DRILLING AND COMPLETION COMMITTEE

IRP # : 2
Completing and Servicing Sour Wells

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

Volume 2 – 2022

EDITION: 3
SANCTION DATE: 2022 January

CANADIAN ASSOCIATION OF ENERGY CONTRACTORS
CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS
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2.0 Preface

2.0.1 Purpose

The purpose of this IRP is to provide information and recommendations for the completing and servicing of sour wells.

> **Note:** The primary focus in on service rig operations with but the general safety considerations apply to all operations and is included here rather than the specific servicing IRPs noted below.

For information regarding servicing without a service rig refer to the following specific service IRPs on the Energy Safety Canada website:

- IRP 04: Well Testing and Fluid Handling
- IRP 13: Wireline Operation
- IRP 15: Snubbing Operations
- IRP 21: Coiled Tubing Operations
- IRP 26: Wellbore Remediation
- IRP 27: Wellbore Decommissioning

2.0.2 Audience

The intended audience for this IRP is any person or company engaged in completion or service activities on sour wells using a service rig.

It is the licensee's responsibility to ensure these practices are followed.

2.0.3 Scope and Limitations

The scope for this IRP is completing and servicing sour wells with a service rig. It is assumed that other IRPs cover the basics of the servicing operations without a service rig.

The scope includes on-shore operations in the Western Canadian Sedimentary Basin (i.e., British Columbia, Alberta, Saskatchewan and Manitoba).

The scope includes general safety considerations for working with sour that apply to all operations whether with a service rig or not for sour and elevated sour operations. These safety considerations are referenced from the specific IRPs for that service.

The IRP does not cover basic equipment, operational, safety or procedural requirements for non-sour wells. It discusses only what is required above and beyond those basic requirements when dealing with a sour well.

2.0.4 Revision Process

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

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

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

2.0.5 Sanction

The following organizations have sanctioned this document:

Canadian Association of Energy Contractors (CAOEC)

Canadian Association of Petroleum Producers (CAPP)

Petroleum Services Association of Canada (PSAC)

Explorers & Producers Association of Canada (EPAC)

2.0.6 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.

2.0.7 Background

This IRP was originally developed (edition 1) as an Alberta Recommended Practice by the Blowout Prevention Well Servicing Committee (BPWSC) and subsequently updated by the Well Services Review Committee in 2003 (edition 2).

In 2017 DACC had the document reformatted to their new template and style guide then launched a full scope review of the document in 2018 to create edition 3. This full scope review changed the name of the document to remove ‘critical’ from the title and changed the scope of the document to deal with sour servicing operations completed with a service rig. Non-service rig detail can be found in the specific servicing IRPs (i.e., IRP 13: Wireline Operations, IRP 15: Snubbing Operations, IRP 21: Coiled Tubing Operations, IRP 26: Wellbore Remediation and IRP 27: Wellbore Decommissioning). As part of this review the document was updated to define the sour requirements and then the additional (elevated sour) requirements necessary based on release rate and proximity (formerly critical sour in this document). Terminology changed from critical sour to elevated sour to use language that is not jurisdiction-specific. This edition did NOT simply make all of the previously critical sour requirements apply for all sour wells. All IRP statements were reviewed to verify and distinguish between sour and elevated sour requirements.

Some sections of IRP 05: Minimum Wellhead Requirements refer to a producing wellhead as a christmas tree. As part of the Volume 3 revision of IRP 02, all references to christmas tree were changed to wellhead.

2.1 Introduction

IRP 02 provides recommended practices for the planning, equipment and fluid handling for safe completion and servicing operations on sour wells using a service rig. It also covers the elastomer and safety considerations for any servicing operation for a sour well with or without a service rig and provides information about sweeting sour fluids.

The following IRPs can be referenced for more detailed information about specific services or basic requirements for all operations:

- IRP 04: Well Testing and Fluid Handling
- IRP 05: Minimum Wellhead Requirements
- IRP 07: Competencies for Critical Roles in Drilling and Completions
- IRP 13: Wireline Operations
- IRP 15: Snubbing Operations
- IRP 21: Coiled Tubing Operations
- IRP 26: Wellbore Remediation
- IRP 27: Wellbore Decommissioning
- IRP 28: Wellsite Waste Management

The focus for this IRP is the practices and equipment requirements above and beyond those required for non-sour wells. The additional requirements for elevated sour scenarios are identified. The recommendations were created with the following priorities:

- The safety of on-site personnel.
- The safety of the public.
- The protection of the environment.

2.2 Definitions

2.2.1 Sour

Sour wells contain hydrogen sulphide (H_2S). The definition of sour varies depending on how it is being used in the document.

When discussing equipment and manufacturing requirements NACE MR0175/ISO 15158 is the standard and a sour well is one with an H_2S concentration of 0.05 psi partial pressure.

When discussing the protection of workers OH&S regulations are the standard and the exposure limit is 10 ppm.

When discussing license or other regulator designation for a well sour includes any concentration of H_2S.

H_2S can require additional equipment, metallurgic and/or safety considerations above and beyond those required of sweet wells.

Sour gas contains H_2S and may contain carbon dioxide (CO_2) at various partial pressures and ratios. These gases make any aqueous environment acidic and potentially corrosive. In addition, the presence of H_2S may make well servicing materials, both surface and downhole, susceptible to environmental embrittlement mechanisms.

In thermal and Steam-Assisted Gravity Drainage (SAGD) environments, the combination of high temperature and H_2S introduces another level of complexity to the well servicing operations. Special considerations include, but are not limited to, the following:

- Scrubbing and venting requirements in sour heavy oil operations.
- Wellhead requirements for observation and stratigraphic wells in the not-yet-steamed areas.
- Accelerated corrosion rate due to thermal activities.
- Well control complications of non-brine kill fluid (due to processing plant restriction), non-condensable gas (NCG) injection and response measures (e.g., sour gas ignition with low gas-oil ratio wells and heavy oil shear ram requirements).

Refer to IRP 03: In Situ Heavy Oil Operations for more information about the implications of sour operations in the thermal environment.

2.2.2 Elevated Sour

The H_2S release rate (RR) and/or proximity to population or habitation may trigger a further increase (elevation) in response, equipment or safety requirements. The regulatory definition of sour, the triggers for elevation in sour requirements and the terminology used to describe the elevation in sour requirements vary by jurisdiction. Alberta and Saskatchewan regulations refer to wells with the elevated requirements as critical sour while British Columbia regulations refers to them as special sour.

IRP 02 uses the generic terminology of elevated sour to identify wells that meet the elevation triggers in order to move away from jurisdiction-specific terminology and to avoid confusion with critical tasks, critical servicing and critical roles.

The sections below identify the definitions and triggering criteria by jurisdiction. Other triggering criteria may include the following:

- Occupational Health and Safety (OH&S) regulations for H_2S exposure
- Licensee specific practices
- Service company specific practices

2.2.2.1 Alberta

The Alberta Energy Regulator (AER) defines sour wells as a well with hydrogen sulphide (H_2S).

Sour wells with increased requirements are called Critical Sour. Their definition (from AER D056: Energy Development Applications and Schedules) is as follows.

“The AER designation of a well for drilling purposes with an H_2S release rate greater than or equal to 2.0 m^3/second or other wells with a lesser H_2S release rate in close proximity to an urban centre.”

The proximity criteria are as follows:

- RR >0.01 m^3/s but <0.1 m^3/s and the well is located within 500 m of an urban centre
- RR >0.1 m^3/s but <0.3 m^3/s and the well is located within 1.5 km of an urban centre
- RR >0.3 m^3/s but <2.0 m^3/s and the well is located within 5.0 km of an urban centre

The AER definition of an Urban Centre is as follows:

“A city, town, village, summer village, or hamlet with no fewer than 50 separate buildings, each of which must be an occupied dwelling, or any similar development the AER may designate as an urban centre.”

The AER definition of a surface development is as follows:

“Dwellings that are occupied full time or part time, publicly used development, public facilities such as campgrounds and places of business, and any other surface development where the public may gather on a regular basis. Includes residences immediately adjacent to the EPZ and those from which dwellers are required to egress through the EPZ.”

2.2.2.2 British Columbia

The BC Oil and Gas Commission (BCOGC) defines sour wells (in the BCOGC Glossary) as follows:

“Sour gas: Sour gas is natural gas that contains measurable amounts of hydrogen sulphide (H_2S).

“Sour crude oil: Processed and/or dehydrated sales oil for refinery feedstock in which the effective hydrogen sulphide partial pressure exceeds 0.3kPa at the bubble point absolute pressure.”

Sour wells with increased requirements are called “Special Sour”. Their definition (from the BCOGC Operations Manual) is as follows.

“The criteria for a special sour well in B.C. are:

- *Any well from which the maximum potential H_2S release rate is 0.01 m^3/s or greater and less than 0.1 m^3/s and which is located within 500 metres of an urban center.*
- *Any well from which the maximum potential H_2S release rate is 0.1 m^3/s or greater and less than 0.3 m^3/s and which located within 1.5 kilometres of an urban center.*
- *Any well from which the maximum H_2S release rate is 0.3 m^3/s or greater and less than 2.0 m^3/s and which is located within five kilometres of an urban center.*
- *Any well from which the maximum potential H_2S release rate is 2.0 m^3/s or greater.*
- *Any other well which the Commission classifies as a special sour well having regard to the maximum potential H_2S release rate, the population density, the environment, the sensitivity of the area where the well would be located, and the expected complexities during the drilling phase.”*

The BCOGC asks that the following be completed on their Sour Well Information Form:

- Nearest occupied dwelling
- Nearest urban centre
- Nearest school
- Nearest populated area (km)

The BCOGC does not have a definition of urban centre in their glossary.

2.2.2.3 Saskatchewan

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

- The distance of the well from an urban municipality, occupied dwelling or public facility
- The well's maximum potential H_2S release rate.

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

- Maximum potential H_2S RR >2.0 m^3/s
- Maximum potential H_2S RR >0.3 m^3/s but <2.0 m^3/s and the well is located within 5.0 km of an urban municipality, occupied dwelling or public facility
- Maximum potential H_2S RR >0.1 m^3/s but <0.3 m^3/s and the well is located within 1.5 km of an urban municipality, occupied dwelling or public facility
- Maximum potential H_2S RR >0.01 m^3/s but <0.1 m^3/s and the well is located within 500 m of an urban municipality, occupied dwelling or public facility

2.2.3 Sour vs. Elevated Sour in IRP 02

This document defines the requirements for all sour wells and operations then specifically identifies the additional requirements for elevated sour situations using the elevated sour terminology.

2.2.4 H_2S Concentration

The H_2S concentration is important for determining the appropriate safety equipment (e.g., PPE, monitoring, etc.) and procedures to protect personnel as per OH&S regulations and for determining the Emergency Planning Zone (EPZ). See 2.12.6 H_2S Monitoring for more information about determining concentration.

H_2S can react with rust or corrosion deposits on equipment to form iron sulphide. This reaction occurs in an oxygen free atmosphere where hydrogen sulphide gas is present or where the concentration of hydrogen sulphide is greater than that of oxygen. This happens most often in closed vessels, tanks or pipelines. Iron sulphide is a pyrophoric material (i.e., it can ignite spontaneously when it is exposed to air).

High concentrations (between 4.3% and 46% of gas by volume in air as per Alberta OH&S Regulations) can catch fire and explode if there is a source of ignition. When the gas is burned, other toxic gases such as sulphur dioxide (SO_2) are formed. H_2S is incompatible with strong oxidizers such as nitric acid or chlorine trifluoride and may react violently or ignite spontaneously. When H_2S is released into the air it will form SO_2 and sulphuric acid in the atmosphere.

2.3 Planning

Servicing sour wells comes with inherent risks due to the sour fluids. This impacts the equipment, metallurgic and safety requirements that need to be covered during planning.

The demands placed on those involved in planning a sour workover or completion operation are higher than those for non-sour operations due to the inherent complex nature of the operation, the increased risk from the sour fluids and the public impact of the operation.

IRP The licensee shall address any hazards and complications, actual or potential, for all sour well servicing operations in the job plan. This is particularly important in elevated sour wells or wells with high H_2S concentration.

IRP Planners shall have the technical, organizational and operational competence to plan the sour operation.

CSA Z246.2 Emergency preparedness and response for petroleum and natural gas industry systems is a good resource for emergency response planning that meets federal and provincial requirements.

2.3.1 Risk Assessment

IRP A hazard and risk assessment to identify all of the risks, for both licensee and service provider operations, shall be completed and mitigations shall be included in the planning for the operation.

IRP 02 does not prescribe any specific risk assessment methodology but does include a template for a 5x5 Risk Matrix that can be used for the risk assessment. Samples completed for a licensee and a service provider have also been included. These templates can be found in Appendix B.

2.3.2 Emergency Planning Zone

The EPZ is a geographical area surrounding a site (i.e., well, pipeline or facility) containing hazardous product that requires specific emergency response planning by the licensee in order to ensure the safety of the public near the site.

IRP The licensee must define an EPZ and follow local jurisdictional regulations for determining the EPZ.

Consider the following:

- Site-specific features of the area.
- Information from public consultations.
- Population density.
- Topography.
- Access/egress routes through the EPZ.
- Potential H_2S release rate.

IRP EPZ information shall be made available to all service providers involved in operations.

2.3.3 Emergency Response Plan

The licensee's Emergency Response Plans (ERP) identify the procedures that are to be in place in order to appropriately respond to an emergency situation at the wellsite. Well servicing operations may have their own emergency response procedures specific to their service but still have to follow the licensee ERP.

> **Note:** Sour operations have different external concerns to be managed than a non-sour operation (e.g., air monitoring requirements, air supply for operations or rescue operations, emergency access and egress, etc.). See 2.12 Safety for more information about H_2S specific requirements.

IRP The licensee shall have an ERP in place for all sour servicing operations and the ERP shall identify the procedures and equipment to protect workers, the public and the environment.

IRP The ERP must meet the criteria identified by the local jurisdictional regulator.

IRP For an elevated sour servicing operation, a site-specific ERP shall be created for the service being provided and the ERP shall be reviewed with on-site personnel before work begins.

IRP For an elevated sour servicing operation, site-specific procedures shall be reviewed with on-site personnel before work begins to ensure adequate personnel are available to satisfy the ERP requirements.

IRP An up-to-date ERP should be in place for all completions and servicing operations.

2.3.4 Information for Service Providers

Accurate documentation for all parties involved in on-site operations is important for ensuring a safe operation.

IRP Wellsite information, the well's regulatory classification, well history and documentation shall be made available to all service providers.

IRP Calculated values for shut-in tubing head pressure (SITHP) shall be made available to all service providers.

2.3.5 Wellsite Equipment

IRP The operational plan shall identify all the necessary equipment (operational and safety) to ensure safe operations.

Requirements are identified in the following sections:

- 2.4 Wellheads
- 2.5 Well Control Equipment
- 2.6 Downhole Equipment
- 2.7 Tubular Goods
- 2.8 Fluids and Circulating Systems
- 2.11 Elastomers
- 2.12 Safety

2.3.6 Wellsite Personnel

2.3.6.1 Competency

IRP Individuals involved in the operation, from the licensee or other service providers, shall be deemed competent to participate in the tasks required during the operation (as defined in IRP 07: Competencies for Critical Roles in Drilling and Completions).

Note: Participants may work alone or, if in training, under the direct supervision of another competent worker (with the trainee being assigned a designated mentor).

IRP The individual's competency shall have been evaluated using a competency evaluation program for the role they have in the operation (as per IRP 07: Competencies for Critical Roles in Drilling and Completions).

For personnel in critical roles (as defined in IRP 07: Competencies for Critical Roles in Drilling and Completions), the licensee may require additional experience levels in sour and elevated sour operations in some situations (e.g., based on anticipated pressures or in deep sour wells).

IRP Worker competency requirements shall be identified as part of the planning process.

IRP The licensee shall confirm worker competence (both licensee and service provider) prior to commencing operations.

2.3.6.2 Supervision

IRP The licensee shall provide adequate and competent supervision for the operation.

This may require multiple on-site representatives (e.g., wellsite supervisors, H_2S Safety Supervisors, mentors, etc.).

See IRP 07: Competencies for Critical Roles in Drilling and Completions for more information about supervision and competency requirements.

2.3.6.3 Availability

IRP The licensee representative (wellsite supervisor) shall be on site during all active sour well operations

IRP The licensee shall designate a secondary licensee representative who will be the primary contact in the event the primary licensee representative is unavailable. This shall be documented in the ERP.

IRP The rig manager or a competent designate shall be on site during all active sour service rig operations.

IRP A minimum 4-man rig crew for each shift shall be in place during all sour rig operations.

2.3.7 Wellsite Responsibilities

2.3.7.1 Licensee Representative (Wellsite Supervisor)

IRP The licensee representative shall be responsible for ensuring the appropriate personnel and equipment are on site to manage the ERP in the event of an incident.

IRP The licensee representative shall be responsible for verification that the appropriate H_2S safety equipment has arrived on site.

IRP The licensee representative shall have an understanding of flaring regulations and SO_2 dispersion (as per flaring permit).

IRP The licensee representative shall be responsible for verification that the certification and configuration of all equipment is suitable for sour operations for the jurisdiction.

IRP The licensee representative shall ensure that all fit for duty requirements are followed

2.3.7.2 Service Provider Representative(s)

IRP The service provider representative(s) shall follow the licensee ERP and work with the licensee to ensure they are able to respond to the conditions of the ERP in terms of equipment and personnel (e.g., field level hazard assessments, job/task hazard assessments, standard operating procedures, etc.).

2.4 Wellheads

IRP 05: Minimum Wellhead Requirements identifies minimum wellhead requirements to be followed. This section covers the recommended practices above and beyond what is required in IRP 05 in order to complete, workover or remediate sour wells with a service rig.

IRP All wellhead components must be suitable for sour service and NACE MR0175/ISO 15156 compliant.

IRP All wellhead components shall, at minimum, comply with IRP 05: Minimum Wellhead Requirements.

The following topics are covered in IRP 05: Minimum Wellhead Requirements:

- Configurations
- Components
- Manufacturing and Material Requirements
- Pressure Testing
- Inspections and QA
- Wellhead Protection

2.4.1 Flowing Wells

Flowing wells include single, dual and hot oil circulating wellheads.

IRP For wells where the annulus valve is used in process, an additional annular valve should be installed to provide unimpeded access to the annulus at all times.

2.4.2 Sour Pumping Wells

Pumping sour wellheads require different components than standard pumping wells (see Figure 1 below). See the sections on Critical Sour, Sour and Corrosive Wells and Artificial Lift Wells in IRP 05: Minimum Wellhead Requirements for more information.

IRP A pumping well that is sour or is capable of flowing to surface should be equipped with a dual packing pollution control stuffing box. Including a master valve and/or a double ram rod blowout preventer (BOP) with hydraulic control on the pumping wellhead should also be considered.

IRP Fittings upstream of the emergency shutdown (ESD) valve shall be flanged or studded.

IRP The pressure switch or pilot to activate the ESD valve and to shut down the pump jack should be located between the pumping tee or cross and the ESD valve.

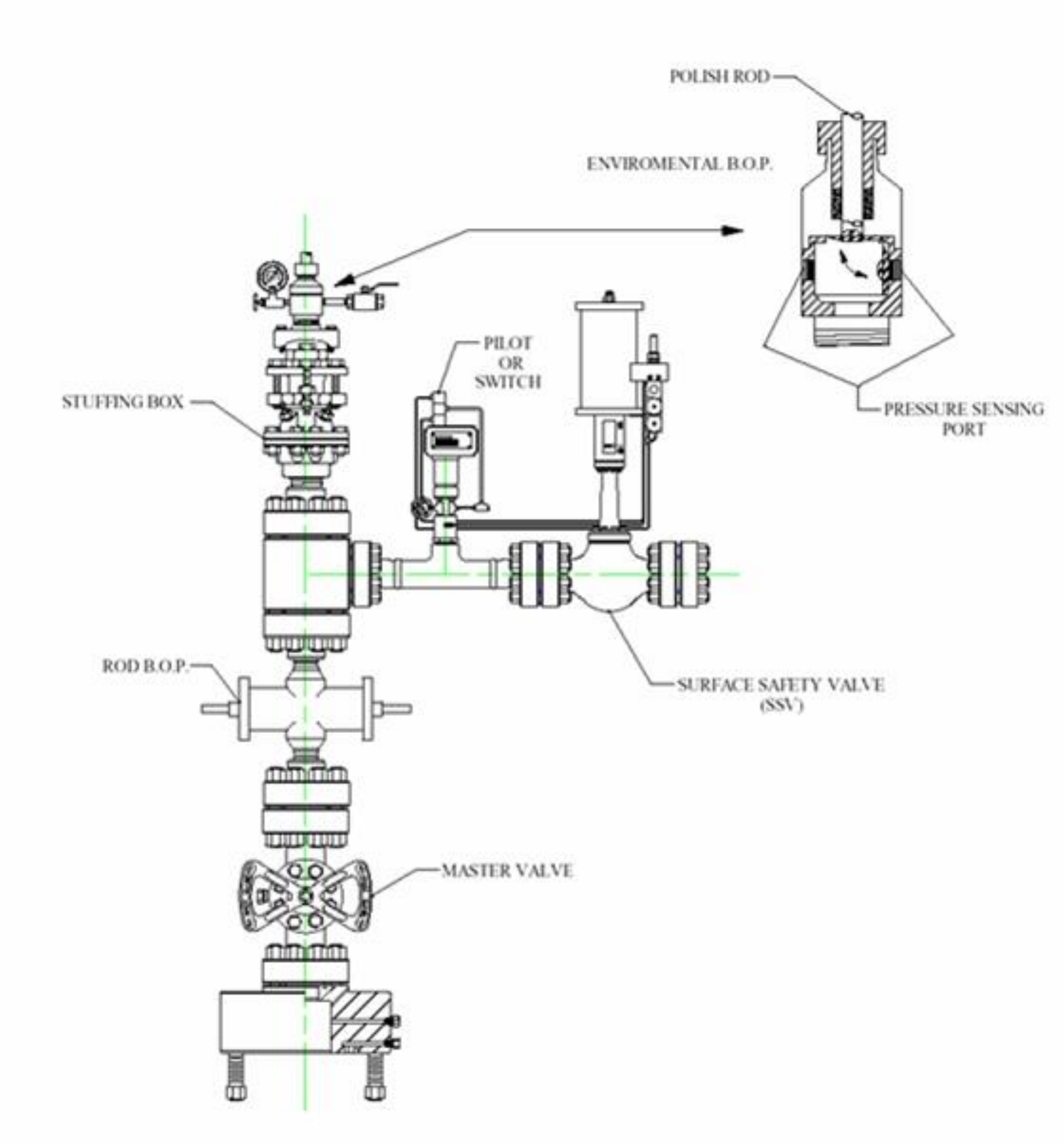
IRP A flanged master valve shall be utilized in conjunction with the rod BOP for use in workovers or jobs with polished rod failures.

IRP Wellheads for elevated sour wells shall be equipped with a dual packing pollution control stuffing box or a shut-in device (e.g., check valve) shall be installed in the vertical run of a pumping wellhead (such as the environmental BOP in Figure 1) to prevent an H_2S release to atmosphere in the event of a polished rod break.

The environmental BOP has two primary functions:

1. To provide a seal across the bore in the event of a polished rod failure (e.g., by a spring-loaded flapper).
2. To detect stuffing box leaks and shut down the pump jack by equipping a pressure switch at the pressure sensing port.

Figure 1. Typical Sour Pumping Wellhead Configuration



2.4.3 Wellhead Safety Shutdown Systems

IRP All wells to be flowed with a surface pressure greater than 1379 kPa and H_2S content greater than 1% shall have an ESD valve (as per IRP 04: Well Testing and Fluid Handling).

IRP All elevated sour wells on production and capable of flowing to atmosphere shall be equipped with an ESD valve.

IRP The ESD valve shall have an API maximum working pressure rating (MWPR) equal to or greater than the bottomhole pressure of the producing formation.

IRP The ESD valve should be immediately downstream of the wing valve and pressure switch (if used).

IRP ESD valves should be ‘fail-safe closed’ (i.e., control line pressure open, flowline pressure with spring assisted close).

Fusible plugs can be installed in the ESD valve control line to fail-close the valve in case of fire.

The ESD valve may be either direct-controlled, sensing pressure change at the valve, or remote-controlled, where sensing devices are remotely located at various high risk areas throughout the system.

IRP Remote controlled ESD valves should be used for elevated sour wells.

IRP Where an ESD valve is installed in conjunction with a surface controlled subsurface safety valve (SCSSV), the ESD valve should close before the SCSSV to reduce wear of the SCSSV.

IRP High/low pressure pilots should be installed downstream of the wellhead ESD valve.

Multi-pilots (sensing other parameters) can be utilized to activate the wellhead ESD valve. Placement of these pilots is dependent on the licensee's surface facilities.

2.4.3.1 Production Testing – Temporary Facilities

IRP ESD valves shall be installed on the wellhead during all sour production testing operations.

IRP The mode of actuation for the ESD valve should be pneumatic (i.e., air to open, spring assisted close).

IRP Supply gas should be dry and non-flammable, preferably nitrogen.

IRP Control lines should be rubber or plastic to enable easy interruption of gas supply. An exception would be the use of steel lines where there are operations that could damage the rubber or plastic hoses.

IRP A minimum of three remote shut-down actuators should be located along common paths on the lease site. Recommended locations are as follows:

- The office trailer(s)
- The testing unit
- An additional upwind location

Remote shut-down actuators are manual and can be actuated to shut in the well if there is a release.

IRP The location of remote shut-down actuators must be clearly identified (e.g., by flags or signs). All workers on site need to be made aware of the location of the remote shut down actuators.

IRP Function testing of all remote and automatic ESD valves shall be performed prior to initial start-up.

IRP ESD valves should fully close in less than 30 seconds.

IRP Remote shut down function tests should be performed daily except where it would disrupt/interfere with production testing requirements, in which case the test could be done at an alternate time (e.g., during a rate change).

IRP Visual inspection of the ESD valve and shut-down system should be performed daily.

IRP Prior to the start of testing operations, all equipment upstream of the chokes, including the ESD valve, shall be pressure tested to a minimum of 1.1 times the SITHP but not exceeding the maximum working pressure of the equipment.

IRP The ESD valve and other equipment upstream of the choke should be pressure tested to their rated working pressure.

2.4.3.2 Production Testing - Permanent Facilities

IRP Except for pumping wells, sensing devices for automatic shut in should be downstream of the ESD valve.

Mode of actuation may be pneumatic, hydraulic or electric depending on well requirements and licensee preference.

IRP Supply gas lines and fittings should be AISI 316 stainless steel or equivalent.

IRP The ESD system should include, but not be limited to, high/low line pressure detection.

IRP Permanently attached lock-open devices shall not be used on ESD valve actuators.

IRP Function testing should be performed monthly.

IRP A differential pressure test should be performed every three months to test for leaks.

IRP The results of function tests and differential pressure tests should be recorded.

> **Note:** Function testing and leak testing are not required for shut in or suspended wells.

IRP When temporary lock-open devices are used on sour wells (i.e., during well maintenance) they shall be heat-sensitive lock-open devices.

IRP Heat-sensitive lock-open devices shall be able to maintain the ESD in the fully open position at atmospheric temperatures up to 65 °C (150 °F) with the valve body pressurized to its rated working pressure and the actuator supply pressure bled to atmospheric conditions. The lock-open device shall be designed such that any part released upon actuation of the device shall not create a potential hazard to personnel.

IRP The lock-open device shall allow the valve to automatically close from actuator forces alone (i.e., no pressure in the valve body or energy supply to the actuator cylinder) within 6 minutes after being subjected to, and maintained in, a controlled environmental temperature of 540 °C ± 14 °C (1000 °F ± 25 °F).

IRP Eutectic materials used shall meet the manufacturer’s design requirements for fusing within a temperature range of ± 10 % around the nominal melting point. The heat-sensitive device shall be designed to actuate at a maximum sustained temperature of 200 °C (400 °F).

See API Spec 6A for more information.

2.4.4 Moving a Service Rig On or Off the Well

The recommendations in this section apply to perforated sour wells capable of production both prior to moving a service rig onto the well and when rigging down and moving a service rig off the well.

IRP **The well shall be shut in with the surface lines isolated and depressurized.**

IRP **H_2S shall be purged or flushed from surface lines.**

IRP **Valve removal thread shall only be used as a temporary barrier to allow replacement of annulus valve and shall not be used for applications such as permanent well barrier or chemical injection..**

2.4.5 Wellhead/BOP Removal

The producing formation needs to remain isolated at all times during BOP and/or wellhead removal.

IRP **At least two competent barriers shall be in place before the wellhead/BOP is removed from a flowing well, with at least one of them tested. The barriers shall be in place until the wellhead/BOP is installed.**

IRP **When the BOP is installed there shall be two competent barriers available.**

The following types of barriers can be considered:

- An appropriate density kill fluid that can be used to load or kill the well.
- A backpressure valve (BPV) could be installed in the tubing hanger.
- A downhole isolation plug (e.g., wireline plug) could be set.

IRP **If kill fluid is the secondary barrier, the downhole isolation plug shall be set at a depth that provides sufficient hydrostatic pressure above the plug. If hydrostatic pressure is insufficient a second plug shall be used.**

IRP **If used, the downhole isolation plug shall have both a positive and negative pressure test. A positive test shall be 7000 kPa differential. The negative test shall be to the maximum differential available or 7000 kPa.**

IRP **Dual barriers are not possible for elevated sour wells on rod pump so the well shall be loaded with an appropriate density kill fluid and flow checks shall be completed prior to removal of the wellhead.**

IRP During wellhead or BOP removal, a stabbing valve assembly must be available and meet the following criteria:

- Have a working pressure rating greater than the shut-in wellhead pressure.
- Be rated for sour service.
- Be equipped with the correct tubing threads. Crossovers may be used but should have the proper inside diameter to allow for well control.

IRP The stabbing valve assembly, including tubing threads, should be inspected and checked for functionality prior to removing the wellhead or BOP.

2.4.6 Stimulation

IRP The maximum allowable stimulation treatment pressure (e.g., sand or acid fracture, acid squeeze) should be designed based on equipment and operational condition.

IRP All wellhead valves exposed to acid stimulation should be opened, closed and greased after completion of an acid job.

For more information about fracture heads see IRP 05: Minimum Wellhead Requirements.

2.4.7 Wellhead Isolation Tools

Wellhead isolation tools isolate the master valves and/or BOP components with the ability to shut in the well if the isolation tool fails.

IRP Wellhead isolation tools should not be used in sour applications unless mitigation procedures are put in place to prevent a release to atmosphere.

IRP If a wellhead isolation tool is to be used, the following shall be completed/verified:

- A risk assessment of the use of the wellhead isolation tool.
- Verification of elastomers and seals suitability for sour service.
- A risk assessment of where the vented well fluids are sent in the event of a seal failure.
- Securement of the bleed off line.
- Shop pressure testing to a minimum of 1.5 times the rated working pressure before every job.
- Inspection, greasing and pressure testing of plug valves after every job.
- Logging of all parts, their material and date of servicing.

- Use of flanged or clamped connections between the wellhead isolation tool and the fracture iron.

IRP All seals should be replaced after any H_2S service.

IRP During well work, pressure shall not exceed 90% of the rated working pressure of the wellhead isolation tool.

IRP If a hammer union is required its pressure rating must be consistent with fracture iron pressure ratings.

Refer to the Wellhead Isolation Tools section in IRP 05: Minimum Wellhead Requirements for more information about isolation tools.

2.4.8 Wellhead Grease

IRP The grease used for wellhead service should be suitable for sour operations and be serviced and maintained as per manufacturer specifications.

2.5 Well Control Equipment

Much of the information in this section is covered in BOP training courses and matches regulations set out in AER D037: Service Rig Inspection Manual. Refer to either resource for more information.

IRP All well control equipment must be suitable for sour service and NACE MR0175/ISO 15156 compliant.

IRP Casing condition shall be considered prior to setting the test pressure.

Consider expected pressures during well kill and treatment operations.

IRP The annulus between the production casing and tubing should be pressure tested to a minimum of 1.1 times the SITHP but not exceeding the maximum working pressure of the equipment

2.5.1 BOP Stack

IRP In all cases, the BOP system must be as per local jurisdictional regulations and sized to accommodate the completion string components or work string being used.

The annular preventer is considered to be the system backup.

2.5.1.1 Ram Requirements

Residential density (Table 3) and complexity levels (Table 4) are used to determine whether shear blind rams are required for the well servicing operation (Table 2). Complexity levels are based on complexity factors (Table 5) of formation complexity, operational complexity and H_2S content.

IRP Shear rams shall be used where operational complexity and residential density analysis indicate a high level risk factor during a completion or workover (see Table 2).

IRP Where Table 2 indicates shear blind rams are to be considered, the following should be assessed:

- The complexity of the operations to be conducted.
- The risk of problems occurring during the operation.
- The adequacy of procedures and equipment to prevent or mitigate problem.
- The feasibility of evacuating on site personnel and nearby residences in the event of a release.

Table 2. Shear Blind Ram Requirements

Complexity Level	Residential Density			
	1	2	3	4
1	Not Required	Not Required	Considered	Considered
2	Not Required	Not Required	Considered	Considered
3	Not Required	Considered	Considered	Considered
4	Considered	Considered	Required	Required

Table 3. Residential Density

Value	Description
1	No residences within the emergency planning radius and no urban center or public facility within five km.
2	Eight or fewer residences within the emergency planning radius and no urban center or public facility within 5 km.
3	32 or fewer residences within the emergency planning radius and no urban center or public facility within 1.5 km.
4	More than 32 residences in the emergency planning radius or urban center or public facility within 1.5 km.

Table 4. Complexity Levels

Formation Complexity	Operational Complexity	H_2S Content	Complexity Level
High	High	High	4
High	High	Low	4
High	Low	High	3
High	Low	Low	3
Low	High	High	3
Low	High	Low	2
Low	Low	High	2
Low	Low	Low	1

Table 5. Complexity Factors

Group	Primary Factors	Secondary Factors	Specifics
Formation	Geologic Confidence		Uncertainty in pressures, permeability or inflow potential
	Pressure		Kill difficulties at pressure gradients > 9.81 kPa/m or BHP > 70 MPa
	Permeability/ Fractures		Difficulty in maintaining kill fluid column with fractures or high permeability
		Inflow Potential	High consequences if well not killed
		Adjacent Recovery Methods	Pressure anomalies due to waterflood, gas injection or tertiary recovery
		Formation Stability	Problems with high fines production/abrasion
		Condensates	Complexities in kick detection and control procedures
		Temperature	Sealing difficulties at formation temperature >125ºC
Operations	Downhole Configuration • Small diameter restrictions • Abrupt diameter restrictions • Quantity of tools/ • equipment		• Size/space restraints and increased swabbing potential at OD < 114 mm • Difficulties with liners • Size/space restraints and complexity of installation/ servicing/removal
	Program of Operations • Stimulations • Stripping and snubbing		• Material stress considerations • Number and difficulty of operations
	Wellbore Condition • Primary cement quality • Casing burst vs reservoir pressure • Casing integrity • Corrosion • Restrictions		• limitation on packer placement • loss of shut-in capability if pressure exceeds casing burst limitations on shut-in pressure • CO_2 or brine content • Waxing, hydrating, scaling
	Depth		Difficulties at > 3500 m

Group	Primary Factors	Secondary Factors	Specifics
	Deviation		Difficulties at deviations > 20º or doglegs > 50/30
	Workover Fluids • Gas solubility • Safety aspects		• Higher solubility with oil base • Increased danger with flammable fluids
H_2S Content	High H_2S		H_2S content >20%
		Low H_2S	H_2S content <20%

Note: If any one of the primary complexity factors for the specific complexity group is applicable then the group is rated as high complexity. Judgment is necessary when evaluating the effect of the secondary factors with respect to the rating for the group.

2.5.1.2 Ram Configuration

IRP Where shear rams are required (as per Table 2) the configuration shall be as shown in Figure 2 below. In this configuration the shear ram is an accessory to a fully-equipped sour service BOP stack.

IRP A shear/blind ram (Figure 3 below) shall be considered an alternative in place of a conventional blind ram.

IRP With this configuration a ram blanking tool must be available on location to provide a back up to the sealing capabilities of the blind ram.

IRP Ram blanking tools shall not be used in annular preventers unless the preventer design specifically allows for their use and the dimensions of the ram blank are such that it can be used safely.

Blanking tools can not be used with spherical type annular preventers.

Ram blanking tools can significantly increase the operational risk if used improperly. Refer to manufacturer specification for details about installation and use.

Figure 2. Elevated Sour Well Servicing BOP Stack with Shear Blind Ram

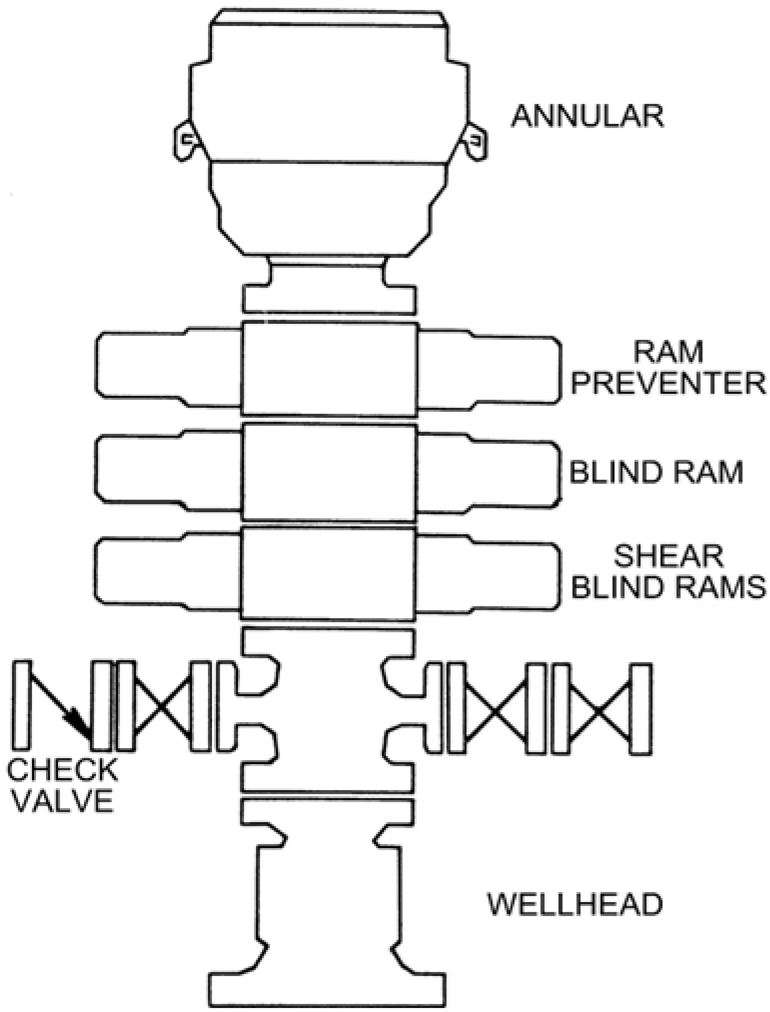
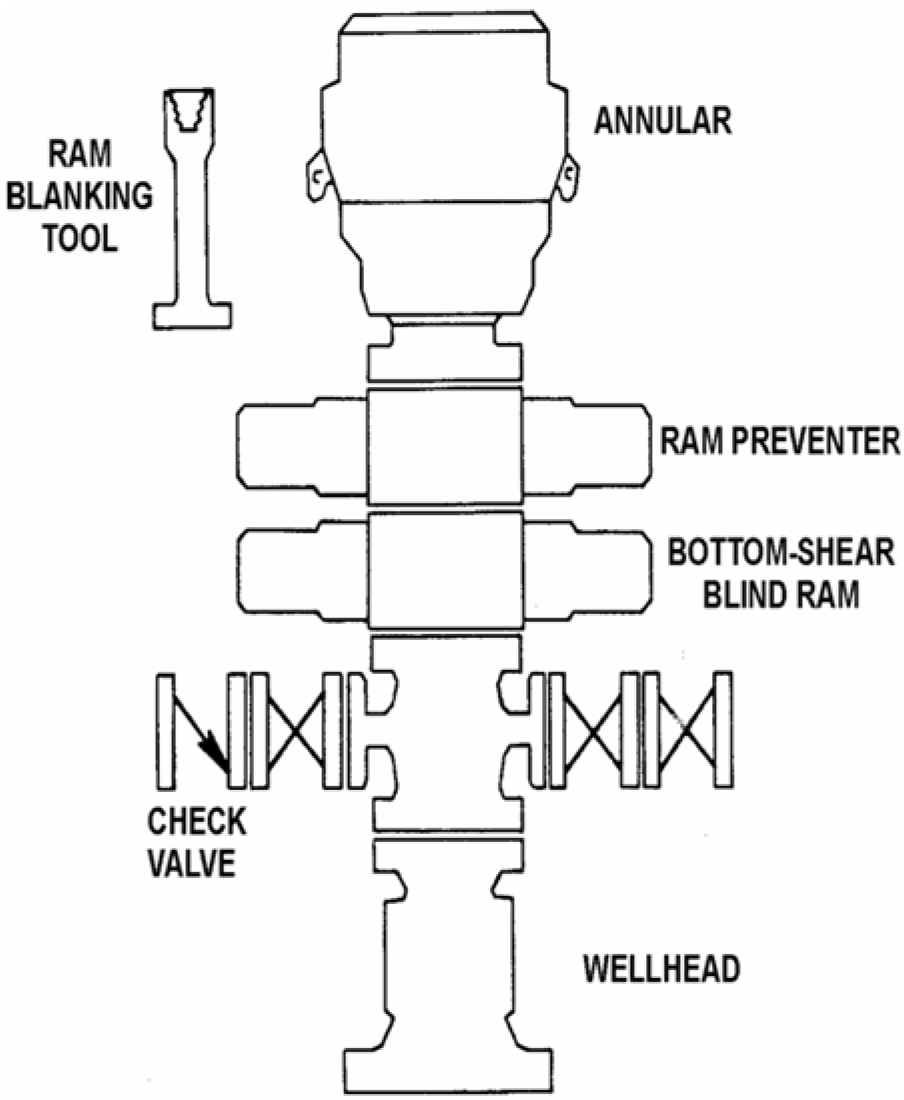


Figure 3. Elevated Sour Well Servicing BOP Stack with Shear Blind Ram Optional Configuration



2.5.1.3 Spools

BOP spools are required to couple the BOP to the tubing head adapter spool (wellhead component) and to provide access to the wellbore or tubing/casing annulus.

IRP Flanged BOP working spools with two flanged side outlets shall be used for elevated sour wells.

IRP BOP ram side outlets should not be used.

Additional spools may be used where BOP configurations are more complex than the regulatory minimum configurations.

IRP Primary BOP connections should be kept to a minimum.

IRP The number of spools should be kept to a minimum to reduce potential leak points and complexity.

IRP All spools must conform to applicable API and NACE MR0175/ISO 15156 standards. See AER D036 Appendix 5 and Appendix 16 for more information.

IRP Working spool outlets must include full opening gate valves to serve as primary control.

IRP The kill side shall include a primary valve and a check valve.

IRP The bleed off line shall have a primary and a secondary (back-up) valve.

IRP The valves shall be rated to a working pressure equal to or greater than the BOP.

IRP Where sour fluids are being circulated or flowed from the well, the bleed off line shall include a remotely actuated surface safety valve.

2.5.2 Manifolding

IRP The service rig pump manifold shall not be used as a well control manifold for recovering sour fluids.

IRP A sour service separator and combustion system (e.g., flare stack, incinerator, etc.), including appropriate manifolding (based on pressure rating, sizing, etc.), must be used to process sour well effluent.

See IRP 04: Well Testing and Fluid Handling for more information about handling sour fluids and 2.8 Fluids and Circulating System for recommendations regarding equipment requirements for handling fluids for sour well operations.

2.5.3 Accumulator

2.5.3.1 Sizing

It may be the case that shearing the completion or work string in use places greater capacity demands or pressure requirements on the accumulator than the regulatory requirements. This needs to be considered when sizing the accumulator on an elevated sour well.

IRP **Where a shear ram is used (in addition to the required BOP stack, see Figure 2) the accumulator shall be sized to either operate the required BOP as per applicable local jurisdictional regulations or shear the completion string without recharge, whichever is the greater volume.**

IRP **Where the shear/blind ram replaces the blind ram in the required BOP stack (Figure 3) the accumulator must function the BOP as per applicable local jurisdictional regulations and must be sized to provide sufficient power fluid to shear the completion string without recharge.**

IRP **The back-up system nitrogen supply must be capable of closing all blowout preventers including the shear/blind ram and shear pipe in use.**

2.5.3.2 Fluids

Hydraulic oil or a glycol/water mix are acceptable power fluids, provided proper maintenance procedures are in place and are approved by the original equipment manufacturer (OEM).

IRP **Bacteria build up in the glycol/water fluid shall be treated out.**

IRP **Seals shall be checked regularly.**

IRP **Hydraulic oil shall be processed to remove or accommodate water contamination.**

2.5.3.3 Power Supply

Auxiliary power is not required as a minimum standard because, by design, an accumulator will function without external power and a backup is required for the accumulator system.

The use of an auxiliary power supply at the licensee's discretion.

2.5.3.4 Hydraulic Lines

IRP All hydraulic BOP control lines shall be tested to the maximum operating pressure of the accumulator system for five minutes prior to commencing operations.

IRP Hydraulic lines must be fire sheathed (protected) for a minimum of seven metres horizontal distance from the wellbore.

IRP Hydraulic hose couplers within seven metres of the wellbore must be lock type or hammer union type couplers.

2.5.3.5 Control Locations

IRP Where shear rams are employed in addition to the required BOP stack (Figure 2) the control shall be solely at the master panel (accumulator) to avoid accidental shear ram closure.

IRP If the shear ram replaces the blind ram (Figure 3) the remote panel must operate the ram.

IRP All sour well BOPs must have both master and remote controls. The master control must be able to function all BOP operations.

IRP The remote control must be accessible at driller's position with the master controls at least 25 from the wellbore, located at the accumulator.

2.5.3.6 System Monitors

IRP All control manifolds shall have system pressure gauges.

IRP Pressure gauges shall be checked weekly or with each rig move.

IRP An accurate accumulator pressure gauge must be located at the driller's position.

System alarms are optional.

2.5.3.7 Reservoir Venting

IRP The accumulator reservoir shall be vented outside the building and the vent line must be accessible for handheld H_2S monitoring.

Primary hydraulic seal leaks may result in sour fluids entering the accumulator reservoir.

IRP The vent should be inspected for sour fluids on routine safety checks.

2.5.4 Tubing Safety Valves (Stabbing Valves)

IRP The stabbing valve must be a NACE MR0175/ISO 15156 compliant full-opening valve with the proper threads to mate to the completion string thread in use.

IRP The minimum internal diameter should be equal to or larger than the completion string in use. Crossovers may be used but should have the proper inside diameter to allow for well control.

IRP The stabbing valve must have a pressure rating equal to or greater than the BOP pressure rating.

IRP There should be two stabbing valves on location.

IRP The stabbing valve(s) must be stored in an area immediately accessible to the wellbore and left in the open position. The valve(s) must be kept clean, properly maintained, ice-free and ready for use.

IRP Handles and/or counter balances should be used.

2.5.5 Heating Requirements

IRP Heating must be used on all BOP systems when the body temperature during operations is below -10°C. The BOP must be ice-free.

IRP The heat source must be suitable for the electrical area classification in which it is used.

See AER D037: Service Rig Inspection Manual for more information.

2.5.6 Equipment Quality Assurance

2.5.6.1 Elastomers

Refer to 2.11 Elastomers and Appendices D and I for more information about elastomers.

2.5.6.2 Inspections and Function Testing

IRP Daily visual inspection of all BOP components and systems shall be performed.

IRP Function tests must be conducted as per local jurisdictional regulations.

2.5.6.3 Certification

IRP All metallic BOP components which may be exposed to sour effluent must be certified as being manufactured from materials meeting the requirements of NACE MR0175/ISO 15156.

IRP Certification documentation shall be available for all components.

IRP The contractor supplying the BOP equipment must ensure the certification is current and that any modification or retrofit of BOP systems is completed using components which meet or exceed original equipment manufacturer specifications.

Components may be qualified by third party inspection firms.

2.5.6.4 Maintenance

IRP BOP systems must be shop serviced and overhauled every three years.

IRP Whenever the main flanges or any primary well control component are disassembled, the ring gaskets shall be replaced with new gaskets.

2.5.6.5 Testing

IRP BOP equipment shall be pressure tested (stump test) to its working pressure prior to installation on the well.

2.5.6.6 Records and Enforcement

IRP All contractors supplying BOP equipment shall maintain documentation pertaining to equipment material certification, testing, repair and maintenance. This data shall be available for review by the operating company and applicable local jurisdictional regulator as required.

IRP Where such records are not available for the equipment, the equipment must be certified prior to use. Recertification must be acceptable to the applicable local jurisdictional regulator and the licensee.

2.5.7 Installation and Operation

IRP BOP equipment shall be fully assembled and tested prior to installation on the well.

IRP All BOP components shall be pressure tested for a minimum of 10 minutes each to 1400 kPa and the lesser of the working pressure of the BOPs or the formation pressure.

IRP Stabilized pressure of at least 90% of the test pressure must be maintained over a 10 minute interval.

IRP A no leak policy shall be in place for any component that can impact BOP functionality.

IRP Test results shall be documented and filed for future reference.

IRP All BOP tests shall be witnessed by the licensee and rig contractor representatives.

IRP A function test and pressure test must be performed If any component of the BOP is disassembled (e.g., opening of ram gates).

IRP Following initial inspection, BOP components shall be pressure tested weekly to the maximum anticipated working pressure.

IRP The primary well control components, with the exception of the shear ram, shall be functioned daily provided it is operationally safe to do so (based on current well operations). All function tests and BOP drills shall be recorded on the tour sheet.

The function tests may coincide with BOP drills where more than one crew is used on a completion or workover.

IRP Crews should be exposed to function testing on an alternating basis (i.e., daylight crew one day and night crew the next) when more than one crew is used for the completion or workover.

2.6 Downhole Equipment

In producing wells, downhole equipment is installed to enhance production and/or provide for additional well security. There is a wide variety of tools available which have been grouped into commonly recognized categories (e.g., packers, nipples, etc.). The downhole equipment recommendations focus on the procedures that may affect the security of the well.

IRP All downhole equipment and components must be suitable for sour service and NACE MR0175/ISO 15156 compliant.

IRP Safety factors for all equipment should be verified

Refer to Appendix C for more information about material requirements.

2.6.1 Tubular Accessories

Tubular accessories may include, but are not limited to, the following:

- Profile nipples and accessories
- Mandrels
- Expansion Joints
- Subsurface tubing hangers
- Sliding sleeves

IRP Mechanical properties of tubular accessories installed in a tubing string shall be equivalent to the minimum internal yield strength, collapse pressure, compression and tensile load strength required for the tubing string.

IRP Tubular accessories shall be rated to at least the maximum anticipated differential pressure with application and installation done in close consultation with the equipment manufacturer.

IRP Landing nipples and mandrels shall be installed in an elevated sour well tubing string.

Simplicity in design configuration is a significant benefit. Ensure that the threads are compatible with the tubing string and properly cleaned, lubricated and torqued. Ensure that the equipment is not run upside down and that all components in the tubing string are dimensionally compatible.

IRP Equipment shall be positioned so that any seals are subject to as little movement as possible to avoid premature leaks.

IRP Nipple profile accessories shall be installed with sour service wireline.

Consider the following when installing or retrieving nipple profile accessories:

- Ensure the nipple profile accessories and tubular areas above and below are free of any foreign material (e.g., rubber, sand, scale, iron sulfide and/or sulphur).
- Ensure the profile is clear of obstructions.
- Avoid removing an equalizing prong until the differential pressure is as close as possible to equalization.

IRP If air could be present in the tubing, the steps outlined in IRP 04: Well Testing and Fluid Handling shall be followed to eliminate hazards associated with downhole explosions prior to pulling the nipple profile accessory.

2.6.2 Capillary Tubing

Capillary tubing is very small tubing that can easily be compromised during installation. There are limited sizes, materials and manufacturers available to the industry. The feasibility of an installation needs to be evaluated within the constraints of currently available equipment.

IRP The capillary tubing string shall be designed with the following safety factors:

- A 2.0 safety factor applied to the manufacturer's minimum tensile strength specification.
- A 1.125 safety factor applied to the collapse pressure rating.
- A 1.0 safety factor applied to the working pressure.

IRP The capillary tubing should be run or pulled using a spooling machine and an overhead sheave assembly.

IRP The capillary tubing shall be pressured with hydraulic oil, strapped to the tubing body and equipped with protectors over the tubing collars.

IRP Only capillary quality liquids shall be injected. This will help reduce the potential of plugging.

IRP The surface injection pump shall be equipped with a pressure relief valve to avoid bursting the capillary tubing in the event of plugging.

IRP **The capillary tubing string shall be equipped with a surface check valve. The exception is cases where the capillary tubing is used in conjunction with subsurface safety valves.**

2.6.3 Bridge Plugs, Packers and Packer Accessories

IRP **Bridge plugs and packers shall be rated to at least the maximum anticipated differential pressure with installation and application design performed in close consultation with the equipment manufacturer.**

IRP **These ratings shall be based on materials of construction, casing size and weight and axial loading of the packer as well as calculations using minimum material properties, minimum dimensions, laboratory test data and appropriate formulas.**

IRP **The burst, collapse and tensile strength ratings of accessory equipment (e.g., seal assemblies, seal bore extensions) shall be based on calculations using minimum dimensions, minimum material properties and appropriate formulas plus manufacturer test data.**

The use of an annular packoff device (i.e., packer) ensures annular integrity. However, in artificial lift installations annular packoff devices may create operating challenges such as gas locking, de-waxing or the inability to circulate kill fluid.

IRP **If an annular packoff device option is not feasible, additional corrosion and barrier control procedures shall be in place.**

IRP An annular packoff device (i.e., packer) should be installed in all elevated sour wells based on an assessment of release rate and proximity to surface developments.

IRP **The tubing string shall be installed in a manner that accounts for all forces in the wellbore, including pressure and temperature at each downhole component.**

IRP **All packers and accessories shall be dimensionally checked and shop pressure tested to ensure integrity of the tools.**

IRP All casing should be scraped and/or a gauge ring run prior to running any packer or accessories into the well.

Where a liner top is used, ensure the liner top is free from debris and burrs when running a packer or accessories into a well with liners.

IRP The packer or bridge plug should not be set in a casing coupling because it can add stress, jeopardizing the casing coupling and the ability for the packer to seal.

IRP When releasing retrievable packers and bridge plugs, the packing elements should be allowed to retract prior to tripping the tubing out of the hole.

Closely monitor trip speed when tripping the packer or bridge plug out of the hole to keep from swabbing the well in.

2.6.4 Surface Controlled Subsurface Safety Valves

The purpose of the SCSSV is to provide for wellhead redundancy in the event of a catastrophic failure. It may be necessary to provide a line of defence against wellhead failures because of potential vulnerability to the erosive and corrosive effects of produced fluids or mechanical failures such as faulty manufacturing or third-party damage.

Refer to manufacturing specifications and applicable industry standards (e.g., API Spec 14 Standards) for requirements and information to aid in selection, manufacture, testing and use of SCSSVs.

IRP Components which form an integral part of the tubing string (i.e., tubing retrievable valves and nipple profiles) shall be of at least equivalent internal yield pressure, collapse pressure, compression and tensile load strength required for the tubing string.

IRP All components of the subsurface safety valve and lock mandrel shall be of sufficient strength and composition to ensure the valve functions properly in all well operating environments.

The reliability of the SCSSV will vary from well to well. Where the sealing ability of the SCSSV would be impaired due to downhole conditions (e.g., sulphur deposition) or where the downhole completion configuration cannot easily accommodate SCSSVs (e.g., wells on artificial lift, concentric dual completions, etc.) alternative protective measures may be used. On-lease kill systems and reinforced wellhead enclosures are two systems that may be considered as alternative measures when SCSSVs are impractical.

IRP An SCSSV must be installed in flowing elevated sour producing wells when required by local jurisdictional regulations.

IRP SCSSVs shall be run to a minimum depth of 30 m below casing flange.

A valve set 30 m below ground level is normally adequate protection from surface impacts. Valves may have to be set deeper due to potential earth movement or operating conditions such as sulphur deposition. Consult the manufacturer regarding maximum setting depth to ensure fail-safe close functionality.

IRP In wireline retrievable SCSSV installations, a flow coupling shall be installed directly above and below the SCSSV nipple profile.

IRP Each flow coupling should be a minimum of 0.3 m in length.

Wireline retrievable SCSSVs restrict flow up the tubing string causing both turbulence and increased velocity. Flow couplings may help prevent the premature erosion of the tubing in the vicinity of the SCSSV.

IRP Every valve shall be function and leak tested upon installation (refer to manufacturer specification and API Spec 14 Standards for testing procedures). See Appendix D for more information.

IRP The licensee shall establish a function test and leak test program with the test frequency tailored to the field or area specific.

IRP Accurate records of the frequency and results of function and leak tests shall be maintained by the licensee.

IRP A valve that fails an operational test should be serviced as soon as possible.

IRP Accurate records of the servicing frequency shall be maintained by the licensee.

Documented field service data may allow prediction of the service frequency.

A valve operating in an elevated sour environment may be subject to severe corrosion and erosion conditions. SCSSV reliability and performance can be improved with regular maintenance.

Fusible plugs can be installed in the SCSSV control line to fail-close the valve in case of fire.

2.6.5 Artificial Lift Equipment

There are many considerations for using artificial lift in elevated sour wells. The risk of blowouts is generally low because the reservoir pressures are low. However, some artificial lift techniques require use of complicated equipment or design compromises (e.g., such as not using a packer) which can increase the chance of mechanical failures and increases the complexity of the workover.

Prior to installing artificial lift, calculate the H_2S release rate for the producing formation at its present condition. If depletion is sufficiently advanced the well may no longer be elevated and an application for change of status can be made to the local jurisdictional regulator. If accepted, install artificial lift in compliance with local jurisdictional regulations for sour service.

Minimum requirements for artificial lift equipment are discussed in detail in IRP 05: Minimum Wellhead Requirements.

2.6.5.1 Rod Pumping

IRP The Modified Goodman Diagram from API RP 11BR shall be used for the design of axial loading in sucker rods. Corrosivity of the sour environment shall be factored into the design.

Attempt to keep all of the sucker rods in tension at all times. This may require the use of sinker bars above the pump.

IRP The stress level in a sucker rod string shall be determined whenever there is an installation on a new well or whenever there has been a large change in pumping conditions (e.g., water cuts pump speed, pump size).

IRP Techniques shall be employed to reduce wear of sucker rods/tubing. Techniques to consider include the following:

- Use of a tubing anchor.
- Use of sinker bars above the pump.
- Sand control techniques and friction reducing mechanisms such as rod centralizers.

IRP Inhibitors, coatings, special alloy rods or continuous sucker rod should be considered, with special attention to the coupling area, for reducing sucker rod stress corrosion cracking.

Some manufacturing processes of sucker rod end areas results in a product that may be susceptible to stress corrosion cracking.

2.6.5.2 Jet Pumping

IRP The housing of a jet pump shall have at least an equivalent internal yield pressure and collapse pressure of the required tubing.

IRP The tubing or casing string(s) containing the power fluid shall be designed to account for burst and collapse.

IRP Production tubing design factors shall be applied to jet pump tubing.

IRP Design should allow for removal of the nozzle without pulling the tubing whenever possible.

2.6.5.3 Electric Submersible Pumping

IRP Where a packer is required for electric submersible pumping, a means shall be provided to allow for filling the tubing with appropriate kill fluid (i.e., if a standing (check) valve is used above the pump it should be removable).

2.6.5.4 Plunger Lift

IRP Plunger lift lubricators shall have an internal working pressure rating at least equivalent to that required for the wellhead assembly.

IRP The design burst pressure shall be at least 1.5 times the maximum working pressure rating.

IRP The catcher/lubricator assembly shall be inspected on a regular basis for fatigue cracks and pressure tested to at least 1.5 times its operating pressure on a yearly basis.

IRP There must be an ESD valve installed between the wellhead and the catcher/lubricator.

The upper master valve can be converted to an ESD by installing an automatic operator on the bonnet assembly.

2.6.5.5 Gas Lift

IRP The gas lift system shall include check valves so that production fluids are isolated from the casing.

2.7 Tubular Goods

The failure of a tubing string is not sufficient in itself to result in an immediate release of sour gas. Prudent tubing design can help minimize the need or potential for servicing operations on elevated sour wells. Quality assurance for tubular goods is essential to the installation and operation of a competent tubing string (see 2.10 Quality Programs for Well Pressure Containing Equipment).

The standards and requirements for tubular goods are defined in IRP 01: Critical Sour Drilling. While IRP 01 refers to casing, the same industry codes and standards apply to the tubular goods used in well servicing. IRP 02 includes only information specific to servicing operations that is different from that outlined in IRP 01.

Refer to IRP 01 for specific information about the following:

- Casing Design and Metallurgy
- Manufacturing Guidelines
- Chemical Composition
- Tensile Testing
- Hardenability Testing
- Hardness Testing
- Grain Size Determination
- Hydrostatic Testing
- Sulphide Stress Cracking Testing
- Hydrogen-Induced Cracking Testing
- Inspection

It is the responsibility of the reader to apply the relevant requirements of IRP 01 and IRP 02 for the tubing design and operation being performed.

IRP All tubular goods must be suitable for sour service and NACE MR0175/ISO 15156 compliant.

2.7.1 Design Requirements

2.7.1.1 Stress Conditions

IRP Tubing design should consider variations in fluid pressures, temperature and densities to account for all potential tubing movements.

IRP Tubing movements, when restrained by a packer, should be converted to an equivalent force and included in the tubing string analysis.

IRP Tubing design should consider the following:

- Packer design and limitations to ensure that length variations do not result in the tubing leaving the packer seal bore (stung or landed tubing) and do not result in sufficient forces to unseat the packer (landed or latched tubing). Similar consideration should be given to tubing completed with a tubing anchor.
- Temperature effects under maximum production rates (both friction and gas expansion can contribute to temperature effects).
- Pressure differentials across the tubing and across the packer for both initial production and depleted reservoir production.

IRP Wells to be stimulated should include the following design parameters:

- Stimulation fluid temperature at bottomhole equals surface temperature or as derived from a computer simulation.
- Maximum surface pressure based on maximum allowable surface treating pressure.
- Fluid density equals maximum fluid density present in the wellbore at any time during the stimulation.

Note: Ignore frictional pressure drop to allow for sandoff conditions if pumping proppant.

2.7.1.2 Design Criteria

IRP Tubing design criteria should include the following:

- Tension: Evaluated at the top joint of the tubing string and at all points of tubing size/weight/grade crossover with respect to the lesser of the tensile strength of the tubing body or coupling.
- Burst: Evaluated at surface and the bottom joint (i.e., at packer) and at all points of size/weight/grade crossover.
- Collapse: Evaluated at surface and the bottom joint (i.e., at packer) and at all points of size/weight/grade crossover.

- Maximum Principal Triaxial Stress (sometimes called maximum fibre stress): Evaluated at surface and the bottom joint (i.e., at packer) and at all points of size/weight/grade crossover. In the lower (buckling) stress portion of the string, analyze at the outer fibre under setdown conditions and at both the inner and outer fibre under producing and stimulation conditions.

2.7.1.3 Design Factors

IRP Tubular design factors (i.e., tension, burst, collapse, maximum principal stress) must meet local jurisdictional regulations.

IRP Design factors for work strings should include appropriate overpull provisions.

IRP Design factors shall be calculated based on tensile strengths, burst resistances and collapse resistance as prescribed in API TR 5C3.

IRP The collapse rating must be reduced when the tubing is subject to axial (tensile) stress as per API TR 5C3.

IRP The maximum principal stress design factor shall be calculated based on the specified minimum yield strength (SMYS) of the material.

IRP Premium connection burst, collapse and tensile ratings not listed by API should be obtained directly from the manufacturer.

2.7.2 Marking

IRP All pipe and couplings shall contain legible inspection and/or manufacturer stencil for identification and traceability. Re-marking the pipe immediately upon recovery from the well is recommended to maintain traceability.

2.7.3 Non-Compliant and/or Used Tubing

Refer to the Casing Design and Metallurgy section of IRP 01: Critical Sour Drilling for manufacturing specifications for new tubing (i.e., tubing that has never been run in a well). The criteria below apply to tubing to be used in elevated sour service that is not compliant with IRP 01 specifications or used tubing (i.e., tubing that has previously been run in a well).

2.7.3.1 Used IRP 01 Compliant Tubing

IRP Used pipe originally manufactured in compliance with IRP 01 specifications shall only be used if it passes the following inspection:

- Full length API drift.
- Full body inspection for longitudinal and transverse defects, inside diameter (ID) and outside diameter (OD).
- SEA inspection on one joint in 20 (see 2.7.5.10 General Inspection Guidelines).

IRP Pipe should be marked to allow future traceability back to this inspection.

IRP Pipe that was originally manufactured to meet or exceed this IRP should also be re-stencilled with an appropriate designation upon recovery from the well to provide traceability.

2.7.3.2 Used Non-IRP 01 Compliant Tubing

IRP Used tubing not originally made in compliance with IRP 01 specifications shall be treated in the same manner as new, non-IRP compliant tubing (see below). In addition, it shall receive full length drift testing. Straightening of tubing shall not be permitted.

2.7.3.3 New Non-IRP 01 Compliant Tubing

IRP New tubing not originally made in compliance with IRP 01 specifications shall only be used if it passes the inspection and testing requirements outlined in the Inspection section of Casing Design and Metallurgy in IRP 01.

2.7.4 Documentation

IRP The following mill certification records shall be maintained by the licensee:

- Chemistry.
- Mechanical and metallurgical properties (grain size, microstructure).
- Hardenability and hardness readings.
- Results of Sulphide Stress Cracking (SSC) and Hydrogen Induced Cracking (HIC) tests.

IRP Results of third-party tests and inspections performed in accordance with 2.7.3 Non-Compliant and/or Used Tubing shall be maintained by the licensee.

2.7.5 Tubular Connections

This section covers carbon and low alloy steel tubing connections intended for use in sour service applications.

Note: The connection type recommendations are based on general well principles. Additional simulation and/or modelling may indicate that a connection type different from these recommendations can be used.

IRP Tubing simulation/calculations should be conducted with an appropriate modelling tool to qualify selected connection types based on the specific operating parameters of the well.

IRP Tubular goods shall be stored, inspected, used, maintained and reconditioned in accordance to the following API specifications:

- API RP 5A5 Field Inspection of New Casing, Tubing, and Plain-end Drill Pipe
- API RP 5B1 Gauging and Inspection of Casing, Tubing and Line Pipe Threads
- API RP 5C1 Recommended Practice of Care and Use of Casing and Tubing
- API Spec 5CT Casing and Tubing
- API Spec 5B Threading, Gauging, and Inspection of Casing, Tubing, and Line Pipe Threads

Premium and semi-premium connections are defined in Appendix I. Table 6 describes the service levels discussed in this section.

Table 6. Service Level Definitions

Service Level	Description
Light service	• Meant for oil wells or low- pressure gas wells with the following characteristics: • Differential pressures less than or equal to 21 MPa. • Depths less than or equal to 3500 m. • Non-deviated or mildly deviated well path (less than 20º angle from vertical, less than 5º/30m dogleg severity). • Temperatures and fluids that do not affect the ability of the thread lubricant sealing with the external-upset-end (EUE) connection. Check with the thread lubricant manufacturer for specific data on the proposed thread lubricant. • Non-corrosive service.

Service Level	Description
Moderate service	Similar to light service but with added complications such as the following: • Temperatures and fluids that affect the ability of the thread lubricant sealing with the EUE connection. • More deviated wells than described in Light Service. • Differential pressures greater than 21 MPa.
Harsh service	Meant for more complex wells that may include complications such as the following: • High differential pressure. • High temperatures. • Highly deviated wells. • A corrosive environment such that resilient seals are not effective or a more streamlined flow path is desired in the coupling area. • An abrasive/erosive environment such that a more streamlined flow path is desired in the coupling area. • Well service work requiring stripping or snubbing.

2.7.5.1 Light Service

IRP Premium, semi-premium or API EUE connections shall be used for light service.

IRP All new and used tubing connectors should be inspected at mill or storage yard prior to wellsite shipment.

See 2.7.5.10 General Inspection Guidelines for recommended mill/yard inspection requirements.

2.7.5.2 Light Service Work String

IRP Work string connections should be visually inspected for galled threads, swaged pin noses and/or belled boxes at a frequency of 1 joint per 20 after four or five trips or extensive milling operations.

Note: These problems areas are more prevalent on API EUE connectors.

2.7.5.3 Light Service Production String

IRP Both pin and box threads should be washed clean, preferably with a mechanical power thread cleaner equipped with non-metallic bristles immediately prior to running.

IRP Connectors shall be visually inspected for galled threads, swaged pin noses and/or belled boxes.

IRP A hardened, ground API thread profile gauge should be used for locating stretched or damaged API 8-round threads. A frequency of one per twenty joints depending upon overall thread condition should be sufficient in most instances. If numerous joints are rejected by this method a more rigorous inspection frequency is warranted.

IRP The tubing connections shall be pressure tested either individually or collectively over the entire tubing string.

Pressure testing may be conducted with inert gas or a clean, low viscosity liquid.

When EUE work strings are utilized as the final production string, pay particular attention to monitoring of pin advancement into the coupling during make-up (see 2.7.5.10 General Inspection Guidelines).

Multiple “make and break” of the work string to similar torque values may cause progressive pin advancement thereby increasing axial and box hoop tensile stresses.

IRP A torque shoulder feature should be considered if pin advancement is a concern.

2.7.5.4 Moderate and Harsh Service

IRP Semi-premium or premium connections should be considered for moderate service.

IRP Premium connections shall be used for harsh service.

IRP All new and used tubing connectors shall be inspected at mill or storage yard prior to wellsite shipment.

See 2.7.5.10 General Inspection Guidelines for recommended mill/yard inspection requirements.

2.7.5.5 Moderate or Harsh Service Work String

IRP Both pin and box threads shall be washed clean using a mechanical power thread cleaner equipped with non-metallic bristles and visually inspected on each trip. This is recommended due to galling propensity of metal-to-metal seals.

IRP After extensive milling/drilling operations connectors shall be closely inspected prior to and after breakout for thread and/or metal to metal seal damages belled boxes or swaged pin noses.

A steel straight edge may be used to aid visual inspection.

2.7.5.6 Moderate or Harsh Service Production String

IRP Both pin and box threads shall be cleaned using a mechanical power thread cleaner equipped with non-metallic bristles immediately prior to running.

IRP A qualified thread inspector should be on-site prior to and during running of the production string to assist in thread inspection.

IRP Each connector shall be visually inspected, prior to make up, on the rig floor.

IRP Special emphasis should be placed on metal-to-metal seal inspection particularly if the production string had been used as a work string.

IRP The tubing connections shall be pressure tested either individually or collectively over the entire tubing string.

Pressure testing may be conducted with inert gas or a clean, low viscosity fluid.

IRP When work strings are used as final production strings, the connection shall be visually monitored for excessive pin advancement during make-up.

Note: Connectors with torque shoulders are susceptible to excessive pin advancement when subjected to milling/drilling operations.

2.7.5.7 Connection Thread Lubricants

The thread lubricant is the primary sealing mechanism for API EUE and some semi-premium connectors.

Degradation of the solids carrier (grease base) may occur and can result in uneven dispersion of damming solids. This may reduce seal integrity because the damming solids will not be uniformly distributed along thread roots and crests when applied. Oil bleed to surface of the lubricant in a container may indicate grease degradation.

Thread lubricants are subject to degradation with increasing temperature and harsh fluid environments. Consultation with the connection and lubricant manufacturers is advised.

IRP Only approved API Modified thread lubricants or equivalent shall be used.

This allows for the use of non-lead based lubricants provided they have been qualified for the intended service.

IRP Thread lubricant which is more than two years old should not be used on production strings.

IRP Application of thread lubricant should be consistent and thorough to achieve a leak proof connection.

IRP Thread compound should be applied uniformly covering all threaded and seal areas. Check with the connection manufacturer to see if pin only, box only or both pin and box lubrication is recommended.

IRP Thread compound should not be over-applied as excess compound can cause other downhole and/or reservoir issues (e.g., decreased well productivity, obstructions in the well, etc.).

IRP Threads and lubricant used shall be clean.

2.7.5.8 Connection Make Up

IRP Connections should be engaged by hand before power tightening when possible.

IRP Assembly in the horizontal position should be avoided.

IRP The markup target should be based on position not torque.

IRP The following should be considered or performed for make up:

- Ensure elevators are vertically aligned with the center of the wellbore to mitigate misalignment problems. A stabbing platform should be used if there is sufficient room in the derrick.
- Pick-up and visually check seal and threads for damage if the connector is incorrectly stabbed (i.e., if it is cross-threaded or if the pin nose hits the box face first).
- Do not rock pipe to facilitate stabbing or make-up.
- All production string connections should be started by hand to minimize cross threading and thread damage.
- Connection should be made-up at manufacturer's recommended speed or maximum 25 rpm and kept constant during make-up (as per API RP 5C1).
- Tongs should hang level during make-up.
- The snub line should be as close to 90º from torque arm as possible.
- Power tongs and back-ups should be reasonably close together to prevent bending the connector.
- Connections should be made-up to manufacturer's recommended torque. Thread plating, coating or thread lubricant type may have pronounced effects on applied torque. The connection and lubricant manufacturers should be consulted for appropriate torque and friction factor values.
- For premium connections use a load cell with torque gauge in snub line to monitor torque. Do not rely on hydraulic pressure gauges. Ensure the load cell

has been recently calibrated. In addition, a torque monitoring unit should be considered for use while making up work string and production string connectors for Moderate or Harsh Service.

- At minimum, the unit should have a torque alarm system. A torque/turn/time unit is preferred for production strings.
- Work strings may have pins that are reduced in diameter due to successive yielding by repeated makeups.

2.7.5.9 Connector Thread Break Out

IRP Equal emphasis should be placed on connector break out as it is placed on make up, especially semi-premium or premium connectors. Position break-out tongs close to the coupling.

IRP The coupling should not be hammered to break the joint

2.7.5.10 General Inspection Guidelines

The inspection guidelines in this section apply to all service levels:

IRP Only qualified thread inspectors should be utilized at the mill or storage yard.

IRP When proprietary (i.e., non-API) connectors are being threaded, a third-party inspector or a qualified representative of the licensee should verify that the manufacturer's specified inspection procedures and frequencies are adhered to.

IRP Due to corrosion potential of stored tubing, an evaluation of the threaded connector condition (including seal areas) should be conducted on production tubing prior to wellsite shipment. A visual thread inspection as per API RP 5A5 is recommended.

IRP The maximum duration between last inspection and utilization of tubing should be less than 12 months. This duration may be impacted by storage practices, thread protector type and the thread lubricant's properties for corrosion resistance.

IRP In addition to standard API inspection practices for used tubing connection, end area inspection (SEA inspection) as per API RP 5A5 utilizing wet Magnetic Particle Inspection (MPI) should be conducted in the storage yard prior to use. An inspection frequency of one joint per twenty for IRP 01 compliant tubing is recommended. High frequency of connector rejection would require more frequent testing.

IRP For non-IRP compliant tubing, SEA inspection should be conducted on every joint.

IRP Supplemental coupling inspection wet MPI per API Spec 5CT should be conducted at the mill.

IRP API EUE work strings and used tubing intended for production string applications should be randomly checked for pin advancement in storage yard prior to wellsite shipment.

Refer to API RP 5C1 for information about the distance requirements between box ends.

IRP The following areas should be checked when inspecting used tubing threads:

- Pulled round threads
- Galling
- Fatigue cracks in the last engaged thread

2.7.5.11 Documentation

IRP The results of the inspections from 2.7.5.10 General Inspection Guidelines should be maintained by the licensee and include the following:

- Inspection company
- Date of inspection
- Inspection performance

IRP The inspection company should stencil an identifier on the tube to allow traceability back to the inspection performed.

2.7.6 Running and Handling

Adherence to proper running and handling procedures can reduce the risk of a pipe or connector failure downhole. API RP 5C1 is a thorough and practical guide for the running and handling of oilfield tubular goods.

2.7.6.1 Transportation and Handling

IRP Tubing for sour service should be transported and handled using techniques that minimize both connection and pipe body damage. The following specific handling should be followed:

- Tubing should have thread protectors on both ends.
- Tubing should be strapped down with nylon straps or chains with rubber protection underneath. Straps or chains should be secured only where tubing is on stripping.

- Tubing is to be unloaded on location by picker or tubing ramps onto pipe racks. A spreader-bar with a choker-sling at each end is recommended by API RP 5C1. When using ramps, lower one or two joints at a time and avoid contact that may damage threads.

2.7.6.2 Drifting and Running

Damaged pipe can deteriorate more rapidly in sour conditions.

IRP The licensee should ensure that the equipment and techniques used to run the tubing do not cause other pipe body or connection damage that could cause a failure in service. Proper tools and running procedures need to be in place.

If the tubing is coated follow the coating manufacturer's specifications for drifting and running procedures.

2.7.7 Corrosion Monitoring and Inspection

Monitoring and inspection procedures are normally necessary to confirm that process parameters are within design limits. Monitoring is the ongoing monitoring of the corrosion process and measures taken to control it. Inspection is the provision of mechanical integrity assurance. Inspection provides data points against which corrosion monitoring is often related or quantified.

2.7.7.1 Monitoring Methods

There are numerous methods available to monitor the effect of corrosion on tubular goods. Each method has its own merits and limitations so reliance on one single method can lead to erroneous evaluation of the tubing condition.

Monitoring methods can be divided into the following two categories:

1. Intrusive measurements which require production to stop.
2. Non-intrusive measurements which can be performed without interrupting flow.

A variety of monitoring techniques are included in Appendix E. The most common are caliper logs, inspection logs, coupons, electronic monitoring methods, iron counts and visual inspection. The most effective is a complete visual inspection with selective destructive testing of the tube throughout the string. Unfortunately, this can only be accomplished during a workover.

IRP Monitoring techniques should be selected on an individual well basis depending on parameters such as operating condition and well history.

Consider field results from the offset wells to assist evaluating specific wells.

2.7.7.2 Monitoring Schedule

IRP On new completions the extent of tubing corrosion should be monitored within six months of start-up, unless field history dictates a lesser frequency is justified.

Most corrosion related tubing failures occur due to localized corrosion rather than general metal loss corrosion. Severe pitting can occur rapidly in some environments. The six-month schedule suggested for a new well should identify whether a problem exists. The method selected is at the licensee's discretion.

IRP An ongoing tubing corrosion-monitoring program should be implemented on all elevated sour wells on production. Field history may indicate that this is not required but analysis should be performed to ensure that the production characteristics are similar to the rest of the field.

IRP The frequency of the monitoring schedule should be set based on, but not limited to, the following criteria:

- The methods selected.
- How aggressive the environment is (e.g., partial pressures of CO_2 and H_2S, brine content, temperature, presence of hydrocarbon condensate, oxygen concentration, elemental sulfur and sulfur solvents such as dimethyl disulphide (DMDS) or diallyl disulphide (DADS)).
- The inhibitor program.
- Tubular condition.

IRP The initial monitoring frequency should not exceed two years for wells that exhibit corrosion potential.

Field experience and the success of mitigation programs may indicate that a lesser or greater frequency is more appropriate.

IRP If production characteristics change the inspection frequency should be re-evaluated.

IRP A tubing inspection log should be run during the initial production test and every five years thereafter. Frequency should be increased if corrosion is apparent.

If a caliper log is run, ensure the tubing is internally inhibited immediately after logging. The caliper fingers may disrupt the natural (i.e., iron sulphide scale) or routine inhibition of the tubing surface and accelerate local corrosion.

2.7.7.3 Tubing Performance Under Corrosive Conditions

Some monitoring procedures have the potential to directly measure pipe thickness but scale and other deposits can affect the results of the measurements.

Monitoring methods only identify potential corrosion problems. Correlation between the monitoring results and pipe condition is necessary. This correlation is dependent on various factors (e.g., monitoring method, mitigation program, fluid rates and composition, pipe grade, failure history, time, etc.).

IRP The physical properties should be recalculated when corrosion is found to ensure that adequate mechanical strength remains.

2.7.7.4 Corrosion Mitigation in Tubulars

IRP Mitigations for tubular corrosion shall be in place.

The following can be considered to mitigate corrosion:

- Corrosion inhibition (batch and/or continuous)
- Special tubular grades
- Tubular coatings
- Corrosion allowance

2.7.7.5 Corrosion Mitigation in the Annular

IRP The annular fluid shall be inhibited with a compatible chemical package designed to remain permanently in suspension to help prevent annular corrosion.

IRP This chemical package should contain the following:

- A filming corrosion inhibitor.
- Oxygen scavenger.
- A neutralizing agent.
- A “disinfectant” that effectively destroys organic life (not necessarily a biocide).

The following are acceptable annular fluids:

- Sweet crude.
- Diesel.
- Stabilized condensate.
- An inhibited fresh water or brine.

Refer to 2.11 Elastomers for elastomer compatibility information.

IRP If a workover is performed, the tubing should be visually inspected to check the effectiveness of the inhibitor. Consider running a casing inspection log across the interval if external pitting is apparent. Information about these activities should be recorded and kept in the well's corrosion file.

2.7.7.6 Corrosion Mitigation in External Casing

IRP The need for cathodic protection of the production casing should be evaluated on a field basis.

IRP If required, a properly designed cathodic protection system should be installed within one year of rig release.

IRP The entire cathodic protection system should be properly operated and maintained. The cathodic protection units should be kept in continuous operation and rectifier DC outputs measured and recorded monthly. This information should be placed in a permanent well file and reviewed annually.

2.7.7.7 Records

Accurate records can assist in the assessment of tubing condition and the effectiveness of the corrosion mitigation program.

IRP Records should be kept on an individual well basis and include, at minimum, the following:

- Fluid analysis: producing rates and temperatures, gas dew point, location of free water production in string.
- Tubular string details: failure history, workover details (if a workover is conducted, include the internal and external visual inspection results).
- Monitoring methods and results.
- Corrosion mitigation program.

IRP Records should be updated with each operation performed on the well and at any time the tubing is pulled from the well.

2.8 Fluids and Circulating System

This section addresses the minimum acceptable standards for equipment and completion/workover fluids for well control and fluid handling on elevated sour wells when the sour zone is open. If the zone is mechanically plugged off then other fluids with less density than the kill fluid may be used once the BOPs are installed.

The Energy Safety Canada Well Service BOP Manual describes circulation methods and kill procedures.

2.8.1 Surface Equipment

For purposes of this IRP, surface equipment includes the following:

- Circulating pumps
- Manifolds
- Discharge lines
- Return lines
- Independently installed check valves (e.g., for swabbing purposes)

IRP Surface equipment must be suitable for sour service and NACE MR0175/ISO 15156 compliant.

The working pressure limits of equipment need to be considered during equipment selection to ensure that the equipment is capable of safe operation at the anticipated pressures.

IRP Surface equipment must have a working pressure equal to or greater than the lesser of

1. The working pressure of the wellhead or
2. 1.1 times the maximum anticipated shut-in pressure.

2.8.1.1 Backup Pumps

A rig pump failure could lead to an uncontrolled flow.

IRP For wells that cannot be shut in (hard shut in) during pumping operations, a backup pump with manifold must be on location to maintain control of the well if the rig pump fails.

IRP For wells that can be shut in (hard shut in) during pumping operations, contingency plans must be in place for a backup pump with manifold to be brought to location if the rig pump fails.

2.8.1.2 Rig Pump

Pump sizing is site specific and dependent on the casing size, tubing size and well condition.

IRP The rig pump must have a discharge rate of sufficient capability to control the well.

IRP The pump and manifold must be adequately heated during winter operations to prevent freezing.

2.8.1.3 Rig Tank

IRP Rig tanks shall only be used for kill fluids and shall not be used to return or hold sour fluids form the well.

IRP Sour effluent must not be emitted to the atmosphere. It must be directed through temporarily installed separation equipment to closed storage vessels equipped with vapour recovery systems or directed to an existing flowline capable of handling sour production fluids.

IRP Rig tank degassers shall not be used on open rig tanks for sour servicing operations.

IRP The rig tank must provide for accurate fluid gauging and include the primary mixing system.

IRP Rig tanks must be adequately heated during winter operations to prevent freezing.

Rig tanks equipped with properly maintained steam coils will prevent freezing and steam contamination of fluid.

2.8.1.4 Shale Shaker or Rig Tank Trough

IRP Shale shakers or rig tank troughs shall not be used when sour effluent is being circulated from the well.

Production test equipment does not have the capability of handling large size solids. Closed pressure vessels are available that are capable of handling large sized cuttings and diverting sour gas to flare or to a vapour recovery system

2.8.1.5 Premix Tank

The first factor in determining the need for supplemental mixing equipment is the type of fluid being used. For fresh water or produced formation water there may not be a need for a premix tank. For a viscosified fluid system a premix tank can provide the following benefits:

- Allows the licensee to circulate the hole and mix kill fluid at the same time.
- Allows continuous agitation of fluids at surface.
- Provides extra fluid storage capacity.
- Reduces mixing time when used in conjunction with Service Rig mixing equipment.

2.8.1.6 Sour Fluid Storage

IRP Sour fluid storage tanks shall be used for storage of all sour fluids.

IRP Storage tanks containing sour fluids or sour gasified fluids must meet the following criteria:

- Be grounded and bonded.
- Be purged prior to storing sour fluids.
- Have mechanical gauge for gauging tank level.
- Be equipped with connections for circulating the tank to add scavengers and for unloading.
- Be equipped with steam coils during winter operations to prevent fluids from freezing and steam contamination.

2.8.2 Completion and Workover Fluids

The primary functions of a completion or workover fluid are to control formation pressure, transport movable solids and minimize formation damage.

Selection of completion or workover fluids is determined based on site-specific operations and well conditions. Completion and workover fluids required can range from complex high density viscosified fluids to fluids such as fresh water, brines or hydrocarbon-based fluids.

Use of hydrocarbon fluids can have the following impact on well control:

- It can reduce the warning signs for a kick.
- It can increase the solubility of H_2S.
- It can slow the reaction time of scavengers.

IRP Hydrocarbon fluids should be used with caution.

2.8.2.1 Dissolved Sulphide

It is important to determine if dissolved sulphides are present in the completion or workover fluid. A decrease in pH in a water-based fluid is an indicator that sulphides may be present in the fluids.

The Hach Test and Garrett Gas Train are used to detect the presence of sulphides. The Garrett Gas Train is a quantitative method of determining the amount of dissolved sulphides.

IRP Dissolved sulphide levels of 10 ppm or greater must be treated with scavengers prior to circulating to an open system.

IRP Dissolved sulphide levels greater than 0 ppm should be treated with scavengers prior to circulating to an open system.

IRP Dissolved sulphides in the completion fluids shall be monitored.

2.8.2.2 Fluid Volume and Storage

IRP All fluid volumes on location shall be monitored and recorded at the start of each crew change, before and after filling the hole, circulating and tripping.

IRP The volume of usable completion fluid required on location is the hole volume plus a surface backup volume of 100% of hole volume plus tank bottoms.

2.8.2.3 Fluid Density

IRP Density of the completion fluid shall be maintained at a minimum 1400 kPa overbalance of the formation pressure.

IRP The density and viscosity of the completion fluid should be checked and recorded at the following times:

- Start of each crew change.
- Prior to filling the hole.
- When circulating or tripping.
- When circulating bottoms up.
- When completion fluid is contaminated.

2.8.2.4 Packer Fluids

IRP Packer fluids shall be inhibited to prevent corrosion.

IRP Corrosion inhibitors should be soluble and premixed in the packer fluid and circulated into the annulus.

IRP Water based packer fluids should contain oxygen scavengers and biocides.

IRP Solids-free packer fluids should be used.

Diesel fuel is commonly used to top off the annulus to prevent surface freezing.

2.8.3 Recycling or Reuse of Stimulation, Flowback and Produced Fluids

Stimulation, flowback or produced fluids may contain H_2S. As a general rule, the H_2S concentration in the gas phase is much higher (e.g., 10 times) than the H_2S concentration in the liquid phase.

IRP Health and safety shall be considered when reusing flowback or produced fluid.

Considerations include, but are not limited to, H_2S concentration, temperature and Naturally Occurring Radioactive Materials (NORM) management.

IRP H_2S should be removed before it can be re-incorporated into the stimulation fluid. See 2.9.5 Handling H_2S for more information.

IRP Fluids should be stabilized for transfer or use in servicing operations.

IRP Closed systems should be utilized to ensure containment of all volatile fluids.

IRP Emissions must be managed to ensure H_2S is not released to the atmosphere.

IRP Test methods must be established to ensure no off-gassing.

IRP Scavengers can be utilized to mitigate sour off-gassing but fluid should be closely monitored for fugitive emissions.

IRP In cases where stabilized fluid with vapor phase H_2S is at acceptable levels (as defined in OH&S regulations), decreasing pH should be avoided to ensure there is no additional vapor phase release of H_2S to the atmosphere.

IRP Safety precautions should be taken when entering any enclosed or restricted ventilation area which currently contains, or has contained, stored sour fluid.

See IRP 28: Wellsite Waste Management for more information about handling, storage and reuse of flowback and produced fluids.

2.9 Well Servicing

This section covers the implications and considerations for servicing a sour well by a third-party service that would support a service rig operation. This information is above and beyond what is already defined for independent operations in IRP 13: Wireline Operations, IRP 15: Snubbing Operations and IRP 21: Coiled Tubing Operations.

Section 2.12 Safety addresses general matters to be considered about safety during sour operations. This section refers to non-safety operational considerations.

IRP Bolting must be suitable for sour service and NACE MR0175/ISO 15156 compliant.

IRP Precautions should be taken in freezing conditions to prevent elastomeric failure and inhibit the formation of gas hydrates in the surface equipment.

IRP Pickers, mast units, rigs and wireline units shall be grounded to equal potential between the flow lines, wellhead and all equipment.

2.9.1 Wireline Operations

Refer to IRP 13: Wireline Operations for information about surface pressure control equipment and operating procedures for wireline operations (including all slickline, braided line and coated line).

IRP Breathing apparatus should be worn when installing, bleeding off and breaking the integrity of the pressure control system and kept on until the well head is shut in and secure.

IRP Lubricator bleed off lines shall be tied into a flare stack or an H_2S scrubbing system (see 2.9.5.3 Scrubbing).

2.9.2 Snubbing Operations

Refer to IRP 15: Snubbing Operations for information about snubbing operations.

2.9.3 Coiled Tubing Operations

Refer to IRP 21: Coiled Tubing Operations for information about coiled tubing operations.

2.9.4 Swabbing Operations

Swabbing doesn't necessarily keep all of the H_2S in the system.

IRP For elevated sour wells, other artificial lift options should be considered instead of swabbing.

IRP H_2S must not be swabbed to rig tanks or released to atmosphere.

IRP The vent line on the saver head line on the lubricator shall be capped or tied into scrubbers to avoid venting H_2S during swab to surface.

IRP All piping and pumping equipment must be rated for sour service (as per NACE MR0175/ISO 15156).

IRP Inhibitors shall be used to prevent corrosion to the sand line and drum.

IRP There shall be communication protocols in place between the rig crew and those performing testing operations while swabbing.

IRP There shall be tested dual barriers in the swab tree (e.g., sand line isolation, saver head, etc.).

IRP Adequate air supply shall be on location and rigged in when H_2S concentration is greater than 10 ppm.

IRP Floorhands removing lubricator to check cups shall use breathing apparatus when H_2S concentration is greater than 10 ppm.

IRP Saver head rubbers shall be changed at regular intervals to ensure viability.

2.9.5 Handling H_2S

Producers are responsible for all H_2S emissions in terms of to release to atmosphere. The three main options for H_2S control are combustion, scavenging and scrubbing. Scrubbing has both low pressure and pressurized options.

IRP For scrubbing and scavenging, procedures and test methods shall be in place to ensure safety, process efficiency and show quantifiable results. Methods to determine spent chemicals shall be in place to prevent a release to atmosphere. Release to atmosphere shall not be the indicator that chemical has reached saturation with H_2S or hydrocarbon.

IRP Safety Data Sheets (SDS) for all scrubbing or scavenging fluids must be on site.

IRP Chemical compatibility checks shall be performed for all chemicals used in the process to prevent unplanned chemical reactions.

2.9.5.1 Combustion

Combustion involves using flare or incineration to combust H_2S in gas streams. The challenge with combustion of H_2S is the creation of $S0_2$.

IRP Combustion must be as per local jurisdictional regulations for flaring (e.g., AER D060: Upstream Petroleum Industry Flaring, Incinerating, and Venting).

2.9.5.2 Scavenging

Scavenging is the process of injecting chemicals into fluid to neutralize H_2S. There are many available options for scavenging. Introducing chemicals into fluids, especially process fluids, can have effects on equipment, formation and, in some cases, can alter the properties of fluids.

2.9.5.3 Scrubbing

Low pressure scrubbing uses chemical/mechanical processes to remove H_2S from gas streams before it is released to atmosphere. This is commonly used to control emissions from atmospheric storage tanks, control emissions during truck loading operations and bleed off small amounts of gas (e.g., from lubricators or casing vents).

Pressurized scrubbing can be used to remove H_2S prior to flaring or to pipeline. Removing H_2S before flaring prevents $S0_2$ creation during the combustion process.

Gas venting from scrubber may not be sour but could be flammable. Ensure the scrubber has sufficient clearance from all possible ignition sources and that any accidental gas venting from a scrubber does not jeopardize worker safety.

2.9.6 Wellbore Remediation

Refer to IRP 26: Wellbore Remediation for information about wellbore remediation.

2.9.7 Wellbore Decommissioning

Refer to IRP 27: Wellbore Decommissioning for information about wellbore decommissioning.

2.9.8 Wellhead Freezing

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

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

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

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

2.9.9 Well Suspensions

Suspension requirements for sour wells are based whether they are sour or elevated sour (see per 2.2 Definitions) and considers the population density and the presence of public facilities or transportation corridors in the vicinity of the well.

IRP **All local jurisdictional regulations for suspension of sour wells must be followed.**

See AER D013: Suspension Requirements for Wells for more information about suspending wells.

Additional wellhead protection measures may be required when suspending a sour or elevated sour well. Consider the following:

- Design lease roads so that normal traffic does not pass near the wellhead.
- Construct berms or ditches to separate the lease roadway from the wellhead.
- Prevent access to the wellhead via physical means (i.e., wellhead cage or jersey barriers) with enough distance to prevent accidental damage.
- Use fencing around the perimeter of the lease.
- Use dual barriers to ensure well suspension integrity.

2.10 Quality Programs for Well Pressure Containing Equipment

Well pressure control or pressure containing equipment needs to be suitable for its intended service.

IRP A suitable quality program, in particular for well pressure containing equipment not manufactured in compliance with an applicable API specification and API Spec Q1 quality program, should be in place.

IRP Well pressure control equipment utilized for sour well completion and servicing operations shall be manufactured and maintained under a quality program to ensure conformance with the design specifications, including suitability for sour service.

2.10.1 API Equipment Manufacturing

Pressure control equipment includes BOPs, lubricators and stabbing valves.

IRP Well pressure containing equipment utilized in sour wells made to API specifications must be manufactured by an API licensed manufacturer.

IRP The equipment shall conform to all requirements of the applicable API specification and the manufacturer's written procedures in accordance with the manufacturer's approved quality Program.

IRP Technical quality requirements beyond the scope of and/or which exceed the technical/quality requirements of the applicable API specification shall be per manufacturer's written procedures.

More information about the documentation requirements can be found in API Spec Q1 and ISO 9001.

2.10.2 Non-API Equipment Manufacturing

This equipment includes circulating systems, line pipe, pump manifolds and tank manifolds.

IRP Well pressure containing equipment utilized in sour wells not requiring compliance to API specifications shall be manufactured by a company that has a quality program that addresses the following areas:

- Procurement control and traceability
- Incoming inspection
- Calibration of measurement and testing equipment
- Handling, storage and shipping procedures
- Quality records
- Personnel qualifications
- Inspection plans
- Manufacturer's mark
- Size and rated working pressure

IRP Well pressure containing equipment utilized in sour wells not requiring compliance to API specifications shall be identified as such in accordance with manufacturer's written procedures.

2.10.3 Quality Control Measures for Non-API Equipment

IRP The minimum quality control measures set out in Table 7 shall be used to ensure the well pressure containing equipment is suitable for sour well operations.

Note: Other tests may be required for special applications (e.g., Charpy impact testing for low temperature notch toughness).

Table 7. Minimum Quality Control Measures for Non-API Well Pressure Containing Equipment

Method	Notes
Mechanical Tests	Common tests are tensile and hardness
Non-Destructive Examination (NDE)	Common methods are ultrasonics, magnetic particle, dye penetration, visual
Dimensional Verification	Must conform to design specifications
Chemistry Verification	Must confirm to design specifications
Traceability to End User	Traceability of component from raw material through manufacturing processes to end user
Wellsite Traceability	Component(s) must be marked in such a fashion so that on-site personnel can verify that the component delivered to the well site is suitable for sour service

Appendix F lists destructive and non-destructive methods for the evaluation of materials.

2.10.4 Shop Servicing

Repair or service refers to cleaning, replacement of components and/or reworking of any API specified dimension within the tolerances implicated on the applicable API specification. Remanufacture refers to rework of OEM specified dimension and/or welding.

IRP Shop servicing and repairs shall be performed by either an API licensed manufacturer or a company that meets the requirements noted above

IRP Remanufacturing should only be performed by the OEM to ensure the proper operation of remanufactured equipment.

See AER D036: Drilling Blowout Prevention Requirements and Procedures, Appendix 5 - Requirements for Certifying, Storing, and Documenting Drill-Through Equipment for more information about equipment storage, servicing, repair and certification.

2.11 Elastomers

Elastomers are sealing components constructed of non-metallic materials such as the annular preventer and ram rubbers, bonnet or door seals and packing for BOP secondary seals. They are a material that is capable of recovering substantially in shape and size after removal of a defoming force.

Additional technical information on elastomers is available in the resources found in the Elastomers section of Appendix H.

2.11.1 Seal Design

Sealing materials normally include elastomers, elastomers in conjunction with plastics or elastomers/plastics bonded to metals for structural support. Plastics such as Teflon, Ryton or PEEK are polymers that are stronger and have better chemical resistance than elastomers but do not have the resilience (rebound) properties of elastomers. Plastics can be used in conjunction with elastomers for anti-extrusion back up.

There are many different elastomeric and plastic seal configurations available for well servicing and completion equipment. O-ring, V ring, bonded seals and compression force activated seals are some of the more common seal configurations.

Seal design is generally done by the equipment manufacturer.

IRP The following factors should be considered about seals:

- Seal movement: Differences between static and dynamic seals should be taken into consideration in the design.
- Service period: The length of service should be considered when selecting seal materials as often seal material will perform satisfactorily for a short service period but would be unsuitable for extended service periods.
- Seal maintenance: This is an important factor in selecting sealing materials. A wellhead seal may be relatively inaccessible and therefore require long-term performance, whereas a wireline lubricator seal can be changed out after each job.
- Changing service conditions: Seal selection should be based on longer-term changes that may occur in the well's produced fluids such as increasing H_2S or temperature. Also, initiation of secondary or tertiary recovery could have effects on sealing materials.

2.11.2 Service Conditions

Elastomers can be degraded as a result of exposure to commonly used chemical such as amines, sulphur dispersants or stimulation fluids.

IRP All elastomers must be suitable for sour service.

IRP All elastomers shall be compatible with the pressure testing fluids or any other fluid that may come into contact with the seals.

Consider the following environmental factors when choosing elastomers:

- Pressures
- Temperatures
- Testing fluids
- Servicing fluids (e.g., stimulation fluids, amines, sulphur solvents)
- Wellbore fluids (e.g., H_2S)
- Any other fluid that may come in contact with the seals

Elastomers and plastics have upper and lower temperature limitations that are usually published by the seal manufacturer and are available through them or the equipment supplier. Similarly, the general chemical resistance of elastomers at low temperatures may be critical for BOPs or other equipment. Supplementary heating could be required for the BOP element based on equipment manufacturer's guidelines or local jurisdictional regulations (e.g., AER D037: Service Rig Inspection Manual).

Gas can migrate into an elastomer under pressure. When pressure is released quickly gas may escape causing seal rupture (rapid gas decompression (RGD)). Consider a material's resistance to RGD when seals may be exposed and are not replaceable after rapid release of pressure. NORSOK M-710 specifies testing to exhibit resistance.

IRP When the use of sulphur solvents such as DMDS are contemplated DMDS resistant elastomers or metal-to-metal seals should be used to ensure long term sealing integrity.

2.11.3 Testing and Evaluation

IRP If there are any unknown environmental factors for the service application, testing of seals based on anticipated field conditions shall be performed.

IRP Suitability of elastomers and other sealing material shall be verified with manufacturer and meet all intended service requirements.

Pressure will affect seal mechanical design and operating parameters more than it affects the seal material. Rapid depressurization of the system can cause rupture of the seal material (explosive decompression).

IRP Testing to exhibit resistance to rapid gas decompression should be completed when seals may be exposed and are not replaceable after a rapid release of pressure.

The T5 temperature measured by the ASTM D1053 test or the TR10 plus 5°C temperature measured by the ASTM D1329 test can be used as estimates of a minimum operating temperature for an elastomer. The Glass Transition Temperature (Tg) of the elastomer is also used to help determine the low temperature capability.

Fluid exposures can cause changes in the seal material. Some of these changes are reversible and others are not. For example, the seal swelling caused by gas or oil permeation may reverse itself once the elastomer is removed from the exposure environment. H2S exposure to elastomers can cause additional cross linking of the elastomer to occur which results in embrittlement. This change is irreversible.

The aromatic component of mineral oil-based fluids that can be present in crude oil, invert emulsion drilling fluids and stimulation fluids can swell and weaken some elastomers. Alcohol, such as methanol, causes some elastomers to lose their resilience. Amine based corrosion inhibitors and sulphur solvent chemicals such as DMDS are very aggressive to many elastomers.

Negative effects of these chemicals can vary depending on the elastomer, service and concentration of chemicals. This effect may be difficult to predict and may require specific testing to determine adverse effects.

For non-metallic seals, such as elastomers, standard tests for sour environment can be found in API, ASTM, NACE, ISO and NORSOK standards. See the following:

- API 6A Annex F.1.13.5: Thermochemical Performance of Seal Materials
- NACE TM0187: Evaluating Elastomeric Materials in Sour Gas Environments
- ISO 23936: Petroleum, petrochemical and natural gas industries - Non-metallic materials in contact with media related to oil and gas production – Part 2: Elastomers
- NORSOK M710: Qualification of non-metallic materials and manufacturers - Polymers

2.11.4 Quality Control

IRP The licensee shall ensure that records are kept to identify the elastomer materials in use for first line well pressure control seals because there are no standard markings on most elastomer seals to indicate the elastomer material.

The first line well pressure control seals include equipment such as BOP elements, hydrostatic seals and wireline lubricator O-rings.

Many elastomers have a shelf-life due to sensitivity to sunlight and humidity. Inventory control is especially important because most elastomers look alike. Even in the same generic category such as nitrile, small chemical and dimensional variances made by manufacturers will drastically change the elastomer effectiveness for the given application.

IRP Storage and handling should be included in the quality control program.

2.12 Safety

This section discusses the specific safety practices and equipment, above and beyond general wellsite safety requirements, for completing and servicing sour or elevated sour wells with a service rig.

2.12.1 Fluids

IRP **The SDS must be current and available for use on site.**

IRP **Written procedures and fluid specifications must be available to all workers on location for safe handling and mixing of the completion/workover fluid.**

IRP **Transportation of Dangerous Goods (TDG), Workplace Hazardous Materials Information System (WHMIS 2015), applicable provincial Occupational Health and Safety regulations and local jurisdictional regulations must be adhered to.**

2.12.2 Equipment

Ambient temperature can impact the effectiveness of breathing apparatus exhalation valves, batteries, hoses and other rubber or flexible fittings.

IRP **A plan shall be in place for proper operation and maintenance of equipment in low or high temperatures.**

IRP **Equipment shall not be used outside the manufacturer specified operational limits for temperature**

IRP **All safety equipment shall be used, maintained, inspected and stored according to the manufacturer specifications and local jurisdictional regulations.**

2.12.3 Working With Explosives

Operations that involve the use of explosives (e.g., perforating) may involve the use of detonators. There are radio frequency (RF) safe detonators and non-RF safe detonators. Non-RF safe detonators can interfere with some transmitters (e.g., H2S monitors, radios, cell phones).

IRP When using detonators, particularly non-RF safe detonators, all transmitters should be shut off from the time the detonator is removed from its protective casing until the device is down hole a safe distance.

IRP Gas detection monitors must be turned back on as soon as it is declared safe to do so.

IRP In the case of a perforating gun misfire, all transmitters must be turned off while the gun is lifted out of the hole and until such time as it is declared safe to turn them back on.

2.12.4 Pre-Job Safety Meeting

IRP A safety meeting shall be held with all personnel on location prior to commencing operations or when there is any change of scope.

IRP Topics relating to sour operations that shall be covered in pre-job safety meetings are as outlined in Table 8.

Table 8. Pre-Job Safety Meeting Topics

Topic	Discussion Points	Notes
Scope of work	Discuss: • Objectives and Expectations • Nature of the job and services to be performed • Potential hazards	• Discuss the overall job procedures • Identify roles and responsibilities • Collect feedback
Site-specific hazards	Well Characteristics (e.g., pressure, percent H_2S, etc.)	• At minimum, include shut-in wellhead pressure and H_2S/CO_2 concentrations. • SDS
Site-specific hazards for more complex operations	Additional discussion points as operations become more complex	• Well deliverability (gas, condensate/oil, water) • Bottomhole pressure and temperature • Scales (sulphur, iron sulfide, other scales) • Wax, asphaltenes • Hydrates • Abnormal hole conditions

Topic	Discussion Points	Notes
Potentially serious hazards that require specific attention	Discuss: • H_2S release • Wellbore integrity • Well Kill practices	• Ignition criteria • Mechanical component review • Casing/tubing condition • Kill Fluid density
Site-specific policies and procedures	Discuss: • Work permits and procedures • Lock-out procedures • Ground disturbances • PPE requirements • Site training requirements (see 2.13 Wellsite Personnel Training and Experience)	Review all pertinent service company policies and procedures: • JSAs • ERPs • Hazard identification • Hazard assessments Review all licensee requirements: • Work authorization • Hazard assessments
Command Structure and Responsibilities	Review position hierarchy and ensure roles and responsibilities are defined in the event of a well control incident	• Shut-in criteria • Road block assignments • Ignition criteria • Muster area responsibilities • Personnel on site (headcount)
Communications	Ensure all call out numbers are confirmed.	• Local jurisdictional regulator contact • Local emergency authorities • Stakeholder communication
Security	Lease entrance control	Licensee-specific security measures
Emergency Procedures	Personnel need to understand the ERP	• Location of wind monitoring devices (socks or flagging) • Identification of any on-site emergency alarms • Emergency shut-down procedures • Location of site emergency equipment, such as first aid station or kit, fire extinguishers, air packs, etc. • Evacuation procedures and egress routes • Identification of safe briefing area • Location of nearest medical treatment facility and method for transporting injured workers

2.12.5 Breathing Apparatus

IRP Respiratory protection (breathing apparatus) must be available on location for all sour operations and must be fit-tested prior to use.

IRP Breathing apparatus must be utilized when continuous work is performed in an H_2S atmosphere exceeding 10 ppm.

The breathing apparatus can be Self Contained Breathing Apparatus (SCBA) or Supplied Air Breathing Apparatus (SABA) providing there are sufficient SCBA for emergency rescue operations. Refer to local OH&S regulations for SCBA and SABA specifications.

IRP There shall be a sufficient number to allow one breathing apparatus for each person directly involved with the sour operation or immediate emergency response to the sour operation.

IRP The minimum number of SCBA units available for each service rig must be as per local jurisdictional regulations.

In most jurisdictions the minimum is two units but in British Columbia it is four.

IRP A back-up air supply should be available for contingency purposes for all types of breathing apparatus.

Effective back-up may take the form of a spare trailer, a compressor located off the wellsite or a trailer at the local supplier that can be called out.

IRP The acquisition time for back-up air should be as low as possible.

IRP When using SABA, an auxiliary air supply sufficient for emergency egress shall be available.

2.12.6 H_2S Monitoring

IRP H_2S monitoring must be in place for all sour operations and must conform to local jurisdictional regulations.

The types of monitoring are as follows:

- Continuous area monitoring e.g., rig rat type)
- Personal monitor (i.e., gas detection monitor – single or 4-head)
- Periodic integrated sampling (i.e., tubes, pressurized gas samples)

IRP Personal gas detection monitors shall be used at all times.

IRP Area monitoring should be positioned in areas where workers will be present or may enter.

IRP All monitors must be capable of detecting H_2S at 10 ppm.

IRP All monitors must have proof of calibration.

IRP All monitors shall be tested daily to verify calibration.

IRP Workers shall wear a portable personal monitor when H_2S exposure is possible or area monitoring is unavailable.

IRP Lead acetate type indicators shall not be used as a substitute for continuous monitoring.

2.12.7 Continuous Mobile Downwind Surveillance Unit

IRP A continuous downwind monitor should be considered as part of Emergency Response Plan procedures.

An adequate mobile surveillance unit would be equipped with the following:

- A low range H_2S analyzer.
- a low range SO_2 analyzer.
- A strip pan recorder.
- Wind speed and direction indicators.
- Uninterruptible communications with the wellsite.

IRP In the event of a substantial release of H_2S or SO_2, an effective means of tracking the plume shall be in place to ensure the safety of others in the area.

Mobile air monitoring services are available for production testing, flaring operations and blowouts.

IRP Mobile air monitoring equipment shall be available on stand-by or within close proximity (i.e., minimal/reduced response time) when the wellsite is close to a major residential or recreational area and a release presents a risk to the public.

2.12.8 On-site Wind Monitoring

IRP A device to accurately measure wind speed and direction (in addition to a wind sock and/or flagging) should be considered to aid in the prediction of gas release direction and dissipation rate. Alternatively, localized current meteorological data could be utilized.

2.12.9 Emergency Warning System

IRP Equipment and procedures must be in place to warn area users of an H_2S release (e.g., residents, workers, recreational users, etc.) and appropriate actions to take when the warning system is activated.

Some examples include the following:

- Personal visit
- Information signs
- Telephone network
- Pagers
- Sirens or other audible devices

IRP Audible devices should be located for maximum coverage, particularly in heavily wooded or low-lying areas.

IRP To avoid public confusion, emergency warning systems shall not conflict with any pre-existing regulator-approved ERPs and warning systems for the area.

IRP Procedures shall be established to advise the public of appropriate action to take when the system is activated.

2.12.10 Control Stations

IRP Any wellsite where there is the potential for H_2S should have a warning sign posted at each control station.

IRP The following equipment should be in place at each access control station:

- A portable continuous H_2S monitor.
- One SCBA and one spare 30 minute cylinder.
- One portable road barricade.
- One gas detector with low range H_2S and SO_2 tubes.
- One reflective vest.
- A means of two-way communications with the site.
- One flashlight.
- A reliable and effective means to record entries and exits from the lease.

- A checklist for briefing visitors on the emergency evacuation plan.
- A stop sign.
- Other signs as required.
- Spare batteries for each battery powered piece of equipment.

IRP A system shall be in place to record who is present on the wellsite at all times. This includes names and a headcount.

IRP The checklist for briefing visitors should be signed by the visitor after orientation and kept on site until the visitor has left the site.

2.12.11 Ignition Systems

IRP An ignition system shall be available in case of a well control event.

IRP For elevated sour operations the primary ignition system shall be remotely operated with a secondary ignition system available.

IRP Ignition equipment has specific techniques for usage and should only be operated by competent personnel.

Appendix A: Revision Log

Edition 3

Edition 3 was sanctioned in January 2022. It reflects a complete editorial review and reformat to current IRP template and style guide completed in 2017 and then a full scope review that began in 2019.

Table 9. Edition 3 Revisions

Section(s)	Notes
All	Reformat/Editorial Review Revisions Document reformatted to current DACC Template and Style Guide. Incorporated information previously in appendices at the end of certain sections to be either part of the section or their own appendix at the end of the document.
All	Content Review Reviewed all content and updated to distinguish between sour and elevated sour. Changed christmas tree to wellhead throughout. Other terminology updated to match IRP 05. Removed content that was not specific to sour operations (e.g., lighting requirements). References all moved to end of document.
2.0 Preface	Update purpose, audience scope to match current document. Update background to include information relevant to this edition.
2.1 Introduction	Added to document.
2.2 Definitions	Added to document as basis for terminology used throughout for sour vs. elevated sour (instead of critical sour).
2.3 Planning	Added section with new content and content formerly in the safety and wellsite personnel training and experience sections. Updates to match new IRP 07 content.
2.4 Wellheads	Reorganized information so all flowing well information is together and all pumping wells information is together. Included information on fracture heads, wellhead isolation tools and wellhead grease (but not the prescriptive information that was formerly in Appendix B as it was out of date). Removed information on Tree Savers and wellhead recorders. Removed prescriptive content for well suspensions and replaced with generic information and reference to AER D013 (now in 2.0 Well Servicing). Note: A new IRP on Well Suspensions will be coming in the future (IRP 30). Wellhead freezing updated and moved to 2.9 well servicing.

Section(s)	Notes
	Removed most of the diagrams. Kept only typical sour pumping wellhead. Appendix C service equipment diagrams was removed. Appendix D frac head was removed. Appendix E of material requirements was moved to new Appendix C and revised (see below). Appendix F Wellhead and servicing materials was removed. Appendix G Modified Goodman Diagram was removed. Appendix G with calculation of shut-in tubing head pressures was removed and replace din the document with an IRP that the information needs to be provided as part of planning (2.3).
2.5 Well control Equipment	Formerly Service Rig BOP Stack Accumulator and Manifold. Reviewed RAM requirements and added information about blanking tool use. Removed lighting requirements. Moved appendix a diagrams to section 2.5. Removed material requirements tables. Appendix B shear blind ram requirements now in 2.5.1.1 Ram Requirements.
2.6 Downhole Equipment	Nipples, inserts, mandrels etc. now referenced as Tubular accessories. Removed Appendix A metallurgical recommendation table. Appendix B Corrosion Resistant Alloys and stainless steels information removed. Kept only information on common corrosive mechanisms. Now Appendix C. Appendix C Serviced Equipment and modified goodman diagram removed and replaced with content in the section on referencing API calculations. Appendix D Downhole Tool Applications removed. Appendix E Tool Positioning and Number removed. Appendix F Test Procedures for Installed SCSSVs now Appendix D and updated. Formulas removed and replaced with references to appropriate resources.
2.7 Tubular Goods	Removed manufacturing specifications (metallurgy, inspection, etc) and referenced IRP 01 where information is more comprehensive. Cleaned up terminology for compliant vs. non-compliant tubing. Appendix A Direct Corrosion Monitoring Methods now table in Appendix E. Appendix B Indirect Corrosion Monitoring Methods now table in Appendix E.
old 2.6 Braided Wireline Operations	Appendix A – diagrams removed. Appendix B Wireline Servicing Equipment removed. Section replaced with reference to IRP 13 in 2.9 Well Servicing.
2.7 Slickline Operations	Appendix A – diagrams removed. Appendix B Wireline Servicing Equipment removed. Section replaced with reference to IRP 13 in 2.9 Well Servicing.
Old 2.8 Snubbing Operations	Appendix A – diagrams removed. Section replaced with reference to IRP 15 in 2.9 Well Servicing.
Old 2.9 Coiled Tubing Operations	Appendix A – diagrams removed. Appendix B Coiled Tubing Units/Equipment removed.

Section(s)	Notes
	Section replaced with reference to IRP 21 in 2.9 Well Servicing.
2.8 Fluids and Circulating Systems	Reviewed and updated.
2.9 Well Servicing	New section to outline references to other well servicing IRPs and provide new information on Swabbing, Handling H2S, wellhead freezing and well suspensions.
2.10 Quality Programs for Well Pressure Containing Equipment	Clearly differentiate API and non-API. Appendix A Minimum Quality Control Measures for Non-API Well Pressure Containment Equipment now in section 2.10.3 Quality Control Measures for Non-API Equipment. Appendix B Material Evaluation Methods for Critical Sour Well Operations now in Appendix F. Definitions now in Appendix G.
2.11 Guidelines for Selection of Elastomeric Seals	Much of the educational type content reviewed and revised. Appendix A Outline of Typical Properties for Common Oilfield Elastomers removed.
2.12 Safety	General content for all well servicing removed and only items specific to sour/elevated sour remain. They have been reviewed. Note: Energy Safety Canada is preparing documentation about the general safety requirements that will likely be published before this IRP is sanctioned. Once available that document will be referenced from this section.
Old 2.13 Suspension Practices	Information moved to 2.9 Well Servicing and cleaned up to reference D13. Appendix A Well Suspension Schematics removed. Appendix B Inspection Checklist for Suspended Wells/Suspension Guidelines for Inactive Wells removed. Note: A new IRP for Well Suspensions will be available at a future date (IRP 30). At that time this IRP will be updated to reference the new IRP.
Old 2.14 Wellsite Personnel Training and Experience	General information removed. Relevant information moved to 2.3 Planning and updated to match concepts of new IRP 07.
Appendix C: Material Requirements	Removed tables of metallurgic requirements for specific components. Kept only reference materials for more information.
Appendix G: Glossary	Merged Acronyms and definitions as per template. Updated Acronyms to include all acronyms used in document. Updated Definitions to include all definitions used in document.
Appendix I: References	Reviewed and updated all references to current versions.

The following individuals helped develop Edition 3 of IRP 02 through a subcommittee of DACC.

Table 10. Development Committee

Name	Company	Organization Represented
Stephen Pun (chair)	Cenovus Energy	CAPP
Brian Hanson	Savanna Well Servicing	CAOEC
Steve Martinson	AMGAS	PSAC
Randal McNeill	TARA Energy Services	SME
Brian Murphy	Formerly of Shell Canada	SME
Preston Reum	Precision Well Servicing	CAOEC
Trevor Schable	CNRL	CAPP

Edition 2

Edition 2 was sanctioned in April 2006 and published in January of 2007. It reflects a review by the Well Services Review Committee and covered the following sections:

- 2.1 Wellheads
- 2.2 Service Rig BOP Stack Accumulator and Manifold
- 2.5 Fluids and Circulating System
- 2.6 Braided Wireline Operations
- 2.7 Slickline Operations
- 2.10 Quality Programs for Well Pressure Containing Equipment
- 2.12 Safety
- 2.13 Suspension Practices

Table 11. Edition 2 Development Committee

Name	Company	Organization Represented
Dustin Brodner	Petro-Canada	CAPP
John Butala	BP Canada Energy Company	CAPP
Art Congdon (Chair)	Petro-Canada	CAPP
Bob Cunningham	Canadian Petroleum Safety Council	CPSC
Joe Foose	Burlington Resources	CAPP
Adel Girgis	Alberta Energy and Utilities Board	Regulator

Name	Company	Organization Represented
Craig Goodall	Talisman Energy	CAPP
Mark Hornett	Burlington Resources	CAPP
Murray Sunstrum	Enform	
Russell Nelson	Shell Canada	CAPP
Jack Thacker	Husky Energy	CAPP
Larry Thorhaug	Pajak Engineering	PSAC
Harold Wells	BP Canada Energy Company	CAPP

Edition 1

Edition 1 of IRP 02 was Originally developed as Alberta Recommended Practice by the Blowout Prevention Well Servicing Committee.

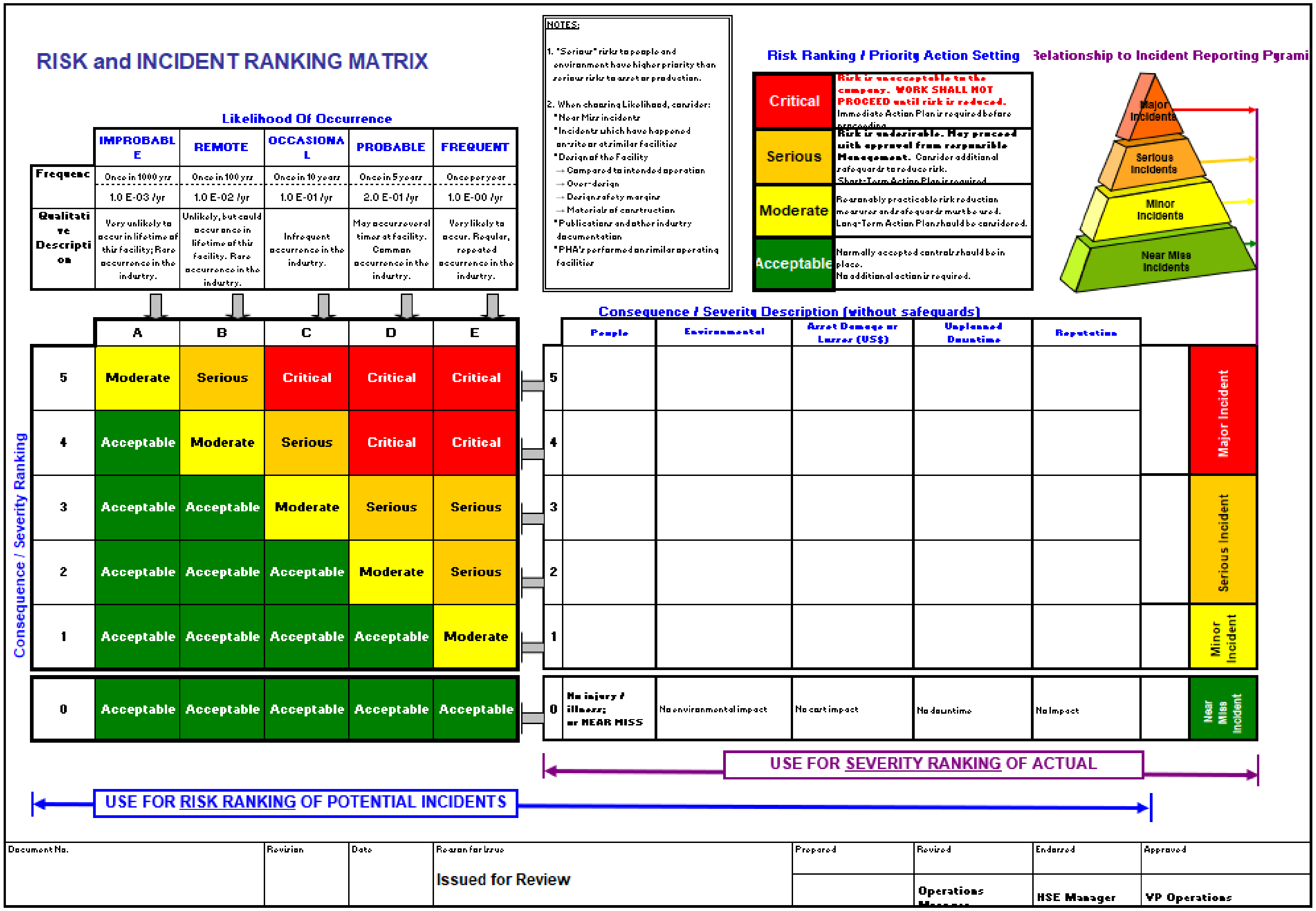
Appendix B: Risk Matrix

IRP 02 includes a template 5x5 Risk Matrix that can be used to perform a risk analysis for any sour operation. Along with the template are samples populated from a licensee (operator) and service provider perspective.

These are samples only and provided as a starting point. The template needs to be populated with information specific to each organization and their risk thresholds.

The figures below are pictures of these templates. The Excel spreadsheets can be found on the IRP 02 page of the Energy Safety Canada Website.

Figure 4. Risk Matrix Template



RISK and INCIDENT RANKING MATRIX

Likelihood Of Occurrence

	IMPROBABLE	REMOTE	OCCASIONAL	PROBABLE	FREQUENT
Frequency	Once in 1000 yrs 1.0 E-03 /yr	Once in 100 yrs 1.0 E-02 /yr	Once in 10 years 1.0 E-01 /yr	Once in 5 years 2.0 E-01 /yr	Once per year 1.0 E-00 /yr
Qualitative Description	Very unlikely to occur in lifetime of this facility; Rare occurrence in the industry.	Unlikely, but could occur once in lifetime of this facility. Rare occurrence in the industry.	Infrequent occurrence in the industry.	May occur several times at facility. Common occurrence in the industry.	Very likely to occur. Regular, repeated occurrence in the industry.

NOTES:

1. "Serious" risks to people and environment have higher priority than serious risks to asset or production.
2. When choosing Likelihood, consider:
   - Near Miss incidents
   - Incidents which have happened on-site or at similar facilities
   - Design of the Facility
     - Compared to intended operation
     - Over-design
     - Design safety margins
     - Materials of construction
   - Publications and other industry documentation
   - PHA's performed on similar operating facilities

Risk Ranking / Priority Action Setting

Critical	Risk is unacceptable to the company. WORK SHALL NOT PROCEED until risk is reduced. Immediate Action Plan is required before proceeding.
Serious	Risk is undesirable. May proceed with approval from responsible Management. Consider additional safeguards to reduce risk. Short-Term Action Plan is required.
Moderate	Reasonably practicable risk reduction measures and safeguards must be used. Long-Term Action Plan should be considered.
Acceptable	Normally accepted controls should be in place. No additional action is required.

Relationship to Incident Reporting Pyramid

Major Incidents
Serious Incidents
Minor Incidents
Near Miss Incidents

Consequence / Severity Ranking

	A	B	C	D	E
5	Moderate	Serious	Critical	Critical	Critical
4	Acceptable	Moderate	Serious	Critical	Critical
3	Acceptable	Acceptable	Moderate	Serious	Serious
2	Acceptable	Acceptable	Acceptable	Moderate	Serious
1	Acceptable	Acceptable	Acceptable	Acceptable	Moderate
0	Acceptable	Acceptable	Acceptable	Acceptable	Acceptable

Consequence / Severity Description (without safeguards)

	People	Environmental	Asset Damage or Losses (US$)	Unplanned Downtime	Reputation		
5							Major Incident
4							
3							Serious Incident
2							
1							Minor Incident
0	No injury / illness; or NEAR MISS	No environmental impact	No cost impact	No downtime	No Impact		Near Miss Incident

USE FOR SEVERITY RANKING OF ACTUAL

USE FOR RISK RANKING OF POTENTIAL INCIDENTS

Document No.	Revision	Date	Reason for Issue	Prepared	Revised	Endorsed	Approved
			Issued for Review		Operations Manager	HSE Manager	VP Operations

Figure 5. Operator Example

RISK and INCIDENT RANKING MATRIX

Likelihood Of Occurrence

	IMPROBABLE	REMOTE	OCCASIONAL	PROBABLE	FREQUENT
Frequency	Once in 1000 yrs 1.0 E-03 /yr	Once in 100 yrs 1.0 E-02 /yr	Once in 10 years 1.0 E-01 /yr	Once in 5 years 2.0 E-01 /yr	Once per year 1.0 E-00 /yr
Qualitative Description	Very unlikely to occur in lifetime of this facility; Rare occurrence in the industry.	Unlikely, but could occur once in lifetime of this facility. Rare occurrence in the industry.	Infrequent occurrence in the industry.	May occur several times at facility. Common occurrence in the industry.	Very likely to occur. Regular, repeated occurrence in the industry.

Consequence / Severity Ranking

	A	B	C	D	E
5	Moderate	Serious	Critical	Critical	Critical
4	Acceptable	Moderate	Serious	Critical	Critical
3	Acceptable	Acceptable	Moderate	Serious	Serious
2	Acceptable	Acceptable	Acceptable	Moderate	Serious
1	Acceptable	Acceptable	Acceptable	Acceptable	Moderate
0	Acceptable	Acceptable	Acceptable	Acceptable	Acceptable

NOTES:

1. "Serious" risks to people and environment have higher priority than serious risks to asset or production.

2. When choosing Likelihood, consider:
   - Near Miss incidents
   - Incidents which have happened on-site or at similar facilities
   - Design of the Facility
     - → Compared to intended operation
     - → Over-design
     - → Design safety margins
     - → Materials of construction
   - Publications and other industry documentation
   - PHA's performed on similar operating facilities

Risk Ranking / Priority Action Setting

Critical	**Risk is unacceptable to the company. WORK SHALL NOT PROCEED until risk is reduced.** Immediate Action Plan is required before proceeding.
Serious	**Risk is undesirable. May proceed with approval from responsible Management.** Consider additional safeguards to reduce risk. Short-Term Action Plan is required.
Moderate	Reasonably practicable risk reduction measures and safeguards must be used. Long-Term Action Plan should be considered.
Acceptable	Normally accepted controls should be in place. No additional action is required.

Relationship to Incident Reporting Pyramid

Consequence / Severity Description (without safeguards)

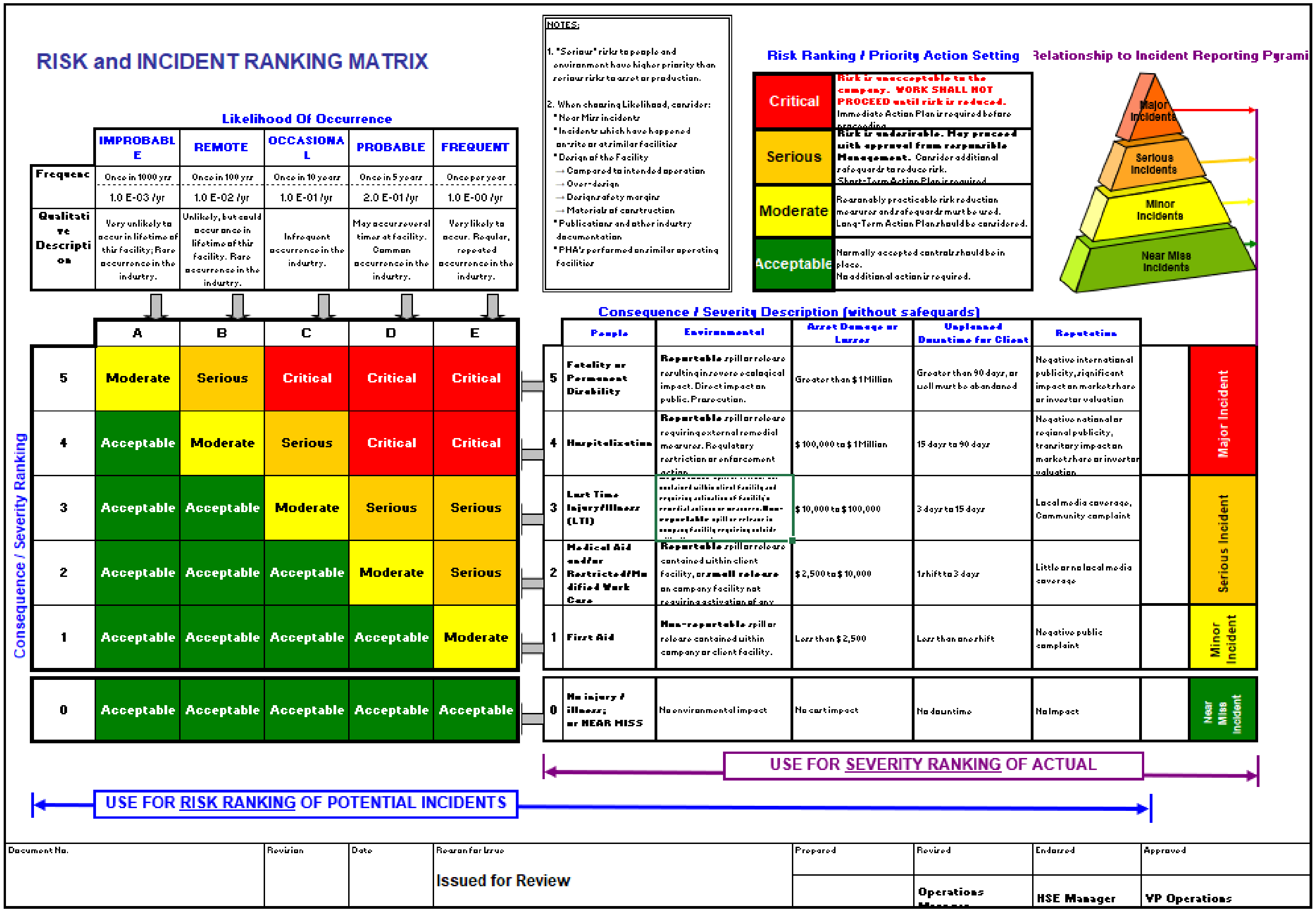
	People	Environmental	Asset Damage or Losses (US$)	Unplanned Downtime	Reputation		
5	Multiple Fatalities	**Reportable** spill or release into water resulting in severe ecological impact. Direct impact on public. Prosecution.	Greater than $75 Million	Greater than 90 days, or well must be abandoned	Negative international publicity, significant impact on marketshare or investor valuation		Major Incident
4	Single fatality or Permanent Disability	**Reportable** spill or release into water requiring external remedial measures. Regulatory restriction or enforcement action.	$10 Million to $75 Million	15 days to 90 days	Negative national or regional publicity, transitory impact on marketshare or investor valuation		Major Incident
3	Lost Time Injury / Illness (LTI)	**Reportable** spill or release not contained within facility and requiring activation of facility's remedial actions or measures.	$1 Million to $10 Million	3 days to 15 days	Local media coverage, Community complaint		Serious Incident
2	Restricted Work Case	**Reportable** spill or release contained within facility, or small release not requiring activation of any remedial measures.	$100,000 to $1 Million	1 shift to 3 days	Little or no local media coverage		Serious Incident
1	First Aid and/or Medical Aid	**Non-reportable** spill or release contained within facility.	Less than $100,000	Less than one shift	Negative public complaint		Minor Incident
0	No injury / illness; or NEAR MISS	No environmental impact	No cost impact	No downtime	No Impact		Near Miss Incident

USE FOR SEVERITY RANKING OF ACTUAL

USE FOR RISK RANKING OF POTENTIAL INCIDENTS

Document No.	Revision	Date	Reason for Issue	Prepared	Revised	Endorsed	Approved
(Example) 1234-567	R2	Dec. 5, 2019	Issued for Review	Superintendent	Completions Manager	HSE Manager	D&C Director

Figure 6. Service Provider Example



Appendix C: Material Requirements

Sulphide stress corrosion cracking can result in rapid failure of materials. Similarly, as noted in NACE MR0175/ISO 15156, austenitic stainless steels can fail rapidly from chloride stress corrosion cracking in certain environments.

Material selection for wellheads, well servicing equipment, BOPs, downhole equipment, wireline equipment and coiled tubing equipment needs to consider all conditions and parameters through the life of the well. Minimum testing protocols, such as hardness test or non-destructive test, are required to verify material quality in new, retrievable and re-used equipment or components.

The following outlines some of the industry standards for material requirements and specifications in a sour environment:

- API Spec 6A: Specification for Wellhead and Tree Equipment
- API Spec 11B: Specification for Sucker Rods, Polished Rods and Liners, Couplings, Sinker Bars, Polished Rod Clamps, Stuffing Boxes, and Pumping Tees
- API Spec 16A: Specification for Drill-through Equipment
- API Standard 6AR: Repair and Remanufacture of Wellhead and Tree Equipment
- API Standard 16AR: Standard for Repair and Remanufacture of Drill-through Equipment
- NACE MR0175/ISO 15156: Materials for use in H2S-containing environments in oil and gas production
- NACE MR0176: Standard for Metallic Materials for Sucker-Rod Pumps for Corrosive Oilfield Environments
- ASME Section IX: Qualification Standard for Welding, Brazing, and Fusing Procedures
- IRP 05: Minimum Wellhead Requirements
- IRP 13: Wireline Operations
- IRP 21: Coiled Tubing Operations

Appendix D: Test Procedures for SCSSVs

Function Test

A function test is a test of the SCSSV surface equipment under static conditions (i.e., well is shut in).

The following are the steps in the function test:

1. Record the control pressure.
2. Isolate the control system from the well to be tested.
3. Shut the well in at the wellhead.
4. Wait a minimum of five minutes. Check the control line for loss of pressure, which may indicate a leak in the system.
5. Bleed the control line pressure to zero to shut in the SCSSV. Close in the control line system and observe for pressure buildup, which may indicate faulty SCSSV system. If pressure buildup occurs take corrective action.

Leak Test

A leak test follows a function test and involves applying a differential pressure across the valve by bleeding off the pressure at the wellhead.

The following are the steps in the function test:

1. Bleed the pressure off the wellhead to the lowest practical pressure and then shut in the well at the wing or flowline valve. When possible, bleed flowline header pressure down to, or below, wellhead pressure and observe the flowline and wellhead for a change in pressure, which would indicate a faulty surface valve. Any leaks through the wing, or flowline valve, must be repaired before proceeding with the rest.
2. Observe the tubing pressure build up for one hour or measure flow from the well. Record and report leakage rate. For gas wells, flow rate can be computed from pressure build up formulas as found in API RP 14B Annex A.

For oil wells, the pressure build up depends on the static fluid level and the amount of gas in the oil. If the fluid level is below the SCSSV the formula for gas wells can be used. If the fluid level is above the SCSSV the leakage rate should be measured.

1. If the SCSSV failed to close or if the leakage rate exceeds 25.5 m^3/hr (0.4 m^3/min.) gas or 400 cc/min. liquid take corrective action.
2. Use the manufacturer's recommended reopening procedure after the SCSSV tests successfully.
3. When the SCSSV has been determined to operate properly and is opened, the control line pressure needs to be tied back into the system control pressure and the well can be placed back on production. Check well test rate. A significant reduction in the well test rate may be the result of the SCSSV not reopening fully.

Appendix E: Corrosion Monitoring Methods

Table 12. Direct Corrosion Monitoring Methods

Technique	Principle	Advantages	Disadvantages
Mechanical tubing Caliper Survey	Measure tubing ID and change with time	• Can identify regions in tubing where corrosion exists • Can identify pitting corrosion	• Scale buildup will affect results • Cost • Some tool limitations on smaller tubing • Downhole temperature limitation
Ultrasonic/ Magnetic Induction Log	Measure tubing material loss	• Can identify regions in tubing where corrosion exist. • Can identify pitting corrosion	• Scale buildup will affect results • Cost • Downhole temperature limitation
Visual Inspection	Direct visual inspection of tubing when pulled	• Can identify regions in tubing where corrosion exists • Can identify pitting corrosion • Can inspect each joint • No extra costs if tubing pulled for workover • Positive indication of corrosion	• Generally not practical to pull tubing for inspection only • Abrasive cleaning often necessary
Radioactive Joints	Place joint(s) in corrosion susceptible area(s)	• Can identify regions in tubing where corrosion exists • Direct indication of corrosion activity	• Does not distinguish general corrosion from pitting • Cannot directly determine corrosion rate
Sacrificial Pup Joints	Check produced fluids for radioactive solids	• Can identify regions in tubing where corrosion exists • Can identify pitting corrosion • Inexpensive • Destructive test possible	• Cannot change position Once tubing run • May never pull tubing

Table 13. Indirect Corrosion Monitoring Methods

Technique	Principle	Advantages	Disadvantages
Wellhead and Slipstream Coupons	Weight Loss	• Easy to install • Measures corrosion rates • Visual inspection can identify pitting	• Requires time to work • Not reliable for pitting corrosion
Electronic Monitoring – Electrical Resistance Probe	Change in resistance as probe corrodes	• Readings are much quicker than coupons	• Sensitive to deposits on probe • Averages corrosion • Not reliable for pitting corrosion
Electric Monitoring – Linear Polarization	Measures solution corrosivity	• Can be effective in optimizing corrosion mitigation programs	• Subject to fouling • Requires reasonable solution conductivity • Does not measure actual corrosion rates
Electronic Monitoring – Electrochemical Noise	Sensitive monitoring on probe elements	• Instantaneous measurements • Can distinguish between pitting and general corrosion	• Relatively expensive
Subsurface Coupons	Set in tubing measuring weight loss	• Measure corrosion rates • Visual inspection can identify pitting	• Change flow regime • May not be representative of actual corrosion • Difficult to retrieve
Downhole Scale Samples	Scrape off scale inside tubing to identify deposit chemistry	• Can check various sections • Presence of iron-based corrosion product may indicate some type of corrosion process	• Corrosion process may not be detrimental to tubing

Note: Surface measurements are not always representative of corrosion processes or conditions down hole.

Appendix F: Material Evaluation Methods

Table 14. Material Evaluation Methods

Type	Test	References	Notes
Non-Destructive Testing	Chemical Analysis	ASTM A751-20	• Used to establish the hardenability of the material and the likelihood of having hard heat affected weld zones which would be susceptible to SCC. • Used to determine the material type and its conformance to Tables I, II, and III of NACE MR0175/ISO 15156. • Used to confirm compliance with the one percent Nickle content restriction of NACE MR0175/ISO 151156.
	Eddy Current Inspection	ASME Section V ASTM E309-16	• Used for the detection of cracks and volumetric defects in tubular products, but variations in test equipment do allow for the inspection of other types of components
	Hardness Testing	ASTM E10-18 ASTM E18-20	• Used to confirm compliance with the one hardness restrictions of NACE MR0175/ISO 151156.
	Liquid Penetrant Inspection	ASME Section V ASTM E165-18	• Used to detect surface defects on non-magnetic components but can be used for magnetic components. • Several types are available with widely varying sensitivities. • For the detection of SCC use one of the more sensitive methods.
Magnetic Particle Inspection		ASME Section V ASTM E709-21	• Used to detect surface defects and near surface linear discontinuities in magnetic components. • For small fine cracking such as SCC, wet fluorescent techniques should be used.
Radiography		ASME Section V ASTM E1030-21	• Used to evaluate welds and castings for volumetric defects.
Ultrasonic Inspection		ASME Section V	• Used to evaluate welds and castings for volumetric defects and linear discontinuities (i.e., cracks).

Type	Test	References	Notes
Destructive Testing	Bend Testing	ASTM A370-20 ASTM A751-20	• Used to measure a weld or material's ability to deform under load without cracking or suddenly failing (usually used for weld procedure and welder qualification testing).
	Impact Testing	ASTM A370-20	• Used to establish a relative measure of the material's or weld's resistance to fracture at low temperatures under high and suddenly applied loads.
	Tensile Testing	ASTM A370-20	• Used to establish the yield and tensile strength of a material or weld as well as its ductility and whether it complies with the minimum specified values for that particular grade.

Appendix G: Glossary

The following glossary terms have been defined from an IRP 02 context.

AER Alberta Energy Regulator (formerly the AEUB)

ANSI American National Standards Institute

ASME American Society of Mechanical Engineers

API American Petroleum Institute

ASTM American Society of Testing Materials

BOP Blowout Preventer

BPV Backpressure Valve

BPWSC Blowout Prevention Well Servicing Committee

Calibration Comparison and adjustment to a standard of known accuracy.

CAOEC Canadian Association of Oilwell Energy Contractors

CAPP Canadian Association of Petroleum Producers

CO_2 Carbon Dioxide

CRA Corrosion-Resistant Alloy

DACC Drilling and Completion Committee Glossary Definition

DADS Diallyl Disulphide

DMDS Dimethyl DIisulphide

EPAC Explorers & Producers Association of Canada (EPAC)

EPZ Emergency Planning Zone

ERP Emergency Response Plan

ESD Emergency Shut Down (Valve)

EUE External-Upset-End (connection)

HIC Hydrogen Induced Cracking

HSN Highly Saturated Nitrile

ID Inside Diameter

IRP Industry Recommended Practice

JSA Job Safety Analysis

kPa Kilopascal

LPI Liquid Penetrant Inspection

MWPR Maximum Working Pressure Rating

MPI Magnetic Particle Inspection

NACE National Association of Corrosion Engineers

NCG Non-Condensable Gas

NORM Naturally Occurring Radioactive Material

OD Outside Diameter

OEM Original Equipment Manufacturer

Off-Gassing Gasses evolved from fluids. Off-gas can create an emission as it escapes a contained space and contacts the atmosphere.

OH&S Occupational Health & Safety

PPM Parts per Million

Premium Connections Premium connections have at least two additional features beyond API threads (e.g., alternate thread profiles, torque shoulder, metal to-metal seals).

Production Casing The casing which is packed off in the secondary seal of the tubing head.

PSAC Petroleum Services Association of Canada

PSL Production Specification Level

RF Radio Frequency

RGD Rapid gas decompression

RR Release Rate (of H_2S)

SABA Supplied Air Breathing Apparatus

SAGD Steam-Assisted Gravity Drainage

SCBA Self Contained Breathing Apparatus

SDS Safety Data Sheet(s) (formerly MSDS - Materials Safety Data Sheets)

SEA (Inspection) End area inspection (formerly “special end area inspection)”

Semi-Premium Connections Semi-premium connections have at least one additional feature beyond API threads (e.g., torque shoulder, resilient seals).

SCSSV Surface Controlled Subsurface Safety Valve

SITHP Shut-In Tubing Head Pressure

SMYS Specified Minimum Yield Strength

Sour Service Equipment Equipment manufactured to be resistant to Sulphide Stress Cracking in accordance with NACE MR0175/ISO 15156.

SO_2 Sulphur Dioxide

Stress Corrosion Cracking (SCC) Brittle failure by cracking under combined action of tensile stress and corrosion in the presence of water and hydrogen sulfide or chloride.

Surface Safety Valve An automatic wellhead valve assembly which will close upon loss of power supply (as per API Spec 6A). It is designed to shut in a well automatically in the event of abnormal pressure fluctuations in the flowline (due to fire, ruptured line, surface equipment faults/failure, damaged wellheads, etc.).

Well Pressure Containing Equipment Well completion and servicing equipment that includes but is not limited to wellheads, BOPs, wireline lubricators, tubing, landing nipples and plugs and downhole packers.

WHMIS (2015) Workplace Hazardous Materials Information System

Appendix H: References and Resources

American Petroleum Institute

API RP 5A5, API Recommended Practice 5A5 (2015): Field Inspection of New Casing, Tubing, and Plain-end Drill Pipe, Seventh Edition, Includes Errata (2009).

API RP 5B1, API Recommended Practice 5B1 (R2015): Gauging and Inspection of Casing, Tubing and Line Pipe Threads, 1999.

API RP 5C1, API Recommended Practice 5C1 (R2020): Recommended Practice for Care and Use of Casing and Tubing, 1999.

API RP 11BR, API Recommended Practice 11BR (R2020): Recommended Practice for the Care and Handling of Sucker Rods, Ninth Edition.

API RP 14B, API Recommended Practice 14B: Design, Installation, Repair and Operation of Subsurface Safety Valve Systems, Sixth Edition.

API Spec Q1: Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry, Ninth Edition, Includes Errata (February 2014), Errata 2 (March 2014), Errata 3 (2019), Addendum 1 (June 2016) and Addendum 2 (2018).

API Spec 5B: Threading, Gauging, and Inspection of Casing, Tubing, and Line Pipe Threads, Sixteenth Edition, Includes Errata 1 (2018), Errata 2 (2018), Addendum 1 (2018), Addendum 2 (2019) and Addendum 3 (2021)

API Spec 5CT: Specification for Casing and Tubing, Tenth Edition, Includes Errata 1 (2018), Errata 2 (2019), Errata 3 (2020) and Addendum 1 (2021)

API Spec 6A: Specification for Wellhead and Christmas Tree Equipment, Twenty-First Edition, Includes Errata 1 (2019), Errata 2 (2020), Errata 3 (2020) and Addendum 1 (2020).

API Spec 11B: Specification for Sucker Rods, Polished Rods and Liners, Couplings, Sinker Bars, Polished Rod Clamps, Stuffing Boxes, and Pumping Tees, 27th Edition (With Errata 1, October 2010, Errata 2, February 2011)

API Spec 16A: Specification for Drill Through Equipment, Fourth Edition, Includes Errata 1 (2017), Addendum 1 (2017).

API Std 6AR: Standard for Repair and Remanufacture of Wellhead and Tree Equipment, Second Edition.

API Std 16AR: Standard for Repair and Remanufacture of Drill-through Equipment, First Edition, Includes Errata 1 (2017).

API TR 5C3: Calculating Performance Properties of Pipe Used as Casing or Tubing, Seventh Edition, Includes Addendum 1.

American Society of Testing Materials

ASTM D1053-92a (2018), Standard Test Methods for Rubber Property—Stiffening at Low Temperatures: Flexible Polymers and Coated Fabrics, ASTM International, West Conshohocken, PA, 2018, www.astm.org

ASTM D1329-16, Standard Test Method for Evaluating Rubber Property—Retraction at Lower Temperatures (TR Test), ASTM International, West Conshohocken, PA, 2016, www.astm.org

DACC

Available from Energy Safety Canada website at www.EnergySafetyCanada.com:

- IRP 01: Critical Sour Drilling
- IRP 03: In Situ Heavy Oil Operations
- IRP 04: Well Testing and Fluid Handling
- IRP 07: Competencies for Critical Roles in Drilling and Completions
- IRP 13: Wireline Operations
- IRP 14: Non-Water Based Drilling Fluids
- IRP 15: Snubbing Operations
- IRP 21: Coiled Tubing Operations
- IRP 26: Wellbore Remediation
- IRP 27: Wellbore Decommissioning
- IRP 28: Wellsite Waste Management

European Committee for Standardization

Petroleum and natural gas industries – Downhole equipment – Subsurface safety valve equipment. BS EN ISO 10432:2004. Standards Policy and Strategy Committee, January 2005.

International Organization for Standardization

ISO 9001:2015 Quality Management Systems - Requirements.

ISO 23936-2:2011: Petroleum, petrochemical and natural gas industries - Non-metallic materials in contact with media related to oil and gas production - Part 2: Elastomers

National Association of Corrosion Engineers

NACE MR0175/ISO 15156, Petroleum and natural gas industries - Materials for use in H2S-containing environments in oil and gas production (Identical to ISO 15156-1:2015, ISO 15156-2:2015, ISO 15156-3:2015), November 2015.

NACE MR0176-2020: Standard for Metallic Materials for Sucker-Rod Pumps for Corrosive Oilfield Environments, August 2020.

NACE TM0187-2011: Standard Test Method - Evaluating Elastomeric Materials in Sour Gas Environments

Other

ASME Section IX, 2019 ASME Boiler and Pressure Vessel Code, Section IX: Welding and Brazing Qualifications, July 2019.

Energy Safety Canada Well Service BOP Manual

CSA Z246.2 Emergency preparedness and response for petroleum and natural gas industry systems, January 2018

NORSOK M710: Qualification of non-metallic materials and manufacturers – Polymers, October 2014.

Provincial Regulations

Alberta

Available from www.aer.ca:

- AER Directive 013: Suspension Requirements for Wells
- AER Directive 036: Drilling Blowout Prevention Requirements and Procedures
- AER Directive 037: Service Rig Inspection Manual
- AER D071: Emergency Preparedness and Response Requirements for the Petroleum Industry
- AER ID 90-01: Completion and Servicing of Sour Wells

Available from www.alberta.ca:

- Alberta Occupational Health and Safety Act, First Aid Regulation, Edmonton, Alberta.
- Alberta Occupational Health and Safety Act, General Safety Regulations, Edmonton, Alberta.
- Alberta Occupational Health and Safety Act, Noise Regulation, Edmonton, Alberta.
- General Safety Regulation, Part 5 – Personal Protective Equipment; Noise Regulation
- Oil and Gas Conservation Act, Oil and Gas Conservation Rules, Regulation 151/1971, With amendments up to and including Alberta Regulation 158/2017

British Columbia

Available from www.WorkSafeBC.com:

- Occupational Health and Safety Regulation, Part 8 - Personal Protective Clothing and Equipment; Part 7, Noise Control; Part 11, Fall Protection
- British Columbia Occupational Health and Safety Legislation

Manitoba

Available from www.gov.mb.ca:

- Manitoba Occupational Health and Safety Legislation

Saskatchewan

Available from www.gov.sk.ca:

- Occupational Health and Safety Regulations, Part VII - Personal Protective Equipment; Part VIII, Noise Control and Health Conservation
- Saskatchewan Occupational Health and Safety Legislation

Elastomers

Practice for Rubber and Rubber Lattices   Nomenclature, D1418 85, ASTM, Philadelphia, PA.

Definitions of Terms Relating to Rubber, D1566 87a, ASTM, Philadelphia, PA.

Classification System for Rubber Products in Automotive Applications, D2000-86, ASTM, Philadelphia, PA.

Machine Design, Elastomers and Rubbers, April 14, 1988, pg. 185-200.

Proven Methodology for Elastomer Life Estimation Utilized in the Energy Sector, J.K. Arora, B.G. Parker, H. Salem, University of Akron, Akron, Ohio, September, 1998.