DRILLING AND COMPLETION COMMITTEE

IRP 04:

Well Testing and Fluid Handling

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

Volume 04 (Draft 21 October 9, 2024) – 2024

CANADIAN ASSOCIATION OF ENERGY CONTRACTORS

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

CANADA'S OIL & GAS ENTREPRENEURS™

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Availability

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

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4.0 Preface

4.0.1 Purpose

The purpose of this document is to provide recommended practices for safe well testing and fluid handling operations.

4.0.2 Audience

The intended audience for this document includes oil and gas company engineers, field consultants, well testing and fluid handling personnel, other specialized well services personnel and local jurisdictional regulators. It is assumed that the reader has at least a basic understanding of well testing and fluid handling operations.

4.0.3 Scope and Limitations

The scope for this IRP includes land-based operations in Western Canada spanning from British Columbia (BC) to Manitoba and the Territories.

It includes personnel requirements and operational procedures pertaining to well testing and the loading, unloading and transportation of fluids. IRP 4 is not intended to replace local jurisdictional regulations or the transportation regulations that are already defined in the Transportation of Dangerous Goods (TDG) regulations. While the IRP addresses operations in western Canada the logic can be applied to other jurisdictions.

The recommendations within IRP 4 are the general, minimum recommended procedures and best practices necessary to carry out operations in a manner that protects people (the public and workers) and the environment. IRP 4 does not eliminate the need for a risk-based approach for each company's individual operations.

4.0.4 Revision Process

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

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

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

4.0.5 Sanction

The following organizations have sanctioned this document:

Canadian Association of Oilwell Energy Contractors (CAOEC)

Canadian Association of Petroleum Producers (CAPP)

Enserva

Explorers & Producers Association of Canada (EPAC)

4.0.6 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.

4.1 Introduction

An integral part of the exploration and development of oil and gas resources is reservoir evaluation. Evaluation methods with the greatest inherent environmental and safety concerns are those which remove reservoir fluids by means of drill stem testing, well testing or any other methods of flowback. The safe handling of highly volatile reservoir or stimulation fluids and corrosive or toxic fluids are of concern when evaluating a well to avoid developing a combustible hydrocarbon gas/air mixture.

The environmental, safety and health risks associated with well testing and fluid handling can be minimized by implementing prudent procedures, using properly designed equipment and ensuring workers are properly trained.

4.2 Roles and Responsibilities

4.2.1 Minimum Owner and/or Prime Contractor Requirements

The Owner and/or Prime Contractor is responsible for all activities on a lease. The safety of on-site workers and environmental protection takes precedence over well testing and fluid handling requirements.

Refer to IRP 07: Competencies for Critical Roles in Drilling and Completions for more information about ensuring worker competency.

IRP Owners and/or Prime Contractors shall prepare a program of operations available to all service companies involved to view before starting the job.

IRP The program of operations should include, but is not limited to, the following:

- The purpose of the operation
- Relevant well data
- Communication of area and well characteristic hazards
- Equipment requirements and layout having regard for pressures and flows expected
- Environmental and safety considerations relative to on-site workers and the public
- Special procedures to be employed
- Flowback objectives
- Flowback sequence in appropriate detail
- Technical contact in case of unexpected program deviations
- Emergency Response Plan with contacts and procedures

IRP Owners and/or Prime Contractors must provide first aid equipment, transportation, and/or attendants, as specified by the local jurisdictional regulations.

IRP When a reportable volume of wellhead gas is produced, either to an orifice device or through a separator, the Owner and/or Prime Contractors must notify the local jurisdictional regulator as required.

4.3 Safety Considerations

Worker safety guidelines and recommendations are meant to supplement existing local jurisdictional regulations and occupational health and safety (OHS) requirements and are provided as a minimum operating practice.

4.3.1 Minimum General Safety Standards

IRP The following minimum standards must be followed:

- All workers must be fit for duty.
- All workers must wear appropriate personal protective equipment (PPE) while on the work site.
- Where respiratory Protective Equipment is required, workers must be clean shaven with fit testing completed according to local legislative requirements.
- Wellsite illumination must meet regulatory requirements and be sufficient to safety perform the job (see the Energy Safety Canada Lease Lighting Guideline).
- Fall arrest equipment and a fall protection plan must be available as required by local jurisdictional regulations.
- Appropriate firefighting equipment must be available as determined by the hazard assessment, the fire and explosion control plan, and applicable regulations.
- Smoking and vaping are allowed in designated areas only and must not be within 25 metres (m) of potentially flammable vapours.
- The potential for hot work needs to be considered during the hazard assessment to obtain work permits before any work or maintenance.
- First aid and washing facilities as needed based on risk assessment.
- Safety Data Sheets for hazardous materials required for the operation.

IRP The following minimum standards shall be followed:

- Weapons shall not be allowed on location except for emergency ignition of uncontrolled gases or if an approved wildlife management plan is in place. See the Energy Safety Canada Wildlife Awareness A Program Development Guideline.
- Wind direction indicators shall be present on location (e.g., windsocks, flagging tape).
- Equipment spacing and operations shall be assessed to ensure that the potential for a fire and explosive condition is not created.

Note: Fire and explosive conditions are created when sufficient volumes of air, fuel and an ignition source combine in the required quantities. The fire triangle or fire tetrahedron provides examples of air, fuel, and ignition sources. See the Energy Safety Canada Fire and Explosion Hazard Management Guideline.

- All personnel shall report to the supervisor, complete a hazard assessment, then report to the onsite supervisor if available, and/or assigned representative before entering the work area.

4.3.2 Pre-Job Safety Meeting

IRP A pre-job safety meeting must be held and documented, and a hazard assessment performed and communicated before commencing any operation.

Topics for the pre-job safety meeting include, but are not limited to, the following:

- A list of personnel on location
- Emergency contacts and procedures, safety equipment on location and their operation, muster points and exclusion zones
- Scope of work
- Hazards and corresponding hazard controls
- Procedures to be followed
- Responsibilities of each person involved in the operation
- Pertinent well, fluid, and chemical characteristics (i.e., Safety Data Sheets)
- Simultaneous and concurrent operations

IRP Safety Data Sheets (SDS) for hazardous chemicals, fracturing fluids and production fluids must be on location and reviewed.

IRP Following the pre-job safety meeting a detailed shift handover should be conducted and documented including a review of cross shift operations, notes, and an onsite walk around.

IRP Interim safety meetings shall be held any time conditions or job scope change from the initial scope.

IRP The Owner and/or Prime Contractor shall obtain a flare permit if applicable, and the permit shall be reviewed and conspicuously posted.

4.3.3 Well Testing Personnel

IRP The well testing company and the Owner and/or Prime Contractor shall determine how many qualified well testing workers are required to safely operate flowback equipment.

IRP To determine the number of qualified well testing workers needed, the following should be considered:

- Scope of the operations:
  - Offset well history
  - The complexity and layout of the equipment and operations involved
  - Rigging in and out operations
  - Job tasks that the workers will need to complete, that are not directly associated with well testing (e.g., fluid transfer, lease maintenance).
  - Duration of flowback
  - Volume and waste management
  - Additional procedures that are required (e.g., tank gauging flare enrichment, circulating fluids, operating line heaters, use of tank farms and the operation of choke manifolds in erosive environments).
- The level of risk identified on the pre-job hazard assessment:
  - Expected production rates and surface pressures
  - Simultaneous operations (SIMOPs)
  - Flow stream characteristics including chemical, biological, and radioactive substances and exposure limits (e.g., Benzene, Naturally Occurring Radioactive Material (NORM), hydrogen sulphide (H_2S), silica)
  - Sand content and potential erosion
  - The volatility of produced natural gas condensates and the volume of off-gassing
  - The management, storage, and transportation of the produced well effluents
  - Weather conditions
  - Distance to lodging and emergency services

4.3.3.1 Minimum Well Testing Workers Qualifications

IRP At a minimum, well testing personnel shall have the following:

- Intermediate First Aid as per the Canadian Standard Association (CSA) Standard Z1210-17 (R2021) First Aid Training for the Workplace – Curriculum and Quality Management for Training Agencies
- H_2S Alive®
- Common Safety Orientation and company specific Safety Orientation
- Workplace Hazardous Materials Information System (WHMIS)
- Transportation of Dangerous Goods (TDG)

IRP Well testing personnel should have additional training including but not limited to the following:

- NORMs awareness
- Benzene awareness
- Fire and explosion training
- Wildlife awareness

IRP The well testing service provider shall identify the competencies required for well testing personnel. See the Energy Safety Canada Supervisor Competency A Program Development Guide.

4.3.3.2 One Competent Well Testing Worker per Shift

IRP If one competent well testing worker per shift is to be used on a location, the following should be considered in addition to the considerations noted above (See 4.3.3 Well Testing Personnel):

- Ensure a Hazard Assessment/Job Safety Analysis (JSA) has been completed and documented to confirm the tasks are suitable for one worker.
- Implement a Working Alone Plan.
- Address tasks that involve breaking the integrity of a closed system (e.g., choke change).
- Manage the use of emergency shut down devices.

IRP Confined space activities must not be conducted by a lone worker.

4.3.4 Minimum Personal Protective Equipment (PPE) Requirements

IRP The employer shall develop a personal protective equipment policy, considering the potential hazards at the work site.

IRP The following minimum personal protective equipment required for the work site shall be

- CSA approved hard hat,
- CSA approved work boots,
- CSA approved safety glasses,
- fire retardant outerwear,
- gloves suitable for the task and
- garments made of natural fibers worn under the fire-retardant outerwear.

IRP Additionally, the following personal protective equipment should be considered:

- CSA approved hearing protection where sound levels exceed 85 decibels (dBA)
- Chemical protective gloves selected according to the Safety Data Sheet
- CSA approved fall protection equipment when working at height
- CSA approved respiratory protection equipment when required by the hazard assessment and atmospheric monitoring
- Cold weather clothing and footwear

IRP Fit testing and audiometric testing, as per local legislative requirement, must be completed where RPE and hearing protection equipment is required.

4.3.5 Well Designation for H_2S Environments

Sweet and sour designations are used by industry and local jurisdictional regulators as a reference for administrative purposes. For technical purposes, specific concentrations of H_2S dictate the appropriate equipment requirements to conduct the tasks in a manner that maintains the health and safety of the worker while ensuring the integrity of the equipment. The well designations of this IRP are centred on H_2S content, which is the most frequently encountered hazardous substance by well testing workers.

There may be other hazardous substances that need to be considered when planning work programs to ensure worker safety. Occupational exposure limits (OEL) vary by province and the applicable provincial OEL should be referred to when substances other than H_2S are known to be present at the well site. The well designations in this IRP are designed for worker safety when working in H_2S environments.

4.3.6 Respiratory Protection

IRP At a minimum, the Owner and/or Prime Contractor must ensure the following breathing equipment is provided:

- Two self-contained breathing apparatus (SCBAs) must always be on location (regardless of well designation). Additional SCBA may be required as per local jurisdictional requirements.

- H_2S concentration determinations must be performed while wearing breathing apparatus.
- At a minimum Supplied Air Breathing Apparatus (SABA)must contain an adequate air supply system complete with air cylinders, manifold, work lines and egress packs and a minimum of two back packs (i.e., SCBAs).

Refer to local jurisdictional regulations and CSA-Z94.4 Selection, Use and Care of Respirators for more information.

IRP Workers must wear suitable respiratory protective equipment when required by local jurisdictions or when they will be exposed to harmful substances or hazardous atmospheres exceeding the OEL.

IRP A competent safety standby person, equipped with appropriate rescue equipment, shall monitor workers who are wearing SABA.

4.3.7 Gas Detection Monitoring for Explosive and Flammable Limits

IRP The Owner and/or Prime Contractor must ensure a gas detection meter capable of measuring lower explosive limits (LEL) is available on site.

IRP Where an owner representative is not assigned to the site, the Owner and/or Prime Contractor shall ensure a gas detection meter is available to the site workers.

IRP The gas detection meter must be properly calibrated, and personnel must be properly trained to use it.

See 4.5 Other Types of Flowbacks for more detail on the requirement of gas detection and flowing wells to open tank systems.

Refer to the Energy Safety Canada Fire and Explosion Hazard Management Guideline for more information.

4.3.8 Equipment Inspections

IRP Well testing companies should establish a routine equipment inspection program that is structured to reject or repair service-related defects and improper field replacements in accordance with local jurisdictional requirements and OEM recommended practices or company specific standards.

IRP To reduce the impact of environmental factors such as corrosion, erosion and stress cracking, equipment should be designed, fabricated, inspected, and tested to meet the demands of its most severe anticipated service conditions.

IRP Well testing companies shall repair or alter piping and vessels in accordance with this IRP and local jurisdictional requirements. See 4.4.8.6 Codes on Construction.

IRP Equipment must be routinely serviced and tested by qualified/competent workers as per the manufacturer's specifications or regulatory requirements. The Owner and/or Prime Contractor is responsible to ensure an onsite pre-job safety equipment inspection is completed (see Appendix B: Pre-Flow Inspection Checklist).

4.3.9 Grounding and Bonding

IRP Cable utilized for grounding and bonding shall be in good condition and the insulation undamaged.

Grounding provides electrical continuity to enable electrical currents to dissipate into the earth.

IRP The Owner and/or Prime Contractor shall provide a suitable ground point.

IRP The Owner and/or Prime Contractor and service company should collaborate to determine an acceptable resistance level for the current being dissipated and the area where the grounding is applied.

Note: For larger electrical systems, a lower resistance ground of 10 ohms is generally considered adequate.

IRP Before starting transfer operations, trucks must be grounded directly to the earth or bonded to a properly grounded object.

Bonding ensures equipment that is connected by hose or piping has the same electrical potential, preventing the formation of different electrostatic potentials. This reduces the likelihood of a spark being created in the presence of flammable vapors.

IRP Before and during operations, a continuity check shall be performed using an ohmmeter at predetermined intervals.

4.4 Well Testing Design Considerations

4.4.1 Process Flow Diagrams

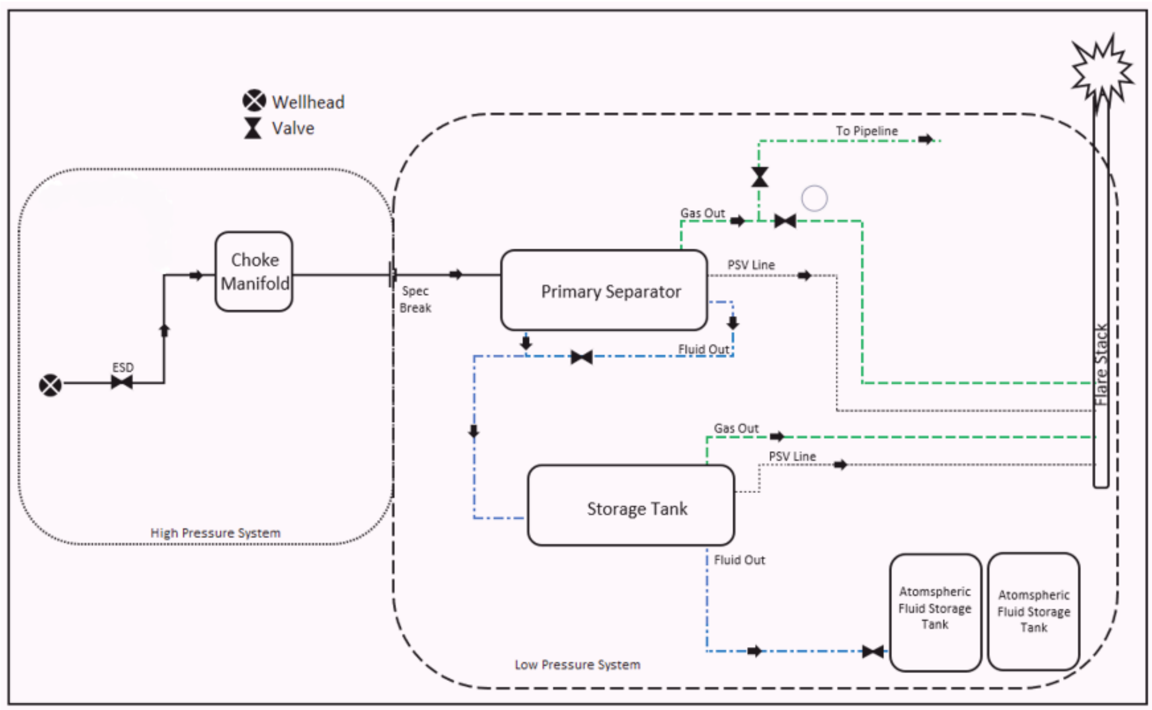
IRP Process flow diagrams (PFDs) should be included when planning and designing a flowback operation to provide a high-level picture of onsite tasks for frontline workers.

PFDs are not to be confused with Process and Instrumentation Diagrams (P&ID). P&IDs are much more detailed, showing all system instrumentation and are suitable for detailed design and hazard and operability study. However, PFDs provide a simplified picture to ensure equipment is rigged-in safely.

IRP Key elements of a PFD should include the following, as needed:

- Each major piece of equipment (e.g., tanks, choke manifolds, chokes, flares)
- Direction of flow
- Pressure rating of the piping and components
- Pressure rating and volume of pressure vessels
- Specification breaks, if any (e.g., high to low pressure, large to smaller inside diameter)
- Locations of valves, check valves, tees, data headers, injection ports, etc.
- Locations of sample points
- Safety devices, if needed (e.g., emergency shut down valves, high pressure switches)

Figure 1. Process Flow Diagram Example



4.4.2 Erosion and Velocity Considerations

The premature wear and failure of piping and components can be attributed to erosion caused by solids (e.g., wellbore debris, sand) and well fluids. This is influenced by factors such as velocity, flow stream density and pressure staging practices. Erosion within flow piping and components can result in

- worker exposure to toxic, acidic, basic, and abrasive well effluents,
- unintended release of liquids and environmental damage,
- disruptions in the well production process.

IRP Workers shall be able to control and measure the velocity to establish a maximum acceptable flow velocity and reduce excessive velocity and corresponding erosion.

With proper erosion mitigations followed, premature wear of piping and components can be reduced through

- implementing positive trim in chokes (fixed choke) as it is less susceptible to washing than adjustable trim,

- evaluating choke trim materials to ensure materials are suitably rated,
- decreasing the erosion at pressure drop locations by reducing the pressure differential at each step in the process through pressure staging which can be done by utilizing dual drop manifold(s),
- suitably sizing the primary separator to provide sufficient pressure drop reduction downstream of the choke manifold,
- limiting turns/swings in the flow line to decrease turbulence, pressure drops and erosion,
- installing targeted/cushion swings at corners,
- installing larger inside diameter piping to lower the velocity and corresponding erosion,
- using chokes and avoiding the choke manifold bypass (gut line) to decrease velocity upstream of the choke manifold,
- using tested and company approved chemicals for removal of foam and emulsions to assist in the separation of sand finds that can carry over to the gas and oil phases of the separator,
- regularly removing sands from the primary separator to avoid carry over to the gas and oil phases of the separator.
- installing a length of pipe immediately behind the choke manifold to help normalize the flow stream prior to the primary separator.
- conducting periodic and planned inspections of the flow piping, inlets and outlets to proactively identify and replace washed fittings.

4.4.3 Radiant Heat

Atmospheric flaring during flow operations to a flare stack is common in the upstream oil and gas industry. Prolonged atmospheric flaring can produce additional hazards to the work site. Potential risk factors associated with atmospheric flaring and radiant heat include

- discomfort, heat exhaustion and skin damage for workers stationed near the flare stack,
- overheating of nearby tools and equipment, leading to hot surfaces that pose a risk of contact burns for workers and the potential ignition of combustible materials,
- overheating of vegetation and fuels, with the potential for spontaneous combustion.

Factors that can affect the radiation from a flare stack include

- Gas composition (British thermal unit (Btu) value)
- Flame type (lazy, lift off, steady)

- State of fuel/air mixing (as per the design of the flare stack)
- Soot and smoke formation
- Quantity being burned
- Liquid in the flare gas (natural gas condensates)
- Flame temperature
- Flare burner design
- Combustion equipment condition
- Smoke suppression fluid quantity (this could be viewed as flare enrichment for Western Canadian operations)
- Flammability limits
- Proximity to vegetation and combustible materials
- Height of the flare stack

Radiant heat risk factors can be reduced by

- designing and operating flares for a maximum thermal radiation of 1.58 kilowatt per square metre (kW/m^2) (500 British thermal units per hour per square foot ($Btu/h\text{-}ft^2$) - 4.73 kW/m^2 (1500 $Btu/h\text{-}ft^2$),
- calculating radiation (radiant heat) from the flare stack using the following formula (see American Petroleum Institute (API) 521 Pressure-relieving and Depressuring Systems).

Equation 1. Calculating Radiant Head from the Flare Stack

$$D = \sqrt{\frac{\tau \cdot F \cdot Q}{4\pi \cdot K}}$$

Note: This calculation does not account for a lazy flame.

For more information refer to local jurisdictional requirements.

4.4.4 Gas Flares

IRP Well Test Supervisors must confirm with the Owner and/or Prime Contractor the presence of a flare permit or ensure that proper notification has been done.

IRP Gas flares should be operated with the following considerations:

- Follow the original equipment manufacturer's (OEM's) specifications and local jurisdictional requirements (whichever is more stringent).

- Avoid using check valves within the flare line. Flashback controls, such as flame arrestors and purge or blanket gas practices, should be operated within OEM specifications and if applicable, local jurisdictional requirements.

IRP Gas flares must be operated in accordance with local jurisdictional requirements and with the following considerations:

- Owners and/or Prime Contractors must define flare stack diameters and height to prevent H_2S emissions and reduce SO_2 fallout.
- Flare stacks must be spaced to prevent combustion of vegetation or other nearby materials.
- Flare stacks must be installed and operated according to the OEM's specifications.

See Appendix D: Flare Stack Maximum and Minimum Flare Rates.

4.4.5 Dispersion Modelling

Dispersion modelling is used to predict the ground level concentrations of one or more sources of air pollutants (e.g., SO_2).

IRP The Owner and/or Prime Contractor shall complete dispersion modelling in accordance with the local jurisdictional requirements where the flaring operation is conducted.

IRP The dispersion modeling should consider the following factors when determining if the flaring conditions will meet regulatory requirements:

- Proximity to rural or urban centres
- Season during which the flaring occurs
- Meteorological data such as wind speed, ambient temperature, expected precipitation
- Terrain characteristics
- Flaring duration (i.e., total hours flared)
- Continuous vs intermittent flaring
- Gas Characteristics such as H_2S concentration, gas composition, high heating value of the gas
- Flare stack height
- Flare stack tip diameter
- Maximum gas flaring rate
- Total volume of gas flared
- Whether dilution gas is used and at what rates

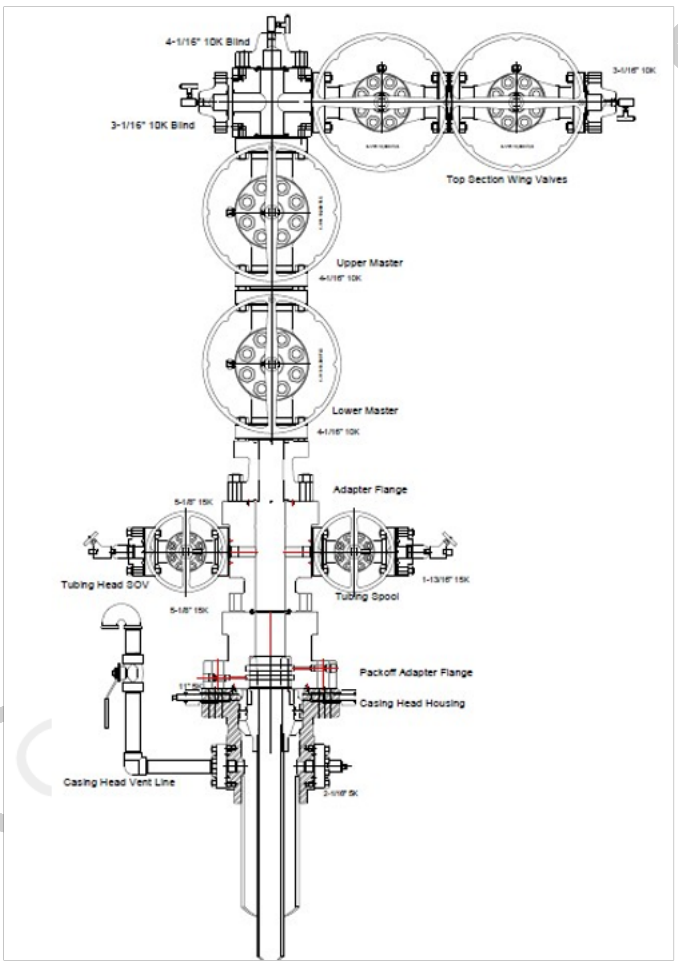
4.4.6 Wellheads

IRP Wellheads should be selected, designed, manufactured, installed, pressure tested, and pressure rated in accordance with IRP 05: Minimum Wellhead Requirements.

IRP To protect the integrity of the wellhead valving a working valve shall be installed directly downstream of the wellhead primary master valve or casing valve before commencing flowback operations. See Figure 2. Example wellhead with Working Valve.

See IRP 5 Minimum Wellhead Requirements for wellhead design.

Figure 2. Example Wellhead



4.4.7 Flare Knockouts

Flare knockouts add another layer of process safety by preventing liquid carryover in flow systems. Using pressurized vessels in flare, vent and pressure relief lines ensures no fluid is released up the flare stack when handling liquids in the system.

Flare stacks can be configured with a widened section (i.e., catch can or knockout) at the base of the flare stack to manage minor amounts of condensation but will not be able to manage liquid carry over into the system.

IRP Flare knockouts should be considered in the design criteria to ensure process safety and environmental mitigation when required. Key considerations include the following:

- Number of vessels connected to the flare system on site
- Maximum design rates through the process including gas liquid ratio, gas composition, and liquid composition
- Distance from flare stack
- Volume
- Light hydrocarbons
- Sour vs sweet service
- Process upset
- Pressure Safety Valve (PSV) sizing and number tied into the process
- Number of vessels tied into the flare system on site
- Pipeline failure
- Liquid carryover
- Pressure rating to meet process requirements
- Pressure drop across the process
- Assessment and mitigation of restrictions in the knockout system
- Lockout/tagout in process controls to ensure a clear flow path through the knockout system
- Ambient and process temperature
- Procedures for volume checks, emptying, or managing fluid levels

IRP Hazard assessments shall be conducted to ensure the flare knockout system is appropriately sized for the worst-case scenario based on design criteria.

4.4.8 Equipment Specifications

4.4.8.1 General

IRP The Owner and/or Prime Contractor must ensure there is sufficient means of fluid management.

IRP Equipment flow capacities and pressures shall be sized for the anticipated flow rates of the program.

Flow capacities may be derived from detailed calculations, monographs or with guidance from the OEM.

IRP The upstream system and the liquid storage stage must be designed to eliminate and/or control the escape of vapours to the environment.

IRP Atmospheric liquid storage shall be designed and operated to limit the escape of flammable and toxic vapours to the atmosphere.

4.4.8.2 Emergency Shut Down Devices

IRP An ESD must be installed as per local jurisdictional requirements. See IRP 2 Completing and Servicing Sour Wells. Also, see Alberta Energy Regulator (AER) D071: Emergency Preparedness and Response Requirements for the Petroleum Industry and British Columbia Energy Regulator (BCER) BC Emergency Management Manual for details regarding site emergency response plan requirements for when a residence or roadway is within emergency boundaries.

IRP An emergency shut down device (ESD) shall be considered in the following situations:

- During flowback if a coil or tubing string is present through master valves
- If the wing valve is not in an accessible location (e.g., based on height, safety zone considerations)
- If the well contains H_2S
- If the hazard assessment indicates the valve may be necessary (e.g., potential for abrasives, operating pressures, fluid make-up, substances that fall under exposure control plans)

IRP Workers should be made aware of the location and use of emergency shutdown controls.

IRP The maximum allowable working pressure (MAWP) of the ESD should be equal to the MAWP of the wellhead.

IRP If the MAWP of the ESD is lower than the MAWP of the wellhead there should be a working valve between the wellhead and the ESD to prevent the ESD from overpressure.

IRP The ESD should be installed on the wellhead whenever possible or as close to the wellhead as reasonably practicable.

IRP The ESD should be installed on the wellhead using flanged connections.

IRP The internal dimension of the ESD should be sufficient to prevent flow restrictions and minimize the risk of internal wear or plugging that could compromise the ESD's ability to shut in the well.

IRP If the ESD activates during flowing operations, the cause of the activation should be investigated, a hazard assessment completed, and the operator's or service provider's start-up procedure evaluated, considering the fluids and pressures in the system.

IRP Before conducting flow and pressure testing the ESD shall be verified to ensure it is within its certification and maintenance period. Keep all relevant documentation/certification available for immediate reference.

IRP After installation, pressure tests should be conducted on all ESD connections, upstream and downstream up to the maximum allowable working pressure.

4.4.8.2.1 Function Testing

IRP ESDs shall be function tested before flow is introduced through the valve.

IRP ESDs should close in under 30 seconds.

IRP Periodic function testing of ESDs should be considered as closure times can be impacted by hose size and length, ambient temperature, wellbore pressures and wellbore debris.

IRP ESD function tests should be documented with the closure time identified.

4.4.8.3 Pressure Pilots/Shutdown Switches/Transmitters

Pneumatic pressure pilots can be used to protect the integrity of vessels, piping, or pipelines.

IRP The set points for pressure pilots, switches, and transmitters must not exceed the maximum allowable working pressure.

IRP Pressure pilots, shutdown switches and transmitters should be set, calibrated, and documented by a competent technician. Electric pressure/level/temperature switches/transmitters can be utilized in conjunction with pneumatic ESD systems with the installation of solenoids.

IRP A function test of each pressure pilot, shut down switch and transmitter should be conducted and documented to ensure the installed ESD closes within 30 seconds.

4.4.8.4 Pressure Safety Valves

IRP PSVs must be directed to a safe area for discharge.

IRP If PSVs are vented with piping to atmosphere, the installation of weather caps on discharge piping should be considered to prevent any blockage from entering and potentially creating a blocked flow situation.

IRP Vessel PSV lines must be directed to a flare stack with a continuous pilot on wells containing H_2S.

IRP PSV discharge piping shall not have any internal dimension reductions unless otherwise verified by a professional engineer to maintain adequate relief rates.

IRP Valves should not be present in PSV relief lines.

IRP Fuel gas PSVs on scrubbers are not required to be routed to the flare stack but should be piped to a height where gas plumes will not endanger nearby workers.

IRP The following shall be taken into consideration if PSV discharge piping will be combined with another PSV and verified by a professional engineer to maintain adequate relief rates:

- Number of vessels
- Pressure rating of vessels
- Intended use of the vessel
- Anticipated flowrate
- H_2S content
- Source pressure
- Type of PSVs
- PSV discharge line dimensions
- Low point drain for discharge

Refer to local jurisdictional requirements, CSA B51:19, Boiler, Pressure Vessel, and Pressure Piping Code and ASME Boiler and Pressure Vessel Code Section VIII - Rules for Construction of Pressure Vessels for more information.

IRP PSV maintenance should be conducted by a licensed service provider at intervals in accordance with local jurisdictional requirements (e.g., Alberta Boilers Safety Association, Technical Safety BC). Specific company policies may be more stringent and should be followed accordingly.

4.4.8.5 Heat Requirements

IRP Heat requirements should be considered to address the flowing well characteristics including, but not limited to the following:

- Carbon dioxide (CO_2) content
- H_2S
- Emulsion/wax formation
- Solution gas
- Solids
- Chemical/fluid freeze points
- Ambient temperatures
- Hydrate potential (see 4.7 Hydrates)

4.4.8.6 Codes on Construction

IRP Metallic equipment used in H_2S service must adhere to API and National Association of Corrosion Engineers (NACE/NACE International – now The Association for Materials Protection and Performance (AMPP)) requirements.

IRP Pressurized tanks used for flowback, or storage of fluids produced from a sour well must be manufactured under a quality program to ensure conformance with design specifications utilizing materials that meet the requirements of NACE MR 0175-2021/ISO 15156-1:2020 Petroleum and Natural Gas Industries – Materials for Use in H_2S-Containing Environments in Oil and Gas Production (latest edition).

IRP Forgings and fittings such as flanges, caps, valves, controllers must be identifiable by markers from API, American National Standards Institute, CSA, Original Equipment Manufacturers (OEM) markers and a Canadian Registration Number.

IRP Pipe should be identifiable by fabrication standards, drawings, or purchase orders. Pipe marking by low stress dies is discretionary.

IRP Pressure equipment must be manufactured and constructed as per local jurisdictional requirements and standards.

Consult the latest editions of the following resources for more information:

- American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code
- ASME B31.3, Pressure Piping
- ASME B16.5, Pipe Flanges and Flanged Fittings
- CSA B51, Boiler, Pressure Vessel and Pressure Piping Code
- CSA Z245.12, Steel Flanges
- CSA Z662, Oil and Gas Pipeline System Code
- NACE MR0175-2021/ISO 15156-1, 2020, Petroleum and Natural Gas Industries – Materials for use in H_2S Containing Environments in Oil and Gas Production
- Alberta Safety Codes Act
- Saskatchewan Boiler and Pressure Vessel Act
- British Columbia Safety Standards Act

4.4.8.7 Pressure Vessels

IRP The manufacturer's plate and corresponding vessel specific information must be affixed to the pressure vessel.

IRP Pressure vessels must be manufactured, maintained, and operated in accordance with the OEM's specifications and local jurisdictional regulations (e.g., Safety Codes Act and Pressure Equipment Safety Regulation).

4.4.8.8 Pressure Piping

IRP Line pipe threading should not be used above 3000 kilopascals (kPa), for pipe sizes above 33 mm (1" nominal) unless a hazard assessment has been completed and additional controls evaluated.

IRP Line pipe threading ratings shall adhere to the manufacturer's specifications at a minimum and API 6A Specification for Wellhead and Christmas Tree Equipment at a maximum.

For all external upset end threaded tubing, refer to the manufacturer's specifications for pressure ratings.

IRP Pressure piping must be manufactured, maintained, and operated in accordance with the OEM's specifications and local jurisdictional regulations.

IRP Swivels shall not be used in flowback operations.

4.4.8.9 Wellhead and/or Permanent Infrastructure Connections

IRP A hazard assessment must be conducted to determine the appropriate wellhead and/or permanent infrastructure connections.

IRP Processes must be in place during the planning stage to ensure that all equipment is selected and operated within the OEM's specifications.

IRP The planning phase should consider any permanent infrastructure impacts such as potential specification (spec) breaks between equipment, to ensure operation within the manufacturer's technical specifications.

IRP Technical specifications for wellhead connections must be identified and documented prior to connecting to the wellhead.

4.4.8.10 Other Connections

Connections that are not defined by standards such as ASME, API, or CSA, may be acceptable (e.g., Camlock connections, Unibolt connections) provided the following conditions are met:

- The working pressure temperature rating is clearly stated by the manufacturer.
- The manufacturer has established the working pressure according to proper engineering standards.
- The connection is suitably rated for the product.

IRP Components should be identifiable through OEM markings or product catalogues if such catalogues uniquely identify the component and are traceable to it.

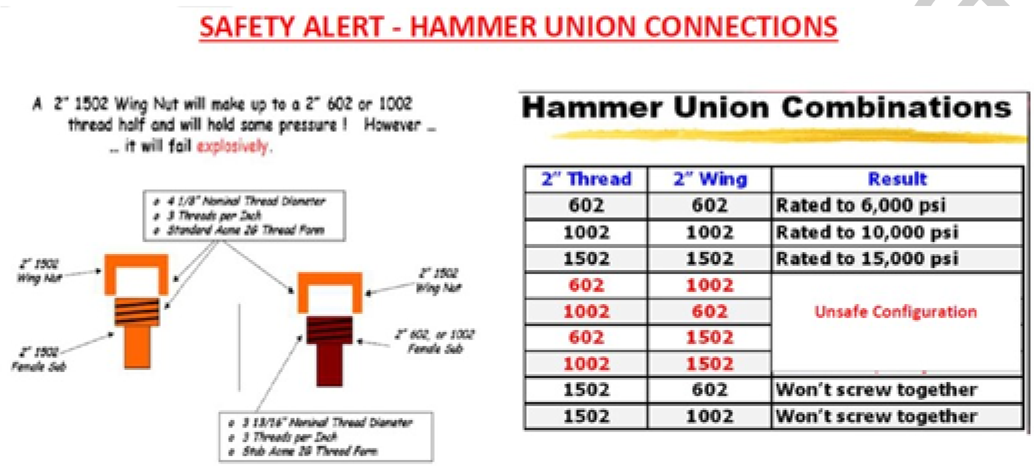
IRP All 50.8 millimetres (mm) (2") unions shall have a unique identification system. Table 2 shows a sample union identification system using colour coding.

Note: A recognized system is provided as an example. The testing company's quality control manual may use alternative systems.

Table 2. Union Identification

Union Figure Number or Name	Colour	Reichs-Ausschuß für Lieferbedingungen (RAL) Colour Code
602	Red	3020
1502	Blue	5002
Guiberson/607	White	9010

Figure 3. Mismatched Unions have Caused Fatal Accidents



2" Thread	2" Wing	Result
602	602	Rated to 6,000 psi
1002	1002	Rated to 10,000 psi
1502	1502	Rated to 15,000 psi
602	1002	Unsafe Configuration
1002	602	
602	1502	
1002	1502	
1502	602	Won't screw together
1502	1002	Won't screw together

4.4.8.11 Flexible Pipe

IRP **Flexible pressure piping (e.g., swivel joints, pressure hose) must be suitably rated for the pressure, product, and temperature it will be used for and exposed to, as identified by the manufacturer.**

IRP **All flexible piping must be secured as per local jurisdictional requirements.**

4.4.8.12 Elastomers

IRP **Elastomers must be suitably rated for the intended flow conditions.**

IRP Flowing characteristics and effluent properties of the well (e.g., H_2S, potential of hydrogen (pH), temperature, methanol, aromatics, condensate properties) should be considered when selecting elastomers for compatibility.

Refer to IRP 02: Completing and Servicing Sour Wells, Guidelines for Selecting Elastomer Seals and NACE TM 0187-1987, Evaluating Elastomeric Materials in Sour Gas Environments for more information.

4.4.9 Well Testing Equipment Spacing

IRP The IRP 4 Minimum Equipment Spacing table available from Energy Safety Canada should be reviewed as a general guideline to meet spacing requirements and provincial regulations.

IRP Locations with multiple services and concurrent operations can produce additional hazards. The following should be considered when positioning well testing equipment on a location:

- Potential flammable gas sources and ignition points (e.g., sample points, choke manifold bleedoff points)
- Worker exposure to toxic chemicals, high noise sources and high-pressure lines
- Common wind direction and operations downwind of the test equipment and flare stack
- The location of well testing and third-party high-pressure lines
- The content of the producing well (e.g., H_2S, NORMs). Refer to local jurisdictional requirements for exposure limits.
- Distance from the flare stack and potential fuel sources, such as chemicals, vegetation, workers, and other equipment. See 4.4.3. Radiant Heat and 4.4.4 Gas Flares for additional information.

IRP All flame generating equipment should be considered flame type unless the equipment is fitted with a suitable flame arrestor system.

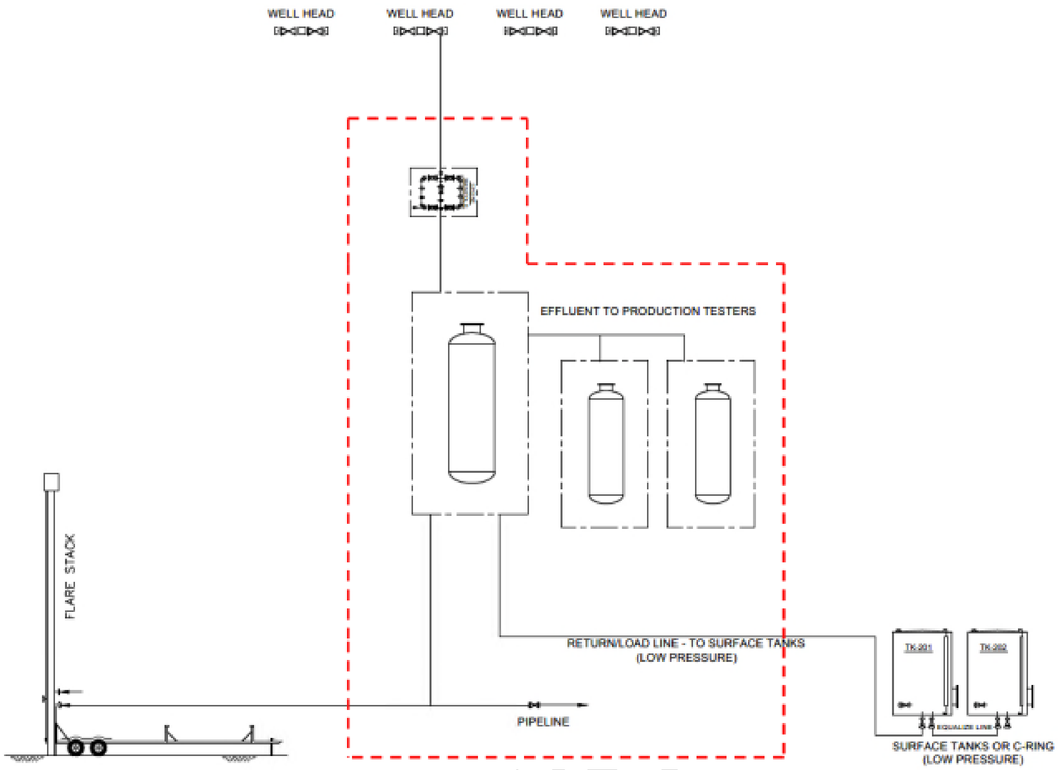
Refer to IRP 20: Wellsite Design Spacing Recommendations for spacing guidelines and recommendations.

4.4.9.1 Well Testing Exclusion Zone

An exclusion zone is a predefined area with the potential for increased exposure to high-risk hazards where access is restricted to workers or limited to only trained workers. Some form of approval is required for workers to enter the exclusion zone.

Exclusion zones may already be identified in existing documents such as company SOPs and technical procedures. See Figure 4. Well Testing Exclusion Zone.

Figure 4. Well Testing Exclusion Zone



IRP Exclusion zones shall be defined and identified to all on-site personnel.

IRP Exclusion zone boundaries shall be determined based on a site-specific hazard assessment.

4.4.9.2 Approval to Enter an Exclusion Zone

It may be necessary to enter or pass through an exclusion zone to during operations to perform short-duration tasks.

IRP There shall be a process in place to approve worker entry to the exclusion zone. This process shall include minimizing the number of workers entering the zone and the duration for which they are in the zone.

IRP The number of workers and frequency of which they enter or pass through the exclusion zone shall be kept to a minimum.

The process this approval takes will vary by site, Owner, Prime Contractor and/or Service Company and may depend on local jurisdictional regulations.

4.4.9.3 Propane Storage Tanks

IRP Propane storage tanks must not be located within a tank dike containing flammable liquids and they must not be filled above 80% capacity.

IRP Propane storage tanks must be secured and transported in accordance with TDG and local jurisdictional requirements.

IRP Propane tanks must have clearly visible certification labels.

IRP The vaporizer shall be a minimum of eight metres from the propane storage tank(s) and 10 m from the base of the flare stack.

IRP The following should also be considered before placing propane storage equipment:

- The interconnecting pipe from the propane storage tanks to the vaporizer should be hard-piped and the interconnecting material should be fire resistant.
- The vaporizer should be inspected and cleaned regularly in accordance with OEM standards.
- The supply and filling lines should be positioned outside of high traffic areas (i.e., foot and vehicular traffic).
- Tarping of propane vessels for use with external heat sources to vaporize liquid propane during cold weather operations should only be used with equipment that has been manufactured and certified for that application (e.g., steam wand, heat blanket).
- Valved ports on the propane storage tanks should be plugged when not in use.
- Consideration should be given to the direction of discharge if the PSV on the propane storage vessel is triggered.

IRP When using a vaporizer, the equipment must be placed at a distance from the wellhead that meets the minimum requirements set by the local jurisdictional regulator for open flame equipment. All other potential sources of vapour must be considered when positioning the vaporizer to prevent a fire or explosion.

IRP Consideration should be given to using steel lines near flare stacks, incinerators, and the vaporizer.

IRP A check valve shall not be installed between propane storage tanks and a vaporizer. Vaporizers are designed to vent back to the propane tank. Failure to follow this statement could result in over pressurizing of the vaporizer.

4.4.9.4 Multiple Certified Pressurized Tanks

IRP Where two or more certified, pressurized tanks are used as either a primary flow vessel or for storage of fluids, the tanks must be a minimum of 25 m from the wellhead and can be placed side-by-side.

4.4.9.5 Non-Certified, Non-Registered Vessels or Pressure Tanks

IRP All non-registered, non-certified vessels or pressure tanks must be at least 50 m from the wellhead, 50 m from the flare stack or any open flame, and 25 m from flame arrested equipment (e.g., line heater).

4.4.9.6 Electrical and Electronic Area Classification

IRP The temperature classification of any electrical or electronic device within the classified area should be considered. The auto-ignition point of the gases or chemical vapours that may be present should also be considered.

IRP All equipment installed in a hazardous location as defined by the Canadian Electrical Code (CEC), Part 1, Section 18, must be installed in accordance with the electrical code. If the equipment does not meet the CEC, the equipment must be outside the hazardous location. API RP 500 Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class 1, Division 1, and Division 2, provides classifications of hazardous locations at petroleum facilities.

Table 3. Hazardous Locations Summary Chart

Definition of Zone or Division	CEC Hazardous Location Classes and Division	CEC Hazardous Location Zones
An area in which an explosive mixture is continuously present or present for long periods	Class I, Division 1 (Gases)	Zone 0 (Gases)
	Class II, Division 1 (Dusts)	Zone 20 (Dusts)
An area in which an explosive mixture is likely to occur during normal operation	Class I, Division 1 (Gases)	Zone 1 (Gases)
	Class II, Division 1 (Dusts)	Zone 21 (Dusts)
An area in which an explosive mixture is not likely to occur during normal operation and if it occurs, it will exist only for a short time	Class I, Division 2 (Gases)	Zone 2 (Gases)
	Class II, Division 1 (Dusts)	Zone 22 (Dusts)
	Class III, Division 1 (Fibres)	
	Class III, Division 2 (Fibres)	

IRP When placing electrical components near processing equipment consideration should be given to the following changing conditions throughout the duration of the job:

- Adequate ventilation

- Physical properties of gas and vapours
- Environmental conditions such as wind and temperature
- Duration of gas and vapours present
- Volume or concentration of the gas and vapours (i.e., minimum level of explosive material present)
- Electrical components need to be accessible for emergency shut down.

IRP The following diagrams (Figures 5-10) from the Technical Safety Authority of Saskatchewan's Code of Electrical Installations at Oil and Gas Facilities 5th Edition 2021, should be referenced when determining spacing of electrical equipment.

Figure 5 Hazardous Area Classification Diagram – Process Vents and Instrument & Control Devices Vents

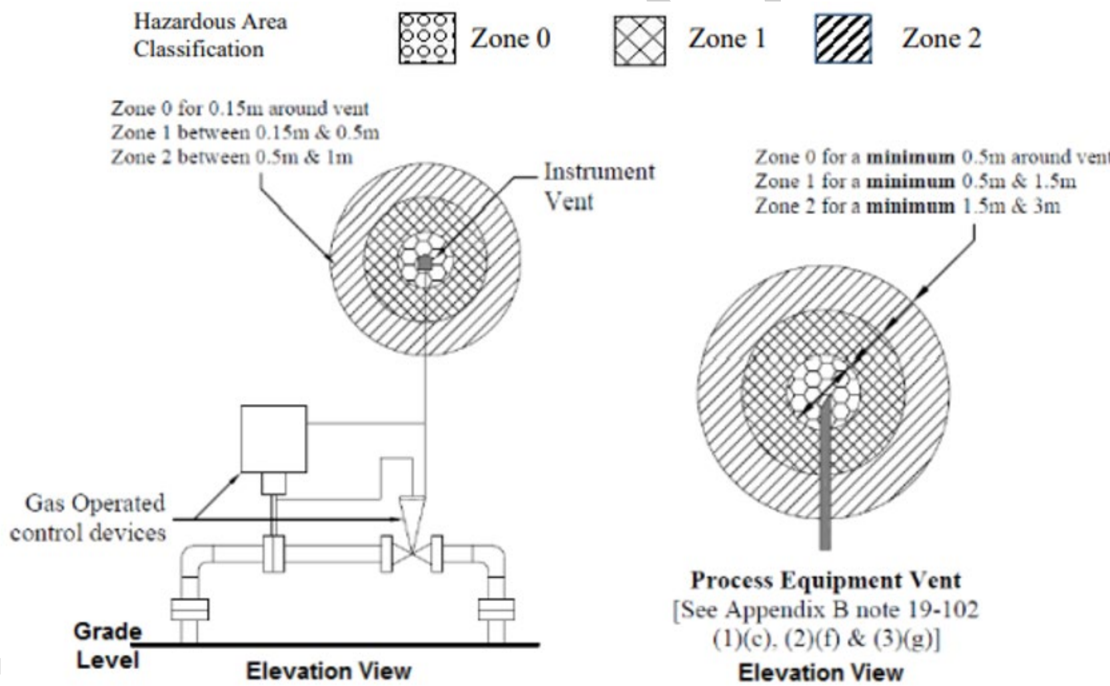


Figure 6. Hazardous Area Classification Diagram – Transmission or Process Facility

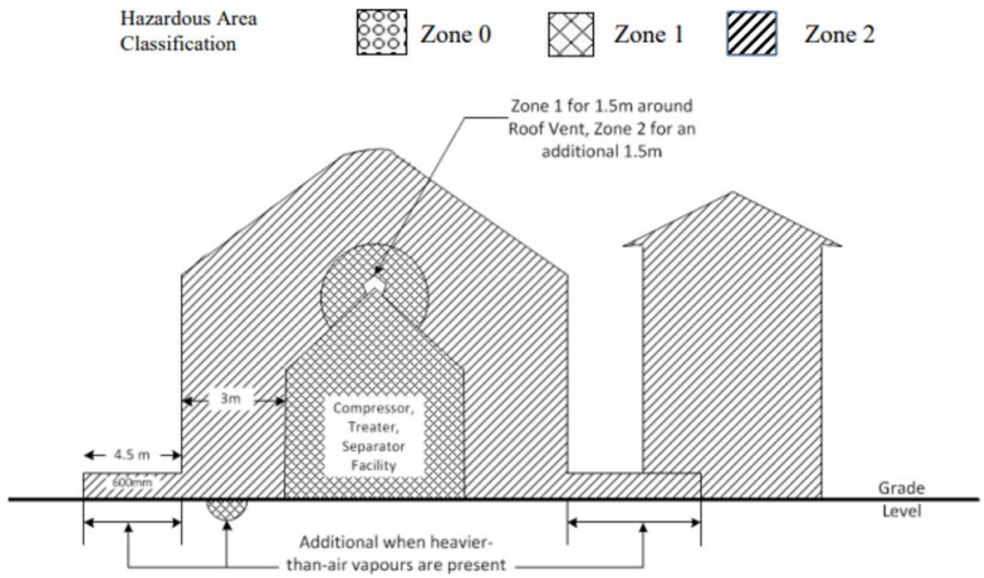


Figure 7. Hazardous Area Classification Diagram – Outdoor Valves, Pumps, Manifolds

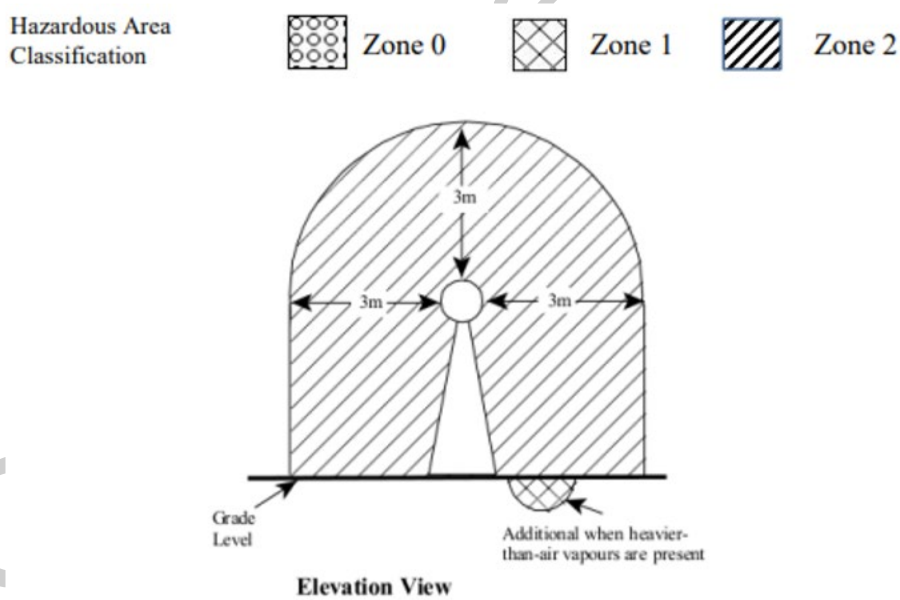


Figure 8. Hazardous Area Classification Diagram – Typical Wellhead

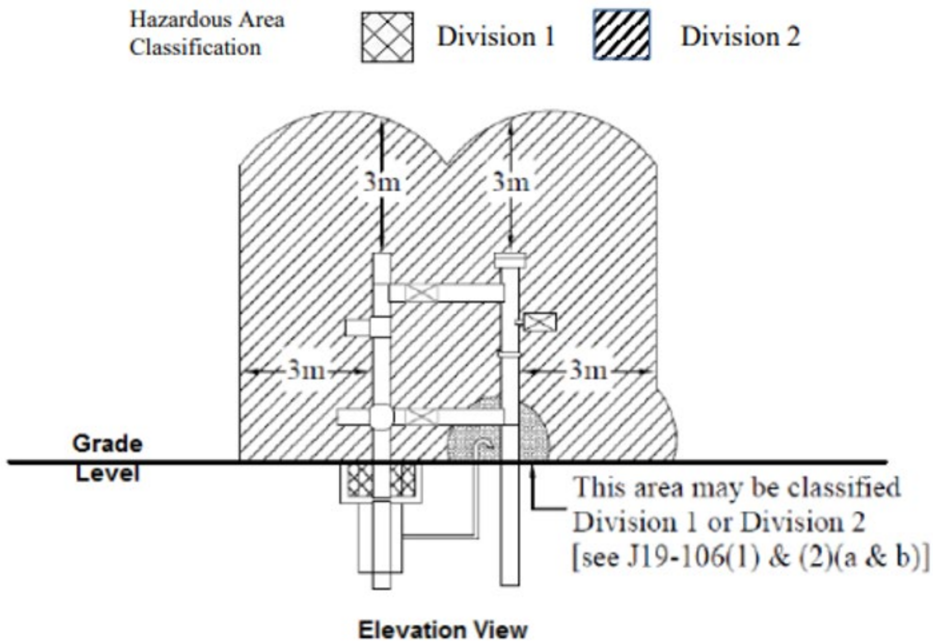


Figure 9. Hazardous Area Classification Diagram – Storage Tank for Flammable Liquids

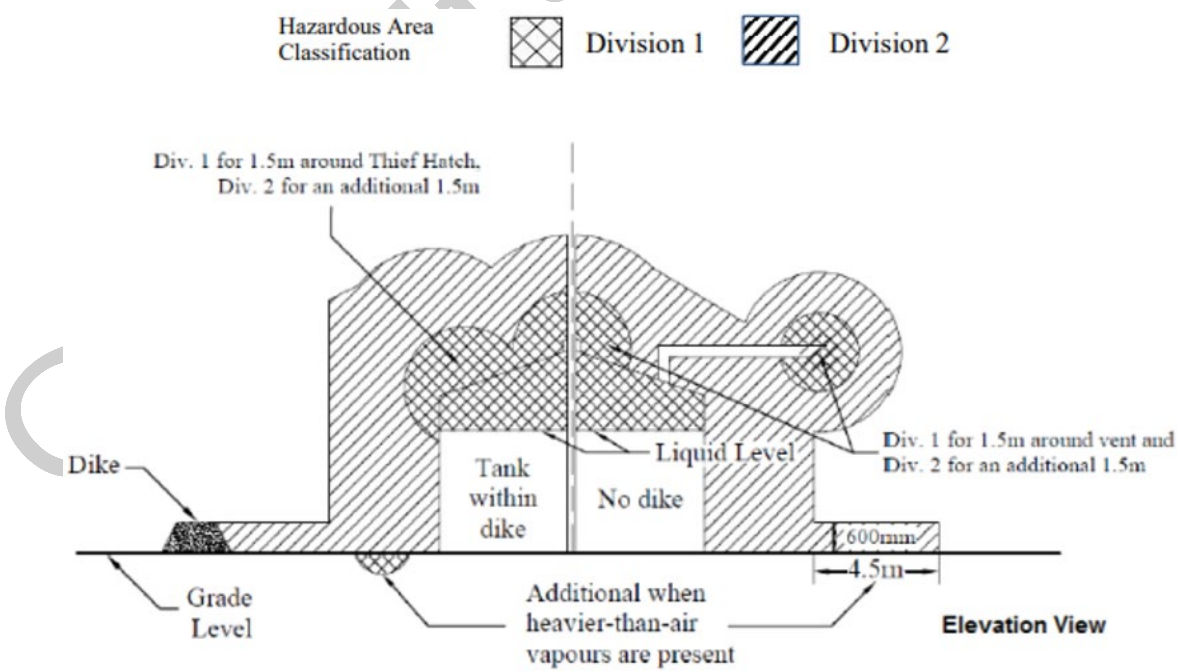
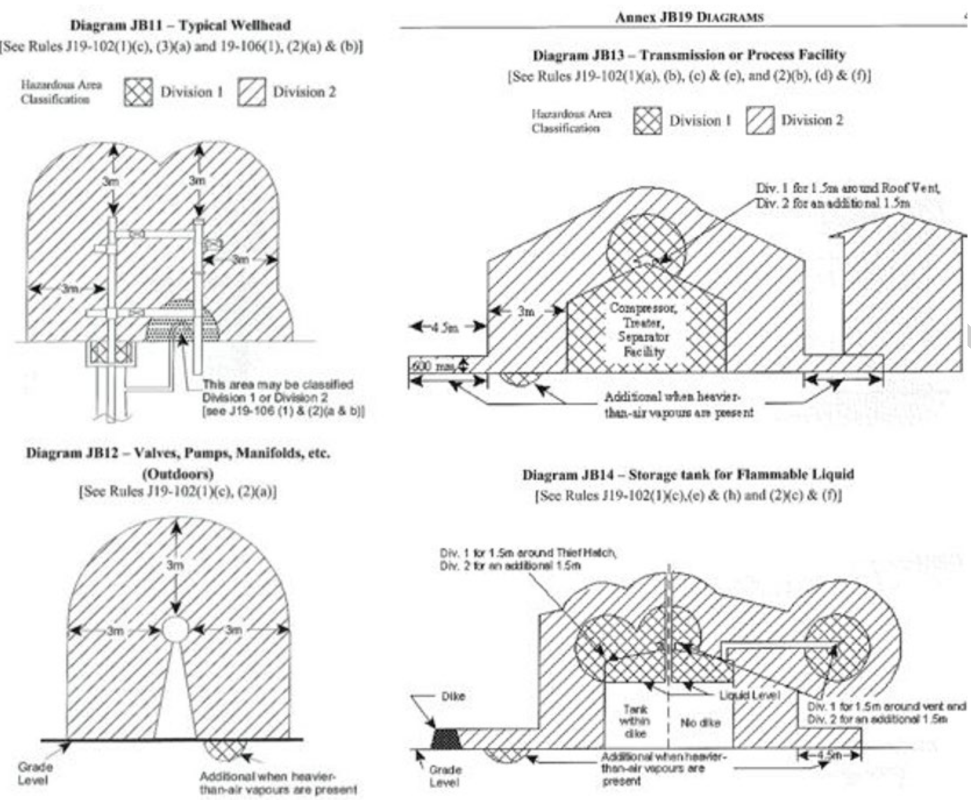


Figure 10. Code for Electrical Installations at Oil and Gas Facilities



4.4.10 Pre-Flow Equipment Inspection

IRP A pre-flow check must be performed, documented and signed off by a competent person before putting the equipment into service. The following checks must be included in the pre-flow check:

- Follow an inspection check list.
- Tighten all connections.
- Secure all lines adequately to restrict movement in case of failure.
- Include all lines in a quality control program to ensure pipe integrity.

See Appendix B for an example of a Production Testing Services Pre-Flow Inspection Checklist. Applicable details of the checklist are recommended.

4.4.11 Pressure Testing

IRP Following the rig-in of test equipment and associated flowlines, hydraulic pressure testing of the lines and equipment shall be conducted with adequate lighting. If the structural integrity of the piping system has been broken at any time after the initial pressure test, subsequent pressure tests

shall be completed to revalidate the structural integrity of the system unless operating conditions do not allow.

If hydraulic pressure testing is not practicable, pressure testing with a gas may be conducted, per the local jurisdictional requirements.

IRP All connections shall be pressure tested before starting operations.

IRP All equipment must be inspected before pressure testing to ensure it is rated for the test pressure.

IRP The maximum test pressure must not exceed the maximum allowable rated pressure of the lowest rated component in the system being tested.

IRP The pressure test must be documented and readily available.

IRP At a minimum, the system should hold test pressure for as long as necessary to detect leaks, which is indicated by a stable pressure reading, without any visible leakage. Test durations may vary depending on whether the pressure stabilized. Manufacturers, Owners and/or Prime Contractors and/or local jurisdictional requirements may require more stringent testing.

IRP During the pressure testing procedure and start up, all non-essential workers shall vacate the surrounding area of the testing equipment, flow lines and wellhead.

Open-ended piping (e.g., flare lines, pressure relief lines and vent lines) and atmospheric production tanks can be pressure tested against a valve that is subsequently opened and locked out during flow operations.

4.4.12 Purging

4.4.12.1 Purging the Well String and Wellhead

IRP Dry tubing should be displaced by nitrogen (N_2), CO_2, fluids, or using the procedures outlined in this IRP. See 4.4.4 Gas Flares.

IRP When dry tubing with air is opened to the formation, a fluid cushion should be run in the string. If the well has enough energy, the cushion can be brought back to a tank. The returning cushion purges the tubing string. Wellhead pressure should not be allowed to build up prior to the cushion return.

> **Note:** It is not always practical to displace tubing air prior to operations such as under-balanced perforating or drill stem testing.

IRP Owners and/or Prime Contractors and well testing companies must assess the planned procedure when air exists in the well string.

4.4.12.2 Pre-Purging Procedures and Checks

IRP The following pre-purging procedures and checks should be used:

- Pressure vessels should have hydrocarbons removed before introducing air into the system.
- All system elements should be electrically bonded to each other and grounded to the earth as per Owner and/or Prime Contractor's procedures.

A wellhead or ground rod may be used as a grounding device.

IRP Baseline and post current checks should be completed to verify grounding and bonding.

4.4.12.3 Purge Mediums for Purging Surface Equipment

IRP Purging should be completed using a vapour purge medium to displace air.

Inert gas is preferred for purge medium. If flammable gas is to be used, consider additional hazard controls, recognizing that the purge medium will create explosive mixtures before air purging is complete.

See 4.4.21 Air Entrainment and Purging for more information.

IRP Air and well effluent must not be flowed into a pressure vessel. It can only be directed to a pressure vessel after all the air is out of the system and the well effluent has been checked for any oxygen content. This can be done with a gas detection device.

See 4.5.2 Pumping or Circulating a Well to an Open Top Tank and the Energy Safety Canada Fire and Explosion Hazard Management Guideline for more information.

4.4.12.4 Purge Vapour Measurement

IRP The purge vapour should be measured, or the required volume should be calculated.

> **Note:** Liquid volume-to-vapour or mass-to-vapour conversions are permitted if the liquid volume or mass vaporized is measured accurately and if it is ensured that all the liquid is vaporized. Numerous calculations are available as per the well testing service provider.

4.4.12.5 Purge Volume

IRP The volume to be purged should be calculated before purging.

IRP For purge mediums heavier than air, purging should be a minimum of 1.5 times the calculated volume and purging should be from the bottom up.

IRP For purge mediums lighter than air, purging should be a minimum of 2.5 times the calculated volume and purging should be from the top down.

Note: The 1.5 times and 2.5 times are based on differences in specific gravities of the fluids between the purge fluid and the fluid within the system.

Note: Top-down purging is impractical in some situations. If bottom-up purging is employed with purge mediums lighter than air, a minimum of five times the calculated volume should be displaced. See Figure 11. Purge Volumes Quick Reference Chart.

Figure 11. Purge Volumes Quick Reference Chart

Quick Reference Chart - Purge Volumes

Purge Medium	Cylinder Volumes	Vessel Sizes							
		8m3	12m3	14m3	16m3	18m3	24m3	32m3	60m3
Propane		Must be a **MINIMUM** of 1.5X vessel volume (to remove oxygen from vessel).							
Purge Volume Required For Each Vessel Size:	**Vessel Volume x 1.5 =**	12 m3	18 m3	21 m3	24 m3	27 m3	36 m3	48 m3	90 m3
100LB Cylinder Liquid Volume: Gas Volume:	**Number of cylinders required:** 0.091 m3 (liquid) 24.752 m3 (gas)	0.5 bottles	0.75 bottles	1 bottle	1 bottle	1.2 bottles	1.5 bottles	2 bottles	3.75 bottles
450L Pig Liquid Volume: Gas Volume:	Percentage required: 0.36 m3 (liquid) @ 80% full 97.92 m3 (gas) @ 80% full	10%	15%	18%	20%	23%	30%	40%	74%
1000 Gal Bullets	**Percentage required:**	1.2%	1.8%	2%	2.3%	2.6%	3.5%	4.7%	8.7%
	Timed purge in minutes:	8	12	14	16	18	24	32	60
Liquid Volume/Bullet: Gas Volume/Bullet:	3.2 m3 (liquid) @ 80% full 870.4 m3 (gas) @ 80% full								
Nitrogen		Must be a **MINIMUM** of 2.5X vessel volume (to remove oxygen from vessel).							
Purge Volume Required For Each Vessel Size:	**Vessel Volume x 2.5 =**	20 m3	30 m3	35 m3	40 m3	45 m3	60 m3	80 m3	150 m3
Reg. Cylinder 2400PSI Gas Volume:	**Number of cylinders required:** 8.6 m3	2.3 cyl's	3.5 cyl's	4.1 cyl's	4.7 cyl's	7 cyl's	9 cyl's	9.5 cyl's	17.5 cyl's

*Note - most percentages/volumes have been rounded up.

4.4.12.6 Purging with Wellhead Gas (Sweet)

IRP The well should be flowed slowly to the separator unit, then to the flare line, and then to downstream vessels.

4.4.12.7 Purging Sequence

IRP Purging should be done in a downstream sequence (e.g., flow line to heater to separator to flare line, to downstream vessels).

IRP Downstream vessels should be isolated and purged one at a time.

4.4.12.8 Pre-Flow Purge

IRP The pre-flow purge shall be complete once the vessel mixture is above the upper explosive limit.

4.4.12.9 Post Flow Purge

IRP The post-flow purge shall be complete once the vessel mixture is below the lower explosive limit.

4.4.12.10 Intermediate Purging

IRP Where practical, the well testing system should be re-purged whenever air is accidentally or operationally introduced during the test and during long duration swabbing where air is repeatedly drawn into the system.

4.4.13 Operational Considerations

4.4.13.1 General Start-up Procedure

IRP Before start-up, all non-essential workers shall vacate the area surrounding the testing equipment, flowlines, and wellhead. These workers shall not return to the area until cleared to do so by the Owner and/or Prime Contractor (after consultation with the Well Test Supervisor).

IRP The following steps should be performed at start-up:

1. Open the master valve and record pressures (with the wing valve closed).
2. Open the wing valve to the choke manifold.
3. Open the choke manifold to a pre-determined choke size to avoid pressure locking the choke. See Appendix C Standard Operating Procedures for Choke Manifold Operation.
4. Adjust the choke slowly to the pressure vessel. Set operating pressures immediately and set liquid levels as soon as possible.
5. Begin vessel leak checks immediately, closely followed by downstream checks.

Note: For sour wells, workers performing detailed leak checks must don respiratory equipment.

6. Evaluate the well for H_2S content. Utilize field knowledge to determine baseline frequency for H_2S concentration checks. Shut in the well if additional equipment or workers are required.

See Appendix E Hydrates, for liquid loading and hydrate charts, to ensure proper flowing conditions.

4.4.13.2 General Flowback Considerations

IRP The flowback procedure should include the following:

- Regular hazard assessments
- Recording of measurements as per local jurisdictional regulations
- Continuous monitoring of safety systems and equipment
- Continuous monitoring of air entrainment in tanks connected to a flare stack (see 4.4.21 Air Entrainment and Purging)
- A safety standby person fully equipped and in place to affect rescue if needed
- Monitoring and documentation of flare rates and volumes
- Documentation of shift handover and walk-arounds

IRP If the equipment or the procedure cannot safely accommodate the flow, the well testing company's supervisor of the shift must have the ultimate authority to reduce the flow or shut in the well.

4.4.13.3 Shut In Procedures

IRP The following general procedure should be used:

1. Shut in the choke manifold, then shut in the wing valve.
2. Monitor the shut in wellhead pressures as directed and consider hydrate prevention.
3. Shut in the master valve(s).
4. Displace all produced fluids to storage (or pipeline).
5. Monitor to determine the LEL, UEL, and OEL.
6. Complete a hazard assessment to manage the exposure levels.
7. Shut down flares.
8. Rig out and remove equipment from the location.
9. Ensure the pressure rating of the fittings meet or exceed the maximum wellhead shut in pressure.

Note: It is recommended that all blind flanges on the wellhead be replaced with tapped plugs having a needle valve to check for pressure leakage past all wellhead valves.

10. Inform the client representative of the status of stored fluids still on location.
11. Ensure all unused chemicals are returned to suppliers or are disposed of appropriately.

Note: If there is breaking of a connection outside of a choke, see 4.4.12.1 Purging the Well String and Wellhead.

IRP Consideration should be given to tank/vessel cleaning alternatives rather than entering the confined space to clean the tank or vessel.

4.4.14 Sparging

Sparging is a process which uses water (either produced or fresh) to remove sand from a separator in the form of a slurry, without removing the vessel from service.

Using a high-volume pump/high-pressure pump, water is pumped into the separator through sparge coils located within and near the bottom of the separator. The coils are designed with nozzles to allow for water to be injected into the separator at pressure making the sand accumulate as a slurry and removing it through drain nozzles in the bottom of the separator. The slurry is then transferred into another storage tank or separator where it can be removed and disposed of.

IRP When performing or planning sparging operations, the following items should be considered:

- Pressure rating of the vessel being sparged
- Maximum output pressure of the pump
- Pressure safety devices correctly set for the operation
- Liquids used to complete the sparging operation
- Direction of flow is controlled to prevent well fluids from feeding back to the pump through the use of check valves or backflow prevention
- Sparge nozzle design
- Sour content of the vessel being sparged
- Area the slurry is being moved to (e.g., another tank, open top tank, sand filtering system)

IRP Sour fluids shall not be used to sparge.

IRP Pressure protection should be installed when the maximum operating pressure of the high-pressure pump is greater than the maximum allowable working pressure of the separator or associated equipment used in the sparging operation.

4.4.15 Entering a Pressure Vessel

In some cases, using an inert purge medium for all operations may not be practical. Flammable purge mediums, like propane, can be used successfully if workers follow specific precautions and procedures.

An inert medium also presents its own hazards (e.g., lack of oxygen and non-breathable). The following are meant to assist in the assessment of hazards.

IRP Closed tanks must be depressurized and must not be on vacuum before opening the system. If available on site, purge the system with inert gas. Evacuate as much fluid (and solid) as possible before opening the system.

IRP A confined space entry permit must be completed, and a hazard assessment conducted before opening a system that allows entry or partial entry of a person, such as a closed tank system.

IRP A confined space rescue plan must be implemented if a worker will enter a confined space.

IRP The individual who completes the confined space entry permit must have confined space entry training.

IRP The following must be considered when completing the safe work permit:

- Ensure all potential ignition sources have been eliminated.
- Ensure continuous air monitoring is in place.
- Remove all non-essential people from the immediate area.
- Ensure all individuals involved in opening the closed system have proper personal protective equipment such as fire-retardant coveralls and breathing apparatus.
- Follow local jurisdictional requirements for confined space entry.

Note: Consider the use of purge mediums such as N_2, CO_2, and water flood. The use of combination flush/vacuum pump trucks will help to clean out the system before opening for inspection.

4.4.16 Produced and Recycled Fluids

IRP Where produced vapours and recycled fluids or solids are allowed to escape to atmosphere, steps should be taken to ensure the safety of onsite workers. The properties of any produced and recycled fluids or solids should be evaluated to identify and address the potential hazards. Examples of these potential hazards include

- selecting appropriate fluid handling procedures as per the SDS,
- addressing emulsions (e.g., foam),
- establishing criteria for shutdown when using an atmospheric tank,
- establishing a disposal method,
- identifying OELs,
- atmospheric monitoring, including LELs, H_2S content, O_2 levels.
- identifying radioactive material (tracers),
- determining corrosive effects,
- assessing degradation of elastomers, and
- identifying naturally occurring radioactive material (NORM).

4.4.17 Oils

IRP The properties of the produced oils should be evaluated for flammability, such as LELs and upper explosive limits (UEL), and solid deposition problems like paraffin.

Note: There is a general relationship between flammability and the C1-C7 content of a hydrocarbon fluid. Flammability increases with C1-C7. Also, Reid vapour pressure increases as C1-C7 content increases. See Appendix F: Glossary, Reid vapour pressure definition.

4.4.18 Gas

IRP The properties of the produced gases should be evaluated for the following hazards:

- Flammability (LEL and UEL)
- Solid deposition problems (e.g., sulphur)
- Hydrate potential
- H_2S content
- Water saturation and free water content

4.4.19 Water

IRP The properties of the produced water should be evaluated for possible gas entrainment and ignition potential.

IRP When tanks are placed next to the lease road exit (e.g., small leases or remote locations to comply with other spacing requirements), adequate transportation should be available for workers in case of an emergency. This transportation should be off the lease when no other means of egress are available.

4.4.20 Tanks

4.4.20.1 Rig Tanks

IRP Where gas vapours are vented to atmosphere from an open tank system, the tank must be a minimum of 50 m from the wellhead. Coalbed methane and shallow wells must be at least 35 m from wellhead.

IRP Where a degasser is used to separate gases and liquids, it should be in a separate compartment of the rig tank. The degasser should be configured such that a sufficient head of fluid in the tank is maintained for efficient gas separation.

IRP Flowback operations must be discontinued if liquid carry over from the degasser vent line occurs. An appropriately sized, pressurized vessel must be used.

IRP Consideration must be given to an appropriately sized, pressurized vessel if gas volumes are sufficient to sustain stable combustion.

IRP Venting should be reduced in accordance with local jurisdictional requirements.

See 4.5 Other Types of Flowbacks for flowing to open top tanks.

4.4.20.2 Aboveground Atmospheric Storage

Atmospheric storage tanks are predominantly used for fluid storage and are not considered capable of containing pressure. Most atmospheric tanks are designed with seven kilopascals (16 ounces (oz)) hatches and the roof is typically designed to shear at 14 kPa (two pounds per square inch (psi)).

IRP When producing sour fluids, atmospheric tanks must be equipped with a suitable vapour gathering or scrubbing system to ensure that H_2S vapours are not released to atmosphere.

IRP Odours should be reduced or eliminated via use of equipment or process.

IRP Atmospheric storage tanks shall have a fluid level indicator.

IRP If any maintenance or work is required on top of an atmospheric storage tank, a hazard assessment must be completed.

Note: The tops or lids of atmospheric storage tanks are not designed to serve as a work platform.

IRP Fill lines shall be secured to the aboveground, synthetically lined wall storage systems (C-ring).

IRP Hydrocarbons and H_2S or material incompatible with liners shall not be stored in aboveground, synthetically lined walled storage systems. Refer to AER Directive 055 Storage Requirements for the Upstream Petroleum Industry.

4.4.20.3 Other Tanks

IRP Pressurized tanks or a closed system should be used for flowing, liquid storage, swabbing, well suspension, or workover operations that have the potential for light hydrocarbon gases to vent off or accumulate, which can lead to a risk of fire and explosion.

IRP When flowing a well with H_2S, suitably rated equipment must be installed, and a closed-system design must be used to prevent the escape of sour gas to the atmosphere.

IRP Storage and handling of sour fluids must be completed within the design parameters of the equipment to avoid exposure to workers.

IRP Additional consideration should be given to the following:

- Potential worker exposure to hazardous substances
- Sour concentration
- Production rates
- Total volumes
- Local jurisdictional requirements
- Equipment spacing
- Surface development proximity
- Transportation
- SIMOPs
- End of job handling considerations

Refer to IRP 02: Completing and Servicing Sour Wells and NACE MR 0175/ISO 15156-1: 2020 Petroleum and Natural Gas Industries – Materials for use in H_2S Containing Environments in Oil and Gas Production for more information.

Note: Refer to NACE MR0175/ISO 15156-1:2020 Petroleum and Natural Gas Industries – Materials for use in H_2S Containing Environments in Oil and Gas Production.

4.4.20.4 H_2S Scrubbers

IRP Where H_2S scrubbers are used, the scrubber must be suitably sized for the concentrations and rate of the H_2S vapour present to ensure the vapours are eliminated.

IRP The manufacturer's specifications should be followed for proper care, use and maintenance of equipment and to ensure chemical compatibility.

IRP A daily inspection must be completed to ensure no freezing or volume of chemical is accumulated.

IRP Exhaust from H_2S scrubbers should be evaluated to ensure additional hazards are not created like worker exposure, accumulation of flammable gases and distance to potential ignition sources.

IRP Consideration should be given to the size and rating of the scrubber unit to handle the flow rate of the unit the scrubber is tied to. For example, when tying onto a vac truck, ensure the scrubber can handle the H_2S concentrations and rates.

Note: Be aware that when carbon-based scrubbers are placed downstream of H_2S scrubbers, H_2S carrying over to the carbon-based scrubber could be an ignition source and could cause a fire. Refer to OEM or service provider for more information. Ensure scrubbers do not exhaust H_2S into the carbon-based scrubber.

4.4.20.5 Location of Tanks

Refer to the IRP 4 Minimum Equipment Spacing Table and IRP 20: Wellsite Design Spacing Requirements, for information about spacing for tanks.

4.4.21 Air Entrainment and Purging

IRP Owners and/or Prime Contractors and Service Companies must eliminate or mitigate explosive hazards due to air entrainment in pipes, vessels, and tanks.

Ignition sources are not always identifiable, but could include the following:

- Flashbacks from flares
- Static electricity
- Friction heat (from valve operation or high velocity debris)

- Localized hot spots in partially open (unbalanced) valves
- Spontaneous combustion at critical pressures and temperatures
- Spontaneous combustion of compounds such as sulphides
- Electrical currents from lightning and power sources (including cathodic protection)

Air sources upstream of the choke include the following:

- Air from dry-run tubing (i.e., for under balanced perforating)
- Coiled tubing unit operations using air
- Swabbing, when the well goes on vacuum
- Reaction productions (i.e., hydrogen peroxide washes)

Air sources downstream of the choke include the following:

- Initial air, as the equipment arrived
- Air that is re-introduced from the wellhead side
- Air that is pulled into production tanks through open or leaking hatches when a vacuum condition exists

  Note: The vacuum can be caused by fluid withdrawal and by excessive venturi action at flare stacks when tanks are vented to flare. Changes in ambient temperature can result in a draw of air from the flare stack (e.g., daylight only operations).

4.4.22 Opening a Well with Air in the Flow String

It is sometimes necessary to open a well when there is air behind the master valve.

IRP When a well or pipeline contains air, an inert medium should be used to displace the air. Never displace air with a flammable gas.

IRP Prior to flowing a well that may contain air, a hazard assessment must be performed to ensure fire and explosion hazards do not exist.

IRP Owners and/or Prime Contractors and service companies should consider the following procedures:

- All non-essential workers should be removed from the test area.
- The tubing should be flow-purged of explosive mixtures as soon as possible after operations such as tubing conveyed perforating. The well should not be shut-in for build-up until the purge is completed.

Note: Pressuring up the volatile mixture increases the danger of an in-line explosion.

- The wing or master valve should be equalized by downstream pressure (N_2, CO_2 or water) before opening to reduce friction and initial in-rush.

IRP A check valve should be inserted into the flowline system where a well could go on vacuum during swabbing.

IRP A valve should be in the system to isolate the well from the downstream vessel in case the well goes on a vacuum while running in the hole with the swabbing apparatus. The saver-sub should be tightened. A regulated purge vapour to follow the swab cups back down the hole should be considered.

IRP Piping and vessels shall be purged free of air once the air has been removed from the well.

IRP Owners and/or Prime Contractors should notify nearby residents as required by local jurisdictional regulations.

4.5 Other Types of Flowbacks

4.5.1 Flowing, Pumping or Circulating to an Open Top Tank

IRP Venting should be reduced in accordance with local jurisdictional requirements.

IRP In operations where gas vapours are expected from produced fluid, the hazards to on-site workers, equipment, and the public, must be assessed and deemed safe before proceeding by reducing or eliminating any potential explosive or otherwise hazardous atmosphere.

IRP The hazard assessment should include discussion of procedures, sources of ignition, personal protective equipment, and identification of hazardous atmospheres.

IRP Installing a suitably rated pressure vessel and flare stack should be considered instead of venting in the following situations:

- If gas or vapours have a toxic effect above the occupational exposure limit or can pool, resulting in explosive mixtures
- If venting or fugitive emissions may result in H_2S or other offensive hydrocarbon odours outside the surface lease boundary
- If venting to atmosphere may release well effluents to the environment
- When there is a need to shut down the operation before fluids are splashed or flowed over the sides of the open tank system
- To comply with local jurisdictional methane venting requirements

IRP When H_2S is present a vessel and flare stack must be installed when venting is expected.

IRP The open top tank shall be designed with an inlet diffuser and a device to prevent splashing and misting of the fluid.

IRP The tank should have a fluid level indicator.

IRP Potential ignition sources must not be placed near open top tanks.

IRP The following additional safety equipment must be on location prior to flow:

- Gas detection monitor with bump gas
- Spill containment kit
- A process to monitor and control the flow of traffic onto location that orients personnel to the hazards on lease.

IRP The following should be considered when flowing to an open top tank:

- A pressure control device to regulate pressure and flow
- Using a pressure indicator immediately downstream of the pressure control device to monitor pressure applied to the inlet of the open top tank
- Installing suitably rated hard piping from the wellhead to the open top tank inlet
- Installing a piping restraint device as per local jurisdictional requirements.
- Establishing an exclusion zone to prevent workers from being exposed to the contents of the open top tank
- Ensuring no worker(s) enters the exclusion zone while flowing, circulating or pumping to an open tank system
- Sweeping the area for LELs after shutting in the flow and allowing time for the vapours to dissipate
- Addressing erosional affects (see 4.4.2 Erosion and Velocity Considerations)

4.5.2 Pumping or Circulating a Well to an Open Tank System

IRP Any loading/unloading of fluids from open tank systems shall be done with the well shut in and no flow to the open-top tank. This can only be done after the area is proven safe by the gas detection device.

IRP A written safe operating procedure, including a hazard assessment/JSA, should be available on-site. This procedure should consider safe and effective control and handling of the well effluent and ensure that all air has been displaced from the well after the job, before shutting in or producing the well.

4.5.3 Swabbing

IRP A check valve and an additional shut-off valve should be installed on the flow line when swabbing. The shut-off valve should be closed while running in the hole if the well is on vacuum. Consideration should be given to using a purge medium to follow swab cups while running in the hole.

Note: Check valves do not always seal 100%. The manual shut-off valve is a backup for the check valve.

The purpose of this procedure is to prevent drawing air or the flame from the flare into the production tank or into the tubing when running the swab cup back into the well. The introduction of air into the system can lead to a combustible mixture. See 4.4.21 Air Entrainment and Purging for other considerations to prevent air entrainment.

IRP Where gases produced are being flared, appropriate backflash control measures must be taken. Consider examples such as not having the flare lit, stopping the job to re-purge, and applying a continuous fuel gas feed.

IRP All potential ignition sources on location that are not required for the operation (e.g., rig pump, boiler, heaters, and vaporizers) shall be shut down during swabbing of hydrocarbons or moved to a safe distance.

IRP A hazard assessment must be completed or reviewed for the proper procedure to be performed.

IRP While swabbing to an open tank system where gas vapours are vented to the atmosphere, lease control must be in place.

4.5.4 Snubbing Operations

4.5.4.1 Handling Bleedoffs from the Snubbing Unit

IRP The bleedoff line from the snubbing unit to the separator shall be equipped with a choke manifold or isolation valve in case of loss of control of the remote control valve on the snubbing stack.

IRP The line upstream of this choke manifold must be pressure tested to the anticipated maximum shut-in casing pressure.

4.5.4.2 Flowing Casing and Handling Snubbing Bleedoff

IRP A designated flowline shall be installed with flow control that is not associated with the flowing well stream to ensure the snubbing unit bleedoff line is maintained at atmospheric pressure.

Note: Maintaining pressure on the snubbing unit bleedoff line can result in pressure, toxic gas and chemical exposure to workers positioned in the snubbing basket.

IRP The flowline shall have temperature and pressure data acquisition points to mitigate the risk of down-hole and surface hydrate conditions. This shall be discussed during the pre-job safety meeting.

Note The snubbing unit bleedoff line may be directed to a second separator, such as a low stage vessel, downstream of the primary separator, provided its operational pressure is reduced to atmospheric pressure and well effluents will not be introduced from the primary separator while the snubbing unit is bled off.

If only one separator is on location or the secondary separator cannot meet the condition as laid out in this document, then the bleedoff can be directed to an independent vent line on the flare stack, provided the well is dry and fluid production is not anticipated.

IRP The bleedoff from a snubbing unit should be directed to a pressurized vessel whenever possible.

Refer to IRP 15: Snubbing Operations for more information.

4.5.5 Recovery and Handling of High Vapour Pressure Fluids (Liquid Petroleum Gases)

IRP The well licensee must have all applicable approvals required by local jurisdictional regulators, on each site.

IRP A Reid Vapour Pressure (RVP) test shall be performed by qualified personnel using equipment which meets ASTM D323 Standard Test Method for Vapor Pressure of Petroleum Products (Reid Method) or ASTM D5191 Standard Test Metod for Vapor Pressure of Petroleum Products and Liquid Fuels (Mini Method).

Note: A hydrometer is not an acceptable device for measuring RVP.

IRP Fluid produced from the wellbore shall be continuously monitored for changes until the properties have stabilized.

Note: Not all High Reid Vapour Pressure Fluids are flammable. Some non-flammable fluids are liquid carbon dioxide, liquid oxygen and liquid nitrogen.

IRP Handling of liquids with high vapour pressures shall be conducted in compliance with established safe work procedures. Safe work procedures shall be reviewed before starting work.

IRP High Reid Vapour Pressure fluids shall not be stored in atmospheric storage tanks.

4.6 Loading, Unloading and Transportation of Fluids

4.6.1 Fluid Hauling Carrier Procedures

IRP Fluid Hauling companies must adhere to the following procedures and practices:

- All shipping documents and appropriate placarding must be in place as per TDG regulations.
- All inspection certificates must be current for the vehicle and the tank hauling the fluid as per Transport Canada requirements.
- Tank specifications must meet the requirement for the fluid to be hauled.
- Drivers must be properly trained in accordance with local jurisdictional and Transport Canada requirements.
- Fluid hauling trucks must have functioning, intake air shut offs as required by local jurisdictional regulations.
- The tank truck must be bonded, and a continuity check completed before loading or unloading fluid from a grounded tank (See Appendix F: Glossary, for definition).

IRP Workers must be properly trained in loading and unloading procedures and the proper use of safety equipment during the operations. This includes training on the use of breathing equipment, gas detection and explosive monitoring devices.

IRP A supplied air respirator (i.e., SCBA, SABA) must be available if airborne hazards cannot be eliminated by engineering or administrative controls.

IRP All equipment valves, fittings, hoses, and hatch seals must be rated and maintained in good working order as per CSA B620.

IRP Owners and/or Prime Contractors must implement and maintain all spill containment plans and procedures.

IRP Workers transporting sour fluids shall have valid H_2S Alive®, WHMIS and TDG certificates.

IRP To ensure worker safety, any sweet fluids transported immediately after a sour load shall be treated as if they were sour loads.

4.6.1.1 Atmospheric Conditions

IRP Tank or vacuum trucks must not operate in explosive environments. Diesel engines must be equipped with a positive air shut off device as per local jurisdictional requirements.

IRP The truck, tanks, or combined system shall have a system in place to protect workers from H_2S if it is present.

IRP Vented vapours must be within allowable exposure limits and atmospheric conditions set by the local jurisdictional regulations.

4.6.1.2 During Well Swabbing Operations

IRP The tank truck to be loaded must be parked as per local jurisdictional regulations.

IRP No individual shall be in the cab of a truck while fluids are transferred to the truck and/or trailer during swabbing operations.

IRP The tank truck shall be shut off during loading and unloading operations.

IRP No worker shall service or maintain the vehicle while flammable, combustible or explosive materials are loaded or unloaded.

4.6.1.3 Fluid Characteristics

IRP Owners and/or Prime Contractors must provide truck operators with the SDS of the fluids being transported in accordance with the applicable regulations (TDG/WHMIS).

IRP Applicable local jurisdictional regulations such as TDG and WHMIS must be adhered to when transporting hazardous substances. Owners and/or Prime Contractors are responsible to train operators on the proper transfer, handling, and transportation of flammable and combustible liquids.

IRP The properties of all produced fluids to be transported must be evaluated for the following:

- H_2S
- pH
- API gravity
- Flashpoint
- Salinity
- Basic Sediment and Water (BS & W)

- Fluid class, as required for TDG
- NORMs

IRP Shippers of the fluid must make or have SDS information available for workers.

4.6.2 Loading, Unloading and Transportation Practices

4.6.2.1 Fluid Transfer Considerations

IRP Conductive hoses shall be used whenever possible during transfer of flammable and combustible fluids.

IRP Hoses shall be inspected and a new inspection tag applied annually.

IRP Hose specifications shall be readily available. Visual inspections of the hose shall be included in the pre-job hazard assessment.

IRP Vacuum and Tank trucks must be grounded and bonded regardless of the hose type used, and a continuity check must be completed.

4.6.2.2 Pressure Loading

IRP Atmospheric tank trucks without scrubbing systems should only be used to haul sweet fluids.

IRP A well shall not be flowed directly to a tank truck.

IRP All vents must be closed, and all fluid transfer lines capped while transporting the fluid.

IRP Tank trucks should be vented to a flare stack only when the following conditions are met:

- Proper procedures are in place and documented (pre-job hazard assessment/JSA).
- The tank truck is suitably purged.
- There is a redundant back flash control mechanism in the vent line to the stack (flame arrestor and make-up gas).
- The system, including the tank truck and the tanks being emptied will not allow air into the system.

IRP When loading and unloading fluids from a pressurized flowback tank or storage tank that a live well is flowing to, the tank truck must be positioned as per local jurisdictional regulations. Additionally, the pressure

capabilities of the tank on the truck must not be exceeded when utilizing a certified pressurized tank truck.

IRP A fluid level shall always be maintained in the pressurized flowback or storage tank.

IRP Gases vented from the tank truck shall be directed safely away from personnel and equipment and ignition points.

IRP The pressure of the pressurized flowback vessel shall be reduced to the minimum pressure required to transfer the fluid to the tank truck.

IRP The wheels of the tank truck shall be chocked while transferring the liquids.

4.6.2.3 Sour and Volatile Hydrocarbon Fluids

IRP Where there is a possibility of vapour breakout and pressure build-up on the tank truck due to agitation or increased ambient temperature, the sour fluid must be transported in a certified pressurized tank truck as per Transportation of Dangerous Goods and local jurisdictional requirements.

IRP Operators of trucks equipped with on-board scrubbers must ensure that their units are maintained as per the manufacturer's recommendations.

IRP A closed system must be utilized for the transportation of flammable and H_2S containing fluids.

4.7 Hydrates

During well testing, hydrate formation depends on reservoir conditions and can be influenced by factors such as H_2S development, water salinity and changes in dew point during production. Hydrates may form due to temperature decrease or flow restriction even without a sudden drop in pressure. This can occur in flow strings, surface lines, or in areas with sudden expansion or pressure drops, such as flow provers, orifices, backpressure regulators, and chokes.

IRP When pumping methanol to prevent hydrate formation, the effectiveness of the methanol in produced water should be considered. Changes in water salinity can impact the hydrate temperature curve.

IRP Chemicals intended to dissolve existing hydrates or inhibit/prevent hydrates from forming shall be evaluated for to ensure there is no incompatibility that could damage the wellbore or surface equipment.

IRP When conducting pre-job hazard assessments, the system should be reviewed to determine potential locations for hydrate formation.

4.7.1 Awareness and Prevention

IRP The Owner and/or Prime Contractor shall identify potential hydrate concerns by monitoring bottomhole temperatures, the presence of free water, H_2S and CO_2 content, gas gravity, and downhole restrictions.

IRP Documented pre-job safety meetings and/or hazard assessments shall be completed when the elements of the hydrate triangle are present (see Appendix E: Hydrates, Figure 16: Hydrate Triangle).

IRP When elements of the hydrate triangle are present, mitigation techniques (e.g., line heaters, staging of pressure drops, heat wrap, methanol, hot water) should be utilized to prevent ice build-up during initial flow on the inside walls of the piping systems.

IRP When pumping, hydrate mitigation measures such as downhole temperature gradients and timelines to flowback should be considered. Evaluate pumping rates and wellbore tubular configurations to ensure effectiveness of hydrate mitigations.

IRP The pressure testing medium should be evaluated to determine downstream impacts on hydrate formation.

IRP Hydrate mitigation down the tubing and/or annulus, if applicable, should be considered prior to flowing and during any extended shut-in periods.

IRP Hydrate mitigation should be considered for all surface equipment before flowing, and during any extended shut-in periods or cold weather operations.

IRP During start up, ambient temperatures shall be evaluated to identify any conditions that could cause a decrease in temperature, potentially leading to hydrate formation due to adverse heat transfer.

IRP Hydrate charts/tables shall be available on the well site. The Well Test Supervisor shall be trained and competent in the use of these charts and tables.

IRP After shutting down due to hydrate formation, the surface flow lines shall be proven clear by purging them with methanol and/or a warm gas or fluid before disconnecting the lines.

IRP The surface flow lines shall never be disconnected until hydrates are proven to be removed or mitigation procedures are in place.

4.7.2 Removal

For hydrate removal techniques refer to Energy Safety Canada and any local jurisdictional requirements.

IRP Mitigation processes should be reassessed to ensure they are adequate.

Note: Hydrates travelling through pipes have a high potential for plugging, over-pressuring or rupturing lines.

IRP Once hydrate removal has been confirmed the integrity of the surface equipment should be assessed (e.g., pressure tests, overpressure conditions and visual inspections).

Appendix A: Revision Log

The revisions to IRP 04 are logged in the following tables.

Edition 6

Edition 6 of IRP 04 involved a full scope review of the IRP. Specific changes are highlighted in the table below.

Table 4. Edition 6 Revisions

Section	Remarks and Changes
General	Updates to current IRP template: • Disclaimer • Range Update Enform to Energy Safety Canada • Range of obligation terminology • Revision log/acknowledgments • Moved definitions and acronyms to an Appendix for Glossary (Appendix F) • Terminology and style updates to match current IRPs and DACC Style guide Removed Pressure Rating Formula and Tables for Seamless Pipe that were formerly in Appendix B.
4.3 Safety Considerations	• Replaced Worker Safety with Safety Considerations • Removed Complete Well on Paper • Removed sections regarding two and three qualified well testing workers
4.3.6 Respiratory Protection	New section added.
4.3.7 Gas Detection Monitoring for Explosive and Flammable Limits	New section added.
4.3.9 Grounding and Bonding	New section added.
4.4 Well Testing Design Considerations	• New section added. • Included content regarding process flow diagrams, erosion and velocity considerations, radiant heat and flare knockouts. • Updated Equipment specifications to include emergency shut down devices, pressure testing, function testing, pressure pilots and pressure safety valves. • Updated Electrical and Electronic Area Classification Content and included recommendations. • Added content regarding sparging and dispersion modelling.

Section	Remarks and Changes
	• Removed flare pits.
4.4.11 Operational Considerations	• Replaced Operational Safety with Operational Considerations. • Moved general safety information regarding pre-job safety meeting and start-up at night to 4.3. Safety Considerations.
4.4.9.1 Well Testing Exclusion Zone	• Added content regarding well testing exclusion zone and approval to enter the exclusion zone.
4.5 Other Types of Flowbacks	• Revised to consider alternative means to atmospheric venting.
4.6 Loading, Unloading and Transportation of Fluids	• Updated section. • New section, Fluid Transfer Considerations, added which includes hose recommendations. • Added recommendations for fluid hauling carrier procedures that involve pressure loading and fluid transfer, atmospheric conditions and during well swabbing operations.
4.7 Hydrates	New section added to provide recommendations for hydrate prevention and removal.
Appendix B: Pre-Flow Inspection Checklist	Updated and reformatted the checklist.
Appendix C: Standard Operating Procedures for Choke Manifold Operation	New procedure added to provide a consistent guideline for safe and efficient operation of a choke manifold.
Appendix D Flare Stack Maximum and Minimum Flare Rates	• Removed Flare charts for 2”, and 4” flare stack sizes • Added flare exit velocity calculation and an explanation of the coloured lines in the flare charts.
Appendix E: Hydrates	• Updated wording. • Added chart showing hydrate prediction with H_2S and methanol Reduction.
IRP 4 Minimum Equipment Spacing Table	Created IRP 4 Minimum Equipment Spacing Table.

The following individuals helped develop this edition of IRP 4 through a subcommittee of DACC.

Table 5. Edition 6 Development Committee

Name	Company	Organization Represented
Bakhtiar Ahmed	Chevron Canada	CAPP
Tony Baker	Grant Production Testing	Enserva
Adrian Campbell	ARC Resources Ltd.	CAPP
Ryan Chursky	Skyline Testing	Enserva
Glenn Doiron	Ideal Completions	Enserva

Name	Company	Organization Represented
Gary Ericson	Saskatchewan	Regulator
Braydon Garagan	TARA Energy Services	CAPP
Steve Gordon	CNRL	CAPP
Randal McNeill	Formerly with TARA Energy Services	CAPP
Mike Nelson	Grant Production Testing	Enserva
Andrew Robinson	Alberta Energy Regulator	Regulator
Blair Tindall	Skyline Testing	Enserva
Peter van Eerde	Longshore Resources	CAPP
Aaron Veillette	Colter Energy	CAOEC

Revision History

In 1988, a Well Testing and Fluid Handling subcommittee was formed consisting of representatives from CAODC, CAPP, PSAC, Alberta OH&S and the Alberta Energy Regulator (formerly ERCB). Under the auspices of the Drilling and Completion Committee (DACC), the subcommittee's mandate was to investigate and develop minimum recommended practices for the safe testing of wells and handling of fluids. The Alberta Recommended Practice (ARP) documents were developed during well testing and fluids handling operations at wells in Alberta and were fully supported by the Alberta AER and Alberta OH&S.

In 1999, the scope and breath of recommended practices encompassed many more issues, companies, associations and governments. The reference to Alberta in the title of these practices changed to Industry Recommended Practice (IRP) to better reflect this broader scope. Where industry has grown to other regions of western Canada, these IRPs continue to assist companies in their daily operations. These IRPs are intended to follow the user to any site, anywhere in the world, as a minimum operating practice.

In 2005, IRP 4 was reviewed and updated to reflect the changes in industry and legislation. With approval from DACC, a new committee was formed to address the need for a complete review and update of the document.

In 2009, a new section was added: 4.3.7 High Reid Vapour Fluid Recovery and Handling. Hyperlinks were updated on all other sections.

In 2012 section 4.3.7 High Reid Vapour Fluid Recovery and Handling was revised. Hyperlinks were updated on all other sections.

In 2014, IRP4 was transferred into a new DACC IRP template and all sections were reviewed by the committee and updated to reflect current standards and practices in the industry.

In 2024, IRP 4 was transferred into a new DACC IRP template and all sections were reviewed by the committee and updated to reflect current standards and practices in industry.

Appendix B: Pre-Flow Inspection Checklist

Contractor:	Operator:	
Lease Location/LSD:	Sour Content (ppm):	
Service Company:	Service Company Representative:	
Inspected by:	Date (yy/mm/dd):	Time (24 hr):
Well Activity:		
Check each item that is adequate. Any item that is inadequate must be corrected.		

Signs					
☐	No smoking	☐	Danger High Pressure	☐	H_2S (if required)
☐	Designated Smoking Area	☐	No vehicles/Unauthorized Persons	☐	Operator Name/Phone #
Safety					
☐	Emergency Response Plan	☐	Ear Protection	☐	Eye Protection
☐	Pre-Start up Safety Meeting	☐	Fire Retardant Clothing	☐	CSA Approved Hard Hats
☐	Fire Extinguishers	☐	Adequate Lighting	☐	Facial Hair
☐	H_2S Gas Detector & Manual	☐	Work Masks Worn Outside	☐	Side Packs Checked
☐	Back Packs Checked	☐	Air Supply Checked	☐	Two Air Lines Reach Tanks
☐	Wind Direction Indicators	☐	First Aid Supplies	☐	Certificates (H_2S Alive, First Aid, WHMIS, TDG)
Wellhead					
☐	Current wellhead pressures	☐	Working Pressure Rating MPA	☐	Functioned, Services, Pressure Tested Valves
☐	ESD Valve Working Pressure MPA	☐	Remote Shutdowns (OST)	☐	Gauge in Place
Flowline					
☐	Size	☐	Working Pressure ____ MPA	☐	Pressure Tested (hydro, Inert Gas)

☐	Blocked/Leveled	☐	Secured & Free of Ice, Snow, Mud	☐	Pressure tested to: ____ MPA
☐	Connections confirmed to be installed per the OEM				
Deadweight Line					
☐	Pipe Schedule	☐	Working Pressure ____ MPA	☐	Pressure Tested (hydro)
☐	Secured	☐	Blocked Valve	☐	Connections confirmed to be installed per the OEM
Gas/Oil/Waterline					
☐	Secured	☐	Blocked/Leveled	☐	Connections confirmed to be installed per the OEM
Pop Line					
☐	Pipe Size _____	☐	Secured & Free of Ice, Snow, Mud	☐	Blocked/Leveled
☐	Pop Riser Pilot in Place	☐	Riser Secured	☐	Connections confirmed to be installed per the OEM
Other					
☐	Check Valve in Place on Pipeline	☐	Plant Operators Notified of Procedure	☐	Flame Arrestors in Place
☐	Flame Arrestor _____ in.	☐	Flame Arrestor Checked	☐	Purge System for Tank Trucks
☐	H_2S Scrubber in Place for 400bbl Tanks	☐	H_2S Scrubber in Place on Tank Trucks	☐	Tank Lines Checked
☐	Tank Manifold Checked	☐	Tank Manifold Bonded to Tanks		
Shipping Line					
☐	Bonded to Tank	☐	Length _____ m	☐	Blocked/Leveled
☐	Dip Pail	☐	Isolation Valve	☐	Truck Bonding
☐	Fire Extinguishers	☐	Connections confirmed to be installed per the OEM		
Propane Line					
☐	Hard Pipe to Vaporizer	☐	Blocked/Leveled	☐	Bonded
☐	Connections confirmed to be				

	installed per the OEM				
Tanks					
☐	Bonded to Wellhead	☐	On Planks	☐	Level
☐	Valves Work	☐	Valves Set	☐	Tank Stairs
☐	Thief Hatch	☐	Gas Blanket	☐	Tanks Purged
☐	Vertical Line ____ in.	☐	Flame Arrestor _____ in.	☐	Flame Arrestor Checked
☐	Block Valve	☐	Vertical Line Secured	☐	Drain at Low Point
☐	Stack Line Clear	☐	Vertical Line Bonded	☐	Berm Checked
☐	Pressure Alarm				
Stack (Dia. mm. X m)					
☐	Lines Clear	☐	Pilot Checked	☐	Shooter Tube Checked
☐	Flare Catcher	☐	Igniter Checked	☐	# of Guy Wires
☐	0 – 15 m Wires (3)	☐	15 – 35 m Wires (3 min.)	☐	35 – 60 m Wires (6 min.)
☐	Correct Angels Flagged	☐	3 Clamps/Cable (1" apart)	☐	Clamps Correct Position
☐	Shackles Straight	☐	Stack Straight	☐	Fire Hazard Checked
Spacing					
☐	Wellhead to Separator 25 m	☐	Separator to Tank 25 m min.	☐	Separator to Stack 25 m min.
☐	Wellhead to Tanks 50 m	☐	Tanks to Flare 50 m	☐	Flare to Wellhead 50 m
☐	Propane Tank to Wellhead 25 m	☐	Non-Certified Propane Tank to Wellhead 50 m	☐	Vaporizer to Propane Tanks 25 m
Circulating Pump and System					
☐	Check Valve Working Pressure ____ MPA	☐	Storm Chokes Working Pressure _____ MPA	☐	Reservoir Full
☐	Flowlines Blocked	☐	Heater Checked		
Heater					
☐	Upper Coil Schedule	☐	Upper Coil Working Pressure ____ MPA	☐	Stack Gasket Checked
☐	Bath Full	☐	Choke Inspected	☐	Supply Gas Checked
☐	Pilot Checked	☐	Main Burner Checked	☐	Flame Arrestor Checked

☐	Heater Preheated				
Separator					
☐	Separator Working Pressure MPA	☐	Relief Valve Checked	☐	Pressure Tested
☐	Valves Operational	☐	Lines Clear	☐	Instrument Supply System Checked
☐	BP Valve Stroked and Serviced	☐	Front Manifold Set	☐	Inside Valve Set
☐	Deadweight Manifold Set	☐	Deadweight Line Full	☐	Methanol Barrel Safe
☐	Liquid Meters Bypassed	☐	Floats Checked	☐	Dump Controllers Set
☐	Hi-Lows Checked				
Lease Trailer and Light Plant					
☐	Safety Board	☐	Portable Water	☐	Safety Binder
☐	WHMIS Labelling	☐	Safety Meeting Posted	☐	Flare Permit Posted
☐	Fire Extinguisher	☐	Fire Blanket	☐	Furnace Lit
☐	Office Area Clean	☐	Lockers Clean	☐	Bench Area Clean
☐	Floor Clean	☐	Step Level		
General					
☐	Flashlights C1-D1	☐	Test Program Available	☐	Chemical Clothing
☐	Mobile Phone Good Working Order	☐	Test Kits Checked	☐	Purging Completed
☐	Government Notified	☐	Flashing Permit Obtained	☐	Area Residents Notified
Comments/Explanations:					

Name	**Signature**
Owner Representative:	
Contractor:	
Service Company:	

Appendix C: Standard Operating Procedures for Choke Manifold Operation

STANDARD OPERATING PROCEDURES FOR CHOKE MANIFOLD OPERATION

Standard Operating Procedures (SOP) for Choke Manifold Operation

Objective

The objective of this SOP is to establish guidelines and procedures for safe and efficient operation of a choke manifold system. A choke manifold can have many configurations but ultimately, they have two independent sides. This is a generic procedure on how to safely operate and work from side to side of a manifold.

Scope

This SOP applies to all well testing employees or contractors involved in the operation of a choke manifold system.

Responsibilities

1. The employer is responsible for overseeing the implementation of this SOP and ensuring compliance with its provisions.
2. The Supervisor is responsible for ensuring that all personnel under their supervision are trained, competent, and comply with the procedures outlined in this SOP.
3. The worker is responsible for following this procedure.

Reference Documents

- WorkSafeBC 23.69 – Flow Piping Systems
- Alberta Occupational Health and Safety Code (OHSC) - Part 188
- Alberta OHSC 783 Well site piping system
- Saskatchewan Occupational Health and Safety Regulation (OHSR) 9-20 Pressurized hoses
- Saskatchewan OHSR 29.36 Piping systems at well sites
- Manitoba 16.26 - Pressurized hoses
- Manitoba 41.22 Well operation and servicing
- Manufacturers Operation Manual(s) for operation and maintenance
- Energy Safety Canada – 10 Life Saving Rules

Hazards

- Chemical (toxic, flammable, corrosive)
- Ergonomic (strain)
- Hazardous atmosphere
- Heat (high temperature process)
- Lifting (heavy)
- Line of fire
- Pressure energy
- Mechanical failure
- Pinch/crush points
- Spills (loss of containment)
- Abrasive erosion

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STANDARD OPERATING PROCEDURES FOR CHOKE MANIFOLD OPERATION

Emergency Equipment Required

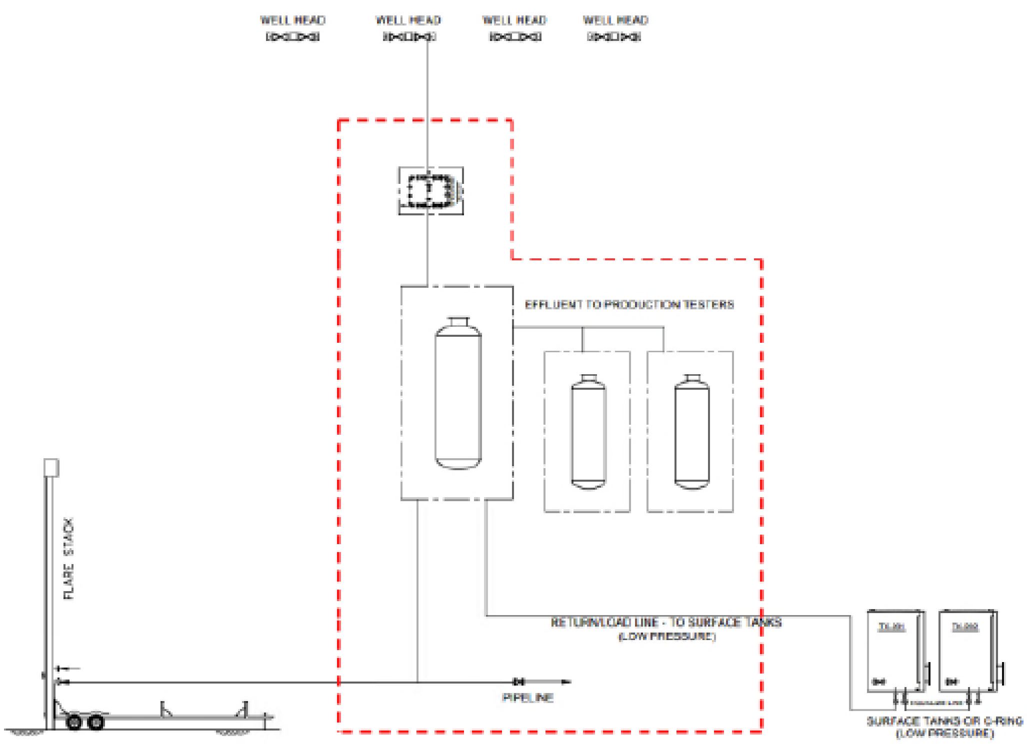
1. Emergency Shut Down (ESD) / Remote Valve

Preparation

1. Workers in the area must be notified of a planned break in integrity and moved to an upwind position.
2. Exclusion zones should be established based on risk assessment conducted at the site. Only authorized personnel can enter the exclusion zone. (see Figure 1)
   2.1. Consider Simultaneous Operations (SIMOPS) and integrated services during the risk assessment.
3. Personal protective equipment (PPE) must be worn at all times.
4. All equipment must be inspected before use and any defects must be reported to the Testing Supervisor. Defective equipment must be taken out of service.
5. All required tools should be present in the work area.
6. Breathing apparatus must be donned if the atmosphere is not within occupational exposure limits.
7. Emergency response procedures must be in place and reviewed by workers.

WARNING: Be aware of body positioning to mitigate LINE OF FIRE related hazards (potential line of fire energy sources include valves, plugs, choke bonnets, etc.).

Figure 1: Example Exclusion Zone



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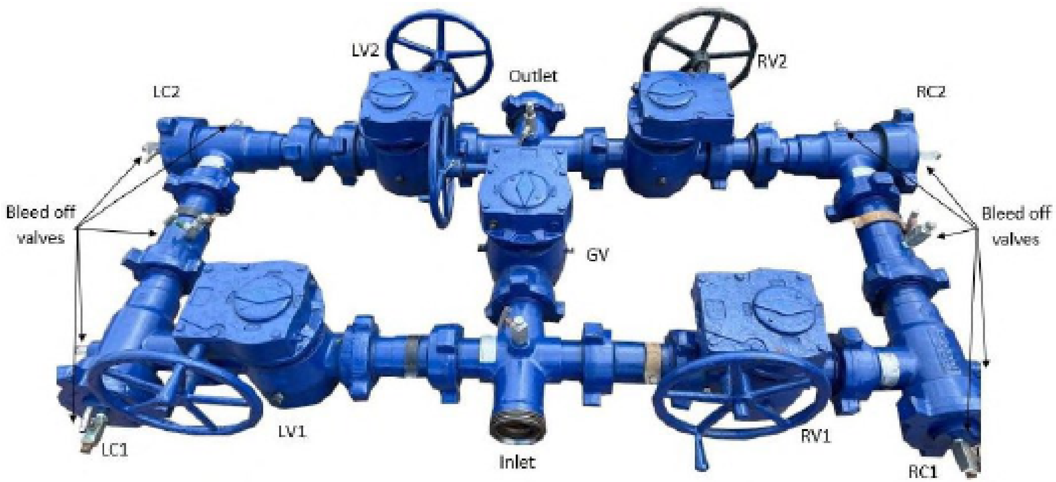
STANDARD OPERATING PROCEDURES FOR CHOKE MANIFOLD OPERATION

Diverting Well Flow on Choke Manifold Procedure

Refer to Figure 2: Manifold Diagram. This figure will be used as an example to divert flow from the right side (RC1, RC2) of the choke manifold to the left side (LC1, LC2).

Figure 2: Manifold Diagram



Steps to divert well flow on a choke manifold right (flowing) side to left (non-flowing) side

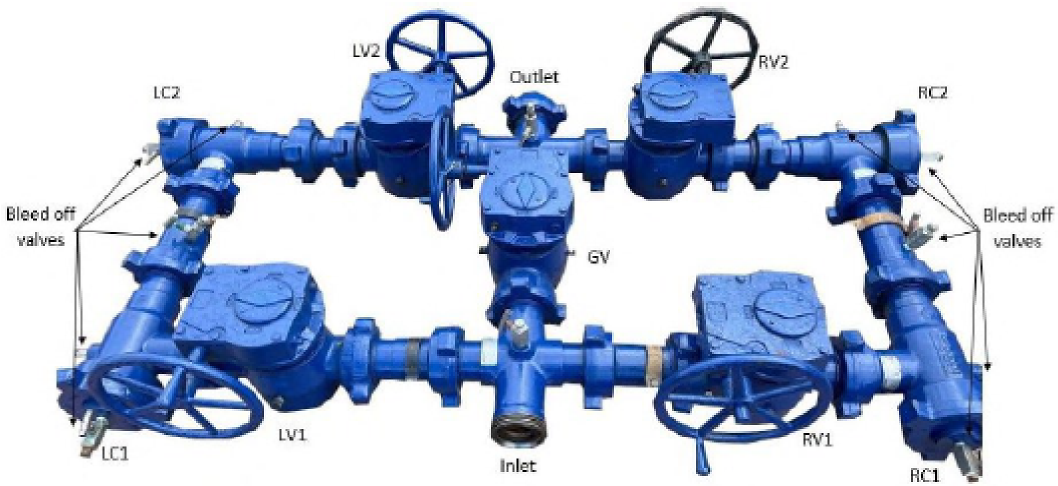
1. Prepare to divert flow from the right side (RC1, RC2) of the choke manifold to the left side (LC1, LC2) of the choke manifold, by confirming the following:
   1.1. Verify all line restraints are positioned to avoid obstruction or damage to line restraints if restraints are deemed required.
   1.2. Verify all bleed off valves are closed and plugged on the left side of the manifold.
   1.3. Verify choke caps are secured and tight on the left side of the manifold.
2. Grease valves to ensure energy isolation is achieved.
   2.1. Refer to manufactures specific procedures for greasing valves.
3. Divert flow from the right side of choke manifold to the left side of the choke manifold.
   3.1. Open the left side downstream manifold valve (LV2).
   3.2. Monitor for leaks and pressure equalization.
   3.3. If no leaks are present and the pressure is stable, open the left side (LV1) upstream manifold valve while simultaneously closing the right (RV1) side upstream manifold valve to divert flow.
   3.4. Close the downstream right) side manifold valve (RV2).

STANDARD OPERATING PROCEDURES FOR CHOKE MANIFOLD OPERATION

Installing Choke Trim Procedure

Refer to Figure 2: Manifold Diagram. This figure will be used as an example to install a choke trim.

Figure 2: Manifold Diagram



Steps to install choke trim for an energized choke manifold system

1.1. Prepare to remove and replace choke trim in the choke manifold by verifying that both upstream and downstream (RV1, RV2) are in the closed position and valve position is clearly indicated.

2. Prior to bleeding off pressure from the right side of the manifold (isolated):
   - 2.1. Ensure that area is clear of non-essential personnel.
   - 2.2. Utilize respiratory protective equipment for potentially hazardous atmospheres (all personnel involved in the procedure, including safety support).
     Note: wind direction must be considered to ensure workers in the area are not exposed to hazardous atmospheres.
   - 2.3. Remove plugs and open bleed off valves on the right side of the manifold that the choke change is occurring.
     - 2.3.1. Ensure that all well fluids are captured and properly disposed of.
   - 2.4. Verify there is no pressure on the right side of the manifold (i.e., the side being changed).
     - 2.4.1. Use a hand chemical pump to remove a blockage ff there is a blockage in any bleed off valves and ensure no pressure is trapped.
   - 2.5. Remove choke caps once depressurization is verified.
     - 2.5.1. Remove choke trim from the choke body.
     - 2.5.2. Replace with the selected choke trim ensuring threads are clean and lubricated.
   - 2.6. Install choke cap(s).
     - 2.6.1. Inspect and clean the sealing surface of the choke body and the o-ring on the choke cap.
     - 2.6.2. Replace the o-ring on the choke cap if there are noticeable defects.
     - 2.6.3. Install choke cap on choke body.
     - 2.6.4. Hand tighten the choke cap to seat the o-ring onto the choke body sealing surface.
     - 2.6.5. Complete the installation by tightening the choke cap union.
     - 2.6.6. Close and plug all bleed off valves.

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Appendix D: Flare Stack Maximum and Minimum Flare Rates

The flare tip diameter must be properly sized for the anticipated flaring rates with high H_2S concentrations. The AERflare spreadsheet provides a range of recommended values. Flare stacks should be designed to avoid downwash due to low exit velocities and excessive noise due to high exit velocities. Additional information is available on the AER’s Directive 060 webpage.

The charts in figures 12 to 15 are provided as a reference and were developed using the calculation for flare exit velocity (See Equation 2.).

Equation 2. Flare Exit Velocity

$$V = \frac{Q}{10^3 * 24 * 3600 * \left(\frac{\pi}{4} * \left(\frac{DIA\_mm}{1000}\right)^2\right)}$$

V is the flare exit velocity in metres per second (m/s).

Q is the flow rate in 103 cubic metres per day (m3/d).

Dia_mm is the exit diameter in millimetres (mm).

The horizontal blue line shown in the charts is set at 10 m/s which is typically the 99^{th} percentile wind speed in Alberta. The flare exit velocity should be above this level to reduce the likely hood of the flame being drawn backward into the flare stack and associated pressure vessels (flashback). The red line is set at 330 m/s which is the approximate speed of sound. This is the maximum exit velocity possible but is very noisy and requires a well-designed tip and igniter to prevent flame lift-off and possible extinction. The orange line is set at 95 m/s which is the maximum exit velocity to ensure combustion efficiency and to prevent excessive noise and flame lift-off.

Figure 12. Gas Exit Velocity of 101.6 mm (4” Pipe)

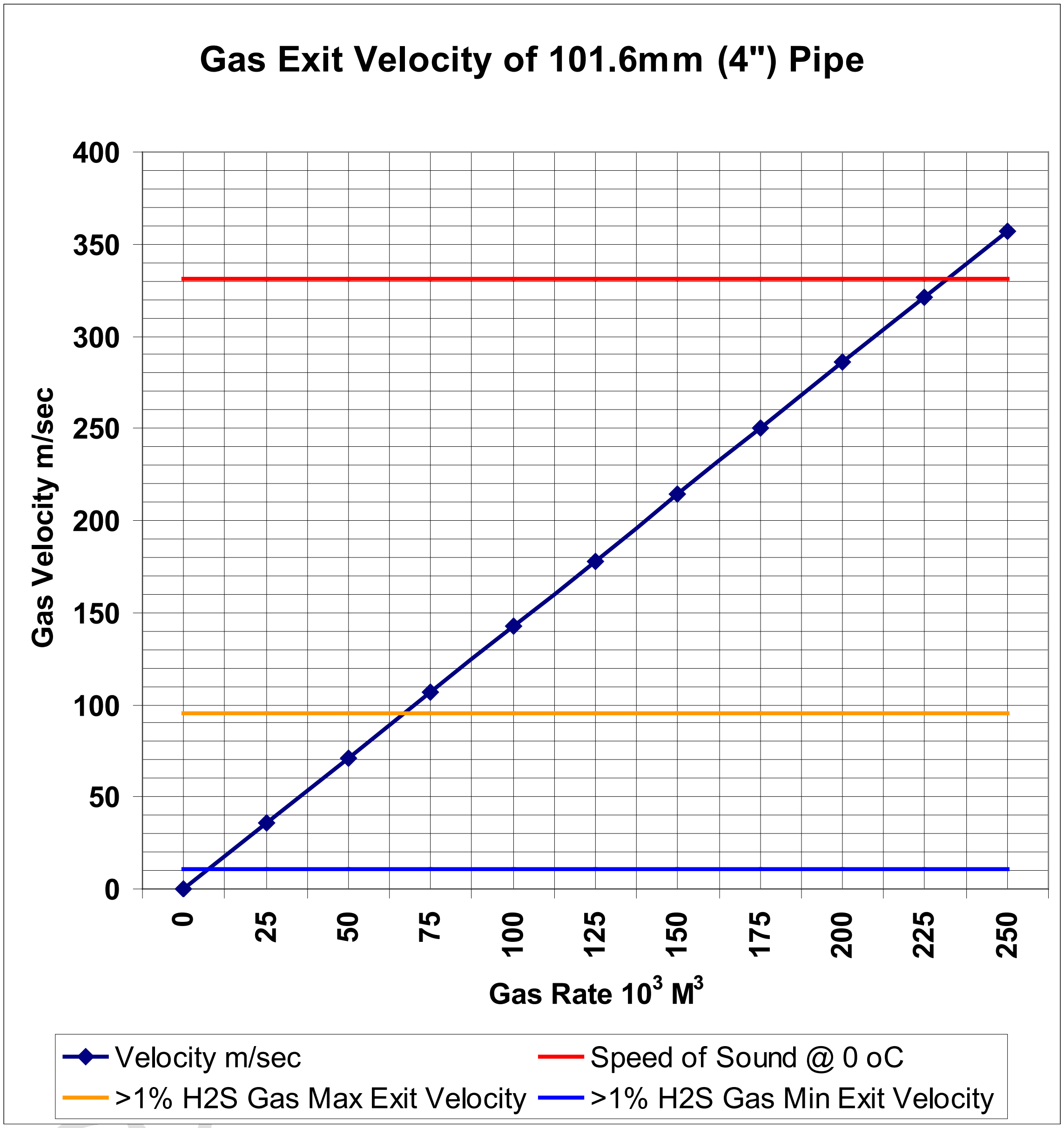


Figure 13. Gas Exit Velocity of 152.4 mm (6” Pipe)

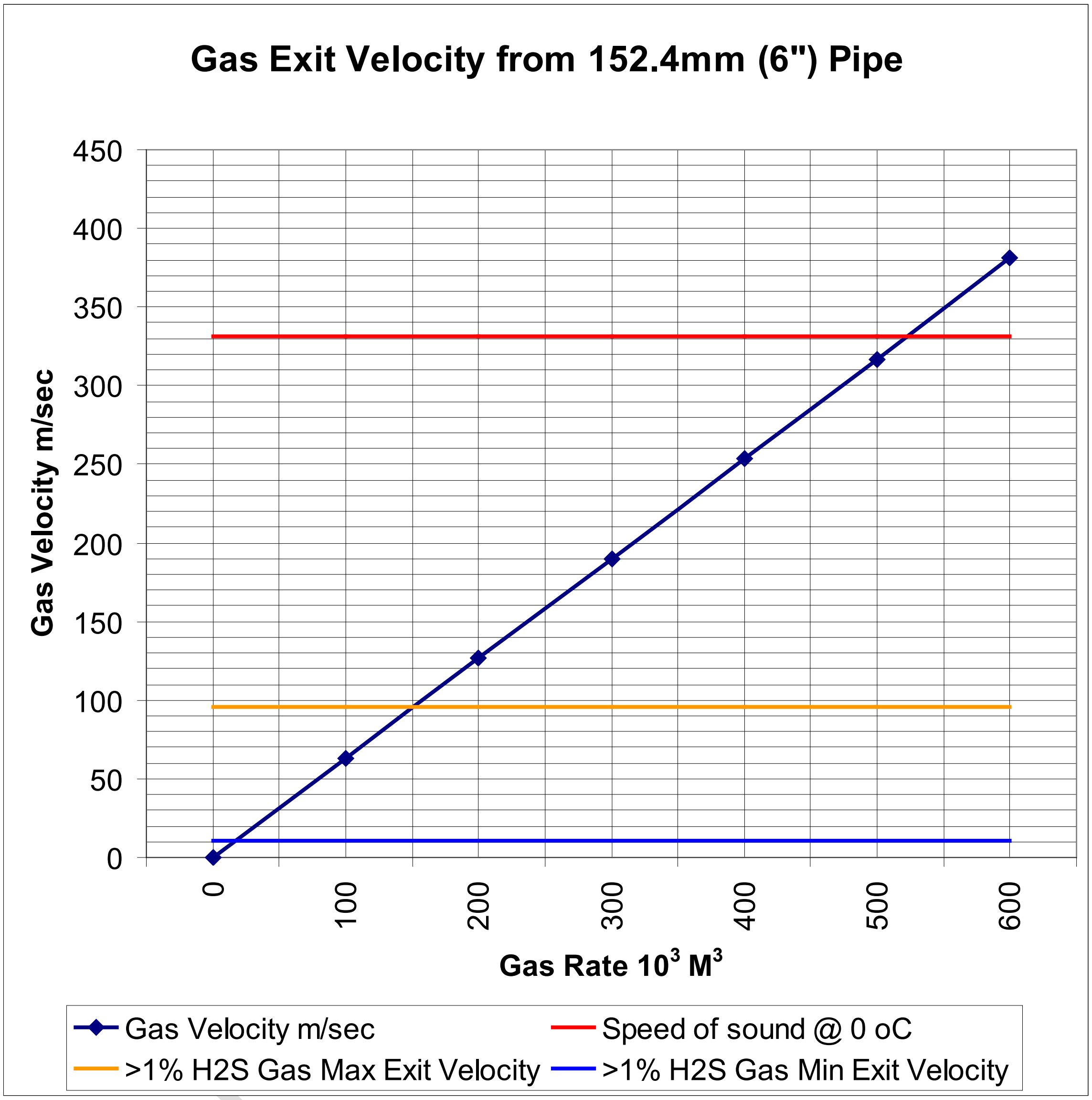


Figure 14. Gas Exit Velocity of 203.2 mm (8" Pipe)

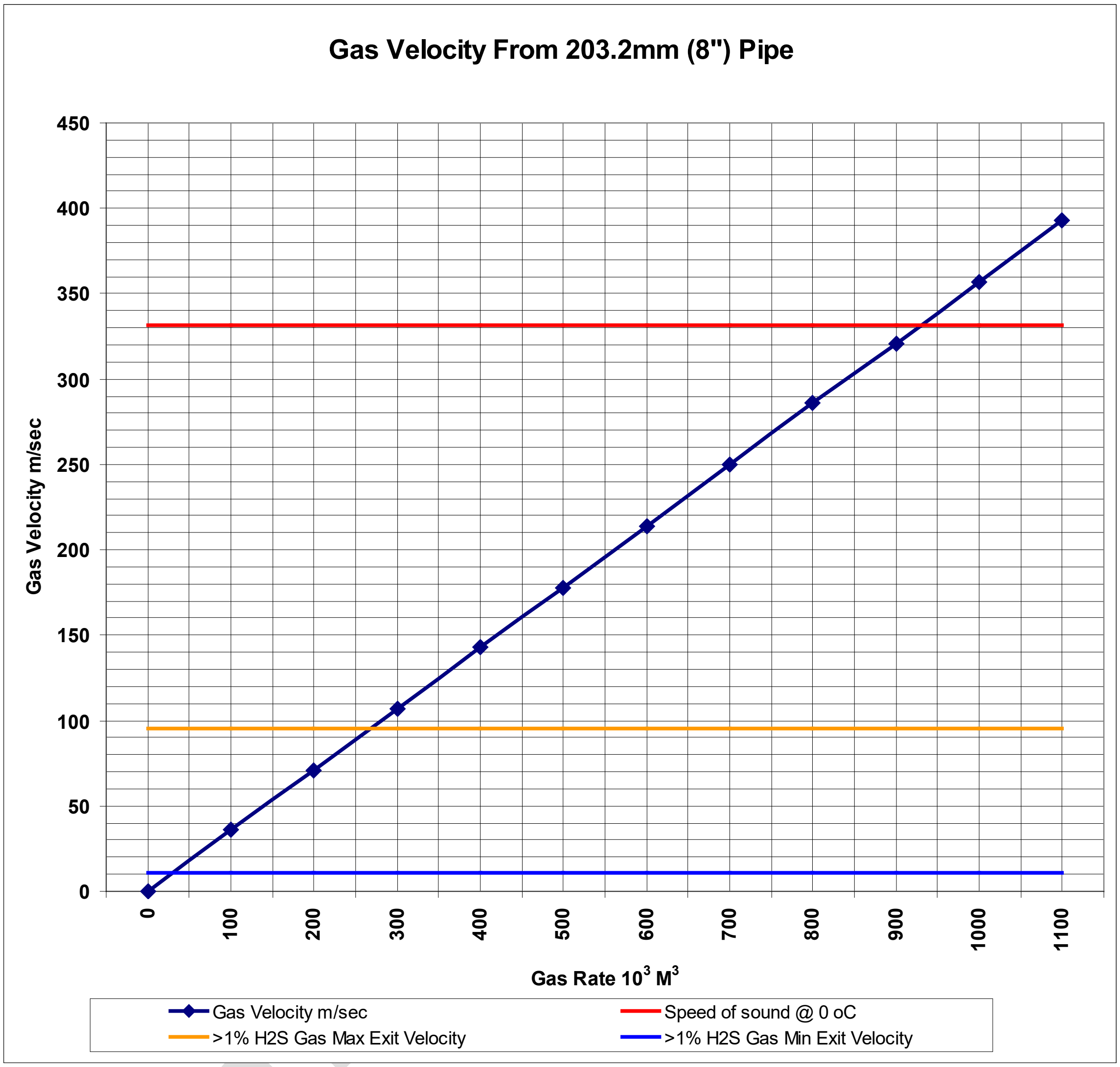
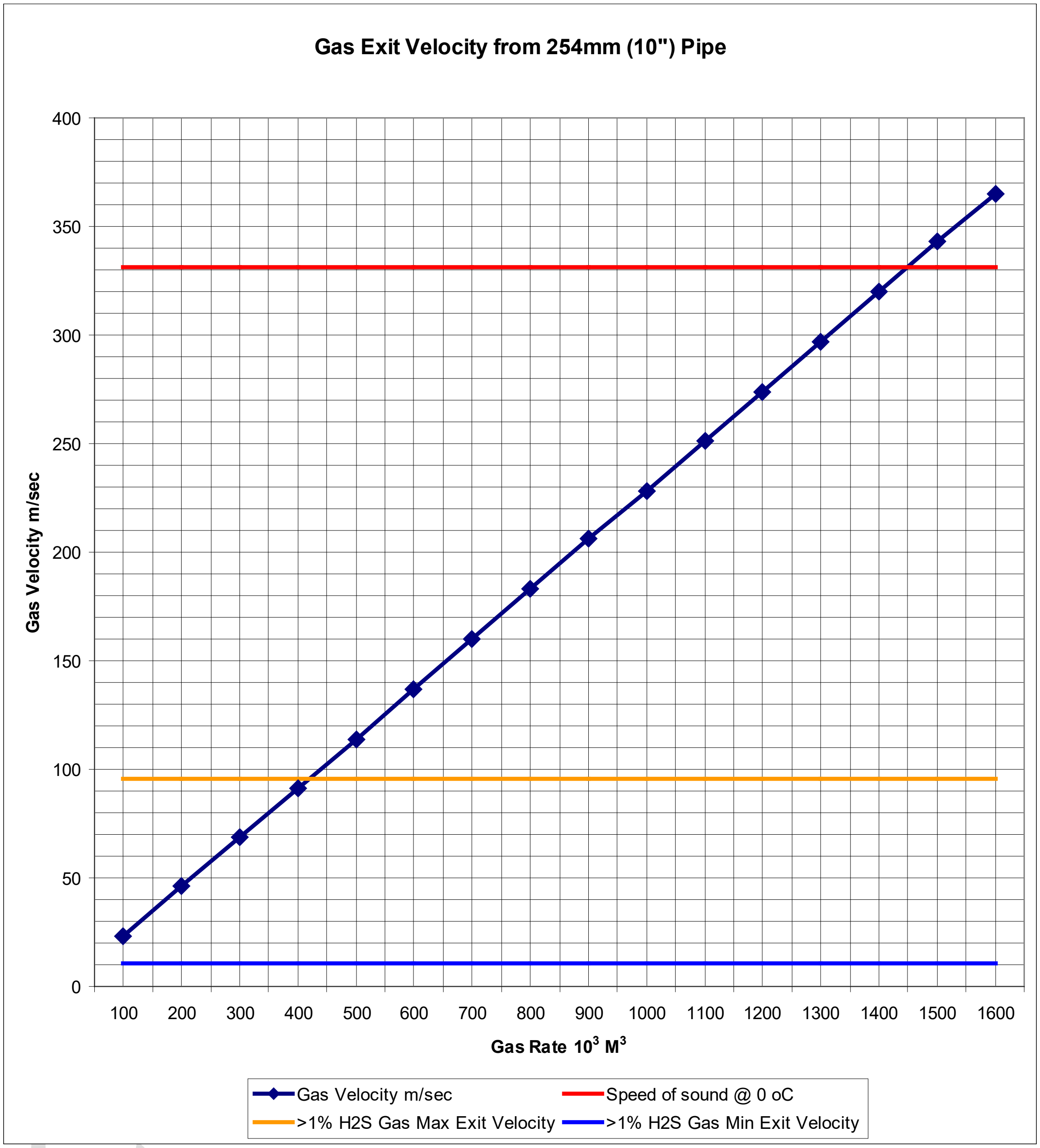


Figure 15. Gas Exit Velocity of 254 mm (10” Pipe)



Appendix E: Hydrates

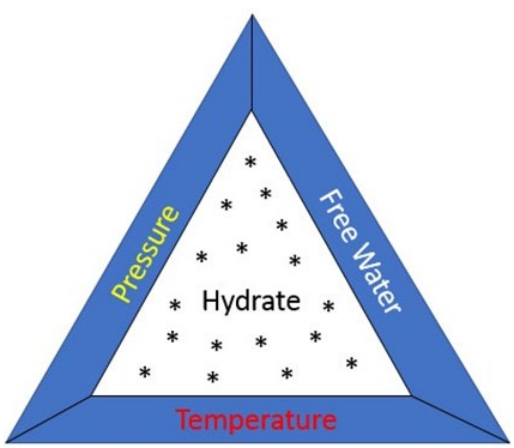
Awareness and Handling

Hydrates are commonly thought of as ice plugs resulting from freezing water. While water plays a role in hydrate formation, hydrates are distinct from ice as they are saturated with gas, which can create flammability and worker exposure hazards and can occur above freezing conditions any time of the year.

There are no regulations specific to hydrates. Provincial regulations require the identification of known safety hazards and management of hazardous energy.

Hydrates are crystalline solids composed of cages of water molecules around natural gas molecules. These solid crystalline compounds are formed by hydrocarbon gases such as methane, ethane, propane and impurities like nitrogen, carbon dioxide and hydrogen sulphide, combined with water under reduced temperature and pressure. The extent to which a gas or impurity will occupy the space between water molecules depends on the solubility of the compound in water. All gases will dissolve in water to some degree at normal temperatures and atmospheric pressure conditions. The figure below illustrates the relationship between water, gas, pressure and temperature. If any of the required elements are missing or outside the required range, hydrate formation does not occur.

Figure 16. Hydrate Triangle



Generally, changes in pressure occur when flow restrictions or reductions are introduced. For pipelines, this could be a change in pipe diameter, a bend in the pipe, the addition of instrumentation or valves, or even the accumulation of fines and wax. When fluids and gas travel past a restriction, they are moving from high pressure to low pressure states. The pressure change expands the fluid causing a decrease in temperature, which is known in thermodynamics as the Joule-Thomson effect. As the hydrate forms and grows, it continues to contribute to the restriction until the flow is completely blocked.

The Joule-Thomson effect (sometimes referred to as the JT effect) is also called the Joule-Kelvin. The Joule Thomson effect is the change in temperature that accompanies expansion of a gas without the transfer of heat.

The amount of gas that dissolves in water to occupy spaces between water molecules depends on the temperature and pressure. When pressure is high, gas compresses and fills the spaces until they are saturated. This saturation from high pressure can occur at temperatures well above the freezing point of water, which explains why hydrates occur in warm gas streams. Once water is saturated with gas, chemical bonds change and crystal growth begins, leading to the eventual formation of a solid mass of water and gas.

Condensation of water from natural gas under pressure occurs when the temperature is at or below the dew point at that pressure. Hence, the hydrate temperature would be below and perhaps the same as, but never above the dew point temperature. (Dew point is the state of a system characterized by the co-existence of a vapour phase with an infinitesimal quantity of liquid phase in equilibrium. Dew point pressure is the fluid pressure in a system at its dew point.)

Each component of natural gas has a different water solubility. As a result, hydrates form at different pressures and temperatures for different compounds. Heavier gases, like pentane, are too large to occupy the spaces between water molecules, whereas lighter gases, like methane and ethane, do so readily. The figure below illustrates hydrate formation for different gas activities. Higher gravities mean heavier gases. Heavier gases form hydrates at lower pressures than lighter gases. Also, hydrates from both light and heavy gases will form at higher pressures, even with flowing temperatures above 20 degrees Celsius (°C).

Refer to Energy Safety Canada Prevention and Safe Management of Hydrates in Process Equipment for hydrate formation modeling minimum requirements.

Figure 17. Natural Gas Hydrate Chart

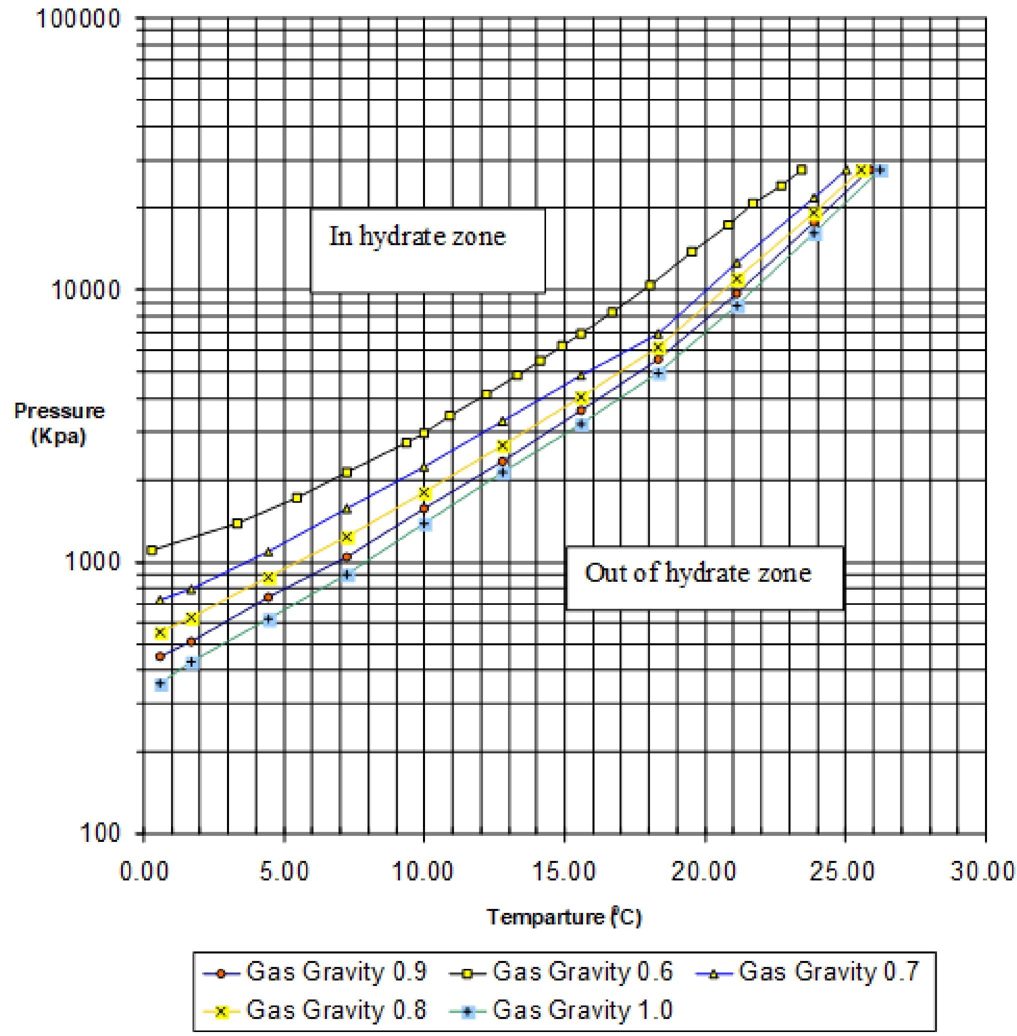


Figure 18. Sour Natural Gas Hydrate Chart

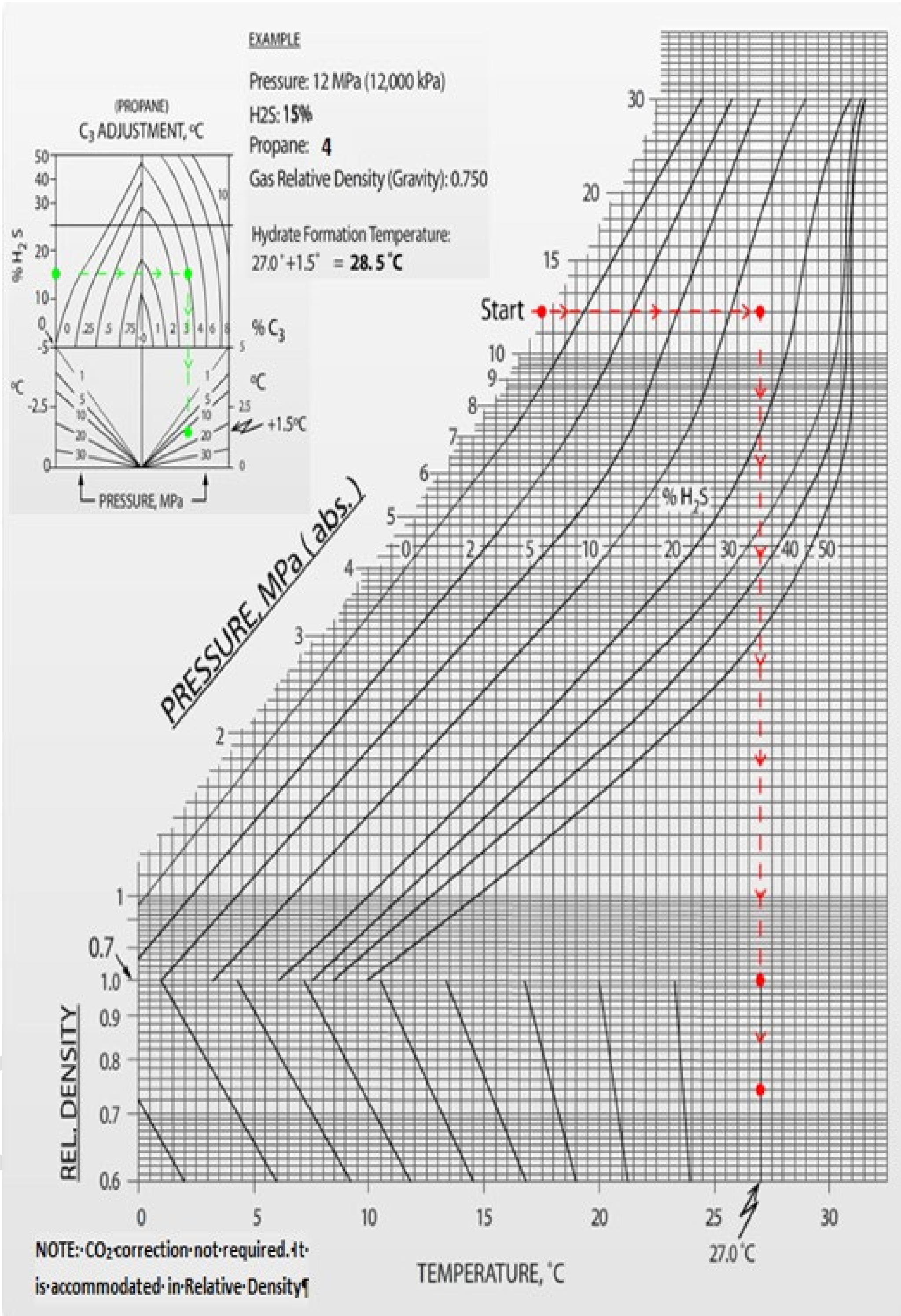
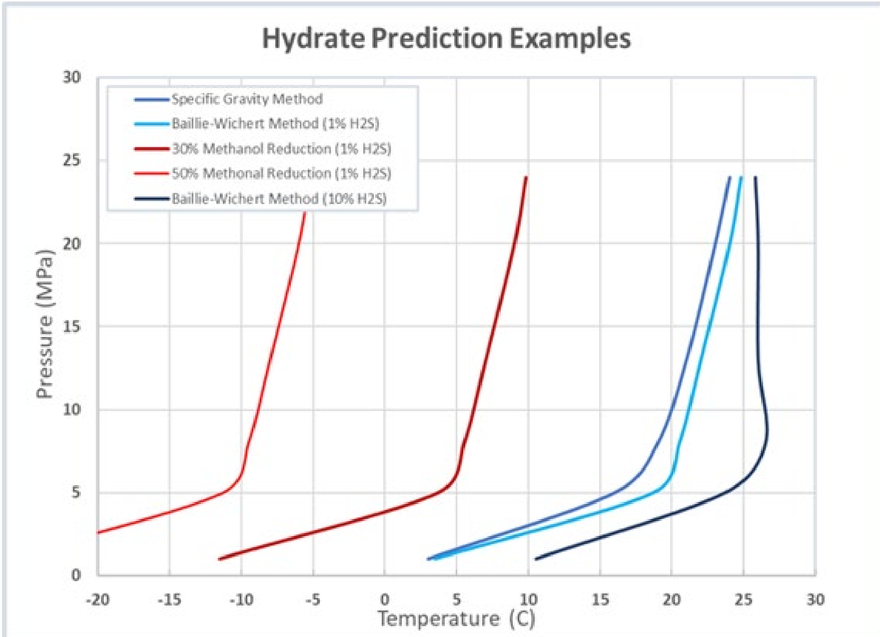


Figure 19. Hydrate Prediction with H_2S and Methanol Reduction



Appendix F: Glossary

Adequate: For the purposes of this IRP adequate is defined as the result of conducting a hazard assessment and mitigating the risks associated with the job to be performed.

Adequate Lighting: The visibility must be such that the worker will be able to exit the worksite to a secure area in the event of an emergency. Flashlights, rig lights and vehicle lights can be considered as emergency back-up lighting. (See Lease Lighting Guideline.)

AER Alberta Energy Regulator

AMPP Association for Materials Protection and Performance

API American Petroleum Institute

ASME American Society of Mechanical Engineers

ASTM American Society of Testing and Materials (now ASTM International)

BCER British Columbia Energy Regulator

Bleedoff To equalize or relieve pressure from a vessel or system.

Bonding A low resistance path created by connecting conductive metal parts to ensure they have the same electrical potential and capacity to safely conduct any current likely to be imposed.

Btu British thermal unit

Btu/h-ft^2 British thermal units per hour per square foot

CAOEC Canadian Association of Oilwell Energy Contractors

CAPP Canadian Association of Petroleum Producers

CEC Canadian Electrical Code

Closed System A closed system refers to a handling system in which the odours or emissions from the wellbore effluent are either flared or vented to atmosphere through an H_2S scrubber, in a controlled manner.

Coiled Tubing Unit Operations Coiled tubing units (CTU) are commonly used in other flowbacks to recover wellbore effluent. Nitrogen, carbon dioxide or air is used to move and lift proppant, produced sand or stimulation fluids such as acid, chemicals or hydraulic fracture treatment fluids from the wellbore. Coiled tubing unit operations may also be undertaken to evaluate well-production capability.

Combustible Liquid Any liquid with a closed cup flash point at or above 37.8°C. Combustible liquids at temperatures at or above their flash points are considered flammable.

Confined Space A confined space is an enclosed or partially enclosed area with limited or restricted entry or exit. It is not designed or intended for continuous human occupancy. It is or may become partially hazardous to a worker entering or the confined space may complicate the provision of first aid, evacuation, rescue or other emergency response services. Refer to applicable OHS regulations.

CO_2 Carbon dioxide

CPA Canadian Petroleum Association

CSA Canadian Standards Association

DACC Drilling and Completions Committee

dBA Decibels

Dew Point The state of a system characterized by the co-existence of a vapour phase with an infinitesimal quantity of liquid phase in equilibrium.

Dew Point Pressure The fluid pressure in a system at its dew point.

DIA_mm is exit diameter in millimetres.

Drill Stem Test A method of determining the producing potential of a formation. This is done by removing the hydrostatic pressure of the drilling fluid column and allowing formation fluids or gas to flow into an evacuated or partially evacuated drill string or production string. This allows the formation pressures to be monitored and measured to calculate flow and depletion rates. A drill stem tester represents the company responsible for the downhole and surface equipment used in identifying the content and production capability of the formations to be tested.

Elastomer A natural or synthetic rubber or packing element, used to seal piping connections under pressure, which has the ability to undergo deformation under the influence of a force and regain its original shape once the force has been removed.

Emergency Shutdown Device (ESD) It is a hydraulically or pneumatically operated, high-pressure valve installed on the wellhead with remote or automatic shutdowns. Its purpose is to provide a means to remotely shut in the well in an emergency. An ESD is required on wells to be flowed having a surface pressure greater than 1379 kPa and an H_2S content greater than 1% or release of one tonne of sulphur per day.

Employer A who is self-employed in an occupation, a person who employes or engages one or more workers, including a person who employs or engages workers from a temporary staffing agency, a person designated by an employer as the employer's representative or a director or officer of a corporation or a person employed by the employer who oversees the occupational health and safety of the workers employed by the corporation or employer.

EPAC Explorers & Producers Association of Canada

Erosion The wear of material by mechanical means. Solids contained in the produced fluids stream typically result in erosion of surface flow control equipment. Factors that affect erosion rates include concentration, type and size of solids and transport velocity.

ESD Emergency Shut Down (valve)

Exclusion Zone A designated area of hazards with the highest risk and requires authorization to enter.

Flammable Liquid Any liquid that has a closed-cup flash point below 37.8°C.

Flowback Where pressure on a well is bled off and the well continues to flow and is allowed to flow to establish a rate of gas and fluid from the well.

Grounding A permanent conductive path to earth. Sometimes referred to as 'earthing' this accomplishes system stabilization and establishes an equipotential plan in the surrounding soil.

H_2S Hydrogen Sulphide

High Vapour Pressure Hydrocarbons Hydrocarbon mixtures with a Reid vapour pressure greater than 14 kPa or an API gravity greater than 50° are high vapour pressure hydrocarbons.

> **Note:** Reid Vapour Pressure is determined in a laboratory test. API gravity can be readily measured in the field. C1-C7 content can also be indicative of a fluid's flammability. Flammability increases with increasing C1-C7 content. If available, fluid analyses should be reviewed. Fluid and ambient temperatures should be considered.

Hydrate Crystalline solids composed of ‘cages’ of water molecules around natural gas molecules. These solid crystalline compounds are formed by hydrocarbon gases (methane, ethane, propane) and impurities (nitrogen, carbon dioxide, hydrogen sulphide) combined with water under reduced temperature and pressure.

IRP Industry Recommended Practice

JSA Job Safety Analysis

Joule Thomson Effect The change in temperature that accompanies expansion of a gas without the transfer of heat.

kWh/m^2 Kilowatt hours per square metre

LEL Lower Explosive Limit

m/s metres per second

m3/d cubic metres per day

mm millimetres

Make-up Gas Make up gas is usually propane or sweet well gas which is used as a purge or blanket gas to prevent oxygen getting into the flare or incinerator for flashback control. This may be used to increase plume rise or combustion. Make up gas is also known as blanket, purge or enrichment gas.

Metallurgy The science and technology of metal.

N_2 Nitrogen

NACE National Association of Corrosion Engineers (NACE International)

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

NORM Naturally Occurring Radioactive Materials

Occupational Exposure Limit The maximum acceptable level of a hazardous substance (chemical or physical) to which a worker can be exposed to for a length of time (usually eight hours) without experiencing harmful effects.

OEL Occupational Exposure Limit

OEM Original Equipment Manufacturer

OHS Occupational Health and Safety

Other Flowbacks Other flowbacks refers to operations, other than production testing and drill stem testing, in which gas or fluids are flowed or induced to flow from the wellbore. This includes well killing operations and the recovery of well stimulation fluids and solids by flowing, pumping, swabbing or by the circulation of fluids (i.e., coiled tubing.) See 4.5 Other Types of Flowbacks for information specific to testing.

Owner A trustee, receiver, mortgagee in possession, tenant, lessee or occupier of any lands or premises used or to be used as a place of employment and any person who acts for or on behalf of an owner as an agent or delegate.

Personal Protective Equipment (PPE) Clothing and equipment that is worn or used to provide protection against hazardous substances or environments.

PFD Process Flow Diagram

pH Potential of Hydrogen

Prime Contractor In relation to a multiple employer workplace, the directing contractor, employer or other person who enters into a written agreement with the owner of that workplace to the be prime contractor or if there is no agreement, the owner of that workplace.

PSAC Petroleum Services Association of Canada

PPE Personal Protective Equipment

PPM Parts per Million

PSV Pressure Safety Valve

Purge The removal of hazardous substances or air within pipe, pipeline, vessel, or other containers with fuel, inert gas or fluid to prevent creating an explosive atmosphere.

Reid Vapour Pressure (RVP) Reid Vapour Pressure is an indirect measure of the evaporation rate of volatile petroleum solvents using standard analytical methods defined by ASTM D323 or D5191. These test methods are used to determine vapour pressure of volatile petroleum liquids at 37.8°C (100°F) with an initial boiling point above 0°C (32°F).

SABA Supplied Air Breathing Apparatus

SCBA Self-contained Breathing Apparatus

SDS Safety Data Sheet

Self-Contained Breathing Apparatus (SCBA) A respirator that has a portable supply of breathing gas and is independent of the ambient atmosphere. SCBA's include both open-circuit and closed-circuit respirators.

Service Company Means a person, corporation or association who is contracted to supply, sell, offer, or expose for sale, lease, distribute or install a product or service to another company, usually the owner of the worksite.

SICP Shut-in Casing Pressure

SITP Shut-in Tubing Pressure

SIMOP Simultaneous Operations

SOP Standard Operating Procedure

Sour Hydrogen sulphide content in a process or a well.

Stimulation A treatment performed to restore or enhance the productivity of a well. Stimulation treatments fall into two main groups, hydraulic fracturing treatments or matrix treatments. Fracturing treatments are performed above the fracture pressure of the reservoir formation and create a highly conductive flow path between the reservoir and the wellbore. Matrix treatments are performed below the reservoir fracture pressure and generally are designed to restore the natural permeability of the reservoir following damage to the near wellbore area. Stimulation in shale gas reservoirs typically take the form of hydraulic fracturing treatments.

Supplied Air Breathing Apparatus (SABA) A unit that consists of a small air cylinder (less than 5 minutes of breathing air) and air mask. It is intended to be carried on the hip of a worker with the ability to connect, by hose, to numerous larger air cylinders. This type of configuration is used for extended work periods where a worker is exposed to an H_2S or other hazardous breathing environment.

Surface Development 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 emergency planning zone and those from which dwellers are required to egress through the EPZ.

Swabbing To reduce pressure in a wellbore by moving pipe, wireline tools or rubber cupped seals up the wellbore. If the pressure Is reduced sufficiently, reservoir fluids may flow into the wellbore and towards the surface. Swabbing is generally considered harmful in drilling operations because it can lead to kicks and wellbore stability problems. In production operations, however, the term is used to describe how the flow of reservoir hydrocarbons is initiated in some completed wells.

Sweet A process or well that does not contain hydrogen sulphide.

Swivel Joint (Chiksan) A series of short steel pipe sections that are joined by swivel couplings. The unit functions as a flexible flow line that provides a flow path between the control head and the floor manifold.

TDG Transportation of Dangerous Goods

UEL Upper explosive limit

Well-Killing Operations Well-killing operations are operations in which well effluent is circulated from the wellbore using a fluid of sufficient density to prevent further influx of reservoir fluids. The process is continued until the well is incapable of flow.

Well Testing Well Testing is an operation where a company supplies equipment and the continuous presence of qualified test workers for the purpose of measuring and handling wellbore effluents through production equipment. Such operations include, but are not limited to:

- Flowing a well to production equipment or tank
- Flow measurement with chokes, flow provers or other devices
- Initiating flow by swabbing, coiled tubing or any such artificial lift method

WHMIS Workplace Hazardous Materials Information System

Worker A person who is engaged in an occupation in the service of an employer.

Appendix G: References and Resources

Energy Safety Canada

Available from www.energysafetycanada.com:

- Fire and Explosion Hazard Management Guideline
- Lease Lighting Guideline
- Wildlife Awareness A Program Development Guideline

DACC References

Available from www.energysafetycanada.com:

- IRP 01: Critical Sour Drilling
- IRP 02: Completing and Servicing Sour Wells
- IRP 04 Minimum Equipment Spacing Table
- IRP 07: Competencies for Critical Roles in Drilling and Completions
- IRP 15: Snubbing Operations
- IRP 20: Wellsite Design Spacing Requirements

Local Jurisdictional Regulations and Information

Alberta

Available from www.alberta.ca:

- Alberta EDGE (Environmental and Dangerous Goods Emergencies) Dangerous Goods and Rail Safety publication
- Environmental Protection and Enhancement Act
- Occupational Health and Safety Code
- Pressure Equipment Exemption Order
- Pressure Equipment Safety Regulation
- Private Sewage Disposal Systems Regulation

- Safety Codes Act

Available from www.aer.ca:

- Directive 033: Well Servicing and Completions Operations – Interim Requirement Regarding the Potential for Explosive Mixtures and Ignition in Wells
- Directive 034: Gas Well Testing, Theory and Practice
- Directive 037 Service Rig Inspection Manual
- Directive 038: Noise Control
- Directive 040: Pressure and Deliverability Testing Oil and Gas Wells
- Directive 058: Oilfield Waste Management Requirements for the Upstream Petroleum Industry
- Directive 059: Well Drilling and Completion Data Filing Requirements
- Directive 060: Upstream Petroleum Industry Flaring, Incinerating and Venting
- Directive 071: Emergency Preparedness and Response
- Directive 087: Well Integrity Management

British Columbia

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

- Petroleum and Natural Gas Act
- Safety Standards Act

Available from www.bc-er.ca:

- Drilling and Production Regulation
- BC Emergency Management Manual
- BC Flaring and Venting Reduction Guideline
- Energy Resource Activities Act
- Oil and Gas Activity Operations Manual
- Well Testing and Reporting Requirements Guide

Available from www.worksafebc.com:

- Occupational Health and Safety Regulation

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

- Petroleum and Natural Gas Act

Manitoba

Available from www.gov.mb.ca:

- Drilling and Production Regulation
- Workplace Safety and Health Act and Regulation

Saskatchewan

Available from www.saskatchewan.ca:

- The Saskatchewan Employment Act
- The Occupational Health and Safety Regulations
- Saskatchewan Boiler and Pressure Vessel Act
- Technical Safety Authority of Saskatchewan Code for Electrical Installations at Oil and Gas Facilities 5th Edition 2021

Available from www.worksafesask.ca

- Occupational Health and Safety Guidelines and Documents

Government of Canada Resources

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

- Canadian Electrical Code
- Canadian Guidelines for the Management of Naturally Occurring Radioactive Materials (NORM)
- TDG Bulletin: Produced water
- Transportation of Dangerous Goods Regulation (SOR/2001-286), February 2020
- Workplace Hazardous Materials Information System

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- *CSA Z662, Oil and Gas Pipeline System Code*, 2019 Edition. Toronto, Ontario, Canada
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