

Directive 087

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Well Integrity Management

Contents

1	Introduction	2
1.1	Purpose of This Directive.....	2
1.2	AER Requirements	2
1.3	What's New in This Directive	3
1.4	Records Retention	3
2	Isolation Packers	3
2.1	Testing and Reporting	3
2.1.1	Maintaining a Triennial Testing Schedule	4
2.1.2	Testing Procedures	5
2.2	Repairing.....	6
3	Surface Casing Vent Flow & Gas Migration	7
3.1	Classification.....	7
3.1.1	"Serious" Surface Casing Vent Flow	7
3.1.2	"Considered Nonserious" Surface Casing Vent Flow.....	8
3.1.3	"Nonserious" Surface Casing Vent Flow	8
3.1.4	"Serious" Gas Migration	8
3.1.5	"Nonserious" Gas Migration	8
3.1.6	Reclassification of SCVF or Gas Migration	9
3.2	Testing	9
3.2.1	Surface Casing Vent Flow.....	9
3.2.2	Gas Migration	10

3.3	Reporting	10
3.4	Repairing.....	11
3.4.1	Option 1 – Routine Repair Program (AER Approval Not Required)	12
3.4.2	Option 2 – Nonroutine Repair Program (AER Approval Required).....	13
3.4.3	Option 3 – Deferral of Repair (AER Approval Required).....	13
4	Surface Casing Vent Assemblies	15
4.1	Exemption Criteria	15
5	Casing Failures.....	16
5.1	Reporting	16
5.2	Repairing.....	16
Appendix 1	Definitions	19
Appendix 2	Suggested Procedures for Testing for Surface Casing Vent Flows	21
Appendix 3	Suggested Procedures for Testing for Gas Migration.....	23
Appendix 4	Suggested Gas Identification Techniques and Annular Flow Testing Procedures.....	25
Table 1.	Minimum isolation packer testing requirements (unless otherwise specified in an AER approval).....	4

1 Introduction

1.1 Purpose of This Directive

This directive contains testing, reporting, and repair requirements for isolation packers, surface casing vent flows (SCVFs), gas migration, and casing failures.

1.2 AER Requirements

The following AER requirements are 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, Regulating Development > Compliance > [Compliance Assurance Program](#).

1.3 What's New in This Directive

Changes related to carbon dioxide (CO₂) enhanced oil recovery (EOR) storage and CO₂ sequestration schemes have been made to sections 3.1.1 and 3.2.1 and to appendix 1. Because a licensee of a geothermal well must follow requirements in this directive, references to the [*Geothermal Resource Development Rules*](#) have been added.

1.4 Records Retention

- 1) The licensee must keep all testing, monitoring, and repair records created or collected under this directive for the life of the well plus two years, unless otherwise authorized by the AER.
- 2) The AER may at any time require licensees to produce any documentation required under this directive.

2 Isolation Packers

Questions about this section should be submitted to ResourceCompliance@aer.ca.

2.1 Testing and Reporting

A packer isolation test means a pressure test of the tubing and casing annulus designed to evaluate the integrity of the wellhead, casing, tubing, and packer.

- 3) Effective January 1, 2021, licensees must conduct isolation packer testing as per table 1, unless other testing requirements are specified in an AER approval.
- 4) The test results must be reported through the designated information submission system between January 1 and December 31, within the same calendar year the test was performed.
- 5) Licensees are responsible for interpreting and reporting test results.
- 6) An isolation packer test record must contain all of the information contained in sections 2.1.2 and 2.2 of this directive for each well tested. A packer test form is available on our website.

Table 1. Minimum isolation packer testing requirements (unless otherwise specified in an AER approval)

Well type	Test schedule	Minimum pressure test length (minutes)*	Minimum test pressure (kPa)
Production well with H ₂ S greater than 50 moles per kilomole, unless the well is produced by artificial lift	annual	15	1400
Injection and disposal wells			
Class 1a	annual	15	The greater of 7000 kPa or 1.3 times the wellhead injection pressure (not exceeding the approved maximum wellhead injection pressure)
Class 1b (including Class II/1b)	annual	15	1400
Class II (including Class II/IV)	triennial	15	1400
Class III (including Class II/III)	annual	15	1400
Acid gas	annual	15	1400

The AER publishes a list of wells each calendar year that are potential candidates for packer isolation testing through the designated information submission system. This list is not to be relied on as complete and is only to be used as a guide. Licensees are responsible for knowing their inventory and ensuring that all packer testing requirements are met.

Testing requirements for the initial placement of packers for injection and disposal wells is specified in *Directive 051*.

After initial placement, for all wells where a packer is required, the packer must remain in the wellbore, be tested for the life of the well, and meet all requirements of this directive until suspension requirements of *Directive 013: Suspension Requirements for Wells* or abandonment requirements of *Directive 020: Well Abandonment* are met, or the well is converted to a well type where a packer is no longer required.

2.1.1 Maintaining a Triennial Testing Schedule

Annual means at least once every calendar year (January 1 to December 31).

Triennial means at least once every three calendar years.

- 7) Where a triennial testing frequency is permitted (see table 1), a licensee must do all of the following:
 - a) Develop an effective program to monitor well integrity between packer isolation tests.
 - b) Provide documentation of the (corporate or site specific) monitoring program to the AER upon request.

- c) Investigate any indications of well integrity failure such as continuous or sudden pressure changes, annular fluid level changes, or anomalies that may indicate a well integrity failure between triennial tests.

It is recommended that, between packer isolation tests, licensees record, at a minimum, monthly tubing and casing pressures to track any pressure changes that may be indicative of a failure.

2.1.2 Testing Procedures

- 8) For the duration of the pressure test, the pressure must never drop below the minimum listed in table 1, and the rate of the pressure change must show a decreasing trend towards stabilization.

Rate of change means the amount of pressure change over a 1-minute period trended throughout the pressure test.

Licensees should conduct packer isolation tests at as close as practical to normal operating well conditions.

- 9) The maximum overall pressure change for the test duration must not exceed 50 kPa to be considered satisfactory.
- 10) Licensees must conduct and record packer isolation tests using calibrated (as per manufacturers specifications) digital pressure gauge equipment that has a minimum resolution of 1.0 kPa. The data must be collected by using digital pressure gauge equipment with data logging capability or by manually recording the data. Digital pressure gauges with data logging capabilities must be set to record at a minimum interval of 15 seconds (minimum four times per minute), and manually recorded data must be recorded at a minimum interval of one reading per minute for the duration of the test. The use of rotary chart equipment for packer isolation testing is not accepted.
- 11) Licensees must conduct packer isolation tests using the procedures provided below for the applicable case.

Case 1 – Casing pressure >1400 kPa prior to bleed down

- Record initial casing and tubing pressures.
- Bleed the casing pressure off and record the bleed-off volume and the types of any gas or fluid recovered. Volumes may be estimated where measurement is impractical.
- Record the shut-in casing pressure after a minimum of 24 hours.
- To be considered satisfactory, the pressure change over a 24-hour period must not exceed 50 kPa.

Case 2 – Casing pressure ≤ 1400 kPa prior to bleed down

- Record initial casing and tubing pressures.
- Bleed the casing pressure off and record the bleed-off volume and the types of any gas or fluid recovered. Volumes may be estimated where measurement is impractical.
- Pressure test the casing annulus as described in table 1 and record the annular fill volume.
- Bleed the casing pressure off and record the shut-in casing pressure after a minimum of 24 hours.
- To be considered satisfactory, both the pressure change during the 15-minute pressure test and the pressure change over a 24-hour period must not exceed 50 kPa.

Case 3 – No initial casing pressure

- Record initial casing and tubing pressures.
- Pressure test the casing annulus as described in table 1 and record the annular fill volume.
- Bleed the casing pressure off.
- To be considered satisfactory, the pressure change during the 15-minute pressure test must not exceed 50 kPa.

Case 4 – Licensee designed test customized for well operations

Test procedures must effectively identify any well integrity concerns or potential failures in the tubing, casing, packer seal, or wellhead seal assembly; meet the minimum pressure and duration requirements specified in table 1 when pressure testing; and be documented.

2.2 Repairing

- 12) Any failure identified through a packer isolation test, site visit, or triennial monitoring program must be reported through the designated information submission system within 30 days of detection.
- 13) Upon detection, licensees must investigate failures and complete necessary remedial work and retest for hydraulic isolation. Repair must be completed and satisfactory test results reported through the designated information submission system within 90 days of failure detection.

If a casing failure is discovered as a result of packer isolation testing or repairs, the casing failure must also be reported through the designated information submission system within 30 days of detection. The failure cannot be considered repaired until a satisfactory packer isolation test is conducted and reported or until AER suspension requirements (*Directive 013*) or abandonment requirements (*Directive 020*) are met.

The initial pressure test requirements in *Directive 051* apply when a packer is repaired, reset, or replaced.

3 Surface Casing Vent Flow & Gas Migration

Questions about this section should be submitted to WellOperations@aer.ca.

A surface casing vent flow (SCVF) is the flow of gas or liquid out of the surface casing annulus (often referred to as internal migration). Note that steam and steam condensates (with no hydrocarbons or other fluids present) venting from the annulus of an operating thermal well does not in itself indicate an SCVF. The AER must be notified at WellOperations@aer.ca if a vent flow is identified through intermediate casing annuli.

Gas migration is the flow of gas or liquid that is detectable at surface outside of the outermost casing string (often referred to as external migration or seepage).

3.1 Classification

3.1.1 “Serious” Surface Casing Vent Flow

14) An SCVF is classified as “serious” in any of the following situations:

- a) A nonsaline water zone not covered by cemented surface casing or by the cement of the next casing string. Nonsaline water is any water with total dissolved solids equal to or less than 4000 milligrams per litre (mg/L).
- b) The stabilized average gas flow is ≥ 300 cubic metres per day (m^3/d) or a surface casing vent stabilized shut-in pressure is greater than
 - i) one-half the formation leak-off pressure at the surface casing shoe or
 - ii) 11 kPa/m multiplied by the surface casing setting depth in metres.

For the purposes of SCVF, stabilized shut-in pressure is defined as an SCVF shut-in pressure that does not build over 2 kPa/hour over a six-hour period or can be reasonably estimated to not exceed the pressure limits outlined above.
- c) Hydrogen sulphide (H_2S) is present.
- d) Hydrocarbon liquid (oil) is present.
- e) Water is present in the vent flow, regardless of flow rate (excluding steam condensation on thermal wells).
- f) The well was previously abandoned (cut and capped).
- g) The SCVF was caused by a wellhead seal or casing failure.

- h) The SCVF constitutes a fire, public safety, or environmental hazard.
- i) The well also has an identified gas migration problem.
- j) The well is associated with a CO₂ EOR storage scheme or CO₂ sequestration scheme as described in *Directive 065* and the CO₂ concentration of the surface vent gas is above five per cent.

3.1.2 “Considered Nonserious” Surface Casing Vent Flow

Despite requirement 14(a), an SCVF in a well where a nonsaline water zone is not covered by cement may be classified as “considered nonserious” when all of the following conditions are met:

- a) The SCVF has a stabilized average gas flow of less than 300 m³/d.
- b) The stabilized shut-in pressure does not exceed 11 kPa/m multiplied by the surface casing setting depth in metres.
- c) The flow is only gas containing no hydrogen sulphide and no hydrocarbon liquid, drilling mud, water, or other contaminants.
- d) There are no producing domestic or agricultural water wells from the unprotected aquifers within a 1 km radius.

- 15) A licensee must reclassify an SCVF as “serious” if conditions change such that the above conditions are no longer met.

3.1.3 “Nonserious” Surface Casing Vent Flow

- 16) An SCVF is classified as “nonserious” if none of the conditions in section 3.1.1 are present.

3.1.4 “Serious” Gas Migration

- 17) A gas migration is classified as “serious” if any of the following conditions are met:

- a) There is a fire, public safety hazard, or off-lease environmental impact such as groundwater contamination.
- b) The well was previously abandoned (cut and capped).
- c) There are producing domestic or agricultural water wells from the unprotected aquifers within a 1 km radius.

3.1.5 “Nonserious” Gas Migration

- 18) A gas migration is classified as “nonserious” if none of the conditions in section 3.1.4 are present.

3.1.6 Reclassification of SCVF or Gas Migration

- 19) All SCVF or gas migration reclassification requests must be submitted, along with supporting documentation, to the AER at WellOperations@aer.ca.

3.2 Testing

3.2.1 Surface Casing Vent Flow

- 20) Licensees must conduct an SCVF test or a surface casing annulus flow test on a well at the following times:

- a) within 90 days of drilling rig release or before the start of thermal operations, whichever is earlier;
 - b) before initial fracturing operations for a single-barrier system (see [Directive 083: Hydraulic Fracturing – Subsurface Integrity](#));
 - c) between 60 and 90 days after completing fracturing operations for a single-barrier system (see [Directive 083](#));
 - d) if the well is associated with CO₂ EOR storage or CO₂ sequestration as described in [Directive 065](#), before the start of injection and between 60 and 90 days after injection;
 - e) within 30 days of detecting a SCVF;
 - f) before conducting surface abandonment operations (see [Directive 020](#)); and
 - g) upon re-entry of an abandoned well.
- 21) Where an SCVF test (such as a bubble test) indicates that a leak may be present, and a vent flow is confirmed, licensees must obtain a stabilized flow rate and a stabilized shut-in pressure trend.
- 22) After detecting a “nonserious” or “considered nonserious” SCVF, the licensee must perform an SCVF test in each of the following two calendar years to detect possible changes.
- a) If these tests show a consistent or declining trend in stabilized shut-in pressure and flow rate, then the licensee must conduct another follow-up test in the sixth calendar year after the SCVF was first detected to confirm that the SCVF stabilized shut-in pressure and flow rate are still stable or declining. If there are no changes to the SCVF status after the first, second, and sixth annual tests are completed, or if the SCVF has died out, no further annual testing is required.
 - b) If these tests indicate that the stabilized shut-in pressure or flow rate is trending towards becoming a “serious” SCVF, then additional annual testing is required until the licensee can reasonably demonstrate that the SCVF status will not become a “serious” SCVF.

- 23) The results of the required test after the initial detection of an SCVF do not need to be submitted to the AER unless requested. However, the licensee may submit them when submitting their incident report if they wish.

Appendix 2 provides some suggested procedures for SCVF testing.

3.2.2 Gas Migration

- 24) Licensees must conduct in-soil gas migration testing if surface soil testing methods indicate a gas migration is present. Gas migration testing must be conducted when environmental conditions will provide a relevant and reliable reading (e.g., frost-free ground and not after periods of rainfall).

- 25) Licensees must conduct gas migration testing on wells with one casing string at the following times:
- a) within 90 days of drilling rig release or before the start of thermal operations, whichever is earlier;
 - b) before initial fracturing operations (see *Directive 083*);
 - c) between 60 and 90 days after completing fracturing operations (see *Directive 083*);
 - d) within 30 days of detecting a gas migration;
 - e) before conducting surface abandonment operations (see *Directive 020*); and
 - f) upon re-entry of an abandoned well.
- 26) If the well is within Townships 45–52, Ranges 1–9, West of the 4th Meridian, or Townships 53–62, Ranges 4–17, West of the 4th Meridian (see *Directive 020*, figure 6), licensees must
- a) conduct gas migration testing within 90 days of drilling rig release or before the start of thermal operations, whichever is earlier, and
 - b) conduct gas migration testing before surface abandonment (cut and cap).

Appendix 3 provides some suggested procedures for in-soil gas migration testing.

The AER recommends that all wells be tested for gas migration before abandonment.

3.3 Reporting

- 27) The licensee must notify the AER through the designated information submission system within 30 days of detecting an SCVF or gas migration at a well.
- 28) If a “nonserious” or “considered nonserious” SCVF becomes “serious,” the licensee must notify the AER through the designated information submission system within 30 days of the

test and must report in the comments tab the date in which the SCVF was detected to be “serious.”

- 29) If a casing failure is discovered as a result of testing for SCVFs or gas migration, the casing failure must be reported separately through the designated information submission system within 30 days of detection.
- 30) After successful repair, reports of SCVFs and gas migration must be closed in the designated information submission system before submitting information for the well licence abandonment.

A company can view all of its open and closed SCVF and gas migration reports in the designated information submission system.

3.4 Repairing

- 31) The licensee of a well with a “serious” SCVF or gas migration must repair the problem within 90 days of detection.
- 32) The licensee of a well determined to have a “nonserious” or “considered nonserious” SCVF or gas migration must repair the problem at the time of well abandonment.
 - a) Should an SCVF or gas migration problem become “serious,” the licensee must conduct repairs within 90 days of the classification changing.
- 33) In accordance with sections 3.012 and 3.013 of the *Oil and Gas Conservation Rules* or sections 97 and 98 of the *Geothermal Resource Development Rules*, whichever is applicable, and the AER’s *Directive 020*, a licensee must repair all well integrity issues when abandoning a well upon the termination of the mineral lease or upon a request for a re-entry for repair (as per conditions specified by the AER).
- 34) If a well does not have a licence status of “abandoned,” “rec-certified,” or “rec-exempt” and is determined to have an SCVF or gas migration, AER nonroutine approval is required before work may be started on a fourth repair attempt and onwards. (AER approval of the first three repair attempts is not required where the conditions in section 3.4.1 are met).
 - a) If the licensee plans to request a deferral of repair as outlined in section 3.4.3, the request must be received by the AER as soon as practicable after detection and before the 90-day repair deadline.
- 35) If a well has a licence status of “abandoned,” “rec-certified,” or “rec-exempt” and is determined to have a surface casing vent flow or gas migration, licensees must investigate the problem and submit a mitigation plan with proposed timing for the repair of the well to WellOperations@aer.ca within 90 days of the detection date.

- a) AER nonroutine abandonment approval is required before re-entering the well (see Directive 020).
- b) All repair attempts require AER nonroutine approval.

36) In the event that liquid is present at a “serious” SCVF, the licensee must also ensure the following:

- a) All fluids are contained at surface to prevent any on- or off-lease damage.
- b) The surface casing vent assembly does not freeze during the winter months.
- c) The SCVF is not a result of a wellhead seal leak or casing failure.
- d) The vent assembly remains open to atmosphere (*Oil and Gas Conservation Rules* section 6.100(1) or *Geothermal Resource Development Rules* section 29 (1)).

Installation of a burst plate or anything else that could potentially restrict the flow of fluids from the vent assembly requires AER approval.

37) A licensee must not pump any type of fluid down the surface casing annulus for the purpose of repairing an SCVF or gas migration.

There are three options available to a licensee: (1) routine repair, (2) nonroutine repair, and (3) deferral of repair.

38) Licensees must be able to reasonably demonstrate they have located the source of the SCVF or gas migration and that proposed repair operations will make every effort to establish contact with the flow path to surface.

3.4.1 Option 1 – Routine Repair Program (AER Approval Not Required)

Licensees do not need prior AER approval to repair routine SCVF or gas migration provided that all of the following conditions are met:

- This attempt is the first, second, or third attempt.
- The source depth or formation of origin is determined (e.g., incorporating appropriate combinations of fluid analysis, diagnostic logging suite, geological interpretation, etc.).
- The SCVF or gas migration problem is stopped or eliminated within three attempts by perforating or creating slots and cementing the casings either
 - at or below the source and circulating cement across the source formation or
 - at the barrier immediately above the source, if performing a cement squeeze.
- The repair attempt is conducted below the base of groundwater protection depth or 15 metres below the surface casing shoe, whichever is deeper.

- The cement and additives used in the repair program meet AER minimum cement requirements (see [Directive 009: Casing Cementing Minimum Requirements](#) and *Directive 020: Well Abandonment*).
- The repair method does not use deformation or destructive methods (i.e., section milling, thermite, etc.) that will either prevent or severely restrict regaining access to the lower wellbore in the event the repair attempt is unsuccessful.
- The casing is pressure tested to the maximum operating pressure for 10 minutes. Note, the pressure test trend must demonstrate a decreasing rate of change approaching a stabilized pressure close to the maximum operating pressure over a minimum 10-minute period.

3.4.2 Option 2 – Nonroutine Repair Program (AER Approval Required)

This option is to be used if the licensee designs a repair program that deviates from the criteria outlined in option 1.

- 39) The repair program must be submitted to the AER for approval before implementation and before the repair deadline. The program must include all of the following:
- a) method used to identify the source of the SCVF or gas migration,
 - b) all relevant logs,
 - c) casing and cementing details,
 - d) base of groundwater protection depth,
 - e) current wellbore schematic and complete details of the proposed repair program,
 - f) proposed repair depth and method,
 - g) summary of any previous attempts to repair the SCVF or gas migration, and
 - h) summary of surface casing vent flow rates and stabilized shut-in pressures at detection and before and after each of the previous repair interventions.

Licensees may use the variance request forms found on our website.

3.4.3 Option 3 – Deferral of Repair (AER Approval Required)

- 40) AER approval is required to defer repair of a serious SCVF or gas migration or both.

Deferral of Repair

The licensee's repair deferral request should include the following information:

- written assertion that the subject well is currently an active well (meaning not an "inactive well" as defined in *Directive 013*),

- the length of time of deferral,
- the source depth or formation of origin,
- written assertion that the licensee owns the mineral rights to produce the source formation,
- current wellbore schematic including cementing details on all strings of casing,
- review of offset water wells and aquifers,
- a risk analysis confirming that the SCVF or gas migration will not contribute to potential cross-flow contamination of porous intervals or groundwater,
- written assertion that multiple aquifers do not exist within the uncemented interval,
- the proposed monitoring schedule, and
- description of proposed containment systems to ensure that there is no on- or off-lease release of fluids.

Deferral with Installation of a Burst Plate

If the repair deferral request includes the installation of a burst plate, the licensee should include the following additional information:

- written assertion that the SCVF is only nonsaline water (there is no gas or other hydrocarbons present),
- the flow rate and the stabilized shut-in pressure, and
- confirmation that the vent flow is not a result of a wellhead seal leak or casing failure.

Deferral of Repair by Producing a Serious SCVF

If a licensee plans to produce a “serious” SCVF, the repair deferral request should include the following additional information:

- the source depth or formation of origin of the SCVF,
- written assertion that the licensee owns the mineral rights to produce the source formation,
- SCVF gas composition and confirmation that the gas contains 0 per cent H₂S, and
- written assertion that
 - the cemented portion of the surface casing or the next casing string covers the deepest known groundwater,
 - a pressure-relief device is installed to ensure that excessive pressure is not exerted below the casing shoe when the system is shut in,

- a check valve is installed downstream of the pressure-relief device to prevent backflow,
- the SCVF is continuously measured and reported on the monthly production reports,
- the SCVF is tied in and placed on production within 60 days of receiving approval,
- the licensee will report to the AER the date the SCVF is tied in, and
- the vent flow will be able to flow to line conditions.

If a licensee produces a “nonserious” SCVF, AER approval is not required; however, the same criteria, timelines, and design considerations for producing a “serious” SCVF apply.

4 Surface Casing Vent Assemblies

Questions about this section should be submitted to WellOperations@aer.ca.

Unless otherwise provided, licensees must install a vent assembly to comply with section 6.100(1) of the *Oil and Gas Conservation Rules* or section 29(1) of the *Geothermal Resource Development Rules*, whichever is applicable. A well does not require a vent assembly if it meets the exemption criteria in section 4.1.

4.1 Exemption Criteria

- 41) Wells, with the exception of thermal wells, are not required to install a surface casing vent assembly if all of the following are true:
 - a) The true vertical depth of the well is less than 1000 metres (m).
 - b) The gas deliverability is less than 28 000 m³ per day absolute open flow (AOF).
 - c) The hydrogen sulphide (H₂S) content is 0.00 moles per kilomole.
 - d) There is no evidence of surface casing annular flow of gas, water, or liquid hydrocarbon.
- 42) For wells that did not have a surface casing vent assembly installed, if gas, water, or liquid hydrocarbon is migrating to surface, the licensee must install a permanent vent assembly on the well that meets the criteria outlined in section 6.100 of the *OGCR* and test, report, and repair the vent flow in accordance with this directive.

If the well does not have a surface casing vent assembly, the licensee must conduct a surface casing annular flow test consistent with timelines set out in section 3.2.1.

For all other cases, approval from the AER is required for exemption.

Appendix 4 provides some suggested procedures for gas identification techniques and annular flow testing.

5 Casing Failures

Questions about this section should be submitted to WellOperations@aer.ca.

A casing failure is the loss of ability for any casing string in a well to contain and prevent the escape of fluids at expected operating conditions.

43) If a well is no longer capable of operating without fluid containment concerns due to a lack of casing integrity, or if a section of casing in the well is preventing the licensee from performing any type of downhole operation, then the well must be repaired using one of the options in section 5.2 or the licensee must justify to the AER why the current wellbore configuration should be acceptable.

5.1 Reporting

44) The licensee of the well must report a casing failure within 30 days of initial detection through the designated information submission system.

- a) When reporting depth of the casing cement top, if there is no confirmed (logged) cement top or cement returns to surface, theoretical calculations can be used to determine the cement top. In the comments section, provide the information used to calculate the theoretical cement top.

45) All casing failure reports must be closed with a reported resolution in the designated information submission system before the repair deadline and before reporting the surface abandonment.

46) If the casing failure is in the production zone, then the licensee must close the incident report in the designated information submission system with a repair resolution of “failure in the production zone.” A well with this type of failure must still be abandoned or suspended in accordance with *Directive 020* or *Directive 013*.

5.2 Repairing

47) The licensee must begin planning the repair immediately, and all repairs must be completed within 90 days of the detection date.

There are three options to repair casing failures: (1) routine, (2) nonroutine, and (3) deferred.

Option 1 – Routine Repair (AER Approval Not Required)

The following resolutions are considered routine and do not require AER approval:

- Bridge plug set in accordance with *Directive 020* criteria
- Cement squeeze/plug

- Replace failed casing
- No further action where failure is in the production zone (A failure in the production zone is any failure that occurs within the same formation as the completed interval or within the next formation provided that there are no other effective porous zones between the casing failure and the completed interval.)

Option 2 – Nonroutine Repair (AER Approval Is Required)

48) All other resolutions, including those listed below, are considered nonroutine:

- a) Casing patch
 - b) Cemented liner
 - c) Packer
 - d) Bridge plug, not set in accordance with *Directive 020*
- 49) Nonroutine casing repair programs must be submitted to WellOperations@aer.ca for approval before beginning work.

Licensees may use the variance request forms found on our website.

Option 3 – Deferral of Repair (AER Approval Required)

- 50) Deferral requests are nonroutine, and AER approval is required to defer the repair of the casing failure.
- 51) A request to defer or waive repairs of a casing failure must be submitted, along with supporting documentation, to WellOperations@aer.ca before the repair deadline.

Appendix 1 Definitions

carbon dioxide EOR storage scheme	An area approved for enhanced oil recovery and net geological storage of CO ₂ as described in <i>Directive 065</i> .
carbon dioxide sequestration scheme	Wells approved for the permanent geological storage of CO ₂ as described in <i>Directive 065</i> .
casing failure	A casing failure is the loss of ability for any casing string in a well to contain and prevent the escape of fluids at expected operating conditions.
gas migration	A flow of gas or liquid that is detectable at surface outside of the outermost casing string (often referred to as external migration or seepage).
surface casing	The first string of casing that is set in a well (including conductor pipe set beyond 30 m). It provides structural integrity to support the blowout preventer (BOP) system and subsequent tubulars run in the well and has sufficient pressure integrity to facilitate well control.
surface casing vent flow (SCVF)	The flow of gas or liquid out of the surface casing annulus (often referred to as internal migration).
thermal well	A well that penetrates a reservoir that is, was, or has the potential to be artificially heated.

Appendix 2 Suggested Procedures for Testing for Surface Casing Vent Flows

The Lloydminster Area Operations Group Gas Migration Team developed the following testing procedures for surface casing vent flows. While the AER acknowledges the use of these procedures within the province, it also recognizes that there are various methods of testing for an SCVF.

Bubble Test

Recommended Equipment

- A container of water (from 500 millilitres to 1 litre)
- Pipe fittings, small hose (minimum 6 mm, maximum 12 mm inside diameter), or other equipment necessary to direct gas flow from vent downwards into the water container

Testing Procedures

- Ensure that there are no gas leaks at fittings and welds.
- Ensure that all valves in the vent line are open.
- Connect test fittings to vent so that gas flow can be directed into the container of water.
- Immerse hose a maximum of 2.5 cm (1 inch) below the water surface.
- Observe for 10 minutes. Note any gas flow (i.e., bubbles) indicating a positive vent flow.
- Record observations.
- If there is a positive vent flow, determine the rate and stabilized shut-in surface casing pressure.

Rate Determination

Equipment selection should be based on previous observations indicating what flow rate and pressure range can be expected. A calibrated flow meter capable of measuring low or intermittent flow rates is necessary to measure low volumes accurately. An orifice well tester (with proper orifice plate) may provide satisfactory measurements if 24-hour shut-in pressure is 200 kPa or greater and builds quickly.

The licensee must install and use the equipment according to manufacturer's instructions, keeping in mind the following:

- The pressure/volume range of the equipment is not to be exceeded.
- The fittings, wellhead, etc. should not leak nor exceed their working parameters.
- Casing vents are to be left open when equipment is removed, unless specifically directed by the AER to close them.

Determination of Stabilized Shut-in Surface Casing Pressure

Recommended Equipment

- Digital pressure gauge equipment with data logging capability or by manually recording the data. (The use of a rotary chart equipment for stabilized shut-in pressure testing is not acceptable.)
- Pressure-relief valve calibrated to release at a pressure equal to 11 kPa/m multiplied by the setting depth of the surface casing (m)

Testing Procedures

- Install digital pressure gauge and pressure-relief valve.
- Ensure that there are no gas leaks at fittings and welds.
- Digital pressure gauges with data logging capabilities must be set to record at a minimum interval of 15 seconds (minimum four times per minute), and manually recorded data must be recorded at a minimum interval of one reading per minute for the duration of the test.

Monitor the readings to determine the stabilized maximum pressure and record both the pressure and the time it took to achieve it. If the pressure does not stabilize, resulting in the test being terminated or the relief valve being triggered, record the highest pressure that was achieved.

In the context of an SCVF, “stabilized shut-in pressure” is defined as an SCVF shut-in pressure that does not build over 2 kPa/hour over a six-hour period or can be reasonably estimated to not exceed the pressure limits for the pressure-relief valve.

- Remove equipment and leave casing venting.

Appendix 3 Suggested Procedures for Testing for Gas Migration

The Lloydminster Area Operations Group Gas Migration Team developed the following testing procedures for gas migration. While the AER acknowledges the use of these procedures within the province, it also recognizes that there are various methods of testing for gas migration.

The licensee must follow the ground disturbance requirements described in the *Pipeline Act* and *Pipeline Rules*.

Gas migration testing must be conducted when environmental conditions will provide a relevant and reliable reading (e.g., frost-free ground and not after periods of rainfall).

If full-scale readings are not obtained, the soil horizon should be examined to ensure that readings are not the result of contaminated soils due to spills of diesel fuel, solvents, oil, etc. If contaminated soils are suspected, retesting is recommended.

Licensees should take into consideration the impact of soil saturation levels, shallow water table, the necessity to have the sample probe in the vadose zone, and the possibility that the wellhead may be in a fully saturated surface depression.

Licensees should use equipment that is capable of measuring methane.

Instruments should be calibrated in accordance with manufacturers specifications and checked daily when in use.

Ensure that you have sufficient sample testing points covering a sufficiently large area to detect any potential gas migration.

Recommended Test Point Locations

- Two within 30 cm of wellbore on opposite sides
- At 2 m intervals outward from the wellbore every 90° (a cross with the wellbore at centre) to a distance of 6 m
- At any points within 75 m of wellbore where there is apparent vegetation stress

Recommended Equipment

- Equipment capable of penetrating a minimum of 50 cm deep and a maximum of 64 millimetres (mm) in diameter
- Calibrated explosion meter or other instrument capable of detecting hydrocarbon at 1 per cent lower explosive limit (LEL)

- Equipment or material to seal hole at surface while soil gases are being evacuated from the soil through the instrument

Testing Procedures

- Perform instrument check (calibration, voltage, zero, etc.).
- Make a hole a minimum of 50 cm deep.
- Isolate the hole from atmospheric contaminations.
- Insert hose, wand, or other equipment a minimum of 30 cm into hole, maintaining a seal at surface to prevent atmospheric gas and soil gas mixing.
- Withdraw soil gas sample. The volume, rate, etc. will depend on the instruments being used. Ensure that a sufficient sample is removed to purge lines and instruments.
- Record observations.
- Purge instrument and lines.

Appendix 4 Suggested Gas Identification Techniques and Annular Flow Testing Procedures

The AER considers the following methods and monitoring devices acceptable for testing surface casing annular flow. Alternative methods and testing equipment (such as acoustic or ultrasonic detection equipment) may also be acceptable and will be evaluated by the AER on a case-by-case basis.

- Licensees should be aware of the surrounding environment when using sampler devices such as the lower explosive limit (LEL) meter, toxic vapour analyzer (TVA), and photoionization detection (PID).
 - Licensees should take into consideration other methane sources such as biogenic methane (swamp gas), hydrocarbon-based soil contamination, and gas migration.
 - Licensees should take into consideration the impact of soil saturation levels, shallow water table, the necessity to have the sample probe in the vadose zone, and the possibility that the wellhead may be in a fully saturated surface depression.
 - Atmospheric conditions such as temperature, wind speed, smog, and humidity (e.g., fog, rain, snow, sleet) should be suitable for drawing a detection sample.
 - The ability to detect leaks drops significantly when used in ambient temperatures below 0°C.
- Licensees should use equipment that is calibrated and capable of measuring methane.
- Licensees should sample according to manufacturers' standard operating procedures to ensure that a proper sample is obtained.

Soap Test

- Spray a soap solution in the annulus between the surface casing and the next casing string. Observe the annulus to determine if any bubbles have formed.
- If no bubbles are observed, the well is presumed to have no detectable emissions or leaks. If any bubbles are observed, further investigation is required.

Portable Gas Detector Method

A suspected surface casing annular flow source can be successfully detected using a portable gas detector.

- This is done by placing an LEL meter (which should be capable of drawing a sample into the instrument) close to the surface casing to determine whether gas is present. It is important to

follow the original equipment manufacturers' operating specifications as a number of factors may influence the test's success, and each LEL meter will operate slightly differently.

- If no gas is detected, the test is finished.
- If gas is present, further steps should be taken to quantify the leak.

Photoionization Detection (PID) Instrument

- Use a PID instrument that has been set up by the manufacturer to analyze methane gas (CH_4). This will ensure that the instrument is not affected by other hydrocarbon gases, chemicals, water, or contaminated soils.
- Follow manufacturer's procedure to determine if gas is present indicating surface casing annular flow per steps for the portable gas detector method.

Toxic Vapour Analyzer (TVA)

The TVA (i.e., flame ionization detector) is an instrument similar to the PID, and the procedure outlined in that section should be followed.

Portable Laser Methane Detector

A portable laser methane detector is set to analyze CH_4 . As a result, this detector is totally unaffected by other hydrocarbon gases, chemicals, water, or contaminated soils.

- Follow manufacturer's procedure to determine if gas is present indicating surface casing annular flow per steps for the portable gas detector method.

Infrared Camera Method

- A suspected surface casing annular flow source can be scanned and recorded to video with an infrared emissions camera.
- If a gas leak is detected, a digital photo of the leak source is taken and the leak identification information is entered into the leak survey data collection sheet.

Testing Procedure for Identifying Surface Casing Annular Flow

Casing Stub Exposed

- Identify the presence of gas by using either one of the monitoring instruments listed above or an alternative method approved by the AER.
- Confirm that the gas is not from background sources (e.g., biogenic methane, hydrocarbon-based soil contamination, etc.).

- If hydrocarbon liquid is present, a surface casing vent assembly must be installed.
- After the vent is installed, further testing is required in accordance with section 3.

Casing Stub Not Exposed

- Create holes 30 centimetres (cm) deep and a maximum of 64 millimetres in diameter at four points around the well at a distance of 30 cm from the wellbore.
- Isolate the hole from atmospheric contaminations for two to five minutes.
- Insert measuring equipment at least 25 cm into the hole, ensuring a seal at surface to prevent atmospheric gas from mixing with soil gas.
- Take the reading and, if gas is present, expose the surface casing and follow testing procedure for exposed casing stubs.

As the source of the surface casing annular flow may be difficult to determine, an organized and methodical sampling process should be in place so that a proper inspection can be conducted. The process must be documented and should include a sketch or diagram of the grid search for reference.