



DRILLING AND COMPLETION COMMITTEE

IRP 27: Wellbore Decommissioning

An Industry Recommended Practice (IRP)
for the Canadian Oil and Gas Industry

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27.0 Preface

27.0.1 Purpose

The purpose of this document is to provide best practices to perform safe, efficient, permanent wellbore decommissioning while mitigating adverse impacts to the environment and protecting groundwater.

This IRP is not intended to be a training document for inexperienced personnel. Refer to documentation provided by local jurisdictional regulators for materials that introduce the reader to this topic.

27.0.2 Audience

The intended audience for this document is industry personnel involved in the planning and execution of wellbore decommissioning activities. It is assumed that the reader has at least a basic level of understanding of the concepts and processes involved in wellbore decommissioning.

27.0.3 Scope and Limitations

This document refers to the on-shore wellbore decommissioning operations for the Western Canada Sedimentary Basin. It may be used by other jurisdictions in Canada as a reference document.

The scope of IRP 27 includes identification of all steps to decommission the wellbore including any potential issues there may be with decommissioning (i.e., remediation required). It introduces a risk-based approach to decommissioning and identifies the risk categories to consider.

The IRP 27 scope excludes the following:

- Specific techniques and methods for wellbore remediation (which are defined in IRP 26: Wellbore Remediation and referenced in this IRP) other than those which are only or predominantly relevant to wellbore decommissioning.
- Surface reclamation work (i.e., civil work, facilities, pipelines (including pipelines to the wellhead)).
- Drill and abandon (D&A) zonal abandonment or plug back (downhole cement and plug back) and abandonment plugs which are covered in IRP25: Primary Cementing.

27.0.4 Revision Process

IRPs are developed by the Drilling and Completions Committee (DACC) with the involvement of both the upstream petroleum industry and relevant regulators. Energy Safety Canada acts as administrator and publisher.

Technical issues brought forward to the DACC, as well as scheduled review dates, can trigger a re-evaluation and review of this IRP in whole or in part. For details on the IRP creation and revisions process, visit the Energy Safety Canada website at www.energysafetycanada.com.

A complete list of revisions can be found in Appendix A.

27.0.5 Sanction

The following organizations have sanctioned this document:

Canadian Association of Oilwell Drilling Contractors (CAODC)

Canadian Association of Petroleum Producers (CAPP)

Petroleum Services Association of Canada (PSAC)

Explorers & Producers Association of Canada (EPAC)

27.0.6 Acknowledgements

The following individuals helped develop IRP 27 through a subcommittee of DACC.

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27.0.7 Range of Obligations

Throughout this document the terms ‘must’, ‘shall’, ‘should’, ‘may’ and ‘can’ are used as indicated below:

Table 2. Range of Obligation

Term	Usage
Must	A specific or general regulatory and/or legal requirement that must be followed. Statements are bolded for emphasis.
Shall	An accepted industry practice or provision that the reader is obliged to satisfy to comply with this IRP. Statements are bolded for emphasis.
Should	A recommendation or action that is advised.
May	An option or action that is permissible within the limits of the IRP.
Can	Possibility or capability.

27.0.8 Copyright Permissions

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Table 3. Copyright Permissions

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Figure 2. Leakage Potential Along a Wellhead	23.6.6 SCVF/GM Repair	AER

27.0.9 Background

The process of taking a well permanently out of service has been described by several different names including abandonment, plug and abandon, plugging and wellbore abandonment. Regulations in many jurisdictions use the term “abandonment”.

This IRP moves away from the abandonment terminology due to the negative connotation to those not familiar with the oil and gas industry. Abandonment suggests the well is left in its existing, possibly unsafe, state and the owner simply walks away from their responsibilities. This is not oil and gas industry practice. Globally, the industry has been moving to the term “decommissioning”. This is the terminology IRP 27 uses except when referencing specific regulations.

While the terminology has changed the steps have not. Decommissioning requires a thorough review process to determine the existing state of the wellbore, identify potential risk(s) and identify the steps required to leave the wellbore in a state that will not present a hazard to the environment, people or property now or in the future.

IRP 27 does not stand on its own for all of the work necessary to decommission a well. Most of the remediation work that can be required at time of decommissioning is discussed in detail in IRP 26: Wellbore Remediation and is not duplicated here. IRP 27 references IRP 26 where appropriate.

27.1 Introduction

There are a variety of well types to be decommissioned. The complexity of the decommissioning operation depends on the type and state of the well. Some wells require simple operations while others can be more complex requiring significant effort to manage risk and meet long term isolation objectives.

Many operations require submission to or approval from the local jurisdictional regulator. This can be time-consuming and inefficient when similar procedures are used repeatedly in what are currently considered non-routine situations.

IRP 27 promotes a risk-based approach to decommissioning planning that identifies specific risk categories and parameters to review. The goal of moving to a risk-based approach is to improve the analysis of the risks involved to make decommissioning efforts more consistent and routine while protecting workers, the public and the environment.

The risk-based approach has the following benefits:

- Explicit criteria for environmental protection are used.
- Geology, well construction, wellbore and wellsite specific conditions are considered.
- Results are outcome/objective based and focused on longevity.
- Resources can be focused on higher-risk wells.
- Technological innovation is encouraged.

While IRP 27 promotes the risk-based approach it recognizes that all decommissioning operations still, at a minimum, have to follow local jurisdictional regulations. The recommendations put forth in this document are not intended to replace the regulations but it is hoped that consistent and repeated use of this approach will impact future regulatory decisions about what is routine or non-routine and eventually alter the definition of non-routine operations to include only truly unique scenarios.

IRP 27 includes information about planning for decommissioning operations and makes recommendations for decommissioning a zone (or zones). Some recommendations exceed the regulatory minimum in order to improve the long-term safety of decommissioned wellbores. The risk-based approach identifies whether these additional measures are warranted for a given well.

27.2 Risk-Based Decommissioning

The risk-based approach to planning is intended to help planners identify potential problems that may be encountered during the decommissioning operation based on key risk categories, contributors and escalation or de-escalation factors for those risks. While there is a numerical risk level shown for the risk contributors, it is for ranking purposes within each risk category only. The risks contributors within each category are considered to be unique to that category and don't necessarily have a valid comparison across categories. IRP 27 does not provide a numerical formula to rank of one category against another or one well against another in terms of effort or risk and the risk-based approach is not intended to be used in that way.

The risk categories are described in the following sections:

- 27.6 H₂S Release Rate
- 27.7 Surface Location
- 27.8 SCVF/GM History
- 27.11 Subsurface Parameters
- 27.12 Well Design and Construction
- 27.13 Hydraulic Isolation
- 27.15 Re-Entry for Repair

The risk categories are discussed in priority sequence in terms of considerations but regardless of the risk category, remediation needs to start from the bottom of the well and work to surface. Most of the risk categories have key contributors to risk and all have risk escalation factors.

Note: Each risk category can be a risk contributor or escalation factor for most of the other risk categories and is not explicitly identified as such within each section.

Well age, while not identified as a risk category, can impact decommissioning operations and be an escalation factor for any of the risk categories. Appendix B discusses some specific technological and procedural challenges and innovations from different eras of drilling and completion operations to consider.

The key contributors to risk have been assigned a risk level and are numerically ranked by severity (high to low) based on long-term public safety and environmental concerns while considering potential future development.

Note: The key contributors are ranked **within** each risk category and are not meant to be compared across risk categories. A key contributor with a risk level of five (high) in one risk category does not necessarily carry the same risk as a key contributor with a level of five in another category.

This risk-based approach relies on the information gathering described in 27.4.2 Information Gathering and the regulatory information described in 27.3 Definitions and Regulation.

27.3 Definitions and Regulation

Decommissioning is a highly regulated operation. While each jurisdiction has its own regulations, they all have similar decommissioning objectives. A complete list of regulations referenced in this IRP can be found in Appendix H.

IRP All local jurisdictional regulations for wellbore classification and decommissioning must be followed (at minimum).

27.3.1 Routine vs. Non-Routine

Each jurisdiction has terminology for routine and non-routine decommissioning. Non-routine scenarios typically require additional submission, notification, review and/or approval from the local jurisdictional regulator.

IRP 27 defines a routine decommissioning operation as one that does not require the additional regulatory review/approval.

IRP All non-routine decommissioning operations must have either a submission or notification of the decommissioning plan to the local jurisdictional regulator (e.g., B.C.) or approval to implement (e.g., Alberta, Saskatchewan). Consult with the local jurisdictional regulator for specific requirements.

27.3.2 Serious vs. Non-Serious SCVF/GM

IRP 27 uses the AER definitions of serious and non-serious surface casing vent flows (SCVF) and gas migration (GM) as found in AER Draft Directive xxx: Well Integrity Management (draft currently open for comments, replaces ID 2003-01).

IRP 27 refers to this as the categorization of the SCVF/GM.

27.3.3 Sour, Critical Sour and Declassification

A sour well is a well with hydrogen sulphide (H₂S). Sour wells have increased equipment, metallurgic and safety requirements compared to sweet wells. The H₂S release rate (RR) and/or proximity to population or habitation may trigger a further increase in requirements and/or response that designates them as Critical Sour (Special Sour in B.C.). See Appendix C for definitions and criteria.

A decline in the absolute open flow (AOF) potential can occur over the production life of the well. When this occurs a submission can be made to the local jurisdictional regulator to change (declassify) the status of the well to a non-critical/special classification.

IRP Declassification can be a tool to enable fit-for-purpose operational planning but declassification status should be re-evaluated for decommissioning to ensure an appropriate decommissioning approach is used.

Note: The well may have been declassified if it was originally licensed as sour but not found to be sour when produced and/or completed or there may be other legitimate reasons for declassification that may not warrant the additional rigor required of an actual critical sour well. Consult with the local jurisdictional regulator for guidance in these situations.

27.3.4 Level-A Intervals

Each jurisdiction has terminology for the classification of intervals. B.C. and Alberta use the term Level-A. Saskatchewan doesn't have a term to collectively describe these situations but does reference similar criteria as a Level-A interval.

IRP 27 uses Level-A interval to describe intervals that meet at least one of the following criteria:

- Have been used for injection of acid gas.
- Have an H₂S concentration in excess of 15 percent.
- Have been designated as critical sour (see 27.3.3 Sour, Critical Sour and Declassification).
- Injection or disposal wells where the injection/disposal formation pressure is greater than the pool discovery pressure.
- Gas wells where the discovery pressure or pool pressure is greater than 14 kPa/m.
- Have been used for disposal of oilfield/industrial waste or produced water/specified waste (not brine equivalent). See IRP 28: Wellsite Waste Management for more information on handling oilfield waste (expected to be published in draft form in Q1 2021).

27.3.5 Ability to Recharge

At the time of decommissioning it is important to consider the possibility that a depleted interval will, over time, recharge to the pool discovery pressure.

IRP If subsurface evaluation indicates a pool has the potential to recharge, zonal decommissioning should be based on the recharge value.

IRP The ability for depleted intervals in the well to recharge shall be evaluated by a qualified professional.

27.3.6 Protecting Groundwater

Requirements for the protection of groundwater vary by jurisdiction. Refer to the Groundwater Protection sections of IRP 26 (under Job Type and Input Data Analysis) for more information about the requirements.

IRP 27 refers to Base of Groundwater Protection (BGWP) terminology recognizing this is equivalent to the B.C. terminology of Base of Usable Groundwater (BUGW).

27.3.7 Porous Zones

IRP 27 follows the AER definition of porous zone as found in AER D020.

IRP 27 defines a porous zone as a zone that

- has carbonates with effective porosity greater than one percent,
- has sandstones with effective porosity greater than three percent,
- has offset production, regardless of the porosity or
- has drill stem test formation fluid recoveries greater than 300 linear metres or gas volumes greater than 300 cubic metres.

The definition of 'effective porosity' varies by jurisdiction. Consult local jurisdictional regulations for specifics.

Typically, a different cut off value for porosity is used for sandstones vs. carbonates. Consider consulting with subsurface experts on a well by well basis to understand, from the original open hole logs, what porosity exists behind casing and in the broader geologic context of the well.

Regulations typically indicate that porous zones need to be isolated from each other but some exceptions can be made with submission to the local jurisdictional regulator. Some exceptions include, but are not limited to, the following:

- Isolating geologic formations of a comparable age together as a geologic package.
- Isolating zones together that have been produced together during the life of the well.
- When porous zones behind casing that are up hole from the production/injection interval have been proven (regionally) incapable of producing.

27.4 Planning

When planning a wellbore decommissioning project there are many factors that need to be considered. These include the following:

- Well type
- Current subsurface, wellbore and surface conditions
- Well design and history
- Local jurisdictional regulations

27.4.1 Objectives

The key objective of wellbore decommissioning is the protection of people and the environment by providing a permanent well integrity solution to take a well out of service in a manner that doesn't compromise or complicate the ability to re-enter the well for any future issues or repairs.

This protection is accomplished through the following:

- Permanent protection of groundwater.
- Permanent isolation of all porous zones and/or producing intervals from each other, covering off all potential flow paths (unless commingling is approved by the local jurisdictional regulator for decommissioning).
- Elimination of SCVF and GM.
- Adherence to local jurisdictional regulations for wellbore decommissioning.

27.4.2 Information Gathering

The following information is required to enable analysis of the risk categories, risk contributors and risk escalation/de-escalation factors and complete project planning:

- Location information about the wellsite (e.g., directions, road and lease access, proximity to urban centres, First Nations Settlement Land, Metis Settlement Land or environmentally sensitive areas, etc.)
- Current information about the surface equipment (e.g., wellhead details, other equipment details, etc.).
- Current information about the wellbore and subsurface conditions (e.g., depths, pressures, temperatures, pore pressure and fracture gradients, cement to

surface, cement top, porous intervals, groundwater depth, wellbore fluids, H₂S content, flow potential, cross-flow potential, casing repairs, etc.)

- Complete well history (e.g., licensing, design plans, drilling fluid information, drilling/completions/servicing information and problems, primary cement job detail, etc.).
- Existing logging for the well. Additional logs may be required.

Note: Existing or additional well logs may assist in identifying potential cementing deficiencies or challenges in cased or open hole applications. Formation or borehole image logs (i.e., optical, acoustic or electrical imaging logs) may prove useful in determining casing condition, presence of faults or natural fractures and their orientation.

- Regulations regarding decommissioning in the area and type of well.
- Geochemical samples.
- SCVF or GM data and regulatory classification (see 27.3.2 Serious vs. Non-Serious SCVF/GM).
- Updated survey for site access including existing road conditions, bridge condition and list of assets still on location.
- Information regarding any suspension method(s) used on the well.

Note: Wells are suspended prior to decommissioning but there are some points to consider while suspending the well that can make decommissioning easier (e.g., putting packers/bridge plugs, etc. in the same place as they would be required for decommissioning so they don't have to be moved prior to decommissioning, use suspension fluids that are compatible with decommissioning so they don't have to be swapped out, prevent freezing of fluids, etc.). See AER D013 for more information about suspending wells.

27.4.3 Considerations

Consider the following when planning a wellbore decommissioning operation:

- Well type and wellbore fluids.
- Current condition of the well (e.g., fish in hole, ghost hole/side tracks, casing failures, etc.).
- Wellbore preparation to gain access to the applicable zone(s) (e.g., removing downhole equipment).
- Wellbore remediation(s) required (see IRP 26: Wellbore Remediation).
- Requirements for surface mineable areas or other below-surface/surface impacts on access (e.g., rivers, urban areas, etc.).

- Regulatory submission/approval requirements.
- Changes in subsurface over time, including ability to recharge (see 27.3.5 Ability to Recharge) and fluid composition (e.g., sweet to sour).
- Isolation requirements for producing or injection zones, up-hole porous zones and groundwater.
- Surface equipment requirements.
 - Sour formations may require equipment for returns.
 - Surface pressure control needs to suit the interval(s) to be perforated and currently open.
- Well kill plan to overbalance the formation pressure in the currently open or to be opened zones by as much as 1,000 to 1,500 kPa to prevent reservoir fluids from entering the wellbore during the decommissioning operation. Consider the use of corrosion inhibitors if kill fluids are corrosive.
- Waste disposal plan (see IRP 28: Wellsite Waste Management for more information about waste disposal, draft publication expected Q1 2021).
- Post-decommissioning wellhead plan (e.g., is a rental master valve required?).
- Service(s) requirements and availability.
- Operational readiness reviews, fit for purpose pre-job meeting(s).
- Contingency plans.
- Post-job evaluation and regulatory submission requirements.
- Emergency Response Plans (ERPs), Emergency Planning Zone (EPZ), Hazard Planning Zone (HPZ).
- Enhanced Oil Recovery (EOR) schemes (for well to be decommissioned and wells nearby).

The planned application of some servicing operations (e.g., multi-stage hydraulic fracturing operations, acid gas injection, CO₂ injection or EOR schemes) to an existing production region can impact the decommissioning risk profile. Introducing processes with a different pressure regime and/or conditions than expected for the design of the subject decommissioning can lead to a future failure.

Note: In these cases, it is the responsibility of new licensee contemplating the new production/injection/EOR scheme to ensure there is adequate isolation of adjacent wells that may be impacted by the new operations. See the Interwellbore Communication sections in IRP 24: Fracture Stimulation for more information.

During execution of the decommissioning plan there is potential to introduce or discover new issues that need to be addressed (e.g., ghost holes, side tracks, casing failures, fish in the hole, etc.). Refer to 27.11.10 Areas Requiring Remediation and IRP 26: Wellbore Remediation for information about dealing with these concerns.

27.4.4 Execution Efficiencies

Consider the following opportunities for efficiency:

- Evaluate existing well equipment for use in decommissioning design (e.g., packers, tubing, liner tops, etc.). It may be possible to leave equipment in the well as part of decommissioning design.
- Plan for flexibility and contingencies to address subsurface and wellbore uncertainties.
- Optimize capability of work unit(s) and consider alternatives to traditional equipment and methods.
- Leverage new technologies and products (in partnership with local jurisdictional regulators).
- Plan large campaigns of similar work scope and take advantage of regulatory programs such as area-based closure to leverage efficiencies and learning curves.
- Seek opportunities for campaign efficiencies and pad simultaneous operations.

27.4.5 Information Analysis

Once all the information about the well has been gathered it can be analyzed to determine whether any of the risk categories, risk contributors or risk escalation/-de-escalation factors are present.

Note: Some decommissioning projects will require approval from the local jurisdictional regulator (see 27.3.1 Routine vs. Non-Routine).

IRP If any of the risk category contributors are present a risk assessment shall be completed to identify and include the appropriate mitigations in the project scope.

Use the well detail, risk categories, risk contributors and risk escalation/de-escalation factors along with the results of the risk assessment (if completed) and recommendations in 27.5 Zonal Decommissioning to complete the decommissioning project plan.

27.5 Zonal Decommissioning

The plugging methods identified in this section are the current industry recommended practices to meet or exceed the minimum objectives and requirements for routine work in all regulatory jurisdictions when there are no apparent problems (risk categories) at the start of planning or decommissioning operations. This includes all completion types (i.e., open hole, liners or perforated).

IRP Selection and validation of the isolation material and technique for the isolation job shall be as per IRP 26: Wellbore Remediation.

See Appendix E for more information about using an isolation medium (or technique) other than cement.

Table 4 in 27.5.1 Zone Type and Decommissioning Actions identifies decommissioning actions by zone type. When multiple zones are open all zones have to be assessed individually. Once assessed the appropriate action can be determined. Actions may include addressing multiple zones together (see 27.3.7 Porous Zones) or commingling zones at time of decommissioning but those activities may require submission/notification and/or approval by the local jurisdictional regulator.

Suspended wells will sometimes have a mechanical plug (see 27.5.5 Mechanical Plugs). When considering an action type that includes a mechanical plug (action type 2 or 3 described below) it may be possible to use the existing mechanical plug for decommissioning if it can be proven that the plug still has integrity to pass a pressure test from above and is situated at the appropriate location in the well. This may be considered non-routine. Consult local jurisdictional regulations for decommissioning a suspended well for more information about using the suspension plug.

27.5.1 Zone Types

The following are the key zone types in a zonal decommissioning operation:

- Type A – Level-A (see 27.3.4 Level-A Intervals for definition)
- Type B – Completed (perforated, open hole, leaking)
- Type C – Over-pressured (Pool Discovery) (i.e., can't be killed with fresh water)
- Type D – Corrosive fluids (e.g., H₂S, CO₂ – see Appendix D for more information)
- Type E – Bitumen bearing

Note: A zone may be a single type or multiple types.

27.5.2 Action Types

There are six action types (isolation plans) that can be taken in depending on the zone type.

27.5.2.1 Action Type 1 (CIT)

Action type 1 is to perform a casing integrity test (CIT).

Note: Performing a CIT is the minimum action that can be taken and may be required for the other action types as an investigative step.

Local jurisdictional regulations specify test pressure, duration and acceptance criteria.

If the well passes the test then no further decommissioning action for the zone is required.

IRP If the well does not pass the test then the leak must be diagnosed and treated as a casing failure.

IRP For non-completed intervals that do not contain a corrosive fluid and are not over-pressured, a minimum of a casing integrity test should be completed.

27.5.2.2 Action Type 2 (MP+8)

Action type 2 is to set a mechanical plug (see 27.5.5 Mechanical Plug Selection) with 8 vertical metres of cement (MP+8). Regulations typically require the mechanical plug to be set within 15 m of the completed interval or within the same formation as the completed interval. It is acceptable to move the plug up hole and set across a caprock formation as long as there is no distinct porous interval between the completed formation and the plug setting depth and as long as the plug setting depth is not above top of annular cement.

Note: If assessment shows multiple non-completed zones with this type of action required and there is adequate hydraulic isolation between those zones, it may be possible to decommission only the top zone with action type 2 and reduce the action type for the subsequent zones. This requires evaluation of completion type and cement quality behind casing between these zones. Refer to section 27.13 Hydraulic Isolation for more information.

IPR When possible the placement of the isolation inside the casing should align with the non-porous rock and good cement integrity outside of casing (i.e., the rock-to-rock approach).

An alternative may be to circulate a cement plug in place. This is considered a non-routine approach if the zone is perforated and the planned cement plug is not 15 m below to 15 m above. This may be a preferred option if there is no suitable caprock directly above the perforations and the intent is to create hydraulic isolation from inside pipe across non-porous rock. Consult local jurisdictional regulations for requirements and notifications/approvals required.

27.5.2.3 Action Type 3 (MP+30)

Action type 3 is to set a mechanical plug (see 27.5.5 Mechanical Plug Selection) with 30 vertical metres of cement inside the casing on top of the plug (MP+30).

IPR When possible the placement of the isolation inside the casing should align with the non-porous rock and good cement integrity outside of casing (i.e., the rock-to-rock approach).

An alternative may be to circulate a cement plug in place. This is considered a non-routine approach if the zone is perforated and the planned cement plug is not 15 m below to 15 m above. This may be a preferred option if there is no suitable caprock directly above the perforations and the intent is to create hydraulic isolation from inside pipe across non-porous rock. Consult local jurisdictional regulations for requirements and notifications/approvals required.

27.5.2.4 Action Type 4 (CS+30)

Action type 4 is to perform a cement squeeze, with or without a retainer, with 30 vertical metres of cement inside the casing above the formation top (CS+30). Refer to the Technique Selection of IRP 26: Wellbore Remediation for discussion about when to use a retainer.

The objective of this action is to have cement squeezed into perforations or open hole sections with 30 vertical metres of cement above the formation top.

Note: Requirements vary by jurisdiction for intervals defined as Level-A (e.g., squeeze pressure, minimum cement volumes, etc). Refer to local jurisdictional regulations for specific requirements.

Other plugging methods may be more efficient for this action type but would be considered non-routine (e.g., bridge plug plus 60 metres of cement).

27.5.2.5 **Action Type 5 (TMP+TC)**

Action type 5 is to set a thermal-rated mechanical plug with thermal cement to a minimum of 15 vertical meters above the top of the shallowest bitumen bearing formation (TMP+TC).

IRP Bitumen bearing formations outside a regulator-designated oil sands area should be treated like non-bitumen bearing formations (action types 1-4).

IRP In a bitumen bearing formation within a regulator-designated oil sands area, a thermal cement plug must be set inside of casing across the bitumen bearing zones from 15 meters below or plug back, whichever is shallower, to 15 meters above the formation top.

Note: An evaluation of thermal potential and submission/approval by the local jurisdictional regulator may permit an alternate action.

27.5.2.6 **Action Type Evaluate**

IRP For a Level-A interval the licensee shall conduct a risk assessed evaluation of the interval.

Include the following in the evaluation:

- Cementing records.
- Cement evaluation log (if run or if required).
- Formation factors (e.g., porosity, gas presence, pressure profile, type and severity of corrosive fluids, etc.).

IRP For a non-Level-A interval, the licensee should consider conducting a geological and cementing review.

Determine the appropriate action based on local jurisdictional regulations, results of the evaluations and review(s) and the considerations listed in 27.5.4 Considerations.

27.5.3 Zone Type and Decommissioning Actions

It is the responsibility of the operator to use the information available to make assessments about the cement top (TOC) and state of hydraulic isolation in the well. Table 4 below is intended as a tool to ensure the right questions are being asked and sound engineering judgement is used for decisions related to wellbore decommissioning. Analysis of all the available information and risk assessment using the factors identified in 27.5.4 Considerations below may result in a decision to use a different action than shown in the table.

It is suggested to begin on the conservative side with the action type for each zone as described in the table and then work through the considerations to assess risk and determine whether a lesser approach is acceptable for a given situation. If there is insufficient information available to make the engineering judgement it may be desirable to run a full-length cement bond log (CBL) or other logs to gather more information.

IRP The decision to decrease action type shall be based on engineering judgement in the context of local jurisdictional regulations.

When reading the table, start from the upper left and work across then down. The boxes in yellow (without text) indicate that type isn't relevant to the outcome due to the other boxes marked in red (yes) or green (no).

For example, when dealing with a Level-A completed well (type A=yes and type B=yes), it doesn't matter whether the well is over-pressured (type C) or has corrosive fluid (type D). The action taken for a Level-A completed well will always be action type 4.

The suggested approach is to first individually assess every zone a well penetrates. After working through the table for each individual zone the decommissioning strategy for the entire wellbore can be assessed.

If the well has multiple non-completed zones requiring a zonal decommissioning as per Table 4, the lower zones may not require individual isolation if there are isolation plugs above, based on a review of well-specific risks. This does not require regulatory approval as long as the zones are not completed.

Table 4. Recommended Actions by Zone Type

Zone Type					Action
Type A Level-A	Type B Completed	Type C Over- pressured (On Discovery)	Type D Corrosive Fluid	Type E Bitumen Bearing	
				Yes	Type 5 (TMP+TC)
Yes	Yes			No	Type 4 (CS+30)
No	Yes	Yes		No	Type 3 (MP+30)
No	Yes	No	Yes	No	Type 2 (MP+8)
No	No			No	Type 1 (CIT)
	No		Yes	No	Type Evaluate

27.5.4 Considerations

The following might increase risk and may drive a decision to increase in the action type required:

- Known unconventional (hydraulic fracturing) development or injection or disposal in zone (happening or anticipated) that may result in a future over-pressured scenario.
- Presence of geohazard such as faulting that may result in shearing or connection to higher pressure formations.
- Previous failed decommissioning operations, leaking remediation, casing patch, etc.
- Casing exposure to corrosive fluids

The following may reduce risk and may drive a decision to decrease in the action type required:

- Proven hydraulic isolation (via logging) behind casing across the zone of interest as well as competent caprock (non-porous). Cement records (primary cement job logs indicating cement returns to surface, absence of SCVF, GM or other integrity problems) and offset well log data may be used, with engineering judgement, to evaluate cement coverage in the absence of a full-length cement log.

- Assessment by a qualified sub-surface professional (e.g., open hole logs) indicates the formation will not flow (non-porous).
- Casing grade used is appropriate for formation fluids (e.g., sour service casing) with analysis of corrosion mechanism and risk of failure over time by a qualified professional. See Appendix D for additional information about risk escalation factors and mitigations when corrosive fluids are involved.
- Non-completed formations in the same wellbore with zonal isolation above (considering known and potential future use of the subsurface).
- Zone is depleted and geological assessment indicates it is unlikely to recharge.

In the absence of well-specific data (e.g., formation pressure gradients, presence of H₂S, presence of porosity, etc.) regional models and field experience can be used to develop the decommissioning strategy. When data quality or confidence is low conservative assumptions are encouraged.

27.5.5 Mechanical Plugs

The functional intent of a mechanical plug set inside casing for zonal decommissioning is to serve as a platform until the isolating medium placed on top of the plug has set and become self-supporting. The mechanical plug, in combination with the isolating medium, also serves as a component of the initial isolation barrier system as part of the formation to formation isolation envelope until the design life of the mechanical plug has been exceeded. At that point the permanent isolation inside casing is expected to be provided solely by the isolating medium.

A successful mechanical plug needs to form a competent seal with the casing (validated by a pressure test from surface), resist differential pressure up to its design limit and stay in position at depth until the isolating medium placed on top has developed full compressive strength and can function as the permanent long-term barrier in the well..

Over the long term, the mechanical plug and any uncemented OD and/or ID of the casing above and below an isolation will experience significantly elevated rates of corrosion compared to a similar length of casing that is cemented and/or isolated both inside and outside. This is due to significant long-term differences in end-rate casing corrosion compared to OD/ID corrosion rates of exposed or inadequately cemented casing. A well-placed zonal isolation within a caprock, with competent backside cement and a fit for purpose isolation medium placed inside casing, can be an isolating system that will provide a permanent formation to formation wellbore seal.

Mechanical plug integrity and design life (i.e., the length of time it can be considered to be contributing to an isolation system) are influenced by plug characteristics (e.g., design, construction, metallurgy and elastomers) and the wellbore environment at

setting depth (e.g., the presence of acid gas, mechanisms for hydrogen embrittlement or mechanisms for hydrogen induced cracking).

Plug design and construction parameters to consider are as follows:

- Pressure rating for maximum expected differential pressure.
- Slip hardness for casing material at target setting depth.
- Number of potential leak paths.
- Type of elastomers for main body element and any O-rings or seals.
- Metallurgy of all components of the plug (e.g., slips, buttons, springs, mandrel, etc.).
- Fluid compatibility/corrosion risks from wellbore fluids above and below the mechanical plug.

27.5.5.1 Plug Types

There are several mechanical plug options and each has advantages and disadvantages as outlined in Table 5 below.

Note: Mechanical plug types are not all viewed as equivalent in all jurisdictions and some require regulatory approval for use in a zonal decommissioning inside casing.

Table 5. Plug Type Characteristics, Pros and Cons

Plug Type	Characteristics/Pros/Cons
Permanent	<ul style="list-style-type: none"> • Typically combines simple design with minimal potential for leaks, based on a construction without O-rings. • Can be made from cast iron, steel, brass or composite materials. • Once set, typically via a setting tool, the bidirectional slips resist movement up or down. • Do not have a releasing functionality but are generally designed to be easy to mill out. • Most cannot be run through casing restrictions such as profiles, crossovers and casing damage. They have a limited casing weight range in which they can be set and require a running clearance close to nominal drift of the casing in which they are designed to be set. • In applications where the target setting depth is past a restriction, there are classes of high expansion permanent bridge plugs available that can be run through a restriction and set in larger tubulars below. However, the maximum expansion range is typically limited to one standard pipe size larger and these plugs are generally not rated for differential pressure unless they are topped with cement. • Element material choices are typically limited in terms of “off the shelf” availability (standard service element material and premium service element material). Check with supplier for elastomer compatibility and options for custom order.

Plug Type	Characteristics/Pros/Cons
Retrievable	<ul style="list-style-type: none"> • Can be released and retrieved, often in a single run, using a retrieving tool. • Are generally set on wireline and can be retrieved on slickline with light spanging or jarring. • Typically made from a low alloy steel but speciality plugs can be made out of more exotic corrosion resistant alloys (CRAs). • Cons include the number of potential leak paths, a potential to not release when commanded to do so and difficult milling operations to remove them when they do not release. • Designed for a narrow range of casing weights so typically have a tight running clearance which prevents their use below restrictions. • The retrieval mechanism would almost certainly be compromised if it were to be used as a platform for cement unless a layer of sand is placed on top of the plug after the pressure test and before placing the cement. • The use of retrievable plugs is currently considered non-routine in all jurisdictions.
Inflatable	<ul style="list-style-type: none"> • Set hydraulically and expand outwards until contacting the casing. Many designs are available. • Used in applications that require a high ratio expansion plug to be deployed through tubing, through a packer or through casing damage and be set in larger casing below. • They do not have high differential pressure or axial load ratings once set because they rely on a system of ribs vs. slips to prevent upward and downward motion and their structure has to be able to expand at high ratios. • Often not considered unless dictated by wellbore geometry.
Swellable	<ul style="list-style-type: none"> • Relies on the fluid that it is run in or the produced fluid of the well in order to set. • The expansion is a gradual process, generally taking days to weeks to reach full set. • Due to this slow expansion they are normally applied as an annular seal.
Retainer	<ul style="list-style-type: none"> • A retainer that has not yet been stung into and activated with pipe is generally acceptable as a bridge plug. • Many retainers can also be modified with the addition of a bullnose to convert a retainer into a bridge plug. • Currently acceptable as routine if un-activated.
Packer + Plug in Packer Bore	<ul style="list-style-type: none"> • When a packer is present in a well at a suitable depth to serve as part of an inside casing plug for a zonal isolation, it is common to set a smaller permanent bridge plug inside the packer bore. This turns the packer into a bridge plug across casing. • Currently acceptable as routine.
Packer + Tailpipe Plug	<ul style="list-style-type: none"> • Currently considered non-routine in all jurisdictions.

27.5.5.2 Considerations

Table 6. Considerations for Choosing a Mechanical Plug

Consideration	Notes
Casing restrictions	<ul style="list-style-type: none"> Restrictions may exclude plugs designed for nominal ID and require the use of high-expansion plugs or inflatable plugs. High-expansion or inflatable plugs will either have a reduced pressure rating or no pressure rating unless topped with isolating medium.
Suspected leaking or damaged casing	<ul style="list-style-type: none"> Leaks or damage to casing may interfere with the ability to test the plug from surface if the leak or damage is above the intended setting point of the plug. It may be possible to position the mechanical plug and isolation medium above the leak point or damaged casing. This would be a non-routine scenario and may require a risk assessment of formations behind pipe and TOC/hydraulic isolation.
Re-Entry Requirements	<ul style="list-style-type: none"> The relative ease with which the plug can be milled or drilled out impacts the ability to re-enter a previously decommissioned zone.
Acid Gas	<ul style="list-style-type: none"> Acid gases, particularly H₂S, can lead to rapid onset catastrophic failure of materials so it is critical that plug metallurgy is fit for purpose when acid gases are present. Controlled hardness (<22 HRC) 4130/4140 or L-80 material that is NACE MR0175/ISO 19165 compliant can be a cost-effective material for acid gas environments. Chrome or high nickel CRAs can also be selected for CO₂ or H₂S environments (respectively) to better suit the expected environment and will have a longer effective design life.
Hydrogen Embrittlement	<ul style="list-style-type: none"> Hydrogen embrittlement can cause cracking and failure of materials. Passivating scales such as iron sulphide are impermeable to hydrogen and tend to trap hydrogen inside the material, increasing the likelihood of a failure.

27.5.5.3 Plug Conveyance

Mechanical plugs are typically conveyed on wireline, coiled tubing or jointed pipe. They are set through an explosive charge, a hydraulic setting tool or through mechanical means. The plugs can be logged on depth, located on depth mechanically or set based on wireline or pipe depth.

27.5.5.4 Plug Location

IRP When determining where to place the mechanical plug and isolation medium, the following should be considered to ensure the internal and external hydraulic isolation medium aligns with competent non-porous rock to form a permanent formation to formation isolation:

- Cement quality behind casing.
- Caprock location and the maximum anticipated pore pressure of any open zones below.
- Shallower porous intervals and the potential for crossflow.

IRP Mechanical plugs should not be set across connections, particularly for non-premium connections.

27.5.5.5 Isolation Plug Verification

IRP A positive pressure test must be completed before cement placement to validate the integrity of the plug and ensure there are no leak paths.

Once the isolation medium is set it creates an isolation plug.

Inflow tests are optional and can validate the integrity in the direction that the plug needs to hold.

Tagging with weight can be used to verify location to ensure the plug hasn't slipped, ensure cement has set and that the top of cement meets the minimum requirement.

IRP Where a cement plug is not placed on a tested platform (e.g., a permanent bridge plug) the cement top must be verified by tagging with at least 1800daN weight and pressure tested to 7 MPa over hydrostatic for 10 minutes.

Note: Wireline tag is not currently an accepted plug verification method.

IRP Mechanical plugs must be pressure tested to at least 7 MPa over hydrostatic for 10 minutes. Acceptance criteria is final pressure after 10 minutes must be at least 90% of the starting pressure, with a decreasing pressure drop trend.

A true positive pressure test is achieved by calculating the hydrostatic pressure on either side of the plug and then applying enough pressure from surface to meet, and safely exceed, the hydrostatic pressure below the plug.

IRP A negative pressure test (inflow test) should be performed on a zonal isolation where practicable.

Note: This is generally achievable on zones that are over pressured. It can also be done on balanced or sub-hydrostatic formations by removing fluid above the plug.

In some cases, inflow testing may require an extended period of time in order to get a positive confirmation of integrity. The use of a Horner plot can be beneficial in these circumstances to provide a quantitative pass/fail.

27.5.5.6 Dump Bailing Considerations

Dump bailing is a rigless means, generally wireline conveyed, of placing an isolation medium above a platform (i.e., a mechanical plug) in a well to provide isolation.

Current regulations relating to dump bailed isolating mediums reference cement so this section refers to cement as the assumed isolating medium. Alternatives to cement are available and are discussed in Appendix E.

The information in this section is provided in as an attempt to standardize dump bailing procedures and make the results repeatable in order to improve the integrity of dump bailed cement and increase confidence in that integrity.

Regulations regarding the use of cement as an isolating medium do not require it to be tagged to confirm that it has set up to an acceptable compressive strength when placed on top of a pressure tested platform.

Some of the limitations of dump bailing are shown in Table 7.

Table 7. Limitations of Dump Bailing

Limitation	Description
Inclination	<ul style="list-style-type: none"> Placement is limited due to the typical methods of conveyance into the well and the geometry and physics of the bailer. High inclination cement plugs are better to be circulated in place using pipe, enabling longer continuous plugs. vs. dump bailing.
Quality control	<ul style="list-style-type: none"> Cement is mixed in small batches and not always by cementing specialists. Focus can be on ease of placement and ensuring that the cement exits the bailer when activated rather than the quality/strength of the isolation plug.
Contamination	<ul style="list-style-type: none"> Wellbore fluids (e.g., fresh water, brine, inhibited fluid, etc.) can interfere with cement set up. Sodium chloride (NaCl) brines can act as an accelerator in low concentrations and as a retarder in high concentrations. Calcium chloride (CaCl₂) is different from sodium chloride and is a significant true accelerator. The higher the concentration of CaCl₂ (above three percent) the more unpredictable the results.

Limitation	Description
Multiple runs in large casing	<ul style="list-style-type: none"> • There are practical limitations on maximum cement plug length inside casing per run and implications on continuous cement plug length in large casing when multiple runs are required.
Shrinkage	<ul style="list-style-type: none"> • There are fewer options for cement additives to improve sealing characteristics for kit-based cements used in dump bailing (compared to larger batch or continuous mix cement jobs from primary or remedial cementing specialists).

IRP A cementing specialist should be consulted and/or a lab test should be performed when considering additives or blend changes to address shrinkage.

IRP Operators should retain a surface sample of as-mixed dump bailed cement slurry for at least 24 hours to validate that the cement blend has set up.

Note: There is no regulatory requirement to retain samples to validate the sealing properties of the cement plug but this can be a quick and cost-effective method to confirm that the cement blend as mixed will set up to a solid.

Cement blend considerations for dump bailing are shown in Table 8.

Table 8. Cement Blend Considerations for Dump Bailing

Consideration	Notes
Downhole temperature	<ul style="list-style-type: none"> • Specification of accelerator/retarder is temperature dependent. • Too much accelerator risks pre-set of cement in the bailer. • Too much retarder risks ability to reach required compressive strength. • Select a blend suitable for the expected downhole temperature. Consider thermal cement where conventional class G is not suitable (based on temperature limitations). See 27.5.2.5 Action Type 5 (TMP+TC) for more information.
Downhole pressure	<ul style="list-style-type: none"> • Required compressive strength is based on the pressure differential the cement isolation is expected to withstand. • The type of cement selected influences the length of cement plug required to develop the required compressive strength. • Resin-based, low permeability gypsum cement plugs will require shorter linear length than Class G cement to develop a comparable compressive strength.
Mixing requirements	<ul style="list-style-type: none"> • The mix water ratio used when blending cement is critical to the performance of the cement plug. • Adding mix water over and above the design ratio for the blend has historically been done to ensure that the as-mixed cement will exit the bailer cleanly. However, this can interfere with proper set up and compressive strength of the cement plug.

Consideration	Notes
Shrinkage	<ul style="list-style-type: none"> Consider the addition of expansion agents to reduce shrinkage tendencies of class G cement to avoid development of a micro-annulus against the casing ID as the cement sets up.

IRP Supplier recommendations for mix water ratios should be followed for the dry-mix cement blend.

Dump bailed cement is typically conveyed with wireline or tubing. A floating bailer is also available that allows for placement of cement without wireline or a rig. This uses a bailer with buoyancy tuned for the expected fluids in the well.

Table 9 shows important considerations for placement of dump-bailed cement.

Table 9. Considerations for Placement of Dump-Bailed Cement

Consideration	Notes
Length of cement plug	<ul style="list-style-type: none"> Select a suitable length of cement plug for the type of cement and required compressive strength. Ensure that the length of the plug is not less than regulatory minimums. The intent is to place the planned volume of cement in as few bailer runs as practical to minimize plug contamination at the interfaces between runs.
Deviated wells	<ul style="list-style-type: none"> Consider the vertical depth of the resultant cement plug and target to provide the appropriate length in terms of true vertical depth. For wireline conveyed dump bailing runs, a typical limitation in target inclination for successful placement is 60 degrees. For higher deviations, tubing conveyed dump bailed cement is an option but in high inclination applications consider a longer length cement plug circulated in place.
Top of cement vs. top of formation/shale caprock location	<ul style="list-style-type: none"> Where possible, target to place a cement plug in a location with competent cement behind casing at a depth with a natural cap rock. This ensures that the cement plug is placed as part of a formation to formation barrier for long term integrity.

27.6 H₂S Release Rate

The release of H₂S into the atmosphere can be harmful to people and animals. When H₂S is present the risk level for the decommissioning operation is increased. There are increased operational and safety requirements for sour operations and even further requirements based on proximity to population and release rate (RR) (referred to in this document as critical sour - see 27.4.3.3 Sour, Critical Sour and Declassification for details).

H₂S release rates directly affect the well's emergency planning zone (EPZ). The H₂S release rate, the EPZ and proximity to public centres, dwellings, etc. can have a direct correlation to the number and type of personnel and equipment required on site. Higher release rates may add further complexities to the planning and implementation of decommissioning operations.

27.6.1 Risk Level

The risk level for this category is defined by regulatory classification of the well or by the release rate of H₂S at the time of decommissioning.

Table 10. H₂S Release Rate Risk Level

Release Rate/Designation	Risk
Regulator designates as critical sour	5
RR > 2.0 m ³ /s	5
RR > 0.3 m ³ /s but < 2.0 m ³ /s	4
RR > 0.01 m ³ /s but < 0.3 m ³ /s	3
RR > 0.00 m ³ /s but < 0.01 m ³ /s	2
RR = 0.00 m ³ /s	1

27.6.2 Risk Escalation Factors

27.6.2.1 Casing failure

A casing failure may impact the well control operations for the well and/or may require the use of snubbing equipment (see IRP15: Snubbing Operations for more information about snubbing).

27.6.2.2 Surface location

Proximity to urban areas may require ERP's and additional safety equipment. Proximity and release rate may drive a decision to exceed the minimum regulatory requirements for number of barriers.

Refer to IRP 02: Completing and Servicing Critical Sour Wells for more information.

27.6.2.3 Potential Recharge of the Zone

The capability (or likelihood) of the zone recharging may drive a decision to exceed the minimum regulatory requirements for isolation.

27.6.3 Mitigations

Mitigations for release rate depend on the following:

- Accurate current well data, particularly sour content.
- Regulations for the well type.
- Accurate release rate calculations (see 27.6.4 Determining Release Rate).

Declassification of the well may be an option (see 27.3.3 Sour, Critical Sour and Declassification).

27.6.4 Determining Release Rate

IRP The local jurisdictional regulator must be consulted to determine whether H₂S release rate is to be based on current conditions/classification (at the time of decommissioning) or original classification.

IRP Release rate calculations should be as per CAPP H₂S Release Rate Assessment Guidelines and Audit Forms.

Equation 1. Release Rate

$$RR = H_2S\% \div 100 \times (AOF \div 86,400)$$

Where:

- RR = Surface H₂S release rate (m³/s)
- H₂S% = Maximum H₂S concentration measured as a percentage of the total gas stream
- AOF = Surface absolute open flow potential (m³/d)

The release rate is used to determine the well classification, well level designation (i.e., Level-A) and the EPZ.

27.7 Surface Location

The well's proximity to urban centres, residences, domestic and agricultural water wells, water bodies or parks influences decommissioning operations. Surface location risk is first evaluated at the time of the well license application and any emergency response planning for operational implications is then revisited at the time of decommissioning for longer term risks.

The treatment of developments near decommissioned wells varies by jurisdiction and includes input from the municipalities and developers.

27.7.1 Risk Level

Table 11. Surface Location Risk Level

Surface Location	Risk
Urban Centre within 1.5 km or Water well within EOR Scheme Area	5
Urban centre within 5 km or Surface water body/park within 0.5 km or Water well within 100 m	4
Residence within 0.5 km or Surface water body/park within 1.0 km or Water well between 100 m and 0.5 km away	3
Residence within 1.5 km or Surface water body/park within 1.5 km or Water well between 0.5 km and 1.5 km away	2
No Residence within 5 km or No surface water body/park within 5 km or No water well within 5 km	1

27.7.2 Risk Escalation Factors

27.7.2.1 Sour Fluids

Risk increases when wells with H₂S are near surface developments, residences or urban areas. Additional response planning and equipment may be required and an increased setback is desirable.

The presence of sour fluids may drive a decision to increase the isolation plan (e.g., perform a retainer squeeze of the original producing zone or use a permanent bridge plug with additional cement) to ensure long-term isolation.

27.7.2.2 SCVF/GM

Risk increases when there is a SCVF or GM near surface developments, residences or urban areas. Additional equipment or monitoring may be required to ensure public safety.

27.7.2.3 Insufficient Setback

The regulatory setback requirements for a decommissioned well vary by jurisdiction. For example, Alberta requires five metres (as per AER D079) and Saskatchewan can require up to several hundred metres. Insufficient setbacks can make it difficult to get the necessary equipment onto the site and may drive a decision to exceed the regulatory minimum requirements for isolation.

IRP The operator should work with the developer to ensure sufficient access is maintained to allow for future monitoring or re-entry for repair.

Note: A minimum of 25 metres is necessary for equipment access.

27.7.2.4 Changes Around the Well

The decommissioning and lease clean-up can be impacted if any of the following have been installed or occurred around the well since it was planned and drilled:

- Watertight septic tanks or sewage holding tanks.
- A sub-surface weeping tile effluent disposal field or an evaporation mound.
- Above ground storage tanks containing petroleum substances.
- Sewage effluent discharge to the ground surface.
- A sewage lagoon.
- Buried utilities (electrical, gas, water).
- Existing or planned building or above-ground structure.

Note: These considerations will be in place both before and after decommissioning since many jurisdictions have a guideline on

decommissioned well proximity to surface structures (e.g., AER D079).

- Property lines.
- Unpressurized (pumped) sewer lateral into a building.
- New water well(s).
- A subsurface sewage leaching field.

27.7.2.5 **Surface Mineable Areas**

In surface mineable areas (e.g., coal), the mining operations may excavate down to the point where the casing is exposed. There are additional decommissioning requirements in these areas (e.g., extra isolation below the future excavation depth).

IRP Local jurisdictional regulations for surface mineable areas must be followed.

27.7.2.6 **Near or Adjacent Operations**

Near or adjacent operations (based on radius of influence) can increase pressures or introduce potentially corrosive fluids.

27.7.2.7 **Future Urban Development**

Plans for future development in the area may drive a decision to increase the isolation plan (e.g., with additional bridge plugs or more isolation material) to ensure long-term isolation.

27.7.2.8 **Potential Landscape Change**

Natural changes in the landscape (e.g., flooding, movement of stream beds, erosion, etc.) can limit current decommissioning activities and future re-entry capability. Additional downhole decommissioning methods may be warranted in areas where landscape change is likely.

These methods might include improving the lower isolation, armoring the well at the expected erosion depth and accommodating for stream movement when choosing final cut and cap depth.

IRP Wells where there is potential for landscape change with an anticipated cut and cap depth below two metres from surface should have the location re-measured and recorded prior to cut and cap.

27.7.2.9 **Missing/Incomplete Well Location Information**

Precise documentation of well location is necessary due to landscape changes over time or changes in well ownership. When the location information is incomplete additional processes may be required to correctly locate the well.

27.7.3 Considerations and Mitigations

27.7.3.1 **Cement to Surface**

Risk is reduced if there is cement to surface on production casing and/or the surface casing depth covers the depth of usable groundwater.

27.7.3.2 **Stakeholder Engagement**

Stakeholder engagement early in the planning process, including discussions about eventual decommissioning of the well, can help ensure the stakeholders plans for the immediate area are considered and stakeholders are not adversely affected by well operations or after decommissioning. Adopting a 'good neighbour' notification policy that goes beyond local jurisdictional requirements promotes positive and ongoing communication with all stakeholders about decommissioning activities.

Communication with all of the stakeholders is often the best way to inform and move the wellbore risk on a specific surface location from a high or medium to low. Input from impacted parties, including indigenous peoples on their traditional lands, helps to identify concerns/risks and could instigate risk mitigation practices during execution of the work.

27.7.3.3 **Residential Impact**

Surface locations in proximity to population may require modifications in operating hours (due to noise, light, traffic, etc.) to minimize the impact on residents.

27.7.3.4 **First Nations/Traditional Land Impacts**

Personal relationships are often critical with First Nations groups.

IRP Planning and communications in First Nations regions should be coordinated by experienced stakeholder relations representatives who are familiar with the participants.

When the decommissioning activity is to take place on First Nations territory consult with the First Nations council and/or Indian Oil & Gas Canada regarding regulatory requirements.

27.7.3.5 **Environmental Impact**

Topographical factors and access/egress routes for the well and site need to be evaluated for increased risk of contaminating rivers, streams, etc. outside the site. Presence of these areas nearby may warrant increased surveillance and higher standards for fluid transportation/containment to reduce the associated risks.

Environmentally sensitive areas and regions with species at risk have very specific guidelines for surface location access and damage mitigation practices. There may be multiple regulatory agencies at both the provincial and federal level that deal with special wildlife treatment. Ensure all environmentally sensitive areas are captured early in the planning phase.

27.8 SCVF/GM History

SCVF or GM may be indicators of poor hydraulic isolation across the porous zones, low or poor cement top and/or potential casing failure.

IRP The local jurisdictional regulations regarding the categorization (i.e., serious or non-serious) and remediation of SCVFs or GM must be followed.

IRP If a cement evaluation log does not exist, one must be run as part of preparation for decommissioning if there is a SCVF/GM issue.

27.8.1 Risk Level

The risk level for this category is defined by whether or not the SCVF/GM is considered serious by the local jurisdictional regulator (see 27.3.2 Serious vs. Non-Serious SCVF/GM) and the level of difficulty (simple or complex) associated with the well conditions.

A complex well would include any condition that adds uncertainty or makes the source identification and remediation more difficult. These conditions may include, but are not limited to, the following:

- A combination of SCVF and GM on the same well.
- Subsurface complications or uncertainties (e.g., faults, active seismicity, abnormally pressured formations, active use of the subsurface such as waterflooding, active up hole gas zones, artesian groundwater, etc.).
- Well design or geometry that makes re-entry or access to remediate at or near the source difficult (e.g., sidetracks, multilaterals, fish, liners, previously abandoned zones, etc.).
- Well integrity problems such as casing failure or casing collapse.
- Previous SCVF/GM repair attempts which limited wellbore access.
- SCVF/GM source uncertainty or wellbore crossflow.

A simple well is any well that does not meet the criteria for a complex well.

Table 12. SCVF/GM Risk Level

SCVF/GM	Risk
Serious, complex well	5
Serious, simple well	4
Non-Serious, complex well	3
Non-Serious, simple well	2
No record of SCVF/GM	1

27.8.2 Risk Escalation Factors

27.8.2.1 Well Trajectory

Slant wells have a historically higher incidence of annular gas leakage, due in part to centralization and cementing challenges.

27.8.2.2 Cement Job Design

In some cases, well design has included cement not to surface on some annuli, leading to sustained pressure in that annulus. Cement blend and pumping schedule also influence probability and severity of SCVF/GM. Refer to IRP 25: Primary Cementing for additional guidance in this area.

27.8.2.3 Casing Design

Wells with an intermediate casing string may pose additional challenges in accessing a vent flow gas path in order to remediate. In addition, there may be multiple issues present with sustained annular pressure.

27.8.2.4 Lack of Groundwater Protection

In the event that the primary cement did not achieve protection of groundwater and hydraulic isolation between porous and protected intervals (per local jurisdictional regulations) additional remediation is required.

27.8.2.5 Inaccurate Cement Top Data

Cement returns to surface are generally accepted as confirmation of cement top. However, there can be errors in the reporting of cement returns and fallback can occur at the end of a cement job.

27.8.2.6 Wellbore Access Restrictions

Wellbore access restrictions, including but not limited to the following, can influence the information collection and remediation plan for the SCVF/GM:

- Fish in hole
- Ghost Hole/Sidetracks
- Previously Isolated Zones
- Casing weight changes
- Casing failure/collapsed casing
- Casing patches
- Permanent packers
- Produced sand
- Wax/paraffin
- Scale
- Hydrates

IRP If wellbore access constraints prevent the collection of the required well information (such as cement evaluation logs) or the attempt to remediate at or near the source, the local jurisdictional regulator shall be consulted to determine an approach that is as low as reasonably practicable (ALARP).

27.8.3 Considerations and Mitigations

Identifying the source of a SCVF or GM problem requires detailed investigation and analysis. See 27.9 SCVF/GM Source Identification for specific steps. Some strategies for remediation are found in 27.10 SCVF/GM Remediation.

In many cases a single remediation will not successfully resolve the problem. An iterative remediation strategy with multiple phases of data collection, analysis and remediation may be required for complex cases.

27.9 SCVF/GM Source Identification

If the well has a history of SCVF or GM, the source depth and formation of origin need to be identified. This can be in a variety of ways including the following:

- Well history review
- Offset well review
- Collection and analysis of new and historical vent flow data, carbon isotope data and logging data.

IRP A combination of the above strategies should be used to ensure all available information is taken into account when determining a remediation program.

IRP Regardless of history, licensees should conduct updated SCVF bubble/flow testing in preparation for well decommissioning in order to ensure the information being used to plan a remediation is accurate and aligned with current flow characteristics.

IRP Testing for SCVF and GM must be completed in accordance with local regulatory guidelines.

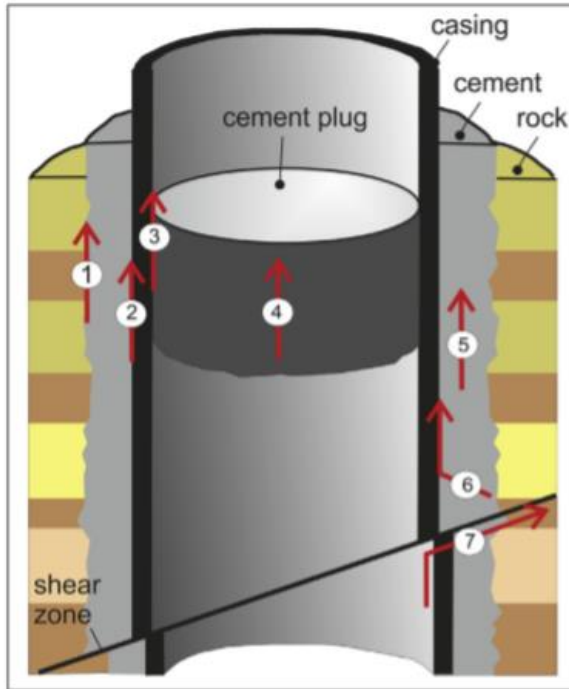
Note: In some jurisdictions this includes a mandated SCVF and GM test at the time of decommissioning (prior to wellhead removal).

IRP If a previous repair attempt was unsuccessful, the source identification process should be repeated to determine if the gas source has changed or if the originally identified source is still communicating to surface.

IRP If the source formation is deeper than the attainable bottom of the well (due to previously decommissioned zones, fish in hole, side tracks, ghost hole, casing collapse or other complications) the licensee should complete a subsurface risk assessment and work with the local jurisdictional regulator to determine the approach to remediation of the SCVF or GM.

The following figures show potential leak paths in a wellbore and at surface and serve to illustrate the difference between SCVF and GM.

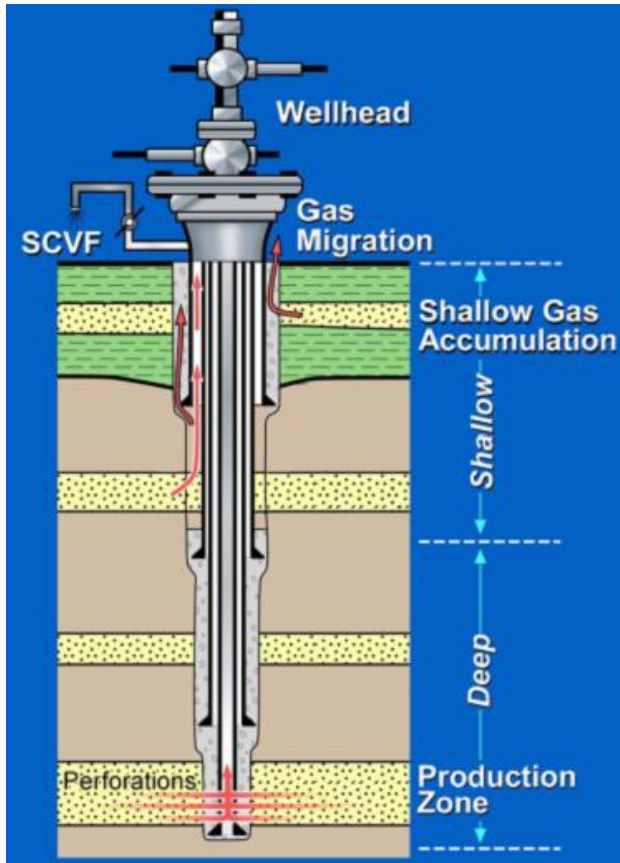
Figure 1. Potential Leak Paths in a Cemented Wellbore¹



The label numbers represent the following:

1. Between cement and surrounding rock formations
2. Between casing and surrounding cement
3. Between cement plug and casing or production tubing
4. Through cement plug
5. Through cement between casing and rock formation
6. Across the cement outside the casing and then between this cement and the casing
7. Along a sheared wellbore

¹ See Appendix I: References for sources for this diagram – Modeling critical leakage pathways in a risk assessment framework: representation of abandoned wells. After Celia et al. (2005) and Davies et al. (2014).

Figure 2. Potential Leak Paths at Surface²

27.9.1 Well History Review

The first step in identifying potential gas sources feeding SCVF/GM is a thorough well history review of all activities including the initial drilling program, well logs (open hole and cased hole) and all subsequent completions and testing data. Drilling and Completion/Testing reports can often hold essential data for SCVF potential source identification.

IRP All available data sources (e.g., Geological, Drilling, Completion/Testing, Logging and Carbon Isotope Interpretation data) should be used when identifying SCVF sources to reduce assumptions and errors.

² See Appendix I: References for source for this diagram – Leakage Potential along a Wellhead. AER.

Consider geological exploration and development methodologies in planning. These include, but are not limited to, the following:

- Regional geological and geophysical mapping and petrophysical analysis using open hole well logs.
- Regional analysis of offsetting gas and oil pools and historical well data to assess probability for gas in individual zones.
- Bypassed pay assessment in subject well.
- Gas storage vs. gas source assessment using recent cased hole and original open hole neutron logs to provide a time-lapse evaluation.
- Drilling or operations reports/tour sheets, including the following:
 - Drilling fluid logs for gas shows, gas kicks, lost circulation zones, potential washouts (open hole calipers or fluid volume/dye calipers). These will often correlate to problem areas during subsequent primary cementing operations.
 - Cementing practices (including drilling fluid removal practices) to indicate risk of microannulus formation, inter-cement channelling or poor formation bonding.
 - Casing specifications and running details may reveal if proper centralization was used, if grade and connection type are appropriate for the operating environment (i.e., sour service, pressure and thermal cycling stresses) or known variables such as failure issues common to specific thread types.
- Completions and testing activities to directly indicate gas potential and productivity, placement of mechanical or isolation plugs, cement-squeezed intervals or potential for mechanical wear or corrosion issues.

27.9.2 Offset Well Review

Offset well evaluation can provide information about the gas sources interpreted at the subject well. The offset wells review can be used to evaluate the following:

- Additional zones that have been tested, experienced gas kicks, etc. to evaluate if similar reservoir characteristics exist at the subject well.
- Remediation attempts (successful or unsuccessful) that can provide guidance to the approach on the subject well, including regional trends in up hole SCVF sources.
- Wellbore integrity issues that could also impact the subject well.
- The potential for offset wells to be a source for cross-well flow in shallower intervals, particularly where GM issues or faulting exist.
- Supplemental information that may be missing at the subject well.

Consider contacting operators, vendors or technical experts with knowledge of the area if experience remediating SCVF/GM in the area is limited.

Documenting key decommissioning job characteristics from similar offset wells can support future remediation efforts (e.g., interval selection, remediation details, success rates).

27.9.3 Surface Casing Vent Flow Data

SCVF data can support gas source identification and includes the gas flow rate and build-up pressure trends. The SCVF data and build-up pressures are also used to determine serious or non-serious categorization (see 27.4.4.2 Serious vs. Non-Serious SCVF/GM).

Higher flow rates and build up pressures are often attributed to deeper gas sources. However, the large variation in annular conditions can have a significant impact on the SCVF build-up pressure trends. Lower SCV flow and build-up pressures have been assumed to indicate shallower sources but could also be a result of better cement bond or greater hydrostatic pressure in the annulus.

IRP Initial SCVF and build-up pressures should be assessed prior to remediation to use as a baseline.

IRP The SCVF rate and pressure build data collection must be conducted as per local jurisdictional regulations.

This typically includes

1. a stabilized flow rate and
2. a stabilized shut-in pressure if possible (under two kPa/hour over a six hour period).

Note: A comparative pressure trend over a 24 hour period may provide some indication of whether the vent flow has been impacted.

IRP A pressure relief valve, or similar device, should be installed on the test assembly when conducting a pressure build up test.

IRP The pressure relief valve should be set at the local jurisdictional regulator's threshold for classifying the build-up pressure as serious.

IRP If it is anticipated that the build-up pressure will reach this threshold, a pressure recorder should be used to determine the rate of pressure build and to confirm the pressure at which the relief valve opens.

Note: This threshold pressure is intended to keep pressure build below surface casing shoe fracture pressure

IRP SCVF data and build-up pressure should be monitored during and post-remediation for comparison to the baseline.

Using a vent flow measurement device during remediation can provide an early indication of success, evidence of a micro-annulus (if the flow is reduced when pressure is applied to the casing) or help reduce extra remediation efforts when performing an intervention on multiple possible gas sources. A post-remediation build-up may not initially conclusively indicate success. It may also indicate a gas storage bleed-off or the potential for additional shallower gas sources. Further remediation may not be required if sufficient time passes to allow for the trapped gas to slowly bleed off.

IRP The surface casing vent assembly should be inspected for leaks during build-up monitoring to rule out the possibility of a false positive result, especially in older wells.

27.9.4 Gas Migration Data

IRP GM data collection must be conducted following local jurisdictional regulations.

Evaluating for successful GM remediation may include the following:

- Running pre- and post-noise logs.
- Visual observation at surface (not always reliable).
- Using a longer-term monitoring program.

Consider background GM levels. Areas such as muskeg may exhibit higher background gas concentrations that occur naturally. This may be confirmed through gas isotope testing for biogenic gas.

Test for GM in a grid-like pattern around the wellbore, up to six metres distant, to determine areas of highest concentration and plume extent.

27.9.5 Carbon Isotope Data

Carbon isotope analysis involves collection of sample gas from a leak path and analysis of the gas for composition and carbon isotopes using specialized lab equipment. The results are interpreted against a baseline data set of reference formation gases. Carbon isotope fingerprinting can be useful in identifying the source formation(s) of gases presenting at surface through SCVF or GM and, when used in combination with other recommended data for SCVF/GM source identification, can increase source identification accuracy.

Carbon isotope analysis is useful for investigating shallow biogenic gas sources. These biogenic gas sources may be naturally occurring rather than due to the presence of the well. Consult with the local jurisdictional regulator to determine whether these sources need remediation and the approvals required.

IRP If carbon isotope data is to be used in source identification the following practices shall be followed:

- Collect samples that are clean and air-free.
- Collect samples in containers appropriate for gas sampling.
- Identify, label and handle following applicable Transportation of Dangerous Goods (TDG) legislation and HSE procedures.
- Use a qualified geochemist to interpret results.

If a robust representative data set is not available for comparison and analysis consider a data sharing program with other operators and labs doing similar work.

IRP Carbon isotope data should not be the only source of information used in isolation to identify the gas source.

Some challenges and precautions to be considered when using carbon isotope data include the following:

- It requires a reliable reference database from representative gas samples. There is significant regional variability in carbon isotope data to be considered when using this baseline data.
- It is important to understand where the lab's comparative gases have come from and what limitations this may pose on the analysis. Reference gases often include SCVF, drilling fluid log and production gas. Carbon isotopes from production gas samples may provide a useful comparison of the isotopic signature for a SCVF source sample if there is no contamination or degradation of the samples. The composition and isotope ratios of source gases may vary depending on how they were obtained, handled and transported. The effect of these factors is not generally well understood.
- Combination of sources may be challenging to interpret.
- The gas samples may be subject to degradation or mixing within the annulus, at surface at time of collection or during transport.
- If a sample is suspected to contain H₂S it typically needs to be put through a scrubber prior to gas composition analysis. This scrubbing may affect some heavier hydrocarbons and hydrocarbon ratios. These effects need to be considered in the analysis and appropriate error bars applied to the interpretation.
- Presence of non-hydrocarbon gas may affect the presentation of some carbon isotopes. If the source identification from carbon isotope data conflicts with other information evaluate the possibility of crossflow or faulting leading to alternate gas conduits. This is particularly relevant in areas with high well density or known history of faulting.

27.9.6 Logging Data

Logging data for source identification includes both open hole logs from the drilling program, where available, and cased hole logs run throughout the well's life and in preparation for decommissioning to support SCVF source identification and planning.

More information about cement log evaluation can be found in IRP 25: Primary Cementing.

IRP Available logging data from the subject well should be considered in gas source identification. If no logging data is available in the subject well, look at data from the nearest offset wells.

IRP The following should be considered for logging and log interpretation for SCVF/GM source identification:

- The gas zones interpreted from open hole logs have a high probability for correlation with historical drilling events (e.g., gas shows/kicks), completions/testing activities (e.g., perforations and gas deliverability evaluations) and potential gas production either at the subject well or offsetting wells. Common data obtained in open hole logging programs which may be useful in SCVF/GM source identification includes the following:
 - Gamma ray for lithology interpretation. Spectral Gamma Ray tools can be useful in removing the influence of radioactive signatures, such as uranium, to confirm depth and thickness of impermeable cap rock formations that may be appropriate targets for remedial activities.
 - Caliper log for wellbore break-out evaluation.
 - Neutron and density porosity logs for reservoir development and gas/oil indicators.
 - Resistivity for gas/oil indicators.
- Cased hole logs can be useful for identifying the current state of a wellbore, especially when overlaid with historic logs to indicate changes over time. A standard suite of cased hole well logs run for remediation programs includes the following:
 - Gamma ray.
 - Neutron and density porosity logs.
 - Cement (radial) bond logs.
 - Noise and temperature logs.

Challenges and precautions associated with log data for gas source identification include the following:

- Log planning and interpretation need to be performed by qualified personnel to ensure the logs collected add maximum value to the source identification process.
- Conventional open hole logs cannot reliably detect faults or fractures that could act as gas conduits feeding SCVF/GM. Seismic data or microimaging logs may be used to interpret the presence of faults.
- Gas zones interpreted from open hole logs at the time of drilling are generally done from the perspective of commercial viability rather than potential leak sources. Crossovers in neutron and density porosity logs show a gas source, but

it is important to consider areas that do not show a crossover with the curves approaching each other.

IRP SCVF/GM source identification should include a re-evaluation of historical logs for zones of potential inflow that may have been overlooked.

The cased hole gamma ray and neutron/density porosity logs are not a direct measurement of the reservoir conditions due to the casing and annular (cement bond) conditions that can impact the logs. However, current cased hole logs can be calibrated to provide valuable data to support gas source interpretations. An additional reason to run cased hole neutron/density logs is to differentiate zones with gas storage as opposed to an actual gas source. This may be achieved by overlaying the open hole and cased hole neutron logs. As gas storage builds up in the annulus or into a former “wet” porous zone, the cased hole neutron logs will indicate gas. Gas storage commonly occurs within a poorer cement bonded interval just under a well bonded cement restriction in the annulus.

CBLs can provide information to support gas source interpretation, enable investigation of the annular conditions through which gas can enter the annulus and identify possible gas migration conduits (i.e., microannulus and/or cement channels). Cement bond logging may be conducted while varying pressures on the casing (for example, 0 MPa down/7 MPa up) in order to aid in identifying presence of a micro-annulus flow path between cement and casing. During a pressure pass, monitoring the vent flow rate to identify if the flow rate is reduced with casing pressure can help identify a micro-annulus SCVF path. Cement bond logs can also support interpretations for gas storage intervals.

Note: An understanding of the density and any change in density of the cement behind casing is necessary for proper calibration of the logging tools.

Noise logging measures the frequency and magnitude of noise that exists in the vicinity of the wellbore which may include movement of gas in an annulus. Noise logging is highly susceptible to the large variation in annular conditions, including the following:

- Cement bond.
- Variation in hydrostatic pressures (or lack thereof).
- Access to other porous and permeable zones through poor cement bond in the annulus.

Gas sources interpreted from noise events have a high correlation to large variations in annular cement bond. The noise events may be associated with pressure changes between well bonded to poorer bonded intervals causing turbulence or as gas enters a small conduit through a cement restriction as it migrates to surface. This is best evaluated and confirmed by a qualified logging expert. Noise logs run pre-remediation

are most reliable for interpreting gas source from below a logged interval. Potential shallow gas sources may be interpreted by a separate post-remediation noise log after successful remediation of deeper gas sources.

Fluid invasion, gas storage and changes in cement integrity over time can be observed through overlay of current log data with past open hole and cased hole logs.

27.10 SCVF/GM Remediation

Table 13 discusses conventional remediation options that may be considered.

Table 13. SCVF/GM Remediation Options

Option	When/Where to Use	Considerations
<p>Accessing the annulus and circulating cement to surface.</p>	<p>This option may be considered if the source has been identified above the top of cement in the annulus (or within the same formation as the identified cement top).</p>	<ul style="list-style-type: none"> • Annular access technique to be used (e.g., perforating, mechanical casing cutting, abrasive cutting, etc.). See the casing repair sections of IRP 26: Wellbore Remediation for more information. • Depth of cement top and locations of other intervals requiring hydraulic isolation. • Relative densities of current annular fluid and cement. • Viability of current TOC to serve as a platform to prevent roping (i.e., loss of cement downhole due to relative density). • Risk of washout or hole collapse. • Pressure limits imposed by fracture gradients of all exposed formations. • Ability to achieve circulation to surface with consideration for hole cleaning fluid and filter cake removal. If acid is to be used, consult local jurisdictional regulations for volume limits when working above the BGWP/BUGW (see 27.3.6 Protecting Groundwater). • Pressure limits of the well elements and surface equipment. • Number of casing strings and access constraints.
<p>Accessing annulus and formation and squeezing cement to stop the gas at the source.</p>	<p>This may be done at the top of the source formation, the interface between the source formation and the caprock, or in the next shallowest caprock formation.</p>	<ul style="list-style-type: none"> • Local jurisdictional regulations for porosity isolation. In general, it is necessary to ensure the depth selected achieves hydraulic isolation between the source and the next porous interval • History of success or failure in the area. • Ability to inject cement into the formation at an acceptable pressure (in consultation with subsurface experts and within safe limitations of wellbore and surface equipment). • Location of TOC and cement quality above and below source (see 27.14 Determining Top of Cement). • Annular or formation access strategy (e.g., perforating, mechanical casing cutting, abrasive cutting, etc.).

Option	When/Where to Use	Considerations
		<ul style="list-style-type: none"> • Selection of perforating charges for hole size and depth of penetration for access to annulus versus injection into formation. • Selection of formation access interval. A common method involves selecting an interval that straddles top of source formation and bottom of caprock to maximize injectivity and minimise ability for gas to find an alternate path. • Choice of sealing medium (type of cement and/or alternate product). • Understanding of surface response in between isolating multiple intervals, collecting additional data and taking adequate time in between remedial attempts to prevent leaving charged gas trapped in annulus (resulting in failure of shallow remediation job due to pressure build). • Swabbing a well dry after perforating and prior to performing cement remediation to reduce hydrostatic head and to determine if source gas enters the wellbore. This may be useful in evaluating whether the perforated interval has intercepted the flow path. • Acid can be used to achieve injectivity (by increasing feed rate into a porous zone or for clearing cement and junk in the annulus) within prescribed pressure limits. Consider proximity to BGWP/BUGW and ensure compliance with local jurisdictional regulations
<p>Section milling to remove a selected interval of casing and cement to allow placement of a cement plug from formation to formation.</p>	<p>This may be done in caprock or across the interface between the source formation and the caprock above.</p>	<ul style="list-style-type: none"> • Geology and caprock. • Location of TOC and cement quality above and below source. • Well and casing integrity. • Presence of multi-annular vent flow or complex well geometry (e.g., capillary lines). • History of success in the area. • Future need to re-enter the wellbore. Drilling through can have a low probability of success and has increased operational complexity compared to other methods. This method is not commonly used in western Canada as a means of remediating SCVF/GM and may be considered non-routine by the local jurisdictional regulator. See the Section Milling section of IRP 26: Wellbore Remediation for more information about section milling.

Alternative methods for isolating and repairing SCVF or GM may also be considered. These methods include alternate products, placement techniques and tools. See Appendix E for more information.

Evaluate the risk of generating an alternate flow path for the source gas based on the ability of the surrounding rock formations to withstand a cement squeeze or if the cement squeeze design exceeds formation fracture gradient. This is of particular concern for shallow remediations as fracture gradients can vary greatly. If selected

intervention depth is too shallow and SCVF gas flow is stopped too far away from the source depth, an unintended consequence may be gas pressure build below the remedial seal leading to an alternate flow path outside the wellbore, including gas migration.

Establish success criteria ahead of the remediation and choose the appropriate post-remediation assessment technique. False negatives can lead to re-entry for repair.

Consider the following:

- Vent flow rate and pressure can fluctuate greatly with temperature and barometric pressure. Conduct testing in frost-free months and consider the effect of temperature when interpreting the data.
- Account for vent flow/GM history. Historically intermittent vent flows may require a longer monitoring period to verify success.
- Comparison of before and after flow rate and stabilized shut-in pressure can be indicators of success. In many cases annular gas builds up over a period of many years and will require time to bleed off after the source has been isolated. A stabilized change in flow or pressure after remediation can be an indication of a second shallower source or an alternate flow path.

IRP Remediation efforts must resolve SCVF/GM issues to regulatory compliance prior to proceeding to surface decommissioning (i.e., cut and cap). If cut and cap is not possible other non-routine solutions need to be discussed with the local jurisdictional regulator.

27.11 Subsurface Parameters

The following can increase the risk in a decommissioning operation:

- Lack of hydraulic isolation
- Cement top
- Pressure
- Formation fluids
- Deliverability
- Decommissioning fluids
- Ability to recharge
- Previously decommissioned zones
- Caverns/Storage
- Areas requiring remediation

27.11.1 Hydraulic Isolation

It is important to know if there is adequate hydraulic cement isolation behind the casing/wellbore annulus, especially where there is potential for flow via a hydrocarbon bearing zone or a water bearing zone (see 27.13 Hydraulic Isolation).

These areas between and above completed intervals need to have hydraulic isolation to prevent any potential cross-flow between different hydrocarbon zones and water bearing zones. The difference may be due to pressure, gas, oil gravity or viscosity, water salinity or a combination of these attributes.

27.11.2 Cement Top

It is important to determine the TOC during the planning phase of decommissioning to ensure isolation of porous water and hydrocarbon bearing zones. TOC impacts the scope of work required to execute the decommissioning.

Risk is increased if cement top is unknown due to the additional steps required to determine TOC (see 27.14 Determining Top of Cement). A low cement top can increase the risk associated with risk categories such as SCVF/GM (see 27.8 SCVF/GM History) and hydraulic isolation (see 27.13 Hydraulic Isolation).

27.11.3 Pressure

The most common cause of non-zonal isolation or inter-zonal formation communication is differing pressure regimes or greater gas mobility compared to fluids in the annulus. It is very important to understand the various potentially different pressure regimes within a wellbore in order to determine the following:

- Safety requirements.
- Equipment requirements.
- Regulatory requirements.
- Procedural requirements.
- Which zones need to be hydraulically isolated due to either a lower pressure or higher pressure than the close proximity zones (which may be above or below the zone to be isolated).

Table 14. Pressure Risk Level

Pressure (kPa/m)	Risk
>14	5
11 - 14	4
9.8 - 11	3
< 9.8	1

Pressure considerations vary by depth.

Table 15. Pressure Considerations by Depth

Depth (m)	Pressure Considerations
3600+	<ul style="list-style-type: none"> • Pressure gradients are probably greater than 11 kPa/m • Deeper formation may exhibit increased pressure gradients due to tectonic pressures and/or over-pressured shales.
1800 – 3600	<ul style="list-style-type: none"> • Pressure gradients greater than 11kPa/m or as low as 7 kPa/m or lower may exist. • Formation may exhibit increased pressure gradients due to over pressured shales or proximity to injection wells or EOR schemes.
0 – 1800	<ul style="list-style-type: none"> • Pressure gradients will generally be less than 10 kPa/m and well control can be achieved by a water gradient. • Formation may exhibit increased pressure gradients due to proximity of injection wells or EOR schemes.

27.11.4 Formation Fluids

The presence of H₂S, CO₂ or NO_x, regardless of the concentration, may require the use of specialized safety equipment and spill prevention measures.

The presence of H₂S or CO₂ can accelerate corrosion and impact the life of iron/metallic components. These fluids can result in a higher risk level in what would normally be considered lower risk or shallower active zones.

27.11.5 Deliverability

The well's ability to flow impacts the zonal decommissioning method due to the increased possibility and consequence of a fluid release. A flowing well may impact the method for conveying the plug (e.g., wireline vs. coiled tubing). Deliverability impacts the ability to kill the well and increases the consequences of a leaking plug.

27.11.6 Decommissioning Fluids

For the purpose of IRP 27, a decommissioning fluid is defined as the fluid(s) left in the well permanently, whether below, between or above any barriers placed or installed inside casing. It does not include any kill fluids or workover fluids that are installed in the well temporarily to maintain well control throughout the well decommissioning process.

IRP Local jurisdictional regulations for decommissioning wellbore fluids must be followed (e.g., AER D020: Well Abandonment section on Use of Inhibitors).

IRP If the fluid being used below BGWP/BUGW does not meet regulatory requirements for use above BGWP/BUGW, a barrier shall be set to prevent mixing of the fluids or the non-compliant fluid shall be circulated out.

Consider the following about decommissioning fluids:

- Environmental impact of fluids on surface and fresh water aquifers.
- Impact to casing longevity.
- Inhibitor effect on cement setting.

27.11.7 Ability to Recharge

IRP Zones with an ability to recharge could potentially have higher downhole pressure in the future so plug selection and decommissioning method should be compatible with the highest predicted pressure differential (see 27.3.5 Ability to Recharge).

27.11.8 Previously Decommissioned Zones

Most previously decommissioned non-Level-A zones that meet the requirements of the regulations at the time they were decommissioned are grandfathered and do not require further decommissioning operations to bring them to current standards. Action does need to be taken in the following situations:

- If the well is leaking.
- If the previously decommissioned zone was a Level-A zone.
- If the uppermost previously decommissioned zone's plug is above BGWP/BUGW.

Leaking zones are covered by re-entry guidelines (see 27.15 Re-Entry for Repair).

Non-grandfathered zones requiring re-decommissioning are considered non-routine operations.

IRP Local jurisdictional regulations for previously decommissioned zones must be followed.

Risk is increased if the previous decommissioning was unsuccessful or blocks access to the zone of interest for the current decommissioning activity (e.g., a gas migration or vent flow source).

27.11.9 Caverns/Storage

Cavern decommissioning increases risk due to an increased risk of cavern collapse and the risk of increasing pressures with salt creep over time.

Refer to CSA Z341: Storage of hydrocarbons in underground formations for information regarding Cavern/Storage wells.

Refer to CSA/ANSI ISO 27916:19: Carbon dioxide capture, transportation and geological storage – Carbon dioxide storage using enhanced oil recovery (CO₂-EOR) for information regarding CO₂ sequestration.

Decommissioning of cavern and storage wells may be non-routine operations (see 27.3.1 Routine vs. Non-Routine). Consult the local jurisdictional regulations for notification and approval requirements.

27.11.10 Areas Requiring Remediation

If the area to be decommissioned has a fish in the hole, ghost hole, side track or casing failure the risk can increase due to the extra operations (remediations) and regulatory approvals required to obtain hydraulic isolation. See IRP 26: Wellbore Remediation for remediation strategies.

27.11.10.1 Casing Failure

A casing failure increases risk because more complicated procedures are required to isolate the casing failure. A previously repaired casing failure may increase the risk of future casing failure and drive a decision to increase the isolation plan to ensure isolation of all zones within the casing failure interval. Other factors to consider include the following:

- Number of porous intervals the casing failure is across.
- Type of fluid within the formations (e.g., BGWP/BUGW).
- Sweet and sour intervals being open to each other.
- Offsetting EOR schemes.

Refer to the Casing Repair sections of IRP 26: Wellbore Remediation for information about investigation and repair/replacement of casing.

27.11.10.2 Fish in Hole

A fish in hole can increase risk because it complicates the operations, particularly if there is a radioactive source.

IRP Approval from the Canadian Nuclear Safety Commission (CNSC) must be obtained before beginning any work on a well with a radioactive source that has been lost in the hole.

Refer to 27.17 Radioactive Source Fish for more information about the regulatory requirements for dealing with radioactive source fish.

If the well can be decommissioned as per local regulations with the fish, the fish can be left in the hole. If not, a non-routine operation (see 27.3.1 Routine vs. Non-Routine) may be required or regulations may require additional effort to remove.

IRP All federal and local jurisdictional regulations pertaining to fishing must be followed.

Fish location, feed rate implications and the number of completed zones impact risk.

If the area of concern does not allow access to uncompleted thermal intervals for proper decommissioning, it may disqualify a buffer area in that zone around the well from future thermal recovery.

27.11.10.3 **Ghost Hole/Side Tracks**

A ghost hole/side track can increase risk because complicated procedures are required to isolate the ghost hole/side track. As the zones within the ghost hole/side track(s) are hydraulically isolated the risk decreases.

If the area of concern does not allow access to uncompleted thermal intervals for proper decommissioning, it may disqualify a buffer area in that zone around the well from future thermal recovery.

27.11.10.4 **Location Considerations**

If the bottom portion of the well has not been decommissioned to local jurisdictional regulatory standard, effort may be required to gain access to these zones to ensure they are properly isolated.

If the area of concern is across the upper or both completion intervals of a multizone completion, the well may have to be decommissioned commingled (a non-routine scenario). To mitigate the risk of this a retainer squeeze can be considered.

27.11.10.5 **Feed Rate Considerations**

If there is feed rate into or past the interval of concern it means there is a location (i.e., open hole, perforations or casing leak) whereby there is communication with a formation. This pathway of communication needs to be isolated so that no fluid or gas can flow either up the annulus or inside the casing.

27.11.10.6 **Number of Completed Zones**

If the ghost hole, side track or casing failure is across multiple zones there may be increased risk and additional effort may be required to ensure hydraulic isolation is achieved.

27.11.10.7 **Access**

If there is access to the bottom of the area of concern then a cement plug can be layered and squeezed to ensure isolation of all zones.

If there is not access to the bottom of the area of concern then obtain a feed rate and perform either a retainer or bullhead squeeze to isolate the zones.

27.12 Well Design and Construction

Original well design and construction can impact decommissioning operations. Unique solutions may be required for complex well design or geometry or for un-planned situations introduced during construction. This can increase risk, usually for the following reasons:

- Increased level of uncertainty.
- Additional/more complicated procedures.
- Equipment required to perform downhole plugging operations.

27.12.1 Risk Escalation Factors

27.12.1.1 Well Geometry

Risk increases when there are horizontals, slants or other deviations from vertical. Slants and deviations can increase the risk of a poor primary cement job, SCVF or GM.

27.12.1.2 Number of Completion Intervals

Risk increases with the number of zones to be decommissioned due to the number of tools that may need to be run in the hole.

27.12.1.3 Unplanned Construction Scenarios

If the area to be decommissioned has a fish in the hole, ghost hole, side track or casing failure risk can increase due to the extra operations required to obtain hydraulic isolation. See 27.11.10 Areas Requiring Remediation for more information.

27.12.1.4 Level-A/Sour Zones

It is important to effectively isolate sour (H_2S) zones or zones containing acid gas (CO_2) to prevent sweet zones from being affected by H_2S or CO_2 .

27.13 Hydraulic Isolation

Permanent hydraulic isolation is the one of the key objectives of zonal decommissioning. The presence of a known or logged TOC, including cement to surface, does not guarantee effective isolation. Other risk factors including channelling or a micro-annulus may still be present.

IRP When determining whether porous zones and groundwater have been adequately isolated, TOC should be considered along with the evidence of hydraulic isolation of the cement existing in the well below TOC.

Understanding of hydraulic isolation in relation to the geologic assessment of the zones proposed for commingling is a key component to making a non-routine commingling application to the local jurisdictional regulator.

27.13.1 Risk Level

Table 16. Hydraulic Isolation Risk Level

Cement Top	Risk
Lack of hydraulic isolation between porous intervals and groundwater	5
Lack of groundwater protection	4
Lack of hydraulic isolation to support a non-routine commingling application	3
Groundwater/Porous intervals deemed isolated (calculated)	2
Groundwater/Porous intervals deemed isolated (logged)	1
Groundwater/Porous intervals deemed isolated (Cement Returns to Surface)	1

27.13.2 Risk Escalation Factors

27.13.2.1 Primary Cement Quality

A primary cement job that does not fully meet objectives or is poor quality can increase the risk of leaks, channeling, poor centralization and other problems that have to be addressed at decommissioning. The quality of cement returns (as recorded in the daily

report) can vary from contaminated water to essentially neat cement. Refer to IRP 25: Primary Cementing for more information about primary cement jobs.

The quality of isolation achieved from the primary cement job can be impacted by the inclination of the wellbore, particularly when in combination with no centralization or under-centralization of the casing.

The primary cementing risk factors can be diagnosed to some degree using logging tools. However, it is impossible (with current technology) to validate with certainty whether the cement in place behind casing is sealing. The TOC needs to be analysed in combination with the rest of the information in the well files and compared to the considerations and best practices in IRP 25: Primary Cementing in order to determine the likelihood of the cement behind casing providing the necessary seal. See 27.14 Determining Top of Cement for additional primary cementing implications as they pertain to cement top.

The presence of a cement blend of sub-optimal quality behind casing will reduce the probability of success in remedial cementing operations for decommissioning. Blends with a higher concentration of fly ash than cement and blends with 8% gel or greater may provide adequate TOC but tend to result in a higher frequency of SCVF and GM issues.

27.13.2.2 **Unknown Cement Top**

Establishing the presence of isolating cement behind casing first requires that the TOC be determined relative to requirements to cover porous zones and groundwater (See section 27.14 Determining Top of Cement). Once the TOC is determined the hydraulic isolation of the cement needs to be evaluated to assess whether the required porous zones and groundwater are isolated.

At the time of decommissioning, the TOC behind casing is pre-determined based on the execution of the primary cement job. A “design for decommissioning” approach during primary cementing following the best practices outlined in IRP 25: Primary Cementing is the best mitigation to ensure the TOC in a well is adequate for decommissioning purposes.

When considering an inside casing isolation decommissioning strategy, compare the calculated or logged TOC to the geologic formations (from open hole logs) to validate cement isolation on the back side of casing relative to caprock depth. This can also validate the extent of hydraulic isolation across the up hole porous zones and base of groundwater.

27.13.2.3 **Unknown Hydraulic Isolation**

Risk-based wellbore decommissioning requires an analysis and judgement of whether the cement present behind casing is adequate in terms of the location of the TOC

relative to formation tops and whether it can be deemed to be providing hydraulic isolation.

When hydraulic isolation is unknown, or known to be inadequate, further investigation or remediation may be required in order to confirm or restore hydraulic isolation, either above or below the zone(s) requiring isolation.

The absence of hydraulic isolation behind casing may preclude the option to make a non-routine application for the decommissioning of commingled zones as a unit unless remediation operations are performed to attempt to establish hydraulic isolation at the top and/or bottom of the geologic package of proposed commingling intervals.

27.13.2.4 Well Design and Construction

The factors described in Table 17 can impact the quality of hydraulic isolation present behind casing either in terms of bond to formation or bond to casing.

Table 17. Well Design and Construction Factors

Factor	Notes
Hole size vs. Casing Size	<ul style="list-style-type: none"> • Adequate annular clearance of casing compared to gauge hole size can help with the radial coverage of primary cementing. • Washouts and hole collapse issues can negatively impact the ability to get good bond to formation. See IRP 25: Primary Cementing for more information.
Casing Design	<ul style="list-style-type: none"> • Location of the casing shoe depths relative to porous zones and groundwater. • Centralization strategy. • Inclination effects.
Liner vs. liner + tieback vs. single string production casing	<ul style="list-style-type: none"> • The amount of liner overlap, separate cementing events for liner and production or intermediate casing or presence of a tieback in the well preventing logging access to cemented outer strings.
Single size casing vs. tapered	<ul style="list-style-type: none"> • May present localized issues with hydraulic isolation in the vicinity of the taper.
Primary cementing considerations	<ul style="list-style-type: none"> • Single stage vs. multi stage. • Lead/Tail Cement selection. • Stage tool usage for multiple stage cementing. • Rotation and/or reciprocation of casing during primary cementing. • Planned cement top vs. calculated or logged. • Preflushes and additives.

27.14 Determining Top of Cement

There are many ways to determine TOC. It does not always have to be measured directly and can be calculated based on the primary cement job execution parameters).

IRP A cement evaluation log should be run in if any of the following conditions exists:

- Theoretical calculations (using an excess of 20 per cent) indicate that the cement top does not extend a minimum of 15 vertical meters above the uppermost porous interval.
- There is a surface casing vent flow or gas migration issue present.
- If there is no surface casing or the surface casing isn't below the BGWP/BUGW and there is no record of cement returns.
- If there is any reason to doubt the effectiveness of the casing cementation.

27.14.1 Cement Returns and Quality

Cement returns observed at surface on the primary cement job are often used as an indicator of TOC during planning when no cement bond log is run. Using cement returns does not account for the possibility of cement fallback that can occur after the primary cement job.

For primary cement jobs where cement was not circulated to surface there is a risk of a false positive TOC (or a muddled TOC) from solids that have settled out over time (from drilling fluid or weighted spacers) or from sloughing in of formation fill from unstable formations.

A comparison of the planned volume of cement to the pumped volume when returns arrive at surface can be an indicator of hole quality, including channelling or washouts. Original drilling reports can also provide insight into hole condition within a specific hole section.

27.14.2 Cement Height Calculations

When cement returns are not observed to surface on the primary cement job and significant losses were not observed, it is acceptable to report a calculated TOC based on hydrostatics, pumped volumes and pump pressure recorded immediately prior to

wiper plug bump on the primary cement job. Hole quality is important to the accuracy of calculated TOCs. Primary cementing volumes can be sized based on gauge hole plus an allowance for wash-outs, or can be based off of open hole caliper log data.

IRP At time of decommissioning, a log should be run to confirm the calculated TOC when there is uncertainty in the calculated TOC as to whether the calculated TOC is adequate for cement coverage behind casing of porous interval(s) or groundwater that needs to be isolated.

IRP At time of decommissioning, a log should be run to confirm the calculated TOC when the calculated TOC using gauge hole volume plus an excess of 20% does not indicate adequate cement coverage behind casing of porous interval(s) or groundwater that needs to be isolated.

27.14.3 Channelling and Fluid Volume Measurement

TOC calculated from hydraulics can indicate higher TOC than originally planned if the cement channelled upwards behind casing during the primary cement job resulting in poor bond quality. When planning the decommissioning look for caliper logs that integrate or pump a fluid dye volume to help validate, on a volume basis, the cement top calculated from hydrostatics alone.

27.14.4 Measuring TOC

The top of cement is not typically logged at the time of primary cement unless problems occurred during the primary cementing.

There are different logging methods that are suitable for measuring cement top behind casing. Consider the following:

- A temperature log can be valuable if it was run shortly after a primary cement job and can differentiate the temperature effects as the cement sets up.
- It is more common for cement to be logged after the it has fully cured and often this logging is deferred to the time of decommissioning. CBLs can provide a qualitative indication of relative bond along the hole length.
- Wells with a primary cement job that was pumped in stages (i.e., through the use of stage tools) will have more than one cement top to calculate or log.
- When the primary cement job has two or more cement blends pumped as a single cement job (lead vs. tail cement), the differences in density and compressive strength can complicate TOC calculations and the ability to accurately confirm TOC with logging.

Foamed cement has low density and lower compressive strength. It can be difficult to pick up on a CBL unless properly calibrated for foamed cement.

IRP When foam cement was pumped on the primary cement job and where lab testing of the cement blend exists, this information should be supplied to the logging contractor in order to calibrate the log to foamed cement.

The difference between a logged pass at zero applied surface pressure and a pressure pass may indicate the existence of a microannulus between cement and casing. Applied pressure for a pressure pass is typically 7 MPa as this aligns with wireline pack-off sealing limitations without having to add a grease head into the lubricator rig up.

IRP When performing a CBL pressure pass, the surface pressure applied should replicate the casing stress state at the time the plug bumped during the primary cement job considering the fluid hydrostatics of the cement, the displacement fluid pumped and the pressure at which the wiper plug bumped.

There are limitations to the available log data specific to the logging tools that were used. These include depth of investigation, calibration to cement compressive strength and logging without known lab testing for compressive strength. Log results can give false positives or false negatives if these limitations have not been considered in the interpretation. See the Cement Log Evaluation section of IRP 25: Primary Cementing for more information about log types and considerations.

27.15 Re-Entry for Repair

The following are common reasons for re-entry:

- To repair a leak.
- To properly decommission a well where there are no records indicating it was cut and capped properly. Sometimes it has to be re-entered and lowered but usually it is only necessary to locate the casing stub with pin finder and do a gas migration test over top.
- To isolate known zones that could see increased pressure due to pressure maintenance schemes.
- To make the well thermally compatible.
- To lower a casing stub to accommodate for new development.
- To prepare wells not decommissioned to the standards required for an enhanced recovery or thermal project.

Re-entry for repair is considered a non-routine operation.

IRP Any wellbore re-entry must have regulatory submission and/or approval before beginning re-entry operations.

IRP A risk assessment should be completed for all of zones in question when there is no evidence supporting proper decommissioning of a previously decommissioned zone.

IRP The leaking zone and all zones above it must be decommissioned to the current standards for the local jurisdiction.

IRP Anything below the leaking zone may be left as it was previously decommissioned. However, zones below the decommissioning depth should be reviewed/investigated for any deeper issues that require repair.

IRP Approval from the CNSC must be obtained before beginning any work on a well with a radioactive source that has been lost in the hole.

Refer to 27.17 Radioactive Source Fish for more information about the regulatory requirements for dealing with radioactive source fish.

If the licensee still holds a valid mineral lease then only regulatory approval to re-enter is required. If the lease has expired then the current mineral lease holder (or the crown for crown land) needs to be notified.

IRP Surface access must be in place for re-entry of a wellbore.

Surface access may involve temporary access or a new lease from the surface owner.

27.15.1 Risk Level

Table 18. Re-Entry for Repair Risk Level

Risk Factor	Risk
Leaking with no casing	5
Leaking outside of casing	5
Leaking inside of casing (BP, SCVF, etc.)	5
Lowering of previously cut and capped well	1

27.15.2 Risk Escalation Factors

27.15.2.1 Trapped Pressures

Trapped pressure increases the risk of the re-entry operation. There is always a risk of trapped pressure when re-entering a well, especially if it is being re-entered due to a leak and particularly if it has a shallow isolation plug. Gas migration can be caused by build-up of a vent flow on a non-vented cap that has created a path outside of the surface casing with a large bubble of high-pressure gas below the isolation plug.

Note: Prior to 2003 the regulatory requirement was to decommission at surface with a five sack cement plug and then weld all casings solid. Any well that has a five sack surface cement plug has risk of trapped pressure below the cement.

IRP Re-entry shall not be attempted without first assessing and addressing the risk of trapped pressures.

27.15.2.2 Open Hole Cement Plug Drill out

The drilling out of open hole cement plugs have a high risk of sidetracking off the isolation plug due to the isolation plug being harder than the formation it is set within (e.g., D&A wells, stratigraphic wells).

27.15.2.3 Leaks

Small leaks at shallow depths can be very difficult to remediate. These may be good applications for an alternate product to cement (see Appendix E).

27.15.3 Process for Re-entry

The general process to re-enter a well is as follows:

- Locate the casing stub or wellbore.
- Conduct ground disturbance and daylight the casing.
- If there is no casing then install conductor and prepare the site for rig access.
- Excavate the casing stub.
- If there is a leak, identify where the leak is coming from.
- Ensure no pressure is present. There may be pressure within a welded cap that would require hot or cold tapping.
- Bring casing back to surface and install wellhead with adequate pressure rating for depth.
- Once the wellhead is installed, sample any string that has pressure and the soil around the well to determine the leak source with isotope analysis.

27.15.4 Wellhead Freezing

When implemented properly, freeze plugs can provide safe secondary well control barriers in situations where full access to the wellbore to install mechanical plugs is limited or other kill methods (e.g., circulation, bull heading) are not possible.

IRP If a freezing operation is to be used it shall be risk assessed and include appropriate mitigations and safety measures. Freezing is not recommended for sour wells.

IRP When used as a secondary barrier the freeze plug shall be suitable for the pressure, temperature and force required to install and support the plug and be pressure tested once in place.

IRP Installation and maintenance of freeze plugs shall be performed by competent personnel (see IRP 07: Competencies for Critical Roles in Drilling and Completions. Providing/implementing a freeze plug would be considered a critical role based on the definitions in IRP 07.).

27.16 Cut and Cap

Cutting and capping the decommissioned well involves removal of the wellhead, cutting the casing below ground and capping with an approved capping method.

Cutting off a wellhead can be dangerous due to the fact that the surface casing is supporting the tension of the production/intermediate casing and liner tension if the liner runs to surface. During drilling the production string carries the weight of the casing and induced tension but when manually cutting it is necessary to ensure adequate support is left on the surface casing until the inner strings have been cut.

The following can increase the risk or complexity of the cut and cap operation:

- A radioactive source left in the hole.
- The need to lower the casing stub.
- Missing or incomplete well location documentation.
- Areas of surface mining (coal or a gravel pit).
- Areas where features or terrain might be expected to change over time or be water covered (e.g. riverbanks, runoff areas).

Refer to 27.17 Radioactive Source Fish for more information about the regulatory requirements for signage for a decommissioned well with radioactive source fish left in the hole.

IRP All wells should have a vent flow check to ensure no vent flow prior to cutting and capping.

IRP **Local jurisdictional regulations for cutting and capping casing must be followed.**

Refer to the following regulations for more information:

- AER D020: Well Abandonment
- AER Draft Directive xxx: Well Integrity Management (draft currently open for comments, replaces ID 2003-01)
- AER D079: Surface Development in Proximity to Abandoned Wells
- Saskatchewan Directive PNG015

Note: B.C. follows AER D020 in principle, with the requirement for a notice of operations to the BCOGC.

Re-entry to lower the casing stub may be a non-routine operation or may require a new license. Consult with the local jurisdictional regulator for specifics.

Missing or incomplete well location information can complicate ongoing monitoring and future access to the well, particularly when there are landscape changes over time, so it is important to ensure there is proper documentation of well location at time of decommissioning.

IRP Exact location of the well and depth of casing stub should be identified and documented when the well is in proximity to an urban area.

Consider GPS co-ordinates (longitude and latitude in NAD-83/UTM zone 12N) to six decimal place accuracy.

Notify the local jurisdictional regulator of the correct position if the actual location is significantly different from the original survey. Further licensing actions may be specified by the regulator.

IRP **If the well is located in an area where surface mining will be conducted the local jurisdictional regulator and the operator of the mine must be consulted to build a plan for cut and cap of the well.**

For wells within an urban area work with the developer to ensure appropriate setbacks and access are in place around the well at the time of cut and cap.

27.17 Radioactive Source Fish

Radioactive (RA) sources are gamma emitting sources and are controlled and licensed federally by the Canadian Nuclear Safety Commission (CNSC).

- IRP** Each Licensee (person, organization, company) that has a nuclear license pursuant to Section 24 of the Nuclear Safety and Control Act, that has care and control of the RA source must have an approved procedure by the CNSC in their license for such operation.
- IRP** CNSC lost in hole procedures indicate that all reasonable attempts must be made to retrieve the lost RA source.
- IRP** The CNSC RA source Licensee must notify, in a timely manner, the CNSC in their regional jurisdiction (preferred) or Ottawa of the potential for loss of a radioactive source during the fishing operations.
- IRP** Any fishing tools in the wellbore when returned to surface must be checked for any residual radiation by a certified survey meter operated by a certified technician competent in the use of the survey meter.
- IRP** If the tool containing the radioactive source is retrieved to surface and the tool is a memory tool (powered by lithium or alkaline batteries) the tool must be gently placed away from the rig in a safe location to allow the tool to cool down.

Damaged lithium batteries may explode under pressure or temperature conditions.

- IRP** Once the retrieved device is cold, the device must be checked for radiation and to ensure the sealed source is not damaged.
- IRP** Prior to leaving the RA source downhole, the CNSC must be notified by the company that owns the logging tool and a Logging Source Abandonment Report (LSAR) issued to the CNSC for approval.

Note: LSAR is the name of the report requested by the CNSC. As such, the word 'abandonment' according to the CNSC regulations refers to the safe non-retrievable underground storage of a radioactive source in a well.

IRP The LSAR to the CNSC must be filed and approved by the CNSC prior to wellbore decommissioning.

IRP The LSAR to the CNSC must, at minimum, include the following:

- The date(s) of occurrence.
- A description of the well logging source involved including the nuclear substance, quantity, chemical and physical form. The physical size of the source and the encapsulating material of the RA source must be indicated.
- The surface location and bottom hole location (if different than surface location) of the well for deviated and horizontal wells.
- The results of the efforts to immobilize and seal the source in place.
- A brief description of the attempted recovery efforts.
- The depth of the actual RA source, along with the depth of the top of the nuclear device (i.e., logging tool).
- The depth of the bridge plug above the RA source to set the cement plug on.
- The depth of the top of the cement plug above the RA Source
- The depth of the diverter assembly on top of the cement plug.
- The depth of the well. TVD and MD (if deviated or horizontal).
- A schematic of the well, showing the location of the source, cement plug, diverter assembly, existing and isolated perforations to be placed in the file.

IRP If fluids are circulated in the well back to surface during fishing operations the licensee must have the appropriate radioactive survey meter to detect low activity levels to determine if there is any radioactive material in the circulating fluid.

IRP The operator of the survey meter must be competent in the use of the survey meter and the handling of radioactive materials.

IRP Any downhole tools that are recovered from the well must be surveyed to confirm there is no radioactive material attached to the tool.

IRP Once the RA source is determined to be lost and the LSAR has been approved by the CNSC the following actions must be completed:

- Set a bridge plug above the RA source lost down hole to act as a platform for the placement of a cement slurry plug.
- Place a cement slurry plug on top of the bridge plug.
 - The length of the cement slurry plug will depend on where the next upper set of perforations are located.

- The cement slurry plug length must be approved by both the local jurisdictional regulator and the CNSC.

Note: It is the responsibility of the operator to send a copy of the LSAR report to the local jurisdictional regulator and keep a copy in the well file. It is the responsibility of the radioactive source licensee to send a copy of the report to the CNSC and to keep a copy in their files

- Set a mechanical diverter assembly on top of the cement slurry plug such that the RA source cannot be drilled through in the future. This diverter assembly must be placed close enough to the RA source that there is no possibility of a drill bit exiting the casing and then re-entering the casing lower down.

IRP A plaque must be securely attached by a permanent chain or device to a location on the wellhead that is easily seen, until the casing is cut and capped.

IRP Once the wellhead is removed, the plaque must be securely attached to the top of the casing cap.

IRP The plaque must be a minimum of 17.8 cm x 17.8 cm (7 in. by 7 in.).

IRP The plaque must be fabricated of a weather and corrosion-resistant material (i.e., stainless steel, bronze or brass).

IRP The plaque must contain the following information:

- Name of well owner
- Location LSD of well, surface and bottom location (if different than surface location)
- Two radioactive symbols of significant size
- The word 'CAUTION' between the two radioactive symbols.
- Quantity and activity of RA source abandoned
- Date of occurrence
- Depth of the RA source and plugback depth
- The words "DO NOT RE-DRILL THIS WELL BEFORE CONTACTING the CANADIAN NUCLEAR SAFETY COMMISSION"
- Telephone number of nearest CNSC location.

An example of the plaque can be found in Appendix F.

Contact information for the CNSC is as follows:

- In western Canada contact the Calgary CNSC office: +1 (403) 292-5181
- Outside western Canada or outside normal office hours in emergency contact
 - Duty Officer, Ottawa CNSC office: +1 (844) 879-0805 (24 hr)
 - Duty Officer, Ottawa CNSC office: +1 (613) 995-0479 (24 hr)

For more information visit www.nuclearsafety.gc.ca.

Appendix A: Revision Log

The revisions to IRP 27 are logged in the following table.

Table 19. Revisions Summary

Edition	Section(s)	Remarks/Changes
1		New IRP sanctioned xxxx

Appendix B: Well Age

Regulations, recommended practices, training and technology have evolved so the age of the well may impact the likelihood of a risk occurring. Wells drilled decades ago often lack essential documentation, especially if ownership of the well has changed, which can increase uncertainties in the planning process.

The information in this section comes from various industry sources and is intended to show some of the potential considerations for wells of a certain era based on regulations, industry practices and technology available at the time. It is not a definitive list.

Table 20. Spud Pre-1955

Consideration	Impact(s)
Early cable tool rig casing cemented in place by dumping cement slurry into the open hole and then placing the casing in the cement slurry in the bottom of the borehole.	<ul style="list-style-type: none"> Usually only the bottom 1-2 joints are cemented in place. Increased risk of open hole crossflow, non-centralized casing, poor casing condition or lack of circulation to surface leading to poor hydraulic isolation.
<p>Poor cement slurry quality due to:</p> <ul style="list-style-type: none"> Equipment. Cement additive(s). Poorly defined (or lack of) cementing procedures. Use of bagged cement caused cement slurry quality and consistency challenges. <p>It wasn't until the 1930s that equipment developed that mixed and pumped cement down the hole in a continuous fashion, improving the quality of the cement job.</p>	<ul style="list-style-type: none"> Increased probability of a lack of hydraulic isolation to potential inconsistency of cement slurry and job execution practices.
Regulations only required covering hydrocarbon zones with cement.	<ul style="list-style-type: none"> Increased probability of a lack of hydraulic isolation due to potential crossflow between upper open hole water bearing zones that need to be isolated.
<p>Wells often have multiple casing strings, often with non-standard sizes.</p> <p>Progression to the use of standardized casing sizes occurred over time.</p>	<ul style="list-style-type: none"> Current bridge plugs don't always fit.
Bagged cement is only option for cementing.	<ul style="list-style-type: none"> Lack of consistency in cement slurry quality may not provide for adequate hydraulic isolation.

Table 21. Spud 1955-1975

Consideration	Impact(s)
Regulations still only required covering hydrocarbon zones with cement.	<ul style="list-style-type: none"> Increased probability of lack of hydraulic isolation due to potential crossflow between upper open hole water bearing zones that need to be isolated.
Bulk cement equipment introduced in the early 1970s but not commonly used so issues surrounding bagged cement still present.	<ul style="list-style-type: none"> Lack of consistency in cement slurry quality doesn't always provide adequate hydraulic isolation.
More focus starts to be placed on the importance of cement additives and cement design.	<ul style="list-style-type: none"> Improved probability of achieving hydraulic isolation with more consistent cement slurry quality.
Ground water protection regulations introduced.	<ul style="list-style-type: none"> Required more stringent practices to ensure hydraulic isolation.

Table 22. Spud 1976-1985

Consideration	Impact(s)
Job execution practices improve and become more standardized.	<ul style="list-style-type: none"> Improved probability of achieving hydraulic isolation with more consistent practices.
Significant increase in activity beginning in the early 1980s meant lack of classroom training. Training is more on the job.	<ul style="list-style-type: none"> Potential for decrease in probability of achieving hydraulic isolation due job execution errors or sub-optimal surface mixing operations that resulted in variation in cement slurry density/integrity.
Introduction of the NEP program in the early 1980s had companies minimizing costs, sometimes at the expense of quality cementing practices.	<ul style="list-style-type: none"> Decreased probability of achieving hydraulic isolation due to inconsistent or improper cement slurry properties for the well conditions (e.g., use of additives, fluid loss, etc.).
Bulk cement capabilities more common place (compared to bagged cement). Improvements in cement quality with new additives, operational design and consistency.	<ul style="list-style-type: none"> Improved probability of achieving hydraulic isolation with more consistent cement slurry quality.
Slant drilling starts to be used. Dispersants, free water and fluid loss agents were seldom used due to shallow depths.	<ul style="list-style-type: none"> Increased free water leads to increased likelihood of issues with hydraulic isolation due channels on the upper side of the wellbore.
Thermal cement blends introduced.	<ul style="list-style-type: none"> Reduced the risk of cement degradation in wells with high temperatures.
Foam cement introduced.	<ul style="list-style-type: none"> Improved probability of achieving hydraulic isolation because it allows for single-stage operations across weak formations. Significantly increased the complexity of the cementing operation because foam cement has very specific pump rate requirements for the ratio of cement slurry to nitrogen for foam quality. Increased complexity increases the risk of poor execution and therefore poor bond. Increased risk of misleading bond log information if logging tool is not calibrated to foam cement.

Table 23. Spud 1986-1997

Consideration	Impact(s)
Poor economic climate due to NEP program remains through the late 1980s. Companies still minimizing costs, sometimes at the expense of quality cementing practices.	<ul style="list-style-type: none"> Decreased probability of achieving hydraulic isolation due to inconsistent or improper cement slurry properties for the well conditions (e.g., use of additives, fluid loss, etc.).
New coupling thread designs for thermal wells.	<ul style="list-style-type: none"> Reduced the risk of pipe separation at joints in high temperature wells.
Drilling rig mud pits replaced with mud tanks.	<ul style="list-style-type: none"> If mud pits were used for wells with oil-based drilling fluids there could be contamination of the soil around the well that will require additional surface reclamation work.

Table 24. Spud Post-1998

Consideration	Impact(s)
Monobore tubular production strings introduced.	<ul style="list-style-type: none"> It is more difficult to place cement properly (i.e., keeping the casing centralized) in the smaller annular spaces which can lead to poor hydraulic isolation. For slim hole applications difficulty is increased.
Standards for cementing practices emerge (IRP 25: Primary and Remedial Cementing (1995) and its successor IRP 25: Primary Cementing (2017)).	<ul style="list-style-type: none"> Improved probability of achieving hydraulic isolation with improved cement slurry properties, practices and placement.

Appendix C: Sour and Critical Sour

A sour well is a well with Hydrogen Sulphide (H₂S). There are increased operational, response and safety requirements for sour operations and even further requirements based on proximity to population and release rate (RR). These further requirements are called critical sour in this IRP and are defined by jurisdiction as noted below.

Alberta

A Critical Sour well as defined in AER D056 and is a designation that reflects the proposed wells proximity to populated centers and its maximum potential H₂S release rate.

A critical well is defined by the following criteria:

- RR > 2.0 m³/s,
- RR > 0.3 m³/s but < 2.0 m³/s and the well is located within 5.0 km of an urban centre,
- RR > 0.1 m³/s but < 0.3 m³/s and the well is located within 1.5 km of an urban centre,

or

- RR > 0.01 m/s but < 0.1 m/s and the well is located within 500 m of an urban centre.

British Columbia

A Special Sour well as defined in the Oil and Gas Handbook is a designation that reflects the proposed wells proximity to populated centers and its maximum potential H₂S release rate.

- Any well with an H₂S release rate between 0.01m³/s and 0.1m³/s and which is located within 500 meters of the corporate boundaries of an urban centre.
- Any well with an H₂S release rate between 0.1m³/s and 0.3m³/s and which is located within 1.5 kilometers of the corporate boundaries of an urban centre.

- Any well with an H₂S release rate between 0.3m³/s and 2.0m³/s and which is located within 5 kilometers of the corporate boundaries of an urban centre.
- Any well that has an H₂S release rate of 2.0m³/s and greater.
- Any other well deemed by the OGC.

Saskatchewan

A Critical Sour well as defined in PNG015 Section 5.2.6, is a designation that depends on two main factors:

- The distance of the well from an urban municipality, occupied dwelling or public facility.
- The well's maximum potential H₂S release rate.

A critical sour well is one that meets any of the following criteria:

- Maximum potential H₂S release rate >2.0 m³/s.
- Maximum potential H₂S release rate >0.3 m³/s but <2.0 m³/s and the well is located within 5.0 km of an urban municipality, occupied dwelling or public facility.
- Maximum potential H₂S release rate >0.1 m³/s but <0.3 m³/s and the well is located within 1.5 km of an urban municipality, occupied dwelling or public facility.
- Maximum potential H₂S release rate >0.01 m³/s but <0.1 m³/s and the well is located within 500 m of an urban municipality, occupied dwelling or public facility.

Appendix D: Corrosive Fluids

Hydrogen Sulphide

Hydrogen Sulphide is slightly soluble in water and can act as a weak acid. However, the primary corrosive effects of H₂S through mechanisms of Sulphide Stress Cracking (SSC) and Hydrogen Induced Cracking (HIC) are well known and addressed by NACE MR-0175/ISO 15156. As outlined in NACE MR-0175/ISO 15156, when a formation may exceed a partial pressure of H₂S greater than 0.3 kPa it may be considered to contain corrosive fluid properties.

Escalation Factors

The following are escalating conditions:

- Low pH.
- Locations with bare metal (ID and OD) not covered by Iron Sulphide scale that become sites for hydrogen ion invasion and accelerated corrosion.

Mitigations

Formation of a semi-protective layer of Iron Sulphide scale on the casing ID can prevent further corrosion of the base metal.

Note: This passivating layer can be removed by flow turbulence and mechanical abrasion.

Carbon Dioxide

Carbon Dioxide is soluble in water, forming carbonic acid which acts as a weak acid and dissociates readily at the metal surface to provide a steady supply of hydrogen ions needed at the cathode to facilitate corrosion via redox reactions. With respect to steel, the formation of a protective coating FeCO₃ after exposures to water and CO₂ can minimize the corrosion rates. The addition of even a low concentration of H₂S (i.e., 200 ppm) will greatly increase the CO₂ corrosion rate. Temperature may greatly affect the formation of the FeCO₃ film and therefore greatly affects the carbon dioxide corrosion rate. Below 60 °C corrosion rate is low. The worst rate falls between 60 - 150 °C. Above

150 °C corrosion rate drops. As such the corrosive effect may be mitigated depending upon the well conditions in the formation such as temperature, water content and the potential for carbonate precipitation.

Presently, NACE has standards for High Pressure CO₂ and the effects on Elastomeric Materials. However, standards for steels has not been addressed. A number of predictive models have been evaluated by the IFE-Institute for Energy Technology at the request of industry. The report IFE/KR/E-2009/003 incorporates inputs from BP, Chevron, ConocoPhillips, ENI, Gaz de France, Saudi Aramco, Shell, StatoilHydro, Total and IFE. The Norsok M-506 model suggests a partial pressure of 10 kPa be considered when looking at the potential corrosive fluid properties. However, most models recommend using the fugacity (effective ppCO₂) of CO₂ rather than the partial pressures. Based on this, if CO₂ corrosion is deemed to be a concern running a predictive model on the wellbore is suggested.

Escalation Factors

The following are escalating conditions:

- Exposed steel not covered by Iron Carbonate.
- Reaction rate increases with temperature up to a peak at 100 C and then decreasing with higher temperatures.

Mitigations

Formation of a semi-protective layer of Iron Carbonate scale.

Note: The formation and removal of this scale is temperature dependent, protecting carbon steel as a strong dense scale at temperatures above 150 C.

High concentrations of Chlorides or Bromides

High concentrations of chlorides or bromides in water are a cause of localized corrosion, which in combination with tensile stresses from residual stresses in the metal or from applied axial loads or burst loads can result in failures due to stress corrosion cracking.

Escalation Factors

The following are escalating conditions:

- Presence of oxygen.
- High temperatures.
- Combined high chlorides with high CO₂ concentrations.

- High tensile stress.
- Any locally work hardened sites in the steel from mechanically induced damage or stress.

Mitigations

pH can be buffered by corrosion inhibitor or natural bicarbonate ion concentrations

Appendix E: Alternate Products and Methods

Definitions

For the purposes IRP 27 the following definitions apply:

- Alternate Method: Any means of plugging a wellbore for the purposes of decommissioning that is not expressly permitted by a jurisdiction's regulations or guidance.
- Alternate Product (AP): Any combination of the following alternatives to cement:
 - A combination of chemical and/or mechanical products that provide permanent hydraulic isolation in the wellbore.
 - Any wellbore sealing material other than a conventional cement blend as outlined in IRP 25: Primary Cementing.

Note: A cement-based product is considered an alternate product if it has advanced or unique properties or contains unconventional additives outside of those specified in the Additives section of IRP 25: Primary Cementing.

- Conventional Method: Any means of plugging a wellbore for the purposes of decommissioning that is expressly permitted by a jurisdiction's regulations or guidance. Each jurisdiction has established its own guidance with respect to permitted methods. For example, AER Directive 20: Well Abandonment establishes a number of conventional methods that are applicable in a variety of situations.

There are many types of alternate products available with information published in various industry papers, laboratory testing, field test results and area specific studies. One source is the Alberta Upstream Petroleum Research report 18-WARI-04 – Chemical Cement Alternatives published in September 2019.

Purpose

The purpose of this appendix is to provide information that planners can use to develop innovative approaches to wellbore decommissioning using products other than cement and/or methods not currently considered conventional. The focus is key considerations for different categories of products that can be used, with emphasis on non-pumpable and mechanical methods, and processes to evaluate an alternate method against established or conventional wellbore decommissioning methods.

Use of an alternate product or method would be a non-routine decommissioning operation.

Objectives

Decommissioning a wellbore using an alternate method has the same objectives as conventional decommissioning as outlined in 27.4.1 Objectives.

Alternative products and methods need to meet or exceed the performance of established and/or conventional methods in the following areas:

- Safety of the public
- Operational safety (i.e., handling, deployment, placement).
- Environmental impact (e.g., emissions or contamination, groundwater protection).
- Permanent Isolation both inside and outside casing.

Consider the following about alternate products:

- Safety in the presence of groundwater. If there is potential for leaching or degradation into ground water conduct a risk assessment with mitigations.
- Permanent stability in the presence of expected wellbore fluids, formation fluids and wellbore conditions. This could include new fluids introduced into or contacting the wellbore from offset well operations.
- Ability to withstand a differential pressure to maintain permanent hydraulic isolation in the wellbore considering the operational requirements of the decommissioning operation and will not move along the wellbore or laterally.
- Ability to maintain permanent hydraulic isolation and well integrity considering future development or impacts on the reservoirs and the ground water the well has penetrated.
- Placement procedures to ensure it can be placed at the required depth and that it does not contact groundwater (if not proven to be safe for use above BGWP/BUGW).

- Ability to remove the product or re-enter the well in the future if required.
- Corrosivity or other detrimental characteristics when considered against current well materials under current and future conditions.
- Safe, reliable and written procedure to handle, store, transport, install, place or dispose of the product.

For the most part, alternate products for use in wellbore decommissioning are intended to be used in a wellbore that has been completed with casing and with no tubing in place.

Consider taking and retaining (for a reasonable time) samples of the product, both premixed and blended, for future evaluations or audits after placement in the well.

Record any limitations of the product discovered during operations to prevent degradation as a result of future operations in the reservoir or wellbore, including novel production technologies.

Potential Applications

The following need to be defined and understood when considering an alternate product for wellbore decommissioning applications:

- Decommissioning objectives.
- Wellbore construction and history.
- Risk factors present in the wellbore.
- Intended application of the technology or product.
- Limitations in physical properties, placement and conveyance.

The use of alternative products may be an option in wellbores or regions where remedial cementing has been shown to be ineffective due to the following:

- Shrinkage of cement during the setting process.
- Inability to place or squeeze cement where required to establish hydraulic isolation.
- Thermal retrogression of cement.
- Poor bonding or contact with casing for isolations inside casing, due to cement properties or shrinkage.
- Inadequate feed rate hindering placement of conventional cement due to low permeability or connectivity.
- Difficulty intersecting a flow channel behind casing.

- The need to remove fill, debris, or other material in un-cemented areas behind casing.
- A requirement to repair leaking zonal isolations due to cement contamination, placement issues, or poor-quality primary cement.

In some scenarios an alternate product, deployed on its own or in combination with conventional remedial cementing methods, may be advantageous to improve the overall probability of successful placement of the permanent isolation. These include scenarios where there are regional decommissioning challenges, site accessibility concerns or long-term project closure commitments. Some examples include the following:

- When prior remedial cementing attempts with conventional methods and/or materials have failed.
- When prior remedial cementing attempts have not resolved SCVF/GM issues.
- When attempts to identify or intersect the leak source in previous attempts have failed.
- In remote areas where access constraints make repeat interventions challenging and a conservative approach leveraging multiple decommissioning methods in combination to achieve a permanent isolation on the first attempt may be desirable.
- When extended monitoring time may be required to ensure that the objective of the remedial program has been obtained and there is increased value in achieving complete isolation on the first attempt.
- When there is the possibility of combining an alternate product in tandem with a conventional remedial cementing method to increase the probability of success for the isolation as a system.
- When there are regional trends in decommissioning challenges in offset wells with similar wellbore conditions such as the following:
 - Drilling and primary cementing operations
 - Wellbore integrity issues
 - Area history
 - Geology
 - Offset production operations

Wellbore Conditions

Table 25 outlines the limitation considerations of alternate products for wellbore decommissioning operations.

Table 25. Alternate Product Limitations

Consideration	Notes
Casing size, weight and grade	The alternate product needs to be suitable for the casing configuration of the subject well.
Wellbore ID restrictions	Max running OD vs minimum ID of the casing to target depth.
Well inclination and doglegs	Ability to convey the alternate product to the target depth and perform as intended at target inclination. Settling may reduce quality of isolation inside casing.
Temperature	The alternate product needs to function, set up and provide a permanent isolation at the temperatures in the well at target depth.
Wellbore fluid	Alternate product compatibility with the native wellbore fluids or abandonment fluids.
Casing integrity	Adequate casing integrity and wall thickness at the target deployment depth to survive the initial deployment of the product and ensure a permanent isolation.
Presence of cement behind casing and quality of bond	Adequate casing integrity and wall thickness at the target deployment depth to survive the initial deployment of the product and ensure a permanent isolation.
Intended application	Compare to design intent of the product or technology (i.e., to target channels or micro-annuli in the primary job or reliance on competent cement on the backside of the casing to provide formation to formation permanent isolation).
Performance concerns in the vicinity of collars	Potential requirement to avoid casing collars to ensure optimum performance of the alternate product

Deployment Considerations

Table 26 identifies considerations for the deployment of alternate products for wellbore decommissioning.

Table 26. Alternate Product Deployment Considerations

Conveyance	Advantages	Disadvantages
Slickline	<ul style="list-style-type: none"> No requirement for grease injection. Variety of metallurgies for sweet and sour environments. 	<ul style="list-style-type: none"> Unable to deploy past ~65 degrees inclination. Limited to mechanical or timer activation/setting. No ability to log on depth.
Wireline	<ul style="list-style-type: none"> Ability to log on depth. Real-time activation from surface. Sensors to provide data on wellbore conditions an/or confirmation of tool function. 	<ul style="list-style-type: none"> Unable to deploy past ~65 degrees inclination without pumping down tools or tractor conveyance.
Coiled Tubing	<ul style="list-style-type: none"> Able to convey tools beyond wireline limitations. Maintains ability to pump. No connections to make while running in hole or pulling out of hole. 	<ul style="list-style-type: none"> Reach limitations due to buckling. Fatigue considerations. Uncertainties in depth correlations Inability to log on depth (except e-coil).
Jointed Pipe	<ul style="list-style-type: none"> Reach and ability to function tools at high inclinations. Maintains ability to pump and able to convey tools beyond wireline limitations. Tools can be logged on depth with wireline. 	<ul style="list-style-type: none"> Leak paths from improperly torqued connections. Uncertainties in depth correlations. Connections to make while RIH/POOH.
Relative Density/ Buoyancy Conveyance	<ul style="list-style-type: none"> Cost-effective deployment. Minimal surface footprint for rig up. 	<ul style="list-style-type: none"> Lack of control and confirmation on AP placement after releasing from surface.

Monitoring

There are two components to consider when developing a monitoring strategy for alternate products:

1. Initial placement and alternate product properties: Confirming the alternate product was placed as planned and the product has developed the expected physical properties to perform as designed.
2. Long-term isolation integrity: Validation that the alternate product is providing permanent isolation as part of a formation to formation isolation system.

Initial placement considerations and alternate product properties include the following:

- Physical and mechanical properties (viscosity, compressive strength build) when mixed, as placed and after adequate time has elapsed to fully develop intended mechanical properties.
- Physical and mechanical properties of surface set samples of product (if applicable).
- Measurements before and during placement (depth, flow rate, conveyance weight loss, pressure build, temperature, power consumption during placement, etc.).

Methods to validate placement and effectiveness of an alternate product include the following:

- Pressure testing
- Inflow testing, including inside and outside casing
- Tagging with set-down weight
- Logging (gamma ray, temperature, CBL, Ultrasonic, caliper, magnetic flux, density logs)
- Radioactive or chemical tracers

Long-term isolation integrity considerations are as follows:

- Pressure and flow detection
- Pressure testing (negative, positive)
- Gas sampling and analysis

Technology Categories

The three broad technological categories for alternate products for wellbore decommissioning are

1. Inside casing isolation
2. Casing to formation isolation
3. Formation to formation isolation

These categories are based on how the alternate product contributes to the overall permanent isolation of the wellbore from formation to formation and whether the product relies on casing integrity, cement behind casing or neither to accomplish this objective.

Note: All APs need to be qualified for the casing they are intended to function within to ensure casing integrity in the well. For more information about qualification of cement alternatives see the PTAC report: Alberta Upstream Petroleum Research report 18-WARI-04 – Chemical Cement Alternatives, September 2019.

For technologies that are new to industry, the region or the play, it is important to have a well-designed trial plan to ensure that the success and failure trends of a given alternate product can be quickly determined and those learnings replicated across a field.

Inside Casing Isolation

Wireline deployed alternative products for inside casing isolation include the following:

- **Modified cements:** Cement with novel blends or additives intended to address the inherent shrinkage of Class G cement as it sets up, to improve the bond to casing and reduce the risk of a micro-annulus. This shrinkage effect is more problematic in dump bailing applications due to shorter overall isolation length.
- **Thermosetting polymers:** Includes resins and epoxies which are mixed as solids-free fluids and designed for the expected bottomhole temperature to set up as solid impermeable plugs upon curing on top of a mechanical platform. Many resins are not miscible with water and can reduce the possibility of contamination from wellbore fluids. Weighted resins can displace wellbore fluids (including some brines) and set up immediately above a platform. Some resins are food grade and therefore non-toxic.
- **Metals:** Application of low melting point metals such as Bismuth and Tin, conveyed to depth and melted just prior to placement through the use of electrical heat or exothermic chemical reactions downhole then resolidified to form impermeable metal alloy plugs on top of a mechanical platform. Metals offer benefits of metal to metal bond inside casing, significant density contrast compared to wellbore fluids and have a displacement effect to eliminate dilution or contamination risks due to immiscibility with wellbore fluids.

- Silicates: Sodium and Calcium silicates will react with soluble metal salts (e.g., calcium chloride) to produce insoluble metal silicate hydrate plugs.
- Bentonite clay: Bentonite has been applied as plugging material due to its characteristic ability to swell and its low permeability. However, bentonite will not set up to form a solid plug.
- Geopolymers: Inorganic, rock-like materials designed to function as artificial stone.

Casing to Formation Isolation

Many of the alternate products mentioned in the inside casing isolation section can be used to effect isolation between casing and formation in combination with an inside casing isolation. In the place and squeeze method, a mechanical plug is set inside casing and perforations or a slot are then created in the casing above the plug. The alternate product is then placed on top of the mechanical plug and squeeze pressure is applied from surface to force the alternate product to flow into the annular space behind casing and solidify. Alternate products can have the advantage of flowing into smaller channels or voids than cement as they are typically solids free and do not tend to dehydrate when squeezed into small voids.

Another technology for casing to cement or casing to formation isolation is the application of mechanical or explosive based tools for casing expansion to seal off micro annuli or to re-fluidize cement behind casing in an area localized to the deployment depth. Tools for mechanical casing expansion can act as follows:

- Expand against casing and cement to produce a seal between casing and formation
- Expand and allow for more ID inside casing

Expansion mechanisms vary and require testing to confirm acceptable deformation to preserve casing integrity.

Formation to Formation Isolation

Achieving a formation to formation isolation to restore caprock integrity and create permanent isolation of the zone (or zones below) typically involves multiple components. Each of these components can potentially introduce a leak path in one of the following categories:

- Hydraulic isolation issues due to primary cement
- Long term corrosion of the casing
- Long term integrity risks to plugs inside the casing

For a cased hole the conventional method to enable cement placement in a formation to formation isolation is the removal of the casing and primary cement by mechanical means (e.g., section milling or casing removal through cut and recovery of uncemented casing to surface). Cement alternatives described in the Inside Casing Isolation section above can then be placed formation to formation. Success of these jobs is typically tied to the ability to maintain the well in a static condition, through hydrostatic or mechanical means, to allow the isolation medium sufficient time to set up and achieve required compressive strength.

There have been technological developments of rigless means to install formation to formation isolations without removing the casing using a conventional method. This requires some form of exothermic energy that will remove the casing and primary cement (if present) through a chemical reaction. Thermite has been used as a source of exothermic energy to develop sufficient temperature to consume wellbore elements such as casing and cement, resulting in the products forming a solid plug of very high hardness at the caprock depth upon cooling.

The basic reaction is as per the following formula:

Equation 2. Exothermic Reaction



Additional chemicals can be added to adjust the reaction properties and products.

For a thermite isolation to be successful the caprock needs to be of adequate strength to contain the pressures of open formations below. Field applications for thermite in wellbore decommissioning have thus far been limited to cemented single casing string isolations. However, in concept, the technology has the potential to address multi-string cemented or uncemented casing applications because the underlying thermite reaction mechanism is not limited by the presence of additional annuli.

A key risk to consider with a thermite isolation is that future re-entry below the depth of the thermite isolation may not be possible given the hardness of the aluminium oxide plug (Corundum - 9.0 on Mohs scale vs. Diamond at 10). This risk increases the shallower the thermite deployment depth due to the proportional length of the wellbore that may no longer be accessible.

Emerging Methods and Strategies

Research and development for wellbore decommissioning strategies is ongoing. Wellbores aren't always designed with decommissioning in mind so continued innovation in ways to achieve permanent isolation is encouraged.

Some new technologies for wellbore decommissioning make use of methods that would not require a service rig to convey the zonal isolation plug or for conducting remedial operations during decommissioning. These rigless methods may include the following:

- Metal alloy plugs, such as a tin-bismuth alloy
- Thermite abandonment plugs
- Mechanical casing expanders for use in vent flow shutoff operations
- Perforating tubing and cementing in place, from surface, potentially leaving packers and tubing in the wellbore

Consider evaluating whether the geological and geophysical properties of shale intervals encountered in the wellbore are suitable for acting as an annular barrier. There is some evidence that under certain circumstances shales may creep into an otherwise fluid-filled annular space or micro-annulus and establish hydraulic isolation. See the following SPE papers for more information:

- SPE-191607-MS: Activating Shale to Form Well Barriers: Theory and Field Examples
- SPE-199654-MS: Simplifying Well Abandonments Using Shale as a Barrier

Appendix F: Radioactive Source Plaque

Figure 3. Sample Radioactive Source Plaque



Appendix G: Glossary

The following terms have been defined from an IRP 27 context.

AOF Absolute Open Flow

Acid Gas A gas that, in the presence of water, can acidify the water (e.g., CO₂ can form carbonic acid, H₂S can form sulphuric acid, etc.).

AER Alberta Energy Regulator

BGWP Base Groundwater Protection

BUGW Base of Usable Groundwater

Cement Bond Log (CBL) Cement bond logs are acoustic tools that measure the amplitude attenuation of a signal from a source as it interacts with the casing, cement and formation sending returns to a receiver. These tools vary in vertical and circumferential resolution based on the number and placement of sources and receivers. Generally, a better result is obtained from a logging tool with multiple receivers arranged circumferentially around the tool, as the overall signal is then averaged by sector instead of having one average measurement for a given depth.

CNSC Canadian Nuclear Safety Commission

CSA Canadian Standards Association

CO₂ Carbon dioxide

Containment Prevention of flow at rate or in total mass sufficient to cause adverse impact.

Corrosive Fluid A corrosive fluid is defined as any fluid that actively contributes to a tendency towards general or localized (i.e., pitting) corrosion in carbon steel due to the concentrations of dissolved species including H₂S, CO₂, and chlorides; through corrosion mechanisms of lowered pH, sulphide stress cracking, hydrogen induced cracking or stress corrosion cracking (SCC). Consult a chemist or materials engineer as a subject matter expert when assessing the well specific corrosion risk from corrosive fluids.

Note: Corrosion due to oxygen driven mechanisms or galvanic corrosion mechanisms are not included in this definition.

Crossflow Fluid or gas flow from one formation to another formation.

DACC Drilling and Completions Committee

Deliverability Ability to flow.

EOR Enhanced Oil Recovery

EPZ Emergency Planning Zone

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

Groundwater Water in the subsurface below the water table. Groundwater is held in the pores of rocks, and can be connate, from meteoric sources, or associated with igneous intrusions.

Note: Water does not have to be potable to be considered groundwater that requires protection.

H₂S Hydrogen sulphide

Hazard Potential source of harm.

HPZ Hazard Planning Zone

HRC Hardness Rockwell Scale "C"

Hydraulic Isolation No unplanned movement of fluids including all phases of liquid, gas and vapor in the wellbore either between zones or to surface. Ability to prevent unplanned annular fluid flow under specific or designed differential pressure.

Hydrogen Embrittlement Due to the small size of free hydrogen ions generated in the oxidation-reduction reactions of typical corrosion mechanisms, these hydrogen ions can move into the crystal lattice structure of a metal and accumulate in voids or grain boundaries as molecular hydrogen. There they can combine into molecular hydrogen and create regions of localized high stress within the material. This phenomenon is called hydrogen embrittlement and can cause cracking and failure of materials. The hydrogen can be naturally occurring in the formation or a product of corrosion. Passivating scales such as iron sulphide are impermeable to hydrogen and tend to trap hydrogen inside the material, increasing the likelihood of a failure.

Level of Risk Magnitude of a risk or combination of risks.

Mechanical Plug A mechanical device that forms an in-casing barrier. A mechanical plug forms a competent seal with the casing (validated by a pressure test from surface), resists differential pressure up to its design limit and stays in position at depth until the isolating medium placed on top has developed full compressive strength and can function as the permanent long-term barrier in the well.

Permanent (Isolation) One million days (as per NORSOK).

Note: While it is the intent of this IRP to meet the one million days definition of permanent it recognizes that this definition comes from off-shore operations. With on-shore operations the wellheads are on surface and don't have all of the same re-entry or repair challenges of a sub-sea wellhead.

Permanent (Well) Barrier Combination of one or several well barrier elements that contain fluids within a well to seal a source of inflow.

POOH Pulling out of Hole

Plug and Abandonment Colloquial term for wellbore decommissioning whereby action taken to ensure permanent isolation of fluids, gases and pressures from exposed permeable zone(s) along a wellbore trajectory by installation of well barriers.

Radioactive Source A logging tool or similar device which has a radioactive source located inside the device.

RIH Running in Hole

Risk The effect of uncertainty on objectives, where risk may be expressed in terms of a combination of a likelihood of occurrence of an event, and the associated severity of potential consequences that may arise as a result of the event.

Risk Analysis Process to comprehend the nature of risk and determine the level of risk.

Risk Assessment Overall process of risk analysis and risk evaluation.

Risk Evaluation Process of comparing the results of risk analysis with the evaluation risk criteria to determine whether the risk and/or its magnitude are/is acceptable or tolerable.

RR Release Rate

Surface Casing Vent Flow The flow of gas and/or liquid or any combination out of the surface casing/production casing annulus (also referred to as sustained casing pressure in jurisdictions where vents are closed).

Stratigraphic Well Non-cased wells, with or without cement plugs.

Well Barrier Element (WBE) A physical element which by itself does not prevent flow but in combination with other WBE's forms a well barrier.

Wellbore The physical hole that makes up the well.

Wellbore Decommissioning Well abandonment (as referenced in AER D020: Well Abandonment and other regulations). This IRP moves away from use of the term 'abandonment' to the more descriptive term of wellbore decommissioning but many regulations still refer to abandonment. See 27.0.9 Background for more information.

Zonal Isolation Zonal isolation is the prevention of communication between discrete porous zones (including between hydrocarbon bearing formations) and freshwater aquifers.

Appendix H: References

DACC References

Available from www.energysafetycanada.com

IRP 02: Completing and Servicing Critical Sour Wells

IRP 24: Fracture Stimulation

IRP 25: Primary Cementing

IRP 26: Wellbore Remediation

IRP 28: Wellsite Waste Management

Local Jurisdictional Regulations

Alberta

Available from www.aer.ca

AER Directives

- Directive 009: Casing Cementing Minimum Requirements
- Directive 013: Suspension Requirements for Wells
- Directive 020: Well Abandonment
- Directive 023: Oil Sands Project Application
- Directive 051: Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements
- Directive 056: Energy Development Applications and Schedules
- Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry
- Directive 079: Surface Development in Proximity to Abandoned Wells
- Directive xxx: Well Integrity Management (draft currently open for comments, replaces ID 2003-01)

- AER ID 2003-01: 1) Isolation Packer Testing, Reporting, and Repair Requirements; 2) Surface Casing Venting Flow/Gas Migration Testing, Reporting, and Repair Requirements; 3) Casing Failure Reporting and Repair Requirements

Oil And Gas Conservation Act – RSA 2000 Chapter O-6

- Part 6 - Licences and Approvals
- Part 7 - Production

Oil and Gas Conservation Rules – 151/1971

- Part 6 – Drilling, Completing and Servicing

British Columbia

Documents and Guidelines

- Acid gas Disposal Wells Summary Document

Dormant Sites

- <https://www.bcogc.ca/industry-zone/dormant-sites>

Drilling & Production Regulation – B.C. Reg 282/2010

- Part 5 – Abandoning, Plugging and Restoring Wells.
- Part 8 – Production, Division 6 – Injection and Disposal

Oil and Gas Operations Manual

- British Columbia Oil and Gas Activity Operations Manual.
 - Chapter 9 - Well Completions, Maintenance and Abandonment
 - Chapter 10 - Well Activity: Production and Injection Disposal

Oil and Gas Activities Act (OGAA) – (SBC 2008) Chapter 36

- Part 9 – OGAA Regulations

Water Sustainability Act – B.C. Reg. 39/2016

Groundwater Protection

- Part 3 – Well Construction, Division 3 – Surface Seals
- Part 9 - Well Deactivating & Decommissioning

Manitoba

Available from www.manitoba.ca

Drilling and Production Regulation

- Part 6 – Drilling, Completing, Servicing and Abandonment

The Oil and Gas Act - C.C.S.M. c. O34

- Part 9 – Oil and Gas Production and Conservation

Saskatchewan

Available from www.saskatchewan.ca

The Oil and Gas Conservation Act –Chapter O-2

Oil and Gas Legislation and Regulations, 2012 – Chapter O-2 Reg 6

- Part 7 – Drilling, Completing and Servicing Wells
- Part 8 – Production Operations

Available from www.saskatchewan.ca/business/agriculture-natural-resources-and-industry/oil-and-gas/oil-and-gas-legislation-regulations-and-ministers-orders

Oil and Gas Directives and Guidelines

- Saskatchewan: PNG005: Casing and Cementing Requirements
- Saskatchewan: PNG010: Well Logging Requirements
- Saskatchewan: PNG015: Well Abandonment Requirements
- Saskatchewan: PNG026: Gas Migration
- Saskatchewan: PNG008: Disposal & Injection Well Requirements.
- Saskatchewan (Water Well) – SR172-66 The Groundwater Regulations
- Saskatchewan – The Water Security Agency Regulations

Other References

- Alberta Upstream Petroleum Research report 18-WARI-04 – Chemical Cement Alternatives, September 2019. Available from <https://auprf.ptac.org/well-abandonment/chemical-cement-alternatives/>.
- CAPP H₂S Release Rate Assessment Guidelines and Audit Forms, July 2012 available from www.CAPP.ca.
- CSA Z341: Storage of hydrocarbons in underground formations, April 2018.
- CSA/ANSI ISO 27916:19: Carbon dioxide capture, transportation and geological storage – Carbon dioxide storage using enhanced oil recovery (CO₂-EOR). 2019.
- Kristiansen, T.G., Dyngeland, T., Kinn, S., Flatebø, R. and Aarseth, N.A. 2018. Activating Shale to Form Well Barriers: Theory and Field Examples. Paper SPE-191607-MS presented at the SPE Annual Technical Conference and Exhibition, Dallas Texas, 24-26 September. doi.org/10.2118/191607-MS
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- TDG Regulations available from the Government of Canada Website (www.tc.gc.ca)
- van Oort, E., Juenger, M., Aldin, M., Thombare, A., McDonald, M., Lucas, A. and Ditlevsen, F. 2020. Simplifying Well Abandonments Using Shale as a Barrier. Paper SPE 199654-MS available from SPE, Richardson, Texas. doi:10.2118/199654-MS

Wellbore Leakage Diagram (Figure 1)

- Celia, M.A, Bachu, S., Nordbotten, J.M., Kavetski, D., Gasda, S.E., 2005, Modeling Critical Leakage Pathways in a Risk Assessment Framework: Representation of Abandoned Wells, Conference Proceedings, Fourth Annual Conference on Carbon Capture and Sequestration DOE/NETI, May 2-5
- Davies, R.J., Almond, S., Ward, R.S., Jackson, R.B., Adams, C., Worrall, F., Herringshaw, L.G., Gluyas, J.G., Whitehead, M.A., Oil and gas wells and their integrity : Implications for shale and unconventional resource Exploration. *Marine and Petroleum Geology*. (published online March 25 2014). <https://core.ac.uk/download/pdf/151160838.pdf>

Wellhead Leakage Diagram (Figure 2)

- Alberta Energy Regulator (www.aer.ca)

