Directive 060

Release date: **[Month XX, 20XX]**

Effective date: **[Month XX, 20XX]**

Upstream Petroleum Industry Flaring, Incinerating, and Venting

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Contents

Abbreviations

AAAQO	*Alberta Ambient Air Quality Objectives and Guidelines* (both the document itself and the objectives described therein)
AEPA	Alberta Environment and Protected Areas
AER	Alberta Energy Regulator
DVG	defined vent gas
EPEA	*Environmental Protection and Enhancement Act*
FEMP	fugitive emissions management program
MDT	minimum detection threshold
MRRCP	methane reduction retrofit compliance plan
NPV	net present value
OGCA	*Oil and Gas Conservation Act*
OGCR	*Oil and Gas Conservation Rules*
OSCA	*Oil Sands Conservation Act*
OVG	overall vent gas
PoD	probability of detection
RCS	reciprocating compressor seal

1 Introduction

1.1 Purpose of This Directive

The Alberta Energy Regulator (AER) *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting* contains the requirements for flaring, incinerating, and venting in Alberta at all AER-regulated petroleum industry wells and facilities as defined in sections 1(1)(w), (aa.1), and (eee) of the *Oil and Gas Conservation Act* (*OGCA*). *Directive 060* requirements also apply to pipeline installations that convey gas (e.g., compressor stations, line heaters) licensed by the AER under the *Pipeline Act*, geothermal resource developments licensed by the AER under the *Geothermal Resource Development Act*, and brine-hosted mineral resource development under the *Mineral Resource Development Act*. With the exception of oil sands mining schemes and operations, *Directive 060* applies to all schemes and operations approved under section 10 of the *Oil Sands Conservation Act* (*OSCA*). *Directive 060* does not apply to any processing plants approved under section 11 of *OSCA*.

Most of these requirements have been informed by and developed in consultation with stakeholders from industry, the public, other provincial and federal government agencies, nongovernmental organizations, and academia to eliminate or reduce the potential and observed impacts of these activities and to ensure that public safety concerns and environmental impacts are addressed before beginning to flare, incinerate, or vent. *Directive 060* requirements are also aligned to ensure compliance with Alberta Environment and Protected Areas (AEPA) *Alberta Ambient Air Quality Objectives and Guidelines* (AAAQOs).

Terms relevant to this directive are defined in appendix 1. Defined terms are presented in **bold** the first time they are used in each top-level section.

1.2 AER Requirements

Following AER requirements is mandatory for the responsible duty holder, as specified in legislation (e.g., licensee, operator, company, applicant, approval holder, or permit holder). The term “must” indicates a requirement, while terms such as “recommends” and “expects” indicate a recommended practice.

Each AER requirement is numbered.

Information on compliance and enforcement can be found on the AER website.

For the purposes of this directive, terms like annually or quarterly are defined as follows:

- Monthly is at least once per calendar month.

- Quarterly means at least once per calendar quarter (January through March, April through June, July through September, and October through December).
- Biannually means at a least once per six calendar months (January through June, and July through December).
- Triannually means at least once per four calendar months (January through April, May through August, and September through December).
- Annually means at least once every four calendar quarters.

For example, if a survey needs to be done annually and the last survey occurred in May 2025 (second quarter), the operator has to perform another survey by the end of the second quarter of 2026 (June 30).

1.3 What's New in This Edition

The section numbers have changed from previous editions, and requirements that used to be in various appendices have been moved unchanged into the main body of the document.

The new "General Requirements" section (section 2) contains much of the text that existed in section 1 of the previous edition.

The content from previous sections 4, 5, and 6 have been consolidated into a single new section 6 titled "Gas Facility and Infrastructure Flaring, Incinerating, and Venting."

A new "Emissions Research and Innovation" section (section 5) has been added, addressing emission research and innovation at emissions testing facilities

Section 7, "Performance Requirements," has been updated to allow signoff from a qualified person in lieu of AER approval in some instances.

Requirements around alternative fugitive emissions management programs (Alt-FEMPs) and FEMPs have been revised by expanding the current number of acceptable FEMPs and providing additional approaches and criteria for what acceptable alt-FEMPs need to include.

CSA Z620.3 performance requirements for flaring, incineration, and enclosed combustion have been incorporated.

Clarification has been added around how these requirements relate to geothermal operations and brine-hosted minerals.

1.4 Access to Production Flaring, Incineration, Enclosed Combustion, and Venting Data

The AER reports flaring, incineration, enclosed combustion, and venting volumes annually in *ST60B: Upstream Petroleum Industry Emissions Report* on the AER website www.aer.ca.

The AER also makes flaring, incineration, enclosed combustion, and venting information available to licensees, operators, and approval holders in order to facilitate solution gas conservation and **clustering** opportunities.

2 General Requirements

Flaring, incinerating, **enclosed combustion**, and venting are associated with a wide range of energy and mineral resource development activities and operations, including the safe disposal of gas associated with drilling, completion, well testing, production, and routine and nonroutine events, as well as managing unplanned upset conditions.

2.1 Flaring, Incineration, Enclosed Combustion, and Venting Decision Tree

1) The licensee or **operator** must use the decision tree shown in figure 1 to evaluate all new and existing **routine** and **nonroutine** flares, **incinerators**, enclosed combustors, and vents, regardless of volume (except for intermittent small sources less than 100 m^3 per month) that are associated with **gas battery**, dehydrator, compressor station, gas plant, and pipeline flaring, incinerating, and venting at existing **sites**. New sites must apply the decision tree shown in figure 1 before application as part of the **facility** design.
2) The licensee or operator must be able to demonstrate how each element of the decision tree was considered and (where appropriate) implemented and provide the analysis to the AER upon request.
3) These evaluations must be also updated before any **planned flaring**, **incinerating**, enclosed combustion, or **venting** occurs.

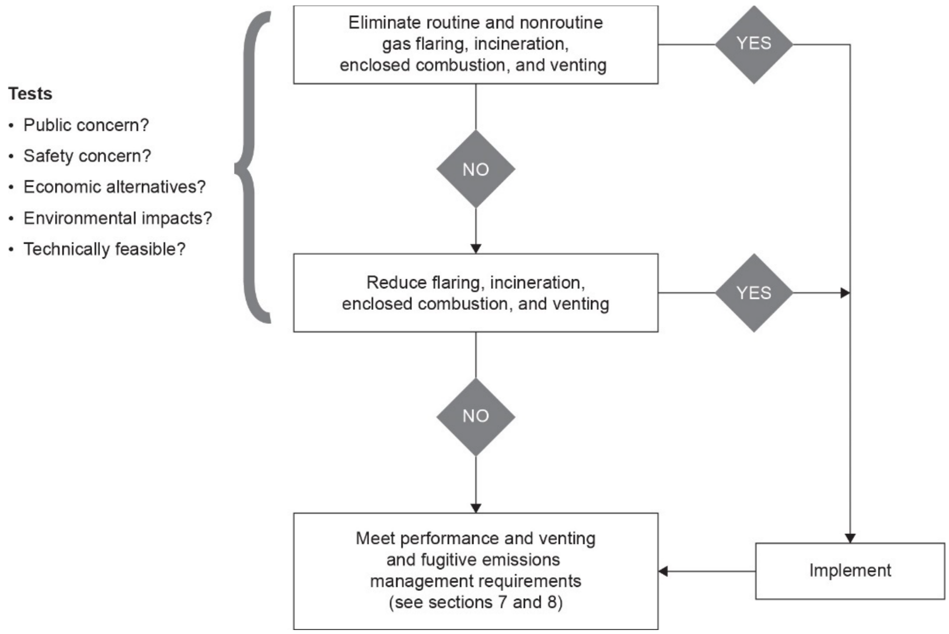


Figure 1. Routine and nonroutine flaring, incineration, enclosed combustion, and venting decision tree

The AER considers **conservation** the best alternative to reduce flare, incineration, enclosed combustion, and vent volumes, followed by combustion to reduce vent volumes. If venting is the only feasible alternative, refer to section 8 for additional requirements.

4) If gas volumes are greater than the applicable limits of section 8 or are sufficient to sustain combustion, the gas must be conserved or destroyed.

5) The licensee or operator must document alternatives that were considered to eliminate or reduce flaring, incineration, enclosed combustion, and venting, how they were evaluated, and the outcome of the evaluation.

6) The licensee or operator must assess opportunities and implement measures to conserve gas or reduce nonroutine flaring, incineration, enclosed combustion, and venting of gas due to the following scenarios:

   a) frequent maintenance or facility shutdowns (one or more events per month) that are a result of the same, related, or interdependent root cause of a nonroutine flaring incineration, enclosed combustion, or venting event

   b) the depressurizing of pipeline systems

7) The licensee or operator must address concerns or objections of residents and **schools** notified in accordance with table 1 related to nonroutine gas battery and gas plant flaring.

8) The sulphur recovery requirements of section 9 and *Interim Directive (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 (e.g., compressor or dehydrator sites).

2.2 Notification Through the Designated Information Submission System

1) The licensee, operator, or approval holder must notify the appropriate AER field centre before planned flaring, incineration, enclosed combustion, or venting operations by completing and submitting an AER flaring/incineration/enclosed combustion/venting notice form within the designated information submission system.

The AER strongly encourages all licensees, operators, and approval holders to follow the OneStop help (available on the AER website) when completing and submitting this form.

2) The licensee, operator, or approval holder must notify the appropriate AER field centre of any operations that may result in a public complaint or concern.

2.3 Notification Requirements

Table 1 outlines scenarios where notification is required, including thresholds for duration of event and volumes. These thresholds are cumulative values resulting from flaring, incineration, enclosed combustion, or venting that occur during any rolling 24-hour period, including consecutive and nonconsecutive. The notification requirements in this section are applicable to all known, planned, or scheduled nonroutine flaring, incineration, enclosed combustion, and venting activities. The requirement is to notify. Consent is not required.

1) The licensee, operator, or approval holder must notify all of the following 24 to 72 hours before planned flaring, incineration, enclosed combustion, or venting operations in accordance with table 1:

    a) all residents and schools within the specified radius

    b) appropriate AER field centre via the designated information submission system, including a contact name and telephone number in case of complaints or emergencies

    c) all rural residents outside towns, villages, and urban centres and within the specified radius

    d) the chief administrative officer or equivalent of a town, village, or urban centre within the specified radius (for incorporated centres and hamlets, it is sufficient to contact only the appropriate administrator)

Table 1. Temporary flaring, incineration, enclosed combustion, and venting notification requirements*

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‡
Temporary and planned nonroutine flaring, incineration, enclosed combustion, or venting	<4	and	<30	No notification
Temporary and planned nonroutine flaring, incineration, enclosed combustion, or venting if gas contains ≤10 mol/kmol H_2S	>4	or	>30	Residents, schools, 1.5 km radius; AER field centre
Temporary and planned nonroutine flaring, incineration, enclosed combustion, or venting if gas contains >10 mol/kmol H_2S	>4	or	>30	Residents, schools, 3 km radius; AER field centre
Temporary and planned nonroutine flaring, incineration, enclosed combustion, or venting through a permanent battery or plant	<4		--	No public notification; Notify the AER if flaring >30 10^3 m^3
Temporary and planned nonroutine flaring, incineration, enclosed combustion, or venting through a permanent battery or plant	>4		--	Residents, schools, 0.5 km radius; AER field centre

* See section 2.2 for information on the designated information submission system and how to notify the appropriate AER field centre.

† Volumes include those from flowback operations. These gases may be hydrocarbon or gases used in fracturing fluids (carbon dioxide or nitrogen) in any mixture.

‡ The AER recommends additional "good neighbour" notification for all temporary flaring, incineration, enclosed combustion, and venting activities for residents and schools that have identified themselves to the licensee, operator, or approval holder as being sensitive to or interested in emissions from the facility within the same notification radius as specified for events of more than four hours.

2) Where advance notification of more than 72 hours (but not longer than 90 days) has occurred, the licensee, operator, or approval holder must also offer the option for renotification 24 to 72 hours before the start of operations. After 90 days, renotification is mandatory.

3) For reporting purposes, hydrocarbon volumes must be distinguished from fracture gas volumes (see section 3.8).

4) Upon AER request, the licensee, operator, or approval holder must provide a list of residents and schools notified within the specified notification radius, as well as a sample of the information provided to residents.

5) Unless the licensee, operator, or approval holder has reached a documented and written agreement with current residents or schools for an alternative method of notification,

notification must be in writing (see appendix 3) and include the following basic information about the flaring, incineration, or venting:

a) licensee, operator, or approval holder's name, contact persons, and telephone numbers

b) the locations of the flaring, incineration, enclosed combustion, or venting

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

d) the 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

f) AER field centre contact telephone number

6) The licensee, operator, or approval holder may conduct a one-time notification program for multiple-well projects in an area that includes the basic information from above, unless the licensee, operator, or approval holder has reached a documented, written agreement with current residents or schools for an alternative method of notification.

7) The licensee, operator, or approval holder may limit the number of repeat notifications to individual residents or schools if

a) the resident or school requests that the number of notifications be reduced;

b) the licensee, operator, or approval holder provides the resident or school with an outline of expected flaring and incineration activities in the area; and

c) the licensee, operator, or approval holder has a written agreement to reduce notifications and obtains acceptance of the agreement in writing from the resident or school.

8) A copy of any written agreements must be provided to the AER upon request.

9) The licensee, operator, or approval holder may conduct a single notification to each resident and school within the notification area and the appropriate AER field centre, rather than a separate notification for each flaring, incineration, enclosed combustion, or venting period throughout the program, if this is acceptable to the current residents and the AER, respectively. The method of notification must be discussed during the initial notification process.

The AER recommends that the licensee, operator, or approval holder consider placing signage on public roads surrounding the temporary flaring or incineration operations indicating the operation type and the contact phone number for inquiries.

2.4 Addressing Resident Concerns

Compliance with *Directive 060* ensures that licensees, operators, and approval holders have considered public safety and environmental impacts before flaring, incineration, enclosed combustion, and venting activities; however, additional concerns or complaints may be expressed by nearby residents or schools regarding impacts of the operational aspects of flaring, incineration, or enclosed combustion (e.g., timing of flaring and associated traffic). The following ensure that the concerns of nearby residents and schools are addressed:

The AER encourages the licensee, operator, or approval holder to work with nearby residents and schools before commencing proposed and existing flaring, incineration, or enclosed combustion activities.

1) The licensee, operator, or approval holder must disclose any unresolved concerns of nearby residents and schools to the appropriate AER field centre before commencing those activities.

2.5 Zero-Flaring Agreements

Flaring is allowed by the AER when done in accordance with *Directive 060*. However, parties may agree to zero flaring, as set out in a zero-flaring agreement (see appendix 4). The agreement must be signed by both parties and filed by the applicant with the well application. Once filed, the zero-flaring agreement becomes a condition of the well licence. Should the licensee, operator, or approval holder fail to adhere to this agreement, operations at the well may be suspended.

Once the well or facility is licensed, if the licensee, operator, or approval holder needs to change this zero-flaring agreement, it must file an application to change the agreement with the AER, with a copy to the co-signers.

1) An application to change a zero-flaring agreement must include the following:
    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
    d) a summary of the consultation and notification that have been done, including confirmation of agreements reached with the parties affected by this agreement
2) Until the AER decides on this application, flaring may only occur as set out in the original zero-flaring agreement.
3) For oil wells, agreement not to flare during well testing means that the licensee, operator, or approval holder has agreed to initially conserve the gas. Later, if it becomes uneconomic to conserve the gas, the licensee, operator, or approval holder must follow the process in section 4.2(5) of this directive to discontinue conservation.

4) The licensee, operator, or approval holder must try to address any landowner or occupant concerns and may use the AER's alternative dispute resolution process if that becomes necessary before applying to the AER to change the zero-flaring agreement.

3 Temporary Nonroutine Flaring, Incinerating, Enclosed Combustion, and Venting

This section applies to both planned and **unplanned** temporary flaring, incineration, **enclosed combustion**, and venting activities through temporary or permanent flare, **incinerator**, or enclosed combustion equipment. Planned **nonroutine flaring, incineration, enclosed combustion, and venting** events (e.g., well servicing, maintenance blowdowns, pipeline depressurizing, turnarounds, well clean up, and well testing) may require a temporary flaring or incineration permit, as described in figure 2. In this section, the terms "incineration" and "enclosed combustion" are used interchangeably except where noted. Unplanned nonroutine flaring and incinerating (e.g., process upsets, emergencies) do not require a temporary permit.

3.1 Decision Tree

1) Licensees must evaluate opportunities to use existing gas gathering systems before beginning temporary maintenance, well cleanup, or testing operations (e.g., "in-line testing"). In-line testing must be done 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 flare permit requests (section 3.4).

2) If in-line testing is not possible, licensees must design completions and well testing programs to minimize emissions while ensuring technically sound well completion and acquisition of sufficient reservoir and productivity information for future development decisions. Refer to *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells* regarding the minimum pressure and deliverability requirements for well testing and on the recommended practices.

3.2 Duration Limits Around Oil and Gas Well Tests

1) Table 2 summarizes the applicable duration limits and associated volume allowances for nonroutine flaring, incineration, enclosed combustion, and venting activities related to oil, gas, coalbed methane, and **condensate**. These time limits are per zone, are nonconsecutive, and do not include shut-in time. These periods include flaring, incinerating, enclosed combustion, and venting during cleanup, completion, workover, and testing. Licensees and **operators** must not exceed the following flaring, incinerating, enclosed combustion, and venting time limits:

    a) **crude oil** wells and **sites**: 72 hours

    b) gas (**nonassociated**, noncoalbed methane, helium) wells: 72 hours

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

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

e) bitumen wells/sites: until flow rates exceed an average of 900 m^3/day for any consecutive three-month period, not to exceed six months (see section 4.3)

f) wet coalbed methane wells (producing more than 1 m+ of water per operating day): see requirement 7 below

Table 2. Summary of well testing duration limits and volume allowances

Licensed well	Duration limit (Cumulative, nonconsecutive hours of flaring)	Duration limit extension	Volume allowances			Additional volume
Gas (nonassociated, non-coalbed, helium)	72 hours as per section 3.2(1)(b), or cleanup complete and stabilized flow reached as per section 3.2(6).	Yes, as per section 3.2(2). Maintain records of supporting justification and submit with the final flare summary report.	Tier 1 ≤600 10^3 m^3	Tier 2 ≤400 10^3 m^3	Tier 3 ≤200 10^3 m^3	200 10^3 m^3 each additional zone: section 3.3.1(2)(d)
Bitumen	Any consecutive 3 months >900 m^3/d average or 6 months whichever is less as per section 4.2(2)	No.	Directed by conservation requirements of section 4.2 and 4.4. Section 4.7 economic assessment to occur when >900 m^3/d (3-month average).			No
Crude oil	72 hours as per section 3.2(1)(a), or cleanup complete and stabilized flow reached as per section 3.2(6).	Yes, as per section 3.2(2). Maintain records of supporting justification along with the section 4.7 economic assessment and submit with the final flare summary report.	Directed by conservation requirements of sections 4.3 and 4.4. Section 4.7 economic assessment to occur when >900 m^3/d during the testing period			No
Condensate (condensate wells are licensed as either a gas well or an oil well)	72 hours as per sections 3.2(1)(a) or (b), or cleanup complete and stabilized flow reached as per section 3.2(6).	Yes, as per section 3.2(2). Maintain records of supporting justification and submit with the final flare summary report.	Directed by conservation requirements of sections 4.3 and 4.4. Section 4.7 economic assessment to occur when >900 m^3/d during the production period.			Section 3.3.1(2)(d) (where licensed as a gas well)

Licensed well	Duration limit (Cumulative, nonconsecutive hours of flaring)	Duration limit extension	Volume allowances			Additional volume
Dry coalbed methane, development well (>1 m^3 produced water)	120 hours as per section 3.2(1)(c), or cleanup complete and stabilized flow reached, as per section 3.2(6).	Yes, as per section 3.2(2). Maintain records of supporting justification and submit with the final flare summary report.	Tier 1 ≤600 10^3 m^3	Tier 2 ≤400 10^3 m^3	Tier 3 ≤200 10^3 m^3	200 10^3 m^3 each additional zone: section 3.3.1(2)(d)
Dry coalbed methane, non-development well (>1 m^3 produced water)	336 hours as per section 3.2(1)(d), or cleanup complete and stabilized flow reached, as per section 3.2(6).	Yes, as per section 3.2(2). Maintain records of supporting justification and submit with the final flare summary report.	Tier 1 ≤600 10^3 m^3	Tier 2 ≤400 10^3 m^3	Tier 3 ≤200 10^3 m^3	200 10^3 m^3 each additional zone: section 3.3.1(2)(d)
Wet coalbed methane (>1 m^3 produced water)	As per section 3.2(7), within 6 months of the well exceeding a cumulative volume of 100 10^3 m^3 during any consecutive 3-month period or the lesser of either 18 months or the Lahee classification tier allowances of 3.3.1(2)(a) are reached	Written request as per section 3.2(7) that justifies the request.	Directed by conservation requirements of section 3.2(7). Gas must conserved within 6 months of the well exceeding a cumulative volume of 100 10^3 m^3 during any consecutive 3-month period or the lesser of either 18 months or the Lahee classification tier allowances of 3.3.1(2)(a) are reached.			Written request as per section 3.2(7) that justifies the request

2) Extensions to the time limits listed in requirement 1(a), (b), (c), and (d) above are allowed, without AER approval, if any of the following are true:

   a) Cleanup of the wellbore is not complete. Cleanup is considered complete when sand, proppant, or acid is no longer produced or when the gas composition meets the minimum pipeline specifications for the nearest pipeline that could accept the gas.

   b) Stabilized flow has not been reached (see section 4.3 of *Directive 040* and section 7.1 of *Directive 034: Gas Well Testing, Theory and Practice*).

   c) There have been mechanical problems with the well.

3) When approval is not required, the licensee must still do the following:

   a) Document the reasons for extension and keep the information on file for review or audit by the AER when requested.

b) Notify the appropriate AER field centre in advance through the designated information submission system as soon as the licensee recognizes that the time limit will be exceeded. The licensee must include reasons for the extension and the expected duration of the flaring, incinerating, enclosed combustion, and venting.

c) If audited, the licensee must justify the need to exceed the time limitation to the AER field centre's satisfaction, or the licensee may be subject to a regulatory response.

4) If more time for well test flaring, incineration, enclosed combustion, or venting is needed for situations other than those identified in requirement 2 above, the AER must be contacted for approval to continue as soon as possible, and no later than the end of the specified testing period.

5) If a temporary flaring/incineration/enclosed combustion permit has been issued, the volume allowed in the permit will take precedence over the time limit described in requirement 1 above.

6) When well test information indicates that cleanup is complete and the well flow is stabilized and all other AER requirements are met (e.g., *Directive 040*), flaring, incineration, enclosed combustion, and venting must be discontinued, even if the time limit or the flaring/incineration permit volume has not been reached. This requirement does not apply to bitumen or wet coalbed methane wells.

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 six months of gas production for an individual well exceeding a cumulative total of 100 10^3 m^3 for any consecutive three-month period (about 1100 m^3/day). Shorter tie-in periods must be pursued wherever possible.

a) Licensees must notify the AER as soon as the cumulative total gas production exceeds 100 10^3 m^3 for any consecutive three-month period at a wet coalbed methane well that is flaring, incinerating, performing enclosed combustion, or venting.

b) For wet coalbed methane wells that do not trigger the requirement above, flaring, incineration, 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) the total cumulative volumes presented in section 3.3.1(2)(a).

c) If additional flaring, incineration, enclosed combustion, 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 licensee must make a written request to the AER as early as possible and no later than the end of the 18-month or volume allowance flare, incineration, enclosed combustion, or vent period. Any request must include the reasons for the extension.

3.3 Permits

Figure 2 depicts the permitting process. Permit conditions apply to planned nonroutine events that are temporary. The AER may suspend well flaring, incineration, or enclosed combustion for noncompliance with conditions of the permit. The licensee must comply with the conditions of the permit.

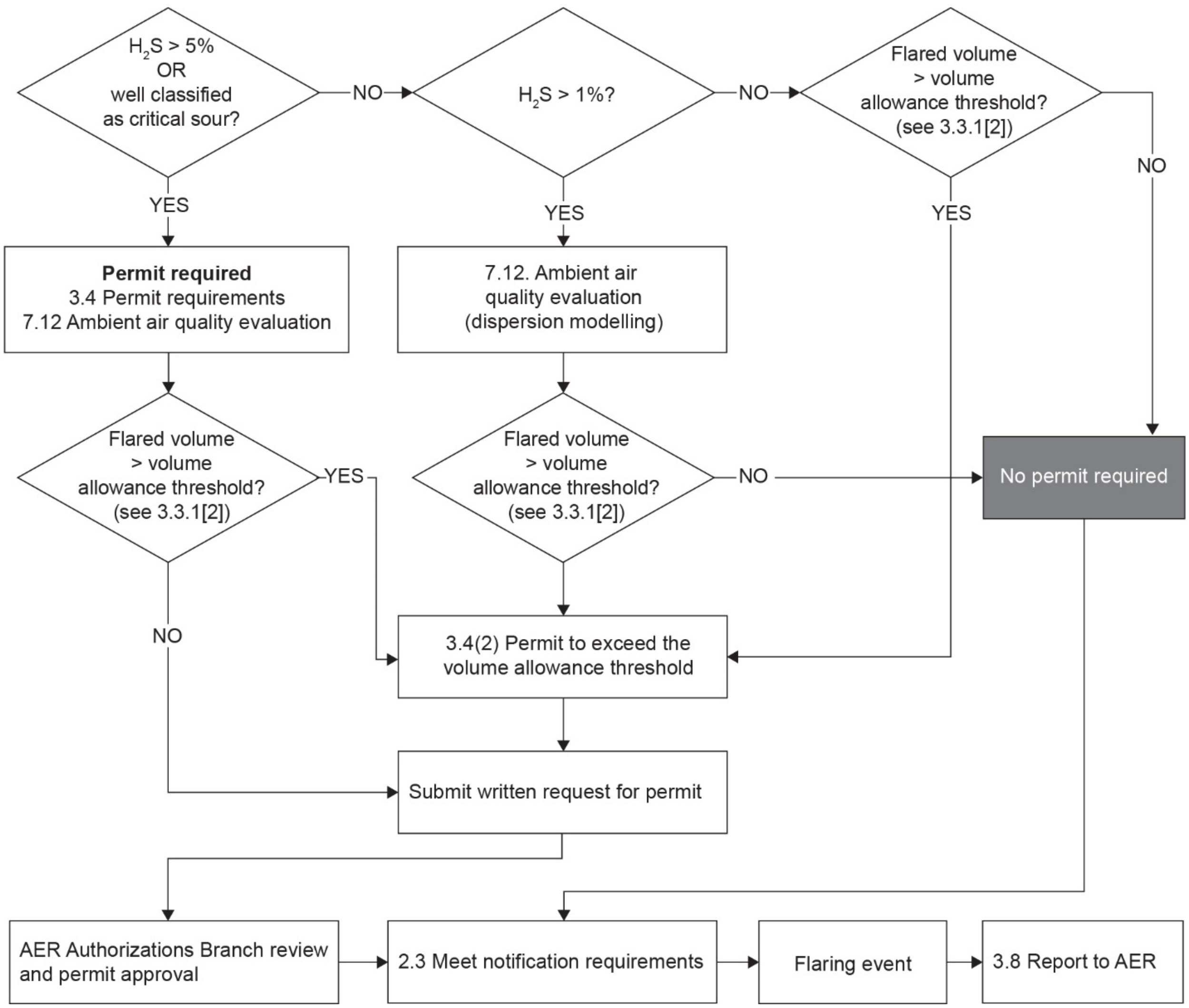


Figure 2. Temporary flaring/incineration/enclosed combustion permit process

3.3.1 Conditions That Require a Permit

1) Licensees must obtain a permit to flare, incinerate, or combust **sour gas** containing more than 50 mol/kmol H_2S (5 per cent) or sour gas from any well classified as critical sour as per *Directive 056: Energy Development Applications and Schedules*.

   a) If operations result in H_2S concentrations that are higher than concentrations at the well (e.g., flaring gas from tanks), the composition of the gas to be burned must be determined in order to establish 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) Licensees must obtain a permit for temporary flaring or incineration of natural gas if gas well test volumes exceed the volume allowance thresholds outlined below. This is based on the volume of gas flowed back from the well (and does not include fuel gas added or volumes from vented nitrogen or carbon dioxide used in fracturing fluid). The volume and duration limits for **crude bitumen** and crude oil well tests are presented in sections 4.3 and 4.4, respectively.

   a) The following volume thresholds apply to gas well (including helium production) tests only. The thresholds are divided into three tiers based on the volume of raw gas flowed back from the well (not including fuel gas added and carbon dioxide [CO_2] or nitrogen used for hydraulic fracturing):

      i) **Tier 1 ≤600 10^3 m^3:** applies to gas 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 gas 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 gas well that has been tied in to facilities appropriately designed to handle production from the formation being tested (e.g., sweet versus sour service).

   b) The volume allowance threshold for a re-entry gas well is the same as the one 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 as the one that applied to the gas well before it was reclassified as experimental or that normally would have applied to the gas 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 AER.

ii) The incremental allowance does not apply to single tests over multiple commingled zones.

3) 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 Permit

Even if a permit is not required, the requirements in sections 2.3, 3, 7, and 8 still apply.

1) A permit is not required if the gas contains 50 mol/kmol H_2S (5 per cent) or less and the total volume (for gas well tests) is less than the volume allowance threshold (see section above).

a) Licensees must evaluate compliance with the one-hour AAAQO for SO_2 if the gas contains more than 10 mol/kmol H_2S (1 per cent). Related dispersion modelling results must be provided to the AER upon request.

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

a) Maximum **sulphur emission** rates do not exceed 1.0 tonne/day over the duration of the event.

b) Total flared, incinerated or combusted volume do not exceed 50 10^3 m^3 over the duration of the event.

c) Equipment is designed to ensure compliance with the one-hour AAAQO for SO_2 or operating procedures are in place to ensure compliance with the AAAQOs. Related dispersion modelling evaluations and design information are documented and available to the AER upon request.

d) Rates and volumes are measured and reported as defined in section 3.8.

e) Notification is provided to the AER. Notification includes total expected gas volumes and sulphur emissions. If applicable, notification provides an explanation of any air quality management plans needed to ensure compliance with the AAAQOs.

3) The AER does not require temporary permits for the use of permanent flares, incinerators or enclosed combustors installed in AER-licensed facilities, including batteries, compressor stations, and gas plants provided that licensees can show, on request from the AER or field centre staff, that

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

b) the flares, incinerators or enclosed combustors are designed to operate safely under the intended conditions in compliance with the AAAQO; and

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

4) Similarly, the AER does not require temporary permits for unplanned nonroutine events such as emergencies. Refer to section 7 performance requirements to ensure that temporary nonroutine systems are adequately designed to operate safely under anticipated emergency and upset conditions.

For planned nonroutine events, including maintenance blowdowns, pipeline depressurizing, and turnarounds, licensees must obtain a temporary permit if required by section 3.3.1, unless exempted in (2) or (3) above.

The AER does not require temporary permits for flaring at oil and bitumen batteries. Refer to the conservation requirements described in section 4.

3.4 Permit Application Requirements

1) Requests for temporary permits must be submitted to the AER via email (Directive060Inbox@aer.ca) and must include complete information on the proposed activity, as requested in the AERflare-incin spreadsheet (available on the AER website) and summarized as follows:

a) a cover letter requesting a permit and informing the AER of any public objections to or concerns about the proposed flaring/incineration

b) information about the site on which flaring/incineration will occur, including location, Lahee classification, and related National Topographical System 1:50 000 scale maps

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

d) information on **planned flaring/incineration/enclosed combustion**, including reasons (e.g., well testing, completions, pipeline depressurizing), H_2S content, flow rates, total volumes, and type of combustion device to be used (i.e., flare or incinerator)

e) if H_2S is present, information on the licensee's assessment of effects on ambient air quality, including results of dispersion modelling for SO_2

f) if H_2S is present, in situations with potential to exceed the **risk-based criteria** (see section 7.12.4) for SO_2, information on the licensee's proposed air quality management plan to prevent exceedances

Any inconsistencies in the request or modelling will result in the request being rejected and returned to the licensee. Permit requests are processed in the order received, and resubmissions will be treated as new permit requests.

2) Requests for a permit due to exceeding the volume allowance threshold must also include the following:

   a) Licensees must provide specific engineering, economic, and operational information to justify flaring, incinerating, or enclosed combustion gas volumes in excess of the volume allowance threshold.

   b) Requests relating to tests to determine if enough 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 requirement 4 below and section 3.5).

   c) Requests relating to tests to determine the relationship between absolute open flow 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 *Directive 040*.

   d) 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 identification of any analogous wells being used for comparison purposes.

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

4) 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 (Licensees may use simplified "netback" economics showing the current operating profit to estimate the recoverable reserves required to pay out facility investment costs; alternatively, licensees 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 licensee must provide a brief description justifying this depletion in relation to the minimum economic reserve.)

g) Justification for pretest cleanup and servicing flaring or incineration if related volumes exceed 200 10^3 m^3

The recommended maximum pressure depletion guidelines are

- 1 per cent of the first 5000 kPa of reservoir pressure, and
- 0.5 per cent 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.

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.

The AER has discretion to deny or approve requested volumes, rates, or conditions. Consideration will be given to total volumes, total sulphur emissions, local land uses, proximity of residences, and potential for exceedance of the AAAQOs before a permit is granted. AER staff will consult with licensees in such situations.

3.5 Flaring and Incineration Permits for Underbalanced Drilling

Permit requirements (section 3.3) and notification requirements (section 2.3) for temporary flaring and incineration also apply to underbalanced drilling.

1) Underbalanced drilling requests must include the following information:

   a) an explanation and supporting documentation on how flaring or incineration rates are determined; possible sources of these estimates are

      i) offset well absolute open flow tests or

      ii) flaring or incineration rates from offset underbalanced drilling operations

   b) the estimated time required to drill the well

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

3.6 Site-Specific Requirements

The following requirements apply to the use of temporary flares, incinerators, and enclosed combustors. Design and operational requirements for temporary flares and incinerators are outlined in section 7.

1) Flares, incinerators, and enclosed combustors must not be operated outside design operating ranges as specified by the designing or reviewing **qualified person** who is a member of the association as defined in the *Engineering and Geoscience Professions Act*.

2) Licensees must determine the H_2S content of flared, incinerated, or combusted gas using Tutweiller or gas chromatography methods as soon as is practical after beginning operation if gas analysis has not been done 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, incineration, or enclosed combustion permit has been issued by the AER, 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 AER field centre notified. Operations must not resume until a permit or permit amendment is issued by the AER 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 more detail, see the most current edition of *Industry Recommended Practice Volume 4: Well Testing and Fluid Handling* from Energy Safety Canada.

3.7 Temporary Facilities for In-Line Tests

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

Section 3.7 of this directive does not apply to **oil batteries**. However, *Directive 056* application requirements apply to both temporary and permanent oil batteries.

1) For extended tests or multiple tests that require temporary facilities to operate for more than 21 days, the licensee or operator must complete an application (see *Directive 056*).

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

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

4) Despite the exemptions and provisions in sections 5.4.3 and 5.6.8 of *Directive 056*, temporary compressors used for testing new gas well production where the gas will be flared, incinerated, or combusted require a licence under *Directive 056*.

Public and AER field centre notification requirements and public consultation requirements for temporary compression and pipeline facilities are provided in *Directive 056*.

5) Any notification made under *Directive 056* related to temporary facilities must include a description of the proposed equipment (including relevant capacities), driver type, and layout (e.g., give the compressor power rating and note whether the driver type is gas, diesel, or electric).

Directive 077: *Pipelines – Requirements and Reference Tools* contains a checklist regarding temporary surface pipelines for well testing purposes.

AER field centre approvals for temporary facilities are valid for 21 days and include the dismantling and removal of temporary facilities (including pipelines) from the lease. Any exceptions, including allowances for downtime during testing, must be referred to the appropriate AER field centre for further review.

Temporary facilities, including pipelines, must comply with relevant AER requirements, including the following:

- Noise control requirements are provided in *Directive 038*: *Noise Control*.
- Emergency response plan requirements for sour operations using temporary equipment are provided in *Directive 071*: *Emergency Preparedness and Response Requirements*.

Requirements for temporary installation of regenerative sweetening processes with **acid gas** are provided in *Directive 056*. All temporary or permanent regenerative sweetening facilities require an *Environmental Protection and Enhancement Act* (*EPEA*) sour **gas processing plant** approval.

3.8 Reporting Gas Well Test Data

1) Well test results and information required by flaring, incineration, and enclosed combustion permits must be submitted in accordance with the requirements of *Directive 040*, the applicable permit, and section 3.9.

   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, incinerator, enclosed combustor, vent, or pipeline, as well as all gas analyses from samples gathered at the wellhead.

   b) Submissions must be in a pressure ASCII standard (PAS) format and submitted via the well test data capture system in the designated information submission system.

For questions on these submissions, email the well test help line at Welltest-Helpline@aer.ca.

2) For all well tests that require permits, a sour gas flaring/incineration data summary report must be submitted to the AER within three weeks of the completion of flaring or incineration (see section 3.9, the issued flare permit conditions, and the AERflare-incin spreadsheet).

3.9 Nonroutine Flaring, Incineration, Enclosed Combustion, and Venting Records (Logs)

1) The licensee, operator, or approval holder must maintain a log of flaring, incineration, enclosed combustion, and venting events and respond to public complaints in order to comply with release reporting requirements.

   a) Release reporting requirements are defined in *EPEA* and the *Release Reporting Regulation* and are clarified in the AEPA's *A Guide to Release Reporting*.

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

   c) Logs must describe each nonroutine flaring, incineration, enclosed combustion, and venting incident and any changes made to prevent future nonroutine events from occurring.

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

   e) Logs must be kept for at least 12 months.

2) All records kept under this section must be made available to the AER upon request.

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

3) In situations governed by temporary flaring/incineration permits, a sour gas flaring/incineration/enclosed combustion data summary report must be completed in full and submitted to the AER within three weeks of the flaring/incineration completion date (available at Regulating Development > Rules and Directives > AER Forms > Directive Forms > *Directive 060* >Appendix 6).

4) All flaring, incineration, enclosed combustion, and venting at a well site (including well tests) must be reported on the appropriate production reporting submissions, including Petrinex (see *Directive 007: Volumetric and Infrastructure Requirements*). All routine and nonroutine volumes of gas combusted in a flare, incinerator, or enclosed combustor must be reported as "flare gas" in Petrinex.

4 Solution Gas Management

Combustion of **solution gas** using a flare, **incinerator**, or an **enclosed combustor** is not considered an alternative to **conservation**, and all volumes must be reported as flared. Conservation opportunities are evaluated as economic or uneconomic based on the criteria listed in section 4.7.

In this section, for the "combined flared and vented volumes," the vented volumes must not exceed the **vent gas** limits in section 8.

4.1 Solution Gas Flaring Reduction Targets

The Alberta solution gas flaring limit is 670 million cubic metres (10^6 m^3) per year

If solution gas flaring exceeds the 670 10^6 m^3 limit in any year, the AER 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.

4.2 General Conservation Requirements

These requirements apply to all **condensate** producing sites, **crude oil batteries**, and **crude bitumen batteries** unless otherwise specified. Requirement 1(a) below also applies to sites licensed under the *Geothermal Resource Development Act* and the *Mineral Resource Development Act*.

1) The licensee or **operator** must conserve gas at all sites where any of the following criteria are met:

    a) The combined volume of **flare gas** and vent gas is greater than 900 m^3/day per site, and the decision-tree process and economic evaluation (see section 4.7) result in a net present value (NPV) greater than –Cdn$55 000.

b) The gas-oil ratio is greater than 3000 m^3/m^3. All wells producing with a gas-oil ratio 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.

c) The AER directs the licensee, operator, or approval holder to conserve flare gas and vent gas, regardless of economics.

2) Conserving facilities within 500 m of a residence with first gas disposition before January 1, 2020, must continue conservation if gas production volumes are greater than 900 m^3/day, regardless of economics. After January 1, 2020, where unconserved gas volumes greater than 900 m^3/day are combusted within 500 m of a residence, licensees or operators must use an incinerator (a flare is not permitted within 500 m of a residence).

3) For any nonconserving site with a combined flared and vented volume greater than 900 m^3/day, an economic evaluation must be completed using the criteria in section 4.7.

The AER may require an economic evaluation for any site that is not conserving and has a combined volume of flare gas and vent gas less than 900 m^3/day if we believe that conservation may be feasible.

4) Conserving facilities must be designed for 95 per cent **conservation efficiency** with a minimum in-service operating time of 90 per cent on an annual basis.

5) If the licensee or operator wishes to discontinue conservation once it has been implemented at any **facility**, including sites where the produced solution gas volumes have dropped below 900 m^3/d, the licensee or operator must submit a request to the AER via email (Directive060Inbox@aer.ca) for approval. The request must include the following:

a) a completed decision tree to evaluate alternatives to discontinuing conservation

b) information on actual annual operating expenses and revenues

c) confirmation of notification to the appropriate AER field centre and residents within 500 m of the intention to discontinue conservation and initiate flaring or venting at a site

d) if conservation facilities are not operational, proof of compliance with table 3 until such time as approval from the AER to discontinue conservation is granted

4.3 Conservation at Crude Bitumen Batteries

1) The licensee or operator of a multiwell bitumen site must build solution gas conservation lines to one common point on the lease as part of initial construction.

2) For new bitumen wells, the test period (excluding completion and cleanup operations) limit is either six months or until combined flared and vented volumes at the site exceed a rolling average of 900 m^3/day for any consecutive three-month period, whichever is less.
   a) As soon as testing shows that combined flaring and venting volumes at the site exceed 900 m^3/day, conservation must be evaluated as described in section 4.7. Volumes are calculated based on a three-month rolling average.
   b) If conservation is required, it must occur as quickly as possible and not extend for more than six months after flow-rate determination. Wells must be shut in if the required conservation is not implemented within the timelines noted above.

Refer to section 8 for the vent gas volume limits from well testing.

4.4 Conservation at Conventional Crude Oil Batteries and Condensate Producing Sites

1) For new oil and condensate wells, 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 72 hours (see section 3.2 and table 2 for further details and extensions to time limits).
2) Upon completion of the testing period, if testing shows that combined flaring and venting volumes at the site will exceed 900 m^3/day, solution gas conservation must be evaluated as described in section 4.7. The wells must be shut in at the end of the test period and remain shut in pending the results of the solution gas conservation evaluation process.

Refer to section 8 for the vent gas volume limits from well testing.

4.5 Clustering

Solution gas is economic to conserve in some areas if licensees and 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 4.7) will be enhanced if conservation is incorporated into the initial planning of larger multiwell projects.

1) Licensees or operators of active production facilities operating within three kilometres (km) of each other or other appropriate oil and gas facilities (including pipelines) must evaluate **clustering** when evaluating solution gas conservation economics.

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

2) The licensee or operator of a multiwell oil or bitumen development 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) The licensee or operator 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* for multiwell oil or bitumen developments must include a summary of the gas conservation evaluation and a description of the licensee or operator's related project plans.

4.6 Power Generation Using Otherwise-Flared/-Vented Gas

Power generation is a means of conserving solution gas. The operator or licensee should consider power generation if distribution lines are nearby or if on-site power is required. The AER may investigate flared and vented volumes as low as 300 m^3/day if it appears that gas is stable.

Approval for the construction and operation of electrical power plants is held by the Alberta Utilities Commission as specified in section 11 of the *Hydro and Electric Energy Act*. The Alberta Utilities Commission's *Rule 007: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines* provides requirements for power plant applications and includes a simplified application form for electric power generating projects of 1.0 megawatt (MW) or smaller. Additionally, power plants with a generation capacity greater than one megawatt at peak load require approval issued by AEPA under *EPEA*.

4.7 Economic Evaluation of Gas Conservation

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

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

2) Licensees or operators must update the conservation economics for any sites that are flaring or venting combined volumes of more than 900 m^3/day and that are not conserving every 12 months. The assessment must

    a) name the responsible individual and the date of completion,

    b) be kept on file by the licensee or operator, and

    c) be provided to the AER upon request (information may be stored at a central location rather than on site).

3) A licensee or operator must provide the evaluation to the AER within five working days of receiving a request.

4.7.1 Economic Evaluation Criteria

1) Economic evaluations of gas conservation must use the criteria listed below. The licensee or operator must consider the most economically feasible option in providing detailed economics. Specific AER economic evaluation submission requirements are listed in section 4.7.2.

2) Evaluations must be completed on a before-tax basis and must exclude contingency and overhead costs.

3) 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 –Cdn$55 000, the licensee or operator must re-evaluate the gas conservation project on a royalties-out basis (not paying royalties). If the evaluation results in an NPV –Cdn$55 000 or more, the licensee or operator must proceed with the conservation project and may then apply to Alberta Energy for an "otherwise flared solution gas" royalty waiver.

4) Price forecasts used in the evaluation of solution gas conservation projects (gas gathered, processed, and sold to market) must use the most recent version of commodity price forecast from GLJ Petroleum Consultants Limited. Gas prices must be obtained from the "Natural Gas and Sulphur Price Forecast Table" in the "ARP" 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/bbl).

5) 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 (http://ets.aeso.ca). The power price must be escalated at the long-term inflation rate (see item 9). Alternatively, the cost of the power displaced at the site may be used.

6) The licensee or operator must have information to support the remaining reserves calculation and the production forecast (including planned drilling programs and pressure maintenance schemes). The production forecast must be reviewed by a **qualified person** who is a member of the association as defined in the *Engineering and Geoscience Professions Act*.

7) The licensee or operator must have a detailed breakdown of capital costs showing equipment, material, installation, and engineering costs. Capital costs must be approved-for-expenditure quality numbers based on selection of appropriate technology. Any capital costs incurred before

the initiation of the solution gas project (i.e., 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 capital cost savings result from implementing gas conservation, such as any equipment that would otherwise be required, the flares 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.

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

9) The economic evaluation must account for any cost savings, such as reduced costs for trucking or equipment rental and reduced carbon levies.

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

11) The most recent inflation rate must be based on the current economic trends report published quarterly on the Government of Alberta website.

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

13) 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 of more than –Cdn$55 000.

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 4.2(5) provides a process whereby the licensee or operator may apply to discontinue conservation if annual expenses exceed annual revenue.

14) If a solution gas conservation project has an NPV less than –Cdn$55 000 and is therefore considered uneconomic on its initial evaluation, the project economics must be re-evaluated annually (within 12 months of the latest evaluation) using updated prices, costs, and forecasts.

4.7.2 AER Economic Evaluation Audit Requirements

1) Economic evaluation audit packages submitted to the AER upon request must contain the following information in SI units (international system of units):

   a) detailed capital and operating cost schedules as set out in sections 4.7.1(6) and (7)

   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, incineration, or venting, how they were evaluated, and the outcome of the evaluation

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

4.8 Public Involvement

Licensees or operators with continuous solution gas flares, incinerators, enclosed combustors, or vents are expected to respond to questions or concerns raised by the public in relation to activities related to the flaring, incineration, and venting of solution gas at upstream petroleum industry facilities. To help respond to the public, public information packages should be prepared and provided. Licensees or operators must also meet consultation and notification requirements in *Directive 056*.

4.8.1 Public Information Package

As a minimum, public information packages should include the following:

- the definition of solution gas, and information on its conservation and use
- an explanation of solution gas flaring, incineration, and venting management options and the decision-tree process

- a summary of analysis completed to determine that flaring, incineration, or venting is needed
- information on general flare, incineration, enclosed combustion, or vent performance requirements and reduction targets
- descriptions of specific actions the licensee or operator will take to eliminate or reduce flaring, incineration, or venting or improve the efficiency of the flare, incinerator, or vent source based on the evaluation
- a list of industry, AER, and government contacts that are related to public consultation and relevant to the project

4.8.2 Limitations on Nonroutine Flaring, Incineration, Enclosed Combustion, and Venting During Outages at Solution Gas Conserving Facilities

1) Production operations must be managed to control **nonroutine flaring, incineration, enclosed combustion, and venting** of normally conserved solution gas in accordance with table 3 below.
2) Table 3 does not apply to **nonassociated gas** (the percentage cutbacks listed in table 3 apply to solution gas only). All nonassociated gas must be shut in during facility outages.
3) Emergency or plant upset shut in of production and reduction of solution gas inlet requirements in table 3 do not apply to thermal in situ production.
4) The licensee, operator, or approval holder must provide notification as required in table 1.

If there is a restriction to the plant inlet, the AER recommends that solution gas processing have priority over the processing of nonassociated gas in order to limit the unnecessary flaring of solution gas.

The AER recommends that wells with the highest gas-oil ratio be the first to be shut in during facility outages and cutbacks.

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.

5) When multiple licensees, operators, or approval holders are involved, they may determine how to best implement the overall required production reductions.
6) If an agreement cannot be reached, each licensee, operator, or approval holder must reduce production as specified in table 3.

Table 3. Requirements during outage of a solution gas conserving facility[*]

Shutdown category	Duration	Operational requirements
Partial equipment outage	<5 days	Unless directed by the AER to flare, incinerate, or conserve all casing gas and tank-top gas, 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 2.0 10^3 m^3 per day subject to limitation on venting as defined in section 8. If the event is ≥5 days, the operator must meet requirements stated below (planned shutdown category, >4 hours duration).
Planned	<4 hours	The licensee or operator must make all reasonable efforts[†] to reduce battery or solution gas plant inlet gas volumes by 50 per cent of average daily solution gas production over the preceding 30-day period.
	>4 hours	The licensee or operator must reduce battery or solution gas plant inlet gas volumes by 75 per cent 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 per cent. • Production may be sustained at rates that will provide sufficient throughput to keep equipment operating safely and within minimum design turndown range. If this volume is greater than 25 per cent of the average daily solution gas production, a variance must be obtained from the AER (email Directive060Inbox@aer.ca; see section 4.8.4). • Residents within 500 m must be notified[‡] at least 24 hours before the **planned flaring** event. • The AER also recommends that the licensee or operator notify individuals who have identified themselves to the licensee or operator as being sensitive to or interested in emissions from the facility. • The appropriate AER field centre must be notified[**] 24 to 72 hours in advance if any of the following occurs: an event exceeds an approval condition; flaring has occurred that could potentially cause an adverse effect; the flared volumes exceed approved limits; flaring occurs that results in smoke or odours; the event extends over a long duration.
Emergency[††] or plant upset	<4 hours	No reduction in the plant inlet is required.
	>4 hours	The licensee or operator must reduce battery or solution gas plant inlet gas volumes by 75 per cent 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 per cent. • Production may be sustained at rates that will provide sufficient throughput to keep equipment operating safely and within minimum design turndown range. If this volume is greater than 25 per cent of the average daily production, a variance must be obtained from the AER (email Directive060Inbox@aer.ca; see section 4.8.4). • Residents within 500 m must be notified[‡] without delay about the flaring event. • The AER also recommends that the licensee or operator notify individuals who have identified themselves to the licensee or operator as being sensitive to or interested in emissions from the facility. • The appropriate AER field centre[**] must be notified without delay if any of the following occurs: an event exceeds an approval condition; flaring has occurred that could potentially cause an adverse effect; the flared volumes exceed approved limits; flaring occurs that results in smoke or odours; the event extends over a long duration.

Shutdown category	Duration	Operational requirements
Repeat nonroutine flaring‡‡		The licensee or operator must investigate causes of repeat nonroutine flaring or venting and take steps to eliminate or reduce the frequency of such incidents.

* See appendix 1 for the definition of "conserving facility" and "partial equipment outage."

† Notwithstanding solution gas reduction requirements listed in table 3, if a sour or **acid gas** flare or incinerator stack is not designed to meet the one-hour AAAQO for sulphur dioxide (SO_2) under high flow-rate conditions, action must be taken immediately to reduce gas to a rate compliant with the AAAQOs (see section 7.12.5).

‡ Refer to section 2.3 for resident notification requirements.

** The appropriate AER field centre must be notified through the designated information submission system. In situations where limits have been exceeded, the appropriate AER field centre must be contacted by telephone before the designated information submission system is notified.

†† Emergency shutdowns or plant upsets are unplanned events at the battery site or at facilities downstream of the battery that causes the nonroutine flaring at the battery.

‡‡ Repeat nonroutine flares are defined as recurring events of similar cause at a conserving facility during a 30-day period.

4.8.3 Planned Shutdown (Turnaround) Considerations

1) A licensee or operator must evaluate and implement appropriate measures to reduce solution gas flaring, incineration, and venting during a facility turnaround or planned shutdown.

Alternatives that minimize impacts of planned shutdowns include the following:

- delivering solution gas to a nearby gas plant or facility that is not on turnaround
- scheduling maintenance at related oil facilities to coincide with the gas plant turnaround
- 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 Oil and Gas Reservoirs*)
- communicating with well, battery, and gas plant licensees or operators to ensure that nonroutine solution gas flaring, incineration, and venting are minimized

4.8.4 Alternatives to Solution Gas Shut-in Requirements

The AER will consider alternatives to the shut-in requirements listed in this directive for solution gas. This will be done only if the licensee or 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.

1) In these special cases, the licensee, operator, or approval holder must consult with the AER (email Directive060Inbox@aer.ca) about alternatives to shutting in for a particular gas plant or battery.

2) A licensee, operator, or approval holder must plan for outages.

If an alternative approach to those listed in table 3 is justified, the AER recommends that the licensee or operator submit a written request to the AER (Directive060Inbox@aer.ca) at least 30 days before a planned shutdown explaining the alternative requested and giving supporting reasons for the request.

The AER recommends that, wherever possible, contact with the AER not be deferred until an actual outage occurs.

5 Emissions Research and Innovation

The AER expects that industry will support and participate in 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;
- reviewing the results of any field testing of combustion efficiency monitoring methodologies;
- improving estimates of the amounts of methane emitted; and
- testing new technologies for emissions detection and reduction.

Emissions testing facilities use various techniques and instruments to accurately quantify an emission of interest. The temporary test is intended to help researchers, regulators, innovators, and industry understand and mitigate emissions.

1) Before an emissions test is conducted, the duty holder of an emissions testing facility must ensure that a **qualified person** has developed a test plan that clearly identifies the test objectives, including the expected emission volumes, emission rates, and test performance criteria.
2) The test plan, objectives, and performance criteria must be provided to the AER upon request.
3) The test plan must be designed to ensure there are no exceedances of the AAAQOs outside of the facility or well **site** lease boundary.
4) Emissions test volumes may supersede the equipment-specific performance requirements and equipment **vent gas** limits stated in section 8. Emissions test volumes are subject to the overall vent gas (OVG) site limit. The OVG site limit in section 8.3 is applicable and inclusive of emissions testing and operational routine and nonroutine site vent volumes.
5) Emissions test volumes must not exceed 500 m^3/d. The requirements of section 8.4.3 are not applicable to emissions test volumes.
6) The licensee, **operator**, or approval holder must notify the appropriate AER field centre before planned emissions testing occurs.

7) An emissions test report that is free of proprietary information must be provided to the AER upon request. The report must include a description of the technology being tested, the test dates, cumulative volume of emissions during the test, and a summary of the test outcomes.

Notifications requirements of sections 2.2 and 2.3 apply to emissions testing. All emissions test volumes are considered nonroutine vent volumes.

6 Gas Facility and Infrastructure Flaring, Incinerating, Enclosed Combustion, and Venting

This section addresses **gas battery**, dehydrator, compressor station, gas plant, and pipeline (gathering and transmission) flaring, incineration, **enclosed combustion**, and venting and includes **routine flaring, incineration, enclosed combustion, and venting** of low-pressure flash gas and other gas streams at gas plants, pipeline system compressors, and dehydration facilities and **nonroutine flaring, incineration, enclosed combustion, and venting** for equipment depressurization for maintenance, process upsets, and emergency depressurizing for safety reasons.

1) The licensee, **operator**, or approval holder must investigate and correct the cause or contributing causes of frequent nonroutine events (one or more event per month).

6.1 Reporting

1) All gas flared, incinerated, enclosed combusted, or vented at a **facility** must be reported in Petrinex to the respective reporting **facility identifier** that is associated with the physical location of where the flaring, incineration, enclosed combustion, or venting activity occurred. For facilities that do not require a licence (such as small booster compressors), the flared, incinerated, enclosed combusted, and vented volumes must be reported at the nearest upstream reporting facility identifier, which may be a well, battery, or pipeline facility. All routine and nonroutine volumes of gas combusted in a flare, incinerator, or enclosed combustor must be reported as “flare gas” in Petrinex.

Additional **measurement** and reporting requirements for gas plants include the following:

2) When **metering** is not required, engineering estimates must be used to report any flared gas not measured (see section 3.9).

3) A licensee, operator, or approval holder must provide a documented system for metering or estimating flared, incinerated, enclosed combusted, and vented gas volumes (as defined in sections 3.9 and 8) upon AER request. All flare events both minor and major must be logged (in accordance with section 3.9) and provided upon request.

4) A licensee, operator, or approval holder must monitor and minimize gas used for flare header purges, flare pilots, **incinerator**, and enclosed combustor pilots.

6.2 Gas Plant Flaring, Incineration, Enclosed Combustor, and Venting Volume Limits

The AER limits the total annual volume of gas disposed of by flaring, incineration, enclosed combustion, and venting at **gas processing plants**.

1) The decision-tree evaluations from figure 1 must be updated annually or when changes at a gas plant materially change plant operations

Acid gas volumes from gas sweetening (which are normally continuously flared) are excluded from the following limits:

2) For gas plants processing more than 1.0 10^9 m^3 per year (raw gas inlet volume), the cumulative volume of flaring, incineration, enclosed combustion, and venting must not exceed the greater of 0.2 per cent of raw gas receipts or 5.0 10^6 m^3 per year. The vent limits of section 8 are applicable.
3) For gas plants processing less than or equal to 1.0 10^9 m^3 per year (raw gas inlet volume), flaring, incineration, enclosed combustion, and venting must not exceed 1.0 per cent of raw gas receipts in the first year of operation and must not exceed 0.5 per cent of raw gas receipts in any subsequent year with the following exception:
4) For acid gas plants processing less than or equal to 0.1 10^9 m^3 per year (raw gas inlet volume), flaring, incineration, enclosed combustion, and venting must not exceed 3.75 per cent of raw gas receipts in any year of operation.
5) If multiple **flare stacks** are available in gas production, gathering, and processing systems, licensees, operators, or approval holders 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.
6) Licensees, operators, or approval holders can deduct **solution gas** flared at gas plants during plant shutdowns lasting more than seven days in calculating the annual flared volumes applicable to (1) and (2) above. These solution gas volumes must be documented and provided to the AER upon request.

6.3 Gas Plant Frequent Nonroutine Flaring, Incineration, Enclosed Combustion, and Venting Events

1) 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 4.

Table 4. 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 per cent 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

- 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 a separate, individual event) or
- volumes greater than or equal to those specified in the table are flared in one contiguous period spanning more than one day (e.g., flaring for four days at a continuous rate of 25 10^3 m^3/d is considered one event).

2) Major flaring events must be identified and logged as a major flaring event.

3) If a sixth major flaring event occurs within any consecutive (rolling) six-month period, the licensee, operator, or approval holder must do the following:

   a) Submit a written exceedance report to the appropriate AER field centre and copy this report to the AER 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 on 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) Obtain AER field centre approval of the proposed plan referred to in 3(a)(ii) above.

If facility modifications are proposed in the plan, and approvals are required by *Directive 056*, AER approval must be obtained before implementing any such actions.

Upon AER field centre approval of the plan, including facility modifications, licensees, operators, or approval holders are expected to expedite schedules for implementing the plan.

After the plan implementation date, the AER may issue a regulatory response if another exceedance of the 6-in-6 criterion occurs within 24 months.

6.4 Additional Requirements for Gas Gathering Systems

1) Gas containing more than five parts per million (ppm) H_2S must not be released from a pipeline without the approval of the AER unless the gas is destroyed such that it meets the requirements in section 7.

6.5 Natural Gas Transmission Systems

This directive applies to flaring, incineration, enclosed combustion, and venting in conjunction with natural gas transmission systems.

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

   a) The economic evaluation in section 4.7 does not apply to evaluating **conservation** of gas from nonroutine pipeline depressurizing for maintenance.

   b) When evaluating conservation of gas from planned nonroutine pipeline depressurizing, licensees must consider the value of gas, the costs of conserving the gas, and the economic effects of extending outages on downstream customers and upstream producers.

2) Flaring or incineration of gas from sweet natural gas transmission pipeline depressurizing may not be practical when impacts on system customers and producers are considered. In such situations, the appropriate AER field centre may allow the venting of gas to reduce the duration of system outages and related impacts.

7 Performance Requirements

These requirements apply to flares, **incinerators**, and **enclosed combustors** in all upstream oil and gas, geothermal, or brine-hosted mineral resource systems for burning sweet, sour, and acid gas, including portable equipment used for temporary operations including well completion, servicing, and testing. Flare, incinerator, and enclosed combustor systems include associated separation equipment, piping, and controls.

For the purposes of this directive, the terms flare and incinerator are no longer used interchangeably; requirements are specific to the type of equipment used.

All requirements in *Directive 060* that apply to incinerators apply to enclosed combustors (a type of incinerator) unless otherwise stated.

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

1) The licensee, **operator**, or approval holder must ensure that a **qualified person** who is a member of the association as defined in the *Engineering and Geoscience Professions Act* is responsible for the design, review, and operating procedures of flare, incinerator, and enclosed combustor systems, including liquid separation, ignition systems, backflash control, piping, spacing, performance testing, maintenance, controls, and for the specification of safe operating procedures.

2) The license, operator, or approval holder must design and operate flare, incineration, and enclosed combustion devices in accordance with the current edition of the Canadian Standards Association (CSA) *Z620.3: Flaring, Incineration and Enclosed Combustion*, which are in

addition to the requirements of *Directive 060*. Where conflicting requirements exist, the more stringent requirement is applied.

3) Equipment and **control device** design information, operating limits, and procedures must be provided to the AER upon request.

4) The licensee, operator, or approval holder must ensure that operating procedures that define the operational limits of flare, incinerator, or enclosed combustor systems are documented and implemented and that these procedures meet the design requirements.

5) Flare, incinerator, and enclosed combustor systems must be operated within the operational ranges and types of service specified by a qualified person. If this equipment is used for emergency shutdowns, this must be considered in the design.

6) In a field service, if using a flare or incinerator that has not previously been field tested, the licensee, operator, or approval holder must be able to provide actual monitoring data to show that performance specifications will be met.

7) 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 unless the **facility** is capable of being shut in if problems arise.

8) *ANSI/API Standard 521: Pressure-Relieving and Depressuring 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.

9) The licensee, operator, or approval holder 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*).

The AER recommends that all licensees, operators, and approval holders use best engineering practices, as well as appropriate engineering codes and standards, in the design and operation of flare systems.

7.1 Conversion Efficiency

Compliance with flare combustion efficiencies can be demonstrated through the evaluation of operational flaring parameters within the AERflare-incin spreadsheet. In addition to requirements specified in *CSA Z620.3* the following apply:

1) Flares, incinerators, enclosed combustors, 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 AAAQOs.

2) The licensee, operator, or approval holder must modify or replace existing flares, incinerators, or enclosed combustors if operations result in off-lease odours, odour complaints, or visible emissions (e.g., black smoke).

7.1.1 Heating Value for Flares

If a flare is subject to requirements from both an AER facility licence and an *EPEA* approval, the more stringent requirement on minimum heating value will apply.

1) The combined net or lower heating value of gas, including **makeup 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 AAAQOs (the licensee, operator, or approval holder is expected to support claims that existing stacks have operated satisfactorily over time), the licensee, operator, or approval holder is allowed to maintain the current heating value provided it is not less than 12 MJ/m^3.

    b) If **flare stacks** experience a repeated occurrence of flame failure, odour complaints, or exceedances of the AAAQOs, the licensee, operator, or approval holder must operate with a combined **flare gas** heating value of not less than 20 MJ/m^3.

    c) The combined net or lower heating value of acid gas plus makeup gas directed to existing or new flares including sour gas plant nonemergency, emergency, and upset systems must be configured to ensure that the flared gas heating value is not less than 12 MJ/m^3 and that the AAAQOs are met.

The AER 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 makeup gas is required, installed equipment controls and operating procedures must be documented and implemented to ensure minimum makeup gas during routine and nonroutine operating conditions.

7.1.2 Minimum Residence Time and Exit Temperature for Incinerators

If an incinerator is subject to an EPEA approval, any requirements regarding minimum residence time or exit temperature in that approval will take precedence over these requirements. The requirements below do not apply to sour gas plants subject to EPEA approvals.

1) For combustion of gases with more than 50 mol/kmol (5 per cent) H_2S, the facility must be designed to automatically shut down if the exit temperature of the incinerator drops below either 600°C or the required temperature to meet the AAAQOs, whichever is higher.
    a) The incinerator must also be equipped with process temperature control and recording.
    b) All violations, together with measures taken to prevent recurrence, must be immediately reported by the licensee, operator, or approval holder to the appropriate AER field centre.
2) Any operator proposing to use combustion technology that does not meet minimum exit temperature and minimum residence time requirements as specified in *CSA Z620.3* must conduct third-party-verified conversion efficiency tests that demonstrate the applicable **carbon conversion efficiency**, **sulphur conversion efficiency**, and **combustion efficiency** are being achieved and must provide results to the AER upon request.
    a) All testing must meet the *Alberta Stack Sampling Code*.
    b) Temperature monitoring and recording requirements would still apply.

7.1.3 Design and Operating Parameters for Enclosed Combustors

1) Enclosed combustors must be designed and operated as per the requirements of section 6.3.5, “Smoke Emissions,” of *CSA Z620.3*.

7.2 Smoke Emissions

Smoke emissions are regulated in accordance with sections 7.040(1) and 9.050(6)(d) of the *Oil and Gas Conservation Rules* (*OGCR*), except under emergency circumstances that involve equipment failure or as otherwise approved by the AER.

1) Routine gas combustion must not result in continuous or repeat black smoke emissions.
2) Any smoke emissions that may result in public concern must immediately be reported to the appropriate AER field centre.

7.3 Ignition

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

In addition to the requirements specified in *CSA Z620.3*, the following requirements apply:

2) At all facilities (excluding gas plants and batteries regulated as **crude bitumen batteries**) 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 depressurizing) sources.

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 AER may require installation of any of the following:

- pilots and automatic ignition
- flame failure detection and alarms

7.3.1 Requests to Extinguish Sour Flare Pilots at All Batteries

Continuous pilots may be necessary where gas is flared, incinerated, or enclosed combusted on a constant or routine basis (see section 7.3) or where sour gas can potentially be released from pressure safety valves or emergency shutdown valves.

Extinguishing a flare pilot to **conserve** natural gas may be safe and appropriate where

- gas is not continuously or routinely flared,
- emergency shutdown valves are not configured to depressurize facilities to flare, and
- maximum foreseeable operating pressures are well below pressure safety valve release pressures.

When considering a request to extinguish flare, incinerator, or enclosed combustor pilots, the AER field centre will take into account both local conditions and the operating history of the facility.

1) The licensee, operator, or approval holder must get approval from the appropriate AER 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 per cent of the maximum stabilized static wellhead pressure of all wells connected to the battery,

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

c) the facility is connected to sweet or level-1 or level-2 sour wells as defined in *Directive 056*,

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 pressure safety valves (subject to section 38(1)(b) of the *Pressure Equipment Safety Regulation* administered by the Alberta Boilers Safety Association), and

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

3) If the licensee, operator, or approval holder proposes to connect additional wells to an existing approval, they must first supply updated information and get approval from the appropriate AER field centre.

The following minimum requirements must be met in any situation where it is proposed to extinguish a flare pilot at a sour facility:

4) 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. *Directive 040* provides regulations for conducting pressure tests on wells.

5) 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. This is subject to section 38(1)(b) of the *Pressure Equipment Safety Regulation* administered by the Alberta Boilers Safety Association.

   b) A pressure gauge or suitable telltale indicator must be installed between each rupture disk and the corresponding pressure safety valve to allow detection of leakage or a disk rupture.

   c) Two block valves in series must be installed for manual depressurizing valves connected to the flare.

   d) The battery must be equipped with a pressure sensor, automatic emergency shutdown valves, 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.

6) 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) The licensee, operator, or approval holder must monitor and document on a weekly basis the pressure between rupture disks and pressure safety valves.

   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 AER field centre, followed by a written incident report giving particulars. Approval to extinguish the flare pilot is then considered void until the licensee, operator, or approval holder demonstrates to the satisfaction of the appropriate AER 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 emergency shutdown valves, must be verified and documented at least once a year.

   e) AER approval to extinguish the flare pilot must be visibly displayed at each site.

7) Residents within the emergency planning zone must be notified of plans to extinguish the flare pilot.

8) The following information must accompany the licensee’s, operator’s, or approval holder’s request to extinguish flare pilots:

   a) a list of all wells connected to the battery, including the following:

      i) normal wellhead operating pressure

      ii) maximum stabilized static wellhead pressure

   b) the maximum design operating pressure of the piping and pressure vessel systems for the battery, including the following:

      i) a list of all pressure safety valves connected to the flare and related release set-pressures

      ii) a list of related rupture disks and burst pressures

c) written confirmation of the following:

   i) none of the wells connected to the facility are completed in pools that have active injection or cycling schemes

   ii) rupture disks on pressure safety valves 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 emergency planning zone have been notified

   v) high-pressure shutdowns are in place, with a statement confirming calibration frequency

7.3.2 Requirements when Extinguishing Sour Flares, Incinerators, or Enclosed Combustors

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. *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. This is subject to section 38(1)(b) of the *Pressure Equipment Safety Regulation* administered by the Alberta Boilers Safety Association.

3) A pressure gauge or suitable telltale indicator must be installed between each rupture disk and the corresponding pressure safety valve to allow detection of leakage or a disk rupture.

   a) Two block valves in series must be installed for manual depressurizing valves connected to the flare.

   b) The battery must be equipped with a pressure sensor, automatic emergency shutdown valves, 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.

4) 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) The licensee, operator, or approval holder must monitor and document on a weekly basis the pressure between rupture disks and pressure safety valves.

   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 AER field centre, followed by a written incident report giving particulars. Approval to extinguish the flare pilot is then considered void until the licensee, operator, or approval holder demonstrates to the satisfaction of the appropriate AER 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 emergency shutdown valves, must be verified and documented at least once a year.

   e) AER approval to extinguish the flare pilot must be visibly displayed at each site.

5) Residents within the emergency planning zone must be notified of plans to extinguish the flare pilot.

6) The following information must accompany the licensee’s, operator’s, or approval holder’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 pressure safety valves connected to the flare and related release set-pressures and

      ii) a list of related rupture disks and burst pressures

c) written confirmation of the following:

   i) none of the wells connected to the facility are completed in pools that have active injection or cycling schemes

   ii) rupture disks on pressure safety valves 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 emergency planning zone have been notified

   v) high-pressure shutdowns are in place, with a statement confirming calibration frequency

7.4 Stack Design

In addition to requirements specified in *CSA Z620.3*, flares and incinerators must meet or exceed the following stack design requirements:

1) Exceptions to the requirement in section 6.2.4, "Stack Height for Ground-Level Thermal Radiation," of *CSA Z620.3* are permitted provided an equivalent level of safety can be ensured and a qualified person who is a member of the association as defined in the *Engineering and Geoscience Professions Act* certifies and stamps the design of the facility. Proof of engineering assessments and controls must be provided upon AER request.

   a) In such cases, the licensee, operator, or approval holder 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.

   b) Access restrictions must include appropriate warning signs, and the area must be clearly marked.

   c) 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 within a distance of 5 times the height of any adjacent buildings must have a height of at least 2.5 times the height of the highest building, tank, or enclosed structure on the lease site. This does not apply to enclosed combustors or 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 and crude bitumen batteries where the H_2S release rate is greater than 0.04 m^3/hr are subject to the minimum height above ground level requirements specified in *CSA Z620.3*, or such greater height as may be required to ensure that the AAAQOs are not exceeded.

4) Flares, incinerators, and enclosed combustors must be high enough to provide adequate plume dispersion to comply with the AAAQOs for SO_2 (see section 7.12).

5) Sufficient stack heights must be used in order to minimize supplemental makeup gas consumption. If the use of supplemental makeup gas is proposed, all other options must be investigated first. Make up gas use and amounts must be justified.

6) Interconnecting lines to the flare, incinerator, or enclosed combustor must be secured to prevent whipping or flailing.

7.5 Sour and Acid Gas Flaring/Incineration Procedures

1) A licensee, operator, or approval holder must meet the requirements in this section or those in table 3, whichever is more stringent and results in more gas being shut in.

2) Devices for combustion of sour or acid gas must be designed and evaluated to ensure compliance with the AAAQOs. Evaluations must use methodologies acceptable to the AER and AEPA. One of the methods described in section 7.12 or AEPA's *Non-Routine Flaring Management: Modelling Guidance* must be used.

3) A cumulative emissions assessment must be conducted if a flaring event is routine and if modelling results of the individual source exceed one-third of the one-hour AAAQO for SO_2 (see section 7.12).

4) It is not necessary to do a cumulative emissions assessment if the **routine flaring** is reasonably expected to be less than four hours. Cumulative assessment requirements are intended to address the effects of multiple 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.

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

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

7) Automated shutdowns must be installed in facilities that are not staffed 24 hours/day (i.e., are semi-attended).

8) Staff responsible for operations must be aware of the current operating procedures and must be trained to follow them.

9) Operating procedures and related dispersion evaluations must be provided to the AER upon request.

7.6 Liquid Separation

Entrained liquids in a flare, incinerator, or enclosed combustor 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 are intended to protect the pipeline system or gas combustion system and to ensure safe operation.

For the purposes of this section and section 7.6.1, the terms “knockout,” “knockout drum,” “scrubber,” and “separator” are used interchangeably. Liquid separation requirements for these devices can be found in *CSA Z620.3*.

1) For manually operated flares, incinerators, and enclosed combustors (e.g., maintenance flares) where the flare, incinerator, or enclosed combustor is normally isolated from the process stream (i.e., manual block valve), visual level indicators are not required when the operator has operating procedures in place to assess and mitigate the risk of liquid carryover. In the absence of an adequate operating procedure, the separator must be emptied before each flaring event.
2) Liquid separation design and operating procedures must be provided to the AER immediately upon request.
3) For flare, incinerator, and enclosed combustor separators or knockout drum design requirements, refer to *Directive 055: Storage Requirements for the Upstream Petroleum Industry* and *CSA Z620.3*. Where conflicting requirements exist, the more stringent requirement is applied.

7.6.1 Exceptions

1) The AER does not require independent flare, incinerator, or enclosed combustor separators in situations where the only vessels connected to the flare, incinerator, or enclosed combustor are production separators equipped with a high-level shut down or equivalent devices or with a system that prevents liquids from entering the flare or incinerator. The following limitations apply:
   a) The high-level shut down must be configured to shut down and block in but not depressurize the facility. The high-level shut down trip level must be set so that adequate vapour-liquid separation is not impaired at maximum liquid level and vapour flow rates.
   b) If liquid carryover involving spills occurs around the flare or incinerator, or if black smoke is formed, the licensee, operator, or approval holder must install adequately sized flare or incinerator separators.
2) The AER does not require independent flare, incinerator, or enclosed combustor separators for combustion devices that destroy trace vent gases emitted from gas dehydrators.

7.7 Backflash Control

Refer to the most recent version of *CSA Z620.3* for backflash control requirements.

7.8 Flare, Incinerator, and Enclosed Combustion Spacing and Setback Requirements

The spacing and setback requirements in *CSA Z620.3* apply.

Refer to the *Forest and Prairie Protection Regulation* for information regarding unforested areas where there is a fire hazard associated with flare and incinerator operations.

1) Unless otherwise directed by the AER, variances from flare and incinerator spacing requirements to on-site equipment are permitted where the licensee, operator, or approval holder has ensured that a qualified person who is a member of the association as defined in the *Engineering and Geoscience Professions Act* is responsible for the spacing and setback design or review of the spacing and setback design for flare, incinerator and combustor systems (including separation, related piping, and controls) and for the specification of safe operating procedures.
2) The licensee, operator, or approval holder must evaluate a spacing variance by consulting relevant codes and engineering practices and conducting a process simulation risk assessment model.
3) The licensee, operator, or approval holder must maintain records for the operating life of the facility that are readily available for audit upon AER request.
4) The licensee, operator, or approval holder must provide proof of engineering assessments, including risk assessment modelling, hazard assessment, and controls, upon AER request.

7.9 Compliance with Fire Bans

Information on fire bans issued by AEPA can be found at www.albertafirebans.ca, directly from local municipal districts, or by calling 1-866-310-FIRE (3473).

7.10 Noise

Refer to *Directive 038: Noise Control* and the most recent version of *CSA Z620.3* for noise requirements.

1) Where conflicting requirements exist, the more stringent requirement is applied.

7.11 Flare Pits

1) Flare pits are not permitted. Exemption requests for cryogenic flare pits were required to be submitted to the AER by December 31, 2015.

Additional requirements for the operation of (cryogenic) flare pits are provided in *Forest and Prairie Protection Act* and its associated regulations.

7.12 Dispersion Modelling Requirements for Sour and Acid Gas Combustion

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

1) The licensee, operator, or approval holder must demonstrate, using dispersion modelling methods outlined in the most recent version of AEPA's *Air Quality Model Guideline* and *Non-Routine Flaring Management: Modelling Guidance*, that SO_2 and H_2S emissions from the burning of sour and acid gas will not result in exceedance of the AAAQOs if the gas contains 10 mol/kmol H_2S or more, or if the **sulphur emission** rate during the combustion event is equal to or exceeds one tonne per day.

A licensee, operator, or approval holder combusting gas below these concentrations and emission rates is encouraged to consider dispersion modelling as part of environmental considerations. Facilities requiring approval from the AER under EPEA may need a more detailed evaluation. A licensee, operator, or approval holder should consult AEPA directly in these instances.

2) Dispersion modelling must be done by qualified person using computer models and methodologies presented in the AEPA *Air Quality Model Guideline* and *Non-Routine Flaring Management: Modelling Guidance*, as directed by AEPA or, if appropriate, the method described in section 7.12 and its subsections.

7.12.1 Modelling Approach

1) The licensee, operator, or approval holder must
   a) select an appropriate model,
   b) be able to demonstrate that the model selected is appropriate and follows AEPA-accepted methodologies and standards, and
   c) use representative operating input parameters (e.g., flow rate, gas composition) within the model and be prepared to demonstrate that those parameters are representative.

The AER sour well test flaring and incineration permit spreadsheets and technical descriptions are available on the AER website www.aer.ca under Regulating Development > Rules & Directives > Directives > Directive 060. They provide a screening analysis of the SO_2 and H_2S 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 AAAQOs, 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 AAAQOs. Due to the short-term nature of temporary nonroutine sources, **risk-based criteria** can be applied. The risk-based criteria apply to well tests and other temporary nonroutine flaring and incineration events. For further information about the spreadsheet refer to the AER flare user guide: *AERflare - User Guide Version 2.01*.

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 AAAQOs.

For routine flaring, a refined dispersion modelling assessment is also required if there are continuous SO_2 emission sources within 10 km of the location or within the isopleth of one-third of the one-hour AAAQO for SO_2 (as described in section 7.12.3), whichever distance is less. This requires that the cumulative effects of the proposed flaring or incineration be assessed in combination with other sources.

A licensee, operator, or approval holder is responsible for ensuring that an appropriately trained and qualified person complete the air quality evaluations.

2) A refined dispersion modelling assessment must include the following:

   a) 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 acceptable data sets are posted on the AEPA website. Additional information about modelling and meteorological data requirements is on the AEPA website.

   b) A wind rose (a representation of the history of wind directions and wind speeds).

   c) Refined modelling source parameters for maximum flow rate (Qmax), average flow rate (Qavg), and one-eighth maximum flow rate (Q/8) from the spreadsheet.

   d) 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).

   e) The maximum predicted one-hour ambient air SO_2 concentration for maximum flow rate (Qmax), average flow rate (Qavg), and one-eighth maximum flow rate (Q/8).

   f) If exceedances of the one-hour AAAQO for SO_2 are predicted, a histogram of 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:

$$\text{Probability of exceedance} = \frac{\text{(Cumulative number of hours with predicted exceedances)}}{\text{(Total hours modelled)}}$$

g) An interpretation of the modelling results (output files or model result printouts may be included if not excessively large).

h) Histograms showing exceedances based on criteria (e.g., wind direction, wind speed, and stability class).

If the risk-based criteria are not met, refer to section 7.12.6 for information on developing an air quality management plan to achieve the risk-based criteria.

3) Requests with management plans must include enough information so that the AER can assess the management plan, including the following:

   a) for each flow rate, a summary table of output, including the following:

      i) 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

      ii) maximum predicted SO_2 concentration for each condition where exceedances are predicted

      iii) the expected overall probability of exceedances before and after implementation of the management plan

   b) for each flow rate, an area map showing the following:

      i) locations of predicted SO_2 ground-level concentration isopleths (with a minimum 10 km radius) in excess of the one-hour AAAQO for SO_2

      ii) sectors with flaring restrictions (if proposed)

      iii) locations accessible with a mobile monitoring unit (if proposed)

      iv) 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 licensee, operator, or approval holder (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

      v) UTM coordinates of stationary monitors, as well as distance and direction from well

   c) a calculation of makeup gas requirements as a percentage of the produced gas being combusted (gas may be used to increase plume rise; care should be taken to minimize gas waste)

d) electronic copies (i.e., Microsoft Word or Excel files) of the management plan and decision tree (if applicable)

The AERflare-incin spreadsheet also evaluates minimum and maximum exit velocities with respect to downwash criteria. The results will help the licensee, operator, or approval holder optimize flare and incinerator design and verify parameters used for temporary flaring and incineration permit requests.

If downwash is predicted, the spreadsheet source parameters will conservatively account for downwash; however, it is recommended that the stack design parameters (e.g., stack diameter) be modified to avoid downwash.

4) 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 the AERflare-incin spreadsheet.

5) Exit diameter is a permitted parameter. A qualified person who is a member of the association as defined in the *Engineering and Geoscience Professions Act* must review the design parameters.

The licensee, operator, or approval holder 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 AER may accept or reject the modified results at its discretion.

7.12.2 Individual Source

1) Initial modelling must be conducted using the screening model assessment provided in the AERflare-incin spreadsheet.

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

If it is not practical to design flares or incinerators of sufficient height for adequate dispersion, the licensee, operator, or approval holder may consider

- using an air quality management plan (see section 7.12.6),
- operating procedures and process controls to prevent emission rates or durations that would exceed the AAAQOs (see sections 7.5 and 7.12.4), and
- adding gas to increase heat release and plume rise. (Proper flare stack height must be used to minimize gas consumption.)

The risk-based criteria discussed in section 7.12.4 do not apply to continuous (nontemporary) 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 continuous source are more than one-third of the one-hour AAAQO for SO_2, then the licensee, operator, or approval holder must conduct an assessment of cumulative effects of all routine SO_2 sources.

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 AAAQO for SO_2 to define the radius of influence.

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

   c) Quantify SO_2 emissions from these other sources and obtain all necessary input data, such as stack height and other parameters (the licensee, operator, or approval holder must share related data with each other 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) SO_2 cumulative assessments are not required for nonroutine flaring, incineration, and enclosed combustion (e.g., well test or planned maintenance blowdown).

   d) Model the cumulative effects of the SO_2 emission sources.

   e) If the sum exceeds any of the AAAQOs, determine the appropriate stack height required to meet all of the AAAQOs. All refined modelling must follow the methods outlined in the most recent version of AEPA's *Air Quality Model Guideline*.

7.12.4 Temporary and Well Test Flaring Dispersion Modelling

This section applies to temporary events that may require a permit (as described in section 3) and well test flaring or incineration activities. These activities include well testing, well cleanup, well servicing, coalbed methane well testing, underbalanced drilling, and sour gas pipeline (as defined in *Directive 056*) blowdown through temporary flare or incinerator equipment. These activities exclude nonroutine flaring or incineration at permanent AER-licensed facilities.

1) The licensee, operator, or approval holder must complete the AERflare-incin spreadsheet.

2) 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 AER upon request. The dispersion modelling within the AERflare-incin spreadsheet may be sufficient if a **screening assessment** is adequate.

3) Sour gas flares and incinerators must be designed for the gas composition and flow rates of the situation for which there is a temporary permit.

4) Equipment design or the operating procedures, or both, must address all modelled predictions that exceed the AAAQOs, excluding predicted values that meet the risk-based criteria. The risk-based criteria only apply to temporary events.

Risk-based criteria for temporary events allow limited exclusion of predicted ambient air quality results, provided that

- the 99th percentile predicted values at a receptor do not exceed the one-hour SO_2 AAAQO, and
- the 99.9th percentile predicted values do not exceed a predicted one-hour SO_2 ambient concentration of 900 micrograms (µg) per m^3.

Note that whereas model predictions up to 900 $\mu g/m^3$ will be considered, actual exceedances of the AAAQOs are never permitted.

Risk-based criteria are incorporated into the flare and incinerator spreadsheets for screening modelling.

5) If refined dispersion modelling is required to determine whether the temporary event meets the risk-based criteria, the refined modelling input files from the spreadsheet must be used.

The AER will also consider use of the risk-based criteria in situations where air quality management plans (see section 7.12.6) are necessary to ensure compliance with the AAAQOs.

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

6) Concurrent temporary sour gas burning (i.e., multiple-well test flaring/incinerating/enclosed combustion) must not occur within 20 km of each other unless a licensee, operator, or approval holder can demonstrate that the cumulative emissions from flaring can meet the AAAQOs.

7) Licensees, operators, or approval holders must retain, for one year after the flaring/incineration/enclosed combustion event, information on dispersion assessments for flares, incinerators, or enclosed combustors that require dispersion modelling but do not require a flaring permit (see section 3.3.2). This information must be provided to the AER upon request.

7.12.5 Nonroutine Flaring and Dispersion Modelling

This section applies to nonroutine planned and **unplanned flaring** from permanent flares. Temporary and well testing activities described in section 7.12.4 are not included here.

"Nonroutine flaring" applies to intermittent and infrequent flaring, incineration, and enclosed combustion. There are two types of nonroutine flaring: **planned flaring** and unplanned flaring.

- Planned flaring—Flare events where the operator has control over when flaring will occur, how long it will occur and the flow rates. Planned flaring results from the intentional depressurization of processing equipment or piping systems. Examples of planned flaring include pipeline blowdowns, equipment depressurization, start-ups, facility turnarounds, and well tests. Note that well testing dispersion modelling criteria are addressed in section 7.12.4.
- Unplanned flaring—Emergency or upset operational activities closely associated with facility health and safety. Flare events where the operator has no control of when flaring will occur. There are two types of unplanned flaring: **upset flaring** and emergency flaring.
  - Upset flaring occurs when one or more process parameters fall outside the allowable operating or design limits and flaring is required to aid in bringing the production back under control. Examples of upset flaring include off-spec product, hydrates, loss of electrical power, process upset, and operation error.
  - Emergency flaring occurs when safety controls within the facility are enacted to depressurize equipment to avoid possible injury or property loss resulting from explosion, fire, or catastrophic equipment failure. Examples of upset flaring include pressure safety valve overpressure and emergency shutdown.

Figure 3 summarizes the process for managing the nonroutine flaring of sour gas.

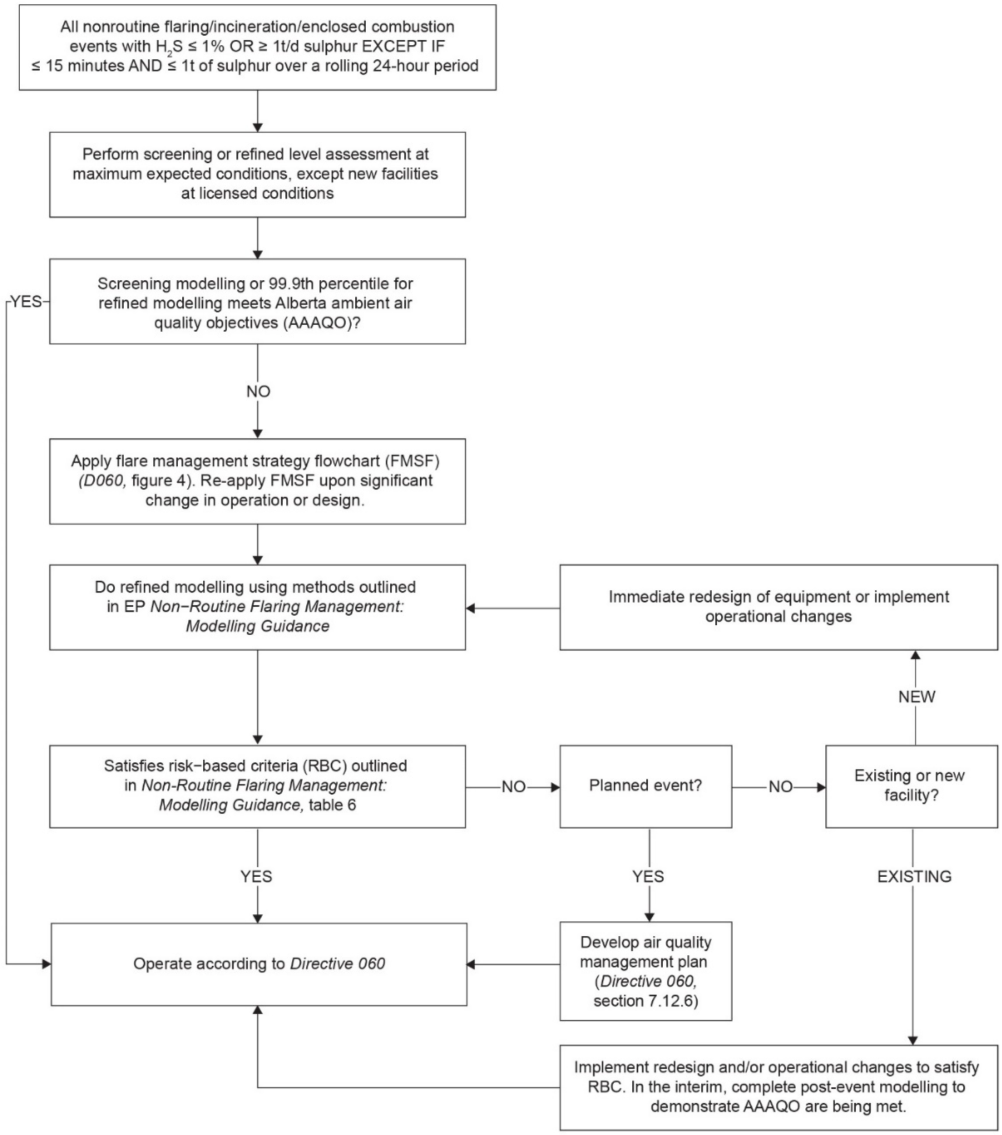


Figure 3. Comprehensive management of the nonroutine flaring of sour gas

1) The licensee, operator, or approval holder must evaluate impacts of nonroutine sour gas flaring on ambient air quality if

   a) it is proposed to burn sour gas containing 10 mol/kmol H_2S (1 per cent H_2S) or more, or

   b) 1 tonne of sulphur mass is released during the event or the day (for multiple releases).

Single nonroutine flare events that are predicted to be less than or equal to 15 minutes in duration and predicted to emit less than 1 tonne of sulphur over a rolling 24-hour period are exempt from modelling requirements.

2) Unless the AER requires otherwise, where previous modelling reports of nonroutine flare events show compliance with the AAAQOs using tools and methods no longer accepted by

AEPA (e.g., SCREEN3, RTDM, ISC3, AQMG, and AER low risk criteria), the facility may continue to operate.

3) If facility emissions change or if the AER requests that new dispersion modelling be conducted, the licensee, operator, or approval holder must apply the flare management strategy flowchart (figure 4) and reassess dispersion modelling using current modelling methodology and tools.

4) For permanent flare stacks, the licensee, operator, or approval holder must assess nonroutine flaring dispersion modelling criteria where facilities lack evidence of dispersion modelling.

5) If emissions change at existing AER-licensed facilities, the licensee, operator, or approval holder must reassess nonroutine flaring dispersion modelling criteria when a renewal or amendment is required.

6) All processing facilities subject to the *Activities Designation Regulation* must remodel upon renewal.

Initial screen modelling may be conducted using the AERflare-incin spreadsheet or dispersion modelling methods outlined in AEPA's *Air Quality Model Guideline*.

7) If nonroutine refined modelling is required or if stack design is impractical, the licensee, operator or approval holder must apply the flare management strategy flowchart (figure 4) or equivalent, and dispersion modelling evaluations must be conducted using methodologies described in AEPA's *Non-Routine Flaring Management: Modelling Guidance*. The flare management strategy flowchart and refined modelling must be reapplied if facility operation or design changes significantly.

8) If modelling of worst-case scenarios shows that the predicted 99.9th percentile hourly concentrations are lower than the AER SO_2 evacuation criteria from *Directive 071*, and the predicted 90th percentile hourly concentration is higher than the AAAQOs for SO_2, then for each unplanned flaring event at the facility, the licensee, operator, or approval holder must conduct post-event dispersion modelling (see section 7.12.5[12]).

9) For planned flaring events, the licensee, operator, or approval holder must develop flare management plans that meet the risk-based criteria to ensure that the AAAQOs are not exceeded and implement them during flaring. It is acceptable for modelling to be based on actual flows and gas compositions, not licensed values.

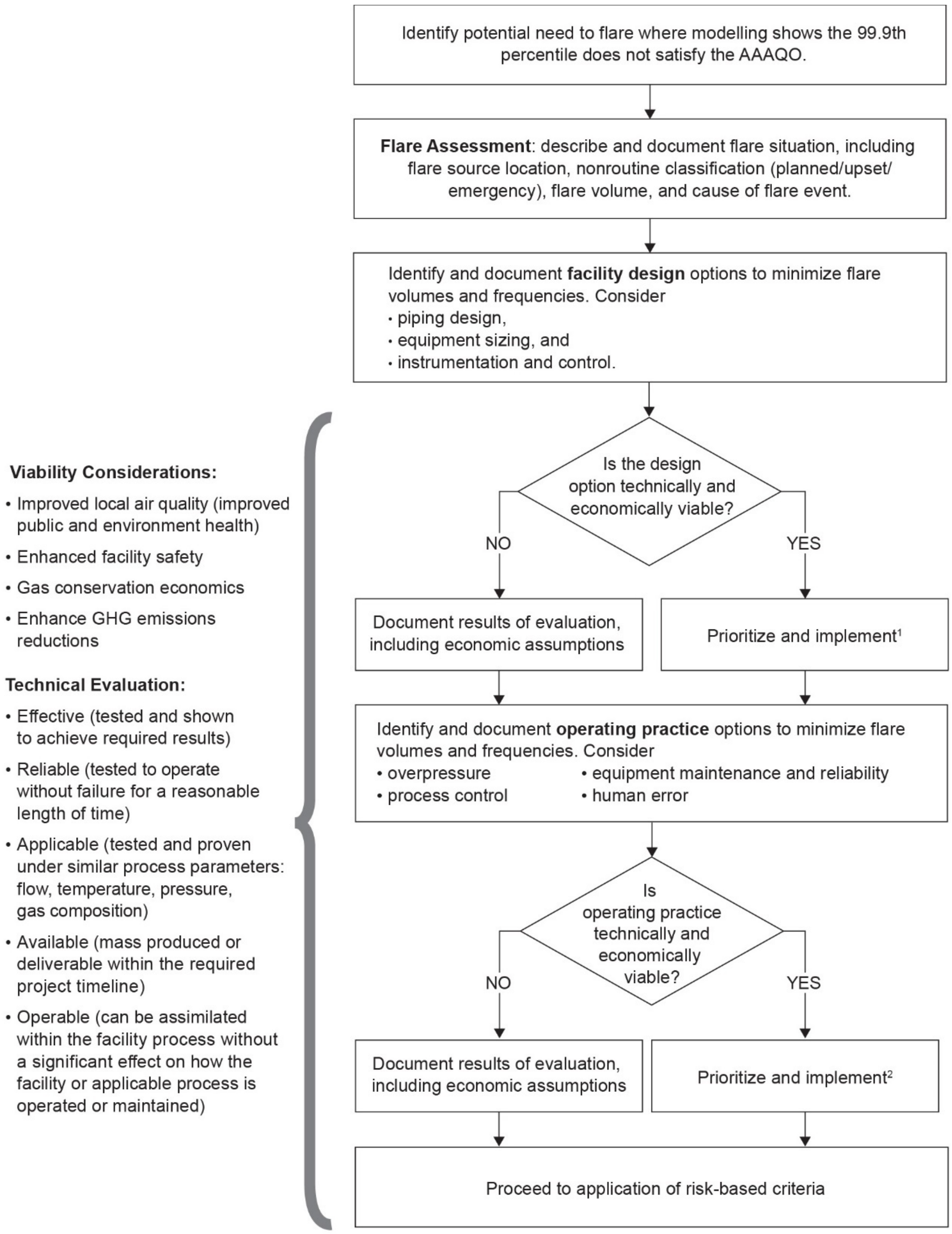
10) If refined modelling for nonroutine flaring is required, the licensee, operator, or approval holder must not exceed the risk-based criteria maximum number of flaring hours per calendar year described in table 1 of AEPA's *Non-Routine Flaring Management: Modelling Guidance*. The licensee, operator, or approval holder must log all flaring events, including flare duration, volume, and rates.

11) If nonroutine flaring exceeds the risk-based criteria maximum number of flaring hours per year described in table 1 of AEPA's *Non-Routine Flaring Management: Modelling Guidance*, or if the event results in an exceedance of the AAAQOs for SO_2, the licensee, operator, or approval holder must conduct post-event dispersion modelling (see section 7.12.5[12]) and contact the AER immediately.

12) If post-event modelling is required, the actual conditions must be used. If site-specific meteorological data during the event is not available, five years of meteorological data from a standard period is recommended using the AEPA data set. One month per year must be modelled from the data set, centred around the month of the event.

If the AER determines that the dispersion modelling has not been completed in accordance with *Directive 060* requirements, the licensee, operator, or approval holder may be subject to a regulatory response.

13) Upon request, the licensee, operator, or approval holder must provide the evaluation to the AER within five working days.



Notes

[1] After prioritization, schedule for implementation in a staged process to ensure operational changes are implemented first, highest priority projects are implemented first, minimum disruption to current operations, adequate capital is available for implementation, and regulatory targets or objectives are achieved.

Figure 4. Flare management strategy flowchart

7.12.6 Air Quality Management Plans for Temporary SO_2 Emissions

If exceedances of the risk-based criteria for SO_2 (see section 7.12.1) are predicted and it is not proposed that flare/incinerator design parameters be altered to mitigate the potential exceedances, approval may be granted by the AER if 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 AAAQOs will be avoided so that the risk-based criteria are met.

1) The air quality management plan may include restrictions during specific meteorological conditions that will limit or avoid operations under conditions that result in predicted exceedances. These atmospheric conditions may include the following:
   a) time of day
   b) wind direction
   c) wind velocity
   d) atmospheric stability
2) Meteorological monitoring may be used as a management plan based on a maximum one-hour rolling (i.e., any consecutive 60 minutes), with **measurements** taken at a frequency of no more than every 15 minutes (i.e., four measurements/hour).
3) 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.
4) Restrictions that may be applied during unfavourable meteorological conditions. Operational restrictions in air quality management plans may include the following:
   a) suspension of flaring or incineration operations
   b) reduction or increase of flaring or incineration rates
   c) requirements that supplemental **fuel gas** meet a minimum heating value or exit velocity
5) If a reduction in flaring or incineration rate or an addition of supplemental fuel gas is proposed, compliance with the risk-based 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.)
6) Ambient air monitoring (mobile and/or stationary) must be where exceedances of the AAAQOs are predicted.
7) Ambient air monitoring in conjunction with appropriate flaring/incineration 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 risk-based criteria are predicted. Stationary monitors are currently accepted to cover an arc of 22.5°C centred on the source.

8) The licensee, operator, or approval holder must provide a National Topographic System (NTS) map of the area (1:50 000) indicating the locations of the stationary monitors and a table with the coordinates (i.e., Universal Transverse Mercator [UTM]).

9) In cases where monitoring is proposed, a licensee or operator, or approval holder must demonstrate that there is good access to all areas with predicted exceedances before a request is submitted.

    a) The AAAQOs must not be exceeded, based on a one-hour average. To accomplish this, the flaring or incineration operation must be immediately shut in if the 30-minute average exceeds the AAAQOs.

10) 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 risk-based criteria must be met for each flow rate.

11) 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 more than 15 minutes is mandatory, as this allows for observations of trends and provides enough time to respond to elevated concentrations.

12) The management plan must clearly define under what conditions flaring or incineration may resume if suspended or may return to normal operations if a management option such as fuel gas is proposed.

13) Flaring or incineration must remain suspended for at least one hour before operations may resume in order to prevent an exceedance or to respond to an exceedance. Flaring or incineration may begin again after one hour or after meteorological conditions change and remain favourable for 30 minutes, whichever is longer.

14) Real-time dispersion modelling flare management plans must be based on maximum predicted concentrations. Pseudo input parameters must be calculated using AERflare-incin. If real-time dispersion modelling goes down, the operator must revert to a conventional flare management plan or shut in.

8 Vent Gas Limits and Fugitive Emissions Management

Vent gas and **fugitive emissions** are sources of methane emissions in the province. This section includes requirements to meet the target set by the Government of Alberta to reduce methane emissions from the provincial upstream oil and gas sector 45 per cent by 2025 from 2014 levels.

In this section, depending on the context, "duty holder" means the holder of an approval under *OSCA*, the holder of a licence or approval under the *Pipeline Act*, *OGCA*, *Geothermal Resource Development Act*, or *Mineral Resource Development Act* or the **operator** of a **facility** where a licence or approval is not required under the *OGCA*.

Figure 5 illustrates how the methane emission sources subject to the requirements in this section have been categorized.

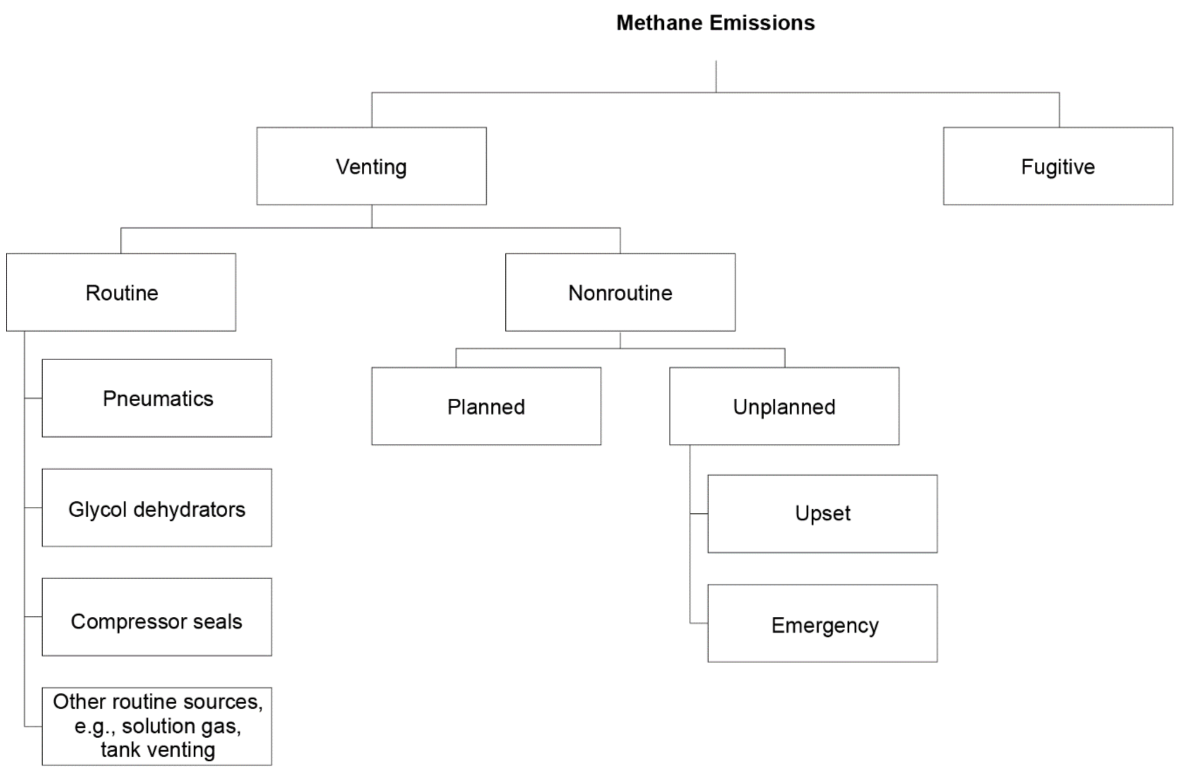


Figure 5. Methane emission sources covered under section 8

Routine venting is continuous or intermittent venting on a regular basis as part of normal operations. The AER recommends that duty holders eliminate all routine venting.

Nonroutine venting is intermittent and infrequent venting and can be planned or **unplanned**.

Fugitive emissions are the unintentional releases of hydrocarbons to the atmosphere.

For facilities operating under an *EPEA* approval or existing AER licence, the requirements in this section are in addition to any conditions in the *EPEA* approval or AER licence.

Unless otherwise stated, for operations in the Peace River area, requirements in this section are in addition to those set out in *Directive 084: Requirements for Hydrocarbon Emission Controls and Gas Conservation in the Peace River Area*.

8.1 Methane Reduction Retrofit Compliance Plan

Since the equipment retrofit and replacement requirements in section 8 may involve advance planning and investment by duty holders to ensure compliance on the date the requirements take effect, the AER will require duty holders to prepare a methane reduction retrofit compliance plan (MRRCP).

1) The duty holder must document an MRRCP that indicates how compliance with section 8.6 will be achieved.

2) The MRRCP must contain, at a minimum, the schedule to replace or retrofit existing equipment and the resources and budget allocated to ensure compliance with the requirements in section 8.6.

3) The MRRCP must be updated annually until January 1, 2023, to reflect material changes or progress made over the year according to the process in figure 6.

4) An executive of the duty holder must approve the MRRCP in writing, attesting that the MRRCP is designed to ensure compliance with the requirements in section 8.6.

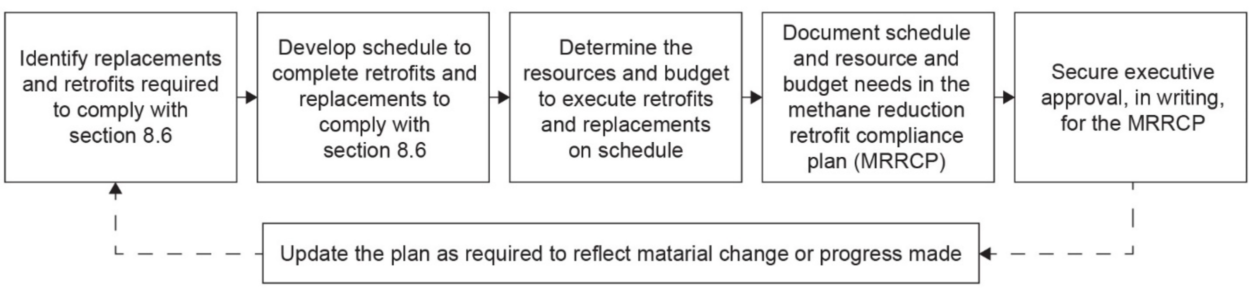


Figure 6. Process for developing and implementing a methane reduction retrofit compliance plan

8.2 Measurement and Reporting of Methane Emissions

Methane emissions may be quantified using continuous **metering**, periodic testing, or estimates based on accepted engineering practices. *Directive 017* identifies when vent gas from a **site** must be quantified using continuous metering or periodic testing, as well as acceptable testing methods. *Manual 015: Estimating Methane Emissions* provides guidance on how to estimate vent gas and fugitive emissions.

The annual methane emissions reporting period is the calendar year. The **operator of record** of a facility on December 31 is responsible for reporting over the entire reporting period, regardless of any changes in ownership during the reporting period.

Additional annual methane emission report requirements are set out in the corresponding vent gas limits and fugitive emissions management sections.

1) The operator of record for a facility that was active in a reporting period must electronically submit via the AER's designated information submission system an annual methane emissions report to the AER by June 1 of the following calendar year or the next business day if the first is not a business day, or as otherwise directed by the AER.
2) Annual inventories must reflect equipment in place at the end of each reporting period.
3) For facilities that do not require a licence (such as small booster compressors), the venting and equipment must be reported to the nearest upstream reporting well, battery, or pipeline facility.

8.3 Overall Vent Gas Limit

Overall vent gas (OVG) is the cumulative volume of all routine and nonroutine vent gas. The OVG vent gas limit is a maximum cumulative vent volume and is not an acceptable vent rate.

1) The duty holder must limit the OVG at a site to less than 15.0 10^3 m^3 of vent gas per month or a cumulative mass of 9.0 10^3 kg of methane per month.

In addition to complying with the OVG limit, the duty holder must comply with the vent gas limits in sections 8.4 to 8.9.

8.3.1 Exceptions

Vent gas from pneumatic devices, compressor seals, and glycol dehydrators are excluded from the OVG limit until January 1, 2023. Noncombustible gas, as described in section 8.9, is excluded from the OVG limit.

8.4 Defined Vent Gas Limit

Defined vent gas (DVG) is the cumulative volume of vent gas from routine venting, excluding vent gas from pneumatic devices, compressor seals, and glycol dehydrators.

The DVG vent gas limit is a maximum cumulative vent volume and is not an acceptable vent rate.

1) The duty holder must design and operate any site with first receipt or production on or after January 1, 2022, to limit the DVG emitted to less than 3.0 10^3 m^3 of vent gas per month per site or less than a cumulative mass of 1.8 10^3 kg of methane per month per site.

8.4.1 Reporting

1) The operator of record must include in the annual methane emissions report

    a) the annual volume of DVG emitted (m^3) by **facility identifier**, and

    b) the corresponding mass of methane emitted (kg) by facility identifier.

8.4.2 Exceptions

If the duty holder has opted to use the average vent gas rate for the **crude bitumen** fleet, as defined in requirement 8.5(1)(b), the methane emitted from the **crude bitumen batteries** is excluded from the DVG limit. Noncombustible gas, as described in section 8.9, is excluded from the DVG limit.

8.4.3 Vent Rate Limits

The AER considers **conservation** the best alternative to reduce flare and vent volumes, followed by combustion to reduce vent volumes. Vent gas that cannot be conserved or that varies in pressure or flow rate can be managed in combustion devices that are equipped with automated ignition that responds to combustion chamber temperature, pressure, or volumetric monitoring instrumentation.

1) If gas vent rates or volumes are sufficient to be combusted, the gas must be conserved or destroyed.

The AER may investigate observed or reported vent rates or volumes as low as 300 m^3/d or less if it appears the vent gas could be **controlled**. The operator may be required to conduct a 24-hour vent rate assessment using direct or parametric **measurement** and quantification to characterize and demonstrate:

- the average hourly flow rate and pressure; and
- the daily cumulative vent volume.

If it appears the vent gas could be controlled, the operator may be required to demonstrate why the vent gas cannot be conserved or destroyed.

8.5 Vent Gas Limits for Crude Bitumen Batteries

This section applies to vent gas from crude bitumen batteries. Excluded from the vent gas limits for crude bitumen batteries are thermal in situ schemes and thermal in situ operations licensed under OSCA and the *Oil Sands Conservation Rules*. Also excluded are batteries with either **crude oil** wells or crude bitumen wells that are within the Peace River area, as defined in *Directive 084*.

1) Effective January 1, 2022, the duty holder must limit vent gas to one of the following:

    a) From each site, to the DVG limit prescribed in section 8.4.

b) From the crude bitumen fleet, to less than an average vent gas rate in each month of 1.5 10^3 m^3 per facility identifier.

The crude bitumen fleet in each month consists of facilities with non-zero production or vent volumes reported to facility identifiers with the following subtype codes:

- 331 Crude Bitumen Single Well Battery
- 341 Crude Bitumen Multi Well Group Battery
- 342 Crude Bitumen Multi Well Proration Battery
- 311 Crude Oil Single Well Battery
- 321 Crude Oil Multi Well Group Battery
- 322 Crude Oil Multi Well Proration Battery that have at least one production string that
  - is reporting oil production from a pool with an assigned density greater than or equal to 920 kg/m^3 at 15ºC, or
  - has a well fluid status of bitumen.

Manual 011: *How to Submit Volumetric Data to the AER* defines the subtype codes.

The average vent gas rate in each month is calculated as follows:

$$\frac{\text{Sum of the vent volumes from the crude bitumen fleet}}{\text{Total number of facility identifiers within the crude bitumen fleet}}$$

8.6 Equipment-Specific Vent Gas Limits

8.6.1 Vent Gas Limits for Pneumatic Devices

The requirements in this section apply to gas-driven pneumatic devices, including **pneumatic instruments** (e.g., controllers, switches, transducers and positioners) and **pneumatic pumps**.

1) The duty holder must prevent or control vent gas from pneumatic instruments installed on or after January 1, 2022.

2) The duty holder must ensure that pneumatic pumps installed on or after January 1, 2022, and that operate more than 750 hours per calendar year do not emit vent gas.

3) Effective January 1, 2023, for level controllers that emit vent gas and are installed before January 1, 2022, the duty holder must evaluate the actuation frequency during normal operating conditions and for level controllers that actuate between 0 and 15 minutes, use a relay that has been designed to reduce or minimize transient or dynamic venting or adjust the actuation frequency to ensure that the time between actuations is greater than 15 minutes.

4) Effective January 1, 2023, for pneumatic instruments other than level controllers that emit vent gas and are installed before January 1, 2022, the duty holder must ensure that the instruments have a manufacturer-specified steady-state vent gas rate of less than 0.17 m^3/hr.

8.6.1.1 Exceptions

If a duty holder can demonstrate that a pneumatic instrument that vents gas is needed to maintain safe operating conditions or to achieve a necessary response time and that there is no other way of accomplishing this while still meeting venting requirement 1, 3, or 4 under section 8.6.1, then that instrument is exempted from the applicable requirement.

1) The duty holder must identify these exempt instruments with a weatherproof, readily visible tag.

8.6.1.2 Reporting

1) The operator of record must include in the annual methane emissions report the following from pneumatic instruments and pumps, by facility identifier:

    a) volume of vent gas emitted (m^3)

    b) corresponding mass of methane emitted (kg)

8.6.2 Vent Gas Limits for Compressor Seals

The vent gas requirements in this section apply to vent gas from the seals of a reciprocating or centrifugal compressor that is rated 75 kW or more and is pressurized for at least 450 hours per calendar year.

8.6.2.1 Compressor Seal Testing

1) For any compressor seal that emits vent gas, the duty holder must test the seal at least every 9000 hours that it is pressurized.

2) The test must

    a) have a maximum single point uncertainty of ±10 per cent for a vent rate greater than 0.70 m^3/hr,

    b) have a maximum total back pressure of less than 1 kPa (includes the back pressure from the measurement device, piping, valving, and fittings) for a vent rate less than 1 m^3/hr,

    c) include all vents from the compressor seal (for reciprocating compressors, this includes piston-rod-packing vents and drains and distance-piece vents and drains—including purge-system vents—and compressor crankcase vent),

d) include all compressor seals that emit vent gas (either by testing at a single common vent terminus point or at each vent of a compressor seal), and

e) be conducted within 10 per cent of the average revolutions per minute and discharge pressure of the compressor. The average is to be based on the 168 pressurized hours prior to testing.

3) The duty holder must ensure that the testing point for each compressor seal that emits vent gas is accessible and clearly identified.

If a compressor seal has been replaced since the last test, it does not need to be retested until the next annual test.

Exception: Reciprocating compressors with piston-rod-packing vents and drains and distance-piece vents and drains (including purge-system vents) that are connected to control do not have to be tested annually. In these cases, gas emitted out of the compressor crankcase is a fugitive emission and subject to section 8.10.

8.6.2.2 Reciprocating Compressor Seals

A reciprocating compressor seal (RCS) includes the piston-rod-packing vents and drains and distance-piece vents and drains (including purge-system vents) on an individual **throw**. The reciprocating compressor crankcase vent is not subject to control requirements. Gas emitted from the crankcase of a controlled reciprocating compressor is a fugitive emission and subject to section 8.10. For uncontrolled reciprocating compressors, any gas emitted from the crankcase is vent gas from an RCS.

1) The duty holder must control vent gas from any seal on a reciprocating compressor installed on or after January 1, 2022, with four or more throws.

2) Effective January 1, 2022, the duty holder must limit vent gas from the RCS fleet to less than 0.35 m^3/hr/throw.

The RCS fleet consists of the duty holder’s reciprocating compressors that are rated 75 kW or more, pressurized for more than 450 hours per calendar year, and either

- were installed before January 1, 2022, or
- were installed on or after January 1, 2022, and have fewer than four throws.

The vent gas from the RCS fleet is calculated as follows:

$$\frac{\sum_{i=1}^{n} v_i}{\sum_{i=1}^{n}(t_i \times c_i)}$$

where

n	=	total number of reciprocating compressors in the fleet
v	=	vent gas volume for the calendar year for the reciprocating compressor (m^3)
t	=	the number of hours per calendar year that the reciprocating compressor is pressurized
c	=	number of pressurized throws for the reciprocating compressor

3) Effective January 1, 2022, the duty holder must bring any RCS with a measured vent gas rate greater than 5.00 m^3/hr/throw to below 5.00 m^3/hr/throw within 30 days of the measurement date.

8.6.2.3 Centrifugal Compressor Seals

1) For centrifugal compressors installed on or after January 1, 2022, the duty holder must limit the vent gas rate to less than 3.40 m^3/hr/compressor.

2) If the measured rate is not below this limit, the duty holder must take action to bring the rate below 3.40 m^3/hr/compressor within 90 days of the measurement date.

3) Effective January 1, 2022, for centrifugal compressors installed before January 1, 2022, the duty holder must limit the vent gas rate to less than 10.20 m^3/hr/compressor.

4) If the measured rate is not below this limit, the duty holder must take action to bring the rate below 10.20 m^3/hr/compressor within 90 days of the measurement date.

8.6.2.3.1 Exceptions

Vent gas from engine or turbine starts and compressor blowdowns is managed under the OVG limit in section 8.3 and excluded from the requirements in section 8.6.2.

8.6.2.4 Reporting

1) The operator of record must include the following in the annual methane emission report:

   a) the volume of vent gas emitted (m^3) from all compressor seals (including seals in compressors rated less than 75 kW and compressors pressurized for less than 450 hr/yr) by facility identifier

b) the corresponding mass of methane emitted (kg) by facility identifier

c) for each reciprocating or centrifugal compressor rated at least 75 kW and pressurized for more than 450 hr/yr, the following:

i) compressor frame serial number or other unique identifier

ii) legal survey location (LSD-SC-TWP-RGWM)

iii) authorization number and name of duty holder

iv) whether the equipment was installed before January 1, 2022, or on or after January 1, 2022

v) compressor type (reciprocating or centrifugal)

vi) if reciprocating, number of throws

vii) if centrifugal, seal type (dry or wet)

viii) whether the piston-rod-packing vents and drains and distance-piece vents and drains are controlled

ix) annual vent gas volume (m_3)

x) annual pressurized time of compressor (hours)

2) The operator of record must base reported compressor seal vent gas volumes on

a) a test result (may include metering), or

b) an estimate based on accepted engineering practices.

When the compressor seal vent is tested, the test result is used to estimate the compressor seal vent gas volume for the period until the next test is conducted. If any seals are replaced between tests, an estimate based on accepted engineering practices can be used to estimate the compressor seal vent gas volume for the period from the seal replacement until the next test is done. For further guidance, see *Manual 015*.

8.6.3 Vent Gas Limits for Glycol Dehydrators

1) The duty holder must limit methane emissions from each glycol dehydrator installed or relocated on or after January 1, 2022, to less than 68 kg of methane/day.

2) Effective January 1, 2022, the duty holder must limit methane emissions from each glycol dehydrator installed or relocated before January 1, 2022, to less than 109 kg of methane/day.

8.6.3.1 Exceptions

Vent gas from glycol regenerators used in refrigeration processes is managed under the OVG limit in section 8.3 and excluded from the requirements in section 8.6.3.

8.6.3.2 Reporting

Refer to *Directive 039: Revised Program to Reduce Benzene Emissions from Glycol Dehydrators* for inventory requirements for active glycol dehydrators.

8.7 Additional Requirements

Provided that all other requirements in section 8 of this directive are met, section 8.031 of the *OGCR* permits the connection of pressure-relieving devices at oil production batteries to open tanks (i.e., “pop tanks”).

1) Hydrocarbon products stored in atmospheric storage tanks at gas plants, compressor stations, and **gas batteries** must not have a true vapour pressure of more than 83 kilopascals (kPa) at 21.1°C if the tanks are vented to the atmosphere.

2) Unless directed by the AER to flare, incinerate, or conserve all casing gas and tank-top gas, temporary, short-term venting is allowed at wells (e.g., for well unloading and liquid cleanup), facilities, batteries where conservation is in place (see **partial equipment outages** in table 3), and pipelines (for natural gas transmission systems, see section 6.4), with the following conditions:

   a) Gas must contain less than 10 mol/kmol H_2S and must not result in exceedances of any of the AAAQOs outside the lease boundary.

   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 2.0 10^3 m^3 and the duration must not exceed 24 hours.

   e) The duty holder must conduct notification in accordance with section 2.3 and table 1.

   f) The AER field centre may consider alternatives to these requirements should special circumstances warrant. The licensee, operator, or approval holder must contact the appropriate AER field centre for approval of alternatives. For pipeline venting exemptions to these requirements, see section 6.4.

   g) Short-term vent gas emissions must not exceed the OVG limit set out in section 8.3 and 8.4.3.

3) The licensee, operator, or approval holder must notify residents and the appropriate AER field centre of nonroutine venting within 500 m and must comply with *Directive 056* in respect of providing information about continuous flaring, incinerating, and venting to persons entitled it. Refer to section 2.3 for nonroutine venting notification requirements.

4) Vent gas must not constitute an unacceptable fire or explosion hazard and must comply with the spacing requirements in section 7.8. Venting must also not occur closer than

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

    b) 50 m from a wellhead for vent stacks other than surface casing vents, or

    c) 25 m from a wellhead for heavy oil/bitumen well, storage tank, or other ignitable vapour including lined earth excavations used for waste oil storage.

5) Backflash control must be used on all vent lines connected to flares, enclosed **incinerators**, or **enclosed combustors**.

6) When equipment is used to control vent gas, the duty holder must design and operate control equipment to conserve or control at least 95 per cent of vent gas captured, with the equipment operating a minimum of 90 per cent of the time vent gas is emitted.

8.8 Requirements for 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 (excluding crude bitumen batteries). This includes gas off stock tanks, pressure safety valves, and equipment blowdown systems.

    a) Sour pressure-relief valves must be tied into flare systems if the gas contains more than 10 mol/kmol H_2S or result in off-lease H_2S odours.

2) At crude bitumen batteries, H_2S must not be vented to the atmosphere at a release rate greater than 0.04 m^3/hr.

    a) Sour pressure-relief valves must be tied into flare systems if the total H_2S release rate is greater than 0.04 m^3/hr H_2S or results in off-lease H_2S odours.

3) Venting or fugitive emissions must not result in any H_2S odours outside the lease boundary. Venting or fugitive emissions must not result in any offensive hydrocarbon odours outside the lease boundary that, in the opinion of the AER, are unreasonable either because of their frequency, their proximity to surface improvements and surface development (as defined in *Directive 056*), their duration, or their strength.

The AER recommends that pressure safety valves and blowdown systems be connected to a flare system where such systems are installed.

4) Venting must not result in exceedances of any AAAQOs outside the lease boundary.

5) Pressurized tank trucks or trucks with suitable and functional emission controls must be used when transporting sour fluids from upstream petroleum industry facilities.

8.9 Noncombustible Vent Gas Requirements

Release of inert gases such as nitrogen and carbon dioxide from upstream petroleum industry equipment or produced from wells may not have a gas composition that can be feasibly conserved or have a sufficient heating value to support combustion, such as helium production and processing. These gases may be vented to atmosphere subject to the following requirements:

1) Noncombustible gas mixtures containing odorous compounds including H_2S must not be vented to the atmosphere if off-lease odours may result. Some noncombustible gas mixtures have the potential to release methane. Alternatives to venting such gas include flaring, incineration, or enclosed combustion with sufficient dilution gas to ensure destruction of odorous compounds.

2) When managing a noncombustible gas mixture that cannot be conserved, the duty holder must choose the control method that minimizes the amount of carbon dioxide equivalent (CO_2e) being released.

    a) The duty holder must ensure a **qualified person** evaluates the resulting CO_2e emissions from the release of noncombustible gases as a vent as compared to a combustion event (flare, incineration, enclosed combustor) applying equations that are published by the manufacturer or using engineering estimates that are published and accepted for current industry emission reporting practices.

    b) The calculated emissions of nitrous oxide and methane resulting from a combustion event must be converted to a CO_2e value using the global warming potential values as required by the *Technology Innovation and Emissions Reduction (TIER) Regulation*.

8.10 Fugitive Emissions Management

The requirements in this section apply only to sites with **active wells or facilities** that are outside of the Peace River area. For operations within the Peace River area, the duty holder is to follow the fugitive emissions requirements in *Directive 084*.

8.10.1 Fugitive Emissions Management Program

1) The duty holder must have a documented fugitive emissions management program (FEMP).

2) The FEMP must be designed to reduce fugitive emissions, contain the elements listed in requirement 3 below, and be updated to reflect any changes to operations.

The duty holder may be directed to carry out additional actions to manage fugitive emissions if the AER determines that they are needed to mitigate potential risks to the environment or safety.

3) The following elements must be included in the FEMP:

   a) contact information of the individual accountable for the FEMP

   b) resources allocated to developing and implementing the FEMP, including which group within the company is responsible for maintaining and updating the FEMP and who will be conducting the surveys and screenings

   c) preventive maintenance practices to reduce or prevent fugitive emissions

   d) the procedures and plans that will be used to meet the required frequency of fugitive emissions surveys and screenings and to complete repairs; indicate any deviations from the prescribed frequency and provide justification

   e) techniques and equipment used for fugitive emissions surveys and screenings, including equipment make and model and any plans to use alternative technologies

   f) calibration methods and equipment maintenance practices for equipment used for fugitive emissions surveys

   g) training programs and certification completed by individuals conducting fugitive emissions surveys or screenings

   h) description of how individuals will be trained and how often they will be retrained or recertified

   i) internal procedures to track, manage, and verify the status of repairs

   j) data management practices and systems to ensure that survey and screening results trigger required repairs and that the repairs are captured for annual reporting

   k) provisions for continuous improvement of the FEMP, including how FEMP data will be used to evaluate program performance

For further information on FEMPs, see *Manual 016: How to Develop a Fugitive Emissions Management Program*.

8.10.2 Fugitive Emissions Surveys

The AER may conduct **fugitive emissions surveys or screenings**. Surveys conducted by the AER do not replace any survey the duty holder is required to complete. If the AER detects fugitive emissions, it will direct the duty holder to make repairs.

Fugitive emissions surveys are not required at facilities that

- are designed to vent all received and produced gas or
- do not have pipelines that transport natural gas (fuel gas, sales gas, marketable gas, and makeup gas) to, from, or on the site and that do not have vent gas control equipment and that only process or produce noncombustible gases.

8.10.2.1 Frequency

1) Subject to requirements 2 and 3 below, the duty holder must conduct fugitive emissions surveys at the frequency specified in table 5.
2) The survey frequency for facilities is dictated by the facility subtype code, as set out in *Manual 011*, and not the equipment on site.
3) The duty holder may adjust survey frequency to align with operational visits at sites where access is restricted. The duty holder must provide justification for the adjusted survey frequency to the satisfaction of the AER, upon request.

Table 5. Frequency of fugitive emissions surveys by equipment or facility type

Equipment or facility type	Facility subtype codes*	Frequency
Sweet gas plants	401	Triannually
Compressor stations (<0.01 mol/kmol H_2S in inlet stream)	601, 621†	
Liquid hydrocarbon storage tanks with vent gas control	N/A	
Produced water storage tanks with vent gas control	N/A	
Gas plants	402, 403, 404, 405	Annually
Straddle and fractionation plants	406, 407	
Compressor stations (≥0.01 mol/kmol H_2S in inlet stream)	601, 621†	
Battery and associated satellite facilities‡	311, 321, 322, 331, 341, 342, 344, 345, 351, 361, 362, 363, 364	

Equipment or facility type	Facility subtype codes*	Frequency
Custom treating facilities	611, 612	
Terminals	671, 673	
Injection/disposal facilities	501, 502, 503, 504, 505, 506, 507	

* Facility subtype codes are from *Manual 011*.

† Subtype codes for compressor stations and gathering systems do not differentiate between sweet and sour gas processing. H_2S content of gas in the inlet stream determines the survey frequency for those facilities.

‡ Wells linked to the facility subtype code but that are not on the same site are excluded from the surveys.

8.10.2.2 Equipment and Methods

1) The duty holder must conduct fugitive emissions surveys using one of the following:

   a) an organic vapour analyzer that detects hydrocarbons at a concentration of 500 ppm and is operated in accordance with the United States Environmental Protection Agency's *Method 21: Determination of Volatile Organic Compound Leaks*

   b) a gas-imaging camera that can detect a stream of pure methane gas emitted at a rate of 1.0 gram per hour or less under controlled laboratory conditions and that is operated within six metres of the equipment being surveyed

   c) other equipment or methods that are equally capable of detecting fugitive emissions; however, the duty holder must, upon request by the AER, demonstrate equivalence

For further guidance on survey methods and equipment, see *Manual 016*.

8.10.2.3 Scope

1) The duty holder must survey the following:

   a) equipment **components** with hydrocarbon throughput

   b) hydrocarbon gas-driven pneumatic devices

   c) tank-top equipment, including thief hatches and gauge-board assemblies

   d) surface casing vents and the area around the wellbore

   e) equipment used to destroy vent gas, including burners, flare ignitors, pilots, and combustors

   f) equipment used to conserve vent gas, including vapour recovery units and vent gas capture systems

8.10.2.4 Training and Equipment Maintenance

1) The duty holder must ensure that individuals conducting fugitive emissions surveys are trained to use fugitive emissions survey equipment.

2) The duty holder must ensure that all equipment used to detect or quantify fugitive emissions is operated, serviced, and calibrated to the manufacturer's recommendations and specifications.

8.10.3 Fugitive Emissions Screenings

8.10.3.1 Frequency

1) The duty holder must ensure that annual fugitive emissions screenings are completed at all well sites except for

- well sites that have been included in a fugitive emissions survey that year,
- well sites where all received and produced gas is vented, and
- well sites with only oil sands evaluation wells or test holes approved under section 2.030 of the *OGCR*.

8.10.3.2 Methods and Equipment

1) The duty holder must conduct fugitive emissions screenings using one of the following:

   a) audio, visual, or olfactory methods

   b) soap solution

   c) other methods or equipment that can detect fugitive emissions, such as unmanned aerial vehicles or truck mounted sensors

   d) fugitive emissions survey methods and equipment.

For guidance on accepted screening methods and equipment, see *Manual 016*.

8.10.3.3 Training

1) The duty holder must ensure that individuals completing fugitive emissions screenings are trained to identify common sources of fugitive emissions.

8.10.4 Repairs

1) The duty holder must repair sources of fugitive emissions or take other action to eliminate fugitive emissions within 24 hours of identification if fugitive emissions

   a) are causing off-lease odours,

   b) are the result of a failed pilot or ignitor on a **flare stack**, or

c) have the potential to cause safety issues.

2) The duty holder must repair all other sources of fugitive emissions or take other action to eliminate fugitive emissions within 30 days unless any of the following applies:

a) A major shutdown is required to complete the repair and there are no safety issues.

- Repair at the next planned shutdown or as directed by the AER.

b) The fugitive emissions, measured using US EPA *Method 21*, have a hydrocarbon concentration less than 10 000 ppm.

- No repair is required; however, these emissions must be quantified at each subsequent survey until the source is repaired.

c) The fugitive emissions are from surface casing vent flow or gas migration.

- Manage in accordance with the timelines in *Directive 087: Well Integrity Management*.

8.10.4.1 Repair Confirmation

1) The duty holder must confirm the integrity of any repair within seven days of the component being brought back into service.

8.10.4.2 Tracking Sources of Fugitive Emissions for Repair

1) The duty holder must track the source of fugitive emissions for subsequent repair unless the repair is conducted immediately upon emissions detection.

The AER recommends that a duty holder physically tag a source that needs to be repaired and remove the tag once the integrity of the repair has been confirmed.

8.10.5 Reporting

1) Subject to requirement 2 below, the operator of record must include the following in the annual methane emissions report:

a) the volume of fugitive emissions (m^3) by facility identifier, including any additional volume detected during an AER survey

b) the corresponding mass of methane emitted (kg) by facility identifier

c) for any fugitive emissions site survey, tank survey, or well screening during the reporting period:

i) the type of survey or screening (site survey, tank survey, or well screening)

ii) the date the survey or screening was completed (YYYY/MM/DD) per site by facility identifier

iii) the number of identified sources of fugitive emissions per site by facility identifier

2) Fugitive emissions screening surveys conducted under section 8.10.3 that do not detect any fugitive emissions are not required to be included in the annual methane emissions report.

8.10.6 Alternative Fugitive Emissions Management Program

The AER may permit innovative and science-based alternatives to the fugitive emissions management program prescribed in sections 8.10.2 and 8.10.3. Alternative programs may incorporate the use of various technologies such as unmanned aerial vehicles, vehicle-mounted sensors, and continuous monitoring devices to detect, track, repair, and report fugitive emissions.

1) To be considered an acceptable alternative fugitive emissions management program (alt-FEMP), a duty holder must choose an emission detection technology that has a documented **minimum detection threshold** (MDT) with a **probability of detection** (PoD) of at least ninety per cent (MDT 90%PoD), established by a qualified person from a third party, for the alt-FEMP **work practice**.

2) To obtain approval for an acceptable alternative fugitive emission management program (alt-FEMP) where the emission detection does *not* have a documented MDT of 90%PoD that was established by a qualified person from a third party, the following must be submitted for review and approval from AER:

   i) the rationale and supporting justification for selecting the technology

   ii) the assumed MDT 90%PoD

   iii) the risks associated with the technology

   iv) the adjusted alt-FEMP work practice to manage the risks

An alt-FEMP work practice describes how, when, where, and at what frequency an emission detection technology is applied to detect emissions and identify sites for **emission detection follow-up**.

3) A duty holder must implement an alt-FEMP work practice that is developed in accordance with the tables below. A duty holder may choose either program 1 or program 2 within table 6 & table 7 where a mobile emission technology has an MDT of 10 m^3/day of methane at 90%PoD.

4) Alternatively, a duty holder must develop an alt-FEMP work practice that is based on modelling that demonstrates equivalent or better emission reduction outcomes as the FEMP requirements in section 8.10.2. The duty holder must provide the AER with modelling results and assumptions for approval.

Table 6. Equivalent alternative FEMP based on a mobile emission detection technology *with* quantification

$MDT_{90\%PoD}$	Program	Alt-FEMP work practice equivalent
10 m^3 of CH_4/day	1	**Site screenings** at the same frequency as table 5 (either annually or triannually depending on facility type). Where fugitive emissions are detected, an emission detection follow-up is required at 80% of emitting sites within 30 days from the site screening date or an immediate fugitive emissions survey within 24-hours from the site screening date at sites with a cumulative volume of detected emissions above 100 m^3 of CH_4/day.
	2	Site screening biannually. Where emissions are detected, an emission detection follow-up is required at 50% of emitting sites within 30 days from site screening date or an immediate fugitive emissions survey within 24-hours from the site screening date at sites with a cumulative volume of detected emissions above 250 m^3 of CH_4 /day.
150 m^3 of CH_4/day	1	Site screening biannually. Where emissions were detected, an emission detection follow-up is required at 60% of emitting sites within 30 days from site screening date.
300 m^3 of CH_4/day	1	Site screening triannually. Where emissions were detected, an emission detection follow-up is required at all emitting sites within 30 days from site screening date.
500 m^3 of CH_4/day	1	Site screening triannually. Where emissions were detected, an emission detection follow-up is required at all emitting sites within 30 days from site screening date, and one additional annual site fugitive emissions survey at all sites must be performed.

Table 7. Equivalent alternative FEMP based on a mobile emission detection technology method *without* quantification

$MDT_{90\%PoD}$	Program	Alt-FEMP work practice equivalent
10 m^3 of CH_4/day	1	Site screenings at the same frequency as table 5 (either annually or triannually, depending on facility type). Where emissions were detected, an emission detection follow-up is required at all emitting sites screening within 30 days from site screening date.
	2	Site screening biannually. Where emissions were detected, an emission detection follow-up is required at all emitting within 30 days from site screening date.
150 m^3 of CH_4/day	1	Site screening biannually. Where emissions were detected, an emission detection follow-up is required at all emitting sites within 30 days from site screening date.
300 m^3 of CH_4/day	1	Site screening triannually. Where emissions were detected, an emission detection follow-up is required at all emitting sites within 30 days from site screening date.
500 m^3 of CH_4/day	1	Site screening triannually. Where emissions were detected, follow-up required at all emitting sites within 30 days from site screening date, and one additional annual site fugitive emissions survey at all sites must be performed.

Table 8. Equivalent alt-FEMP work practice based on a stationary emission detection technology method *with* quantification

$MDT_{90\%PoD}$	Table 5 facility survey frequency requirement	Alt-FEMP work practice equivalent
150 m^3 of CH_4/day	Triannually	Emission detection follow-up triannually, and large emitter emission detection follow-up (>500 m^3 of CH_4/day above baseline sustained for 24 hrs) within 30 days.
	Annually	Emission detection follow-up annually, and large emitter emission detection follow-up (>500 m^3 of CH_4/day above baseline sustained for 24 hrs) within 30 days.
300 m^3 of CH_4/day	Triannually	Emission detection follow-up triannually, and large emitter emission detection follow-up (>500 m^3 of CH_4/day above baseline sustained for 24 hrs) within 30 days, and one additional annual site fugitive emissions survey must be performed at all sites with stationary emission detection equipment.

Table 9. Equivalent alt-FEMP work practice based on a stationary emission detection technology method *without* quantification

$MDT_{90\%PoD}$	Table 5 facility survey frequency requirement	Alt-FEMP work practice equivalent
150 m^3 of CH_4/day	Triannually	Emission detection follow-up quarterly, and large emitter emission detection follow-up (>500 m^3 of CH_4/day above baseline sustained for 24 hrs) within 30 days.
	Annually	Emission detection follow-up biannually, and large emitter emission detection follow-up (>500 m^3 of CH_4/day above baseline sustained for 24 hrs) within 30 days.
300 m^3 of CH_4/day	Triannually	Emission detection follow-up quarterly, and large emitter emission detection follow-up (>500 m^3 of CH_4/day above baseline sustained for 24 hrs) within 30 days, and one additional annual site fugitive emissions survey must be performed at all sites with stationary emission detection equipment.

8.11 Methane Emissions Record Keeping

1) Duty holders must retain records of the following for four years from the date they were created, unless otherwise noted, and provide them to the AER upon request:

   a) Calculations, by site, used to determine the monthly volume and monthly mass of methane from each of the sources below:

      - defined vent gas
      - instruments and pumps
      - compressor seals

- glycol dehydrators
- fugitive emissions

In addition, provide

- the hours of equipment usage or activity rates used in the monthly calculations, and
- the supporting information, such as gas compositions, equipment test results, equipment or component numbers, gas density, conversion factors, and emission factors used in the monthly calculations.

If records are generated for compliance with *Directive 007: Volumetric and Infrastructure Requirements* or section 3.9 of this directive, the *Directive 007* records retention requirements and section 3.9 requirements supersede this requirement.

b) For fugitive emissions, the following:

i) the FEMP that is in effect

ii) sites where access is restricted and the reason for the restricted access

iii) completed training programs and valid certifications for all individuals conducting fugitive emissions surveys and screenings

iv) survey and screening results containing the information set out in the form available at Regulating Development > Rules and Directives > AER Forms > Directive Forms > *Directive 060* > Fugitive Emissions Survey or Screening Record

v) screening surveys conducted under section 8.10.3 that do not detect any fugitive emissions

c) Inventory, updated annually, of pneumatic instruments and pumps that emit vent gas, including the following:

i) tracking identifier or serial number

ii) legal survey location (LSD-SC-TWP-RGWM) and facility identifier

iii) installation or modification date

iv) make and model

v) device type (categorize as pump, level controller, non-level controller)

vi) for level controllers that vent gas, the actuation frequency

vii) for instruments that are exempt under section 8.6.1.1, the reason for the exemption (safety or response time)

d) Documentation that demonstrates that control equipment meets the requirements for vent gas control in section 8.7

e) The MRRCP that is in effect

f) For sites with first production or equipment installed before January 1, 2022, the dates of equipment changes for vent gas emissions management

g) The RCS fleet average vent gas rate calculations

h) Inventories of reciprocating and centrifugal compressors rated at least 75 kW, including the following:

   i) compressor frame serial number or other unique identifier

   ii) compressor power rating (kW)

   iii) legal survey location (LSD-SC-TWP-RGWM) and facility identifier

   iv) whether the equipment was installed before or after January 1, 2022

   v) licence number and licensee

   vi) compressor type (reciprocating or centrifugal)

   vii) number of throws (if reciprocating)

   viii) seal type (dry or wet if centrifugal)

   ix) whether seal vent is controlled or uncontrolled

   x) **control device** operating time, where applicable

   xi) compressor seal change-out date

   xii) the number of hours monthly a compressor was pressurized

   xiii) compressor seal measurement results, in m^3/hr

   xiv)compressor seal measurement dates

   xv) the measurement methodology applied (estimate or test)

   xvi)if a compressor test was conducted, the type of equipment used

2) If a duty holder implements an alt-FEMP, it must retain the following records for four years from the date they were created:

   a) Model run output and assumptions that the alternative FEMP is based on as per section 8.10.6(1)(b)(ii).

b) **Mobile emission detection technology** screening campaign records, including the following, as applicable:

i) site location (LSD)

ii) reporting facility identifier

iii) date and time of measurement

iv) the name and contact information of the fugitive emissions surveyor who conducted the survey or screening

v) description of the detection methodology and equipment used

vi) information justifying the technology selection and assumed MDT90%PoD

vii) latitude and longitude of detection

viii) meteorological data

ix) hydrocarbon emissions detected in kg/h

x) hydrocarbon emissions detected in ppm

xi) site images

xii) process building

xiii) type of emission (vent or fugitive)

xiv) characteristic of emission (continuous or intermittent emission)

xv) component type (with a detected fugitive emission)

xvi) actions undertaken to determine the source and type of emission (i.e., vent or fugitive)

xvii) actions undertaken to reduce emissions detected

c) **Stationary emission detection technology** records must include the following, as applicable:

i) site location (LSD)

ii) reporting facility identifier

iii) site schematic with clear identification of continuous monitoring sensor locations by unique identifier

iv) list of unique identifiers of the sensors

v) latitude and longitude of the sensors

vi) description of the detection methodology and equipment used

vii) information supporting the technology selection and assumed MDT90%PoD

viii) meteorological data used for detection and quantification

ix) sensor uptime for ideal environmental conditions to achieve 90% PoD (hrs)

x) site images/video of last 4 months

xi) site images/video of all emission events of last 4 years

xii) site average 15-minute hydrocarbon emissions detected in kg/h for 4 years

xiii) site average 15-minute hydrocarbon emissions detected in ppm for 4 years

xiv) rationale for not removing emission sources from the site

xv) supporting calculations for cost of removing sources from the site

xvi) sensor calibration records

xvii) sensor maintenance records

xviii) sensor annual uptime (hours)

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** from combustion (by flaring, incinerating, or use as equipment fuel) of sour **solution gas**, from low-pressure produced water flash gas, and from flaring of glycol dehydrator **vent gas**. Appropriate pollution prevention measures must be implemented in such situations to minimize sulphur emissions from combustion of sour or **acid gas**.

Guidelines in *ID 2001-03* apply to **sour gas** plants and other upstream petroleum facilities such as oil production batteries, gas batteries, and pipeline facilities.

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

The sulphur recovery requirements of section 9 and *ID 2001-03* apply to any continuous flaring or incineration of sour gas at gas gathering facilities (e.g., compressor or dehydrator sites).

9.1 Sulphur Recovery Exemption at Solution Gas Conservation Facilities

The AER and AEPA may approve deviations from sulphur recovery requirements in circumstances where sulphur emissions would be minimal and sulphur recovery would render gas conservation uneconomic. This section outlines what is required to receive an exemption.

Solution gas **conservation clustering** schemes that have a total inlet sulphur of between 1 and 5 tonnes/day may be considered for flexibility by the AER and AEPA in the application of *ID 2001-03*. Provisions for deviations from the sulphur recovery guidelines are in section 4 of *ID 2001-03*.

1) The licensee, **operator**, or approval holder must demonstrate to the AER, using the methodology in section 4.7, that implementing sulphur recovery would make the gas plant uneconomic.

2) The licensee, operator, or approval holder must demonstrate that revenues and cost estimates are reasonable.

3) Capital cost estimates for sulphur recovery must be based on appropriate technologies. The licensee, operator, or approval holder must identify cost-effective processes suited to the facilities in question.

4) Information on the following must be available to the AER upon request:

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

   b) incremental energy (e.g., fuel gas) requirements for gas compression and processing related to gas sweetening

   c) incremental energy (fuel gas) requirements for sulphur recovery processes

   d) H_2S concentration of gas, along with expected average sulphur emissions and variability of sulphur emissions

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

5) The licensee or operator must consult with residents within the radius set out in *Directive 056*, specifically explaining that a variance of the sulphur recovery guidelines is being applied for. Any objections must be disclosed in related **facility** applications.

6) The AER and AEPA will consider the scope of the production project, the duration of the sulphur emissions, and the views of the local public in making decisions on applying the sulphur recovery guidelines.

The existing processes used for *EPEA* approvals for sour gas processing plants and for AER 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.

The AER 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. Sour gas facility proliferation guidelines in *ID 2001-03*, section 6, stipulate how the AER will assess this matter.

7) The variances do not apply to sour gas production and processing facilities handling primarily nonassociated gas.

Appendix 1 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).

active facility A facility that has reported an operation (volumetric activity) to Petrinex in the last 12 calendar months or is a nonproduction reporting facility linked to an active facility.

active well A well that has reported an operation (production or injection) to Petrinex in the last 12 calendar months or is classified as an observational well by the AER.

carbon conversion efficiency (CCE) 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. 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

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

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 The practice of gathering the solution gas from several flares or vents at a common point for conservation.

combustion efficiency (CE)	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. CE is reported as the percentage of the net heating value that is released as heat through combustion.
component	A piece of equipment that has the potential to release hydrocarbons. Components include valves, connectors, pump seals, actuator seals, flow meters, pressure regulators, sampling connections, instrument fittings, engine and compressor crankcase vents, sump and drain-tank vents and covers, blowdown system vents, open-ended valves and lines, pressure vacuum relief valves, and gauge-board assemblies.
condensate	Refer to the *Oil and Gas Conservation Act.*
conserve, 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) × 100
conserving facility	Any potential tie-in point that is conserving gas, such as batteries, plants, compressor stations, pipelines, and pump stations.
control	For the purpose of section 8, means to conserve or destroy vent gas. Standards for when equipment is used to control gas are found in section 8.7.
control device	A device that is used to conserve or destroy vent gas.
crude bitumen	Refer to the *Oil and Gas Conservation Act*.
crude bitumen battery	A crude bitumen battery is an oil battery with crude bitumen production that has a density of 920 kg/m^3 or greater at 15 degrees Celsius.
crude oil	A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that is recovered or is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated, and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas, condensate, or crude bitumen.
crude oil battery	An oil battery with crude oil production excluding production that has a density of 920 kg/m^3 or greater at 15 degrees Celsius.

defined vent gas Vent gas from routine venting, excluding from pneumatic devices, compressor seals, and glycol dehydrators.

emergency flaring, incineration, enclosed combustion, or venting Emergency flaring, incineration, enclosed combustion, or venting occurs when safety controls within the facility are enacted to depressurize equipment to avoid possible injury or property loss resulting from explosion, fire, or catastrophic equipment failure. Examples of possible causes of emergency flaring, incineration, enclosed combustion, or venting include pressure safety valve overpressure and emergency shutdown.

emission detection follow-up An emissions investigation to identify the source of an emission, verified with emission detection technology or a fugitive emissions survey.

emissions testing facility A facility or well site as defined in the *Oil and Gas Conservation Act* that has installed specialized equipment to control, quantify, and monitor the volume and rate of planned emissions which is intentionally released into the atmosphere as prescribed in an emission test plan.

enclosed combustor, enclosed combustion A device that combusts waste gas with no visible flame that is limited to a maximum exit temperature or skin temperature. The terms “combustor” and “vapour combustor” fall under the category of enclosed combustor.

facility Refer to the *Oil and Gas Conservation Act.*

facility identifier As defined in *Directive 047*, a unique facility identification code, with four letters and seven numbers (e.g., ABWP1234567), assigned by Petrinex to each facility.

flare gas Gas that is combusted in a flare or other control device at upstream oil and gas operations. Flare gas excludes gas combusted or oxidized in an incinerator, enclosed combustor, or catalytic oxidation.* Types of gas, if combusted in a flare or other control device, that must be reported as flare gas include the following:

- waste gas
- pilot gas
- dilution and makeup gas added to a flare gas stream before flaring or incineration
- acid gas (routine and nonroutine)
- blanket gas, purge gas, and sweep gas
- gas used to operate pneumatic devices (pneumatic instruments, pumps, and compressors starters)
- gas from dehydrator still columns
- gas produced during well completions

- gas produced during well unloading operations
- gas that is flared or incinerated as a result of equipment failures or plant upsets

* A chemical process that uses a catalyst such as palladium, platinum, or other noble metal to oxidize hydrocarbon waste gas.

flare stack A device that combusts waste gas with an open flame above ground level. This includes shrouded and enclosed combustors with visible flame also known as an enclosed flare.

fuel gas Gas that is combusted and the released energy is used in upstream oil and gas operations. Types of gas that must be reported as fuel gas include gas burned by the following:

- engines
- catalytic* heaters and other building heaters
- process vessel burners
- sulphur recovery unit reaction furnaces
- line heaters
- thermoelectric generators

* A chemical process that uses a catalyst such as palladium, platinum, or other noble metal to oxidize hydrocarbon waste gas.

fugitive emissions Unintentional releases of hydrocarbons to the atmosphere. Fugitive emissions include component-based leaks that may result, for example, from wear or failure, abnormal processes, or malfunctioning equipment.

fugitive emissions screening Site-wide evaluation where the primary purpose is to identify fugitive emissions (e.g., from open thief hatches). This is less comprehensive than a fugitive emissions survey.

fugitive emissions survey Site-wide evaluation that uses equipment-based methods to detect and identify sources of fugitive emissions for repair. This is considered a comprehensive evaluation that can assist in reducing both small volumes and large volumes of fugitive emissions.

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.

incinerator A device that combusts waste gas with no visible flame and is temperature-controlled to a minimum exit temperature and a minimum residence time at maximum flow. A direct-fired thermal oxidizer is equivalent to an incinerator for this directive.

makeup gas Raw or processed gas that is added to another gas stream in order to maintain an adequate heating value during flaring or incineration.

measurement A procedure for determining a value for a physical variable. This may include metering, testing, estimating, or calculating.

minimum detection threshold (MDT) The smallest release rate of methane a technology can detect, typically described as kg methane/day.

mobile emission detection technology An emission detection technology that is moved around or at a site for less than 730 hours per calendar year and has a minimum detection threshold and probability of detection.

nonassociated gas Gas produced from a gas pool (i.e., not associated with oil or bitumen reservoirs or with production).

nonroutine flaring, incineration, enclosed combustion, or venting Intermittent and infrequent flaring, incineration, enclosed combustion, or venting. There are two types: planned and unplanned.

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.

operator	Refer to definition in the *Oil and Gas Conservation Act*.
operator of record	The person or organization that keeps records and submits production reports to Petrinex or the AER for a reporting facility identifier, whether or not that person or organization is the sole licensee or approval holder for all facilities or wells that are part of that reporting facility identifier.
partial equipment outage	A conserving facility that has a temporary reduction in output as a result of a planned or unplanned event that shuts down a portion of the facility. For example, when a crude bitumen battery tank vapour recovery unit shuts down while the casing gas continues to be conserved.
planned flaring, incineration, enclosed combustion, or venting	Flaring, incineration, enclosed combustion, or venting where the operator has control over when and for how long it will occur and also has control over release rates. Planned flaring, incineration, enclosed combustion, or venting results from the intentional depressurization of processing equipment or piping systems. Planned flaring, incineration, enclosed combustion, or venting may occur during pipeline blowdowns, equipment depressurization, start-ups, facility turnarounds, and well tests.
pneumatic instrument	A pneumatic device, powered by pressurized gas, used for maintaining a process condition such as liquid level, pressure, or temperature. Includes positioners, pressure controllers, level controllers, temperature controllers, and transducers.
pneumatic pump	A pneumatic device that uses pressurized gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm. Includes methanol and chemical injection pumps but does not include energy exchange pumps.
probability of detection (PoD)	The likelihood that a technology can detect an emission, given variables which could include release rate, windspeed, and distance from measurement to source. This is typically visualized as a logistic regression curve (i.e., an "S" shaped curve).
qualified person	A person holding an accredited professional qualification and acting within that person's professional scope of practice.
risk-based criteria	Refer to AEPA's *Non-Routine Flaring Management Modelling Guidance* for the purpose of *Directive 060* only.

routine flaring, incineration, enclosed combustion, or venting	"Routine" applies to continuous or intermittent flaring, incineration, enclosed combustion, or venting that occurs on a regular basis due to normal operation. Examples of routine flaring include glycol dehydrator reboiler still vapour flaring, tank vapour flaring, flash tank vapour flaring, and solution gas flaring. Routine venting can include gas from • production casing vents, • process vents, • tank vents, • blanketing, • online gas analyzer purge vents, • pneumatic devices, and • desiccant dehydrator regeneration vents and membrane dehydrator purge vents.
schools	All public, private, and charter preschool, elementary, and secondary schools. This includes First Nations and Métis schools but does not include a parent-provided home education program.
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 and Guidelines* 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 and Guidelines*.
site	The area defined by the boundaries of a surface lease for upstream oil and gas facilities and wells (pads counted as one lease).
site screening	A process of detecting emissions on a site or equipment-level with the use of (mobile or stationary) emission detection technology.
stationary emission detection technology	A continuous methane detection technology that is stationary or at a site for greater than 730 hours per calendar year and has a minimum detection threshold and probability of detection.
solution gas	All gas that is separated from condensate, oil, or bitumen production.
sour gas	Natural gas, including solution gas, containing H_2S.

sulphur conversion efficiency (SCE)	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). 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 the following: $$SCE = \frac{SO_{2,stack}}{(SO_{2,stack} + SO_{3,stack} + H_2S_{stack})}$$
sulphur emissions	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.
throw	The parts of a reciprocating compressor from the connecting rod to the cylinder. The number of throws on a compressor is equal to the number of connecting rods off the compressor crankshaft.
unplanned flaring, incineration, enclosed combustion, or venting	Emergency or upset operational activities closely associated with protecting the integrity of the facility and protecting safety. The operator has no control over when these activities will occur. There are two types of unplanned flaring, incineration, enclosed combustion or venting: upset and emergency.
upset flaring, incineration, enclosed combustion, or venting	Upset flaring, incineration, enclosed combustion, or venting occurs when one or more process parameters fall outside the allowable operating or design limits and flaring, incineration, enclosed combustion, or venting is required to aid in bringing the production back under control. Upset flaring, incineration, enclosed combustion, or venting may occur due to the production of off-spec product; the formation of hydrates; loss of electrical power; process upset; or operator error.

vent gas

Uncombusted gas that is released to the atmosphere at upstream oil and gas operations. Vent gas does not include fugitive emissions, but does include the following:

- waste gas
- gas used to operate pneumatic devices
- gas from compressor seals, starters, and blowdowns
- gas from facility upsets and emergency shutdowns
- gas from dehydrator still columns
- gas from production tanks, not including methanol and chemical tanks
- gas released during pigging operations
- gas produced during well completions
- gas produced during well unloading volumes
- blanket gas

work practice

A description of how to apply a technology to gather information about emissions, including operating procedures (e.g., distance from source, measurement time, environmental envelopes and limitations) and identifying locations for emission detection follow-up.

Appendix 2 Background to *Directive 060*

Concerns about flaring prompted the Alberta Energy and Utilities Board (EUB; now the AER) and Alberta Environment (now Alberta Environment and Protected Areas) to support Alberta Research Council research on flaring. Findings reported in 1996 suggested that the efficiency of flare stacks at destroying waste gas was not as high as originally thought and that various products of incomplete combustion were 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. The Canadian Association of Petroleum Producers (CAPP) brought the issue of flaring to the Clean Air Strategic Alliance (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 of 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 reducing flaring.

Royalty Treatment of Flared and Vented Gas

In December 1998, the Government of Alberta created the Otherwise Flared Solution Gas Royalty Waiver Program to encourage the productive use of solution gas currently being flared. For more information, see Alberta Energy *Information Letter (IL) 99-19: Otherwise Flared Solution Gas Royalty Waiver Program* available on Alberta Energy’s Natural Gas Royalty-Related Information webpage.

The program is summarized as follows:

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

The EUB Implements the CASA Recommendations

In 1999, in the first edition of *Directive 060* (then called *Guide 60*), the EUB implemented a solution gas management framework, a decision-tree process, and other CASA recommendations. The guide mandated firm, short-term solution gas flare reduction targets of 15 per cent and 25 per cent 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, incineration, 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 said that implementation of the solution gas management framework and the flare reduction targets by the upstream petroleum industry had successfully resulted in a 53 per cent 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. The team recommended that a 50 per cent 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 in March and June 2005. These recommendations were implemented through a rewrite of *Directive 060* released in November 2006. Significant changes included changing the economic threshold of the feasibility test for solution gas conservation from a net present value of zero to −$55 000. Also, economic evaluations were no longer required for sites that flared, incinerated, or vented less than 900 m^3/day of solution gas. Another significant addition to the directive was the concept of a duration limit for well test flaring and incineration.

Canadian Association of Petroleum Producers' Recommendations

In 2004, CAPP established the Nonroutine Flaring Task Team (NRFTT) to review dispersion modelling requirements for intermittent and infrequent flaring. The NRFTT comprised government and industry. The CAPP document, titled *Sour Non-Routine Flaring Framework*, outlined the new regulatory approach and comprehensive plan for managing nonroutine flaring as developed by the NRFTT, and the process that led to its development.

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

Focus on Methane Emissions

In 2015, the Government of Alberta directed the AER to design and implement requirements that result in a 45 per cent reduction of methane emissions from the upstream oil and gas sector by 2025 from 2014 levels. In 2016, the AER created a multistakeholder committee to provide recommendations to the AER on regulating methane emissions in the province. The committee had representatives from the Government of Alberta, the AER, industry, and environmental nongovernmental organizations.

With consideration of the recommendations from the committee, the AER developed methane emissions reduction requirements in *Directive 060*. The requirements cover both vent gas and fugitive emissions.

A mandatory review of the methane emissions requirements will occur within three years of the requirements taking effect to determine if any adjustments are needed.

Ongoing Research

The AER supports the 2004 CASA recommendations for additional research so that Alberta can continue to move towards the use of practical flare combustion efficiency standards where flaring is necessary.

The AER supports the Petroleum Technology Alliance’s Alberta Upstream Petroleum Research Fund (AUPRF). AUPRF is an industry-sponsored fund supported by CAPP and the Explorer and Producers Association of Canada (EPAC). The objective of AUPRF is to provide an efficient and effective mechanism to coordinate, initiate, fund, complete and communicate on environmental research that is needed by the industry and government regulators to enable a prosperous upstream oil and gas industry that achieves socially and environmentally responsible recovery of Canada’s petroleum resources through effective, market-driven collaboration.

AUPRF supports practical science-based studies that develop credible and relevant information to address knowledge gaps in the understanding and management of high priority environmental and social matters related to oil and gas exploration and development in Alberta. Research reports are shared broadly with the oil and gas industry as well as with regulators, government agencies, and other stakeholders.

Appendix 3 Resident Flaring/Venting/Incinerating Notification Sample Form

We will be flaring/incinerating/venting a (___ % H_2S) well in accordance with AER *Directive 060* at the location stated below.

Flaring/incinerating/venting category (check those that apply)	**AER 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 (780-743-7214)
(Check one)	Medicine Hat (403-527-3385)
Oil well	Red Deer (403-340-5454)
Gas well	Slave Lake (780-843-2050)
	Edmonton – formerly St. Albert (780-460-3800)
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)	
Licensee or Operator Name	
Licensee or Operator Representative	
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 4 Zero Flaring and Venting Agreement

The following serves to outline the agreement between __________________________ (applicant) and __________________________ (landowner or occupant) respecting flaring at the well at W. The applicant agrees to not flare from the well before 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

The licensee, operator, or approval holder may flare in emergency situations for safety of the public or environmental protection.

If the ownership of the well is transferred to another licensee, operator, and/or approval holder, this agreement will remain in effect for the new licensee, operator, or approval holder and it is the licensee, operator, or approval holder's responsibility to advise any successors of this agreement.

This agreement no longer applies once this well is tied into a production facility or once production operations begin.

Applicant Signature________________________ Landowner or Occupant Signature (optional)_________________________

Printed Name _____________________________ Printed Name______________________________

Licensee, operator, or approval holder ____

Location__________________________________

Telephone________________________________ Telephone_________________________________

Email/Fax________________________________ Email/Fax_________________________________

Date ____________________________