, good engineering practices, and all relevant safety codes and regulations.

4) The sulphur recovery requirements of Section 9 and *ID 2001-03: Sulphur Recovery Guidelines for the Province of Alberta* apply to any continuous flaring or incineration of sour gas at gas gathering facilities (i.e., compressor or dehydrator sites).

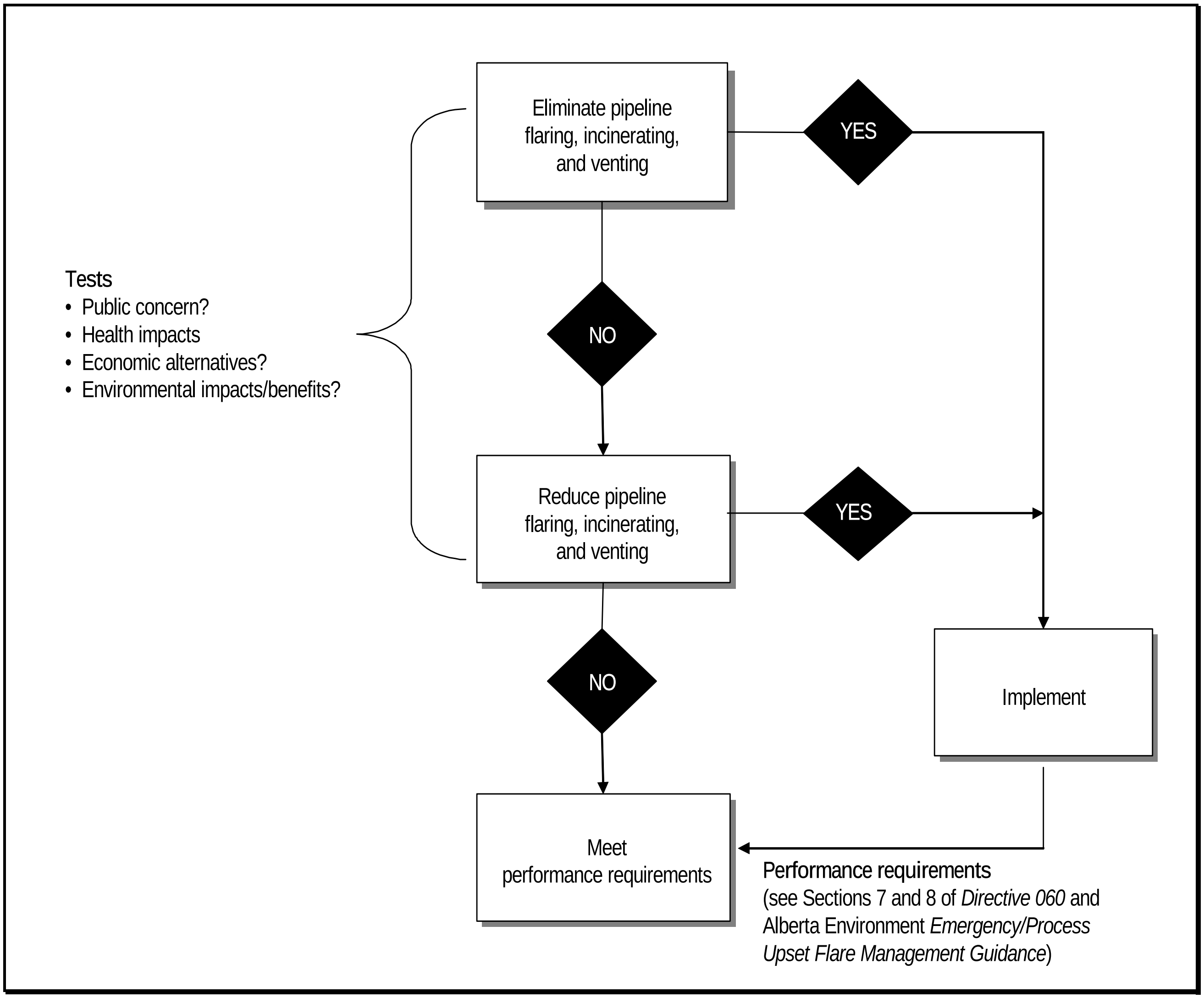


Figure 7. Pipeline Flaring, Incinerating, and Venting Decision Tree (adapted from CASA)

6.2 Additional Requirements for Gas Gathering Systems

1) All monthly flared, incinerated, and vented volumes must be reported separately on the Petroleum Registry of Alberta in accordance with Section 10 and *Directive 007*.

2) Gas containing more than 5 parts per million (ppm) H_2S must not be released from a pipeline without the approval of the EUB, unless the gas is burned such that it meets the requirements in Section 7.

   a) Flaring or incinerating of gas must meet the requirements in Section 7.

   b) Venting of gas must meet the requirements in Section 8.

3) Licensees must obtain an EUB temporary flaring/incinerating permit to use temporary flares or incinerators for the disposal of sour gas containing more than 50 mol/kmol (5%) H_2S, as described in Section 3.3.

a) Permits are not required for disposal of small quantities of sour gas if the requirements defined in Section 3.3.2 are met.

b) Permit request requirements (Section 3.5) apply to temporary flares and incinerators used for sour gas pipeline depressuring, except in emergencies.

4) Notification requirements described in Table 2 apply.

6.3 Natural Gas Transmission Systems

This directive applies to flaring, incinerating, and venting in conjunction with natural gas transmission systems subject to the following provisions:

1) Licensees of sweet natural gas transmission pipelines must minimize venting, flaring, and incinerating volumes.

   a) The economic evaluation in Section 2.8 is not applicable for evaluating conservation of gas from nonroutine pipeline depressuring for maintenance.

   b) Licensees must evaluate conservation of gas from planned nonroutine pipeline depressuring having regard for the value of gas, costs of conserving the gas, and economic impacts of extending outages on downstream customers and upstream producers.

2) Flaring or incinerating of gas from sweet natural gas transmission pipeline depressuring may not be practical when impacts on system customers and producers are considered. In such situations the appropriate EUB Field Centre may allow venting of gas to reduce the duration of system outages and related impacts.

6.4 Notification

1) Licensees must notify residents and the appropriate EUB Field Centre of nonroutine flaring, incinerating, or venting at licensed gas pipeline facilities as follows:

   a) If pipeline facility flaring, incinerating or venting exceeds 4 hours in duration or 30 10^3 m^3, operators must notify as specified in Section 3.9 and Table 2.

   b) In areas where more stringent notification requirements than those defined in Table 2 are required by *IL 98-01* or through other regulatory requirements, licensees must comply with the more stringent requirements.

2) Licensees must provide the appropriate EUB Field Centre with a minimum 24 hours' advance notice of planned pipeline facility outages that will result in flaring, incinerating, or venting.

3) When nonroutine pipeline flaring, incinerating, or venting or is planned, licensees of sweet natural gas transmission pipelines must notify the appropriate EUB Field Centre and discuss the measures taken to minimize emissions.

4) Each purchaser or transporter of sweet natural gas must report the particulars of the disposition and delivery of its gas to the EUB on a monthly basis (*Oil and Gas Conservation Regulations* 12.051).

   a) Flared and vented volumes of sweet natural gas must be reported separately.

7 Performance Requirements

These requirements apply to flares and incinerators in all upstream industry oil and gas systems for burning sweet, sour, and acid gas, including portable equipment used for temporary operations including well completion, servicing, and testing. Flare and incinerator systems include associated separation equipment, piping and controls.

For the purposes of this Directive, the terms flare and incinerator are used interchangeably except as specifically noted in Sections 7.1 and 7.4. In these sections, some requirements are specific to the type of equipment used and this is specified in each requirement.

Although some design or operating specifications are provided, this ***Directive*** **is not a substitute for comprehensive engineering design codes and guidelines.** It identifies minimum EUB regulatory requirements but is not intended as a comprehensive design manual.

1) Operators must ensure that a professional engineer, certified technician, certified engineering technologist or registered engineering technologist[10] is responsible for the design or review of flare and incinerator systems, including separation, related piping, and controls, and for the specification of safe operating procedures.

    a) Equipment and controls design information must be provided to the EUB upon request if the EUB determines that there is a concern with the equipment or controls.

2) Operators must ensure that operating procedures that define the operational limits of flare or incinerator systems are documented and implemented and that these procedures meet the design requirements.

    a) Operating limits and procedures must be provided to the EUB immediately upon request.

    b) Flare and incinerator systems must be operated within operational ranges and type of service specified by the designing or reviewing engineer, technician, or technologist. If this equipment is used for emergency shutdowns, this must be considered in the design.

3) If an operator is using a flare or incinerator in a field service that has not previously been field tested, the operator must be able to provide actual monitoring data to show that performance specifications can be met.

    a) Field testing of newly designed equipment is not allowed unless there are acceptable and redundant combustion systems to ensure that any sweet, sour, or acid gas can be properly combusted if the new equipment fails to perform as predicted or the ability exists for the facility to be shut in if problems arise.

[10] The titles Professional Engineer, Certified Technician, Certified Engineering Technologist, and Registered Engineering Technologist refer to designations as granted by APEGGA or ASET or the equivalent.

4) *API-RP-521: Guide for Pressure-Relieving and Depressuring Systems*, Section 4: Selection of Disposal Systems, as well as applicable fire safety codes, electrical codes, CSA standards, and mechanical engineering standards, are all necessary references for the design of gas combustion systems.

5) Operators must comply with Alberta safety regulations with respect to the design of pressure vessels and piping systems and the design of equipment and operating procedures (see *Pressure Equipment Safety Regulation*).

6) The EUB recommends that operators use best engineering practices in the design and operation of flare systems, as well as appropriate engineering codes and standards.

7.1 Conversion Efficiency

Definitions and calculations for carbon conversion efficiency, sulphur conversion efficiency, and combustion efficiency are found in Appendix 4.

1) Flares and incinerators, and other gas combustion systems, including those using sour gas as a fuel for production or process equipment, must be designed, maintained, and operated so that emissions do not

   a) result in off-lease H_2S odours, or

   b) exceed the *Alberta Ambient Air Quality Objectives.*

2) Operators must modify or replace existing flares or incinerators if operations result in off-lease odours, odour complaints, or visible emissions (e.g., black smoke).

7.1.1 Heating Value and Exit Velocity for Flares

If a flare is also subject to an Alberta *Environmental Protection and Enhancement Act* approval, the more stringent requirement on minimum heating value will apply.

1) The combined net or lower heating value of gas, including make-up fuel gas, directed to a flare must not be less than 20 megajoules per cubic metre (MJ/m^3), except as noted below:

   a) If existing stacks have an established history of stable operation and compliance with the *Alberta Ambient Air Quality Objectives* (operators are expected to support claims that existing stacks have operated satisfactorily over time), operators are allowed to maintain the current heating value provided that it is not less than 12 MJ/m^3.

      i) If flare stacks have a history of flame failure, odour complaints, and/or exceedances of the *Alberta Ambient Air Quality Objectives*, operators must operate with a combined flare gas heating value of not less than 20 MJ/m^3.

   b) The combined net or lower heating value of acid gas plus make-up fuel gas directed to existing or new flares must not be less than 12 MJ/m^3 under any circumstance.

c) Sour gas plant emergency systems must be configured to ensure that the flared gas heating value is not less than 12 MJ/m^3 and the *Alberta Ambient Air Quality Objectives* are met.

   i) The EUB recommends that 20 MJ/m^3 heating value be maintained for nonroutine flaring but recognizes that short-duration emergency flaring with a gas heating value of less than 20 MJ/m^3 may occasionally occur.

2) If fuel make-up is required, it must be specified for flare stacks by a qualified technical professional.[11]

   a) Equipment controls must be installed and operating procedures must be documented to ensure minimum fuel gas make-up during routine and nonroutine operating conditions.

   b) Facilities must be operated in compliance with specified minimum fuel gas make-up requirements.

3) The flare tip diameter must be properly sized for the anticipated flaring rates. The *EUBflare.xls* spreadsheet provides a range of recommended values.

4) Equipment and controls design information must be provided to the EUB upon request if the EUB determines that there is a concern with the equipment or controls.

5) Operating limits and procedures must be provided to the EUB immediately upon request.

7.1.2 Minimum Residence Time and Exit Temperature for Incinerators

If an incinerator is subject to an *Environmental Protection and Enhancement Act* approval, any requirements regarding minimum residence time or exit temperature contained in that approval will take precedence over these requirements. The requirements below do not apply to sour gas plants subject to Alberta Environment approvals.

1) Incinerators must provide a minimum residence time[12] of 0.5 seconds at maximum flow rate or greater as required for complete combustion of heavier gases.

   a) Incinerators must be operated without exposed flame.

   b) If the gas contains less than 10 mol/kmol (1%) H_2S and the unsupplemented heating value of the gas is 20 MJ/m^3 or greater, no minimum residence time is required.

2) Incinerators must operate with a minimum exit temperature[13] of 600°C.

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[11] Professional Engineer, Certified Technician, Certified Engineering Technologist, or Registered Engineering Technologist, as recognized by APEGGA or ASET, or the equivalent.
[12] Residence time is calculated between the top of the final burner and the stack exit.
[13] Exit temperature must be measured within 1 stack diameter of the exit. A shielded thermocouple must be used if the burner flame is visible to the temperature monitor. For further information, consult the Alberta Stack Sampling Code or contact Alberta Environment.

a) For combustion of gases with less than 10 mol/kmol (1%) H_2S and an unsupplemented heating value of 20 MJ/m^3 or greater, no minimum exit temperature or temperature monitoring is required.

b) For combustion of gases with greater than 10 mol/kmol (1%) H_2S, the facility must be designed to automatically shut down if the exit temperature of the incinerator drops below either 600^{o}C or the required temperature to meet *Alberta Ambient Air Quality Objectives*, whichever is higher.

   i) For combustion of gases with greater than 50 mol/kmol (5%) H_2S, the incinerator must also be equipped with process temperature control and recording.

   ii) All violations, together with measures taken to prevent recurrence, must be immediately reported by the operator to the appropriate EUB Field Centre.

3) Any enclosed combustion technology not meeting the above requirements (minimum exit temperature and minimum residence time) must submit third-party verified conversion efficiency test results to the EUB Operations Group for approval, unless the facility is subject to an *Environmental Protection and Enhancement Act* approval.

   a) Test programs and submissions must be provided by a qualified technical professional[14] and must include

      i) inlet gas parameters, including flow rates and composition;

      ii) stack gas exit parameters, including temperature and composition;

      iii) material and energy balance calculations;

      iv) a mass-weighted conversion efficiency value representative of the exit conditions (see Section 7.1.2[6] below);

      v) discussion of the variation of measured and calculated results, depending on sampling location across the stack; and

      vi) discussion of extending test results to other inlet conditions, including discussion of inlet limitations for H_2S concentration and inlet gas flow rate.

   b) All testing must meet the Alberta Stack Sampling Code.

   c) Temperature monitoring and reporting requirements would still apply.

4) Equipment and controls design information must be provided to the EUB upon request if the EUB determines that there is a concern with the equipment or controls.

[14] Professional Engineer, Certified Technician, Certified Engineering Technologist, or Registered Engineering Technologist, as recognized by APEGGA or ASET, or the equivalent.

5) Operating limits and procedures must be provided to the EUB immediately upon request.

6) Operators using incinerators must be able to provide details about the conversion efficiency of the equipment. Any of the following are considered to be acceptable evidence of compliance with this requirement:

   a) the design at the maximum specified capacity meets the residence time, temperature, and conversion efficiency requirements (item 6[b] below), as calculated using the *EUBincin.xls* spreadsheet, or

   b) conversion efficiency for incinerators is 99% or greater, based on one of the following:

      i) the manufacturer's third-party-verified conversion efficiency test results, provided that the tests were conducted under conditions representative of the facility design, or

      ii) actual field measurements of conversion efficiency from the operating facilities following start-up (see also Section 7[3]) .

   c) If conversion efficiency is less than 99%, the incinerator will be considered to operate as a flare and must meet all requirements for flares, including stack height.

7.2 Smoke Emissions

1) Smoke emissions from a well, battery, or gas plant must be controlled in accordance with *Oil and Gas Conservation Regulations* 7.040(1) and 9.050(6)(d), except under emergency circumstances due to equipment failure or as otherwise approved by the EUB Operations Group.

   a) Routine gas combustion must not result in continuous or repeat black smoke emissions.

   b) Black smoke from nonroutine or emergency flaring must not exceed an average of 40% opacity over six consecutive minutes or as defined subsequent to the issue of this directive in the Alberta *Environmental Protection and Enhancement Act Substance Release Regulations*.

2) Any smoke emissions that may result in public concern must immediately be reported to the appropriate EUB Field Centre.

7.3 Ignition

1) Acid gas and sour gas flares and incinerators must have reliable systems to ensure continuous ignition of any gas that may discharge to the device.

   a) At all facilities (excluding gas plants) where the gas contains more than 10 mol/kmol H_2S, a pilot **or** automatic ignition device must be installed on flares and incinerators for continuous (e.g., sour water or condensate tank flash-gas) and intermittent (e.g., emergency depressuring) sources.

b) At gas plants where gas contains more than 10 ppm H_2S, pilots **and** automatic ignition must be installed on flares and incinerators.

c) If repeat failures have occurred or off-lease odours or other impacts have resulted from failure to ensure ignition of sour gas, regardless of H_2S content, the EUB may require installation of

i) both pilots and automatic ignition, and/or

ii) flame failure detection and alarms.

2) Manual flare and incinerator ignition subject to good fire safety practices will be accepted for nonroutine purposes where

a) no continuous gas flow exists, and

b) no automatic relieving systems are connected to the stack.

7.3.1 Requests to Extinguish Flare Pilots at All Batteries

Significant volumes of fuel gas are used to sustain pilots for emergency flares at producing facilities. Continuous pilots may be necessary where gas is flared on a constant or routine basis (see Section 7.3) or where sour gas can potentially be released from pressure safety valves (PSVs) or emergency shutdown valves (ESDVs). In situations where gas is not continuously or routinely flared, where ESDVs are not configured to depressure facilities to flare, and where maximum foreseeable operating pressures are well below PSV release pressures, the potential exists to safely conserve natural gas by extinguishing the flare pilots.

When considering a request to extinguish flare pilots, the EUB Field Centre takes into account both local conditions and the operating history of the facility.

1) Operators must obtain approval from the appropriate EUB Field Centre to extinguish flare pilots at sour gas batteries.

2) The issuing of an approval is only considered if

a) the maximum design operating pressure of production piping and pressure vessel systems is greater than 105% of the maximum stabilized static wellhead pressure of all wells connected to the battery;

b) there will be no continuous or routinely flared gas streams;

c) the facility is connected to sweet or level-1 or level-2 sour wells, as defined in *ID 97-06: Sour Well Licensing and Drilling Requirements*;

d) no active injection or cycling schemes are taking place in or planned for any pools with wells connected to the facility;

e) the facility connections to the flare are isolated with rupture disks upstream of PSVs. This is subject to Section 38(1)(b) of the *Pressure Equipment Safety Regulation* (AR 49/2006), administered by the Alberta Boilers Safety Association (ABSA); and

f) all manual depressuring valves connected to the flare system contain double block valves.

3) Requirements for extinguishing flare pilots are contained in Appendix 13.

4) If operators propose to connect additional wells to an existing approval, they must first supply updated information and obtain approval from the appropriate EUB Field Centre.

7.4 Stack Design

Flares and incinerators must meet or exceed all of the applicable stack design requirements listed below.

1) Flare and incinerator stacks must be designed so that the maximum radiant heat intensity at ground level will not exceed 4.73 kilowatts per square metre (kW/m^2).

   a) Ground-level radiant heat determinations for flares must be based on calculation procedures outlined in the *EUBflare.xls* spreadsheet, *API-RP-521* Section 4.4.2.3, or *GPSA Engineering Data Book* (12th edition), Section 5. Incinerators must be operated without exposed flame.

   b) Exceptions to the requirement in 7.4(1) will be considered on request to the EUB Operations Group, provided an equivalent level of safety can be ensured.

      i) In such cases operators must restrict access to the area where the radiant heat intensity guideline could be exceeded and must ensure that this area is free of combustible materials and vegetation. Access restrictions must include appropriate warning signs and the area must be clearly marked.

      ii) Appropriate procedures (e.g., safe-work permit system) must be in place when it is necessary to work within the area where the radiant heat intensity guideline could be exceeded.

2) Flares and incinerators located within a distance of 5 times the height of any neighbouring buildings must have a height of at least 2.5 times the height of the highest building.

   a) The foregoing does not apply to devices for destruction of trace vent gases, such as those emitted from gas dehydrators.

3) Flare stacks for acid or sour gas containing more than 10 mol/kmol H_2S must have a minimum height of 12 m above ground level.

4) Flares and incinerators must have sufficient height to provide adequate plume dispersion to comply with the *Alberta Ambient Air Quality Objectives* for SO_2 (see Section 7.12).

   a) Proper stack heights must be used in order to minimize fuel consumption. If the use of supplemental fuel gas is proposed, all other options must be investigated first. Fuel gas usage and amounts must be justified.

5) Interconnecting lines to the flare or incinerator must be secured to prevent whipping or flailing.

7.5 Nonroutine Sour and Acid Gas Flaring/Incineration Procedures

Operators must meet the requirements in this section or those in Table 1, whichever is more stringent and results in more gas being shut in.

Devices for combustion of sour or acid gas must be designed and evaluated to ensure compliance with the *Alberta Ambient Air Quality Objectives* for SO_2 in all cases including short-duration nonroutine cases. Evaluations must be conducted using methodologies acceptable to the EUB Operations Group and Alberta Environment. One of the methods described in Section 3.6, Section 7.12, or Alberta Environment's *Emergency/Process Upset—Flaring Management Modelling Guidance* must be used.

1) A cumulative emissions assessment must be conducted if the flaring event will exceed 4 hours and modelling results of the individual source exceed one-third of the *Alberta Ambient Air Quality Objectives* for SO_2 (see Section 7.12)

2) It is not necessary to complete a cumulative emissions assessment if the nonroutine flaring condition is reasonably expected to be of short duration (less than 4 hours). Cumulative assessment requirements are intended to address the effects of multiple and/or continuous SO_2 sources in a given area (see Section 7.12.3). Even if a cumulative emissions assessment is not required, modelling may still be required, as described in Section 7.12.

    a) Operating procedures must be put into place to limit the release duration if the nonroutine stack design is based on the above exception.

    b) If combustion of sour or acid gas for periods greater than 4 hours could occur under planned operating procedures, a cumulative assessment must be completed.

3) If operating procedures and controls are used to limit the magnitude and/or the duration of the event, they must be documented and the facility operated in accordance with these procedures.

    a) Automated shutdowns must be installed in facilities that are not staffed 24 hours/day (semi-attended) to ensure compliance with this requirement.

    b) Staff responsible for operations must be aware of the current operating procedures and trained in following these procedures.

4) Operating procedures and related dispersion evaluations must be provided to the EUB upon request.

7.6 Liquid Separation

Entrained liquids in a flare or incinerator stream may reduce combustion efficiency and contribute to increased emissions of total reduced sulphur compounds, hydrocarbons, and products of incomplete combustion. Proper gas-liquid separation facilities adequate to protect the pipeline system or gas combustion system must be used.

Note that for the purposes of this section and Section 7.6.1, the terms knockout, knockout drum, scrubber, and separator are used interchangeably. These requirements apply to all of these devices.

1) Design information on flare and incinerator system liquid separation equipment must be submitted upon request to the EUB, including as part of *Directive 056* facilities application review processes.

2) Liquid separation equipment must be provided in both temporary (including well test) and permanent flare and incinerator systems to prevent the carryover of liquid hydrocarbons, water, or other liquids.

3) Flare and incinerator separators must be designed in accordance with good engineering practice to remove droplets of 300 to 600 micron diameter and larger (see *API-RP-521*).

   a) Designs must be based on the lowest density hydrocarbon liquids that could be released to the flare or incinerator system.

4) The flare and incinerator separators or knockout drums must be designed to have sufficient holding capacity for liquid that may accumulate as a result of upstream operations, such as hydrocarbon carryover, liquid slugs, and line condensation.

5) Flare and incinerator separators in facilities constructed after the effective date of this directive must be equipped with high-level alarms that can be responded to by the operator prior to liquid carryover, in addition to liquid level indication.

6) All flare and incinerator separators constructed prior to this directive must be provided with visual level indicators, plus high-level facility shutdowns or high-level alarms that can be responded to by the operator prior to liquid carryover, as well as operating procedures to ensure that the liquid retention in the vessel will not exceed the maximum design liquid level during all operating conditions. If impacts such as liquid carryover or unacceptable smoke emissions (see Section 7.2) have occurred as a result of failure to control liquid level, both high-level facility shutdowns and high-level alarms must be provided.

7) High-level alarms and facility shutdowns must be installed on all flare and incinerator separators where liquid streams are directed to the separator for storage or where free liquids are contained in continuously combusted streams.

8) Flare and incinerator separator high-level alarms must be connected to facility alarm panels and/or semi-attended facility alarm call-out systems if the facilities are so equipped.

9) Well test vessels receiving production from oil wells must be equipped with a high-level shutdown, unless attended 24-hours a day and procedures for monitoring liquid levels are in place.

10) Flare and incinerator separators or knockout drums used for liquid storage must be designed and be in accordance with EUB *Directive 055*.

7.6.1 Exceptions to Separator Requirements

The EUB does not require independent flare or incinerator separators in situations where the only vessels connected to the flare or incinerator are production separators equipped with an HLSD (or equivalent devices) or with a system that prevents liquids from entering the flare or incinerator.

The following limitations apply to this exception:

1) The HLSD must be configured to shut down and block in, but not depressure, the battery. The HLSD trip level must be set so that adequate vapour-liquid separation is not impaired at maximum liquid level and vapour flow rates.

2) If liquid carryover involving spills occurs around the flare or incinerator or if black smoke is formed, operators must install adequately sized flare or incinerator separators.

7.7 Backflash Control

Inadequately purged flare or incinerator systems may have sufficient oxygen present to support combustion. Backflash may occur when the linear velocity of the combustible mixture of gas and air in the system is lower than the flame velocity.

1) Operators must take precaution to prevent backflash using appropriate engineering and operating practices, such as

    a) installation of flame arresters between the point of combustion and the flare or incinerator separator, or

    b) provision of sufficient flare header sweep gas velocities (i.e., purge or blanket gas) to prevent oxygen intrusion into the flare or incinerator system.

2) Check valves are not an acceptable form of backflash control.

3) Safe work procedures must be in place to ensure complete purging of oxygen from flare or incinerator systems prior to ignition.

4) Operators must provide information on backflash controls to the EUB upon request if the EUB determines that there is a concern with the equipment or controls.

7.8 Flare and Incinerator Spacing Requirements

Operators must follow good engineering and safety practices in the layout of facilities. Notwithstanding liquid separation requirements, unexpected liquid carryover to flares and incinerators can happen. Adequate spacing of these devices from areas frequented by workers and from sources of combustible gas is prudent. Operators must consult fire protection codes and guidelines as part of facility design.

1) Flares and incinerators must be located, as measured from the base of the stack, at least

    a) 50 m away from wells, not including water disposal wells or water injection wells where there is no risk of flammable vapours,

b) 50 m away from storage tanks containing flammable liquids or flammable vapours, and

c) 25 m away from any oil and gas processing equipment. Item 1(c) does not apply to combustion devices for destruction of trace vent gases, such as those emitted from gas dehydrators. These devices must be designed to prevent ignition of gas that may leak from surrounding equipment (i.e., devices must be equipped with flame arresters).

2) Flares and incinerators must be located, designed, and operated so that no hazard to public property is created. They must be at least

a) 100 m away from surface improvements as defined in *Directive 056* (with the exception of surveyed roadways or road allowances, which must be 40 m from flares and incinerators[15]), and

b) 100 m away from an occupied residence.

3) Flare and incinerator spacing must comply with the requirements defined in the current *Forest and Prairie Protection Regulations* (at the date of this directive, *AR 135/72*).

a) Operators must maintain areas surrounding flares and incinerators to minimize fire hazards.

4) The EUB recommends that operators also comply with the *Forest and Prairie Protection Regulations* in unforested areas where there is a fire hazard associated with flare and incinerator operations.

5) In certain circumstances, the EUB Operations Group may consider variances in flare and incinerator spacing requirements.

a) The EUB discourages variance requests for new facilities.

b) Existing well site equipment spacing waivers in effect prior to the effective date of this directive are maintained.

c) Operators requesting a spacing variance must first consult relevant codes and engineering practices and provide related information in support of the variance request.

7.9 Compliance with Fire Bans

Information on fire bans can be obtained from Alberta Sustainable Resource Development's Web site at http://www.albertafirebans.ca/index.html/, by telephone at 310-fire (3473), or from local municipal districts.

7.10 Noise

1) Flares and incinerators must be designed to operate in compliance with *Directive 038.*

[15] The 40 m spacing requirement applies to public road allowances and roads where the public has open access. There is no spacing requirement for private operator access roadways or private roadways on operating sites.

7.11 Flare Pits

The EUB recommends that operators phase out flare pits used for routine gas flaring.

Flare pits must not be used at any facilities constructed after July 1, 1996. For facilities constructed prior to July 1996, flaring in pits is allowed, provided that the following requirements are met:

1) Produced liquids must not enter the pit, in accordance with the *Oil and Gas Conservation Regulations*, Section 8.080.

2) Flaring of sour gas must comply with the *Alberta Ambient Air Quality Objectives*.

3) Gas containing more than 10 mol/kmol H_2S must not be flared in pits.

4) Operators must conduct evaluations of solution gas flares for flare pits as described in Sections 2.3 and 2.8 and implement the resulting decision.

5) Access restrictions and procedures must be in place in areas around flare pits where ground-level radiant heat intensity at maximum flare rates will exceed 4.73 kW/m^2.

7.12 Dispersion Modelling Requirements for Sour and Acid Gas Combustion

These requirements apply to combustion of sour gas in process equipment, such as steam generators and process heaters, as well as to flares and incinerators.

1) Operators must demonstrate that SO_2 and H_2S emissions from burning of sour and acid gas will not result in exceedance of *Alberta Ambient Air Quality Objectives* using dispersion modelling methods outlined in *Air Quality Model Guideline* (Alberta Environment) if the gas contains more than or equal to

    - 10 mol/kmol H_2S, and/or
    - one tonne per day of sulphur.

    Operators combusting gas below the above concentrations and emission rates are encouraged to consider dispersion modelling as part of environmental considerations. Facilities requiring approval from Alberta Environment under the *Environmental Protection and Enhancement Act* may require more detailed evaluation. Operators should consult Alberta Environment directly in these instances.

2) Dispersion modelling must be completed by qualified technical personnel using computer models and methodologies acceptable to Alberta Environment or, if appropriate, the method described in Section 3.6.

7.12.1 Modelling Approach

The definition for each of the dispersion modelling assessment types, screening and refined, are given in Appendix 4.

1) An appropriate model must be selected, and this choice must be defensible.

2) The operator must be able to demonstrate that the modelling follows accepted methodologies and standards.

3) The operator must use representative input parameters (e.g., flow rate, gas composition) within the model and be prepared to justify that those parameters are representative.

7.12.2 Individual Source

1) Initial modelling may be conducted using the screening assessment provided in the *EUBflare.xls* and *EUBincin.xls* spreadsheets.

2) For a screening assessment, ambient air quality modelling must use the following:

   a) stack-specific terrain extracted from 1:50 000 topographical maps or equivalent,

   b) point source (not flare) option chosen,

   c) full screening meteorology,

   d) rural dispersion conditions, and

   e) emission parameters as calculated by the *EUBflare.xls* and *EUBincin.xls* spreadsheets (e.g., velocity, diameter, and temperature inputs for dispersion modelling).

3) Modelling must address minimum, average, and maximum flow rate conditions.

4) Complex terrain modelling must be used unless terrain elevations are less than the complex terrain criteria, in which case parallel airflow modelling can be applied.

5) The selected flare or incinerator design must not result in ground-level SO_2 concentrations in excess of that in the *Alberta Ambient Air Quality Objectives*.

   a) A refined assessment may be used if the screening assessment results in an impractical stack height.

   b) If it is not practical to design flares or incinerators of sufficient height for adequate dispersion, operators may consider

      i) use of an air quality management plan (see Appendix 8),

      ii) operating procedures and process controls to prevent emission rates or durations that would exceed the *Alberta Ambient Air Quality Objectives* (see Sections 3.6 and 7.5), and

      iii) addition of fuel gas to increase heat release and plume rise. As stated in Section 7.4, proper flare stack height must be used to minimize fuel consumption.

   c) The EUB low-risk criteria discussed in Section 3.6(5) are *not* applicable to continuous (non-temporary) sour gas combustion at permanent facilities.

7.12.3 SO_2 Cumulative Emissions Assessment

If predicted maximum hourly average ground-level concentrations for the individual source are more than one-third of the *Alberta Ambient Air Quality Objectives* for SO_2, then assessment of cumulative effects of all SO_2 sources is mandatory.

1) The following steps must be followed for cumulative emissions assessments:

   a) Identify the farthest downwind location where predictions exceed one-third of the hourly average *Alberta Ambient Air Quality Objectives* for SO_2 to define the radius of influence.

   b) Identify all other continuous sources of SO_2 located within this radius of influence up to a maximum of 20 km; if there are no other sources of SO_2 within the radius, no further modelling is required.

   c) Quantify the emissions of SO_2 from these other sources and obtain all necessary input data, such as stack height and other parameters (operators must share related data on a timely basis). Maximum hourly flow rate conditions must be used for all sources in the radius of influence.

      i) In applications for a continuous source, other sources must be modelled at licensed emission rates.

      ii) In requests for a temporary event occurring at a known time (e.g., well test or planned maintenance blowdown), other sources can be modelled at maximum expected operating emission rates at the time of the temporary event.

   d) Model the cumulative effect of the multiple SO_2 emission sources.

   e) If the sum exceeds the *Alberta Ambient Air Quality Objectives*, determine the appropriate stack height required to meet the *Alberta Ambient Air Quality Objectives*. All refined modelling must follow the methods outlined in *Air Quality Model Guideline* (Alberta Environment, 2003).

8 Venting and Fugitive Emissions Management Requirements

Venting is not an acceptable alternative to conservation or flaring.

8.1 General Requirements

1) All continuous and temporary venting must be evaluated using the decision tree in the appropriate sections of this directive.

2) Operators must burn all nonconserved volumes of gas if volumes and flow rates are sufficient to support stable combustion.

   a) The EUB may investigate vented volumes of 500 m^3/day, or even lower, if it appears that stable combustion of the gas may be feasible. Upon request, operators must provide justification for volumes not combusted.

3) *Oil and Gas Conservation Regulations,* Section 8.031, permits connection of pressure-relieving devices at oil production batteries to open tanks (“pop tanks”), provided that all other requirements in Section 8 of this directive are met.

4) Hydrocarbon products stored in atmospheric storage tanks at gas plants, compression stations, and gas batteries must not exceed a true vapour pressure of 83 kilopascals (kPa) at 21.1°C if such tanks are vented to the atmosphere.

5) Temporary, short-term venting is allowed at wells (e.g., for well unloading and liquid cleanup), facilities, and pipelines (for natural gas transmission systems, see Section 6.3), with the following conditions:

   a) Gas must be sweet.

   b) Gas must not contain any free hydrocarbon liquid (if free hydrocarbon liquids are present in the produced gas, a flare [or other gas combustion device] and liquid separation must be used).

   c) All liquids must be separated and contained in accordance with the storage requirements of *Directive 055*.

   d) Total gas volume must not exceed 2 10^3 m^3 and the duration must not exceed 24 hours. (This does not include the clean-out phase for well testing and servicing, when liquids and noncombustible gases may prevent stable combustion. See Section 8.5.)

   e) Operators must conduct notification in accordance with Section 3.9 and Table 2.

   f) The EUB Field Centre will consider alternatives to these requirements should special circumstances warrant. Operators must contact the appropriate EUB Field Centre for approval of alternatives. For pipeline venting exemptions to these requirements, see Section 6.2.

6) Temporary venting is not permitted within 500 m of a residence unless consented to by the resident and approved by the appropriate EUB Field Centre.

7) Vented gas must not constitute an unacceptable fire or explosion hazard. Any venting must not occur within a distance less than

   a) 25 m from any flame type equipment (for diesel engines equipped with air intake shutoff device, see EUB *Directive 036: Drilling Blowout Prevention Requirements and Procedures*),

   b) 50 m from a wellhead, or

   c) 35 m from a wellhead for well testing and servicing of wells that fall into the category of those listed in Section 1.1 of *Directive 008: Surface Casing Depth Minimum Requirements*. (Venting in association with the water production from these wells [e.g., blowdowns, no service or well test equipment] are exempt from the 35 m spacing), and

   d) spacing requirements in Section 7.8 must be met.

8) Venting at heavy oil/oil sands operations is subject to the spacing requirements described in *ID 91-03: Heavy Oil/Oil Sands Operations*.

9) An appropriate flame arrester, equivalent safety device, or proper engineering and operating precautions (e.g., sufficient sweep gas velocity) must be used on all vent lines from oil storage tanks connected to flare or incinerator stacks.

8.2 Limitations of Venting Gas Containing H_2S or Other Odorous Compounds

1) Gas containing more than 10 mol/kmol H_2S must not be vented to the atmosphere. This includes gas off stock tanks, PSVs, and equipment blowdown systems.

2) Venting must not result in H_2S odours outside the lease boundary. See *Directive 064*, Appendix 11.

   a) The EUB recommends any PSVs or blowdown systems be connected to a flare system where such systems are installed.

3) Venting must not result in off-site exceedances of the *Alberta Ambient Air Quality Objectives*.

8.3 Limitations on Venting Gas Containing Benzene

1) Operators must assess and control benzene emissions such that **cumulative emissions from all sources** (dehydrators plus other sources) at the facility or lease site do not exceed the limits outlined in Table 4 below.

Table 4. Cumulative facility or lease site benzene emission limits

Date facility or lease site commissioned	Benzene emission limits
Prior to January 1, 1999	
• Greater than 750 m to permanent resident or public facility	5 tonnes/yr
• Less than 750 m to permanent resident or public facility	3 tonnes/yr
January 1, 1999, to January 1, 2007	3 tonnes/yr
After January 1, 2007	1 tonne/yr

2) Operators must ensure that vented gas from dehydrators meets the requirements and benzene emission limits specified in *Directive 039: Revised Program to Reduce Benzene Emissions from Glycol Dehydrators*.

  a) Operators must apply the decision tree process for new and relocated dehydrators.

  b) Operators must complete and post a Dehydrator Engineering and Operations Sheet.

  c) Operators must submit an annual Dehydrator Benzene Inventory List as outlined in the Canadian Association of Petroleum Producers (CAPP) document *Best Management Practices (BMP) for Control of Benzene Emission from Glycol Dehydrators*, June 2006.

3) As stated in *Directive 039*, if more than one dehydrator is located at a facility or lease site, the cumulative benzene emissions for all dehydrators must not exceed the limit of the oldest dehydrator on site. Modifications may be required to existing unit(s) to meet the site limit.

As well, any new or relocated dehydrators added to an existing site with dehydrator(s) must operate at a maximum benzene emission limit of 1 tonne/yr or less.

8.4 Venting in Heavy Oil/Oil Sands Operations

1) In addition to the requirements defined in *ID 91-03*:

  a) The release rate criterion is based on cumulative vent gas emissions from continuous sources on the operating site or lease. The release rate limitation includes emissions from hydrocarbon/produced water storage tanks and other heavy oil/oil sands production facilities.

  b) Vent gas consisting primarily of water vapour emitted from secondary water treatment facilities or storage devices (e.g., hot lime softeners and boiler feed water tanks) may be excluded from these requirements.

  c) Operators must design stacks so venting does not result in H_2S odour outside the lease boundary. See *Directive 064,* Appendix 11.

  d) Venting, including emergencies, must not result in exceedances of the *Alberta Ambient Air Quality Objectives*.

e) Operators must ensure that infrequent venting from leaks or periodic venting for maintenance depressurizing and emergency shutdowns can be done safely. Venting of this type is not to be considered in determining the potential H_2S release rate.

8.5 Venting of Noncombustible Gas Mixtures

Release of inert gases such as nitrogen and carbon dioxide (CO_2) from upstream petroleum industry equipment or produced from wells may not have sufficient heating value to support combustion. These gases can be vented to atmosphere subject to the following requirement:

1) Noncombustible gas mixtures containing odorous compounds including H_2S must not be vented to the atmosphere if off-lease odours may result. Alternatives to venting such gas include flaring or incinerating with sufficient fuel gas to ensure destruction of odourous compounds.

8.6 Coalbed Methane Venting

Operators may vent gas as part of the evaluation of coalbed methane development and technologies if the requirements for venting are met (i.e., gas conservation has been determined to be economically infeasible and flows will not support stable combustion). Once conservation or combustion of the gas is possible, these options must be used.

Gas conservation in long-term coalbed methane projects must be evaluated, and test durations are limited by requirements found in Section 3.2.

8.7 Fugitive Emissions Management

1) Operators must develop and implement a program to detect and repair leaks.

    a) These programs must meet or exceed the CAPP *Best Management Practice for Fugitive Emissions Management*.

2) Operators must use pressurized tank trucks or trucks with suitable and functional emission controls when transporting sour fluids from upstream petroleum industry facilities.

9 Sulphur Recovery Requirements and Sour Gas Combustion

Certain types of oil production, gas gathering, and nonassociated gas battery facilities can have significant sulphur emissions originating from combustion (by flaring, incinerating, or using to fuel equipment) of sour solution gas, low-pressure produced water flash-gas, and flaring of glycol dehydrator vent gas. Appropriate pollution prevention measures must be implemented in such situations to minimize sulphur emissions associated with combustion of sour or acid gas.

1) Guidelines set out in *ID 2001-03: Sulphur Recovery Guidelines for the Province of Alberta* apply to sour gas plants and other upstream petroleum facilities, such as oil production batteries, gas batteries, and pipeline facilities.

2) For in situ bitumen sites, the sulphur recovery requirements set out in Table 1 of *ID 2001-03* apply. The sulphur inlet used to determine the sulphur recovery requirement from Table 1 is based on the total sulphur emissions from combustion of sour produced gas as fuel or by flaring or incinerating divided by the number of days over a calendar quarter year.

9.1 Sulphur Recovery Exemption at Solution Gas Conservation Facilities

The EUB and Alberta Environment may waive sulphur recovery requirements in circumstances where sulphur emissions would be minimal and sulphur recovery would render gas conservation uneconomic.

Solution gas conservation clustering schemes that have a total inlet sulphur of between 1 and 5 tonnes/day may be considered for flexibility by Alberta Environment and the EUB in the application of *ID 2001-03.* Provisions for waivers of the sulphur recovery guidelines are set out in Section 4 of *ID 2001-03*.

1) Operators must specifically apply to the EUB for a deviation from the sulphur recovery guidelines as part of related production project applications submitted to the EUB. The application must take the form of a nonroutine *Directive 056* application, and applicants must indicate on the application that the facility will **NOT** comply with the requirements of *Directive 060*.

2) Operators must demonstrate to the EUB that implementation of sulphur recovery would make the gas plant uneconomic using the methodology defined in Section 2.8.

    a) If gas production with sulphur recovery is economic, operators must implement sulphur recovery.

3) Operators must demonstrate that revenues and cost estimates are reasonable.

    a) Capital cost estimates for sulphur recovery must be based on appropriate technologies. Operators must identify cost-effective processes suited to the facilities in question.

    b) Information on the following must be available to the EUB upon request:

        i) volumes of gas available, including assessment of clustering other gas sources in the area;

ii) incremental energy (fuel gas) requirements for gas compression and processing related to gas sweetening;

iii) incremental energy (fuel gas) requirements for sulphur recovery processes;

iv) H_2S concentration of gas, along with expected average sulphur emissions and/or variability of sulphur emissions; and

v) information on technology selection and costs for equipment (compression), gas gathering systems, and sulphur recovery processes. Note that since the economic evaluation is based on incremental costs of gas conservation, equipment costs related to oil production, processing, and transportation must not be included.

4) Operators must consult residents in the radius set out in *Directive 056*, specifically explaining that a waiver of the sulphur recovery guidelines is being applied for. Any objections must be disclosed in related facility applications.

5) The EUB and Alberta Environment will consider the scope of the production project, duration of the sulphur emissions, and views of the local public in making decisions on applying the sulphur recovery guidelines.

a) The existing processes used for *Environmental Protection and Enhancement Act* approvals for sour gas processing plants and EUB approvals will be used to measure public acceptance of any proposals. If there are no unacceptable impacts and nearby residents do not object, meeting the sulphur recovery guidelines may not be required for solution gas facilities.

b) The EUB does not allow multiple nonsulphur recovery sour operating sites in close proximity where it is practical to consolidate the facilities in one location and install sulphur recovery.

i) Sour gas facility proliferation guidelines in *ID 2001-03*, Section 6, stipulate how the EUB will assess this matter.

6) The waiver is not applicable to sour gas production and processing facilities handling primarily nonassociated gas.

10 Measurement and Reporting

The following requirements for measuring and reporting volumes of gas flared, incinerated, and vented are in addition to EUB measurement requirements provided in *Directive 017: Measurement Requirements for Upstream Oil and Gas Operations*, *Directive 007: Production Accounting Handbook*, and the *Oil and Gas Conservation Regulations*.

1) Operators of oil, bitumen, and natural gas production and processing facilities (including well tests) must report volumes of gas greater than or equal to 0.1 10^3 m^3/month (adjusted to 101.325 kPa(a) and 15°C) that is flared, incinerated, or vented on the EUB S-30 Report and the Petroleum Registry of Alberta. This includes reporting all flaring, incinerating, and venting from routine operations, emergency conditions, and the depressurizing of pipeline, compression, and processing systems. However, "incinerated" volumes must be reported as "flared," since the Registry does not allow for reporting of "incinerated" volumes.

2) Operators must be able to demonstrate that volumes of gas are accurately and consistently determined (see Sections 10.1 and 10.2).

3) If production submissions are not routinely submitted for a facility, as is sometimes the case for well completions, and if total volumes are not significant (less than 0.5 10^3 m^3 in total), the EUB Operations Group may waive the reporting requirement. Otherwise, the operator is to obtain a facility code and report the volumes.

4) The EUB recommends that operators meter total flare streams in larger oil and gas batteries, pipeline facilities, and gas processing plants where there could be multiple connections to the flare system from sources such as process equipment, storage tank vents, pressure-relieving valves, manual blowdowns, and emergency vent valves, even when the volume is less than 0.5 10^3 m^3/d on a yearly average.

5) Operators must be able to provide the volume of fuel gas used for flare pilots and flare header purge gas to the EUB upon request (see Section 5.5, item 6).

    a) Fuel gas used in flare systems (including fuel gas make-up to acid gas flares) is to be reported as part of the total fuel gas volume on the Petroleum Registry.

    b) Fuel gas added to flare systems must be subtracted from the measured flare volumes if total flare gas measurement is used downstream of the fuel gas entry point.

6) For gas well gas tied into an oil battery, the operator must report this gas on a separate production statement (for a gas battery) showing the gas delivery to the oil battery. A similar requirement is in place for oil well gas delivered to a gas battery. See *Directive 017*, Section 4.2, for details.

10.1 Metering Requirements and Guidelines

1) Meters designed for the expected flow conditions and range must be used to measure the following flare and vent streams:

a) continuous or routine flare and vent sources at all oil and gas production and processing facilities (including heavy oil and crude bitumen) where annual average total flared and vented volumes per facility exceed 0.5 10^3 m^3/day (excluding pilot, purge, or dilution gas); if all solution gas is flared or vented from any production facilities, the measured produced gas (less fuel gas use) may be used to report volumes flared or vented; in such situations, specific flare or vent gas meters are not required;

b) acid gas flared, either continuously or in emergencies, from gas sweetening systems regardless of volume; and

c) fuel (dilution or purge) gas added to acid gas to meet minimum acid gas heating value requirements or *Alberta Ambient Air Quality Objectives*.

10.2 Estimating Requirements

The EUB will accept estimates of flared, incinerated, and vented gas if measurement is not stated as a requirement in Section 10.1 and the following conditions are met:

1) Operators must be able to demonstrate that reliable and consistent flared, incinerated, and vented gas estimating and reporting systems are in use (see CAPP's *Guide for Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, 2002).

   a) Estimating systems must account for all gas flared, incinerated, and vented from the facility (expressed to the nearest 0.1 10^3 m^3/month) during routine, emergency, and maintenance operations, well deliverability testing, and the depressurising of vessels, compressors, and pipelines.

   b) Volume estimates must be based on engineering calculations.

   c) Procedures or use of software for estimating flare and vent volumes must be developed by a technically knowledgeable person.

   d) If flared volumes are not measured by existing flare meters, a formal system for consistently estimating and reporting these volumes must be in place.

2) Operators must produce documentation describing flared and vented gas estimating and reporting procedures, as well as related operating logs, for review by the EUB upon request.

3) For heavy oil/oil sands operations estimating requirements, see *Directive 017*.

4) The EUB may require that meters be installed where there are failures to demonstrate adequate flare or vent gas estimating and reporting systems.

10.3 Flared, Incinerated, and Vented Gas Reporting

1) All flared and vented gas must be reported as described in EUB *Directive 007*. Incinerated gas must be reported as "flared" gas if an incinerator is used in place of a flare stack. This would not apply to acid gas streams at a gas plant that are flared or incinerated as part of normal operations; in these cases the flared or incinerated acid gas would be reported as acid gas shrinkage, not flared.

2) The operator must report gas flared or vented, wherever possible, at the facility where the flaring or venting took place. This will help industry and EUB staff to match up flaring or venting that is observed in the field with that reported. As part of the Petroleum Registry, flared and vented gas at a facility must be reported separately.

3) When the flaring or venting location is on a gas gathering system but is not from a licensed entity,

   a) it must be reported as an activity associated with the closest licensed facility (e.g., compressor) on the gas gathering system;

   b) if there is no licensed facility on the gas gathering system, it must be reported as an activity associated with the gas gathering system.

4) Operators must not prorate or allocate flared and vented volumes that occur at a facility to other upstream facilities.

5) If there is gas flared or vented during drilling and completion, it must be reported to the Petroleum Registry under the battery subtype code 381.

10.4 Flaring, Incinerating, and Venting Records (Logs)

1) Operators must maintain a log of flaring, incinerating, and venting events and respond to public complaints in order to comply with release reporting requirements.

   a) Release reporting requirements are defined in *IL 98-01* and Alberta Environment's *Release Reporting Guideline*.

   b) Logs must include information on complaints related to flaring, incinerating, and venting events and how these complaints were investigated and addressed.

   c) Logs must describe each nonroutine flaring, incinerating, and venting incident and any changes implemented to prevent future nonroutine events of a similar nature from occurring.

   d) Logs must include the date, time, duration, gas source or type (e.g., sour inlet gas, acid gas), and volumes for each incident.

   e) Logs must be kept for a minimum of 12 months.

2) Flaring, incinerating, and venting records must be made available to the EUB upon request for each production facility, pipeline, and gas processing facility where flaring, incinerating, and venting occur.

   a) Operators may retain logs for remote or semi-attended facilities at a central location (e.g., the operator regional office) where public complaints related to the facility in question would normally be received.

3) In situations governed by temporary flaring/incinerating permits, a Sour Gas Flaring/Incineration Data Summary Report (see Appendix 7) must be completed in full and submitted to the EUB Operations Group within three weeks of the flaring/incinerating completion date.

11 Industry Performance Reporting

A summary of flaring, incinerating, and venting emission details is compiled annually and is available as *ST60B: Upstream Petroleum Industry Flaring Report* on the EUB Web site www.eub.ca.

12 Compliance and Enforcement

EUB regulatory requirements are those rules that an operator has a legal obligation to meet and against which the EUB may take enforcement action in cases of noncompliance. The EUB's enforcement process is specified in *Directive 019: EUB Compliance Assurance—Enforcement*.

During audits, inspections, and investigations, noncompliance with *Directive 060* is initiated, administered, and tracked in a number of EUB compliance categories. Some of these compliance categories and associated EUB directives are

- Drilling Operations – *Directive 036: Drilling Blowout Prevention Requirements and Procedures*
- Well Servicing – *Directive 037: Service Rig Inspection Manual*
- Waste Facilities – *Directive 063: Requirements and Procedures for Oilfield Waste Management Facilities*
- Oil Facilities – *Directive 064: Requirements and Procedures for Facilities*
- Gas Facilities – *Directive 064: Requirements and Procedures for Facilities*
- Well Site Inspections – *Directive 064: Requirements and Procedures for Facilities*
- Pipelines – *Directive 066: Requirements and Procedures for Pipelines*
- Economic Evaluation Audits – *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*

12.1 Noncompliance Events

Noncompliance events are listed in Table 5. The consequence level of each noncompliance—Low Risk (L) or High Risk (H)—is based on the criteria set out in *Directive 019*.

The EUB may enforce or escalate enforcement to any level should conditions warrant.

Table 5. Noncompliance events

DECISION TREE PROCESS		
Consequence	Noncompliance event	*Directive 060* reference
H	Decision tree process not completed for new, existing, and temporary flares, incinerators, and vents as required	Sections 2.3, 3.1, 4.1, 5.1, 6.1
H	Failure to implement results of decision tree (including meeting performance requirements)	Sections 2.4, 2.5, 2.8, 3.1, 4.1, 5.1, 6.1, 9.1
PERMITS/APPROVALS		
Consequence	Noncompliance event	*Directive 060* reference
H	Failure to comply with any condition of permit or approval (temporary permits, volume allowance threshold exceedance permits, and blanket permits)	Sections 3.3, 3.5

(continued)

NOTIFICATION and CONSULTATION		
Consequence	Noncompliance event	*Directive 060* reference
H	Incomplete resident notification and/or consultation	Sections 2.5, 2.9, 2.11, 3.9, 4.2, 5.4, 6.4, 9.1(4), Table 1, Table 2
H	No attempt to comply with resident notification and/or consultation	Sections 2.5, 2.9, 2.11, 3.9, 4.2, 5.4, 6.4, 9.1(4), Table 1, Table 2
L	Failure to notify the appropriate EUB Field Centre of flaring, incinerating, or venting events as required	Sections 2.9, 3.3.2, 3.9, 4.2, 5.4, 6.4, Table 1, Table 2
L	Public information packages not as per requirements	Sections 2.9.1, 3.9
H	Failure to notify the appropriate EUB Field Centre of any unresolved resident concerns regarding permitted sites	Sections 2.10, 3.5.1, 3.9.1

VOLUME/DURATION EXCEEDANCES		
Consequence	Noncompliance event	*Directive 060* reference
H	Flaring, incinerating, or venting solution gas from an oil/bitumen well with a GOR greater than 3000 m^3/m^3	Section 2.5
H	Exceeding oil and gas well test flaring/incinerating and venting duration limits without approval	Sections 2.4, 3.2
H	Noncompliance with solution gas production requirements during planned shutdowns and emergency events	Section 2.11, Table 1
H	Exceeding the annual flare volume limits at a gas plant	Section 5.2
H	Exceeding the major flaring events criteria for gas plants (6-in-6)	Section 5.3
H	Failure to submit an exceedance report within 30 days (6-in-6)	Section 5.3
L	Failure to investigate repeat nonroutine flaring or venting events	Section 5.3
L	Gas is being vented, not burned, where it could support stable combustion	Section 8.1
VISIBLE EMISSIONS		
Consequence	Noncompliance event	*Directive 060* reference
H	Black smoke from nonroutine or emergency flaring events exceeds an average of 40% opacity over 6 consecutive minutes	Section 7.2
L	Routine combustion of gases results in continuous or repeat black smoke emissions	Section 7.2
H_2S GAS		
Consequence	Noncompliance event	*Directive 060* reference
H	Flaring or incinerating sour gas containing more than 50 mol/kmol H_2S or from a critical sour gas well without a permit where required	Sections 3.3.21, 3.7
H	Failure to comply with conditions for flaring or incinerating small volumes of sour gas containing more than 50 mol/kmol H_2S when a permit is not required	Section 3.3.2
H	Failure to discontinue flaring or incinerating sour gas during temporary operations (including well test), or at a gas plant when *Alberta Ambient Air Quality Objectives* have been exceeded	Sections 3.3.2, 3.6, 7.12, Appendix 8
L	Failure to conduct dispersion modelling for flaring or incinerating gas with greater than 10 mol/kmol H_2S where required	Sections 3.6, 7.12
H	Any off-lease H_2S odours	Sections 7.1, 8.2

(continued)

FACILITY DESIGN		
Consequence	Noncompliance event	*Directive 060* reference
L	Failure to have an adequate knockout drum or flare separator where required	Sections 7.6, 8.1
H	No flare or incinerator stack where one is required	Section 8
H	Stack height or design does not conform to *Directive 060* requirements	Section 7.4
H	Sour pressure relief valves not tied into flare systems where required	Section 8.2
H	No flame arrester, equivalent safety device, or adequate engineering and operating precautions to prevent backflash where required	Section 7.7
H	Pilot/ignition devices not available/operable where required (sour and acid gas flares)	Section 7.3
H	Insufficient heating value available to flare	Section 7.1.1
L	Exposed flame from an incinerator	Section 7.1.2
L	Insufficient exit temperature, no automatic temperature shutdown, or no process temperature control and recording where required for incinerators	Section 7.1.2
H	No high-level alarm or high-level facility shutdown on knockout drum/flare separator where required	Section 7.6
H	Operating procedures and/or automatic shutdowns not in place where needed to control major sour/acid gas flaring events	Section 7.5
H	Extinguishing of a sour gas flare pilot without approval	Section 7.3.1
H	Flare or incinerator units not designed or reviewed by a professional engineer, certified technician or certified technologist*	Section 7(1)
H	Flare or incinerator units not being operated within the specified design limits	Section 7(2)
L	Failure to produce approved design drawings, operating limits, or procedures for flare or incinerator units upon EUB request	Sections 7(1), 7(2), 7.1.1, 7.1.2
SPACING		
Consequence	Noncompliance event	*Directive 060* reference
L	Noncompliance with flare and incinerator spacing requirements	Section 7.8
H	Flare or incinerator stack less than 100 m from an occupied residence	Section 7.8
MEASUREMENT and REPORTING		
Consequence	Noncompliance event	*Directive 060* reference
L	Failure to keep flaring, incinerating, and venting logs as required	Sections 5.3, 5.5, 10.4
H	Inadequate flare or vent measurement or estimating procedures	Sections 10, 10.1, 10.2
H	Failure to measure and/or report acid gas	Sections 10, 10.1, 10.3, 10.4
H	Acid gas flare fuel make-up not measured	Section 10.1
L	Acid gas meter not equipped with a continuous temperature recorder	Section 10.1
L	Gas usage not reported or reported inaccurately to the EUB	Section 10, 10(5)
H	Reporting incorrect data on the EUB Sour Gas Flaring/Incineration Data Summary Report	Sections 3.5.3, 3.10, 10.4

*The titles Professional Engineer, Certified Technician, and Certified Technologist refer to designations as granted by APEGGA or ASET, or the equivalent.

Appendix 1 Summary of Revisions

The table below provides a summary of the key revisions in the 2006 edition of *Directive 060* to the existing EUB requirements as defined in *Guide 60 (1999)* and *Guide 60 Updates and Clarifications (2001)*.

Section	**Revisions**
General Comments	This edition includes changes in response to stakeholder feedback on the December 2002 *Draft Guide 60*, plus changes based on recommendations from the CASA Flaring/Venting Project Team (FVPT) in their final reports dated June 2002, September 2004, March 2005, and June 2005.
Section 1: Introduction	Updated the Introduction section in *Directive 060.*
Section 2: Solution Gas Management	- An annual provincial volume threshold for solution gas flaring has been established at 670 10^6 m^3 per year. Recommended by the CASA FVPT, June 2002. (Section 2.1) - Sites flaring and venting less than 900 m^3/day of solution gas are not required to evaluate conservation feasibility. Evaluation is only recommended. Recommended by the CASA FVPT, September 2004. (Sections 2.3, 2.4, 2.5, and 2.8) - Sites must conserve if NPV greater than –$50 000. Recommended by the CASA FVPT, September 2004. (Sections 2.5 and 2.8) - No solution gas flares greater than 900 m^3/day within 500 m of a residence, regardless of economics. Recommended by the CASA FVPT, September 2004. (Section 2.5(1c)) - Nonconserving sites flaring and venting greater than 900 m^3/day must be re-evaluated at least once per year. Recommended by the CASA FVPT, September 2004. (Sections 2.5(2), 2.8(1b) and 2.8(12)) - Conservation facilities must be designed for 95% conservation with a minimum operating level of 90%. Recommended by the CASA FVPT, September 2004. (Section 2.5(4)) - New time limits for well test flaring—see Section 3 of this table for further details. Recommended by the CASA FVPT, June 2005. - Where conservation is required, conventional oil wells **must** be shut in after testing until conservation is implemented. Recommended by the CASA FVPT, September 2004. (Section 2.4(1a)) - Licensees of multiwell heavy oil or bitumen sites must prebuild gas conservation lines to one common point on the lease as part of initial construction. Recommended by the CASA FVPT, September 2004. (Section 2.4(2)) - Where conservation is required for bitumen sites, it must occur as quickly as possible and must not exceed 6 months after flow rate determination. Wells must be shut in if the required conservation is not operational within this time. (Section 2.4(2b(ii))) - Clustering must be considered within a 3 km radius. Recommended by the CASA FVPT, September 2004. (Section 2.6(1)) - Further clarification and detail provided in economic evaluation process. (Section 2.8.1) - For solution gas containing greater than 10 moles per kilomole of H_2S, the operating costs may be assumed to be up to 20% of the initial capital cost. Recommended by the CASA FVPT, June 2002. (Section 2.8.1(6)) - An industry standard electricity price forecast reference provided. Recommend by the CASA FVPT, June 2002. (Section 2.8.1(3))

	- Further clarification and detail provided regarding expectations on data provided for audits of economic evaluations. (Section 2.8.2) - Operators must consult with residents (in accordance with *Directive 056* consultation requirements) prior to licensing if the site might vent natural gas. Recommended by the CASA FVPT, September 2004. (Section 2.9(4)) - Further clarification provided on expectations regarding outages at conserving facilities. (Section 2.11) - Where reductions in solution gas production are required due to conserving facility outages and multiple facilities or operators are involved, the overall reduction in solution gas production may be achieved through use of different reductions at different contributing facilities. It is not necessary to implement equal reductions at each upstream facility. If multiple operators cannot agree on how to achieve the overall reduction required, all operators must implement equal reductions necessary to achieve the overall reduction level. (Section 2.11(6)) - Shut-in of production is not required for partial equipment outages at conserving facilities where small volumes of gas are involved (e.g., tank VRU repair). This is limited to a maximum of 2 10^3 m^3/day for less than 5 days. (Table 1) - In cases where a third party can conserve gas that is deemed uneconomic, the EUB recommends that operators make the gas available, as is, at the lease boundary. Recommended by the CASA FVPT, September 2004. (Section 2.13.3)

Section 3: Temporary and Well Test Flaring and Incinerating	- The decision tree process now applies to temporary flaring, incinerating, and venting. Recommended by the CASA FVPT, June 2002. (Section 3.1)
	- The EUB requires that in-line testing be used when economic to do so. (Section 3.1(2))
	- Time limits have been developed for oil and gas well test flaring/incinerating and venting:
	  - Crude oil – 72 hours
	  - Bitumen – as soon as solution gas flow rates exceed an average of 900 m^3/day for 3 months, not to exceed 6 months
	  - Gas (nonassociated, non-CBM) – 72 hours
	  - Dry CBM (less than 1 m^3 of water per operating day) development well – 120 hours
	  - Dry CBM (less than 1 m^3 of water per operating day) nondevelopment well – 336 hours
	  - Wet CBM (more than 1 m^3 of water per operating day) – within 6 months of producing over 100 10^3 m^3 of gas in 3 consecutive months, or not more than 18 months or the volume allowance threshold, whichever is reached first.
	  - Recommended by the CASA FVPT, September 2004 and June 2005. (Section 3.2)
	- Reasons for exceptions beyond the well test time limits above include cleanup not complete, stabilized flow not reached, or mechanical problems. Extensions for these reasons do not require approval, just notification to EUB Field Centre. Operator must document reasons for extension for possible audit. Recommended by the CASA FVPT, September 2004 and June 2005. (Section 3.2)
	- When testing is complete, the well must be shut in until conservation is in place. Recommended by the CASA FVPT, September 2004 and June 2005. Based on well test data gathered by EUB and reviewed by the CASA FVPT. (Section 3.2(6))
	- Where a flaring/incinerating permit has been issued, the volume allowed in the permit will take precedence over the time limits. In all cases, the need to continue flaring must be justifiable and may be subject to audit. (Section 3.2(5) and (6))

	- Clarification provided that where operations result in higher concentrations of H_2S than that of the well (e.g., flaring/incinerating gas off of liquid tanks), the composition of the gas to be burned at the flare or incinerator must be used for determining whether a permit is required. (Section 3.3.1(1)) - A permit is not required to flare or incinerate small volumes of sour gas. Recommended by the CASA FVPT, June 2002. (Section 3.3.2(2)) - Where fuel gas is used, the gas composition from the well must still be used to determine whether a permit is required (but the resulting composition at the flare stack is used for dispersion modelling). (Section 3.3.1(1)) - Clarification: Volume allowance thresholds apply to gas well tests only. (Section 3.3.1(2)) - Clarification: Low-risk criteria apply to short-duration events, not just well testing. (Appendix 9) - Dispersion modelling for well tests must consider cumulative effects of any continuous sources within a 7 km radius <u>or</u> within the isopleth of one-third of the Alberta Ambient Air Quality Objective for SO_2, whichever is less. This issue was raised through feedback from industry regarding inconsistency with modelling requirements for continuous sources. Modified by EUB to become more consistent. (Section 3.6(6)) - The EUB will not permit concurrent temporary sour gas burning (i.e., multiple well test flaring/incinerating) within 14 km of each other*, unless a company can demonstrate that concurrent flaring can meet Alberta Ambient Air Quality Objectives*. Modified based on feedback from industry. (Section 3.6(7)) - Clarification: Notification requirements detailed in Table 2 also apply to venting - Operators may conduct a one-time notification program for multiwell projects in an area. (Section 3.9(5)) - Zero Flaring Agreement provided, whereby an applicant and a resident may agree to zero flaring. (Section 3.11 and Appendix 12)
Section 4: Gas Battery, Dehydrator, and Compressor Station Flaring, Incinerating, and Venting	- The decision tree process now applies to other sources of flaring, incinerating, and venting other than solution gas. Recommended by the CASA FVPT, September 2004. (Section 4.1) - "Frequent" defined (i.e., one event per month). (Section 4.1(4))
Section 5: Gas Plant Flaring, Incinerating, and Venting	- The decision tree process now applies to other sources of flaring, incinerating, and venting other than solution gas. Recommended by the CASA FVPT, September 2004. (Section 5.1) - A flare volume limit of 0.2% of receipts applies to gas plants processing more than 1.0 10^9 m^3 per year. Previously, the volume limit of 0.5% of receipts applied to gas plants regardless of size. Recommended by the CASA FVPT, June 2002. (Section 5.2) - Operators must investigate and correct causes of repeat nonroutine flaring, incinerating, and venting. Gas plants must not exceed six major nonroutine flaring events in any consecutive six-month period. Recommended by the CASA FVPT, June 2002. (Section 5.3) - Operators must monitor and minimize fuel gas use. Operators must be able to justify fuel gas usage volumes upon request. (Section 5.5)
Section 6: Pipeline Flaring, Incinerating, and Venting	- The decision tree process now applies to other sources of flaring, incinerating, and venting other than solution gas. Recommended by the CASA FVPT, September 2004. (Section 6.1) - Gas containing more than 5 ppm H_2S must not be released from a pipeline without the consent of the EUB Operations Group, unless the gas is burned such that it meets the requirements of Section 7. Edited by EUB for consistency with *Pipeline Regulation*.

Section 7: Performance Requirements	- Use of terminology of flares or incinerators: Throughout the section, these labels are used very specifically to indicate which requirements apply to all devices, as opposed to those requirements that apply just to flare, just to incinerators, etc. (Section 7) - Flare/incinerator systems include associated separation equipment, piping, and controls. (Section 7) - Licensees must ensure that a professional engineer, certified technician, certified engineering technologist or registered engineering technologist is responsible for the design or review of flare and incinerator systems including separation, related piping, and controls and for the specification of safe operating procedures. (The titles Professional Engineer, Certified Technician, Certified Engineering Technologist, and Registered Engineering Technologist refer to designations as granted by APEGGA or ASET or their equivalents.) (Section 7(1)) - Licensees must ensure that operating procedures that define the operational limits of flares, incinerators, or enclosed burners are documented and implemented. Flares and incinerators must be operated within operational ranges and type of service specified by the designing or reviewing engineer, technician, or technologist. (Section 7(2)) - If an operator is using a flare or incinerator in a field service that has not previously been field tested, the operator must be able to provide actual monitoring data to show that performance specifications can be met. Field testing of new equipment will not be considered unless there are acceptable and redundant combustion systems to ensure that any sweet, sour, or acid gas can be properly combusted if the new equipment fails to perform as predicted or the ability exists for the facility to be shut in. (Section 7(3)) - Minimum Conversion Efficiency section: Restructured to create more parallel expectations for both flares and incinerators. The section indicates that the EUB requires good combustion in either case and that this is achieved as follows: for flares, through ensuring minimum heating value of the gas; for incinerators, through exit temperature and residence time. Requirements that are common to both technologies are grouped in the common section before branching into the equipment-specific requirements in the two subsections that follow. The entire section was also reorganized to provide more logic to the hierarchy of requirements. (Section 7.1) - Fuel make-up must be specified for acid gas flare stacks by a qualified technical professional (Professional Engineer, Certified Technician, or Certified Technologist, as recognized by APEGGA or ASET, or their equivalents). (Section 7.1.1(2)) - Smoke Emissions: Section title was changed to be less confusing; "visible emissions" was considered to be vague. (Section 7.2) - At **all** facilities (excluding gas plants) where the gas contains more than <u>10 mol/kmol (1%)</u> H_2S, a pilot <u>or</u> automatic ignition device must be installed on flares/incinerators for continuous (e.g., sour water or condensate tank flash-gas) or intermittent (e.g., emergency depressuring) sources. At <u>gas plants</u> where gas contains more than <u>10 ppm</u> H_2S, pilots <u>and</u> automatic ignition must be installed on flare/incinerator stacks. (Section 7.3 (1)) - Applications to extinguish flare pilots will only be considered if no active injection or cycling schemes are taking place in or planned for any pools with wells connected to the facility**,** <u>unless the maximum design operating pressure of production piping and pressure vessel systems is greater than 105% of the operating pressures.</u> Extra text added to make this consistent with what is already allowed in this section. (Section 7.3.1(2a)) - Clarification that operators must ensure that emergency flaring and incinerating complies with *Alberta Ambient Air Quality Objectives*. The modelling approach used to determine this is currently being reviewed. When complete, it will complement this requirement. (Section 7.5)

	- The terms flare knockout, flare knockout drum, scrubber, and flare separator are used interchangeably. These requirements apply to all of these devices. (Section 7.6) - Liquid separation must be provided in both temporary and permanent flare and incinerator systems. (Section 7.6) - Flare and incinerator separators in facilities constructed after the date of this directive must be equipped with high-level alarms. (Section 7.6(5)) - All flare and incinerator separators constructed prior to this directive must be provided with high-level facility shutdowns or high-level alarms. (Section 7.6(6)) - Well test vessels receiving production from oil wells must be equipped with an HLSD, unless attended 24 hours a day. (Section 7.6(9)) - Operators must take precaution to prevent backflash using appropriate engineering and operating practices, such as installing flame arresters or ensuring sufficient flare header sweep gas velocities. (Section 7.7) - Clarification: Flares and incinerators must be located at least 50 m away from wells, not including water disposal wells or water injection wells where there is no risk of flammable vapours. (Section 7.8(1a)) - Clarification: Flares and incinerators must be located at least 50 m away from storage tanks containing flammable liquids or flammable vapours. (Section 7.8(1b)) - Clarification: In applications for a continuous source, other sources must be modelled at licensed emission rates. In applications for a temporary event occurring at a known time (e.g., well test or planned maintenance blowdown), other sources can be modelled at maximum expected operating emission rates at the time of the temporary event. (Section 7.12.3(1c))
Section 8 – Venting and Fugitive Emissions Management Requirements	- Entire section restructured and rewritten based on input from EUB field staff and industry committees on issues such as shallow gas well venting. - Decision tree process originally developed for solution gas flaring now applies to venting of solution gas and nonassociated gas. Recommended by the CASA FVPT, June 2002 and September 2004. (Section 8.1(1)) - Temporary, short-term venting is allowed at wells, facilities, and pipelines (for natural gas transmission systems, see Section 6.3) with the following conditions: total gas volume does not exceed 2 10^3 m^3 and the duration does not exceed 24 hours (this does not include the clean-out phase for well testing where liquids and noncombustible gases may prevent stable combustion). (Section 8.1(5)) - An appropriate flame arrester, equivalent safety device, or proper engineering and operating precautions (e.g., sufficient sweep gas velocity) must be used on all vent lines from oil storage tanks connected to flare or incinerator stacks. (Section 8.1(9)) - Limitations on venting gas containing benzene: Requirements match those found in *Directive 039*. (Section 8.3) - Fugitive emission management: operators must develop programs to detect and repair leaks. Recommended by the CASA FVPT, September 2004. (Section 8.7)
Section 10 – Measurement and Reporting	- Entire section edited to match *Directive 017* and address all feedback from the Industry Measurement Group.
Section 12 – Compliance and Enforcement	- Updated.

Appendix 2 Background to *Directive 060*

Concerns about flaring prompted the EUB and Alberta Environment to support Alberta Research Council research on flaring. Findings reported in 1996 suggested that the efficiency of flare stacks in destroying waste gas was not as high as originally thought and that a variety of products of incomplete combustion were contained in flare emissions.

The EUB then consulted with stakeholders from industry, the public, and other government sectors and reviewed existing policies on solution gas conservation. CAPP brought the issue of flaring to the CASA Board of Directors in November 1996 and established the Flaring Project Team in February 1997 to develop recommendations to address potential and observed impacts associated with flaring. In its 1998 final report, *Management of Routine Solution Gas Flaring in Alberta: Report and Recommendations of the Flaring Project Team,* the Flaring Project Team recommended a framework for solution gas flaring management and a decision tree process for achieving flare reductions.

The EUB Implements the CASA Recommendations

In 1999 in the first edition of *Directive 060* (then named *Guide 60*), the EUB implemented the solution gas management framework (Section 2), the decision tree process (Section 2.3), and other CASA recommendations. The guide mandated firm, short-term solution gas flare reduction targets of 15% and 25% by the end of 2000 and 2001 respectively relative to the 1996 revised baseline of 1340 $10^6\,m^3$ per year; the guide also defined maximum limits on the total volume of solution gas that could be flared at individual sites if voluntary targets were not met.

In 2000, a new CASA team, the Flaring/Venting Project Team, convened to review progress made on the 1998 recommendations, as well as make further recommendations on flaring, incinerating, and venting. The result was the 2002 report *Gas Flaring and Venting in Alberta: Report and Recommendations for the Upstream Petroleum Industry by the Flaring/Venting Project Team*. The report stated that the implementation of the solution gas management framework and the flare reduction targets by the upstream petroleum industry had successfully resulted in a 53% reduction in solution gas flaring relative to the 1996 baseline. On the basis of that success, the Flaring/Venting Project Team recommended that a similar decision tree process be applied to solution gas venting, well test flaring, and facility flaring. In addition, the team recommended that a 50% reduction target be maintained for all solution gas flaring in Alberta relative to the 1996 baseline. Additional reports and recommendations were put forward in September 2004 and March and June 2005.

Work on further reducing flaring, incinerating, and venting continues.

Ongoing Research

The EUB supports the 2004 CASA recommendations for additional research so that Alberta can continue to move toward the use of practical flare combustion efficiency standards where flaring is necessary. The EUB expects that industry will support and participate in the funding of continued research focusing on

- understanding the relationship between gas composition and combustion efficiency, including the effects of H_2S content;
- understanding the effects of flare stack design, including flare tips on combustion efficiency; and
- reviewing the results of any field testing of combustion efficiency monitoring methodologies that are occurring.

Appendix 3 References and Contacts Cited

EUB Documents[*]

Oil and Gas Conservation Regulations

Bulletin 2004-15: New Well Test Capture (WTC) System Implementation Date Reminder: Changes to Final WTC Pressure ASCII Standard (PAS) Formats and Version 4.0 PAS File Business Rules Implications

Directive 007: Production Accounting Handbook
Directive 008: Surface Casing Depth Minimum Requirements
Directive 017: Measurement Requirements for Upstream Oil and Gas Operations
Directive 019: EUB Compliance Assurance—Enforcement
Directive 028: Applications for Power Plants, Substations, Transmission Lines, and Industrial System Designations
Directive 036: Drilling Blowout Prevention Requirements and Procedures
Directive 037: Service Rig Inspection Manual
Directive 038: Noise Control Directive User Guide
Directive 039: Revised Program to Reduce Benzene Emissions from Glycol Dehydrators
Directive 040: Pressure and Deliverability Testing Oil and Gas Wells—Minimum Requirements and Recommended Practices
Directive 055: Storage Requirements for the Upstream Petroleum Industry
Directive 056: Energy Development Applications and Schedules
Directive 063: Requirements and Procedures for Oilfield Waste Management Facilities
Directive 064: Requirements and Procedures for Facilities
Directive 065: Resources Applications for Conventional Oil and Gas Reservoirs
Directive 066: Requirements and Procedures for Pipelines
Directive 071: Emergency Preparedness and Response Requirements for the Upstream Petroleum Industry

General Bulletin (GB) 2002-05: EUB Requirements for Evaluation of Solution Gas Vent Gas Conservation

Interim Directive (ID) 91-03: Heavy Oil/Oil Sands Operations
ID 94-03: Underbalanced Drilling
ID 97-06: Sour Well Licensing and Drilling Requirements
ID 2001-03: Sulphur Recovery Guidelines for the Province of Alberta
ID 2002-01: Electronic Submission of Production, Disposition, and Transportation Volumetric Information and Well Status Changes

Informational Letter (IL) 98-01: A Memorandum of Understanding Between Alberta Environment and the Alberta Energy and Utilities Board Regarding Coordination of Release Notification Requirements and Subsequent Regulatory Response
IL 2001-01: Appropriate Dispute Resolution (ADR) Program and Guidelines for Energy Industry Disputes

EUBflare.xls and *EUBincin.xls* Spreadsheets

ST13: Alberta Gas Plant/Gas Gathering Activities—Monthly Statistics
ST13A: Alberta Gas Plant/Gas Gathering System Statistics—Annual Statistics
ST60: Crude Oil and Crude Bitumen Batteries Monthly Flaring, Venting, and Production Data
ST60A: Crude Oil and Crude Bitumen Batteries Annual Flaring, Venting, and Production Data
ST60B: Upstream Petroleum Industry Flaring and Venting Report

Alberta Energy Document

Information Letter (IL) 99-19: Otherwise Flared Solution Gas Royalty Waiver Program

Alberta Environment Documents

Air Quality Model Guideline
Alberta Ambient Air Quality Objectives
Environmental Protection and Enhancement Act
Forest and Prairie Protection Regulations (AR 135/72)
Release Reporting Guideline 1028-F

Other Documents

Alberta Pressure Equipment Safety Regulations, Alberta Safety Codes Act, The Pressure Equipment Safety Authority (AR 49/2006)
API-RP-521, Guide for Pressure-Relieving and Depressuring System, American Petroleum Institute, Recommended Practices
Clean Air Strategic Alliance (CASA), 1998, Management of Routine Solution Gas Flaring in Alberta, Report and Recommendations of the Flaring Project Team (Edmonton, Alberta)
CASA, 2002, Gas Flaring and Venting in Alberta, Report and Recommendations for the Upstream Petroleum Industry by the Flaring/Venting Project Team (Edmonton, Alberta)

(continued)

[*] EUB documents are available on the EUB Web site at www.eub.ca and from EUB Information Services, 640–5 Avenue SW, Main Floor, Calgary AB T2P 3G4; Tel: (403) 297-8190; Fax: (403) 297-7040.

Other Documents (continued)

CASA, 2004, Gas Flaring and Venting in Alberta, Report and Recommendations for the Upstream Petroleum Industry, Prepared by the Flaring and Venting Project Team for the Clean Air Strategic Alliance Board of Directors (Edmonton, Alberta)

CASA, 2005, Flaring and Venting Recommendations for Coal Bed Methane Final Report, Prepared by the Flaring and Venting Project Team for the Clean Air Strategic Alliance Board of Directors (Edmonton, Alberta)

CASA, 2005, Flaring and Venting Review of Well Test Time Limits Final Report, Prepared by the Flaring and Venting Project Team for the Clean Air Strategic Alliance Board of Directors (Edmonton, Alberta)

Consumer Price Index forecast, Government of Alberta, Department of Finance Web site www.finance.gov.ab.ca/aboutalberta/economic_bulletins/current_economic_indicators.pdf.

GLJ Petroleum Consultants, *Product Price and Market Forecasts for the Canadian Oil and Gas*, "Natural Gas and Sulphur Price Forecast Table," Quarterly Update, Web site www.gljpc.com/pdfs/pricing.pdf

Gas Flaring and Venting in Alberta: Report and Recommendations for the Upstream Petroleum Industry by the Flaring/Venting Project Team, CASA

GPSA Engineering Data Book (12th edition), Gas Processors Suppliers Association

Guide for Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities, CAPP

Industry Recommended Practice (IRP) Volume 4-2000/02: Well Testing and Fluid Handling, Canadian Petroleum Safety Council

EUB Contacts

Facilities Applications Group: (403) 297-4369
Production/Well Data Services: (403) 297-8952
Operations Group, Compliance and Operations Branch: (403) 297-4485
Field Centres
- Bonnyville: (780) 826-5352
- Midnapore: (403) 297-8303
- Drayton Valley: (780) 542-5182
- Grande Prairie: (780) 538-5138
- High Level: (780) 926-5399
- Medicine Hat: (403) 527-3385
- Red Deer: (403) 340-5454
- St. Albert: (780) 460-3800
- Wainwright: (780) 842-7570

Fort McMurray Office: (780) 743-7214

Appendix 4 Definitions of Terms as Used in *Directive 060*

Acid gas
Gas that is separated in the treating of solution or nonassociated gas that contains hydrogen sulphide (H_2S), total reduced sulphur compounds, and/or carbon dioxide (CO_2).

Associated gas
Gas that is produced from an oil or bitumen reservoir. This may apply to gas produced from a gas cap or in conjunction with oil or bitumen.

Carbon conversion efficiency (CCE)
The CCE quantifies the effectiveness of a device to oxidize hydrocarbons and is the relative conversion of carbon compounds in the reactants to products of complete and incomplete combustion. Incomplete combustion products include unburnt hydrocarbons (hydrocarbon [HC] measured as methane [CH_4]) and other partially oxidized carbon compounds, such as carbon monoxide (CO) in the exhaust. For the purposes of this directive, CCE is reported as the percentage of carbon in the fuel that is converted to CO_2 and is obtained from:

$$CCE = \frac{Mass\ Rate\ of\ Carbon\ in\ the\ Fuel\ Converted\ to\ CO_2}{Mass\ Rate\ of\ Carbon\ in\ the\ Fuel}$$

With this definition, the mass and molar efficiency are the same. An adjustment must be made if there is CO_2 in the inlet stream, as it does not react. The adjustment depends on the fraction of $CO_{2,fuel}$ and hydrocarbons $C_X H_{Y,fuel}$ in the gas stream entering the device and the number of carbon moles (X) per molecule of hydrocarbon. CCE can be determined from exhaust and fuel concentration measurements using

$$CCE = \frac{CO_{2,stack} - (CO_{2,fuel} / (X\ C_X H_{Y,fuel}))(CO_{stack} + HC_{stack})}{(CO_{2,stack} + CO_{stack} + HC_{stack})}$$

This equation reduces to the following familiar expression if the inlet does not contain CO_2 ($CO_{2,inlet} = 0$):

$$CCE = \frac{CO_{2,stack}}{(CO_{2,stack} + CO_{stack} + HC_{stack})}$$

Clustering
Clustering is defined as the practice of gathering the solution gas from several flares or vents at a common point for conservation.

Combustion efficiency (CE)
The CE quantifies the effectiveness of a device to fully oxidize a fuel. Products of complete combustion (i.e., CO_2, H_2O, and sulphur dioxide [SO_2]) result in all of the chemical energy released as heat. Products of incomplete combustion (e.g., CO, unburnt hydrocarbons, other partially oxidized carbon compounds, H_2S, and other reduced and partially oxidized sulphur compounds) reduce the amount of energy released. For the purposes of this directive, CE is reported as the percentage of the net heating value that is released as heat through combustion.

Conservation
The recovery of solution gas for use as fuel for production facilities, other useful purposes (e.g., power generation), sale, or beneficial injection into an oil or gas pool.

Conservation efficiency
Conservation efficiency (%) =
(Solution gas production – Flared – Vented) / (Solution gas production) x 100

Conserving facility	Any potential tie-in point that is conserving gas, such as batteries, plants, compressor stations, pipelines, and pump stations.
Fugitive emissions	Unintentional releases of gas resulting from production, processing, transmission, storage, and delivery.
Gas battery	A system or arrangement of tanks and other surface equipment (including interconnecting piping) that receives the effluent from one or more wells that might provide measurement and separation, compression, dehydration, dew point control, H_2S scavenging where <0.1 tonne/day of sulphur is being treated, line heating, or other gas handling functions prior to the delivery to market or other disposition. This does not include gas processing equipment that recovers more than 2 m^3/day of liquids or that processes more than 0.1 tonne/day of sulphur.
Gas processing plant	A system or arrangement of equipment used for the extraction of H_2S, helium, ethane, natural gas liquids, or other substances from raw gas; does not include a wellhead separator, treater, dehydrator, or production facility that recovers less than 2 m^3/day of hydrocarbon liquids without using a liquid extraction process (e.g., refrigerant, desiccant). In addition, 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 H_2S or SO_2.
Must	The word “must” indicates a requirement that an operator is legally required to meet and for which the EUB will initiate enforcement action for noncompliance.
Nonassociated gas	Gas produced from a gas pool (i.e., not associated with oil or bitumen reservoirs or with production).
Nonroutine flaring, venting, incinerating	Intermittent and infrequent events such as planned maintenance, process upsets, and emergencies that result in flaring, venting, or incinerating.
Oil 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.
Recommended or recommends	The word “recommends” indicates that the procedure or practice described is a guideline that can be used by the applicable party but is not an EUB requirement and does not carry an enforcement consequence.
Refined assessment	This is a more complex and data-intensive level of dispersion modelling. Refined assessments more closely estimate actual air quality impacts by using site-specific meteorological data.
Required	The word “required” means that the specified action or item is a minimum regulatory requirement and is subject to EUB enforcement.
Routine flaring, venting, incinerating	“Routine” applies to continuous flaring, venting, and incinerating.

Screening assessment This is the quickest and simplest dispersion modelling approach. Screening assessments usually provide a conservative (worst-case) estimate of downwind concentrations. If exceedances of the *Alberta Ambient Air Quality Objectives* are predicted by a screening assessment, a refined assessment may be necessary. Alternatively, stack design parameters may be modified until predicted ambient air quality meets the *Alberta Ambient Air Quality Objectives*.

Solution gas For the purposes of this directive, solution gas is all gas that is separated from oil or bitumen production.

Sour gas Gas containing H_2S. Depending on H_2S concentrations, sour gas may pose a public safety hazard if released or may result in unacceptable off-lease odours if vented into the atmosphere.

Source All gas flared, incinerated, or vented from a single operating site, such as an oil battery or multiple-well pad.

Sulphur conversion efficiency (SCE) The SCE quantifies the effectiveness of a device to oxidize sulphur and is the relative conversion of sulphur compounds in the reactants to products of complete and incomplete combustion. Incomplete combustion products include unburnt H_2S, other reduced sulphur compounds (measured as H_2S), such as carbonyl sulphide and carbon disulphide (especially if present in the fuel), and other partially oxidized sulphur compounds, such as sulphur trioxide (SO_3) in the exhaust (measured as SO_3). For the purposes of this directive, SCE is reported as the percentage of sulphur in the fuel that is converted to SO_2 and is obtained from

$$SCE = \frac{Mass\ Rate\ of\ Sulphur\ in\ the\ Fuel\ Converted\ to\ SO_2}{Mass\ Rate\ of\ Sulphur\ in\ the\ Fuel}$$

With this definition, the mass and molar efficiency are the same. SCE can be determined from stack gas concentration measurements using

$$SCE = \frac{SO_{2,stack}}{(SO_{2,stack} + SO_{3,stack} + H_2S_{stack})}$$

Sulphur emissions For the purposes of this directive, this includes all air emissions of sulphur-containing compounds, including SO_2, H_2S, and total reduced sulphur compounds (e.g., mercaptans). Sulphur emissions from flare stacks are expected to be primarily in the form of SO_2, with minor amounts of other compounds.

Sulphur recovery efficiency Sulphur recovery efficiency = (sulphur produced + injected)/(sulphur produced + injected + sulphur emissions), where the sulphur emission is normally SO_2 expressed in sulphur equivalence. All values are units of mass.

Venting The intentional controlled release of uncombusted gas.

Appendix 5 Abbreviations

10^6 m^3	million cubic metres
10^3 m^3	thousand cubic metres
AOF	absolute open flow
APEGGA	Association of Professional Engineers, Geologists, and Geophysicists of Alberta
ASET	Association of Science and Engineering Technology Professionals of Alberta
CAPP	Canadian Association of Petroleum Producers
CASA	Clean Air Strategic Alliance
CO_2	carbon dioxide
CSA	Canadian Standards Association
ESDV	emergency shutdown valve
FIS	Field Information System
GOR	gas-to-oil ratio (gas:oil)
H_2S	hydrogen sulphide
HLSD	high-level shutdown
km	kilometre
kPa	kilopascal
mol/kmol	mole per kilomole
MJ	megajoule
MJ/m^3	megajoule per cubic metre
MW	megawatt
NOWPP	New Oil Well Production Period
NPV	net present value
ppm	parts per million
PSV	pressure safety valve
SECAP	Sulphur Emission Control Assistance Program
SO_2	sulphur dioxide

Appendix 6 Information for Permit Request to Flare or Incinerate in Exceedance of Flared or Incinerated Volume Allowance Threshold (600, 400, or 200 10^3 m^3 Exceedance)

If flared or incinerated volumes are expected to exceed the volume allowance threshold during temporary operations, additional information must be submitted.

1) Underbalanced drilling requests must include the following information:

   a) an explanation and supporting documentation of how flaring or incinerating rates are determined; possible sources for these estimates may come from

      i) offset well AOF tests, or

      ii) flaring or incinerating rates from offset underbalanced drilling operations;

   b) estimated time required to drill the well;

   c) if a well test is proposed, the total volume requested for the test.

2) For well tests that are expected to exceed the volume allowance threshold, the request must include the following information:

   a) a brief description of the development required to bring the well onto production (e.g., length and size of pipeline to tie in well, well site facilities, compression, gas processing facilities);

   b) the minimum recoverable reserves required for the well to be economic (minimum economic reserves);

   c) details of the analysis used to determine the minimum economic reserves (operators may use simplified "netback" economics showing the current operating profit [revenues minus operating costs] to estimate the recoverable reserves required to pay out facility investment costs; alternatively, operators may choose to present a more detailed economic analysis involving features such as discounted gas flow projections);

   d) the estimated recovery factor and surface loss for the pool;

   e) the estimated initial reservoir pressure;

   f) the amount of reservoir depletion being targeted by the test (the operator must provide a brief description justifying this depletion in relation to the minimum economic reserve)—the recommended maximum pressure depletion guidelines are

      i) 1% of the first 5000 kPa of reservoir pressure, and

      ii) 0.5% of the reservoir pressure above 500 kPa;

      (for example, a maximum depletion guideline of 100 kPa is targeted for a reservoir with an initial pressure of 15 000 kPa); and

   g) justification for pretest cleanup and servicing flaring or incinerating if related volumes exceed 200 10^3 m^3.

Note that an incremental volume of up to 200 10^3 m^3 may be added to the permit request in order to provide for pretest cleanup and servicing operations if these are needed to establish the minimum economic reserve without additional justification.

Appendix 7 Sour Gas Flaring/Incineration Data Summary Report

Item	**Report Information**			**Units**
Permit No:				
Company:				
Well Name:				
Unique Well Identifier:				
Permit Issue Date:				
Volume of Raw Gas Flared or Incinerated:	Approved:		Actual:	$10^3\ m^3$
Raw Gas Flow Rate:	Approved (Max.):	Actual (Max.):	Actual (Avg.):	$10^3\ m^3/d$
Actual Fuel Gas Flared or Incinerated (if applicable):	Volume ($10^3\ m^3$):		Rate ($10^3\ m^3/d$):	
Number of H_2S Analyses Conducted:				
H_2S Content of Raw Gas:	Approved (Max.):	Actual (Max.):	Actual (Avg.):	%
Total Sulphur Flared or Incinerated: = 1.35592 (%H_2S÷100) (flared vol.)				tonnes
Flaring Dates:				
Air Monitoring Conducted:	☐ Yes ☐ No (If yes, attach monitoring report)			
Exceedances of the Alberta Ambient Air Quality Objectives (H_2S or SO_2):	☐ Yes ☐ No			
Field Centre Notification Date:		EUB Field Centre Contact:		
Were there any problems while flaring or incinerating?	☐ Yes ☐ No	If yes, was the EUB Field Centre contacted?: ☐ Yes ☐ No If yes, contact name:		
Comments:				
Company Representative:				
Phone Number:	E-mail:			
Fax Number:	Signature:			

This form must be completed in full and submitted to the EUB's Compliance and Operations Branch within 3 weeks of the flaring completion date.

Submit to: **Temporary Flaring/Incinerating Permits**
Compliance and Operations Branch
Alberta Energy and Utilities Board
640 – 5 Avenue SW, 12th Floor
Calgary AB T2P 3G4
Fax: (403) 297-2691

Appendix 8 Air Quality Management Plans for Temporary SO_2 Emissions

If exceedances of the low-risk criteria for SO_2 (see Appendix 9) are predicted and it is not proposed to alter flare/incinerator design parameters to mitigate the potential exceedances, approval may be granted, provided that suitable control measures are in place. In such situations, an air quality management plan must be submitted with the temporary permit request. **The management plan must outline how predicted exceedances of the *Alberta Ambient Air Quality Objectives* will be avoided such that the low-risk criteria are met.**

The air quality management plan may include the following:

1) Restrictions during specific meteorological conditions that will limit or avoid operations under conditions that result in predicted exceedances.

   a) These atmospheric conditions may include

      i) time of day

      ii) wind direction

      iii) wind velocity

      iv) atmospheric stability

   b) Meteorological monitoring may be used as a management plan based on a maximum 1-hour rolling (i.e., any consecutive 60 minutes), with measurements taken at a frequency of no greater than every 15 minutes (i.e., four measurements/hour).

2) The management plan must include specifications for locating meteorological monitoring equipment (if used). Wind monitoring devices must be elevated above the height of trees surrounding the site.

3) Restrictions that may be applied during unfavourable meteorological conditions.

   a) Operational restrictions in air quality management plans may include

      i) suspension of flaring or incineration operations

      ii) reduction of flaring or incineration rates

      iii) requirements for supplemental fuel gas

4) If a reduction in flaring or incineration rate or an addition of supplemental fuel gas is proposed, compliance with the EUB low-risk criteria must be demonstrated with appropriate dispersion modelling results. (Note that reduced flaring or incineration rates do not result in a proportional reduction in predicted concentrations.)

5) Ambient air monitoring (mobile and/or stationary) must be located where exceedances of the *Alberta Ambient Air Quality Objectives* are predicted.

   a) Ambient air monitoring in conjunction with appropriate flaring/incinerating management procedures will only be accepted when it can be demonstrated that monitors can be placed in a manner that is reasonably protective of all locations where exceedances of the EUB low-risk criteria are predicted. Presently stationary monitors are accepted to cover an arc of 22.5° centred on the source. Operators must provide a map of the area (1:50 000) indicating the location(s) of the stationary monitor(s) and a table with the coordinates (i.e., UTM). In cases where monitoring is proposed, operators must demonstrate that there is good access to all areas with predicted exceedances *before* a request is submitted.

b) The *Alberta Ambient Air Quality Objectives* must not be exceeded, based on a one-hour average. In order to accomplish this, ambient air monitoring must occur at intervals of 15-minutes or less. **If the 30-minute average exceeds the *Alberta Ambient Air Quality Objectives,* the flaring or incinerating operation must be immediately shut in.**

6) If there is more than one meteorological condition that requires a management response, or if a combination of meteorological restrictions and ambient air monitoring is proposed, the management plan must be summarized in a flowchart that is clear and concise and can be applied by on-site staff during flaring or incinerating operations. Furthermore, if multiple flow rates are proposed in the management plan, the EUB low-risk criteria must be met for each flow rate.

a) The management plan must clearly specify the frequency at which the meteorological or ambient air quality monitoring data will be monitored by on-site staff. An averaging time of no greater than 15 minutes is mandatory, as this allows for observations of trends and provides adequate time to respond to elevated concentrations.

7) The management plan must clearly define under what conditions flaring or incinerating may resume if suspended or return to normal operations if a management option such as fuel gas is proposed. Flaring or incinerating must remain suspended for at least 1-hour before operations may resume, in order to prevent an exceedance or to respond to an exceedance.

a) Flaring or incinerating may recommence after a 1-hour period or after meteorological conditions change and remain in a favourable sector for 30 minutes, whichever is longer.

Appendix 9 Screening Dispersion Modelling Using EUB Spreadsheet

The EUB Sour Well Test Flaring and Incinerating Permit spreadsheets and technical descriptions are available on the EUB Web site at www.eub.ca/docs/documents/directives/directive060_EUBflare.xls and www.eub.ca/docs/documents/directives/directive060_EUBincin.xls respectively. They provide a screening analysis of the SO_2 dispersion from permanent and temporary flares and incinerators. If the screening level maximum concentration predictions in parallel and complex airflow terrain for a source meet the *Alberta Ambient Air Quality Objectives* (AAAQO), no further analysis is required. The spreadsheet can be submitted in support of the dispersion modelling assessment.

Maximum predictions for routine sources must meet the AAAQO. Due to the short-term nature of temporary nonroutine sources, risk-based criteria can be applied. The EUB low-risk criteria are applicable to well tests and other temporary nonroutine flaring and incinerating events. The flaring spreadsheet uses a nomograph approach to determine the 99th percentile for parallel airflow and indicates if the proposed flaring parameters meet the criteria. If parallel airflow is applicable, no further analysis is required for a temporary flare. For temporary incinerators, refined dispersion modelling must be done to determine if the low-risk criteria are met.

The spreadsheet allows for the addition of fuel gas to enhance the plume rise and reduce the concentration predictions. The user can specify the fuel gas to raw gas ratio for both flares and incinerators. Note that adding fuel gas will not increase the complex terrain criterion. In addition, for flares, the spreadsheet will determine the minimum required to meet the low-risk criteria for parallel airflow and provides a fuel gas log to determine minimum fuel gas for actual H_2S concentrations and raw gas flow rate.

If it is not practical to modify flare or incinerator design parameters, you may consider evaluating the proposed design with more refined dispersion modelling approaches. Additional refined dispersion modelling is required if the screening level maximum concentration predictions in parallel and complex airflow terrain for a source do not meet the AAAQO or if the 99th percentile is required for comparison to the EUB low-risk criteria. A refined dispersion model assessment is also required if there are continuous SO_2 emission sources within 7 km of the location or within the isopleth of one-third of the AAAQO for SO_2 (as described in Section 7.12.3), whichever distance is less. This requires the cumulative effects of the proposed flaring or incinerating to be assessed in combination with other sources. A refined assessment must meet Alberta Environment's *Air Quality Model Guideline* (March 2003).

Operators are responsible for ensuring that appropriately trained and qualified personnel complete the air quality evaluations.

A refined modelling assessment must include the following:

1) A description of the meteorological data source (location, years, and months): For models that require meteorological data, five years of meteorological data from a standard period is recommended. Three months per year must be modelled from the data set centred about the month of the requested permit date. The regional data sets posted on the Alberta Environment Web site at www.gov.ab.ca/env/air/airqual/metdata.htm may be suitable for this. Meteorological data must be representative of expected conditions at the site. (Note that the ambient temperature in the data sets must be modified to match the pseudo-

stack condition exit calculation.) Justification for the selected meteorological data must be provided with the request. Additional information about modelling and meteorological data requirements is provided on the Alberta Environment Web site.

2) Wind rose

3) Refined modelling source parameters for maximum flow rate (Q_{max}), average flow rate (Q_{avg}), and one-eighth maximum flow rate (Q/8) must be from the spreadsheet

4) A summary of the model input parameters (a printed copy of the input file is preferred, as output files may be large and need not be submitted)

5) The maximum predicted one-hour ambient air SO_2 concentration for maximum flow rate (Q_{max}), average flow rate (Q_{avg}), and one-eighth maximum flow rate (Q/8)

6) If exceedances of the one-hour AAAQO for SO_2 are predicted, a histogram as to the overall probability of exceedance based on meteorological data is to be calculated, as follows, by dividing the number of hours with predicted exceedances by the total number of hours used in the meteorological data set:

$$\text{Probability of Exceedance} = \frac{\text{(Cumulative number of hours with predicted exceedances)}}{\text{(Total hours modelled)}}$$

7) An interpretation of the modelling results (output files or model result printouts may be included if not excessively large)

8) Histograms showing exceedances based on criteria (e.g., wind direction, wind speed, and stability class)

If the EUB low-risk criteria are not met, a management plan (see Appendix 8) must be developed to achieve the EUB low-risk criteria. Requests with management plans must include sufficient information so that the EUB can assess the management plan, including

1) for each flow rate, a summary table of output, including

- meteorological conditions (stability class and range of wind speeds and directions) or times of day that result in predicted exceedance of the one-hour AAAQO for SO_2,
- maximum predicted SO_2 concentration for each condition where exceedances are predicted, and
- the expected overall probability of exceedances before and after implementation of the management plan;

2) for each flow rate, an area map showing

- locations of predicted SO_2 ground-level concentration isopleths (with a minimum 7 km radius) in excess of the one-hour AAAQO for SO_2,
- sectors with flaring restrictions (if proposed),
- locations accessible with a mobile monitoring unit (if proposed),
- approximate location of proposed stationary monitors (if proposed) and, if available, a recent air photo showing the approximate location of proposed stationary monitors, as well as specifications of the monitor location in a format usable by the monitoring operator (e.g., UTM coordinates or latitude and longitude), with an acceptable offset distance if this is required to improve

access or telemetry line of site; site reconnaissance must be conducted before submission to ensure that monitors can be placed, and

- UTM coordinates of stationary monitors, as well as distance and direction from well;

3) a calculation of make-up fuel gas requirements as a percentage of the produced gas being combusted (fuel gas may be used to increase plume rise; care should be taken to minimise fuel gas waste); and

4) electronic copies (i.e., Microsoft Word or Excel files) of the management plan and decision tree (if applicable).

The *EUBflare.xls* and *EUBincin.xls* spreadsheets also evaluate minimum and maximum exit velocities with respect to down-wash criteria. The results will assist operators in optimizing flare and incinerator design and verifying parameters used for temporary flaring and incinerating permit requests.

1) If down-wash is predicted to occur, the spreadsheet source parameters will conservatively account for down-wash; however, it is recommended that the stack design parameters (e.g., stack diameter) be modified to avoid down-wash.

2) The spreadsheet provides maximum and minimum exit diameters based on the recommended exit velocities. You must size the exit diameter within the range of exit diameters provided in *EUBflare.xls*. Exit diameter is a permitted parameter and a professional engineer, certified technician, or certified technologist[16] must review the design parameters.

Operators may submit data based on modified modelling methods for consideration; however, results from one of the accepted unmodified models must also be submitted for comparison. Description and scientific justification of the modifications must be provided. Generally, review of permit requests that use a modified modelling method requires more time, and the EUB may accept or reject the modified results at its discretion.

[16] The titles Professional Engineer, Certified Technician, and Certified Technologist refer to designations as granted by APEGGA, ASET, or the equivalent.

Appendix 10 EUB Flaring/Incinerating/Venting Notice Form

Operators are requested to complete the on-line EUB Flaring/Incinerating/Venting Notice Form using the EUB's Field Information System (FIS) and submit it electronically to the appropriate EUB Field Centre. This form is available at www.eub.gov.ab.ca/BBS/dds/dds/dds.htm.

Note that any operations that may result in public complaints must be called in to the appropriate EUB Field Centre 24-hour emergency phone number.

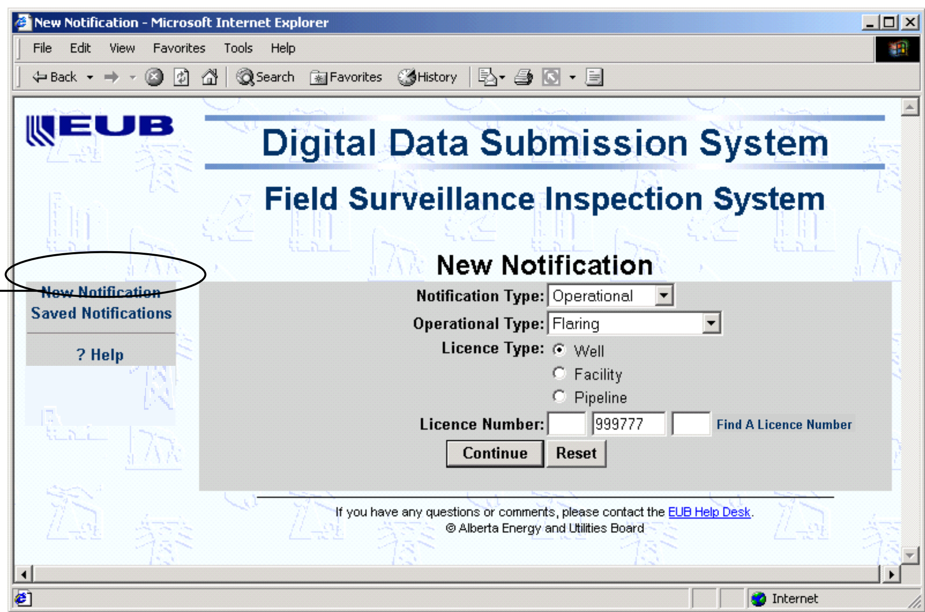
FIS Flaring/Incinerating/Venting Notification Procedure

The following is from the FISWebGuide (pages 31-34).

Add a flaring/incinerating/venting notification

1. To enter a new flaring, incinerating, or venting notification, click **New Notification** in the main FIS window.

Click here to enter a new flaring/ incinerating/venting notification.



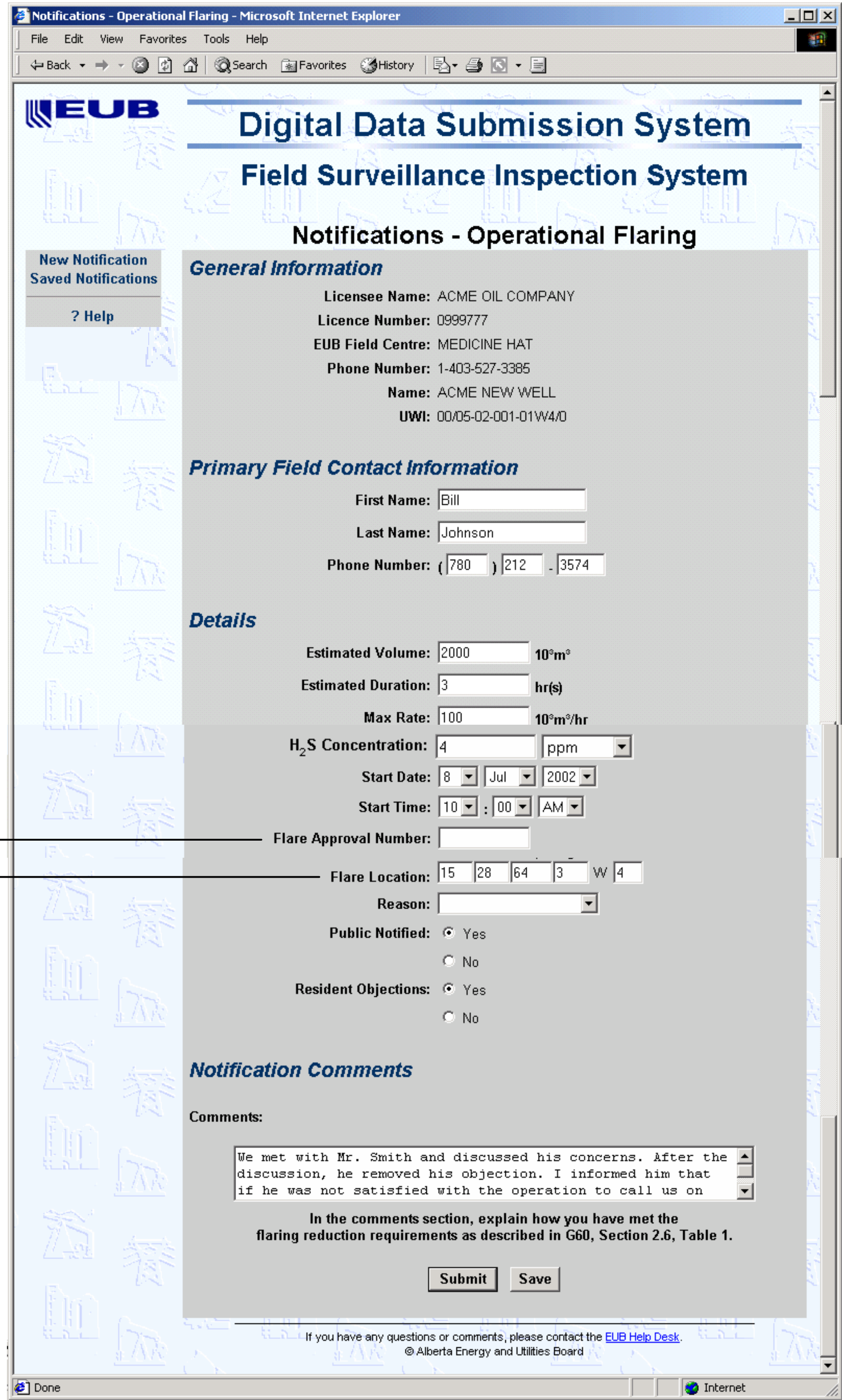
2. Select Operational from the Notification Type drop-down list.

3. Select Flaring or Venting from the Operational Type drop-down list.

4. Enter the well Licence Number that the new notification applies to. This is a required field.

5. Click **Continue** to open the Notifications – Flaring/Venting fields.

This example is for a well.



Flare Approval Number applies only to flaring/ incinerating.

Flare Location is named Vent Location when entering venting notifications.

6. Enter the following flaring/incinerating/venting notification information.

Notifications are time/date stamped when they are submitted to the EUB. As time deadlines are an important part of the notification process, please submit accurate notification information on a timely basis to avoid enforcement action.

Field	Description
Primary Field Contact Information	
First Name	Enter the first name of the primary contact person to contact about the flaring, incinerating, or venting activity.
Last Name	Enter the last name of the primary contact person to contact about the flaring, incinerating, or venting activity. The contact must be based in the field.
Phone Number	Enter the 10-digit phone number of the primary contact person.
Details	
Estimated Volume	Enter the estimated flare, incinerate, or vent volume in 10^3 m^3. **(Required)**
Estimated Duration	Enter the estimated duration of the flaring, incinerating, or venting in hours. **(Required)**
Max. Rate	Enter the estimated maximum rate flaring, incinerating, or venting in 10^3 m^3/hour. **(Required)**
H_2S Concentration	Enter the flaring, incinerating, and venting emission H_2S concentration and select the unit of measurement. Options are mol/kmol, ppm (parts per million), and per cent. (If ppm or per cent are entered, FIS automatically converts to mol/kmol, the unit of measurement in the FIS database.) **Note: (1)** If a venting notification has an H_2S concentration greater than zero, you are asked to confirm that H_2S will be in the vented gas. If so, you must contact the appropriate EUB field centre. (2) A message is also automatically sent to the field centre indicating that a sour gas venting notification was received with the licence number and date. **(Required)**
Start Date	Enter the start date of the flaring, incinerating, or venting. The default is the current system date. Use the drop-down list beside each field to select the day, month, and year in the first row. **(Required)**
Start Time	Enter the start time of the flaring, incinerating, or venting. The default is the current system time. Use the drop-down list beside each field to select the hour, minutes, and AM/PM time. **(Required)**
Flare Approval Number	Enter a flare/incinerate approval number if required by *Directive 060*.
Conserving Battery	If the facility type for a flaring, incinerating, or venting event is Battery, this field is automatically enabled. Select Yes to show gas is normally conserved and sold instead of being vented, incinerated, or flared. Select No to show that gas is not normally gathered and conserved at the battery.

Conversions

ppm x .001 = mol/kmol

ppb x .000001 = mol/kmol

% x 10 = mol/kmol

Flare approval numbers apply only to flaring/incinerating notifications

<table>
<tr><th>Field</th><th>Description</th></tr>
<tr><td>Flare/Vent/ Incinerate Location</td><td>
<table>
<tr><th>Licence</th><th>Location</th></tr>
<tr><td>Well</td><td>The surface location is automatically entered for well licences. This can be modified if required.</td></tr>
<tr><td>Facility</td><td>The LSD, section, township, range, and meridian are automatically shown for facilities. This may be modified if required.</td></tr>
<tr><td>Pipeline</td><td>Enter the exact location of the flaring, incinerating, or venting.</td></tr>
</table>
<table>
<tr><th>Field</th><th>Valid Values</th></tr>
<tr><td>LSD</td><td>01-16
LSD required if Township entered</td></tr>
<tr><td>Section</td><td>01-36
Required if Township entered</td></tr>
<tr><td>Township</td><td>001-126
Required if Meridian entered</td></tr>
<tr><td>Range</td><td>1-30 for W4 &W5
1-14 for W6
Required if Township entered</td></tr>
<tr><td>Meridian</td><td>W4, W5, W6
Required if Township entered</td></tr>
</table>
Required</td></tr>
<tr><td>Reason</td><td>Select the reason for the flaring, incinerating, or venting from the drop-down list. Options are Emergency, Planned Maintenance, Test, and Unplanned Maintenance.
Required</td></tr>
<tr><td>Public Notified</td><td>Select No to show that the public has not been notified of the flaring, incinerating, or venting operation. This is the default and you must explain how you have met flaring/incinerating notification requirements on the Notification Comments tab.

Select Yes to show that the public has been notified of the flaring, incinerating, or venting.</td></tr>
<tr><td>Resident Objections</td><td>Select Yes to show that there are resident objections to the flaring, incinerating, or venting operation. This is the default and you must explain the objection(s) and the appropriate solution on the Notifications Comments tab. If no solution was agreed to, explain the outcome of the objection (for example, hearing).

Select No to show that there were no objections to the flaring, incinerating, or venting.</td></tr>
<tr><td>Notification Comments</td><td>Explain how you have met the flaring/incinerating reduction requirements for flaring/incinerating/venting of gas from conserving facilities (Directive 60, Table 1), or enter comments about public notifications/ objections.</td></tr>
</table>

Please include as much information as possible in the Comments field. Include a secondary contact where possible.

7. Click **Submit** to submit the flaring, incinerating, or venting notification for validation. If errors are found, you are prompted to correct them.

   A DDS acknowledgement is shown on the terminal and e-mailed to the contact if requested for the DDS Login ID.

Appendix 11 Resident Flaring/Venting/Incinerating Notification Sample Form

We will be flaring/incinerating/venting a (___ % H_2S) well in accordance with EUB *Directive 060* at the location stated below.

Flaring/Incinerating/Venting Category (check those that apply)	**EUB Office (check one)**	
Well test flaring	Bonnyville	(780-826-5352)
Well test venting	Drayton Valley	(780-542-5182)
Well test incinerating	Grande Prairie	(780-538-5138)
	Fort McMurray	(780-743-7141)
(Check one)	High Level	(780-926-5399)
Oil well	Medicine Hat	(403-527-3385)
Gas well	Midnapore	(403-297-8303)
	Red Deer	(403-340-5454)
	St. Albert	(780-460-3800)
	Wainwright	(780-842-7570)

Flaring/Venting/Incinerating Comments	
Well Licence No.	
Well Name	
Location of Well (LSD)	
Estimated Flare/Incinerate/Vent Timing (30-day window)*	
Estimated Start Date	
Estimated End Date	
Flaring/Incinerating/Venting Duration	
Estimated Volume (10^3 m^3/day)	
Operator Name	
Operator Contact Name	
Contact Phone Number	
Testing Contractor	
Testing Representatives on Site	
Daytime Cell Phone Number	
Nighttime Cell Phone Number	
Emergency Phone Number	

Please phone (___) ___ - ____ if you would like notification 24 or 48 hours in advance of flaring/incinerating/venting operations.

- 30-day window is to accommodate for weather and operational delays.
- Renotification is mandatory after 90 days.

Note:____

____

If you have questions or concerns, please phone (___) ___ - ______

Appendix 12 Agreement on Zero Flaring

The following serves to outline the agreement between __________________________ (applicant) and __________________________ (landowner or occupant) respecting flaring at the well located at _______________________W___. The applicant agrees to not flare from the well prior to putting the well on production, except as stated below in this agreement or in an emergency. **Venting is not to be used as an alternative to flaring.**

Exceptions

Flaring may occur as indicated below and is limited to at most two of the activities:

- Well Testing Yes? ____ No?_____
- Well Cleanup Yes? ____ No?_____
- Drillstem Testing Yes? ____ No?_____

Emergencies

An operator may flare in emergency situations for safety of the public or environmental protection.

If the ownership of the well is transferred to another operator, this agreement will remain in effect for the new operator and it is the operator's responsibility to advise any successors of this agreement.

This agreement no longer applies once this well is tied into a production facility or upon commencement of production operations.

Applicant Signature_________________________	Landowner or Occupant Signature (optional)_________________________
Printed Name ______________________________	Printed Name_______________________________
Licensee __________________________________	Location__________________________________
Telephone_________________________________	Telephone_________________________________
E-mail/Fax_________________________________	E-mail/Fax_________________________________

Date ____________________________

Appendix 13 Request to Extinguish Sour Gas Flare Pilots

The following minimum requirements must be met in any situation where it is proposed to extinguish a flare pilot at a sour facility:

1) The maximum stabilized wellhead pressure must be determined based on the measured stabilized static wellhead pressure corrected for the hydrostatic head of any liquid present in the wellbore at the time of testing.

   a) This correction for the liquid column hydrostatic head must use the density of the produced water for the entire fluid column present in the wellbore.

   b) The maximum stabilized static wellhead pressure must be determined by a qualified well test professional using accepted engineering practices. EUB *Directive 040* provides regulations for conducting pressure tests on wells.

2) The following features must be incorporated into the facility for consideration of the request to extinguish the flare pilot:

   a) Nonfragmenting rupture disks must be installed on the upstream side of all pressure safety valves (PSVs). This is subject to Section 38(1)(b) of the *Pressure Equipment Safety Regulation* (AR 49/2006) administered by the Alberta Boilers Safety Association (ABSA).

      - A pressure gauge or suitable telltale indicator must be installed between each rupture disk and the corresponding PSV to allow detection of leakage or a disk rupture.

   b) Two block valves in series must be installed for manual depressurizing valves connected to the flare.

   c) The battery must be equipped with a pressure sensor, automatic emergency shutdown valves (ESDVs), and a control system configured to isolate the battery from the well and outlet gas pipeline. There must be no automatically controlled emergency depressurizing valves connected to the flare.

3) Upstream piping to the well must be designed for the maximum pressure that might be encountered. The *minimum* operating requirements for any facility approved for extinguishing flare pilots include the following:

   a) Operators must monitor and document on a weekly basis the pressure between rupture disks and PSVs.

   b) If a rupture disk fails or if odours result from gas released to the flare stack, the flare stack must be lit and immediate notification must be given to the appropriate EUB Field Centre, followed by a written incident report giving particulars. Approval to extinguish the flare pilot is then considered void until the operator demonstrates to the satisfaction of the appropriate EUB Field Centre that related problems have been successfully corrected.

   c) The sweet gas or propane pilot must be ignited prior to any flaring or depressurizing at the site.

   d) The operation of the emergency shutdown system, including ESDVs, must be verified and documented at minimum on an annual basis.

   e) EUB approval to extinguish the flare pilot must be visibly displayed at each site.

4) Residents within the emergency planning zone (EPZ) must be notified of plans to extinguish the flare pilot.

   a) Any concerns or objections of residents to extinguishing pilots must be addressed. Refer to the dispute resolution process discussed in Section 2.10 for guidance.

5) The following information must accompany the operator's request to extinguish flare pilots:

   a) a list of all wells connected to the battery, including

      i) normal wellhead operating pressure, and

      ii) maximum stabilized static wellhead pressure;

   b) the maximum design operating pressure of the piping and pressure vessel systems for the battery, including

      i) a list of all PSVs connected to the flare and related release set-pressures, and

      ii) a list of related rupture disks and burst pressures;

   c) written confirmation that

      i) none of the wells connected to the facility is completed in pools that have active injection or cycling schemes,

      ii) rupture disks on PSVs and two valves in series have been installed on all streams tied into the flare system,

      iii) maximum H_2S release rates will not exceed the level-1 or -2 sour well classification,

      iv) residents within the EPZ have been provided notification, and

      v) high-pressure shutdowns are in place, with a statement confirming calibration frequency.