DRILLING AND COMPLETION COMMITTEE

IRP 30: Temporary Wellbore Suspensions

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

Volume 30 – 2024 Draft 17 2024-04-03

EDITION: 1
SANCTION DATE: INSERT DATE HERE

CANADIAN ASSOCIATION OF ENERGY CONTRACTORS

CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS
Canada's Oil and Natural Gas Producers

EPAC
CANADA'S OIL & GAS ENTREPRENEURS™

ENSERVA™

Copyright/Right to Reproduce

Disclaimer

This IRP is a set of best practices and guidelines compiled by knowledgeable and experienced industry and government personnel. It is intended to provide the operator with general advice regarding the specific topic. It was developed under the auspices of the Drilling and Completions Committee (DACC). IRPs are provided for informational purposes. Users shall be fully responsible for consequences arising from their use of any IRP.

The recommendations set out in this IRP are meant to allow flexibility and must be used in conjunction with competent technical judgment. It is recognized that any one practice or procedure may not be appropriate for all users and situations. It remains the responsibility of the user of this IRP to judge its suitability for a particular application and to employ sound business, scientific, engineering and safety judgment in using the information contained in this IRP.

If there is any inconsistency or conflict between any of the recommended practices contained in this IRP and an applicable legislative or regulatory requirement, the legislative or regulatory requirement shall prevail. IRPs are by their nature intended to be applicable across industry, but each jurisdiction may have different or unique legal requirements. Users of this IRP should consult with authorities having jurisdiction. Users are advised to consider if their operations or practices and this IRP comply with the legal requirements in any particular jurisdiction in which they operate.

Every effort has been made to ensure the accuracy and reliability of the data and recommendations contained in this IRP. However, DACC, its subcommittees, individual contributors and affiliated persons and entities make no representation, warranty, or guarantee, either express or implied, with respect to the accuracy, completeness, applicability or usefulness of the information contained in any IRP, and hereby disclaim liability or responsibility for loss or damage resulting from the use of this IRP, or for any violation of any legislative, regulatory or other legal requirements.

IN NO EVENT SHALL DACC, ENERGY SAFETY CANADA, ANY SUBMITTING ORGANIZATION NOR ANY OF THEIR EMPLOYEES, DIRECTORS, OFFICERS, CONTRACTORS, CONSULTANTS, COMMITTEES, SUBCOMMITTEES, VOLUNTEERS, OR OTHER AFFILIATED OR PARTICIPATING PERSONS BE LIABLE

TO OR RESPONSIBLE FOR ANY PERSON USING AN IRP OR ANY THIRD PARTY FOR ANY DIRECT, INDIRECT, INCIDENTAL, SPECIAL OR CONSEQUENTIAL DAMAGES, INJURY, LOSS, COSTS OR EXPENSES, INCLUDING BUT NOT LIMITED TO LOST REVENUE OR GOODWILL, BUSINESS INTERRUPTION, OR ANY OTHER COMMERCIAL OR ECONOMIC LOSS, WHETHER BASED IN CONTRACT, TORT (INCLUDING NEGLIGENCE) OR ANY OTHER THEORY OF LIABILITY. This exclusion shall apply even if DACC has been advised or should have known of such damages.

Availability

This document, as well as future revisions and additions, is available from

Energy Safety Canada
Unit 150 – 2 Smed Lane SE
Calgary, AB T2C 4T5
Phone: 403.516.8000
Fax: 403.516.8166
Website: www.EnergySafetyCanada.com

Table of Contents

List of Tables

30.0 Preface

30.0.1 Purpose

The purpose of this document is to provide recommended practices for temporarily shutting in or suspending wellbores in a manner that allows for efficient reactivation or transition to permanent wellbore decommissioning.

30.0.2 Audience

The intended audience for this document includes the following:

- Wellbore owners
- Those responsible for planning or executing wellbore shut-ins or suspensions
- Those responsible for the reactivating a shut-in or suspended wellbore or transitioning to permanent wellbore decommissioning.
- Those responsible for communicating shut-in/suspension status to wellbore owners
- Local jurisdictional regulators

30.0.3 Scope and Limitations

The scope of this IRP includes land-based operations in western Canada spanning from British Columbia to Manitoba and the Territories.

It includes planning, execution, and post-execution monitoring of temporary well shut-ins or suspensions, as well as reactivation recommendations for cased oil and gas wells. IRP 30 is not intended to replace local jurisdictional regulations; instead, these regulations are referenced throughout the document.

The scope does not include the following

- recommendations for determining whether to decommission a well (it assumes the decision has already been made to shut in or suspend instead) and
- information about cavern wells.

30.0.4 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.

30.0.5 Sanction

The following organizations have sanctioned this document:

Canadian Association of Oilwell Energy Contractors (CAOEC)

Canadian Association of Petroleum Producers (CAPP)

Enserva

Explorers & Producers Association of Canada (EPAC)

30.0.6 Range of Obligations

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

Table 1. 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.

30.1 Introduction

In the life cycle of a well, there will come a time when the well needs to be taken out of production, either by shutting it in or suspending it for a specific period. In the future, the well will be reactivated, repurposed, or permanently decommissioned. If there is little or no likelihood that the well will be reactivated, the appropriate action is to decommission the well (see IRP27: Wellbore Decommissioning for more information). Timelines for shutting in or suspending wells vary across jurisdictions, and operators need to ensure they comply with local jurisdictional regulations. The recommendations in this document are not intended to replace these regulations.

IRP 30 promotes a risk-based approach to planning and deciding whether to shut in or suspend a well. It identifies specific risk categories and parameters for assessing risk and enabling informed decisions about the most appropriate course of action for the well. The goal of adopting a risk-based approach is to enhance the analysis of risks, ensuring more consistent and effective well shut-ins and suspensions while safeguarding workers, the public and the environment.

The complexity of the shut-in or suspension operation depends on the type and condition of the well. Some wells require simple procedures while others can be more complex demanding significant effort to manage risks and attain long-term isolation objectives. IRP 30 provides information and recommendations for planning and achieving proper shut-in or suspension.

IRP 30 also covers post-suspension integrity testing, monitoring, and inspections along with recommendations for reactivating a well. Case studies in Appendix C are included to help planners understand the defined risk levels in this IRP.

30.2 Definitions and Regulations

30.2.1 Definitions

Below are terms used frequently throughout this IRP with their meanings defined for the purposes of this IRP.

Shut-In Well

A shut-in well that is secured on the surface but does not require a downhole barrier for isolation either by regulation or risk assessment. There are no wellhead leaks, and the well is isolated.

Suspended Well

A suspended well that is secured on the surface with at least one downhole barrier in place and complies with the local jurisdictional requirements for suspension (e.g., based on well type and risk level). There are no wellhead leaks requiring repair as per the regulations and the well is isolated.

Inactive Well

An inactive well has had no recordable volumetric activity for 12 months (or six months for wells designated as critical/special sour by the local jurisdictional regulator).

Decommissioned Well

A decommissioned well is permanently taken out of production in accordance with IRP 27: Wellbore Decommissioning and the local jurisdictional regulator.

30.2.2 Regulations

The following are referenced throughout this IRP.

Regulations for Alberta include the following:

- AER D013: Suspension Requirements for Wells
- AER D020: Well Abandonment
- AER D059: Well Drilling and Completions Data Filing Requirements
- AER D087: Well Integrity Management

- Oil and Gas Conservation Act
- Oil and Gas Conservation Rules

Regulations for British Columbia include the following:

- Drilling and Production Regulation
- Energy Resource Activities Act

Regulations for Manitoba include the following:

- Manitoba Drilling and Production Regulations (The Oil and Gas Act).
- Informational Notice No. 21-04, Well Suspending Guidelines

Regulations for Saskatchewan include the following:

- Directive PNG013: Well Data Submission Requirements
- Directive PNG015: Well Abandonment Requirements

30.2.3 Regulatory Well Status Definitions

Table 2. Regulatory Well Status Definitions

Jurisdiction	Well Status					
	Active	**Shut In**	**Inactive**	**Dormant**	**Suspended**	**Decommissioned**
IRP #30	A well that has reportable volumetric activity.	A well that is secured on surface but does not require a downhole barrier for isolation.	A well that has no reportable volumetric activity.	Not applicable (N/A)	A well that is secured on surface and has at least one downhole barrier in place.	A well that is isolated and permanently decommissioned as per regulations and IRP 27: Wellbore Decommissioning.
Alberta	A well that has reportable volumetric activity.	A well that is not being operated and is left in a safe and secure state.	A well that has no volumetric activity for six consecutive months (for critical sour wells) and 12 consecutive months (for all other wells). A geothermal observation well is deemed inactive when no bottomhole temperature has been taken for 12 consecutive months.	N/A	A well needs to be suspended within one year of becoming Inactive. For inactive cavern wells, the licensee must submit a nonroutine application for the suspension of the well and cavern.	A well that is isolated and permanently decommissioned as per regulations and IRP 27: Wellbore Decommissioning.
BC	A well that has reportable volumetric activity.	A well that is not being operated and is left in a safe and secure state.	A well has not been active for 12 consecutive months. If the well is classified as a special sour or an acid gas disposal and has not been	A well that has <720 hours of production or injection per year for five consecutive years and is categorized as Dormant A, B, or C depending on when it became Dormant (it essentially moves toward a decommissioning deadline after 10 years of inactivity defined as less than	A well needs to be suspended within 60 days of being inactive; requirements for a barrier vary by classification.	A well that is isolated and permanently decommissioned as per regulations and IRP 27: Wellbore Decommissioning.

Jurisdiction	Well Status					
	Active	Shut In	Inactive	Dormant	Suspended	Decommissioned
			active for 6 consecutive months.	720 hours of production or injection per year).		
Manitoba	A well that has reportable volumetric activity.	A well that is not producing nor injecting.	A well or battery that has been operated 15 days or less in a calendar year may be designated by the director as an inactive well. See Drilling and Production Regulation section 54.	N/A	A well needs to be suspended when it has been shut in for more than 6 consecutive months. See Drilling and Production Regulation section 53. See Information Notice 21-04 Well Suspension Guidelines.	A well is considered abandoned according to section 55 and 56 of the drilling and production regulations.
Saskatchewan	Has reportable volumetric activity. A well that is producing or injecting fluid.	A well that can produce or inject but has had the valves at the wellhead turned off; the well has no activities or inventory to report.	A well that can produce or inject but has had the valves at the wellhead turned off; the well has no activities or inventory to report.	N/A	A well must be reported as suspended within 12 months after the last production or injection has occurred. See PNG 32 Volumetric, Valuation and Infrastructure Reporting in Petrinex.	A well that is no longer used for the purpose for which it was drilled or converted, must be abandoned per PNG 015 Well Abandonment Requirements. If the well will be repurposed, approval is required.

Note: The timelines identified in this table are subject to change. Refer to local jurisdictional regulations for the latest timelines.

30.2.4 Regulatory Management Tools

The following table summarizes the jurisdictional regulatory management tools available for shut-in and suspension work:

Table 3. Provincial Electronic Regulatory Management Tools

Province	Tool	Usage and References
Alberta	• OneStop • Inactive Well Licence List • Petrinex • Digital Data Submission (DDS) System reporting	• OneStop is the main management system associated with suspension-related work, ongoing inspections, and reporting. • The Inactive Well License List available on the AER website under the Directive 013 landing page. (This list contains all inactive well licences and related compliance information). • Petrinex data (historical volumetric data) is used to assess compliance with Directive 013. • The DDS system is used for reporting requirements in accordance with Directive 059.
British Columbia	• eSubmissions • Petrinex • Data Centre	• eSubmission is used for reporting requirements in accordance with the Drilling and Production Regulation. • Petrinex data (historical volumetric data) is used to assess compliance with the Energy Resource Activities Act. • Data Center contains all inactive and well suspension reports as well as other related compliance information.
Manitoba	Email submission	• A downloadable excel application form can be accessed at www.gov.mb.ca. • See Drilling and Production Regulations.
Saskatchewan	Integrated Resources Information System (IRIS)	• See PNG 013 Well Data Submission Requirements. • See Oil and Gas Conservation Act, Oil and Gas Conservation Regulation (2012).

30.3 Risk-Based Approach

IRP 30 assumes that a decision not to decommission the well has already been made and provides guidance on the risk assessment, planning and execution of the shut-in or suspension activities. However, many of the risk categories, escalation factors and reduction factors identified in the risk-based approach to planning may be relevant when deciding whether to shut in, suspend or decommission the well.

IRP If a well has little to no likelihood of being reactivated it should be decommissioned rather than shut-in or suspended.

See IRP 27: Wellbore Decommissioning for detail about decommissioning risk assessment and planning.

The risk-based approach is intended to help identify potential concerns for the shut-in or suspension of a well. Specific risk categories, risk escalation factors and risk reduction factors to consider in the risk assessment are identified. Through this risk assessment, a risk level for the well can be determined which will help identify the operational requirements and necessary planning.

IRP At a minimum, local jurisdictional regulations must be followed for shutting in or suspending a well.

30.3.1 Risk Assessment

The operator is responsible to perform the risk assessment using the methodology of their choice. There are many options for conducting a risk assessment and the approach will vary from company to company. The outcome of the risk assessment will be based on the company's risk tolerance and risk analysis methodology. Consider the likelihood of the risk occurring, consequences if the risk does occur, and the required mitigations. It is important to assess the risks and implement appropriate mitigations to safeguard workers, the public and the environment while ensuring the well is left in a safe and secure manner. Conducting future, periodic risk assessments is also essential because the risk profile of shut-in or suspended wells can change over time due to various factors (e.g., changes to well integrity, area development, wildlife zones).

IRP A risk assessment shall be completed for each well to be shut in or suspended to identify the actions and mitigations required.

IRP The risk assessment shall determine the frequency of periodic re-evaluations of risk for each shut-in or suspended well.

IRP 30 identifies common risk categories for assessment (see 30.3.2 Risk Categories), but stresses the importance of incorporating site, operator, or operation-specific information. This risk assessment determines the risk level for the well (see 30.3.3 Risk Level) which provides valuable information to make an informed decision during shut-in or suspension planning.

IRP Although observation wells are excluded from most suspension related regulations, they should be risk assessed for the appropriate action.

30.3.2 Risk Categories

The table below lists common risk categories for shutting in or suspending a well. For each category, examples of risk-escalating and risk-reducing factors are included.

Table 4. Risk Categories

Risk Category	Risk Reduction Factors	Risk Escalation Factors
Hydrogen Sulphide (H_2S) content	• Well is sweet (no H_2S)	• Well contains H_2S
Inactivity duration	• Inactivity is expected to be short term (< one year)	• Inactivity may be longer term (> one year)
Well type	• Oil production • Gas production • Observation well • Water source well	• Disposal of waste fluids • Disposal of produced water • Injection of hydrocarbon or gas (e.g., acid gas) • wells that have been repurposed (e.g., conversion to observation or injection) • Steam injection
Well history (e.g., maintenance, last production date, last intervention, last inspection)	• Complete/known history (i.e., complete well file is available)	• Unknown or incomplete history (e.g., newly acquired wells, transfers with incomplete history)

Risk Category	Risk Reduction Factors	Risk Escalation Factors
Wellbore construction and integrity	• Well has no Surface Casing Vent Flow (SCVF) or Gas Migration (GM) • Base of usable groundwater is protected • No issues during drilling/completions • Well has adequate casing and cement for range of potential operations • Recently completed integrity testing and/or logging (e.g., corrosion log, cement bond log, caliper log)	• Well has a confirmed SCVF and/or GM • Base of usable groundwater is not protected • Casing failure • Significant casing corrosion • Issues encountered during drilling or completions (e.g., poor cement bond, connection make-up issues, casing damage) • Original wellbore construction materials/methods not compatible with potential operations (e.g., drilled sweet then complete sour, convert to geothermal) • Well age may escalate risk. Refer to IRP 27 Appendix B, Well Age • Known offset well integrity issues (e.g., if it is a common problem in the area then risk on the subject well may be increased)
Well location	• Lease is easily accessed in all seasons • Well not in close proximity (within 1 km) to a water body, environmentally sensitive area, or a residence • Stable geotechnical slope	• Lease can only be accessed in certain seasons • Well is in close proximity (within 1 km) to a water body, environmentally sensitive area or a residence • Remote locations (e.g., more difficult to get service, less surveillance, theft) • Geotechnical slope instability (surface and near-surface) • Concerns related to landowners (e.g., access concerns) • Risk of vandalism
Reservoir pressure	• Expected to remain unable to flow to surface	• Reservoir is currently or may in future have the ability to flow to surface
Wellbore fluids	• Wellbore fluids are not believed to have negatively impacted wellbore equipment integrity	• Well was exposed to fluids which may have damaged wellbore equipment (e.g., corrosive fluids) • Well prone to scale formation or solids production (e.g., equipment stuck in hole due to fines or solids production)

Risk Category	Risk Reduction Factors	Risk Escalation Factors
Offset well stimulation interference	• No potential for offset stimulation interference	• Well may be impacted by offset stimulation activity (e.g., fracturing)
Enhanced oil recovery (EOR) or storage scheme	• The well is and will be unaffected by an adjacent EOR scheme • The well is and will be unaffected by carbon capture utilization and storage (CCUS) project (i.e., carbon dioxide (CO_2) plume)	• The well is currently or may be in future, influenced by an adjacent EOR scheme • The well is currently or may be in future, influenced by an CCUS project
Subsurface Production Equipment	• No known issues with equipment	• Equipment limits access to place or test barrier (e.g., subsurface safety valve, sour or abnormally pressured well with pump and rods)
Hydrates	• No potential for hydrate formation	• Hydrates may form if left unmitigated (refer to IRP 04: Well Testing and Fluid Handling for more information about Hydrates)
Surface Equipment	• Surface equipment in good operational condition • Winterized/freeze protected • Left in a secure state	• Tanks or barrels not completely drained • Leaking valves • Flowlines connected • Integrity of the equipment (e.g., age of the equipment, abnormally wet conditions such as an irrigated field, and other environmental conditions) • Unbarricaded

IRP **The risk assessment shall include a review of the above risk categories, escalation factors and reduction factors as applicable. The operator shall also identify additional well and operation-specific factors to include in the risk assessment.**

IRP If a well has more risk escalation than reduction factors or significantly high risk in a category, exceeding the minimum regulatory shut-in or suspension requirements and timelines should be considered.

30.3.3 Risk Level

Once the risk categories, escalation factors and reduction factors are defined and assessed, the well can be assigned a risk level for planning purposes. Table 5 identifies the risk levels used in this IRP.

Note: Local jurisdictional regulations use terms like high, medium, and low to categorize well risk levels. However, these definitions can differ across jurisdictions. The risk levels below are used in IRP 30 as standardized terminology for assigning a risk level to a well during shut-in or suspension planning.

The operator is responsible for determining the risk level based on their risk assessment and the relevant local jurisdictional regulations.

Note: Exceptions and exemptions to the examples in this table can apply. Therefore, it is important to consult the relevant local jurisdictional regulations for the specific well and action. Case study examples can be found in Appendix C.

Table 5. Risk Levels

Risk Level	Definition	Barrier Requirement	Examples
Minimal	Well presents a low degree of risk to personnel and the environment if left in a shut-in state.	No downhole barrier required by regulation or risk assessment; the well will be considered shut-in for IRP purposes.	Case study # 1, 2, 3
Moderate	Well presents a moderate degree of risk to personnel and the environment if left in a shut-in state.	Downhole barrier required; the timeline of installation is to be based on company specific risk or regulation.	Case study # 4, 5, 6, 7
High	Well presents a high degree of risk to personnel and the environment if left in a shut-in state.	Downhole barrier required. Suspend well as soon as practical following inactivity. A secondary barrier may need to be added depending on the risk assessment.	Case study # 8, 9, 10, 11

Note: Wells can change from minimal to moderate to high risk depending on the elapsed time (see 30.2.3 Regulatory Well Status Definitions) and whether the well has received proper care and attention, including monitoring, regular maintenance, and repairs for leaks.

30.3.4 Deciding to Shut In vs. Suspend

The decision to shut in or suspend a well depends on the results of the risk assessment. Wells initially assessed as minimal risk are typically shut in, whereas wells initially assessed to be moderate or high risk are suspended. The status of a shut-in or suspended well may change over time due to changes in the well's risk level or in response to changes in local jurisdictional requirements.

As a reminder, if there is little or no likelihood the well will be reactivated, the appropriate action is to decommission the well (see IRP27: Wellbore Decommissioning for more information).

As the energy industry evolves, it is important to consider forward-thinking factors when assessing the risk of whether a well should be shut-in or suspended. With a growing emphasis on liability, environmental responsibility and sustainability, industry will need to account for the potential of well repurposing, the use of alternative energy sources, regulatory changes, and shifts in environment, sustainability, and governance (ESG) metrics.

In recent years, there has been increasing popularity in repurposing of wells for nontraditional uses. This trend is likely to continue as alternative energy sources become more economically viable. For example, the Western Canadian Sedimentary Basin can safely store carbon dioxide through methods like direct air capture or other forms of carbon capture, utilization, and storage (CCUS) and the demand for this is growing. CCUS may also play a role in hydrogen production.

Repurposing wells to leverage alternative energy sources and reduce carbon and methane emissions will continue to progress and therefore needs to be considered during the risk assessment.

IRP The potential for the subject well, or an offset well to be repurposed for the following activities should be considered as part of the risk assessment:

- Hydrogen production
- Helium production
- Geothermal energy activities
- Brine recovery (e.g., lithium)
- Carbon capture and storage and utilization
- Future potash development

Provincial and federal regulatory requirements will change, and industry standards will evolve. Therefore, compliance requirements related to environmental impact, sustainability goals, and governance practices need to be thoroughly assessed. For example, emissions targets will change as they are established every five years in accordance with the Canadian Net Zero Emissions Accountability Act, which outlines greenhouse gas emissions reduction plans. Each province must meet the requirements of this Act. However, some provinces, such as Alberta, British Columbia and Saskatchewan have developed equivalency agreements with the federal government indicating that their provincial legislation meets or exceeds the emissions reduction targets set in the federal regulations.

IRP A review of provincial and federal regulations and industry best practices shall be conducted during the risk assessment and decision to shut-in or suspend a well, to ensure compliance with current, relevant regulatory requirements.

30.4 Shut-In Planning and Execution

30.4.1 Planning

Following the risk-based approach, only minimal risk wells (as defined in 30.3.3 Risk Level) are left in a shut-in state. Shut-in planning involves the following:

- Confirming the risk level for the well.
- Reviewing local jurisdictional regulations.
- Determining the anticipated duration of shut-in, as well as the frequency of monitoring, inspection, integrity testing and reassessment.

30.4.2 Execution

The steps ensuring isolation may vary depending on the well configuration, but the principles of isolation during shut-in remain the same for all well types. The goal is to secure the well to ensure the safety of workers, the public and the environment.

IRP At a minimum, the following steps should be completed to shut in a well:

- Confirm H_2S readings and required safety equipment are on location prior to starting any operations.
- Inspect the wellhead for leaks.
- Inspect for signs of well integrity issues (e.g., dead vegetation around the well) that may necessitate an updated risk assessment.
- Clean up all spills and contain and control leaks.
- Remove debris from the location.
- Document the tubing and casing pressures (from all strings and annuli).
- Close all wellhead valves and ensure their functionality.
- Refer to 30.8 Subsurface Safety Valves if the well is equipped with subsurface safety valves.

Note: Minimal risk wells considered for shut-in typically do not have a subsurface safety valve, but the presence of the valve can increase risk because it represents a potential failure point and should be considered in the risk assessment.

- Ensure the wellhead is secured (i.e., remove valve handles or chain and lock).
- Ensure there is a method to read pressures (e.g., ported flange or ported bull plug and a bleed-off valve).
- Conduct an SCVF test and leave Surface Casing Vent Assembly (SCVA) open unless otherwise directed by local jurisdictional requirements. If there is no SCVA, the licensee should conduct a gas migration test.
- Conduct any jurisdictionally required pressure testing.
- Winterize to prevent freezing of the wellhead and casing.
- Leave any surface equipment in a secure condition (e.g., chain down pumpjack weights).
- Drain fluid from tanks.
- Lock out power to surface equipment.
- Disconnect wellhead piping as per local jurisdictional requirements.
- Ensure the wellhead is conspicuously marked or fenced for visibility in all seasons.
- Place (or repair) wellhead signage, including 24 hr emergency number.

Other steps to consider include:

- Photographing the well and lease.

  Note: It can be beneficial to photograph the wellhead after shut-in to document the well's condition and the steps taken. These photographs can be useful in the suspension planning or any plan to return the well to production. Some jurisdictions (e.g., BC) may request these photographs as part of the reporting process at some point.

- Disconnecting, purging, or pigging lines, especially if there are no plans to reactivate or suspend the well soon, or if future plans are uncertain. This depends on the long-term well plan.
- Performing gas migration testing if decommissioning is likely and required by the regulator for decommissioning.
- Maintaining cathodic protection if other power sources are removed or disconnected.
- Removing plungers and/or bumper springs on plunger lift wells.
- Ensuring compliance with ongoing regulatory pressure testing requirements for disposal/injection wells.

For rod pump wells, the decision on what position to leave wellhead rod Blow Out Preventers (BOPs) needs to be based on the specific conditions and risks of the well.

If wellhead rod BOPs are to be removed there are two key scenarios to consider. For either of these scenarios, it is important to consider the wellbore fluids, temperatures, pressures, EOR schemes, CCUS, disposal wells, the surrounding environment, and the ability to service the well in the future due to time-weighted well integrity issues such as corrosion.

Option 1 - Pull and lay down pump and rods, cap the well with a fully opening master valve.

- If the insert pump/progressive cavity pump rotor was removed, the tubing is open to the formation and can be pumped down.
- If pump is a tubing pump with an on/off mechanism, a tubing punch can be used to create a hole in the tubing allowing the ability to pump down.
- Additional services are required to pull rods out of the hole compared to backing off the polished rod and landing it at the bottom.
- Surface isolation does not rely on the stuffing box or wellhead rod BOPs.

Option 2 - Back off the polished rod, land rods on the bottom and cap the well with a fully opening master valve.

- There is no ability to pump down tubing unless the tubing is equipped with a tubing drain.
- Third-party services are required to remove the polished rod and land rods at the bottom.
- Surface isolation does not rely on the stuffing box or wellhead rod BOPs.
- To return the well to production or complete decommissioning activities, the rods will need to be fished out of tubing.

If wellhead rod BOPs are to be left installed on a well, there are two key scenarios to consider. For either of these scenarios, It is important to consider the condition of the polished rod, wellbore fluids, temperatures, pressures and the surrounding environment. Periodic inspections and lubrication are important to ensure the wellhead rod BOPs can operate effectively during well control issues.

Option 3 - Leave wellhead rod BOPs open with polished rod in place.

- Isolation relies on the stuffing box to isolate the wellbore and prevent environmental release.
- There may be an increased risk of environmental release if the stuffing box packing leaks.
- Consider stuffing box design and whether there are better alternatives.

Option 4 - Close wellhead rod BOPs with polished rod in place.

- Closing the wellhead rod BOPs can lead to the possibility of them seizing, present challenges in obtaining wellhead pressures, and increase the risk of trapped pressure within the system.

IRP Option 1 should be used first. If Option 1 is not feasible, consider Options 2 through 4.

IRP Chemical barrels shall be drained or removed from the site.

IRP All lines for chemicals shall be disconnected from the pump and capped with a valve for isolation purposes.

30.5 Suspension Planning and Execution

30.5.1 Planning

Following the risk-based approach, moderate and high-risk wells (as defined in 30.3.3 Risk Level) are suspended. Suspension planning involves the following:

- Confirming the risk level for the well (based on barrier requirements).
- Reviewing initial suspension requirements for the appropriate jurisdiction.
- Determining barrier type and depth.
- Determining suspension fluid requirements.
- Determining wellhead requirements.
- Identifying area information which may impact suspension activities.

Note: Production equipment typically needs to be removed to properly set a downhole barrier. This needs to be considered in planning.

See 30.3 Risk-Based Approach for more information about determining risk level and other considerations.

IRP Any downhole suspension work should be completed while considering IRP 27: Wellbore Decommissioning and local jurisdictional regulations for decommissioning. This ensures proper consideration for wellbore integrity and minimizes duplication of intervention work.

IRP For moderate and high-risk wells, a review of the primary cementing operations or Cement Bond Log (CBL) should be completed to ensure annular isolation at the barrier set depth. If there are any concerns about the quality of top of cement, a CBL should be conducted.

IRP A well schematic should be reviewed when planning the suspension. If a schematic does not exist or it is not current, a new or updated schematic should be completed as part of the planning.

The well schematic provides information about the following:

- The final completion of the well including casing sizes, cementing information, depths, inclination, completed zones, barriers in place, and wellhead configuration and specifications
- Metallic materials of construction (e.g., coatings, American National Standards Institute (ANSI)/National Association of Corrosion Engineers (NACE / NACE International) MR0175-2021/ISO 15156:2020 Petroleum and Natural Gas Industries – Materials for Use in H_2S Containing Environments in Oil and Gas Production)

Note: NACE International merged with The Society for Protective Coatings to form the Association for Materials Protection and Performance (AMPP) in 2021.

- Elastomer information
- Fluids left in the wellbore
- Equipment pressure ratings, shear to release ratings, differential ratings

IRP The well's history should be reviewed when planning the suspension.

Well history can provide information about the following:

- Completions issues (e.g., consistent issues with fill from perforations)
- Workover issues (e.g., tools hung up while running in the hole)
- Previous problems the well has experienced
- Equipment currently in the well
- Static pressure gradient information
- H_2S content and/or product fluid composition and its potential impact on the casing, tubulars or equipment left in the hole while suspended
- Hazardous substances such as Naturally Occurring Radioactive Materials or Iron Sulfide
- Cementing data for isolation behind the casing
- Any cased-hole logs available pressure surveys
- Gas analysis
- The presence of an SCVF and/or gas migration

30.5.2 Barriers

Mechanical Plugs are described in IRP27: Wellbore Decommissioning which provides adequate descriptions for some aspects of wellbore suspensions.

Suspension activities may permit the use of different barriers based on the anticipated duration of use other than those defined in IRP 27: Wellbore Decommissioning or local jurisdictional regulations. This may include the use of retrievable suspension plugs and/or elastomers/materials rated for temporary compatibility. Consider using appropriate permanent barriers if it is likely the well will be decommissioned after suspension.

30.5.2.1 Acceptable Barriers

Acceptable barriers are barriers that are pressure testable, designed for hole conditions, and not constrained by a practical amount of time (e.g., a column of fluid is not a permanent barrier).

Examples of acceptable primary barriers include:

- Tubing plug (lock and seal on a nipple profile)
- Casing-set plug or packer (e.g., permanent set plug and cement, wireline retrievable plug for short term suspensions, permanent or retrievable packers)
- Cement plug
- Non-activated cement retainer (which can also be used for decommissioning)

IRP The plug material should be considered in planning such as whether the material is suitable to the well conditions and whether it will be permanent or temporary.

Examples of acceptable secondary barriers include:

- Any primary barrier listed above
- Subsurface safety valves used in combination with another downhole barrier (e.g., a tubing plug). These would typically be used on high-risk wells.
- Fluid column (greater than or equal to formation pressure)
- Back Pressure Valve (BPV)

Note: An uncompleted well is considered to be suspended with the unperforated casing and primary cement acting as the primary barrier.

30.5.2.2 Unacceptable Barriers

IRP The following shall not be used as a barrier:

- Hook wall well plugs (they do not have a permanent profile; they can move around)
- Dissolvable plugs (time-limited if no cement on top)
- Casing blockages (e.g., scale buildup, casing damage, formation fines, ice plugs, fish-in-hole)

- Anything that is not pressure testable (it needs to be able to confirm the barrier is holding pressure)

30.5.2.3 Considerations for Choosing and Installing Barriers

Consider the following when choosing barriers:

- Designing for ease of decommissioning (see IRP 27: Wellbore Decommissioning and local jurisdictional regulations regarding barrier placement)
- Designing for well type (e.g., Cyclic Steam Stimulation (CSS), Steam Assisted Gravity Drainage (SAGD) – strategies that are scheme appropriate)
- Placement of cement on top of mechanical plugs (as per IRP 27: Wellbore Decommissioning)
- Placement of sand on top of plugs to aid in retrievability (if required)
- Wellbore fluids and compatibility (see 30.5.4 Suspension Fluids)
- Pressure rating of plugs and expected pressures
- Casing preparation required
- Lifespan of materials vs. expected duration of the suspension
- Placement of the barrier as close as practical (i.e., as deep as possible) to the producing zone for the following reasons:
  - Setting the plug lower allows for hydrostatic pressure above the plug if the suspended section becomes over-pressured over time.
  - This placement helps ensure that the condition of the pipe above the plug retains integrity (e.g., from corrosive environments).
  - This placement provides room if it becomes necessary to set another plug above.
  - Consider retrievability, milling, and hydrostatic columns.

Retrievable plugs may not be suitable for some suspensions, particularly if decommissioning is to follow suspension. Refer to the Mechanical Plug Types section of IRP 27: Wellbore Decommissioning for more information about retrievable plugs and the impact on decommissioning.

30.5.2.4 Isolation Requirements

There may be different zones requiring independent suspension which may have different barriers and/or follow-up inspection requirements.

IRP When there are multiple zones, each zone should be suspended independently unless commingled abandonment has been approved or accepted by the local jurisdictional regulator.

If suspending multiple zones, consider decommissioning the lower zones to minimize risk on future operations and decommissioning.

30.5.3 Wellhead Configuration/Seals

Review IRP 05: Minimum Wellhead Requirements for wellhead design considerations.

Consider the following regarding wellhead configuration and seals:

- Whether there is a fully opening master valve. If access is restricted (e.g., by Internal Diameter) there are limited options for intervention if the barrier starts to leak.
- Whether the pressure rating of the wellhead is sufficient. It needs to be sufficient to pressure test the barrier to appropriate pressure.

IRP The wellhead should be inspected and function tested by the operator prior to suspension. Wellhead seals should be pressure tested and/or inspected for condition prior to suspension, if possible.

IRP Wellhead seals shall be compatible with planned suspension fluids.

30.5.4 Suspension Fluids

IRP Suspension fluid selection should be reviewed with the planning team, fluid providers, and completion equipment providers to ensure compatibility and longevity.

Consider the following:

- Corrosive properties of native wellbore fluids and anticipated stratifying of the fluid column
- Corrosion implications
- Engineered suspension fluids (e.g., corrosion inhibitor, biocide, oxygen scavenger, potential hydrogen (pH) buffer)
- Long-term corrosivity of brines
- Rigless fluid placement methods (i.e., pumping past a plug prior to setting and top filling after setting the plug)
- Alignment of suspension fluids with the decommissioning strategy
- Use of weighted maintenance inhibitors to protect against casing corrosion
- Protection of the top from freezing
- Protection of groundwater
- Compatibility with elastomer and metallurgy selection
- Compatibility with reservoir characteristics/geology

- Compatibility with future decommissioning efforts (i.e., suspensions sometimes use inhibited fluid, but if there is no plan to reactivate the well, then having fresh water as suspension fluid makes decommissioning easier as it doesn't have to be circulated out).

30.5.5 Execution

The following are the general steps to suspend a well:

- Review well characteristics and history of previous well work.
- Determine suspension parameters (e.g., how long, steps to reactivate or decommission).
- Review selected equipment design and fluids.
- Service wellhead as per the original equipment manufacturer's (OEM's) recommendations.
- Set downhole barrier(s) as required.
- Pressure test as required.
- Circulate suspension fluid if required (i.e., if inhibiting).
- Set up a monitoring plan for leaks or wellhead integrity.
- Pressure test periodically based on regulatory requirements.
- Establish a review process for the suspended well (e.g., continued suspension, reactivation, or decommissioning).

IRP Once the suspension work is completed, the appropriate reporting must be submitted in accordance with the local jurisdictional regulations.

30.6 Post Shut-in/Suspension Activities

Wells that have been shut-in or suspended, including uncompleted wells, require periodic inspection, monitoring, and integrity testing to ensure that the wells remain in a safe state.

30.6.1 Monitoring and Inspections

Inspections of shut-in and suspended wells will be conducted at a frequency defined by the operator's risk assessment and local jurisdictional regulations. At a minimum these inspections will occur at the time of initial shut-in or suspension and at ongoing inspection frequencies specified in local jurisdictional regulations until the well is decommissioned or reactivated. See Appendix B: Inspection Frequencies for more information.

IRP Inspections should be documented and should include the following:

- Visual inspection of wellhead and lease
- Wellhead maintenance:
    - Ensure the wellhead is free of leaks.
    - Service and maintain the wellhead according to the OEM's recommendations.
    - Take pressure recordings from all annuli and the production conduit. In cases where unexpected pressure is identified, conduct diagnostics to evaluate well barriers.
    - Install bullplugs or blind flanges with needle valves on all outlets except the surface casing vent.
    - Leave the vent open and unobstructed if equipped with a surface casing vent assembly unless otherwise required.
    - Function test wellhead valves to ensure proper functionality and service where required. Chain and lock valves or remove valve handles. Ensure valves are in the closed position when locked unless unique circumstances prevent closing the valve (e.g., instrumentation line through valve).
    - Ensure the flowline from the wellhead is disconnected or isolated as per risk assessment or local jurisdictional requirements.
    - Pressure test wellhead seals where applicable/possible.
    - Inspect / function test rod BOPs where applicable.

- Surface casing vent flow (if applicable):
  - Conduct surface casing vent flow tests (e.g., bubble test, liquid measurement).
  - Conduct surface casing vent pressure build-up and flow rate tests as required by local jurisdictional regulations for wells either previously identified as having surface casing vent flow or identified through inspections.
  - Collect gas samples for analysis when necessary to classify the severity of the surface casing vent flow or aid in future decommissioning planning.
- Lease maintenance:
  - Ensure signage at the wellhead and lease entrance meets local jurisdictional regulatory requirements.
  - Control vegetation and noxious weeds around the wellhead and lease.
  - Remove hazards associated with debris and waste on the site.
  - Mark or fence wellheads to prevent inadvertent contact.
  - Inspect the surrounding area for signs of stressed vegetation or gas migration.

IRP Inspections should include photos with the date and time stamped to document the condition of the site during the inspection. Some jurisdictions may require photos to be submitted with the inspection.

IRP Deficiencies found during an inspection should be further investigated, repaired if required, and reported as per local jurisdictional regulatory requirements.

30.6.2 Integrity Testing

Well integrity can be assessed using various methods with pressure testing being the most common for wells with a barrier in place.

IRP If integrity concerns are found, the well should be investigated further, and the risk assessment should be re-evaluated to determine if the risk profile of the well has changed. Any local jurisdictional requirements should be referred to for reporting and repair timelines.

For wells that do not have a downhole barrier, pressure testing is not required, but the following may be indicators of an integrity issue:

- Changes in:
  - wellhead pressure
  - SCVF status

  - production fluid composition
  - H_2S levels
  - Reported impact to water wells nearby

- dead vegetation surrounding the wellhead
- bubbling observed in standing water in the area around wellhead
- audio, visual, or olfactory signs
- aerial surveys

For wells that have been suspended with a downhole barrier in place, periodic pressure testing is required to ensure integrity. The frequency and specification for the pressure test will depend on the operator's risk assessment and local jurisdictional regulations. Careful consideration of pressure testing parameters is key as they pertain to the current and future risk profile of the well.

Key pressure test parameter considerations include:

- Accepted pressure test mediums will vary by area, jurisdiction, and operator, and may include inert gas, fresh water, formation fluid or brine.
- Pressure test duration will vary by area, jurisdiction, and operator based on the time required for stabilization. This may also be impacted by the pressure test medium utilized.
- Maximum pressure applied at surface will be a function of the wellbore design and pressure test medium utilized.
- Pressure test should account for previously cemented perforations and/or casing patches that are exposed.
- Ensure the well is left with a non-freezing fluid in the top two metres of the wellbore.

IRP Sufficient pressure must be applied to effectively test the barrier without over pressuring any wellhead or wellbore components and meet relevant local jurisdictional requirements.

IRP If a well is equipped with tubing and a packer, the integrity of the tubing and annulus must be confirmed independently.

IRP The pressure test medium should be a non-corrosive fluid that is non-flammable and non-damaging.

IRP The burst and collapse ratings shall be reviewed prior to pressure testing tubing or casing. Ensure maximum allowable wellhead pressure (MAWP) is not exceeded.

IRP Pressure tests shall not exceed the pressure rating of the lowest rated component in the system.

IRP The results of the pressure test shall be documented and retained.

IRP At a minimum a pressure test shall be conducted at the time of initial suspension. Subsequent pressure tests shall be done periodically as per local jurisdictional requirements.

If a pressure test fails, refer to local jurisdictional requirements for reporting and timelines for repair.

30.7 Well Reactivation

An operator may choose to return a shut-in or suspended well to production. To do so the operator needs to confirm the availability of active mineral rights, surface lease agreements, and comply with any regulatory requirements associated with reactivating a well. Additionally, there are a series of steps that need to be taken to ensure the well is returned to production safely. Many of these steps are common to both shut-in and suspended wells and primarily involve surface equipment and inspections.

IRP The following steps should be considered before returning a shut-in or suspended well to production:

- Confirm H_2S readings and the availability of required safety equipment on location before commencing any operations.
- Inspect for any signs of a potential well integrity issue (e.g., dead vegetation around the well) that may necessitate an updated risk assessment.
- Clean up spills and contain/control leaks.
- Remove debris from the location.
- Inspect the wellhead for leaks.
- Ensure the wellhead is unsecured and functional.
- Function test all wellhead valves and service as per the OEM's recommendations.
- Mitigate for hydrate formation.
- Ensure there is a method for reading pressures (e.g., ported flange or ported bull plug, and a bleed-off valve).
- Document the tubing and casing pressures (from all strings and annuli).
- Evaluate and confirm the integrity of the tubing and artificial lift equipment.
- Ensure the subsurface safety valve functions properly if the well is equipped with one. (See 30.8 Subsurface Safety Valves).
- Ensure the SCVA is open and conduct an SCVF test unless otherwise required.
- Conduct any pressure testing required by local jurisdictional regulations.
- Ensure any surface equipment to be used is in good functional condition and has been inspected if required (e.g., tanks, pumpjack, Variable Frequency Drive).
- Ensure power has been properly re-instated (by an electrician if required) and confirm cathodic protection is functioning properly.
- Reconnect and confirm the integrity of any wellhead piping as per local jurisdictional requirements.

- Ensure the wellhead is conspicuously marked or fenced and visible in all seasons.
- Place or repair wellhead signage, including a 24-hr emergency number.
- Ensure compliance with ongoing regulatory pressure testing requirements for disposal/injection wells.
- Report the reactivation of the well in accordance with local jurisdictional requirements and retain records.

IRP Any integrity issues must be assessed to determine if repair is required before reactivation.

For shut in wells, specific considerations related to the associated risks and the type of artificial lift equipment (if applicable) are necessary to safely bring a well back into production.

- For rod pump wells, ensure the rod string and pump are connected, and the wellhead BOPs are open.
- For plunger lift wells, ensure the surface equipment is fully functional before running the bumper spring and plunger.

For suspended wells, specific considerations related to regulatory requirements and the risk assessment of the well are necessary before reactivating a well.

Additional steps to be completed to reactivate a suspended well include:

- Pressure testing the barrier per local jurisdictional requirements to ensure wellbore integrity:
    - Do not exceed the MAWP.
    - Do not exceed the pressure rating of the lowest rated component in the system.

Considerations for reactivating a suspended well include:

- Be prepared for pressure and flow below the barrier:
    - Evaluate well history and offset well information to confirm anticipated reservoir pressures.
    - Slowly equalize pressure across the barrier, if possible.
    - Ensure the equipment utilized is sufficient for anticipated pressure while maintaining well control.
    - Have sufficient fluid density to account for any pressure below the plug if drilling through a barrier.

Once the barrier is removed and pressures confirmed, review downhole and surface equipment design to confirm that it is sufficient for the current pressures.

Refer to IRP 2 Completing and Servicing Sour Wells as required.

30.8 Subsurface Safety Valves

30.8.1 Suspending Wells with Subsurface Safety Valves

Wells equipped with subsurface safety valves (SSV) are generally medium to high-risk wells due to their H_2S concentration, release rates, or proximity to population or environmentally sensitive areas. Although the risk level may change over the life of the well as productivity decreases, the method to suspend a well with subsurface safety valves remains similar. This section provides recommendations and considerations for suspending a well with an SSV installed in the completion.

Wells can be equipped with three different types of subsurface safety valves:

1. TRSCSSV (Tubing Retrievable Surface Controlled Subsurface Safety Valve)
2. WLSCSSV (Wire Line Retrievable Surface Controlled Subsurface Safety Valve)
3. SCSSV (Subsurface Controlled Subsurface Safety Valve)

Surface-controlled subsurface safety valves, such as TRSCSSV and WLSCSSV, are fail-safe in the closed position and remain closed unless continuous pressure is applied to the hydraulic control line. The surface control panel hydraulic pump is typically powered by an air-diaphragm pump, which needs to remain operational to keep pressure on the hydraulic control line, holding the surface-controlled subsurface safety valve in the open position. Maintaining pump operation on a suspended well or wellsite is not practical in the context of well suspension.

IRP The hydraulic control line should be protected from possible damage that could compromise its integrity. If feasible, the control line should be terminated and capped with a valve as close to the wellhead as possible.

For wells equipped with an SSV, there is no ability to check and monitor tubing pressure below the valve from surface, which adds a potential risk of trapped pressure.

WLSCSSVs need to be removed from the landing nipple and the well suspended by setting a testable barrier (blanking plug) in the packer or packer tailpipe.

Wells with TRSCSSVs can only be pulled with the tubing. Therefore, they are allowed to remain in place for well suspension.

IRP To mitigate pressure build-up below a closed safety valve, the tubing should be displaced with a non-corrosive fluid, then a testable barrier (blanking plug) should be set in the in the packer or packer tailpipe.

IRP If the well is being filled with fluid, the fluid must be displaced as per the local jurisdictional regulations.

IRP The potential for thermally induced fluid expansion between the packer barrier and closed safety valve should be considered in the suspension.

Leaving the SSV open for several days after tubing fluid displacement and barrier testing will allow thermal fluid expansion to bleed off before closing the subsurface safety valve.

Wells with WLSCSSVs are landed and set in hydraulic landing nipples that connect to the hydraulic control line running to the surface control panel. When the WLSCSSV is removed from the hydraulic landing nipple, the hydraulic control line, which runs to the surface, is in direct communication with the tubing's internal diameter. This means that any fluid and pressure inside the tubing can flow up the hydraulic control line to the surface. If the integrity of the hydraulic control line is compromised at the surface or within the well, uncontrolled flow of tubing or annulus fluids to the surface could occur. Caution should be taken when unsetting the WLSCSSVs if unable to equalize the pressure.

IRP A hydraulic landing nipple dummy valve shall be properly landed and set in the hydraulic landing nipple and shall be pressure tested down the hydraulic control line to ensure its integrity.

While quite rare in Western Canada, some wells are equipped with SCSSVs. This type of safety valve does not use a hydraulic control from surface to open or close the valve. Instead, this type of safety valve is typically set deep, at or near the packer and is fail-safe open and closed by sudden changes in fluid flow conditions. The SCSSV is mounted to a slickline lock and landed in a profile nipple such as the X Nipple using conventional slickline operations. It is also retrievable with conventional slickline operations.

IRP The SCSSV shall be pulled from the well before suspension with a downhole barrier set in the packer or packer tailpipe. If it cannot be retrieved with a slickline, the valve shall be removed by pulling the tubing before continuing with the suspension.

Table 6. Well Suspension Guideline Based on Subsurface Safety Valve Type

TRSCSSV	WLSCSSV	SCSSV
• Tubing fully displaced with non-corrosive fluid • Blanking plug set in the packer and tested • Tubing pressure tested • Safety valve left in closed position • Hydraulic control line disconnected from control panel and blanked with high pressure needle valve • Annulus pressure tested in accordance with local jurisdictional regulations	• WLSCSSV retrieved from the hydraulic landing nipple • Tubing fully displaced with non-corrosive fluid • Blanking plug set in the packer and tested • Tubing pressure tested • Dummy valve installed in the hydraulic landing nipple and pressure tested via the control line • Hydraulic control line disconnected from control panel and blanked with high pressure needle valve • Annulus pressure tested in accordance with local jurisdictional regulations	• SCSSV retrieved from the deep-set landing nipple • Tubing fully displaced with non-corrosive fluid • Blanking plug set in the packer and tested • Tubing pressure tested • Annulus pressure tested in accordance with local jurisdictional regulations

During well suspension, it is possible a TRSCSSV may malfunction, preventing it from opening to set the deep barrier (blanking plug) in the packer. For some models of TRSCSSVs, there are slickline deployed tools which can assist opening a failed TRSCSSV and even permanently lock it to the open position. Once a lock open operation is executed, the TRSCSSV can never be closed again. A locked open TRSCSSV would be considered acceptable for well suspension requirements. However, these accessory tools have very limited availability in Canada. For older models of TRSCSSVs these tools are likely nonexistent.

IRP For wells with malfunctioning TRSCSSVs, the tubing and safety valve should be removed from the well. Once the valve is removed, the risk assessment should be re-evaluated.

Appendix A: Revision Log

The revisions to IRP 30 are logged in the following sections.

Edition 1

Edition 1 is the first edition of this new IRP sanctioned in March 2024.

The following individuals helped develop Edition 1 of IRP 30 through a subcommittee of DACC.

Table 7. Edition 1 Development Committee

Name	Company	Organization Represented
Adam Derry (Co-chair)	360 Energy Liability Management	Enserva
Bailey MacDonald (Co-Chair)	Crescent Point Energy	CAPP
Cole Benson	Halliburton	Enserva
Mason Crandall	Imperial Oil	CAPP
Dale Duffy	CNRL	CAPP
Gary Ericson	Saskatchewan Ministry of Energy	Regulator
Keith Farquharson	Stream-Flo	Enserva
Landon Fraser	Government of Manitoba	Regulator
Dave Fukumoto	BC Energy Regulator	Regulator
Lindsay Gray	ARC Resources Ltd.	CAPP
Stephen Minni	ConocoPhillips	CAPP
Alex Naumescu	Big Guns Energy Services	Enserva
Phil Thomson	RPM Specialty Services	Enserva
Rajan Varughese	AER	Regulator
Mark Woitt	Fervo Energy	Enserva

Appendix B: Inspection Frequencies

Each jurisdiction may have specific inspection and monitoring requirements based on the permit issued for the well.

Table 8. Inspection Frequencies

Jurisdiction	Criteria	Inspection Frequency	Regulatory Reference
Alberta	For the low-risk well types	Five years or one year (dependent on well type classification)	Directive 013
	For medium-risk well types	Five years, three years, or one year (dependent on type of suspension option used)	Directive 013
	For high-risk well types	Five years or one year (dependent on type of suspension option used)	Directive 013
British Columbia	For the low-risk well types	Five years or one year (dependent on well type classification)	Oil and Gas Operations Manual – Chapter 9
	For medium-risk well types	Five years, three years, or one year (dependent on type of suspension option used)	Oil and Gas Operations Manual – Chapter 9
	For high-risk well types	Five years or one year (dependent on type of suspension option used)	Oil and Gas Operations Manual – Chapter 9
Manitoba	N/A	Three years or one year (dependent on type of suspension option used)	Informational Notice No. 21-04
Saskatchewan	N/A	None	N/A

Appendix C: Case Studies

Case Study 1: Minimal Risk

Introduction

The subject well went down with a failed pump and was deemed uneconomic to repair based on current economic conditions. The well will remain down until it is required to produce to retain mineral rights, or it becomes economic to return to production.

Case Study #1 Minimal Risk	
Risk Categories	**Description**
H_2S Content	The well is sweet with no record of H_2S.
Inactivity Duration	One month
Well Type	Oil well
Well History	The well was drilled in the last 10 years by the current licensee and has complete well records.
Wellbore Construction and Integrity	The well had cement returns to surface and no issues during drilling or completion activities. There are no visible signs of a wellbore integrity issue.
Well Location	The well is in a field with all-season access and has a 50 metre (m) by 50 m graveled and fenced lease. There are no residents or water bodies nearby. The well is equipped with remote monitoring to identify leaks.
Reservoir Pressure	The reservoir pressure is low, and the well is unable to flow to surface.
Wellbore Fluids	The wellbore fluids are not known to be corrosive or cause issues that could impact future operations or wellbore integrity.
Offset Stimulation Interference	The well is in an area with no current drilling or fracturing activities.
Enhanced Recovery Scheme	The well is in an area which is slowly being decommissioned and there are no known plans for any enhanced recovery schemes.
Subsurface Production Equipment	Tubing and insert pump with rods, polished rod, and wellhead rod BOP.
Hydrates	The formation and area are not known to cause hydrates.
Surface Equipment	Pumpjack, disconnected flow line.

Risk Assessment

This well is assessed as a **minimal risk** to personnel and the environment. It can be shut in or suspended in accordance with company policy and/or local jurisdictional regulatory requirements. Based on Table 5 Risk Levels, there is no requirement for a downhole barrier if a well is left shut in. The risk assessment should be reviewed if conditions change, or anomalies are observed that could impact integrity.

Case Study 2: Minimal Risk

Introduction

A SAGD steam injection well has been shut in for the last 12 months due to ongoing issues with the associated producer well. There are plans to re-drill the producer well and bring it back online in the future, although the timing is unknown.

Case Study #2 Minimal Risk	
Risk Categories	**Description**
H_2S Content	No records indicate H_2S presence in this well, although offset wells have recorded up to 1000 parts per million (ppm) of H_2S.
Inactivity Duration	The well is currently shut in due to issues with the associated SAGD producer. Once the producer well is re-drilled the injector will be reactivated. This is anticipated that this will occur within the next two years.
Well Type	SAGD Steam Injector
Well History	The well was drilled within the past 15 years, and there is a complete history of well records.
Wellbore Construction and Integrity	The well was designed for SAGD service with cement to the surface and has no SCVF or gas migration issues. A Cement Bond Log (CBL) was completed after drilling. However, it has never been logged to confirm casing integrity.
Well Location	The well is located on an all-season SAGD pad, which is included in operator rounds. There are no nearby water bodies, and public access to the well is restricted.
Reservoir Pressure	The current reservoir pressure is insufficient to allow the flow of liquid to the surface.
Wellbore Fluids	No significant corrosion issues have been identified in the field to date. The casing annulus contains sweet blanket gas and potentially steam, condensate, and bitumen.
Offset Stimulation Interference	There is no potential for offset stimulation interference.
Enhanced Recovery Scheme	This well is part of a SAGD operation and may be affected by offsetting wells.
Subsurface Production Equipment	The well is completed with concentric tubing strings into the horizontal lateral.
Hydrates	There is no potential for hydrates.
Surface Equipment	The wellhead is disconnected from surface equipment, but the rest of the pad surface equipment remains in service.

Risk Assessment

This well is assessed as a **minimal risk**. Despite having several escalation factors, it also has several risk reduction factors including, restricted access that is regularly monitored, well design compatibility with SAGD operations, and the low reservoir pressures that prevent continued flow to surface. Based on Table 5 Risk Levels, there is no requirement for a downhole barrier if the well is left shut in.

Case Study 3: Minimal Risk

Introduction

A cyclic steam stimulation well has cooled off after steam and can no longer be produced. The operator plans to begin the next cycle of steam in approximately six months and intends to shut in the well in the meantime.

Case Study #3 Minimal Risk	
Risk Categories	**Description**
H_2S Content	<2% H_2S
Inactivity Duration	The well is shut-in, awaiting next steam injection cycle in approximately six months
Well Type	Cyclic Steam Stimulation (CSS) – Injector & Producer (bitumen)
Well History	The well has a complete well file and has the same initial operator.
Wellbore Construction and Integrity	There is surface casing and production casing with full cement returns to surface and there is a good cement bond based on the log during completions. There is no known Gas Migration or SCVF. The well had a casing integrity check with a pressure test two years prior and there were no issues at that time.
Well Location	The well is located on an active oil sands lease with road access in any season, and there are no water bodies or residents within one kilometre (km). The nearest town is 25 km away.
Reservoir Pressure	The current reservoir pressure is sub-hydrostatic (i.e., A column of water would overbalance reservoir). The well will not produce without artificial lift.
Wellbore Fluids	The casing and tubing have been purged with an inert gas (packerless completion). The wellbore fluids are not expected to create an integrity concern for any equipment.
Offset Stimulation Interference	The nearest CSS injection is 500 m away from this bottomhole location and is not expected to have an impact on the subject well.
Enhanced Recovery Scheme	No EOR schemes are planned in the vicinity this lease.
Subsurface Production Equipment	The well has production tubing and rod pump equipment spaced in the bypass. There are no known issues with subsurface equipment.
Hydrates	No potential for hydrates.
Surface Equipment	All wellhead valves have been greased and function tested. There are no leaks. The chemical totes are secure with regular surveillance from the well pad operator. The production and injection lines are hooked up to the wellhead.

Risk Assessment

This well is assessed as a **minimal risk.** Only one of the 13 risk categories (H_2S Content) is slightly elevated. As the well poses a minimal risk to personnel and the environment, it can be shut in or suspended based on company policy and/or local regulatory requirements. Based on Table 5 Risk Levels, there is no requirement for a downhole barrier if the well is left shut in.

Case Study 4: Moderate Risk

Introduction

A non-producing well was recently acquired in an asset purchase, with the new operator planning to suspend the well as it is not currently economically viable to produce.

Case Study #4 Moderate Risk	
Risk Categories	**Description**
H_2S Content	The well is sweet with no known history of H_2S. Some H_2S (<0.5%) is present in offset areas in other producing formations.
Inactivity Duration	Suspended for three years due to economics.
Well Type	Suspended producer.
Well History	The well was recently acquired with an incomplete history.
Wellbore Construction and Integrity	The well was drilled in 1995 and was completed with a 114.3-millimetre (mm), 17.26 kilograms per metre (kg/m) L80 liner (collapse of 43.8 MegaPascal (MPa)). Intermediate casing is a 177.8 mm, 43.16 kg/m P-110 (collapse 74.2 MPa) with confirmed good cement quality from CBL completed in 2008.
Well Location	The wellhead is located 800 m from a resident (farmer). The well has all-season access with no water bodies nearby.
Reservoir Pressure	The bottomhole pressure is approximately 25 MPa below the packer and the full fluid column of potassium chloride is calculated at approximately 27 MPa.
Wellbore Fluids	There is inhibited fluid above the packer in the tubing and annulus; potassium chloride based.
Offset Stimulation Interference	In the next three months, there are fracture stimulation activities planned within the same producing zone as the subject well. The closest bottom hole is within 600 m of the Fracture Planning Zone (FPZ) (refer to AER Directive 083 and IRP 24).
Enhanced Recovery Scheme	None planned in future.
Subsurface Production Equipment	Retrievable Production packer installed at 2,700 m (vertical) with an RN-plug is in place in profile below the packer.
Hydrates	No hydrates.
Surface Equipment	A 5k wellhead that was inspected within the last year and is in good condition. The flowline is disconnected, and all storage tanks have been removed.

Risk Assessment

This well is assessed as a **moderate risk** due to its incomplete well history, and proximity to residents and planned fracture activities with lower rated equipment. Given this moderate risk to personnel and the environment, it must be suspended. Based on Table 5 Risk Levels, at a minimum one appropriately rated downhole barrier must be installed to suspend the well. The risk assessment should be reviewed if conditions change, or if anomalies are observed that could impact integrity of the well.

Case Study 5: Moderate Risk

Introduction

The horizontal well was completed and fractured in the Doig interval. The well is equipped with a plunger lift and is located on a multi-well pad with other active wells. Production has been declining and has been intermittent in the past three years.

Case Study #5 Moderate Risk	
Risk Categories	**Description**
H_2S Content	The well records show an H_2S concentration of 3.5%.
Inactivity Duration	Shut in for six months.
Well Type	Gas producer
Well History	The well was drilled in 2009 and was acquired from another operator three years ago. Records and history are available. However, there are some gaps in the information.
Wellbore Construction and Integrity	The well was drilled in 2009 and completed with a 114.3-mm, 22.47 kg/m, L-80 liner tied back to surface. The intermediate is 177.8 mm, 34.3 kg/m L-80 with reports of cement to surface. The surface casing was set at 272 m and does not fully cover the Base of Groundwater Protection (BGWP). The well has an SCVF which is classified as non-serious.
Well Location	The well is located on a shared pad with all-season access for light equipment. Heavy equipment can access the area during dry weather or frozen conditions. There are no water bodies or public access points nearby.
Reservoir Pressure	The reservoir pressure is currently unable to flow liquid to surface.
Wellbore Fluids	Reservoir fluids; 2% CO_2
Offset Stimulation Interference	There is offset stimulation activity in the area. The well is landed above typical stimulation intervals.
Enhanced Recovery Scheme	N/A
Subsurface Production Equipment	The well is completed with a slick tubing string and plunger lift equipment.
Hydrates	No hydrate issues to date.
Surface Equipment	The wellhead is still connected to surface equipment. The rest of the pad surface equipment is in service for the remaining pad wells.

Risk Assessment

This well is assessed as a **moderate risk**. This well has several escalation factors, specifically the H_2S and CO_2 concentrations, which force it into the medium risk category even though the well was designed for this service. As the well poses a moderate risk to personnel and the environment, it must be suspended based on company policy and/or local regulatory requirements. Based on Table 5. Risk Levels, at a minimum, one appropriately rated downhole barrier must be installed to suspend the well.

Case Study 6: Moderate Risk

Introduction

The well was shut in due to declining gas rates. The operator has no plans to resume production from the Halfway zone. The well is being evaluated for potential up hole water disposal zones.

Case Study #6 Moderate Risk	
Risk Categories	**Description**
H_2S Content	The vertical gas well is sour. The last gas analysis indicates 4.0% H_2S present in the producing Halfway formation.
Inactivity Duration	Suspended for four years due to economics.
Well Type	Vertical sour gas production well
Well History	The well was acquired 15 years ago.
Wellbore Construction and Integrity	The well was drilled in 2003. The well has a 139.7 mm, 20.83 kg/m J-55 production casing (collapse of 21 MPa). A surface casing shoe is set 150 m above the BGWP. There is no cement bond log for the well. However, drilling reports indicate 8.0 m^3 of good cement returns to surface.
Well Location	The wellhead is located 700 m from a resident (farmer). The well has all-season access with no water bodies nearby.
Reservoir Pressure	The bottomhole pressure is estimated to be 9 MPa below the packer. A full column of fresh water (Hydrostatic pressure of 16.8 MPa) will exert sufficient hydrostatic pressure to overcome the current Halfway formation pressure.
Wellbore Fluids	The well has Halfway formation water in the tubing and casing. The fluid level depths in the tubing and casing are unknown.
Offset Stimulation Interference	There are planned fracture stimulation activities in the area (in a formation 200 m below the Halfway) within the next three months. The closest bottom hole is 200 m.
Enhanced Recovery Scheme	None planned in future.
Subsurface Production Equipment	A retrievable production packer with X and XN profiles is set at 1,700 m. The production tubing is perforated above a plunger lift spring landed in the X profile.
Hydrates	No hydrates.
Surface Equipment	A 3k single master valve wellhead that was inspected within the last year and is in fair condition. The flowline is disconnected. The separator package has been removed.

Risk Assessment

This well is assessed as a **moderate risk**. This well has several escalation factors, including the H_2S concentration, the condition of the single master valve, and the proximity to a residence. Given the moderate risk to personnel and the environment, it must be suspended based on company policy and/or local regulatory requirements. Based on Table 5. Risk Levels, at a minimum, one appropriately rated downhole barrier must be installed to suspend the well.

Case Study 7: Moderate Risk

Introduction

The injection well was shut in due to flowline issues. It is anticipated to be put back on injection in two to five years when the flowline infrastructure has been replaced as part of a larger optimization project.

Case Study #7 Moderate Risk	
Risk Categories	**Description**
H_2S Content	The formation fluids and the injection water have H_2S content above 1%.
Inactivity Duration	The well is expected to be inactive for two to five years.
Well Type	The well is a produced water injection well with a maximum allowable wellhead injection pressure (MAWHIP) of 21 MPa.
Well History	The well is approximately 20 years old and was completed by the current licensee with a full well history available.
Wellbore Construction and Integrity	The well was originally a producing oil well that was to be converted into an injection well. The casing and cement were designed for the injection pressures and the CBL showed good cement quality throughout the wellbore. The usable ground water is protected by a fully cemented surface casing.
Well Location	The well is in pastureland, with livestock surrounding it.
Reservoir Pressure	The reservoir pressure is estimated at 14 MPa and water will flow to surface if the well is shut in.
Wellbore Fluids	The injection fluids are produced saline water containing H_2S.
Offset Stimulation Interference	Hydraulic fracturing is occurring in the same formation as this well.
Enhanced Recovery Scheme	The well is part of a waterflood project. Although this well is shut in due to infrastructure constraints some of the other offset injectors will remain active which may impact the reservoir pressure.
Subsurface Production Equipment	A coated injection string and retrievable stainless-steel packer with profiles are installed in the well at the required regulatory depth. The annulus has been circulated over to inhibited fresh water.
Hydrates	Hydrates are not a concern.
Surface Equipment	The wellhead is in good condition and properly rated for the MAWHIP.

Risk Assessment

This well is assessed as a **moderate risk** due to the presence of in zone potential offset interference and the reservoir pressure. As the well poses a moderate risk to personnel and the environment, it must be suspended based on company policy and/or local regulatory requirements. Based on Table 5. Risk Levels, at a minimum, one appropriately rated downhole barrier must be installed to suspend the well.

Case Study 8: High Risk

Introduction

The subject well is under new ownership. The new operator is soliciting partner funding to reactivate the subject well and others in the field. The wells may be inactive for more than one year in the process.

Case Study # 8 High Risk	
Risk Categories	**Description**
H_2S Content	<2% H_2S
Inactivity Duration	It is expected that the well could be inactive for more than one year.
Well Type	Oil production
Well History	The well has changed ownership three times and has an incomplete history.
Wellbore Construction and Integrity	Not much is known about the primary cement or casing integrity. Recent testing shows the well has a non-serious gas migration. The well is not surface cased (no usable ground water protection).
Well Location	The well is in a remote wooded area where surveillance is difficult, and an ice road is required to access the lease. No residents or water bodies are nearby.
Reservoir Pressure	The current reservoir pressure is sub-hydrostatic (i.e., a column of water would overbalance the reservoir). The well will not produce without artificial lift.
Wellbore Fluids	The well has produced fluids that were high in asphaltenes and scale, in its productive life.
Offset Stimulation Interference	There are no planned offset stimulation activities.
Enhanced Recovery Scheme	Adjacent wells may potentially be used for carbon capture and storage in an underlying reservoir. However, it is unclear if plumes could reach the subject well.
Subsurface Production Equipment	The production tubing and downhole packer have been in place for 20 years The rod pump has been surfaced.
Hydrates	No known hydrate potential.
Surface Equipment	There is significant rusting of the wellhead and flowlines.

Risk Assessment

This well is assessed as a **high risk** due to several escalating factors present such as, H_2S content, inactivity duration, well history, wellbore construction and integrity, well location, wellbore fluids, enhanced recovery scheme, subsurface production equipment, and surface equipment. As the well poses a higher risk to personnel and the environment if left in a shut-in state, the well must be suspended. Based on the criteria presented in Table 5 Risk Levels, the well requires a downhole barrier as soon as practical.

Case Study 9: High Risk

Introduction

The subject well went down with a failed electrical submersible pump and was deemed uneconomic to repair based on current economic conditions. It is anticipated the well will be repaired and placed back on production in one to two years.

Case Study #9 High Risk	
Risk Categories	**Description**
H_2S Content	Vertical oil well with no known H_2S.
Inactivity Duration	Suspended for two years due to economics (due to high water cut).
Well Type	Oil Well
Well History	The well is in the Legacy Cardium well/field and was acquired 25 years ago.
Wellbore Construction and Integrity	The well was drilled in 1955. The well has a 139.7 mm, 23.07 kg/m J-55 production casing (collapse of 28 MPa). A surface casing shoe is set 300 m above the BGWP. The cement bond log indicates the top at 1200 m.
Well Location	The wellhead is located 1000 m from a residence with all-season access. There is a major water body within 150 m. The well previously produced from the Cardium formation.
Reservoir Pressure	The reservoir is over pressured at 14.8 MPa.
Wellbore Fluids	The well has Cardium formation water in the tubing and the casing is known to be full to surface.
Offset Stimulation Interference	There are planned drilling and fracture stimulation activities in the Cardium formation within the next eight months. The closest bottom hole proximity is 900 m.
Enhanced Recovery Scheme	The field is under an active water flood with an injection well in the next legal subdivision (400 m) injecting 1,000 m^3 of water/day into the Cardium formation at 15 Mpa.
Subsurface Production Equipment	An Electrical Submersible Pump (ESP) is landed at 1,400 m.
Hydrates	No hydrates.
Surface Equipment	A 3k single master valve wellhead was inspected within the last year and found in good condition. The flowline is disconnected, and the power to the ESP's transformer/variable frequency drive unit has been disconnected.

Risk Assessment

This well is assessed as a **high risk**. This well has several escalation factors, such as corrosive fluids in the tubulars, proximity to an active injection well and proximity to a major water body. Based on Table 5 Risk Levels, at a minimum, one appropriately rated downhole barrier must be installed to suspend the well.

Case Study 10: High Risk

Introduction

This CO_2 injection/disposal well will be shut in for a period of 18 months or more to facilitate land access negotiations with the landowner.

Case Study #10 High Risk	
Risk Categories	**Description**
H_2S Content	200 ppm
Inactivity Duration	18 months
Well Type	Vertical CO_2 Injection/ Disposal. 1900 m True Vertical Depth
Well History	The well was drilled in 2012 and completed as a CO_2 disposal well.
Wellbore Construction and Integrity	There are documented cement returns to surface. The surface casing covers the BGWP. The tubing, packer, and casing are pressure competent. There is no SCVF present.
Well Location	The well is in a remote location with all-season access. It is within 200 m of a water body. There are no residents within 5 km.
Reservoir Pressure	The reservoir is over pressured from CO_2 injection.
Wellbore Fluids	The annulus is filled with inhibited fresh water. The tubing is filled with dense phase CO_2.
Offset Stimulation Interference	There is no potential for off-set stimulation interference.
Enhanced Recovery Scheme	Approaching SAGD EOR recovery development in the up-hole zone at 550 m.
Subsurface Production Equipment	The well is completed with a corrosion resistant alloy, permanent packer with tailpipe assembly, a fully functioning TRSCSSV, and bare L-80 tubing.
Hydrates	There is potential for hydrates to form.
Surface Equipment	Conventional dual master injection tree with surface safety valve. Injection lines are still connected to the wellhead.

Risk Assessment

The well is assessed as a **high risk** due to having eight of 12 risk escalation factors indicating the suspension with downhole barriers is required. Carbon dioxide should be displaced from the well to prevent corrosion then, a plug barrier should be set in the packer tailpipe and the TRSCSSV closed. The annulus pressure should be monitored for thermal expansion from impending SAGD advancement. Based on Table 5 Risk Levels, at a minimum, one appropriately rated downhole barrier must be installed to suspend the well.

Case Study 11: High Risk

Introduction

The well was recently shut in due to a lack of sales infrastructure capacity. Repairs and replacement of infrastructure are expected to take several years assuming all regulatory and landowner approvals can be obtained.

Case Study #10 High Risk	
Risk Categories	**Description**
H_2S Content	The well contains 30% H_2S.
Inactivity Duration	Unknown inactivity duration due to third-party infrastructure.
Well Type	High pressure gas well
Well History	The well has changed ownership several times and has been on production for 10 years.
Wellbore Construction and Integrity	The well records are complete with casing inspections and bond logs completed within the last three years showing good casing integrity.
Well Location	The well is less than 5 km from a major urban center.
Reservoir Pressure	The reservoir pressure is sufficient for gas to flow to surface.
Wellbore Fluids	The wellbore fluids are not known to be corrosive.
Offset Stimulation Interference	The well is in an area of high fracture stimulation activity.
Enhanced Recovery Scheme	There is no current enhanced recovery in this area.
Subsurface Production Equipment	The well was completed with production tubing and a packer set just above the completed zone.
Hydrates	The well has the potential to form hydrates.
Surface Equipment	The wellhead equipment is in good condition and rated at 10 000 pounds per square inch (psi).

Risk Assessment

This well is assessed as a **high risk** due to several escalating factors. Based on Table 5 Risk Levels, a barrier will be installed as soon as possible.

Appendix D: Glossary

AER Alberta Energy Regulator

AMPP Association for Materials Protection and Performance

ANSI American National Standards Institute

Base of Groundwater Protection (BGWP) As per AER: “The base of groundwater protection (BGWP) is the best estimate of the elevation of the base of the formation in which non-saline groundwater occurs at that location. However, local variations in geology and topography are typical, so the actual elevation of the base of the designated formation can often vary from what is provided in the BGWP tool.”

BCER British Columbia Energy Regulator

BOP Blow Out Preventer

BPV Back Pressure Valve

CAOEC Canadian Association of Oilwell Energy Contractors

CAPP Canadian Association of Petroleum Producers

CBL Cement Bond Log

CCUS Carbon Capture Utilization and Storage

CO_2 Carbon dioxide

CSS Cyclic Steam Stimulation

DACC Drilling and Completions Committee

Decommissioned Well A decommissioned well is permanently taken out of production as per the requirements of IRP 27: Wellbore Decommissioning and the local jurisdictional regulator.

DDS Digital Data Submission

EOR Enhanced Oil Recovery

EPAC Explorers & Producers Association of Canada

ESP Electric Submersible Pump

FPZ Fracture Planning Zone

GM Gas Migration

H_2S Hydrogen Sulphide

Inactive Well An inactive well has no recordable flow for 12 months (six months for wells designated as critical/special sour by the local jurisdictional regulator).

IRP Industry Recommended Practice

ISO International Organization for Standardization

Kg/m Kilograms Per Metre

Km Kilometre

MAWP Maximum Allowable Wellhead Pressure

MAWHIP Maximum Allowable Wellhead Injection Pressure

MPa MegaPascal

mm millimetre

m^3 Cubic Metre

NACE National Association of Corrosion Engineers (NACE International)

> **Note:** NACE International merged with The Society for Protective Coatings to form the Association for Materials Protection and Performance (AMPP) in 2021.

N/A Not Applicable

PPM Parts Per Million

PNG Petroleum Natural Gas

PSI Pounds Per Square Inch

SAGD Steam Assisted Gravity Drainage

SCSSV Subsurface Controlled Subsurface Safety Valve

SCVA Surface Casing Vent Assembly

SCVF Surface Casing Vent Flow

Shut-in Well A shut-in well that is secured on the surface but does not require a downhole barrier for isolation either by regulation or risk assessment. There are no wellhead leaks, and the well is isolated.

Suspended Well A suspended well that is secured on the surface with at least one downhole barrier in place and complies with the local jurisdictional requirements for suspension (e.g., based on well type and risk level). There are no wellhead leaks requiring repair as per the regulations and the well is isolated.

TRSCSSV Tubing Retrievable Surface Controlled Subsurface Safety Valve

Uncompleted Well A well which was drilled, cased, and cemented but not completed (i.e., perforated), usually due to economics, rig availability or lack of associated infrastructure.

WLSCSSV Wire Line Retrievable Surface Controlled Subsurface Safety Valve

Appendix E: References and Resources

DACC References

Available from www.energysafetycanada.com

- IRP 02: Completing and Servicing Sour Wells
- IRP 04: Well Testing and Fluid Handling
- IRP 05: Minimum Wellhead Requirements for wellhead design considerations
- IRP 26: Wellbore Remediation
- IRP 27: Wellbore Decommissioning

Local Jurisdictional Regulations and Information

Alberta

Available from www.alberta.ca:

- Safety Codes Act
- Occupational Health and Safety Code

Available from www.aer.ca

- Directive 013: Suspension Requirements for Wells
- Directive 059: Well Drilling and Completion Data Filing
- Directive 083: Hydraulic Fracturing – Subsurface Integrity
- Directive 088: Licensee Lifecycle Management
- Frequently Asked Questions Directive 013 and Inactive Well Compliance Program, Updated March 11, 2016
- Inactive Well Licence List
- Oil and Gas Conservation Act
- Oil and Gas Conservation Rules
- OneStop (Suspension & Ongoing Inspections Reporting)

British Columbia

Available from www.bclaws.gov.bc.ca:

- Petroleum and Natural Gas Act

Available from www.bc-er.ca:

- Designated Information Submission System
- Dormancy and Shutdown Regulation
- Drilling & Production Regulation
- Emergency Management Regulation
- Energy Resource Activities Act
- Oil and Gas Activity Operations Manual
- Permittee Capability Assessment Program Guidance
- Well Decommissioning Guidelines
- Well Testing and Reporting Requirements Guide

Available from www.worksafebc.com

- Occupational Health and Safety Regulation

Manitoba

Available from www.gov.mb.ca:

- Drilling and Production Regulation
- Informational Notice 21-04, Well Suspension Guidelines
- Workplace Safety and Health Regulations

Saskatchewan

Available from www.saskatchewan.ca:

- Directive S-01 Saskatchewan Upstream Petroleum Industry Storage Standards
- Directive PNG008 – Injection and Disposal Well Requirements
- Directive PNG013 – Well Data Submission Requirements
- Directive PNG015 – Well Abandonment Requirements
- Directive PNG025 - Financial Security Requirements
- Saskatchewan Occupational Health and Safety Regulations

Government of Canada Resources

Available from www.gc.ca or www.canada.ca:

- Canadian Net Zero Emissions Accountability Act

Other References and Resources

- *ANSI/NACE-MR0175-2021/ISO 15156-1:2020. Petroleum and Natural Gas Industries-Materials for Use in H_2S-Containing Environments in Oil and Gas Production*, fourth edition, 2021. Houston, Texas, United States: NACE International