DACC

DRILLING AND COMPLETION COMMITTEE

IRP 21:
Coiled Tubing Operations

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

Volume 21 – 2017

EDITION: 2.0
SANCTION DATE: May 2017

CAODC
CANADIAN ASSOCIATION OF OILWELL DRILLING CONTRACTORS

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

EPAC
CANADA'S OIL & GAS ENTREPRENEURS™

PSAC
working energy
Leading Energy Services, Supply, Manufacturing and Innovation

Copyright/Right to Reproduce

Disclaimer

This IRP is a set of best practices and guidelines compiled by knowledgeable and experienced industry and government personnel. It is intended to provide the operator with advice regarding the specific topic. It was developed under the auspices of the Drilling and Completions Committee (DACC).

The recommendations set out in this IRP are meant to allow flexibility and must be used in conjunction with competent technical judgment. It remains the responsibility of the user of this IRP to judge its suitability for a particular application.

If there is any inconsistency or conflict between any of the recommended practices contained in this IRP and the applicable legislative requirement, the legislative requirement shall prevail.

Every effort has been made to ensure the accuracy and reliability of the data and recommendations contained in this IRP. However, DACC, its subcommittees, and individual contributors make no representation, warranty, or guarantee in connection with the publication of the contents of any IRP recommendation, and hereby disclaim liability or responsibility for loss or damage resulting from the use of this IRP, or for any violation of any legislative requirements.

Availability

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

Enform Canada
5055 – 11 Street NE
Calgary, AB T2E 8N4
Phone: 403.516.8000
Fax: 403.516.8166
Website: www.enform.ca

Table of Contents

List of Figures

List of Equations

List of Tables

21.0 Preface

21.0.1 Purpose

The purpose of this document is to ensure that guidelines for coiled tubing (CT) operations are in place and readily available for all personnel involved in the development, planning and completion of coiled tubing operations.

IRP 21 is intended to supplement existing standards and regulations. It is also intended to establish guidelines in areas where none existed previously.

Current Occupational Health and Safety and jurisdictional regulations must be consulted. The inclusion of extensive quotes from, or references to, these regulations has been minimized to avoid references to out-of-date regulations.

21.0.2 Audience

The intended audience for this document includes oil and gas company engineers, field consultants, coiled tubing personnel, drilling and service rig personnel, well testing and fluid hauling personnel, other specialized well services personnel, coiled tubing manufacturers and jurisdictional regulators.

21.0.3 Scope and Limitations

This IRP applies to all coiled tubing drilling and coiled tubing well servicing operations performed in a wellbore. Both overbalanced and underbalanced operations are covered.

The well control equipment sections were developed with the consideration that the hydrostatic head of the fluid column may no longer be the primary method of well control. In underbalanced operations, the well control equipment is considered the primary well control mechanism preventing the escape of wellbore fluids and ensuring the safety of onsite personnel.

These recommendations are considered to be the minimum recommended procedures and best practices necessary to carry out operations in a manner that protects people (the public and workers) and the environment. The IRP includes pertinent information about coiled tubing operations including recommendations for the following:

- Operations planning
- BOP stacks and accumulators
- Pipe specifications
- Fluids and circulating systems

- Well pressure-containing equipment
- Elastomeric seals
- Well servicing operations
- Drilling operations

IRP21 refers to other pertinent standards where appropriate and provides information on how to access them. A full list of the documents referred to in this IRP is provided in the References section.

IRP 21 is intended to provide guidelines and best practices for coiled tubing operations in all jurisdictions in Canada. Regulations in the applicable regulatory jurisdiction must be consulted and followed.

This IRP recognizes that the evolution of procedures and practices and advances in technology may improve safety and efficiency. This IRP will be reviewed regularly (as per the revision process below) to allow industry experience and technological advances to be considered.

21.0.4 Revision Process

IRPs are developed by the Drilling and Completions Committee (DACC) with the involvement of both the upstream petroleum industry and relevant regulators. Enform 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 Enform website at www.enform.ca.

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

21.0.5 Sanction

The following organizations have sanctioned this document:

Canadian Association of Oilwell Drilling Contractors (CAODC)

Canadian Association of Petroleum Producers (CAPP)

Petroleum Services Association of Canada (PSAC)

Small Explorers & Producers Association of Canada (SEPAC)

21.0.6 Acknowledgements

The following individuals helped develop this edition of IRP 21 through a subcommittee of DACC.

Table 1. Development Committee

Name	Company	Organization Represented
Don McClatchie (Chair)	Sanjel Corporation	PSAC
Bailey Epp (Co-Chair)	STEP Energy Services Ltd.	PSAC
Adam Alvis	Balanced Energy Oilfield Services Inc.	PSAC
Ossama Bayoumy	Conoco Phillips Canada	CAPP
Dan Brailean	Canyon Technical Services	PSAC
Rick Bruce	Forum Energy Technology	
Greg Chapin	ICoTA Canada	
Rick Eckdahl	Chevron Canada Ltd.	CAPP
Shawn Erick	Lone Star Oilfield Services	
Ryan Grant	Mountain Coil Tubing	PSAC
Dylan Henkelman	WISE Intervention Services Inc.	PSAC
Dean Jenkins	Encana	CAPP
Justin Kitchen	BCOGC	Regulator
Nils MacArthur	Crescent Point Energy	CAPP
Ron MacDonald	AER	Regulator
Justin Meyer	Calfrac Well Services Ltd.	PSAC
Clarke Moir	Shell Canada Ltd.	CAPP
Ben Nowell	Element Technical Services	PSAC
Sam Robb	Trican Well Service Ltd.	PSAC
Ryan Smith	Nexus Energy Technologies	
Jack Thacker	Husky Energy	CAPP
Doug Vaudan	Jewel Energy Services Inc.	PSAC
Tyler Zemenchik	Essential Energy Services	PSAC
Laurie Andrews	Enform (Facilitator/Technical Writer)	
Brianna Walsh	Enform (Support)	

21.0.7 Range of Obligations

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

Table 2. Range of Obligation

Term	Usage
Must	A specific or general regulatory and/or legal requirement that must be followed. These IRP statements are bolded for emphasis.
Shall	An accepted industry practice or provision that the reader is obliged to satisfy to comply with this IRP. These 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

21.0.8 Background

For purposes of this IRP coiled tubing is defined as continuously manufactured steel tubular product spooled onto a take-up reel.

21.0.8.1 **Description of Coiled Tubing Operations**

Coiled tubing operations are upstream petroleum industry operations using specialized equipment and qualified personnel to carry out workovers and drilling on oil and gas wells. Coiled tubing applications fit into two general categories: fluid conveyance applications (pumping) and mechanical applications.

Fluid conveyance applications include, but are not limited to, the following activities:

- Removing sand or fill from a wellbore
- Fracturing/acidizing a formation
- Unloading a well with nitrogen
- Conducting gravel packing
- Cutting tubulars with fluid
- Pumping slurry plugs
- Isolating zones (to control flow profiles)
- Removing scale (hydraulic)
- Removing wax, hydrocarbon or hydrate plugs

Mechanical applications include, but are not limited to, the following activities:

- Setting a plug or packer
- Fishing
- Perforating
- Logging
- Removing scale (mechanical)
- Cutting tubulars (mechanical)
- Shifting Sleeves
- Running a completion
- Performing straddles for zonal isolation
- Drilling

21.0.8.2 Equipment Used in Coiled Tubing Operations

Coiled tubing equipment includes the BOP, stripper, reel, injector head, control cabin and power pack. Auxiliary equipment generally includes fluid pumps and nitrogen pumps. Equipment functionality is outlined in Table 3.

Table 3. Coiled Tubing Equipment Functionality

Equipment	Usage
BOP	Provide emergency well control
Stripper	Provide primary well control
Reel	Storage and transportation of the coiled tubing
Injector Head	Provides the surface drive force to run and retrieve the coiled tubing
Control Cabin	Allows the equipment operator to monitor and control the coiled tubing
Power Pack	Generates the hydraulic and pneumatic power required to operate the coiled tubing unit

21.0.8.3 Personnel for Coiled Tubing Operations

The following crews or personnel may be involved during coiled tubing operations:

- Coiled tubing crews
- Downhole tool specialists
- Drilling and service rig crews
- Electric line and slickline crews
- Oil company representatives

- Pumping services personnel
- Safety supervisors
- Well fracturing crews
- Well testing crews

21.1 Planning

This section discusses the topics to be covered when planning a coiled tubing operation.

21.1.1 Job Objectives

IRP Job objectives should be documented and include a brief summary of the work to be done.

IRP Pressure Category 5 and Critical Sour Wells shall have well documented, detailed risk assessment and contingency plans in place prior to opening the wellhead.

21.1.2 Well Classification and History

Industry and regulators use well classifications for administrative purposes. For technical purposes, pressures and hydrogen sulphide (H_2S) presence (i.e., specific concentrations and potential release rate) dictate the equipment required to perform tasks safely, maintain worker health and safety and ensure equipment integrity.

The Well Servicing Pressure Categories and Drilling Classifications in Tables 4 and 5 were developed for IRP 21 to allow consistent terminology to be used throughout the IRP without having to reference the different terminology used by the various provincial regulators. Different regulations, industry recommended practices and best practices may apply for different well servicing categories/drilling classes of wells. For any conflict or uncertainty regarding which category/class to follow, follow the higher category/class (i.e., the one with the more stringent requirements).

Maximum Anticipated Surface Pressure (MASP) is the highest pressure predicted to be encountered at the surface of a well. Base the pressure prediction on formation pressure minus a wellbore filled with native formation fluid at current conditions. If formation fluid is unknown base the prediction on formation pressure minus a wellbore filled with dry gas from the surface to the completion interval.

Equation 1. MASP

$$\begin{aligned} MASP = {} & Near\ Wellbore\ Reservoir\ Pressure \\ & - Hydrostatic\ Pressure\ of\ a\ Column\ of\ Reservoir\ Fluid \end{aligned}$$

IRP Calculation of MASP shall use the reservoir fluid and not the workover fluid.

IRP Well classification and history should be reviewed as part of operations planning.

IRP MASP shall not exceed the pressure rating of any wellhead component that has the potential to be exposed to well intervention pressure.

Maximum Anticipated Operating Pressure (MAOP) for a given piece of equipment is the highest calculated pressure that a given equipment component will be subjected to during the execution of the prescribed service and/or during a contingency operation.

Equation 2. MAOP

$$MAOP = Near\ Wellbore\ Reservoir\ Pressure\ - Hydrostatic\ Pressure\ of\ Workover\ Fluid + Surface\ Induced\ Pressure\ (\ Fracture\ Treatment\ Screenout, Well\ Kill\ or\ other\ )$$

IRP MAOP shall not exceed the pressure rating of any wellhead component that has the potential to be exposed to well intervention pressure.

IRP Well classification and previous and potential problems should be identified and concisely summarized as background information for wellsite personnel.

Relevant well data would include the following:

- The data listed in 21.8.1.2 Orientation (with the exception of wind direction)
- A history of work carried out on the well
- Current well conditions
- Any operation that may have introduced air, oxidizing agents, etc. into the system

For purposes of IRP 21, a sour well is a well with any level of H_2S.

21.1.2.1 Well Control for Well Servicing

The choice of BOP equipment for coiled tubing well servicing operations is based on the *Well Servicing Pressure Category* which depends on **BOTH** the MASP of the well and the MAOP for the operation and whether the well is sweet or sour.

There are two steps to selecting the appropriate well control equipment:

1. Determine MASP (based on Equation 1) to select the Pressure Category. This determines the number of barriers and required functions.
2. Determine the MAOP for the planned operation (based on Equation 2) to determine the required working pressure rating of the well control equipment.

For example, a low pressure well may require the functions and barriers of Pressure Category 1B but due to the induced pressure of an annular fracturing operation, a 68.9 MPa working pressure may be necessary.

It is important not to confuse these two subjects. Pressure Category and working pressure are separate considerations.

Table 4. Well Servicing Pressure Categories for Blowout Prevention

Well Servicing Pressure Category	MASP	Required Complete Barriers	Recommended Kill Margin	Recommended Rated Working Pressure	Sweet/Sour
Category 0	0 MPa[1]	0	5.0 MPa	5.2 MPa	Sweet
Category 1A	0.1 – 5.2 MPa	1	5.0 MPa	5.2 MPa	Sweet
Category 1B	5.3 – 10.3 MPa	2	7.0 MPa	20.7 MPa	Sweet
Category 2	10.4 – 24.1 MPa	2	10.0 MPa	34.5 MPa	Sweet or Sour
Category 3	24.2 – 51.7 MPa	2	17.0 MPa	68.9 MPa	Sweet or Sour
Category 4	51.8 – 86.2 MPa	3	17.0 MPa	103.4 MPa	Sweet or Sour
Category 5	86.3 – 103.4 MPa	4	17.0 MPa	137.9 MPa	Sweet or Sour
Critical Sour	Release rate and distance to an urban centre				Sour

IRP The selected stack shall have a rated working pressure that allows a kill program to be implemented.

The kill margin in Table 4 is a recommendation for annular kill programs when no other information is available. Different kill margins may be applied provided calculations are performed for the pumped-fluid kill program. The kill procedure plan may include implementation of a circulation method, the lubricate and bleed technique, flowing the well to reduce surface pressure or pumping at lower rates to minimize friction pressure.

Alternate kill plans or kill margins do not impact the Well Servicing Pressure Category.

IRP Any sour well shall be treated, at a minimum, as a Pressure Category 2 well with all of the associated barriers and functions required.

Local jurisdictional regulations define critical sour wells based on release rate and distance from an urban centre. The AER calls these Critical Sour wells and BCOGC

[1] Well is unable to flow under any circumstances.

calls them Class C or Special Sour wells. Consult local jurisdictional regulations for more detail.

Table 5 lists the required functions of the BOP stack for each Pressure Category. This table assumes flowback is taken through the tree below any coiled tubing well control equipment. More detailed descriptions of the functions and sample illustrations can be found in section 21.2 including variations for sour wells. Special considerations for flowback (returns) taken above or as a part of the well control equipment are also discussed.

Table 5. Required Well Control Functions by Pressure Category

Element	**Well Servicing Pressure Category**							
	0	**1A**	**1B**	**2**	**3**	**3 alternate**	**4**	**5**
Minimum Pressure Rating of Equipment	5.2 MPa	5.2 MPa	20.7 MPa	34.5 MPa	68.9 MPa	68.9 MPa	103.4 MPa	137.9 MPa
Coiled Tubing Stripper	Y	Y	Y	Y	Y	Y	Y	Y
Blind Ram			Y	Y	Y		Y	Y
Shear Ram			Y	Y	Y		Y	Y
Shear/Blind Ram						Y		
Kill Port			Y	Y	Y	Y	Y	Y
Slip Ram				Y	Y	Y	Y	Y
Pipe Ram		Y	Y	Y	Y	Y	Y	Y
Shear/Blind Ram					Y		Y	Y
Kill Port #2							Y	Y
Pipe/Slip Ram							Y	Y
Shear/Blind Ram								Y
Double Check Valve		Y	Y	Y	Y	Y	Y	Y

IRP Operating pressure shall NOT EVER exceed the rated working pressure of the well control equipment.

21.1.2.2 Well Control for Drilling

The choice of BOP equipment for coiled tubing drilling operations is based on the traditional well classes which are dependent on the true vertical depth of the well.

Table 6. Well Classifications for Drilling Blowout Prevention

IRP21 Drilling Well Classification		Provincial Classification			
Class	**Description**	**Alta.**	**B.C.**[2]	**Sask.**[3]	**Man.**
Class I	A well in which no surface casing is set	Class I	Class A		Class II
Class II	A well in which the true vertical depth is ≤ 750 m	Class II	Class A		Class II
Class III	A well in which the true vertical depth is > 750 m and ≤ 1,800 m	Class III	Class A		Class II to 1,000 m Class III ≥ 1000 m
Class IV	A well in which the true vertical depth is > 1,800 m and ≤ 3,600 m	Class IV	Class A to 1,850 m Class B to 3,000 m Class C ≥ 3,000 m		Class III[4]
Class V	A well in which the true vertical depth is > 3,600 m and ≤ 6,000 m	Class V	Class C to 5,500 m Class D ≥ 5,5000 m		Class III
Class VI	A well in which the true vertical depth is > 6,000 m	Class VI	Class D		Class III

[2] For wells drilled in British Columbia consult BCOGC Directives/Regulations on well control requirements. This table is a general comparison only.

[3] Individual well classifications are not provided in Oil and Gas Regulations for Saskatchewan.

[4] For Manitoba the classification changes from Class II to Class III at the Devonian Three Forks Formation. That formation is estimated to be at about 1,000 m.

21.1.3 Personnel Requirements

21.1.3.1 Demonstrating Competence

IRP The following personnel shall be able to demonstrate their competence that they fully understand and can handle their individual responsibilities:

- Crew members
- Coiled tubing shift supervisors and coiled tubing supervisors

  Note: For drilling operations, a coiled tubing shift supervisor is equivalent to a driller and a coiled tubing supervisor is equivalent to a rig manager.

- Wellsite supervisors
- Prime contractor representatives

Consult the appropriate provincial legislation for further details on training, certification and competency requirements.

IRP Support personnel (e.g., completion engineers and superintendents) shall be familiar with and have taken into account recommended practices and best practices applicable for the operation being conducted.

Consult IRP 7: Standards for Wellsite Supervision of Drilling, Completion and Workovers for more information.

21.1.3.2 Training/Certification for Well Servicing Operations

IRP Training/certification requirements for coiled tubing crew members, senior operators and shift supervisors for well servicing operations with coiled tubing shall be as per Table 7.

Note: Table 7 is not intended to provide a complete list of training and certification. Specific tasks and/or jurisdictional legislation may require additional training or certification.

Table 7. Training/Certification Matrix for Well Servicing Operations

	H_2S Alive®[5]	TDG	WHMIS	First Aid	Confined Space Entry (Pre-Entry) Portion)	Fall Protection	Coiled Tubing Well Service Blowout Prevention	Crane/Critical Lift Supervision
CT Crew Member	M	M	M	O	O[6]	O[7]	O[8]	O
CT Shift Supervisor / Senior Operator[9]	M	M	M	M	M	M	M	M

M=mandatory O=optional

Wellsite Supervisor requirements are addressed in IRP 7: Standards for Wellsite Supervision of Drilling, Completion and Workovers.

IRP The Wellsite Supervisor for well servicing operations shall have a Coiled Tubing Well Servicing BOP ticket.

[5] Or equivalent industry-recognized certification.

[6] Confined Space Entry Certificate is mandatory for personnel working carrying out such activities but optional for other crew members.

[7] Fall Protection Certificate is mandatory for personnel carrying out such activities but optional for other crew members.

[8] Optional but with the exceptions noted in 21.1.3.5 Experience Required for Critical Sour Operations.

[9] The coiled tubing shift supervisor/senior operator classification indicates an either/or requirement, not both.

21.1.3.3 Training/Certification for Drilling Operations

IRP Training/certification requirements for coiled tubing crew members, shift supervisors/drillers and supervisors/rig managers for drilling operations with coiled tubing shall be as per Table 8.

Note: This table is not intended to provide a complete list of training and certification. Specific tasks and/or jurisdictional legislation may require additional training or certification.

Table 8: Training/Certification Matrix for Drilling Operations

	H_2S Alive®[10]	TDG	WHMIS	First Aid	Confined Space Entry (Pre-Entry Portion)	Fall Protection	First Line Supervisor's BOP Certification	Second Line Supervisor's Well Control Certification
CT crew member	M	M	M	O	O	O	O[11]	N/A
CT shift supervisor/ driller	M	M	M	M	M	M	M for either first or second line	
CT supervisor/ rig manager	M	M	M	M	M	M	N/A	M

M=mandatory O=optional

Wellsite Supervisor requirements are addressed in IRP 7: Standards for Wellsite Supervision of Drilling, Completion and Workovers.

21.1.3.4 Welder Qualifications

IRP All welds in a coiled tubing string proposed for operations in Well Servicing Category 1A and 1B should be performed

- by a welder qualified in accordance with ASME Section IX (or equivalent),
- as per a weld procedure specification (WPS) that has been qualified in accordance with ASME Section IX (or equivalent) and
- by a welder and per a weld procedure qualified by the tubing manufacturer.

[10] Or equivalent industry-recognized certification.

[11] Optional but with the exceptions noted in 21.1.3.5 Experience Required for Critical Sour Operations.

IRP All welds in a coiled tubing string proposed for operations in Well Servicing Category 2, 3, 4, 5 or Critical Sour shall be performed

- by a welder qualified in accordance with ASME Section IX (or equivalent),
- as per a WPS that has been qualified in accordance with ASME Section IX (or equivalent) and
- with the procedure qualification record (PQR) performed on actual coiled tubing specimens.

21.1.3.5 Experience Required for Critical Sour Operations

IRP Any person directly involved in wellsite operations shall comply with IRP 7: Standards for Wellsite Supervision of Drilling, Completion and Workovers.

IRP Any person directly involved in critical sour operations shall comply with either IRP 2: Completing and Servicing Critical Sour Wells or IRP 6: Critical Sour Underbalanced Drilling as well as IRP 7: Standards for Wellsite Supervision of Drilling, Completion and Workovers.

IRP Any individual operating the coiled tubing unit for critical sour wells shall have the drilling/well servicing blowout prevention certificate appropriate to the Well Servicing Category/Drilling Classification.

Anyone who is at the controls of the coiled tubing unit is considered to be operating the unit.

IRP For Critical Sour well servicing operations, coiled tubing supervisors shall have been involved (as coiled tubing supervisors) in five workover or completion operations while these wells were in the sour zone (i.e., supervised on five non-Critical Sour operations while the well was in the sour zone) and work shall have been conducted on wells of similar depth and complexity.

IRP For Critical Sour/Special Sour Drilling operations, coiled tubing shift supervisors/coiled tubing supervisors shall have been involved (as coiled tubing supervisor) in five wells while these wells were in the sour zone (i.e., supervised on five non-critical sour/special sour well operations while the well was in the sour zone) and work shall have been conducted on wells of similar depth and complexity.

21.1.3.6 Supervision

21.1.3.6.1 Shared Responsibility

The representatives of the contractor and operator share responsibility for day-to-day operations on a site.

IRP The ultimate responsibility for supervision of the well operation shall be assigned by the Well Operator (i.e., oil or gas company) to the operator's representative.

Consult the appropriate provincial legislation or the Enform Crossing Borders Report for more information about supervision and responsibilities.

21.1.3.6.2 Operator's Representative

IRP The operator shall designate a primary wellsite supervisor as having overall control in the chain of command.

The primary wellsite supervisor has the overall responsibility to his/her company for the well and for compliance with all regulations relating to the operation of the well.

IRP The primary wellsite supervisor shall be on site or readily available at all times and shall establish a chain of command and line of communication at the wellsite.

21.1.3.6.3 Contractor's Representative

IRP The contractor's representative shall be responsible to the operator's representative for the operation of the rig/unit during the drilling/servicing of the well. This provides for a single chain of command for the well operation.

IRP The contractor's representative shall be responsible to his/her company for the equipment and crew and for compliance with all regulations relating to the operation of the contractor's equipment.

21.1.3.6.4 Critical Sour Underbalanced Drilling Operations

IRP The primary wellsite supervisor shall be designated by the operator as having overall control in the chain of command for critical sour underbalanced wells.

IRP The coiled tubing supervisor shall be available to the operation on a 24 hour on-call basis. Two coiled tubing supervisors shall be available for night moves.

21.1.4 Health and Safety Communication

IRP Safety meetings with all shift personnel on site shall be held

- **before starting operations,**
- **before continuing with an operation that has substantially changed due to changing well or lease conditions,**
- **before any hazardous operation and**
- **at shift change.**

21.1.5 Health and Safety Requirements

21.1.5.1 Hazard Assessments

IRP Coiled tubing operations planning shall include a review of each coiled tubing operation to evaluate the hazards the operation would present.

Each situation will present its own unique circumstances. Below are some identifiable hazards to consider during hazard assessment:

- Environmental factors (e.g., lease conditions, wind speed/direction, lighting, day/night operations)
- Potential of an air/hydrocarbon mix in the wellbore or surface equipment
- Pinch points, slips, trips, falls and manual lifting
- Working in the vicinity of suspended loads
- Moving equipment
- High pressure areas
- Working at height
- Simultaneous/concurrent operations
- Potential for naturally occurring radioactive material (NORM)

21.1.5.2 General Safety Requirements

Safety issues relating to well control are not specifically addressed in this section as they are covered elsewhere and in the Coiled Tubing Well Service Blowout Prevention course and First/Second Line Well Control Certification course mandated in 21.1.3.2 Training/Certificates for Well Servicing Operations and 21.1.3.3: Training/Certificates for Drilling Operations.

IRP The resources in Table 9 should be consulted for general safety information.

Table 9. General Safety Resources

Resource	Description
IRP 1: Critical Sour Drilling IRP 2: Completing and Servicing Critical Sour Wells IRP 6: Critical Sour Underbalanced Drilling	Safety requirements associated with critical sour wells
Jurisdictional legislation, regulations and codes	• Work wear requirements • Facial hair • Operations involving explosives • Lease lighting • Emergency washing facilities • Fire extinguishers • Breathing apparatus • Emergency vehicles • Crane/boom truck operator requirements • Noise restrictions • Hours of service • Other recommended equipment • Other general safety requirements
STANDATA Canadian Electrical Code Jurisdictional legislation	Electrical Bonding and Grounding
Enform Lease Lighting Guideline	Lease lighting
Jurisdictional regulations Worksafe Saskatchewan/Government of Saskatchewan - Thermal Conditions: Hot and Cold Conditions at Work Alberta OH&S – Best Practice Working Safely in Heat and Cold Worksafe BC – Guidelines part 7 – Division 4 – Thermal Exposure	Working in hot/cold weather

See the References for more information about where to find these resources.

21.1.5.3 Coiled Tubing Safety Requirements

IRP There shall be procedures in place and competent personnel on site to deal with the situations listed in Table 10.

Table 10. Coiled Tubing Safety Requirements

Situation	Safety Requirements
Coiled Tubing Overpressure/Overpull	If the CT string is subjected to an overstress it shall be removed from service until an inspection and an evaluation of suitability for use has been carried out by the appropriate service company representative.
Coiled Tubing Run-away	Personnel shall be aware of the specific procedures to deal with situations where a loss of chain traction causes a run-away of the CT string in or out of the hole.
Loss of Pressure Integrity	• Supervisors and operators shall be competent to deal with a loss of integrity of the CT, well control equipment, treating iron and any other components of the operation. • Personnel shall be made aware of the hazards related to a complete separation of the CT string between the gooseneck and the reel. Personnel should stay clear of all areas that may be impacted by such a separation.
Pulling Coiled Tubing Through Stripper	• When pulling out of hole, as the BHA approaches surface, the running speed should be reduced to ensure that a depth counter error will not result in pulling the coiled tubing through the stripper. • When using a BHA of the same OD as the coiled tubing, an upset should be used in the BHA to ensure a “tag out’” on the stripper.
Stripper Element Change-out	Where it is necessary to replace the elements in a stripper assembly during the operation: • Confirm that the barriers in the well control equipment are holding • Mask up for sour conditions on sour wells • Ensure appropriate monitoring devices are used (LEL, H_2S as required) • Ensure that a rescue plan is in place
Crane Safety	• Consult appropriate jurisdictional legislation for specific requirements. • Criteria shall be in place to identify critical lifts. • A critical lift plan shall be prepared for critical lifts. • Working in the vicinity of suspended loads shall be minimized. • Crane shall be operated within and in accordance with manufacturers’ specifications/guidelines. • Consideration should be given to suspending work as required by high wind speed, cold weather or other environmental factors.
Lock-outs	• Consult appropriate jurisdictional legislation for specific requirements. • Maintenance or repair work on the injector head or reel requires lock-out procedures. • Reels shall be physically restrained when personnel are working inside the structure. The reel brake is not sufficient.
Working at Heights	The nature of CT operations requires working at heights. • The applicable regulatory requirements shall be followed. • A rescue plan shall be in place for personnel working at heights.

21.1.5.4 Critical Sour Well Servicing Safety Requirements

For critical sour well servicing safety requirements see IRP 2: Completing and Servicing Critical Sour Wells.

21.1.5.5 Critical Sour Over/Underbalanced Drilling Operations Planning and Safety Requirements

For critical sour overbalanced drilling planning and site safety requirements see IRP 1: Critical Sour Drilling.

For critical sour underbalanced drilling planning and site safety requirements see IRP 6: Critical Sour Underbalanced Drilling.

21.1.5.6 Critical Sour Well Intervention

For critical sour well intervention planning requirements see IRP2: Completing and Servicing Critical Sour Wells.

21.1.6 Emergency Response Plan

IRP Regulatory requirements must be consulted for Emergency Response Plan requirements and content.

IRP Site-specific Emergency Response Plans shall be used in conjunction with the prime contractor's generic or corporate Emergency Response Plan.

21.1.7 Equipment Specifications

IRP Planning for coiled tubing operations shall include determining the appropriate equipment specifications and configurations required for the job. This includes any necessary engineering calculations.

IRP The information in the following sections should be consulted as part of the equipment selection process:

- 21.2 BOP Stack and Accumulator Specifications
- 21.3 Pipe Specifications
- 21.4 Fluids and Circulating Systems
- 21.5 QA for Well Pressure-Containing Equipment
- 21.6 Elastomeric Seals
- 21.7 Well Servicing Operations
- 21.8 Drilling Operations

21.1.8 Operational Practices and Procedures

IRP The recommended practices in this IRP shall be considered when planning the operations and when designing the materials that will be used in the operation being conducted. These recommendations should continue to be followed during the actual operations at the wellsite.

IRP Coiled tubing operational practices and procedures appropriate for the tasks to be completed should be specified.

IRP In the planning phase of every operation, consideration shall be given to the possibility of air already being in the system or the introduction of air into the system during the operation.

If there is a risk of air being in the system consult the Enform Fire and Explosion Hazard Management Guideline for guidance and a summary of critical risk factors.

IRP Procedures shall be in place to address any potentially hazardous situation identified.

21.2 BOP Stack and Accumulator Specifications

This section discusses the BOP stack and accumulator specifications recommended for coiled tubing operations.

Samples of recommended BOP configurations are shown in this section. Best efforts have been made to represent configurations that are typical in the operating industry but these configurations should not be considered exclusive of alternate configurations that provide equivalent or additional levels of well control (e.g., through combination ram functions or alternate pipe or wellbore sealing methods). IRP 21 assumes that all operations will have a wellhead configuration that is compliant with IRP 5: Minimum Wellhead Requirements and all local jurisdictional regulations.

IRP Non-compliant wellheads shall be assessed on a case by case basis to ensure safe operations are possible.

IRP Sufficient support for the weight of the BOP equipment shall be in place to protect the wellhead from damage.

21.2.1 Introduction

IRP The choice of well control component shall take into consideration the pressure testing requirements for the stack (i.e., from above or below or both) as some devices, and specifically some makes of rams, bags or valves, may be designed for pressure testing from below only.

IRP The choice of well control component shall take into consideration the maximum anticipated temperature during the operation, either from the wellbore or from the treatment fluids.

IRP Working pressure rating of all BOP components shall exceed MASP by the kill margin for the specific well type and reservoir.

IRP Working pressure rating of all BOP components shall exceed MAOP by the pressure testing margin and any potential pressure spikes due to the type of operation. Operating pressures during well servicing activities shall not utilize these contingency margins.

21.2.1.1 Definitions

The definitions in Table 11 are used throughout this IRP. When the general terms are used to describe components in a well control stack (e.g., pipe sealing element, blanking element, etc.) the choice of the specific well control component is left to the discretion of the operator. When specific components are referenced (e.g., annular bag, pipe ram, etc.) those components are recommended for operational or other functional reasons.

Table 11. Definitions

General Term	Usage
Barrier	A CT well control element that is a tested mechanical device, or combination of tested mechanical devices, capable of preventing uncontrolled flow of wellbore effluents to the surface. The following mechanical devices, or combination of mechanical devices, are CT well control barriers: 1. The combination of an annular sealing component, or pipe ram sealing component, and a flow check assembly installed within the CT BHA; 2. A single blind ram and single shear ram, or combination shear/blind ram
Pipe Sealing Element	A well control element that provides a pressure seal against a section of pipe of fixed diameter. This may include an annular bag, set of fixed diameter pipe rams, stripper element or other similar technology.
Variable Pipe Sealing Element	A well control element that provides a pressure seal against sections of varying diameters. This may include an annular bag, a set of variable pipe rams or other similar technology.
Blanking Element	A well control element that provides a pressure seal against an open wellbore. This would typically include a blind ram, valve or other similar technology.
Shearing Element	A well control element that provides a clean shear cut of the tubulars located across the element in the wellbore. As a stand-alone ram function, they provide no pressure seal and as such they are not considered to be well control devices. This would typically include a shear ram or other similar technology.
Slip Rams	Ram devices designed to hold the coiled tubing securely in place in the well control stack. As a stand-alone ram function, they provide no pressure seal and as such they are not considered to be well control devices. Where slip rams are run it is recommended that they be bidirectional in design.

21.2.1.2 Coiled Tubing and Jointed Pipe Operational Comparison

This IRP strives for consistency between coiled tubing and jointed pipe methods for control of wellbore pressures and fluids in workover and drilling operations. Consideration is given to the inherent differences in each type of equipment. For purposes of comparison, the coiled tubing stripper is considered to be the equivalent of the hydrostatic head of the wellbore fluid in a jointed pipe overbalanced operation.

In most situations the functional well control requirements for coiled tubing mirror those for jointed pipe operations. There are two exceptions:

1. Shear rams may be required for coiled tubing operations where they are not required for equivalent jointed pipe operations. This recognizes that, since coiled tubing is a continuous length of pipe without joints, it is not possible to back off a joint and drop the string as would be the case for jointed pipe. Shear rams may be required for equivalent classes of wells from jointed pipe operations to enable a method of separation of the pipe.
2. Stabbing valves may be required for classes of jointed pipe operations but not for coiled tubing operations due to the absence of tool joints and the inability to install a stabbing valve into the string. Stabbing valves shall be used where BHAs cannot be lubricated above the wellhead valve of BOPs in one stage, and shall be lubricated in two or more stages out of the wellbore. See 21.2.2.6 Pressure Deployment Considerations for more information.

21.2.2 General Requirements

21.2.2.1 **Stripper Considerations**

Coiled tubing is well suited to underbalanced or live-well operations and is normally used for servicing for those applications where pressure may be seen at surface. In the well control configurations in this section it is acknowledged that not all coiled tubing operations will be underbalanced and some may, in fact, be overbalanced.

IRP In underbalanced coiled tubing operations the stripper shall be rigged up and be a functional (active) part of the well control system but can not be used to replace any other pipe sealing element required in the stack.

A non-energized second stripper may be considered a well control device provided that it is not sealing around the coiled tubing string during operations (wearing out). A wellbore assist stripper does not qualify unless it can be fully retracted to prevent wear of the backup stripper element.

21.2.2.2 **BOP Placement**

Placing the BOPs above the lubricator (well servicing/underbalanced drilling) or guide tube/flow nipple (overbalanced drilling) may result in significant height to the BOP stack which introduces the following risks:

- A top-heavy BOP stack
- Additional leak points below the well control equipment
- Difficulty manually operating, locking or servicing the BOPs

IRP BOPs should be placed directly above the wellhead assembly and below any lubricators.

This positioning avoids top-heavy BOP stacks and allows for manual control of the BOPs without the need for a man-basket or other lifting device.

Flanged risers can be used below the well control equipment when a structure such as a drilling rig or building prevent direct access to the wellhead.

21.2.2.3 Barriers

The flow check assembly installed on the end of the CT string in combination with an annulus-sealing component (stripper, pipe ram or annular) in the well control stack constitutes only one barrier, regardless of the number of annulus-sealing devices installed in the well control stack. In the pressure categories where multiple pipe rams are recommended in the well control stack, these rams are intended to be located at specific points where annulus-sealing capability is required and does not constitute an increase the number of barriers in the stack.

21.2.2.4 Primary Flow Point

The primary flow point may be above, below or between the BOP elements. The abrasive and chemical nature of the produced/circulated fluids impacts the decision about placement.

IRP The well effluent shall not be chemically or mechanically damaging to the BOP elastomers or ram/bag elements.

IRP If the primary flow point is to be above the BOPs, a secondary kill port shall be available to allow for killing the well. The secondary kill port shall be placed below at least one pipe sealing element.

The issue of flowing above or below the BOPs has been a long-standing industry discussion. Flowing through the BOPs is common during drilling operations but not during servicing operations. The distinction between drilling and servicing, and in some cases overbalanced and underbalanced operations, can be very fine from a practical point of view. Pros and cons of flowing above or below the BOPs are shown in Tables 12 and 13.

Table 12. Pros and Cons of Positioning Flow Tee Above the BOP

Pros	Cons
• Well flow can be stopped or controlled if flow tee washes out. • Well flow can be stopped or remotely if choke system washes out.	• The flow of solids through the BOP stack can damage BOP components. • The flow of solids through the BOP stack may prevent proper closing and sealing of the tubing ram or blind ram. • The flowback of certain chemicals or gases may have adverse effects on elastomers (e.g., swelling, strength degradation of elastomers) on BOP Components

Table 13. Pros and Cons of Positioning Flow Tee Below BOP

Pros	Cons
• BOP components are protected from solids to prevent damage and ensure ability to close and seal. • Simplified rig up of flowback lines due to reduced height of flow tee or cross. • BOP components protected from harmful chemicals and gases. • Ability to use flow tee as a kill port when BOPs have been activated.	• Well flow cannot be stopped if flow tee washes out. • Well flow cannot be remotely controlled if choke system washes out.

IRP If there is risk of washout of a flow tee or cross, an additional pipe sealing element should be below the potential washout point. Alternatively, properly reinforced fit-for-purpose flowback equipment should be used.

The recommended well control configurations described in this section consider that there may be operational or other reasons that would recommend one configuration over another.

Refer to 21.6 Elastomeric Seals for information about elastomer compatibility issues.

21.2.2.5 **Check Valve/Tubing Shutoff Device**

Check valves prohibit flow up the coiled tubing from the bottom of the string and protect against uncontrolled wellbore flow in the event of a tubing failure.

IRP Dual check valves in the BHA shall be used on all well servicing operations unless the success or safety of the operation is jeopardized by the presence of check valves.

Operations such as fracturing through coiled tubing may require reverse circulation through the coiled tubing.

IRP In instances where a flow check assembly cannot be used due to job design considerations, a complete barrier such as a single shear/blind ram or equivalent alternative, shall be installed in addition to the standard well control stack configuration.

For configurations where a second shear/blind functionality is already present, no further additions are necessary.

The check valve would not be used when reverse circulation of the wellbore is required as a part of the programmed operation or when running pressure activated firing heads. If significant amounts of fluid are to be reversed through the reel iron then fit-for-purpose inspected flowback equipment is recommended.

IRP Additional contingencies (such as shear and blind rams) shall be included in the well control stack as the alternative tubing shutoff mechanism.

IRP Underbalanced drilling operations shall use a dual check valve assembly.

Check valves are not required for overbalanced drilling operations because the operation is a dead-well operation and kill fluid is ready to pump down the annulus in the event of a reel valve or surface coil failure.

21.2.2.6 Reel Isolation Valve

An isolation valve is required inside the reel to prevent uncontrolled flow at surface in the event of a rotating joint leak and to isolate the rotating joint from the wellbore during rotating joint repair.

IRP An isolation valve shall be located at the reel and downstream from the rotating joint for well servicing and drilling operations where the well is, or is expected to be, live.

IRP In cases where a rotating joint is not run (e.g., hanging strings) the isolation valve shall be located at the core end of the coiled tubing string.

IRP An iron management system shall be in place for the reel iron, swivel and reel isolation valve.

IRP The iron management system shall include, at minimum, pressure testing to a maximum anticipated working pressure and material thickness testing.

21.2.2.7 Pressure Deployment Considerations

In some cases a BHA is run that is of such a length that it cannot be swallowed inside the lubricator and above the blind rams or master valve. The BHA may need to be removed in two or more sections. When this is the case, an additional set of sealing rams or an annular bag is required to provide isolation from the wellbore during removal of the upper section of the BHA.

IRP In any live well operation where the length of lubricator is insufficient to swallow the entire BHA above the blind rams or the wellhead valve, a deployment system shall be in place that

- provides a method of holding the BHA in the BOP stack and
- provides a method of containing wellbore pressure during the deployment procedure.

IRP BOP elements in the stack designated for emergency well control shall not be used for deployment purposes.

The deployment system may be

1. an enclosed hands-free deployment system or
2. an annular bag or a set of pipe rams sized for the BHA that provide the required number of barriers for the Well Servicing Category/Drilling Class. These components would be in addition to the well control components normally required.

21.2.2.8 Ram-Type BOP Elements

IRP All ram-type BOP elements shall be hydraulically operated, have a backup system (as per 21.2.7 Accumulator Configurations for Well Servicing and 21.2.8 Accumulator Configurations for Drilling) and have the ability to be locked in service.

IRP Shear rams run in the BOP stack shall be capable of cutting the outer coiled tubing string, any inner strings (e.g., coiled tubing, wireline or capillary) or any combination of these strings.

IRP The hydraulic fluid requirements for the slip rams shall be included in the total fluid requirements for the BOP stack.

21.2.2.9 Considerations for Underbalanced Versus Overbalanced Operations

Coiled tubing is well suited to underbalanced or live-well operations for servicing. However, grass-roots drilling is typically conducted in an overbalanced condition. For overbalanced drilling operations, the hydrostatic head of the drilling fluid controls well pressure under normal operating conditions such that a coiled tubing stripper is not required for well control but is recommended for flowback management.

IRP A stripper shall be used when conducting underbalanced operations.

IRP A stripper may be included in the well control stack for overbalanced drilling operations but would be considered as redundant equipment and shall not be considered an alternative for any one of the recommended pipe sealing elements.

21.2.3 BOP Stack Configurations for Well Servicing

The well servicing configurations are based on Well Servicing Pressure Category as defined in Table 4 in 21.1.2 Well Classification and History.

Threaded connections are not recommended for wellheads in Well Servicing Category 3, 4, 5 or Critical Sour operations (Figures 6 through 9).

IRP The connections up to the uppermost BOP element must be flanged where regulation requires the wellhead be flanged.

An integral hammer union of the same rating as the BOP body is permitted on the BOP side kill port provided there is a method of isolating this connection from the wellbore in the event of a leak. The most common configuration for this is a Pipe Ram below the kill port.

IRP Connections above the BOP shall be API 6A flanged connections or API 6A hand unions in Well Servicing Categories 3, 4, 5 and critical sour.

Wellhead valves and configurations in Figures 1 through 9 are shown for illustrative purposes only and are not meant to reflect the regulatory requirements.

IRP All BOPs shall be hydraulically operated and connected to an accumulator system.

The recommended well control functions are identified in Table 5 in 21.1.2 Well Classification and History. These functions may be achieved with single rams, combination BOPs or quad BOPs. IRP 21 does not recommend one configuration over another as long as all the required functionality is present.

IRP For returns taken above the tree but below the primary BOP, an additional pipe ram below the flow cross or tee should be used for Well Servicing Pressure Categories 1A, 1B, 2 and 3 if there is risk of abrasive or corrosive washout.

IRP Any well with any H_2S in the reservoir fluid shall have a redundant (backup) pipe sealing element (i.e., stripper, annular bag or pipe ram) to provide a total of two emergency pipe sealing elements in addition to the primary stripper.

IRP Any well designated as critical sour should have a second redundant pipe sealing element to provide a total of three emergency pipe sealing elements in addition to the primary stripper.

Alternative configurations are acceptable as long as the proposed configuration and procedures manage the risk of spills, leaks and loss of well control to the same or higher level of certainty as the recommended equipment.

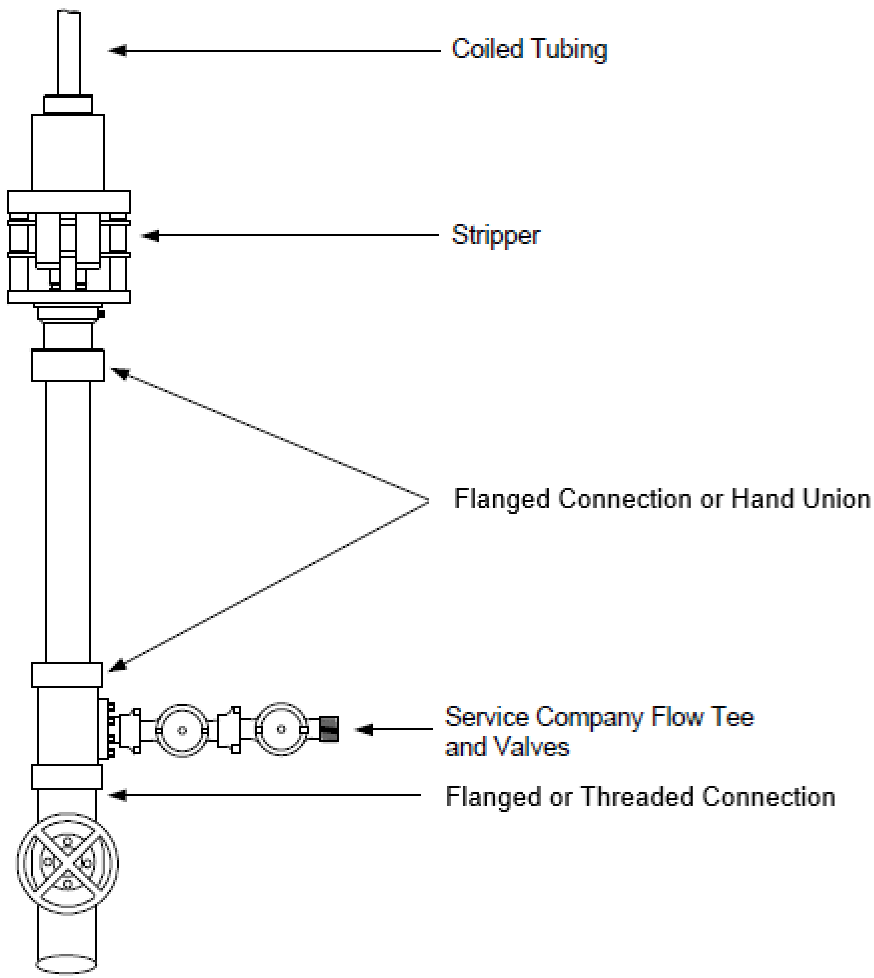
21.2.3.1 Category 0

Well Servicing Category 0 operations have a MASP of 0 MPa and no H_2S content. See Table 4 in 21.1.2 Well Classification and History for more detail.

Well Servicing Category 0 operations require a method of managing flowback from the well to prevent spills. Figure 1 shows a sample configuration for Category 0.

IRP Well control systems for Well Servicing Category 0 operations shall include a flow tee in combination with a stripper or annular bag to control flowback fluids.

Figure 1. Example Configuration for Category 0 Well Servicing Operations



21.2.3.2 Category 1A

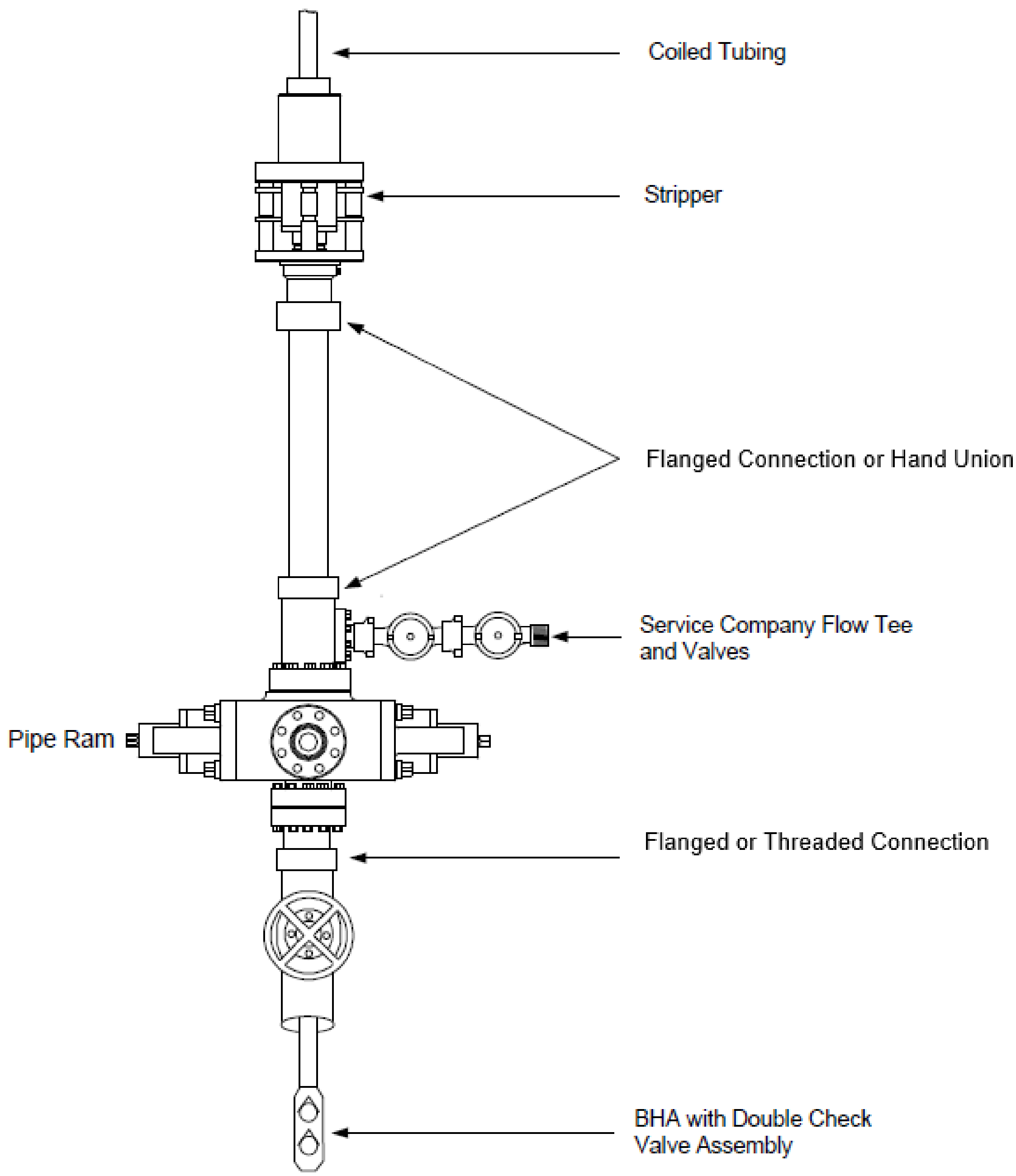
Well Servicing Category 1A operations have a MASP of 0.1 to 5.5 MPa and no H_2S content. See Table 4 in 21.1.2 Well Classification and History for more detail.

IRP Well control systems for Sweet Category 1A Well Servicing operations using coiled tubing shall include the following:

- **A double check valve or float assembly (subject to 21.2.2.4 Check Valve/Tubing Shutoff Device).**
- **A minimum of one pipe sealing element in addition to the coiled tubing stripper.**
- **Either two flare lines with a minimum diameter of 50.8 mm or one flare line with a minimum diameter of 76 mm.**

Figure 2 shows a sample configuration for Category 1A Well Servicing Operations.

Figure 2. Example Configuration for Category 1A Well Servicing Operations



21.2.3.3 Category 1B

Well Servicing Category 1B operations have a MASP of 5.6 to 10.3 MPa and no H_2S content. See Table 4 in 21.1.2 Well Classification and History for more detail.

IRP Well control systems for Sweet Category 1B Well Servicing operations using coiled tubing shall include the following:

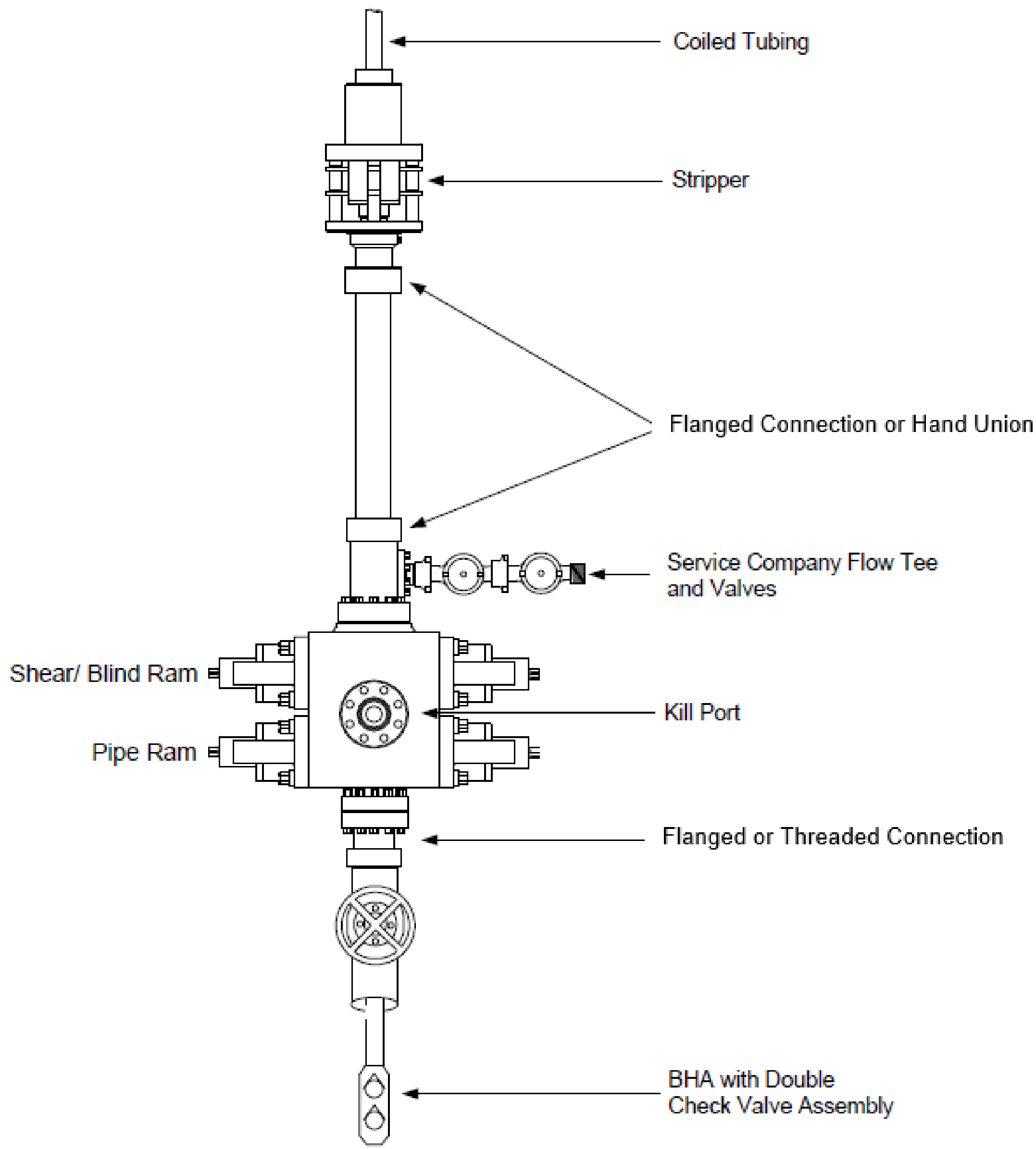
- **A double check valve or float assembly (per 21.2.2.4 Check Valve/Tubing Shutoff Device).**
- **A minimum of one blanking element, one shearing element and one pipe sealing element in addition to the coiled tubing stripper.**
- **50 mm lines throughout.**
- **Either two flare lines with a minimum diameter of 50.8 mm or one flare line with a minimum diameter of 76 mm.**
- **A kill port**.

In Alberta for Pressure Category 1B operations on AER Class IIA heavy oil wells it is acceptable to utilize an annular bag and a stripper if rigging up on a side entry sub in order to minimize the bending moment.

IRP In Alberta, for a Pressure Category 1B operation on an AER Class IIA heavy oil well where a side entry sub is not used, a Pressure Category 1B well control stack shall be used.

Figure 3 shows a sample configuration for Category 1B Well Servicing Operations.

Figure 3. Example Configuration for Category 1B Well Servicing Operations



21.2.3.4 **Category 2 – Sweet**

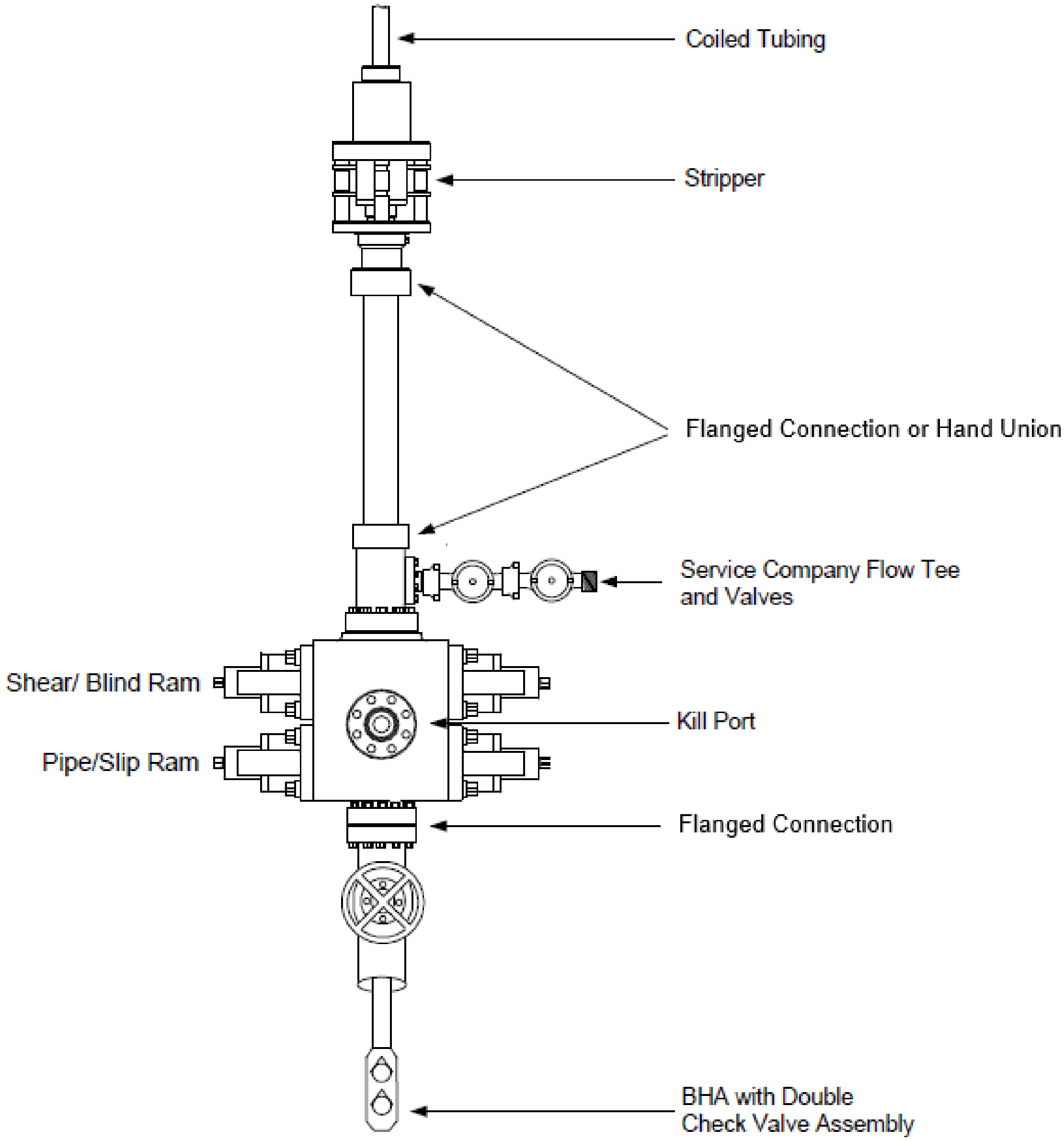
Well Servicing Category 2 operations have a MASP of 10.4 to 24.1 MPa. See Table 4 in 21.1.2 Well Classification and History for more detail.

IRP Well control systems for Sweet Category 2 Well Servicing operations using coiled tubing shall include the following:

- **A double check valve or float assembly (subject to 21.2.2.5 Check Valve/Tubing Shutoff Device).**
- **A minimum of one blanking element, one shearing element, one slip ram and one pipe sealing element in addition to the coiled tubing stripper.**
- **50 mm lines throughout.**
- **A kill port.**

In most cases this configuration would be provided with a Quad BOP stack (as shown in Figure 4). This may be replaced with a combination stack with SHEAR/BLIND rams and PIPE/SLIP rams.

Figure 4. Example Configuration for Sweet Category 2 Well Servicing Operations



21.2.3.5 Category 2 – Sour

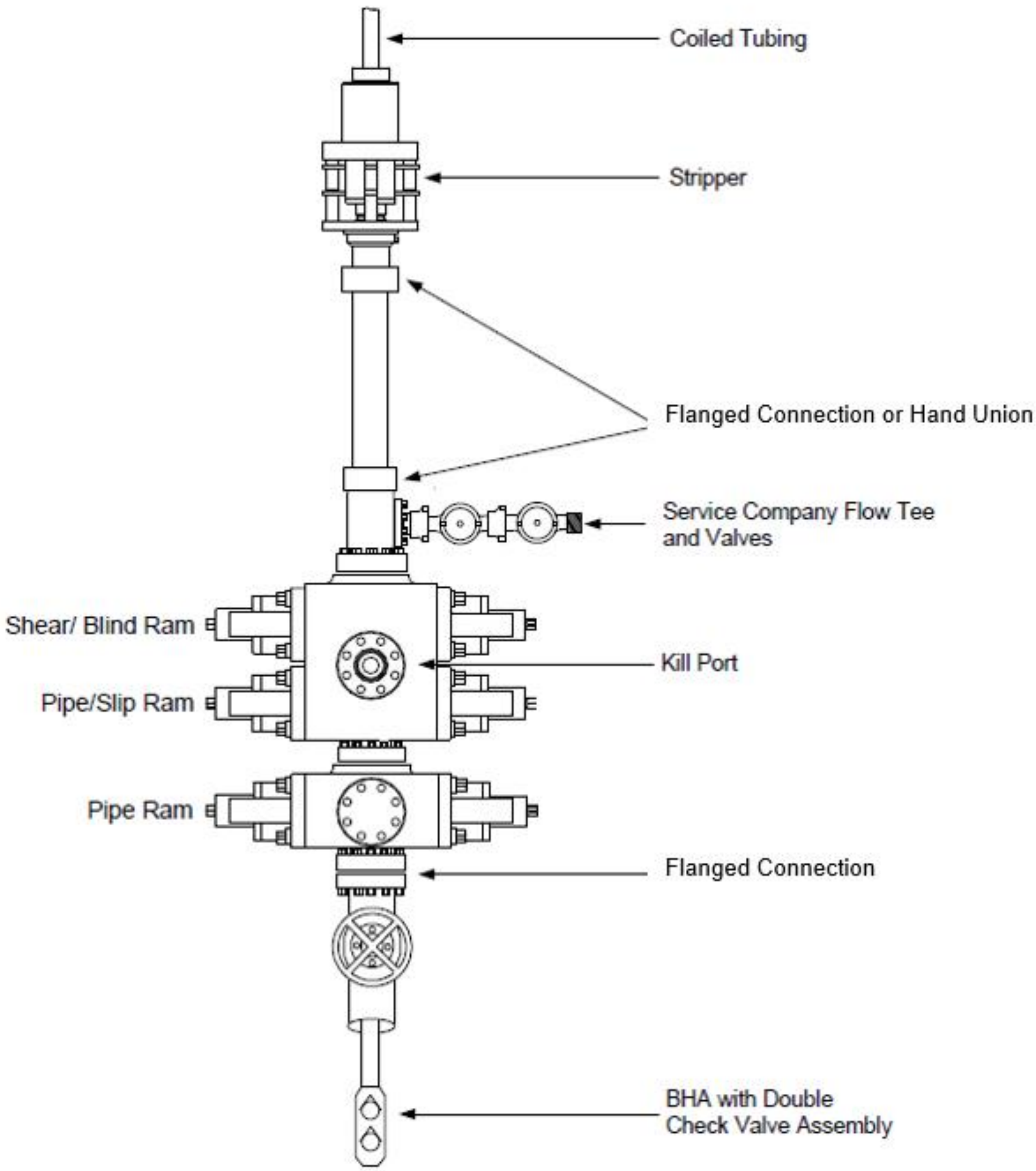
Well Servicing Category 2 operations have a MASP of 10.4 to 24.1 MPa. See Table 4 in 21.1.2 Well Classification and History for more detail.

IRP Well control systems for Sour Category 2 Well Servicing operations using coiled tubing shall include the following:

- **A double check valve or float assembly (subject to 21.2.2.4 Check Valve/Tubing Shutoff Device).**
- **A minimum of one blanking element, one shearing element, one slip ram and two pipe sealing elements in addition to the coiled tubing stripper.**
- **50 mm lines throughout.**
- **A kill port.**

In most cases this configuration would be provided with a Quad BOP and a single ram or a Quad BOP with one ram converted to a combination function to provide the additional pipe sealing element. Figure 5 shows a sample configuration for Sour Category 2 Well Servicing Operations with a Quad BOP Stack. The second pipe sealing element provides a second barrier in the event the stripper needs to be replaced.

Figure 5. Example Configuration for Sour Category 2 Well Servicing Operations



21.2.3.6 Category 3 – Sweet

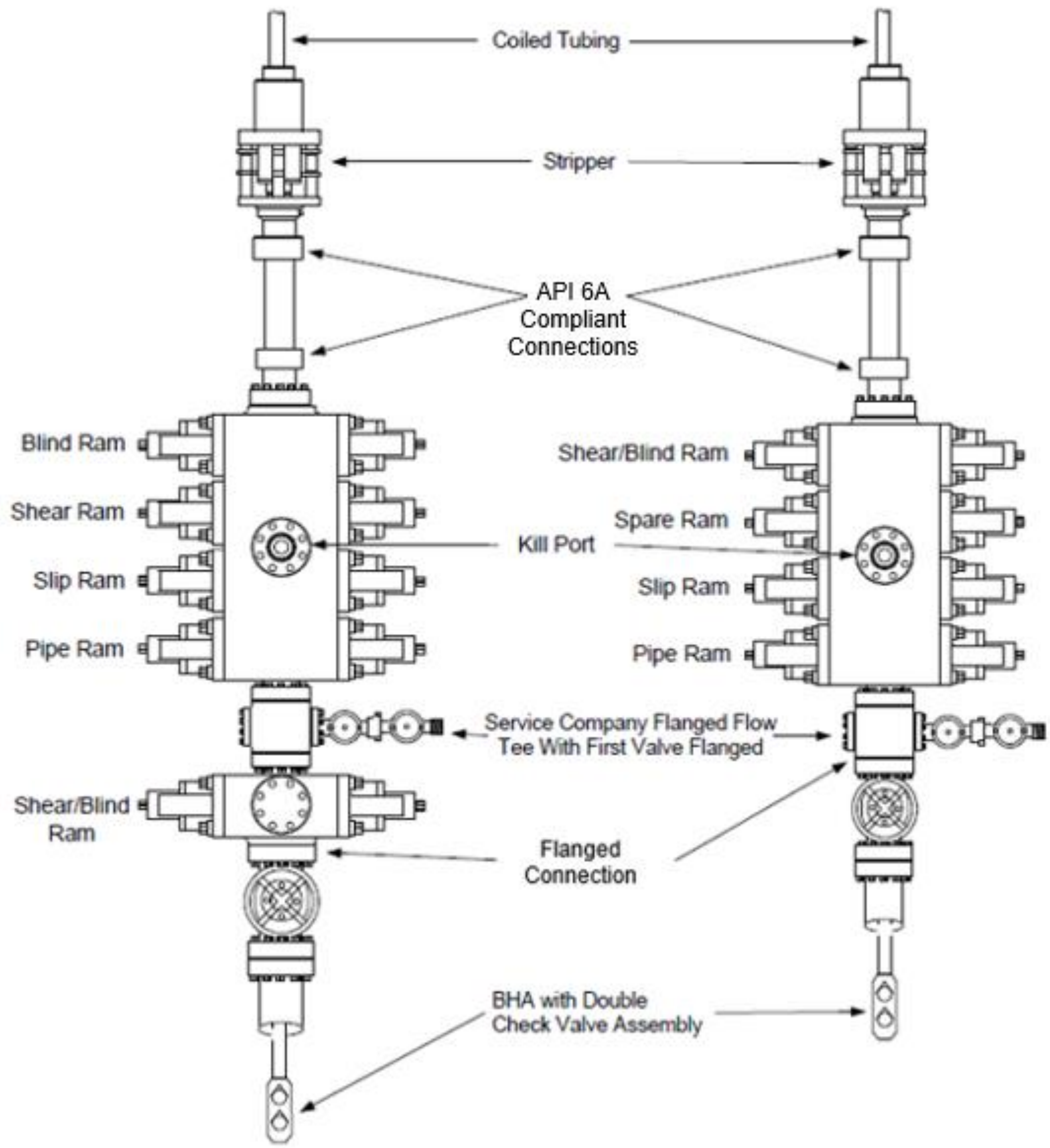
Well Servicing Category 3 operations have a MASP of 24.2 to 51.7 MPa. See Table 4 in 21.1.2 Well Classification and History more detail.

IRP Well control systems for Sweet Category 3 Well Servicing operations using coiled tubing shall include the following:

- **A blanking element that can be closed without upward pipe movement, one shearing element, one slip ram and one pipe sealing element in addition to the coiled tubing stripper.**
- **A dual check valve or float assembly.**
- **50 mm lines throughout.**
- **A kill port.**
- **API 6A compliant unions above the BOP**

If the top blind ram and shear ram are separate (not a combination ram) then a Shear/Blind ram is required below the standard well control stack in the event that collapsed pipe in the BOP prevents the top blind ram from closing (no pipe movement possible). Figure 6 shows two of the possible configurations. Where a Shear/Blind combination ram is used as the top ram, the secondary Shear/Blind is not required.

Figure 6. Example Configurations for Sweet Category 3 Well Servicing Operations



21.2.3.7 Category 3 – Sour

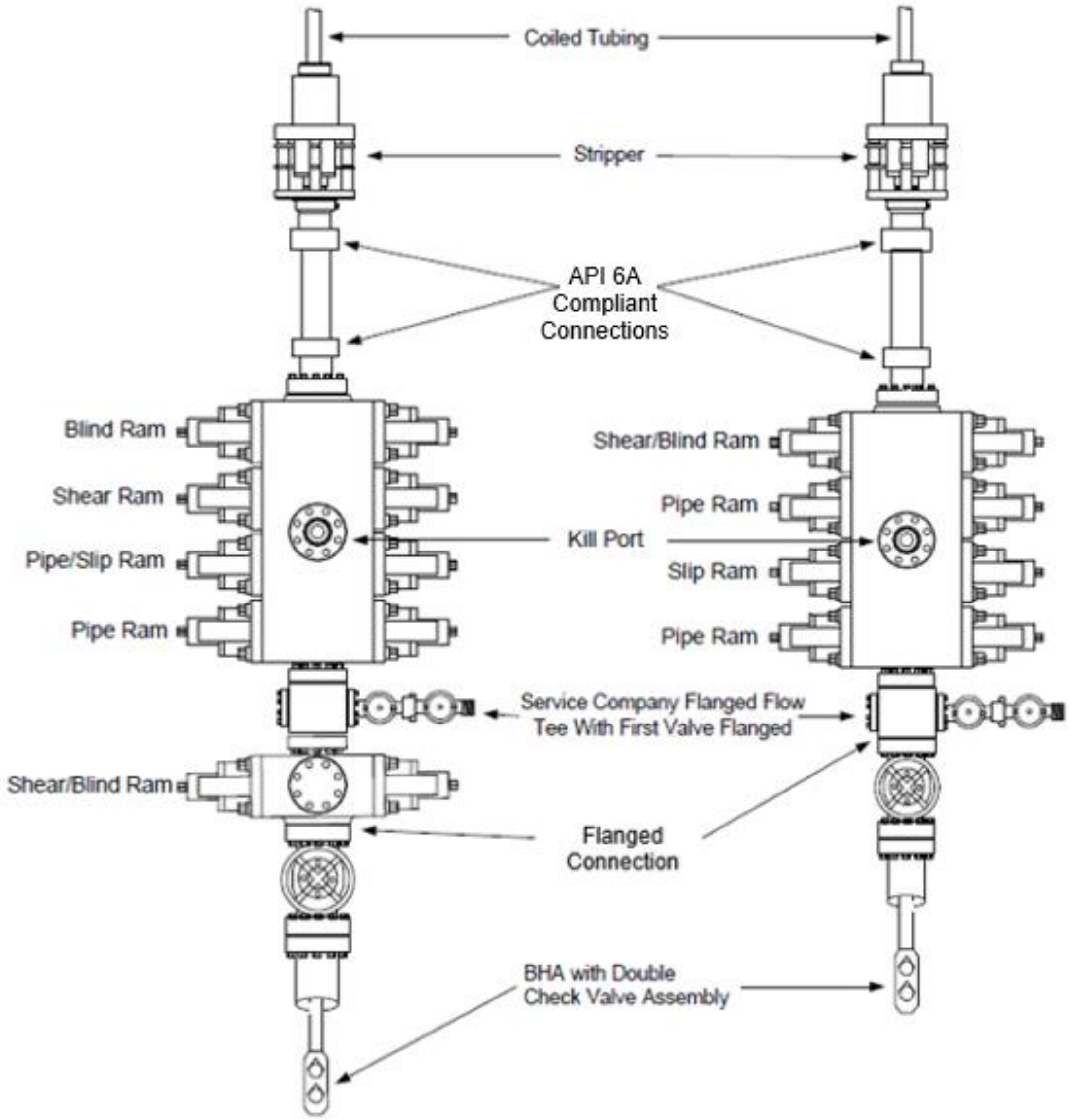
Well Servicing Category 3 operations have a MASP of 24.2 to 51.7 MPa. See Table 4 in 21.1.2 Well Classification and History more detail.

IRP Well control systems for Sour Category 3 Well Servicing operations using coiled tubing shall include the following:

- **A blanking element that can be closed without upward pipe movement, one shearing element, one slip ram and two pipe sealing elements in addition to the coiled tubing stripper.**
- **A dual check valve or float assembly.**
- **50 mm lines throughout.**
- **A kill port.**
- **API 6A compliant unions above the BOP**

The second pipe sealing element provides a second barrier in the event the stripper needs to be replaced. If the top blind ram and shear ram are separate (not a combination ram) then a Shear/Blind ram is required below the standard well control stack in the event that collapsed pipe in the BOP prevents the top blind ram from closing (no pipe movement possible). Figure 7 shows two of the possible configurations. Where a Shear/Blind combination ram is used as the top ram, the secondary Shear/Blind is not required.

Figure 7. Example Configurations for Sour Category 3 Well Servicing Operations



21.2.3.8 Category 4 – Sweet or Sour

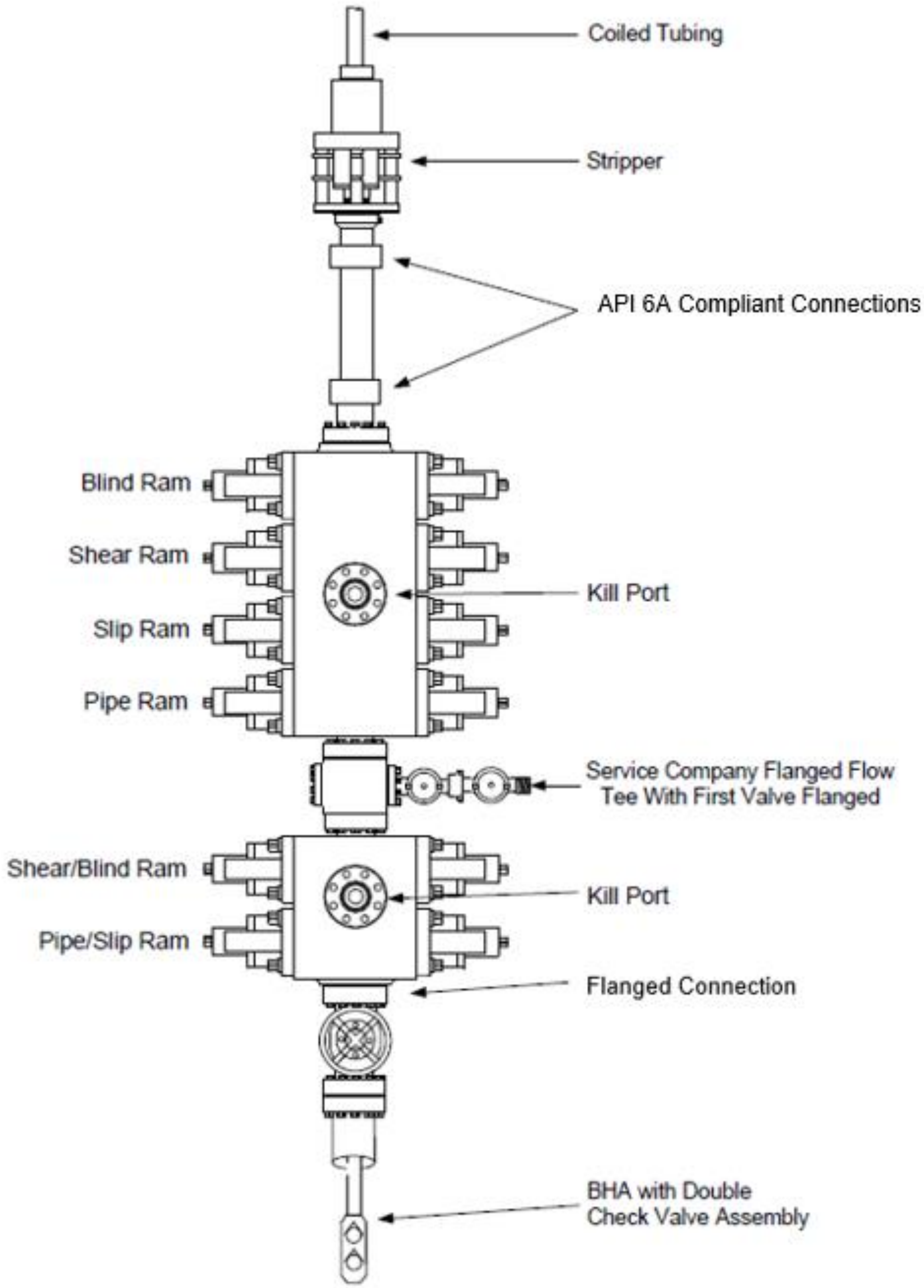
Well Servicing Category 4 operations have a MASP of 51.8 to 86.2 MPa. See Table 4 in 21.1.2 Well Classification and History for more detail.

IRP Well control systems for Sweet or Sour Category 4 Well Servicing operations using coiled tubing shall include the following:

- **A minimum of two blanking elements, two shearing elements, two slip rams and two pipe sealing elements in addition to the coiled tubing stripper.**
- **A dual check valve or float assembly.**
- **50 mm lines throughout.**
- **Primary and secondary kill ports.**
- **API 6A compliant unions above the BOP**

The sample configuration (Figure 8) shows a rig up with a quad BOP stack. This may be replaced with a combination stack.

Figure 8. Example Configuration for Sweet or Sour Category 4 Well Servicing Operations



21.2.3.9 Category 5 – Sweet or Sour

Well Servicing Category 5 operations have a MASP of 86.3 to 103.4 MPa. See Table 4 in 21.1.2 Well Classification and History for more detail.

IRP Well Servicing Category 5 operations shall have a detailed risk assessment performed for every step of the planned activity.

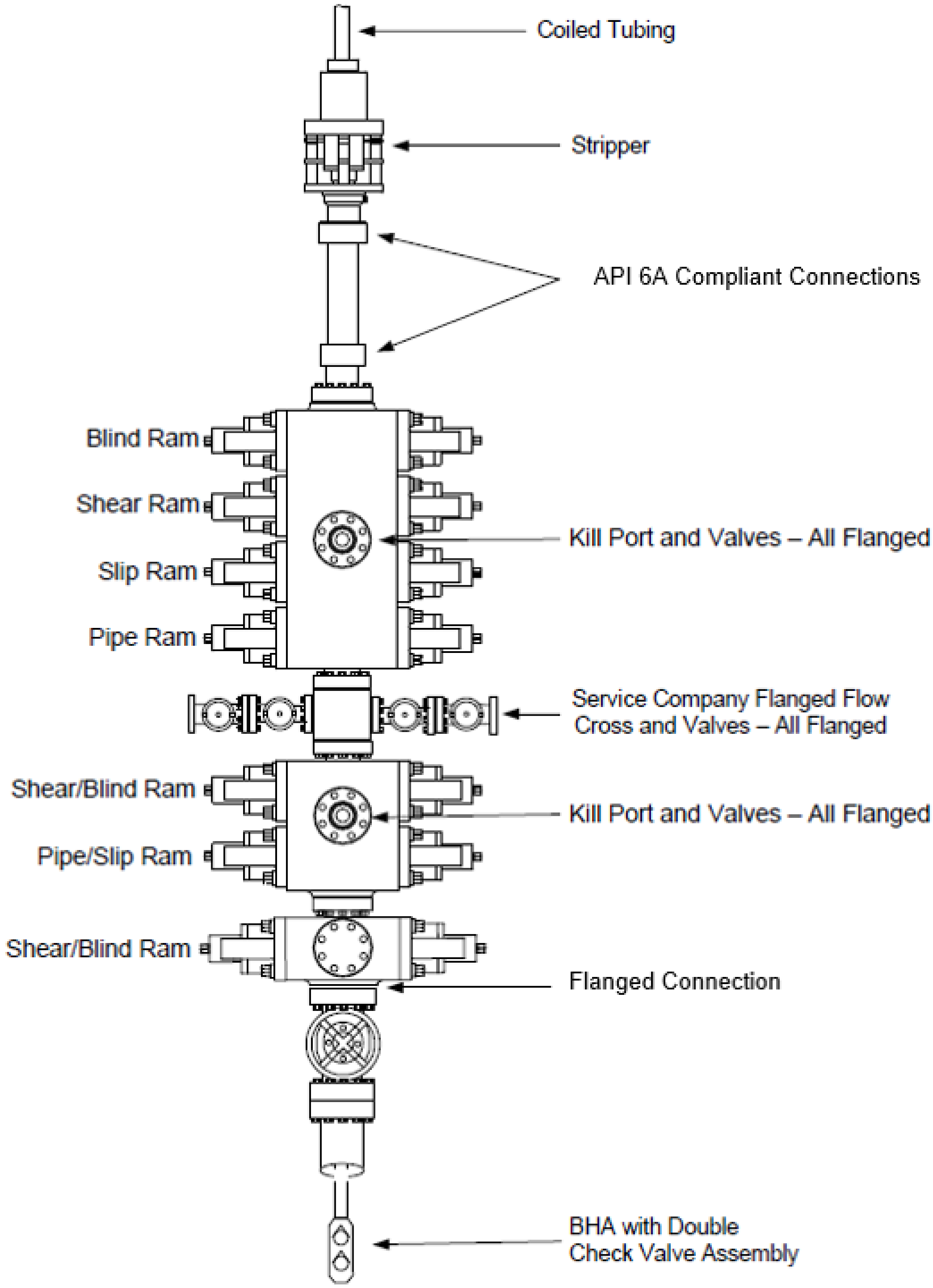
IRP Well control systems for Well Servicing Category 5 Sweet or Sour operations using coiled tubing shall include the following:

- **A minimum of two blanking elements, two shearing elements, two slip rams, two pipe sealing elements and one SHEAR/BLIND single ram mounted directly on top of the wellhead (which is capable of shearing any component in the coiled tubing string and BHA) in addition to the coiled tubing stripper.**
- **A dual check valve or float assembly.**
- **50 mm lines throughout.**
- **Primary and secondary kill ports.**
- **API 6A compliant unions above the BOP**

The sample configuration (Figure 9) shows a quad BOP stack. This may be replaced with a combination stack.

Due to the severe consequences of a well control issue during Pressure Category 5 operations, a SHEAR/BLIND capable of cutting the coiled tubing or the BHA is added immediately above the wellhead as a 3rd level contingency.

Figure 9. Example Configuration for Sweet or Sour Category 5 Well Servicing Operations



21.2.3.10 Critical Sour

A classification of Critical Sour can apply to any of the pressure categories. See Table 4 in 21.1.2 Well Classification and History for more detail.

For wells classified as Critical Sour, a third pipe sealing element is required for additional redundancy

IRP Well control systems for Well Servicing Category Critical Sour operations using coiled tubing shall include the following:

- **A minimum of one blanking element, one shearing element and three pipe sealing elements in addition to the coiled tubing stripper.**
- **A dual check valve or float assembly.**
- **50 mm lines throughout.**

The configuration may include a quad BOP stack or a combination stack as long as all functionality is present. Table 14 describes some configuration options.

Table 14. Critical Sour Configuration Options

Option 1	Option 2	Option 3	Option 4	Option 4
Stripper	Stripper	Stripper	Stripper	Stripper
Annular Bag	Annular Bag	Backup Stripper (non-engaged)	Backup Stripper (non-engaged)	Quad BOP (1 combi PIPE/SLIP ram and 1 pipe ram)
Quad BOP (1 pipe ram)	Dual Combi BOP (1 pipe ram)	Quad BOP (1 pipe ram)	Dual Combi (1 pipe ram)	Single Pipe Ram
Single Pipe Ram	Single Pipe Ram	Single Pipe Ram	Single Pipe Ram	

21.2.4 BOP Stack Configurations for Overbalanced Drilling

The drilling configurations are based on drilling class as defined in Table 5 in 21.1.2 Well Classification and History. Configurations in this section are for overbalanced non-sour drilling only. Overbalanced drilling is discussed in 21.2.5 BOP Stack Configurations for Underbalanced Drilling and Critical Sour Underbalanced Drilling is discussed in 21.2.6 BOP Stack Configurations for Critical Sour Underbalanced Drilling.

Wellhead valves/configurations are shown for illustrative purposes only and are not meant to reflect the regulatory requirements. Local jurisdictional regulations must be consulted for specific regulatory requirements.

21.2.4.1 Class I

See Table 5 in 21.1.2 Well Classification and History for the definition of Drilling Class I for purposes of this IRP.

IRP Well control systems for overbalanced Class I drilling operations using coiled tubing shall be as follows:

- **Contain a minimum of one pipe sealing element.**
- **Have a minimum pressure rating of 1,400 kPa.**

IRP Jurisdictional requirements for depth and other limitations must be consulted.

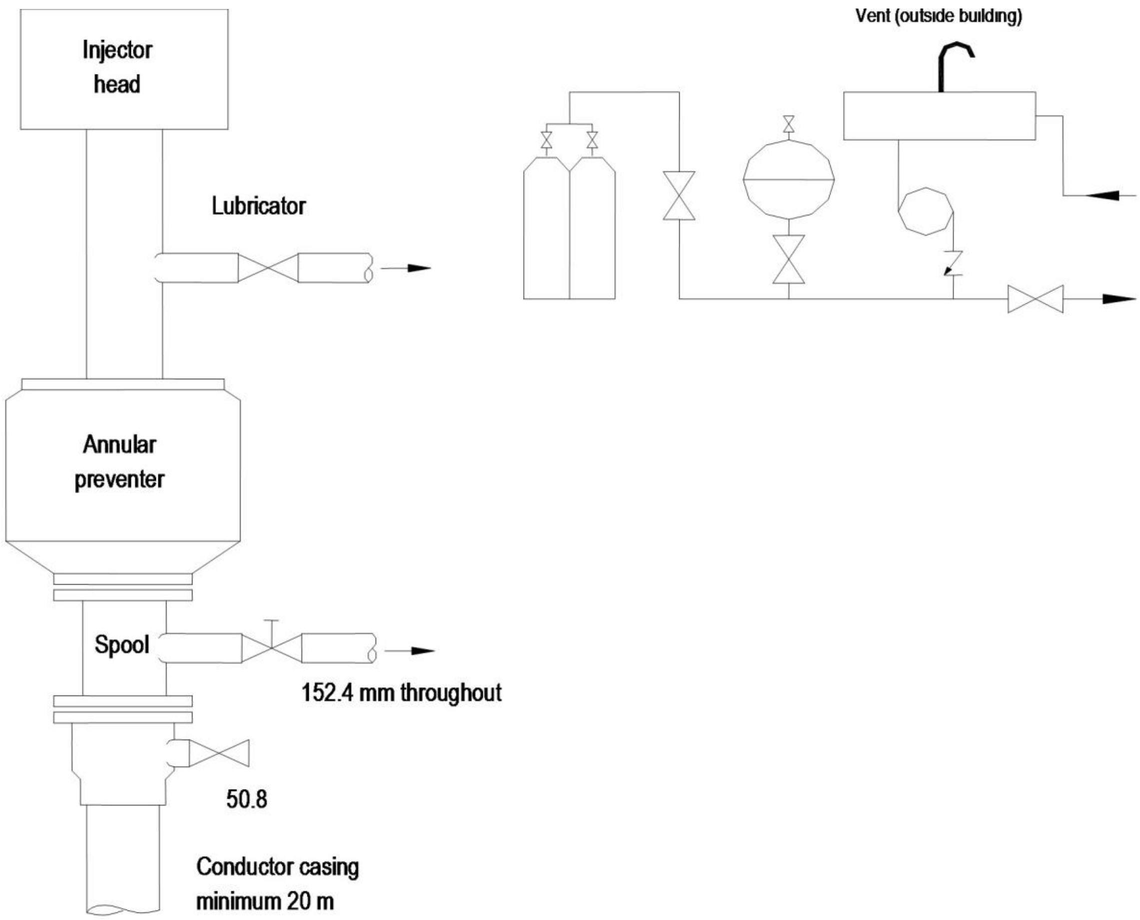
IRP Replacing the annular bag with pipe rams shall not be considered an acceptable pipe sealing element in Class I drilling applications due to the presence of drill collars and positive displacement motors that may place components of variable diameter across the pipe rams and inhibit the sealing capabilities.

A check valve or float assembly is not required for Drilling Class I.

Figure 10 shows the recommended configuration for overbalanced Class I drilling operations.

Figure 10. Recommended Minimum Configuration for Overbalanced Class I Drilling Operations

BOP Stack **Accumulator System**



Notes:

1. The diverter line must be a minimum nominal diameter of 152 mm throughout.
2. Connections between the top of annular preventer and injector head do not have to be flanged or meet the minimum pressure rating requirements. A stripper is optional.

21.2.4.2 Class II

See Table 5 in 21.1.2 Well Classification and History for definition of Drilling Class II for purposes of this IRP.

IRP Well control systems for overbalanced Class II drilling operations using coiled tubing shall be as follows:

- **Contain a minimum of one variable pipe sealing element, one blanking element, a kill spool and one pipe sealing element.**
- **Threaded connections in the manifold system are acceptable.**
- **Have a minimum pressure rating of 7,400 kPa.**

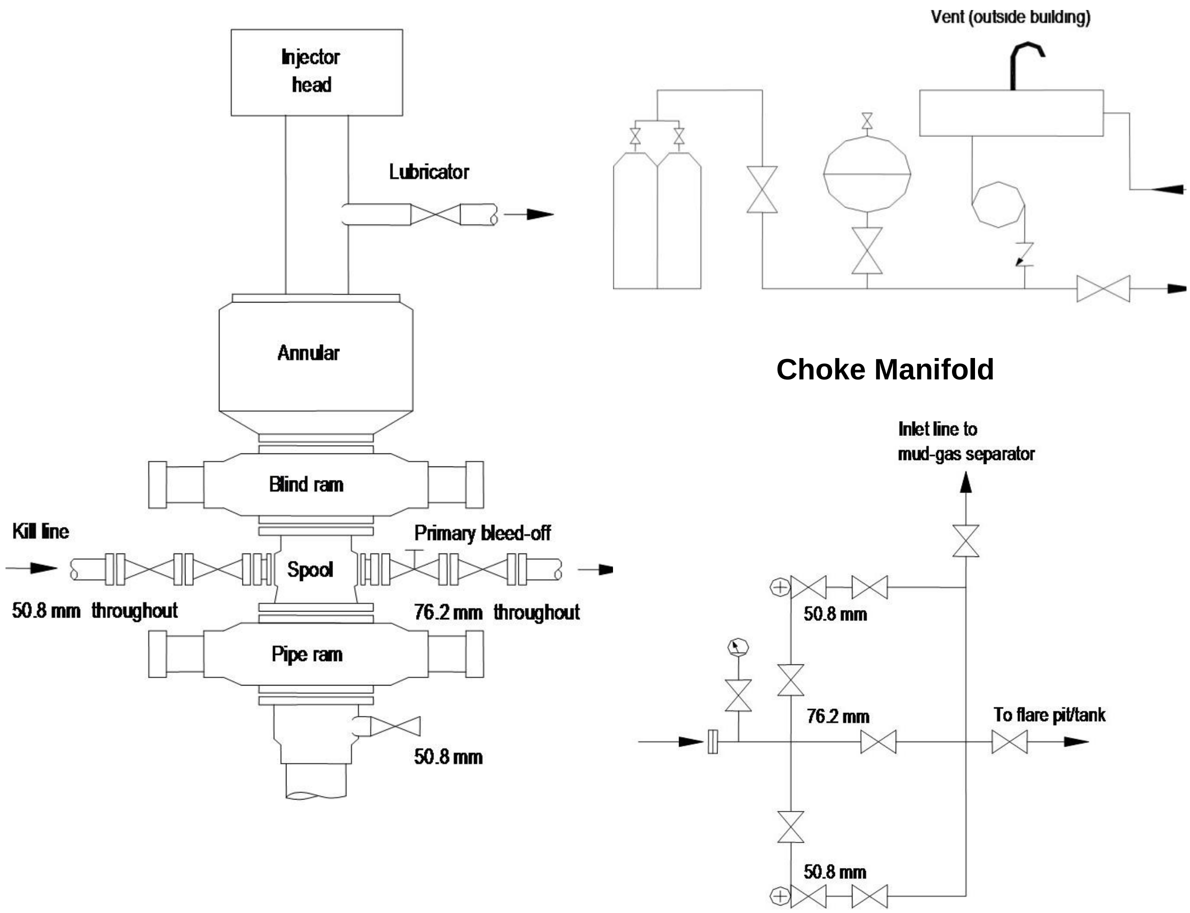
IRP Jurisdictional requirements for depth and other limitations must be consulted.

A check valve or float assembly is not required for Drilling Class II.

Figure 11 shows the recommended configuration for overbalanced Class II drilling operations.

Figure 11. Recommended Minimum Configuration for Overbalanced Class II Drilling Operations

BOP Stack **Accumulator System**



Notes:

1. Bleed-off line, centre line through choke manifold and flare line must be a minimum nominal diameter of 76.2 mm throughout.
2. Lines through chokes must be a minimum nominal diameter of 50.8 mm throughout.
3. Kill line must be a minimum nominal diameter of 50.8 mm throughout.
4. Flanged pipe connections must be used from the drilling spool down to and including the connection to the choke manifold. The remainder of the choke manifold may contain threaded fittings.
5. Connections between the top of the annular preventer and injector head do not have to be flanged or meet the minimum pressure rating requirements. The stripper is optional.

6. Minimum pressure rating for flare and degasser inlet lines is 7 MPa.
7. Hydraulic and manual valve positions in the bleed-off line may be interchangeable.
8. An optional BOP stack arrangement (for Class II wells only) would allow the pipe ram to be placed above the drilling spool.
9. Ram-type BOPs manufactured with integral outlets may be used in place of the drilling spool.

21.2.4.3 **Class III**

See Table 5 in 21.1.2 Well Classification and History for the definition of Drilling Class III for purposes of this IRP.

Well control systems for Class III drilling operations using coiled tubing are equivalent to Class II operations but require a minimum pressure rating of 14,000 kPa instead of 7,000 kPa. Threaded connections in the manifold system are acceptable.

IRP Well control systems for overbalanced Class III drilling operations using coiled tubing shall be as follows:

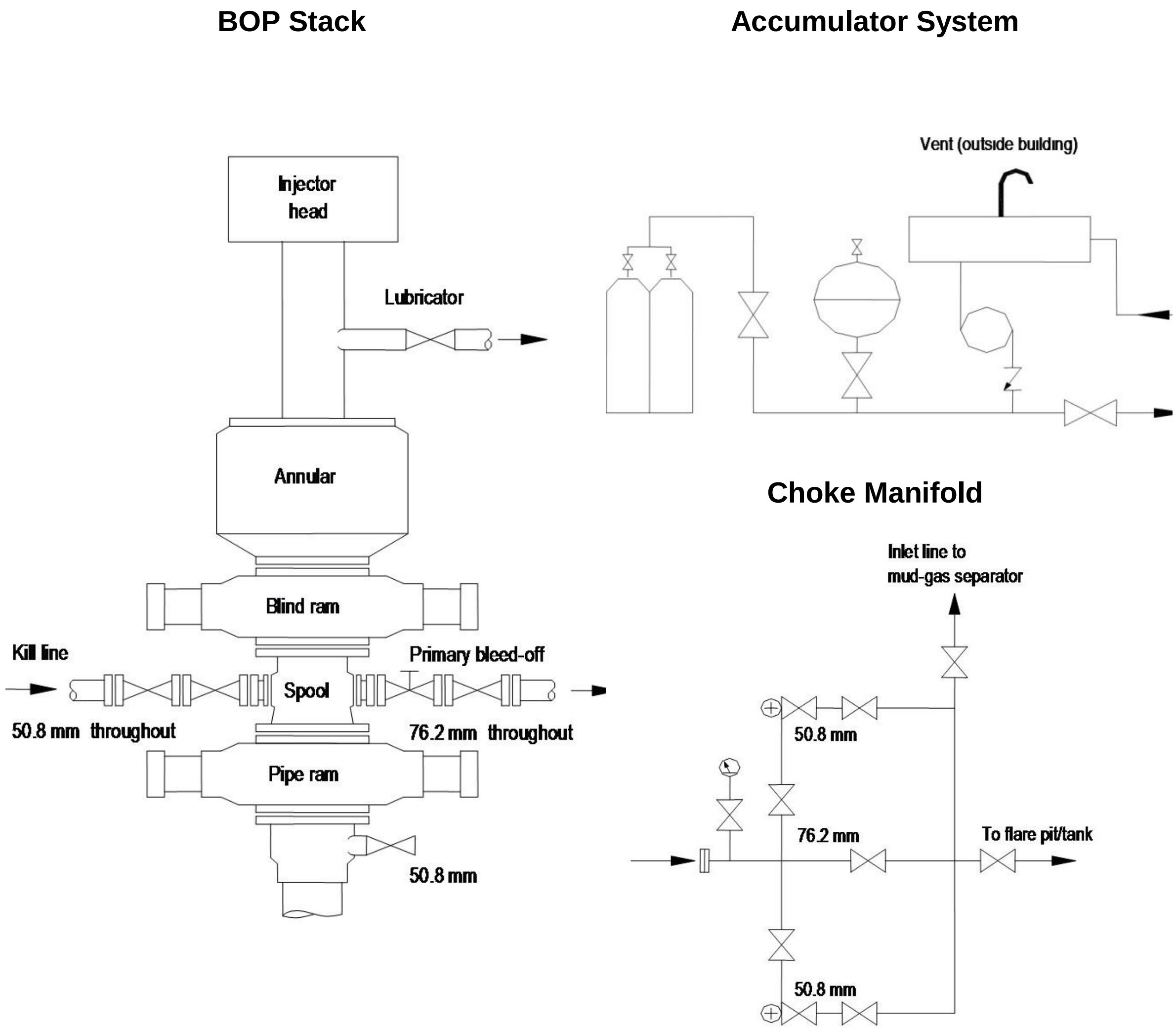
- **Contain a minimum of one variable pipe sealing element, one blanking element, a kill spool and one pipe sealing element.**
- **Threaded connections in the manifold system are acceptable.**
- **Have a minimum pressure rating of 14,400 kPa.**

IRP Jurisdictional requirements for depth and other limitations must be consulted.

A check valve or float assembly is not required for Drilling Class III.

Figure 12 shows the recommended configuration for overbalanced Class III drilling operations.

Figure 12. Recommended Minimum Configuration for Overbalanced Class III Drilling Operations



Notes:

1. Bleed-off line, centre line through choke manifold and flare line must be a minimum nominal diameter of 76.2 mm throughout.
2. Lines through chokes must be a minimum nominal diameter of 50.8 mm throughout.
3. Kill line must be a minimum nominal diameter of 50.8 mm throughout.
4. Flanged pipe connections must be used from the drilling spool down to and including the connection to the choke manifold. The remainder of the choke manifold may contain threaded fittings.
5. Connections between the top of the annular preventer and injector head do not have to be flanged or meet the minimum pressure rating requirements. The stripper is optional.

6. Minimum pressure rating for flare and degasser inlet lines is 14 MPa.
7. Hydraulic and manual valve positions in the bleed-off line may be interchangeable.
8. Ram-type BOPs manufactured with integral outlets may be used in place of the drilling spool.

21.2.4.4 Class IV

See Table 5 in 21.1.2 Well Classification and History for the definition of Drilling Class IV for purposes of this IRP.

Well control systems for Class IV drilling operations using coiled tubing are equivalent to Class II and III operations but require a minimum pressure rating of 21,000 kPa and flanged connections throughout the manifold system.

IRP Well control systems for overbalanced Class IV drilling operations using coiled tubing shall be as follows:

- **Contain a minimum of one variable pipe sealing element, one blanking element, a kill spool and one pipe sealing element.**
- **Have flanged connections throughout the manifold system.**
- **Have a minimum pressure rating of 21,000 kPa.**

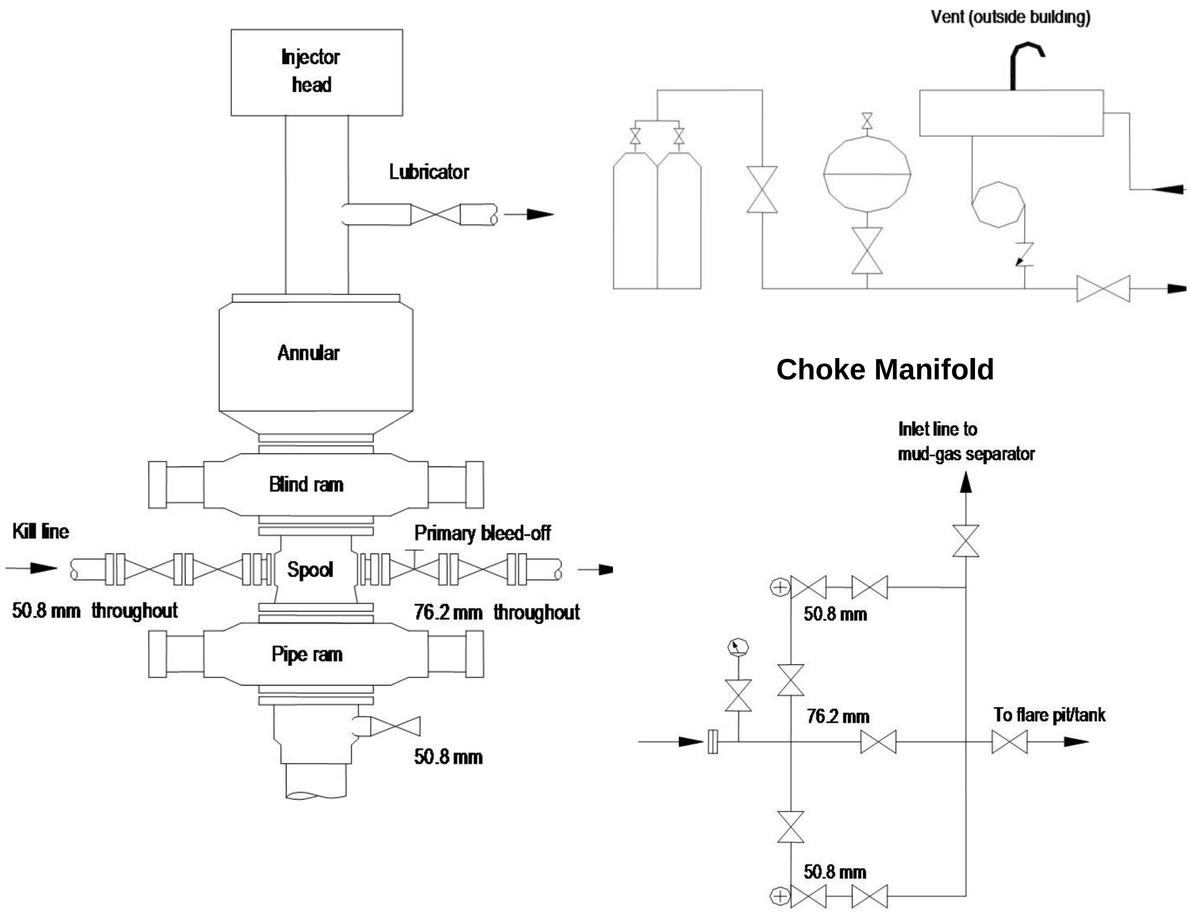
IRP Jurisdictional requirements for depth and other limitations must be consulted.

A check valve or float assembly is not required for Drilling Class IV.

Figure 13 shows the recommended configuration for overbalanced Class IV drilling operations.

Figure 13. Recommended Minimum Configuration for Overbalanced Class IV Drilling Operations

BOP Stack **Accumulator System**



Notes:

1. Bleed-off line, centre line through choke manifold and flare line must be a minimum nominal diameter of 76.2 mm throughout.
2. Lines through chokes must be a minimum nominal diameter of 50.8 mm throughout.
3. Kill line must be a minimum nominal diameter of 50.8 mm throughout.
4. Flanged pipe connections must be used from the drilling spool down to and including the connection to the choke manifold. The remainder of the choke manifold may contain threaded fittings.
5. Connections between the top of the annular preventer and injector head do not have to be flanged or meet the minimum pressure rating requirements. The stripper is optional.

6. Minimum pressure rating for flare and degasser inlet lines is 14 MPa.
7. Hydraulic and manual valve positions in the bleed-off line may be interchangeable.
8. Ram-type BOPs manufactured with integral outlets may be used in place of the drilling spool.

21.2.4.5 Class V

See Table 5 in 21.1.2 Well Classification and History for the definition of Drilling Class V for purposes of this IRP.

IRP Well control systems for overbalanced Class V drilling operations using coiled tubing shall be as follows:

- **Contain a minimum of one variable pipe sealing element, two pipe sealing elements, one blanking element, one shearing element and two kill/bleed-off spools.**
- **Have a minimum pressure rating of 34,000 kPa.**
- **Have flanged connections throughout the manifold system.**
- **Have shear rams and blind rams due to the higher potential for pressure at the depths involved. These ram functions may be separate elements or combined into a common BLIND/SHEAR element.**

Note: This increase in ram functions recognizes the additional requirement for a lower Kelly cock valve for Class V drilling with jointed pipe.

- **A check valve or float assembly may be required.**

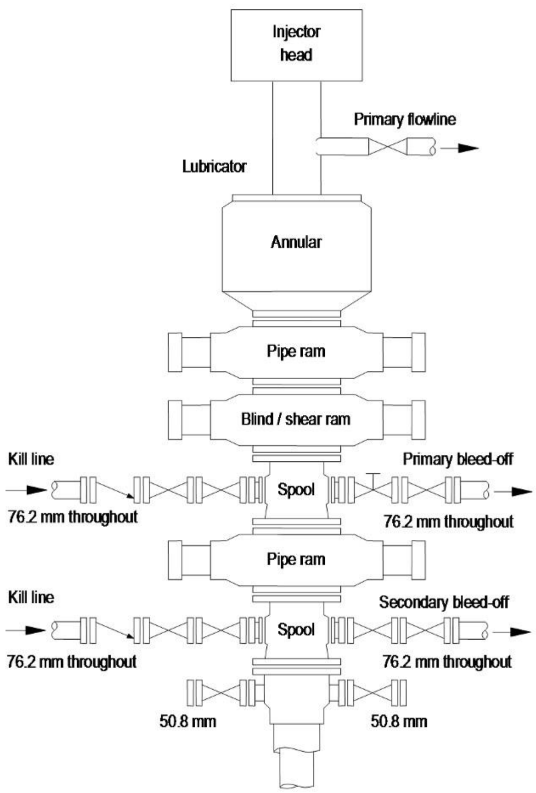
IRP Jurisdictional requirements for depth and other limitations must be consulted.

Figure 14 shows the recommended configuration for overbalanced Class V drilling operations.

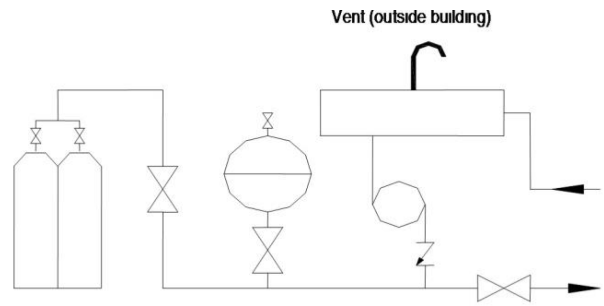
For optional BOP stack configurations see the BOP configurations for critical sour wells in 21.2.4.7 Critical Sour Drilling.

Figure 14. Recommended Minimum Configuration for Overbalanced Class V Drilling Operations

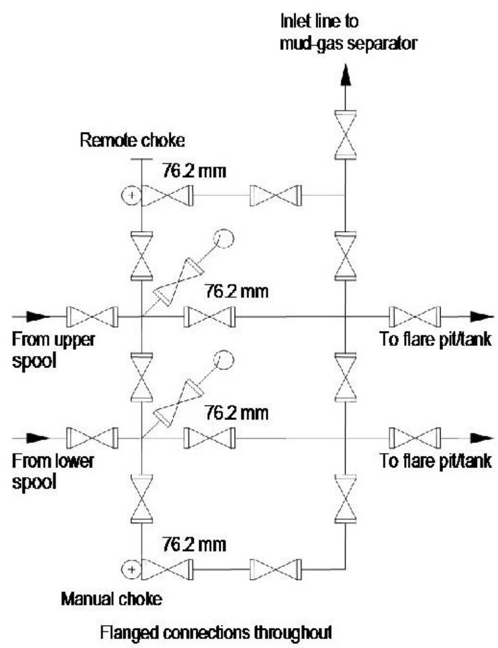
BOP Stack



Accumulator System



Choke Manifold



Notes:

1. Kill, bleed-off, choke manifold and flare lines must be a minimum nominal diameter of 76.2 mm throughout.
2. Flanged pipe connections must be used from the drilling spool to the last valve on the choke manifold (inclusive).
3. Connections between the top of the annular preventer and injector head do not have to be flanged or meet the minimum pressure rating requirements. The stripper is optional.
4. Minimum pressure rating for flare and degasser inlet lines is 14 MPa.

5. Hydraulic and manual valve positions in the bleed-off line may be interchangeable.
6. Ram-type BOPs manufactured with integral outlets may be used in place of the drilling spool.

21.2.4.6 Class VI

See Table 5 in 21.1.2 Well Classification and History for the definition of Drilling Class VI for purposes of this IRP.

Well control systems for Class VI drilling operations using coiled tubing are equivalent to Class V operations but require a minimum pressure rating of 69,000 kPa.

IRP Well control systems for overbalanced Class VI drilling operations using coiled tubing shall be as follows:

- **Contain a minimum of one variable pipe sealing element, two pipe sealing elements, one blanking element, one shearing element and two kill/bleed-off spools.**
- **Have a minimum pressure rating of 69,000 kPa.**
- **Have flanged connections throughout the manifold system.**
- **Have shear rams and blind rams due to the higher potential for pressure at the depths involved. These ram functions may be separate elements or combined into a common BLIND/SHEAR element. This increase in ram functions recognizes the additional requirement for a lower Kelly cock valve for Class VI drilling with jointed pipe.**
- **Have a check valve or float assembly.**

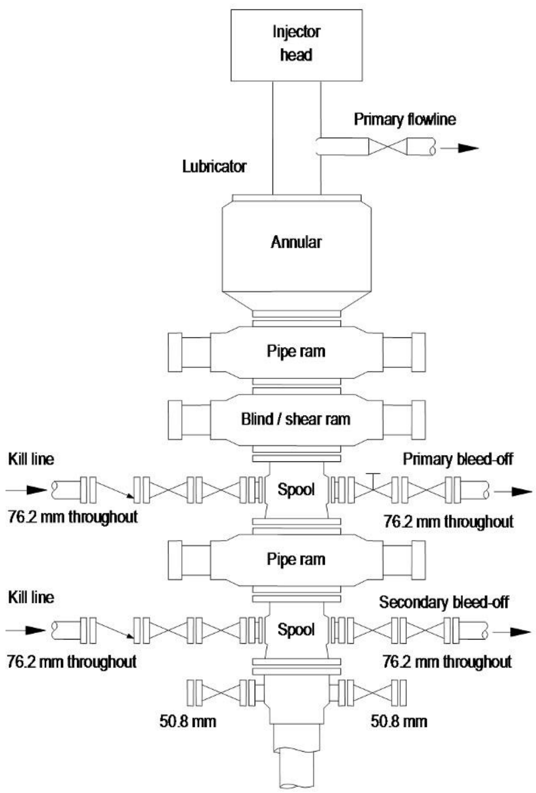
IRP Jurisdictional requirements for depth and other limitations must be consulted.

Figure 15 shows the recommended configuration for overbalanced Class VI drilling operations.

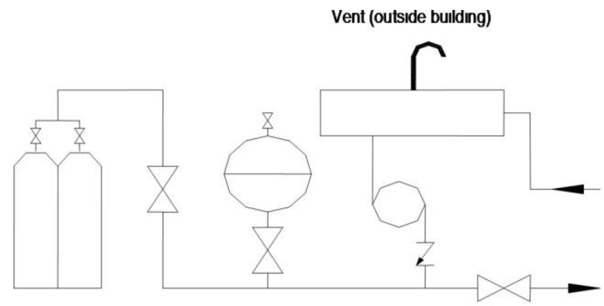
For optional BOP stack configurations see the BOP configurations for critical sour wells in 21.2.4.7 Critical Sour Drilling.

Figure 15. Recommended Minimum Configuration for Overbalanced Class VI Drilling Operations

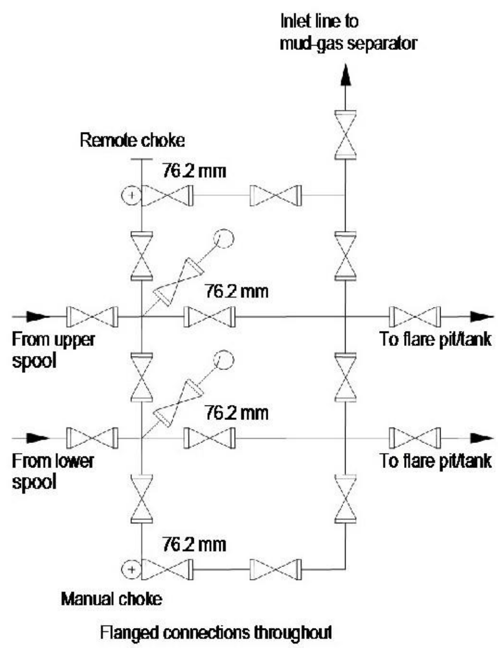
BOP Stack



Accumulator System



Choke Manifold



Notes:

1. Kill, bleed-off, choke manifold and flare lines must be a minimum nominal diameter of 76.2 mm throughout.
2. Flanged pipe connections must be used from the drilling spool to the last valve on the choke manifold (inclusive).
3. Connections between the top of the annular preventer and injector head do not have to be flanged or meet the minimum pressure rating requirements. The stripper is optional.
4. Minimum pressure rating for flare and degasser inlet lines is 14 MPa.

5. Hydraulic and manual valve positions in the bleed-off line may be interchangeable.
6. Ram-type BOPs manufactured with integral outlets may be used in place of the drilling spool.

21.2.4.7 Critical Sour Drilling

IRP Well control systems for overbalanced critical sour drilling operations using coiled tubing shall be as follows:

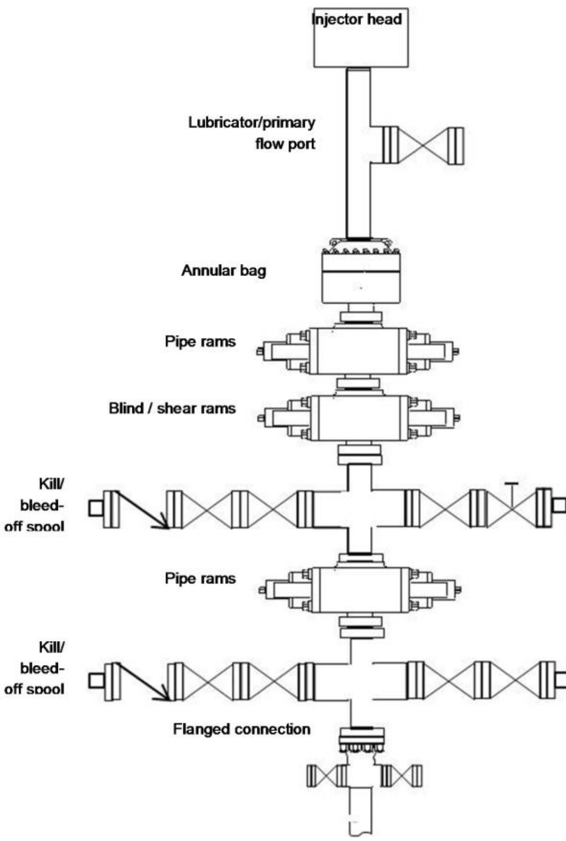
- **Contain a minimum of a primary flow port, an annular bag (variable pipe sealing element), two pipe sealing elements, one blanking element, one shearing element and two kill/bleed-off spools.**
- **Have a dual check valve or float assembly.**
- **Have flanged connections throughout.**
- **Have minimum nominal diameters for kill, bleed-off, choke manifold and flare lines as described for the depths for the drilling classes I through VI (Figures 10 through 15).**
- **Have minimum pressure ratings as described for the depths for the drilling classes II through VI (Figures 11 through 15).**

Three common configuration options (1, 2 and 3) are illustrated in Figures 16, 17 and 18.

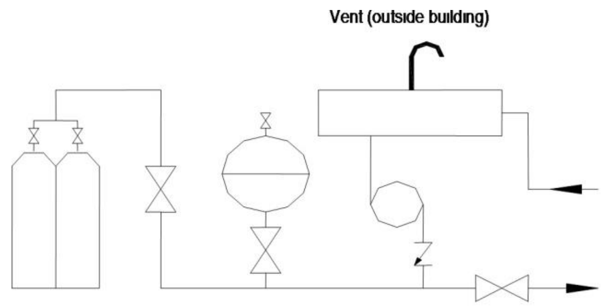
> **Note:** In some cases, the option shown in Figure 16 could be provided with a quad BOP stack. This may be replaced with a combination stack to replace the pipe rams and BLIND/SHEAR rams.

Figure 16. Recommended Minimum Configuration for Overbalanced Critical Sour Drilling Operations – Option 1

BOP Stack



Accumulator System



Choke Manifold

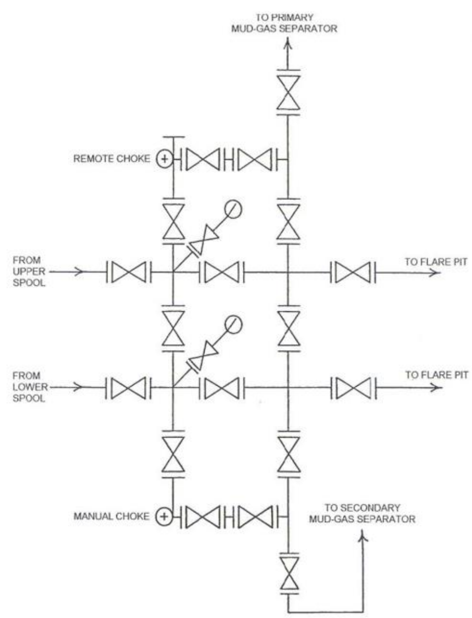
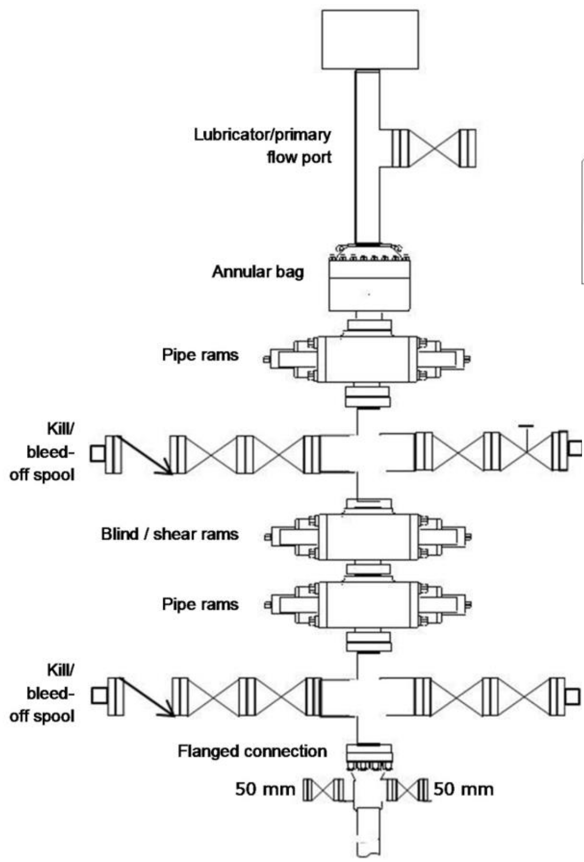
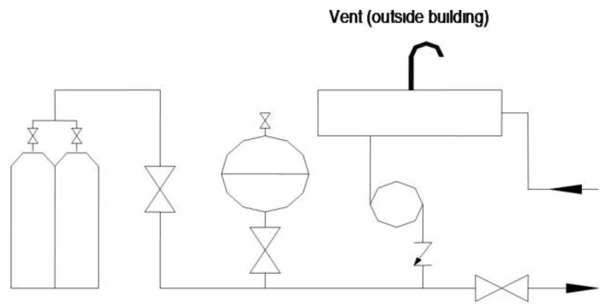


Figure 17. Recommended Minimum Configuration for Overbalanced Critical Sour Drilling Operations – Option 2

BOP Stack



Accumulator System



Choke Manifold

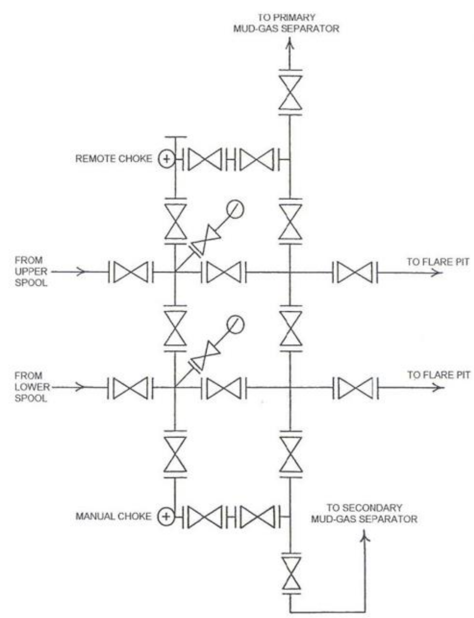
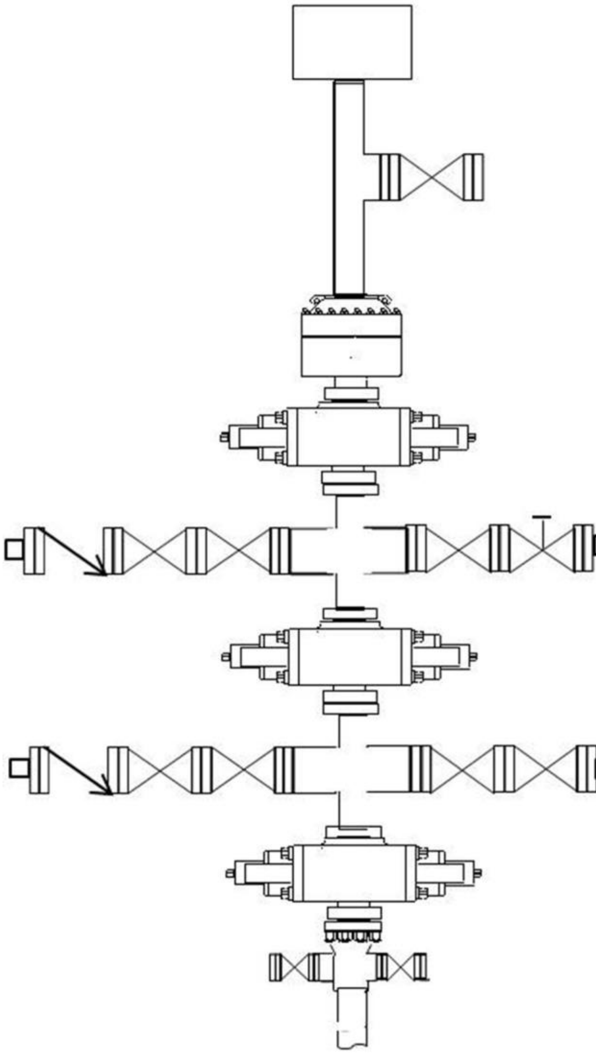
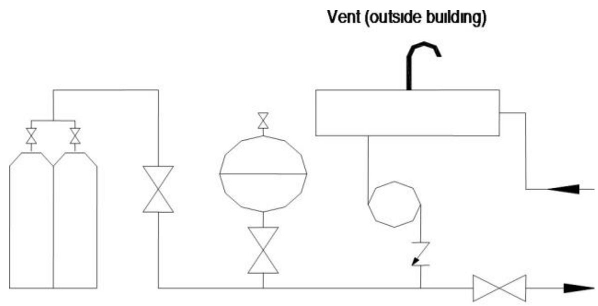


Figure 18. Recommended Minimum Configuration for Overbalanced Critical Sour Drilling Operations – Option 3

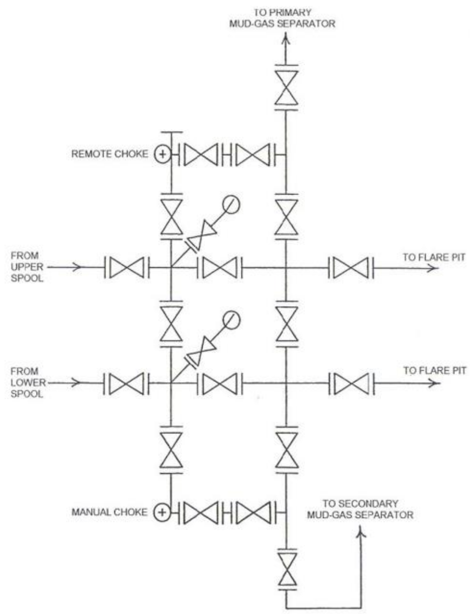
BOP Stack



Accumulator System



Choke Manifold



21.2.5 BOP Stack Configurations for Underbalanced Drilling

The stripper in a live-well coiled tubing operation is the primary method of well control and as such is considered the equivalent of the hydrostatic head of wellbore fluid in "dead-well" operations (which is also the primary method of well control in that operation).

IRP For underbalanced drilling operations for drilling classes I to VI the required minimum well control configuration shall be as shown in Figures 10 through 15 with the addition of a coiled tubing stripper.

IRP In any live well operation where the length of lubricator is insufficient to swallow the entire BHA above the blind rams or the wellhead valve, a dedicated deployment system shall be in place that

- **provides a method of holding the BHA in the BOP stack and**
- **provides a method of containing wellbore pressure during the deployment procedure.**

IRP A dual check valve or float assembly shall be used for underbalanced drilling.

IRP When slip rams are used they should be bidirectional (see 21.2.1.1 Definitions).

21.2.6 BOP Stack Configurations for Critical Sour Underbalanced Drilling

The stripper in a live-well coiled tubing operation is the primary method of well control and as such is considered the equivalent of the hydrostatic head of wellbore fluid in "dead-well" operations (which is also the primary method of well control in that operation).

IRP For critical sour underbalanced drilling operations the minimum well control configuration shall be as shown in Figures 16 to 18 with the addition of a coiled tubing stripper.

IRP Well control systems for overbalanced critical sour drilling operations using coiled tubing shall be as follows:

- **Have minimum nominal diameters for kill, bleed-off, choke manifold and flare lines as described for the depths for the drilling classes I through VI (Figures 10 through 15).**
- **Have minimum pressure ratings as described for the depths for the drilling classes II through VI (Figures 11 through 15).**

IRP A dual check valve or float assembly shall be used for critical sour underbalanced drilling.

IRP When slip rams are used they should be bidirectional (see 21.2.1.1 Definitions).

IRP Well control systems for critical sour underbalanced drilling operations using coiled tubing shall include the following:

- **A minimum of one coiled tubing stripper**
- **A lubricator with primary flowline**
- **A variable pipe sealing element**
- **Two pipe sealing elements**
- **A shearing element**
- **A blanking element**
- **Two kill/bleed-off spools.**

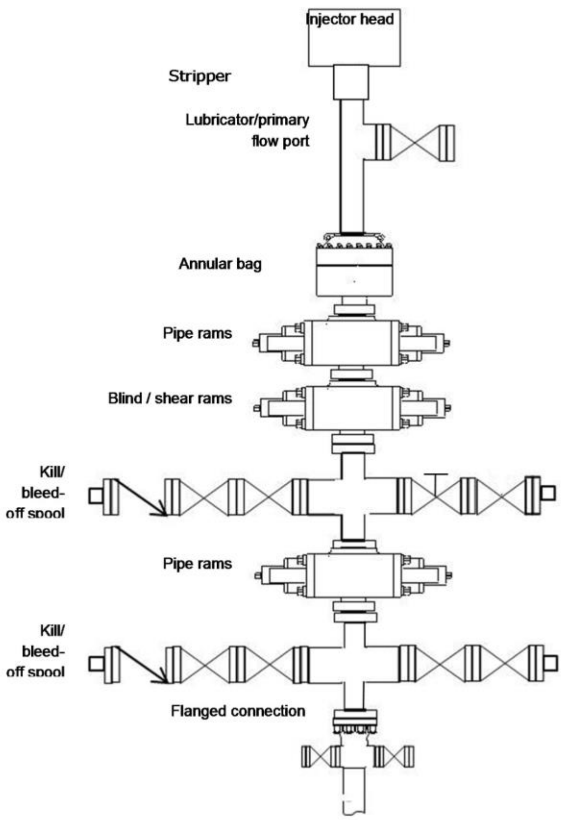
IRP If BOP Option 2 (Figure 20) or BOP Option 3 (Figure 21) is used an appropriately sized ram blanking tool that fits into the top pipe ram must be on site and readily available.

This allows the top pipe ram to perform the function of a blind ram when the drill string is out of the hole.

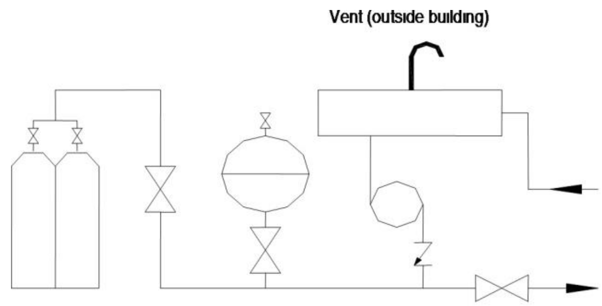
IRP If BOP Configuration 3 (Figure 21) is used there must be sufficient surface or intermediate casing to contain the maximum anticipated wellhead pressure.

Figure 19. Recommended Minimum Configuration for Underbalanced Critical Sour Drilling Operations – Option 1

BOP Stack



Accumulator System



Choke Manifold

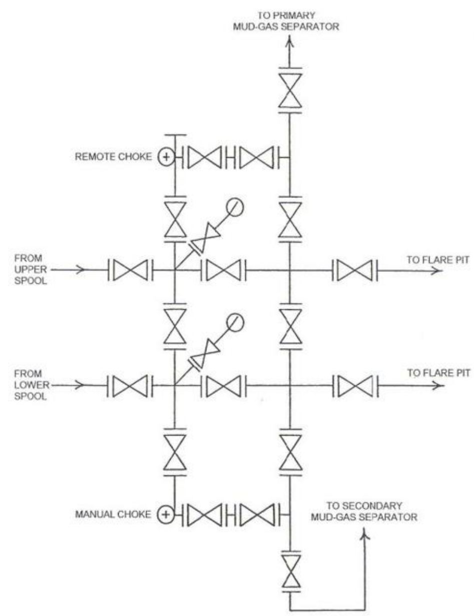
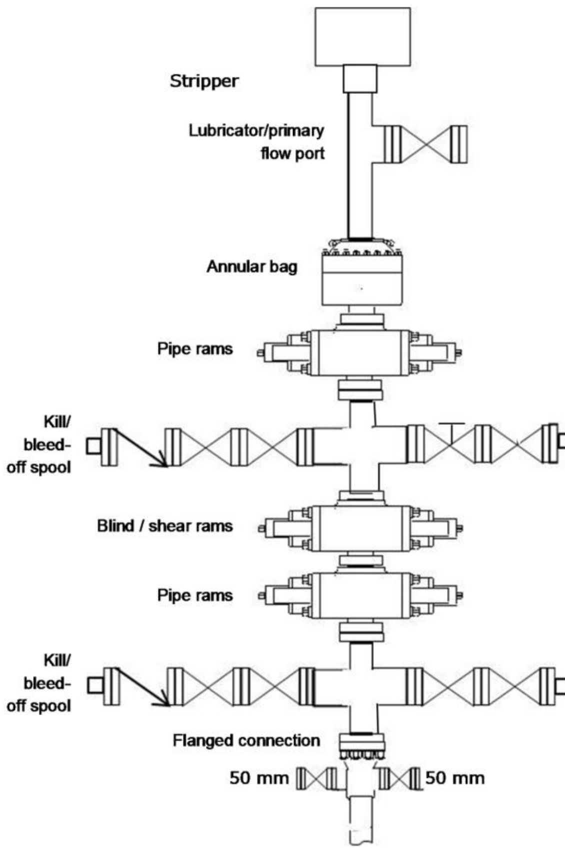
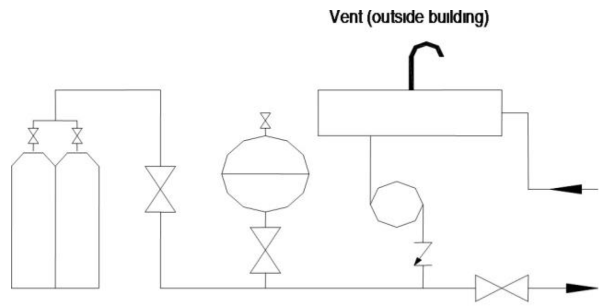


Figure 20. Recommended Minimum Configuration for Underbalanced Critical Sour Drilling Operations – Option 2

BOP Stack



Accumulator System



Choke Manifold

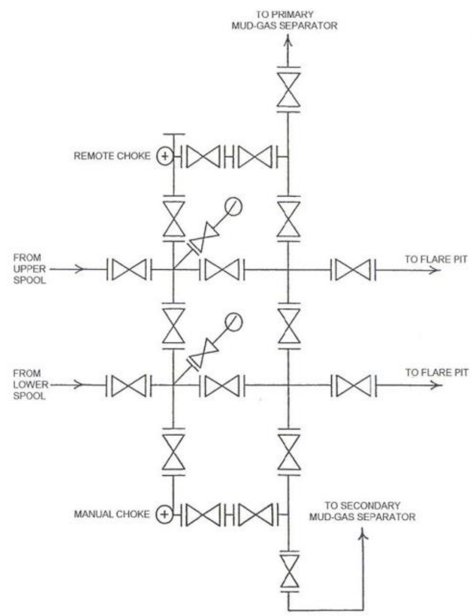
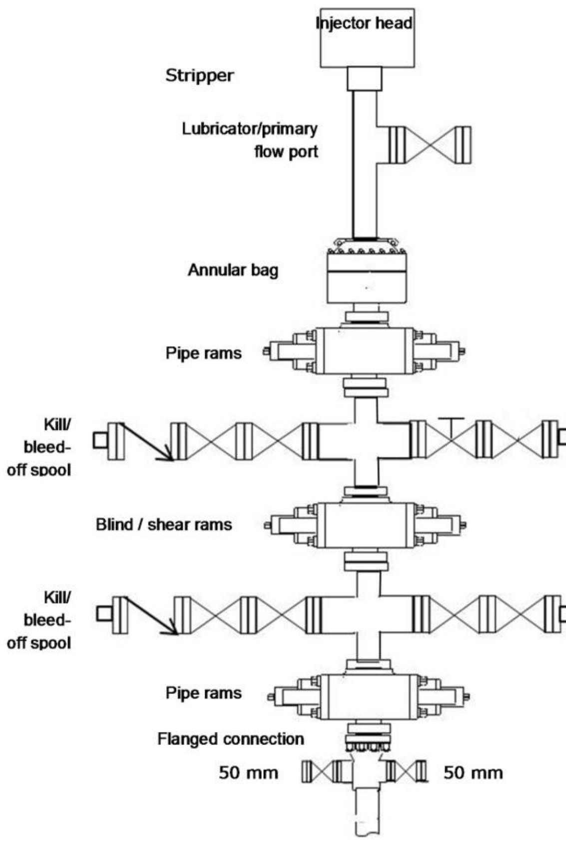
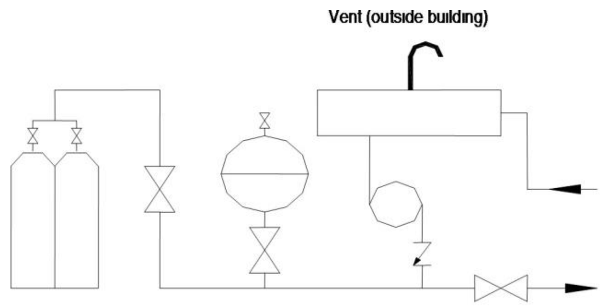


Figure 21. Recommended Minimum Configuration for Underbalanced Critical Sour Drilling Operations – Option 3

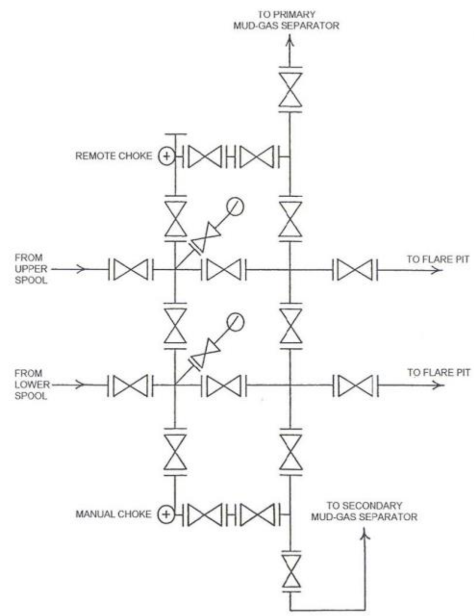
BOP Stack



Accumulator System



Choke Manifold

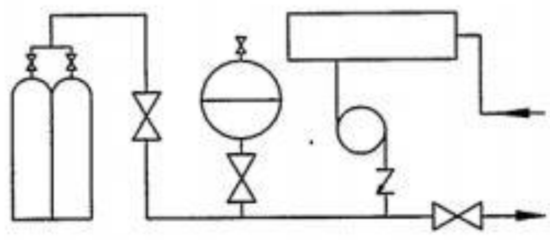


21.2.7 Accumulator Configurations for Well Servicing

Figure 22 shows a typical accumulator configuration for well servicing. Variances are permitted but all accumulator configuration IRPs have to be followed and the applicable functionality provided.

API RP 16ST may be referenced for detailed information about accumulator configurations.

Figure 22. Typical Accumulator System Configuration for Well Servicing Operations



21.2.7.1 **Accumulator Systems**

IRP Accumulator systems for well servicing operations with coiled tubing shall be as follows:

- **All BOPs must be hydraulically operated and connected to an accumulator system.**
- **The accumulator system shall be capable of providing, without recharging, hydraulic fluid of sufficient volume and pressure to close all active BOP components at the same time (in their required function) and retain a minimum pressure of 8,400 kPa on the accumulator system.**
- **The accumulator system shall be capable of functioning all required and active BOP components in the stack.**
  - **An active BOP component is any BOP component that is not locked out (regardless of whether or not it is required in the stack to meet minimum requirements).**
  - **For annular preventers or pipe rams, this requires the preventer to be closed on the coiled tubing in use.**
  - **For blind rams, shear rams or BLIND/SHEAR rams, this requires the preventers to be closed without pipe in the hole.**
- **If additional BOP equipment has been installed and is in use there shall be sufficient usable hydraulic fluid available to close the additional BOP components and meet the requirements above. All additional BOP**

equipment that is not in service must be locked out (e.g., unplugged, handles removed, lines disconnected, etc.).

- **If the existing accumulator system cannot meet these requirements because of the addition of the shear ram or SHEAR/BLIND rams, the accumulator system's capacity and/or pressure shall be increased or a separate accumulator system shall be installed. It is also acceptable to supplement the existing accumulator system with a N_2 booster that will provide sufficient volume and pressure to shear the tubulars and retain a minimum accumulator pressure of 8,400 kPa or the minimum pressure required to shear the tubulars, whichever is greater.**
- **The accumulator system shall be installed and operated according to manufacturer's specifications.**
- **All accumulator specifications shall be available at the coil unit (i.e., manufacturer, number of bottles, capacity of bottles, design pressure, etc.).**
- **The accumulator system shall be connected to the BOPs with hydraulic lines (steel and/or non-steel) of working pressure equal to or greater than the working pressure of the accumulator.**
- **All non-steel hydraulic BOP lines located within seven metres of the wellbore shall be completely sheathed with adequate fire-resistant sheathing. Adequate fire-resistant sheathing for hydraulic BOP hoses is defined as a hose assembly that can withstand a minimum of five minutes of 700° C flame temperature at maximum working pressure without failure.**
- **The accumulator system shall be recharged by an automatic pressure-controlled pump capable of recovering the pressure drop (resulting from the function test of the BOP components) within five minutes.**

Note: When the accumulator is recharged by the unit's hydraulic system (for Well Servicing Categories 1A, 1B and 2), it is acceptable to increase the RPM of the unit's engine to meet the five minute recharge requirement.

- **For all Well Servicing Categories, a check valve must be installed between the accumulator charge pump and the accumulator bottles. This will allow for a change out of the charge pump in the event of a pump failure after the system has been energized.**
- **For all Well Servicing Categories, the accumulator system must be**
  - **capable of closing any ram-type BOP within 30 seconds,**
  - **capable of closing the annular BOP within 60 seconds,**
  - **equipped with readily accessible fittings and a gauge to determine the pre-charge pressure of the accumulator bottles,**
  - **readily accessible and**
  - **connected to a backup nitrogen system.**

IRP **For Well Servicing Category 1A, 1B and 2 operations the accumulator must be located a minimum of seven metres from the wellbore.**

IRP **For Well Servicing Category 3, 4, 5 and Critical Sour operations the accumulator must be as follows:**

- Independent of the unit hydraulics (i.e., separate hydraulic pump and hydraulic reservoir) and located a minimum of 15 m (or as per jurisdictional requirements) from the wellbore.
- Shielded or housed to ensure that the system can be protected from the well in the event of an uncontrolled flow.
- Vented on the accumulator reservoir so that venting takes place outside of a confined space.

21.2.7.2 Backup Nitrogen Systems

IRP **Backup nitrogen (N_2) systems for well servicing operations with coiled tubing shall be as follows:**

- **The accumulator system must be connected to a backup N_2 system.**
- **The backup N_2 system must be capable of providing N_2 of sufficient volume and pressure to concurrently close all active BOP components in their required function and retain a minimum pressure of 8,400 kPa on the backup N_2 system.**
- **The backup N_2 system must be capable of functioning all required and active BOP components in the stack.**
  - **For annular preventers or pipe rams this requires the preventer to be closed on the coiled tubing in use.**
  - **For blind rams, shear rams or SHEAR/BLIND rams this requires the preventers to be closed without pipe in the hole.**
- **If additional BOP equipment has been installed and is in use there must be sufficient usable hydraulic fluid available to close the additional BOP components and meet the requirements above. All additional BOP equipment that is not in service must be locked out (e.g., unplugged, handles removed, lines disconnected, etc.).**
- **The backup N_2 system must be connected such that it will function the BOPs as described above and not allow the N_2 to discharge into the accumulator reservoir or the accumulator bottles.**
- **When the backup N_2 system is tied in downstream of an accumulator regulator valve or valves, isolation valves are required to prevent venting of N_2 through the regulator into the accumulator reservoir tank.**
- **The backup N_2 system must be readily accessible and be equipped with a gauge, or have a gauge readily available for installation, to determine the backup N_2 pressure.**

IRP For Well Servicing Category 1A, 1B and 2 operations the backup N_2 system must be located a minimum of seven metres from the wellbore.

IRP For Well Servicing Category 3, 4, 5 and Critical Sour the backup N_2 system must be located a minimum of 15 m from the wellbore and housed to ensure the system can be protected from the well in the event of an uncontrolled flow.

21.2.7.3 BOP Operating Controls

IRP The accumulator system shall include operating controls at the normal operating position (i.e., control cab for deep units, back of truck for intermediate/shallow units) and remote positions for each BOP.

IRP The position of the operating handles (open/neutral/closed) of the BOP operating controls at one position (operator's or remote) shall not prevent the operation of the BOP components from the other position.

IRP The crew shall be able to close the BOPs from the remote position.

This positioning allows the operating handles of the BOP controls to be repositioned without having to return to the coiled tubing unit in an emergency situation.

21.2.7.4 BOP Coiled Tubing Unit Operating Controls

IRP Each BOP component must have a separate operating control located near the operator's position.

IRP The BOP coiled tubing unit operating controls shall be as follows:

- **Capable of opening and closing each BOP component.**
- **Properly installed, readily accessible, correctly identified and show function operations (i.e., open and close).**
- **Equipped with a gauge indicating the accumulator system pressure.**

21.2.7.5 BOP Remote Operating Controls

IRP Each BOP component must have a separate operating control located at the remote position.

IRP The BOP remote operating controls must be as follows:

- Capable of closing each BOP component.
- Properly installed, correctly identified and show function operations (i.e., open and close).
- Readily accessible and be equipped with a gauge to determine accumulator system pressure.

IRP For critical sour wells the remote controls shall be capable of opening and closing each BOP component.

IRP For Well Servicing Category 1A, 1B and 2 operations the BOP remote operating controls must be located at a remote position a minimum of seven metres from the well.

IRP For Well Servicing Category 3, 4, 5 and Critical Sour operations the BOP remove operating controls must be located at a remote position a minimum of 25 m from the well. These controls must be readily accessible and shielded or housed to protect the controls in the event of an uncontrolled flow.

21.2.8 Accumulator Configurations for Drilling

21.2.8.1 Accumulator Systems

IRP All BOPs shall be hydraulically operated and connected to an accumulator system.

IRP For Class I wells the coiled tubing unit accumulator system must be capable of providing, without recharging, hydraulic fluid of sufficient volume and pressure to

- **open the hydraulically operated valve (HCR) on the diverter line,**
- **close the annular preventer on BHA drill pipe/coiled tubing and**
- **retain a minimum pressure of 8,400 kPa on the accumulator system.**

IRP For Class II, III, and IV wells the coiled tubing unit accumulator system must be capable of providing, without recharging, hydraulic fluid of sufficient volume and pressure to

- **open the HCR on the bleed-off line,**
- **close the annular preventer on drill pipe/coiled tubing/BHA,**
- **close one ram preventer and**
- **retain a minimum pressure of 8,400 kPa on the accumulator system.**

IRP For Class V and VI wells the accumulator system must be capable of providing, without recharging, hydraulic fluid of sufficient volume and pressure to

- **open the HCR on the bleed-off line,**
- **close the annular preventer on the drill pipe/coiled tubing,**
- **close two ram preventers and**

- **retain a minimum pressure of 8,400 kPa on the accumulator system.**

IRP In addition to the above functions, the accumulator system for coiled tubing units for drilling classes V and VI wells must also provide sufficient volume and pressure to shear the coiled tubing and retain on the accumulator system a minimum pressure of 8,400 kPa or the minimum pressure required to shear the coiled tubing a second time, whichever is greater.

- **If the existing accumulator system cannot meet these requirements because of the closing volume requirements for the shear ram, the accumulator system's capacity and/or pressure must be increased or a separate accumulator system must be installed.**
- **It is acceptable to supplement the existing accumulator system with a nitrogen booster that will provide sufficient volume and pressure to shear the coiled tubing and retain a minimum accumulator pressure of 8,400 kPa or the minimum pressure required to shear the coiled tubing, whichever is greater.**

IRP For critical sour wells the accumulator system shall be capable of providing, without recharging, hydraulic fluid of sufficient volume and pressure to

- **open the HCR on the bleed-off line,**
- **close the annular preventer on the drill pipe/coiled tubing,**
- **close, open and close one ram preventer and**
- **if SHEAR/BLIND rams are installed, provide sufficient volume and pressure to shear the drill pipe/coiled tubing and retain minimum pressure on the accumulator system of 8,400 kPa or the minimum pressure required to shear the drill pipe/coiled tubing a second time, whichever is greater.**

Note: If the existing accumulator system cannot meet these requirements because of the addition of the BLIND/SHEAR rams, the accumulator system's capacity and/or pressure must be increased or a separate accumulator system must be installed. It is acceptable to supplement the existing accumulator system with a nitrogen booster that will provide sufficient volume and pressure to shear the drill pipe/coiled tubing and retain a minimum accumulator pressure of 8,400 kPa or the minimum pressure required to shear the drill pipe/coiled tubing, whichever is greater.

IRP The accumulator system shall be as follows:

- **Installed and operated according to the accumulator manufacturer's specifications.**
- **All accumulator specifications must be available at the rig/unit (e.g., manufacturer, number of bottles, capacity of bottles, design pressure, etc.).**
- **Connected to the BOPs and the HCR on the bleed-off line with hydraulic BOP lines (steel and/or non-steel) of working pressure equal to or greater than the manufacturer's design pressure of the accumulator.**
- **All non-steel hydraulic BOP lines located within seven metres of the wellbore must be completely sheathed with adequate fire-resistant sheathing. Adequate fire-resistant sheathing for hydraulic BOP hoses is defined as a hose assembly that can withstand a minimum of five minutes of 700° C flame temperature at maximum working pressure without failure.**
- **All hydraulic BOP line end fittings located within seven metres of the wellbore shall be fire rated to withstand a minimum of five minutes of 700° C flame temperature at maximum working pressure without failure.**
- **A check valve must be installed in the accumulator hydraulic system for all well classes. The check valve must be located between the accumulator charge pumps and the accumulator bottles.**
- **Capable of closing any ram-type BOP within 30 seconds.**
- **Capable of closing any annular-type BOP of a size up to and including 350 mm bore diameter within 60 seconds.**
- **Capable of closing any annular type BOP of a size greater than 350 mm bore diameter within 90 seconds.**
- **Equipped with an accurate gauge to determine accumulator system pressure.**
- **Equipped with readily accessible fittings and gauge to determine the pre-charge pressure of the accumulator bottles.**
- **Readily accessible.**
- **Housed to ensure the system can be protected from the well in the event of an uncontrolled flow.**
- **Adequately heated to maintain the accumulator's effectiveness.**

IRP The accumulator system must be connected to a backup nitrogen system.

IRP The accumulator system shall be located at least 15 m from the wellbore (or must meet jurisdictional requirements).

IRP The vent on the accumulator reservoir shall be installed such that venting takes place outside the building (i.e., side or top of building).

IRP For Class I, II, III and IV wells the accumulator system must be equipped with an automatic pressure-controlled recharge pump capable of recovering the accumulator pressure drop resulting from the function tests of the BOP components and the HCR on the diverter/bleed-off line within five minutes.

IRP The accumulator system shall be recharged by an automatic pressure-controlled pump capable of recovering the pressure drop (resulting from the function test of the BOP components) within 5 minutes

IRP For Class V, VI and critical sour wells the accumulator system must be equipped with two separate automatic pressure-controlled recharge pumps. The primary pump must be capable of recovering the accumulator pressure drop resulting from the function test of the BOP components and the HCR on the bleed-off line within five minutes. The secondary pump must be capable of recovering the accumulator pressure drop resulting from opening the HCR and closing the annular preventer on drill pipe within five minutes.

21.2.8.2 Additional BOP Equipment

IRP If additional BOP equipment has been installed and is in use, there must be sufficient usable hydraulic fluid available to close the additional BOP components and meet the requirements of 21.2.8.1 Accumulator Systems.

IRP All additional BOP equipment that is not in service must be locked out, have the control handles removed or have the lines disconnected.

21.2.8.3 Backup Nitrogen Systems

IRP For Class I wells the backup N_2 system must be capable of providing N_2 of sufficient volume and pressure to

- **open the HCR on the diverter line,**
- **the annular preventer on the drill pipe/coiled tubing and**
- **retain a minimum pressure of 8,400 kPa on the backup N_2 system.**

IRP For Class II, III and IV wells the backup N_2 system must be capable of providing N_2 of sufficient volume and pressure to

- **open the HCR on the bleed-off line,**
- **close the annular preventer on the drill pipe/coiled tubing,**
- **close one ram preventer and**
- **retain a minimum pressure of 8,400 kPa on the backup N_2 system.**

Note: See AER Directive 36: Drilling Blowout Prevention Requirements and Procedures section 6.2 if additional BOP equipment has been installed and is in use.

IRP For Class V and VI wells the backup N_2 system must be capable of providing N_2 of sufficient volume and pressure to

- **open the HCR on the bleed-off line,**
- **close the annular preventer on the drill pipe/coiled tubing,**
- **close two ram preventers and**
- **retain a minimum pressure of 8,400 kPa on the backup N_2 system.**

Note: The backup N_2 system must also provide sufficient volume and pressure to shear the coiled tubing and retain a minimum pressure of 8,400 kPa on the backup N_2 system or the minimum pressure required to shear the coiled tubing, whichever is greater. If the existing backup N_2 system cannot meet these requirements because of the closing volume requirements of the blind shear ram, the backup N_2 system's capacity and/or pressure must be increased or a separate backup N_2 system must be installed. It is acceptable to supplement the existing backup N_2 system with an N_2 booster. This may be the same N_2 booster system that supplements the accumulator.

IRP For critical sour wells the backup N_2 system must be capable of providing N_2 of sufficient volume and pressure to

- **open the HCR on the bleed-off line,**
- **close the annular preventer on the drill pipe/coiled tubing,**
- **close, open and close one ram preventer and,**
- **if SHEAR/BLIND rams are installed, provide sufficient volume and pressure to shear the drill pipe/coiled tubing and retain a minimum pressure of 8,400 kPa on the backup N_2 system or the minimum pressure required to shear the drill pipe/coiled tubing, whichever is greater.**

Note: If the existing backup N_2 system cannot meet these requirements because of the addition of the BLIND/SHEAR rams, the backup N_2 system's capacity and/or pressure must be increased or a separate backup N_2 system must be installed. It is acceptable to supplement the existing backup N_2 system with an N_2 booster. This may be the same N_2 booster system that supplements the accumulator.

IRP The backup N_2 system must be connected so that it will operate the BOPs and HCR on the bleed-off line (as described above) and not allow the N_2 to discharge into the accumulator reservoir or the accumulator bottles (see AER Directive 36: Drilling and Blowout Prevention Requirements and Procedures Appendix 3).

IRP When the backup N_2 system is tied in downstream of an accumulator regulator valve or valves, isolation valves are required to prevent venting of N_2 through the regulator into the accumulator reservoir tank.

IRP The backup N_2 system must be as follows:

- **Equipped with a gauge or have a gauge readily available for installation to determine the backup N_2 pressure.**
- **Readily accessible.**
- **Housed to ensure that the system can be protected from the well in the event of an uncontrolled flow,**
- **Adequately heated to maintain the backup N_2 system effectiveness.**
- **Located at least 15 m from the wellbore.**

21.2.8.4 BOP Operating Controls

IRP The accumulator system must include a set of operating controls that are readily accessible from the driller's position on the rig floor or on control cab and a set of remote operating controls (remote position) for each BOP and the HCR on the diverter/bleed-off line.

21.2.8.5 BOP Unit/Floor Controls

IRP Each BOP component and the HCR in the diverter/bleed-off line must have a separate control located near the driller's position.

IRP The BOP unit/floor operating controls must be as follows:

- **Capable of opening and closing each BOP component and the HCR in the diverter/bleed-off line.**
- **Properly installed, readily accessible, correctly identified and show function operations (i.e., open and close.**
- **Equipped with an accurate gauge indicating the accumulator system pressure.**

21.2.8.6 BOP Remote Operating Controls

IRP Each BOP component and the HCR in the diverter/bleed-off line must have a separate control located at the remote position (typically located at the accumulator).

IRP The BOP remote operating controls must be as follows:

- **Capable of opening and closing each BOP component and the HCR in the diverter/bleed-off line.**
- **Properly installed, correctly identified and show function operations (i.e., open and close).**
- **Readily accessible and be equipped with an accurate gauge to determine the accumulator system pressure.**
- **Located a minimum of 15 m from the well.**
- **Readily accessible and housed to ensure that the remote controls can be protected from the well in the event of an uncontrolled flow.**
- **Adequately heated.**

21.2.8.7 Master Hydraulic Control Manifold Location

The master hydraulic control manifold contains all of the four-way valves and regulators that control the open and close functions of the BOPs and the HCR on the diverter/bleed-off line. The four-way valve directs accumulator hydraulic fluid under pressure to the BOPs.

IRP For critical sour wells the master hydraulic control manifold must be located at the remote position.

IRP For Class I, II, III, IV, V and VI wells (non-critical) the master hydraulic control manifold should be located at the remote position (typically located at the accumulator).

21.3 Pipe Specifications

The requirements in this section reflect the information and data currently available on coiled tubing pipe. It is recognized that ongoing research and testing may result in information that augments or supersedes what is contained in this document. Should such data show that the limitations contained herein are invalid, it is permissible to apply revised limitations provided that a comprehensive body of data exists to support the change. Comprehensive in this case would require testing of the material in sour conditions to identify fatigue limits and the effects of damage caused by the sour environment (e.g., hydrogen induced cracking, sulphide stress corrosion, stress corrosion cracking, etc.). Sufficient testing would need to be carried out to provide a statistically meaningful result.

21.3.1 Grades

Coiled tubing is categorized by its specified minimum yield strength (SMYS). Table 15 summarizes a number of tube grades with their associated mechanical properties.

IRP Actual yield strength and actual ultimate tensile strength for coiled tubing pipe shall be as per Table 17.

Table 15. Coiled Tubing Grades and Mechanical Properties

Grade	SMYS (psi)	Actual Yield Strength (psi)	Actual Ultimate Tensile Strength (psi)
CT-70	70,000	70,000 – 80,000	≥ 80,000
CT-80	80,000	80,000 – 90,000	≥ 88,000
CT-90	90,000	≥ 90,000	≥ 97,000
CT-100	100,000	≥ 100,000	≥ 108,000
CT-110	110,000	≥ 110,000	≥ 115,000

21.3.2 Evaluating Suitability

IRP A computer-based coiled tubing simulator or other documented calculation methods should be used to evaluate the suitability of coiled tubing strings for Well Servicing Category 0, 1A, 1B and 2 operations.

IRP A computer-based coiled tubing simulator or other documented calculation methods shall be used to evaluate the suitability of coiled tubing strings for the Well Servicing Category 3, 4, 5 and Critical Sour operations.

IRP The evaluation process shall determine the outside diameter (OD), wall thickness (taper) and material yield strength of the coiled tubing strings required for the proposed operation.

IRP All critical sour wells shall have the evaluation performed and documented.

21.3.3 Assessing Mechanical Strength

IRP The mechanical strength of the coiled tubing string shall be sufficient to resist all applied forces and pressures with a specified margin of safety.

The margin of safety is typically 80% of yield.

The von Mises equivalent (VME) stress, collapse resistance and burst resistance should be calculated using the actual tubing dimensions (if known) and the specified minimum yield strength. Otherwise, the calculation of these parameters should use the following values:

- Specified OD
- Specified minimum wall thickness
- Three percent ovality

Equation 3. Three Percent Ovality

$$0.03 = \frac{2 \times (OD_{max} - OD_{min})}{OD_{max} + OD_{min}}$$

21.3.3.1 Maximum VME Stress

IRP The maximum VME stress in the tubing during the operation should be less than 80% of the specified minimum material yield strength in the coiled tubing string.

21.3.3.2 Collapse Resistance

IRP The calculated collapse resistance of the tubing at the maximum expected tension should be greater than 125% of the maximum expected collapse pressure.

IRP Collapse resistance should assume zero coiled tubing internal pressure and the greater of the measured maximum ovality or three percent ovality.

21.3.3.3 Overpull at the Maximum Depth Planned

IRP Overpull at the maximum depth planned for the coiled tubing operation should be the greater of

- 2,224 daN (5,000 lb) or
- 125% of the tensile force required at the end of the coiled tubing string for the service or
- 125% of the tension required to operate a disconnect (if equipped).

21.3.3.4 Burst Resistance

IRP The calculated burst resistance of the tubing should be greater than 125% of the maximum expected pump pressure.

IRP Burst resistance shall assume zero pressure outside the coiled tubing.

21.3.3.5 Maximum Accumulated Fatigue

IRP At the conclusion of the planned coiled tubing operation, the maximum accumulated fatigue in any section of the coiled tubing string should not exceed the limits documented in 21.3.11 String-Life Management System.

21.3.3.6 Coiled Tubing Geometry Limits

IRP A coiled tubing string should no longer be considered suitable for well intervention operations if any of the following applies to any section of the string:

- The wall thickness is less than 90% of the specified wall thickness.
- The tubing has ballooned more than 5% (i.e., measured OD > 1.05 x specified OD).
- The annular clearance between the minimum ID of the stripper bushing and the OD of the coiled tubing is less than 0.508 mm (0.020 inch). Bushing may be changed out to provide necessary clearance.
- The ovality is more than 5%.

21.3.4 String Properties

21.3.4.1 Chemical Composition

21.3.4.1.1 Non-Sour

IRP The chemical composition of coiled tubing material for non-sour service should meet the manufacturer's product specifications.

21.3.4.1.2 Sour

IRP The chemical composition of coiled tubing material for sour service should meet the product specifications listed in the Table 16.

Table 16. Chemical Composition Limits for Sour Service Coiled Tubing

Element	Minimum (wt %)	Maximum (wt %)
Carbon	0.05	0.16
Chromium	0.45	0.70
Copper	N/A	0.40
Manganese	0.50	1.00
Molybdenum	N/A	0.23
Nickel	N/A	0.30
Phosphorous	N/A	0.025
Silicon	0.30	0.50
Sulphur	N/A	0.005

21.3.4.2 Mechanical Properties

21.3.4.2.1 Non-Sour

IRP The full-body material mechanical properties of coiled tubing strings for non-sour service should meet the coiled tubing manufacturer's product specifications.

21.3.4.2.2 Sour

IRP Coiled tubing used in sour service shall meet the following minimum requirements unless otherwise demonstrated fit-for-purpose:

Note: These requirements are based on the requirements in ANSI/NACE Standard MR0175/ISO 15156 and are interpreted for the specific characteristics of coiled tubing.

- **Maximum hardness not greater than 22 HRC (or equivalent hardness scales).**
- **The maximum permissible hardness not to be exceeded at any point in the as-manufactured sour service coiled tubing string.**
- **Steel coils used to manufacture coiled tubing are to be produced by the hot-rolling process only.**
- **The longitudinal weld seam is to be annealed after welding.**
- **The tube body is to be stress-relieved after all tube manufacturing cold working.**

IRP Coiled tubing used in sour service should meet the following minimum requirements:

- Microhardness is to be measured by the coiled tubing manufacturer from tube samples taken from the beginning and end of each string of tubing.
- Microhardness tests are to be performed in the as-milled (non-spooled) condition.
- A minimum of nine microhardness measurements is to be made on each sample as follows:
  - Three measurements on the longitudinal weld seam.
  - Three measurements in the longitudinal weld seam heat-affected zone (HAZ).
  - Three measurements in base metal.

21.3.4.3 **Tensile Properties**

IRP Actual yield strength and tensile strength shall be measured by the coiled tubing manufacturer from tube samples taken from the beginning and end of the string of tubing.

IRP Tensile tests should be performed in the as-milled (non-spooled) condition and on full-body tube samples.

If this is not possible on large-diameter and heavy-wall thickness samples, a reduced section (dogbone) sample is permissible. Tensile tests based on strip tensile (dogbone) specimens should be based on one specimen from each of the four quadrants of the coiled tubing specimen and averaged.

IRP Tests shall be performed as per ASTM A-370 and ASTM E8/E8M.

IRP Yield strength should be determined by the 0.2% offset method. For tensile tests on used tubing the 1% pre-strain and offset method should be used.

IRP Yield strength for new coiled tubing strings shall be determined by the 0.2% offset method.

For used coiled tubing strings the 0.2% offset method can give unrealistically low values due to the influence of residual stresses on the stress-strain curve.

IRP The 1% pre-strain and offset method should be used for tensile tests on used coiled tubing.

21.3.4.4 Micro-Hardness Tests

IRP 500 gram (or equivalent) micro-hardness tests of sections from full-tube specimens shall be performed as per ASTM E384 for at least three points in each of the following zones:

- Seam weld
- Seam-annealed area
- Base metal

IRP All hardness conversions from one scale to another shall be performed as per ASTM E140.

21.3.4.5 Flare and Flattening Tests

IRP Flare and flattening tests shall be performed on full-tube as per the more stringent of either of ASTM A450/450M (at minimum) or the coiled tubing manufacturer's documented specification requirements.

21.3.4.6 Hardness of Welds

IRP Hardness of welds in coiled tubing strings shall be as per Table 17.

Table 17. Hardness of Welds

Weld Type	Hardness
Bias Welds	Rockwell hardness (as per ASTM E18) in both the weld and HAZ not to exceed the maximum hardness specified for the coiled tubing string.
Tube-to-Tube Butt Welds	Rockwell hardness (as per ASTM E18) for at least four equally spaced points around the weld circumference in both the weld and HAZ not to exceed that of the maximum specified hardness of the adjacent parent base metal.
Longitudinal Welds	Rockwell hardness (as per ASTM E18) in both the weld and HAZ not to exceed the maximum specified hardness for the adjacent parent base metal.

21.3.5 Welding Coiled Tubing Strings

21.3.5.1 Prohibitions

IRP Unless there is prior approval from the customer, a coiled tubing string containing a butt weld shall not be used for any sour well.

IRP A coiled tubing string containing a butt weld shall not be used for critical sour service.

Flag welds are welds intended to repair only the tubing surface or to mark the surface.

IRP Coiled tubing strings shall not contain any flag welds.

21.3.5.2 Records

IRP Records of all tube-to-tube butt welds should be maintained for the life of the coiled tubing string.

IRP The welding service shall maintain a record (i.e., weld log) for each weld documenting the procedure used and the identification of the welder(s) who performed the weld.

21.3.5.3 Welded Tubing Connection at the Coiled Tubing Reel

IRP If the tubing connection to the coiled tubing reel plumbing is a welded fitting, the weld shall conform to a qualified WPS performed by a welder in accordance with the welder qualifications and procedures specified above.

IRP Non-destructive examination (NDE) inspections shall be as follows:

- **Performed only after the weld cools to ambient temperature.**
- **Show no relevant indications regardless of size (as per ASNT-SNT-TC-1A)**
- **Unacceptable welds are to be cut out and re-welded.**

IRP All welds on tubing connections shall successfully pass either

- **a wet fluorescent magnetic particle inspection (MT) as per ASTM E709 or**
- **a liquid penetrant inspection (PT) as per ASTM E165/165M.**

21.3.5.4 Welder Qualifications

For welder qualification information see 21.1.3.4 Welder Qualifications.

21.3.6 Non-Destructive Examinations

Additional recommended and best practices for Non-Destructive Examinations (NDE) of coiled tubing strings are summarized in Appendix B.

21.3.6.1 NDE of Coiled Tubing Strings

IRP An inspector certified to ASNT Level III for the applicable discipline shall approve all NDE and approvals shall be in accordance with documented NDE procedures.

IRP The approved NDE procedures should be available to the purchaser before the NDE is performed.

IRP If requested, the NDE service shall provide documentation for each NDE procedure that includes the following:

- **A description of the test parameters.**
- **The procedure number and revision level.**
- **A description of the acceptance criteria.**
- **The Level III inspector's approval signature.**

IRP All NDE should be performed by a technician/inspector certified, at a minimum, to ASNT Level II inspector status in the applicable inspection discipline and inspections should be in accordance with the latest edition of ASNT SNT-TC-1A or comparable customer-accepted standard.

IRP Documentation should be available to confirm calibration is current.

21.3.6.2 Full-Length NDE of Coiled Tubing Strings

IRP For new coiled tubing strings, the manufacturer shall perform automated NDE on the full length of the entire body of the coiled tubing string and the weld line for material discontinuities during manufacture.

IRP When NDE is requested on the full length of the entire body of a used coiled tubing string it should be completed after a satisfactory hydrostatic test (as per 21.3.8 Hydrostatic Proof-Testing of Coiled Tubing Strings) and before mobilizing the string for the next service operation.

IRP For intervention in all critical sour wells, an assessment shall be carried out to determine whether a full length NDE inspection of used coiled tubing strings is required. This should include, but not be limited to, operation complexity, well parameters, environmental concerns and previous history of the string.

21.3.6.3 NDE of Bias or Butt Welds in Coiled Tubing Strings

IRP NDE of bias or butt welds in coiled tubing strings shall be as per Tables 18 and 19 and as follows:

- **Rejected welds shall be completely removed (cut out) and re-welded. Removing a flaw from a weld by grinding and filling in or overlaying the flaw is not acceptable.**
- **All bias welds shall be 100% volumetrically inspected by radiographic testing (RT).**
- **All NDE inspections of bias or butt welds shall be performed with the weld at ambient (room) temperature.**

Table 18. NDE of Bias or Butt Welds in Coiled Tubing Strings – Well Servicing

Weld Inspections	Well Servicing Pressure Category							
	0	1A	1B	2	3	4	5	Critical Sour
All welds **should** pass required inspections		Y	Y					
All welds **shall** pass required inspections				Y	Y	Y	Y	Y
All butt welds 100% volumetrically inspected by RT or ultrasonic shear wave testing (UT) with additional liquid penetrant testing (PT) for surface defects.				Y	Y	Y	Y	Not Permitted

Table 19. NDE of Bias or Butt Welds in Coiled Tubing Strings – Drilling

Weld Inspections	Drilling Class						
	I	II	III	IV	V	VI	Critical Sour
All welds **should** pass required inspections	Y	Y					
All welds **shall** pass required inspections			Y	Y	Y	Y	Y
All butt welds 100% volumetrically inspected by RT or ultrasonic shear wave testing (UT) with additional liquid penetrant testing (PT) for surface defects.			Y	Y	Y	Y	Not Permitted

21.3.7 Automated Dimensional Inspections

The purpose of an Automated Dimensional Inspection (ADI) of a coiled tubing string is to determine if the tubing has any dimensional abnormality that would be detrimental to its performance during the intended service (i.e., any deviation from the intended cross-section geometry of the tubing). If an ADI of a coiled tubing string is conducted it should meet the requirements listed below.

IRP ADI of a coiled tubing string should be performed to a written procedure.

IRP The ADI equipment should meet the following criteria:

- Capable of creating a permanent electronic data file for each job. The data should be in a format that can be read with commonly available software.
- Include an electronic depth counter that
  - is capable of measuring the full length of the coiled tubing string,
  - has measurement resolution of ± 30 mm (0.1 ft.) or better and

  - has a tubing length accuracy of ± 0.5%.

- Calibrated to appropriate standards prior to and immediately following the inspection.
- Adjusted to produce optimum signal strength when the reference standard is scanned by the inspection unit in a manner simulating the actual inspection of the coiled tubing string.
- If capable of alerting the operator or marking the location on the coiled tubing for a dimension exceeding a specified limit, the limit(s) should be set according to measurement accuracy.
- The scanning rate of the inspection equipment and the running speed of the coiled tubing through the inspection equipment should be adjusted to provide multiple signals from a given inspection location on the tubing.

IRP The minimum acceptable outputs from automated measurements shall be as follows for each measurement location:

- **Maximum OD (measured) ± .25 mm (0.01 in.)**
- **Minimum OD (measured) ± .25 mm (0.01 in.)**
- **Average OD (calculated)**
- **Ovality (calculated)**

IRP The minimum acceptable output from automated wall thickness measurements is average wall thickness ± 0.005 in (.13 mm) at each measurement location.

IRP Measurement locations should be as follows:

- The OD and wall thickness are to be measured on at least three radials equally spaced around the tubing circumference.
- All dimensional measurements are to be made at regularly spaced axial locations along the string.
- The maximum axial spacing between measurement locations is 1.52 m (5 ft.).

IRP Dimensional inspection reports should be completed by the technician who performed the inspection. The report should include, at minimum, the following:

- The complete results of all ADI performed on a coiled tubing string.
- The axis of plots and headings for tabular data clearly identified and labelled with the corresponding units.
- Serial number or inventory control number of the coiled tubing string.
- Nominal OD, length, specified wall thickness and material of the coiled tubing string.

- ADI methods used.
- Details about ADI equipment including serial numbers of all calibration standards and the last date of their verification.
- ADI procedures followed including reference number and revision level or date.
- Detailed description of the reference standards used and the detection threshold selected for ADI of the coiled tubing string.
- Output from the inspection equipment for scans of the reference standards.
- Results from ADI of the coiled tubing string with the location of each indication exceeding the pre-set limits clearly identified.
- Disposition of each indication.
- Printed name and signature of the technician performing the inspection and the date of the inspection.

21.3.8 Hydrostatic Proof-Testing of Coiled Tubing Strings

This section pertains to hydrostatic proof-testing of new coiled tubing strings, strings in storage or strings being tested (i.e., strings not at the wellsite).

IRP All coiled tubing strings shall be hydrostatically tested by the coiled tubing manufacturer before shipment and subsequently as required by the end user (service company).

IRP All butt welds should have an initial hydrostatic test before operations begin.

21.3.8.1 Plumbing or Piping System

IRP The piping from the pressure source to the coiled tubing string shall be rated at a working pressure that exceeds the required hydrostatic test pressure.

21.3.8.2 Hydrostatic Test Pressure

IRP The required hydrostatic test pressure for new coiled tubing strings shall be, at minimum, as per the equation below.

Equation 4. Hydrostatic Test Pressure

$$P_{HT} = \frac{1.60 \times \delta_{Y_{min}} \times t_{min}}{OD}$$

Where:

- OD = specified CT outer diameter
- Y_{min} = specified minimum yield strength of the material in the CT string
- t_{min} = specified thickness of the thinnest wall section in the CT string minus 0.127 mm (0.005 inches)

IRP Hydrostatic testing pressures exceeding 103 MPa shall be previously agreed upon by all parties involved.

21.3.8.3 Test Medium/Fluids

IRP The pressurizing medium for all tests should be water or a water/antifreeze mixture having pH greater than seven and less than nine.

21.3.8.4 Pressure-Holding Periods

IRP Each pressure test should include a pressure-holding period of a minimum of 15 minutes.

IRP The timing of the pressure-holding period should not start until

- the test pressure has been reached and stabilized,
- the coiled tubing string and the pressure monitoring gauge/chart recorder have been isolated from the pressure source and
- the external surfaces have been thoroughly dried to make any leaks visible.

21.3.8.5 Acceptance Criteria

IRP The coiled tubing string shall show no visible leaks under the test pressure and any pressure drops evident on the pressure recording device during a hold period shall be less than three percent.

21.3.8.6 Pressure Measurement and Recording

IRP Pressure measurement and recording should be as follows:

- All pressure testing is to be performed with calibrated pressure gauges/transducers that have an accuracy of 0.5% of full scale and recorded on a calibrated chart.
- Pressure gauges and charts are to be chosen such that the test pressures fall between 25% and 75% of the full scale of the instrument.

- Charts are to be of sufficient scale to clearly show the tests.
- The recording device clock (time base) is to be set to clearly show the measured test line for each test and provide evidence that the chart line was not dropping or losing more pressure than allowed.
- Pressure test chart records are to be provided with the coiled tubing string's records.
- Each pressure test chart is to include the following documentation:
    - The coiled tubing string's description
    - The coiled tubing string's serial numbers
    - Test pressure
    - Test hold durations
    - Recording device and pressure sensor/transducer serial number
    - Printed name, signature and company affiliation of the designated test operator
    - Date, time and location of test
    - Printed name and signature of customer's representative (if applicable)

21.3.8.7 **Removal of Test Fluid**

IRP The testing contractor should use a documented procedure to displace the test fluid after the hydrostatic test is completed.

IRP After hydrostatic testing, the testing contractor shall ensure that the hydrostatic test fluid, gauge ball, fluid removal pigs and all other debris have been removed completely from the ID of the tubing.

21.3.8.8 **Drifting/Gauging**

IRP All coiled tubing strings shall be drifted/gauged with a metal or nylon ball by the coiled tubing manufacturer before shipment and then again as required for the service or pending operation.

Table 20 shows the acceptable diameter of the drift ball.

> **Note:** The coiled tubing specified in Table 20 is manufactured in imperial units. The metric conversions are provided for information only.

Table 20. Required Drift/Gauge Ball Diameters

Coiled Tubing Specification (Imperial)		Drift Ball		Coiled Tubing Specification (Metric)		Drift Ball
OD (inches)	Wall Thickness (inches)	(inches)		OD (mm)	Wall Thickness (mm)	(mm)
0.750	All	0.375		19.05	All	9.525
1.000	All	0.563		25.4	All	14.30
1.250	All	0.625		31.75	All	15.875
1.500	t ≤ 0.175	1.000		38.10	t ≤ 4.45	25.40
1.500	t > 0.175	0.750		38.10	t >4.45	19.05
1.750	t ≤ 0.145	1.313		44.45	t ≤ 3.68	33.35
1.750	t > 0.145	1.000		44.45	t > 3.68	25.40
2.000	t ≤ 0.175	1.500		50.80	t ≤ 4.45	38.10
2.000	t > 0.175	1.313		50.80	t > 4.45	33.35
2.375	All	1.750		60.32	All	44.45
2.625	All	2.000		66.75	All	50.80
2.875	All	2.250		73.02	All	57.15
3.250	All	2.625		82.55	All	66.75
3.500	All	2.875		88.90	All	73.02

21.3.9 Coiled Tubing String Quality Management

21.3.9.1 **Manufacturing**

IRP The coiled tubing string manufacturer shall maintain and operate within the framework of a quality management system (QMS) that covers the manufacture of the coiled tubing strings.

21.3.9.1.1 Quality Plan

IRP The coiled tubing string manufacturer shall maintain and operate within the framework of a manufacturing quality plan (MQP) covering all operations, processes and activities performed at the coiled tubing manufacturer's manufacturing facility.

IRP The MQP should cover all the activities required by both the coiled tubing manufacturer's in-house quality inspectors and any inspection points required by the customer.

IRP The MQP should contain the following:

- A list of all major manufacturing, inspection and test activities.
- Procedure references (including revision levels) for each manufacturing, inspection and test activity listed.
- Acceptance criteria (or the procedure reference containing the acceptance criteria) for each inspection and test activity.
- Identification of the documents and records produced during manufacturing, inspection and testing that document the verification results of each activity.

IRP If the customer requires on-site quality control, the following provisions should be made:

- Allowance for the customer (or customer's third party inspector) to monitor and witness the specific inspection and test activities.
- Initiation of an advance notification period during which the coiled tubing manufacturer provides notice to the customer to allow the customer representatives to participate as required in the listed inspection points.

21.3.9.1.2 Traceability

IRP The coiled tubing string manufacturer shall maintain traceability on all coiled tubing strings during manufacturing.

IRP This traceability shall be maintained to the original heats of steel strip used to produce the coiled tubing string and the associated certified material test reports (CMTR) providing acceptable test results for mechanical and chemical testing performed on the material.

21.3.9.1.3 Non-Conformance and Request for Exception

IRP The coiled tubing manufacturer should ensure that all non-conforming products are brought into compliance with applicable requirements.

IRP The coiled tubing manufacturer shall not allow non-conformances to be labelled "use-as-is" without first obtaining documented customer acceptance of the request for exemption from the specifications laid out in the IRP.

21.3.9.1.4 Quality Records

IRP The coiled tubing manufacturer shall maintain the following information for each coiled tubing string for a minimum of three years:

- **Coiled tubing manufacturer's name.**
- **Date and location of manufacture.**
- **Manufacturer's serial number or other inventory control number for the string.**
- **Certificate of compliance /statement of conformity to product specifications and MQP.**
- **Total length of the coiled tubing string and length of each wall thickness section.**
- **Master coil and heat numbers for each strip in the string.**
- **Chemical analysis of each strip in the string.**
- **Mechanical properties of each master coil in the string including thickness, yield strength and ultimate tensile strength.**
- **Hardness.**
- **Full body mechanical properties of at least one sample of tube from each end of the milled string, including yield strength and ultimate tensile strength.**
- **Percent elongation in 50.8 mm (two inch) gauge length.**
- **Section micro-hardness for three points each in the seam.**
- **Weld, seam annealed area and base metal.**
- **Results of flare and flattening tests.**
- **Report on full body NDE approved by the NDE technician.**
- **Hydrostatic test data including the properties of the test fluid, maximum and minimum pressures and duration of each holding period.**
- **Chart record of the test.**
- **Drift results and diameter of the drift ball used.**
- **Procedure used to purge the coiled tubing string before storage/shipment.**
- **Procedure and chemicals used to protect the string OD and ID from storage corrosion.**
- **Weld log containing, at minimum, the location of each bias weld and location of each tube-to-tube butt weld (if applicable).**
- **WPS/PQR numbers.**
- **Welder identification.**

- **Report of NDE on each weld signed and dated by Level II NDE technician performing the examination.**

21.3.9.2 Post Production Records

21.3.9.2.1 Traceability

IRP The end user of a coiled tubing string shall ensure traceability is maintained on the coiled tubing string.

IRP This traceability shall be maintained by unique serial number, inventory control number or other appropriate means.

IRP Traceability of coiled tubing strings shall be maintained to the following:

- **Manufacturer's CMTRs**
- **Quality records/data book**
- **End user's inspection and test reports, maintenance records and operating data**

21.3.9.2.2 End Use Documentation/Records

IRP The end user of a coiled tubing string should develop and maintain documentation for each coiled tubing string including the information noted for critical sour well servicing below.

IRP All records should be approved by the person completing the document or record.

IRP For critical sour well servicing, the following shall be developed and maintained:

- **Inspection reports**
  - **Visual**
  - **NDE**
  - **Dimensional**
- **Hydrostatic test reports**
- **Each coiled tubing operation performed with a cross reference to appropriate coiled tubing string life management files**
- **Accumulated fatigue for each segment of the string on computerized managed strings**
- **Exposure to acid and composition of the acid**

- **Steps taken to protect coiled tubing against corrosion before a coiled tubing operation and to neutralize corrosion after the coiled tubing operation**
- **Exposure to H_2S and CO_2**
- **Exposure to abrasive fluids**
- **Fluids pumped for each coiled tubing operation**
- **Purging records**
- **Corrosion protection records**
- **Storage records**

21.3.9.2.3 Velocity String Information for Installation and Removal

IRP The following should be recorded prior to installing a velocity string:

- butt welds in the string
- downhole BHA, nipples or other completion equipment in the string
- fatigue history of the string when installed
- coil info (i.e., OD, length, grade (yield stress of material) and wall thickness)

21.3.10 Maintenance

IRP The end user should use a documented program for maintenance of coiled tubing strings as outlined in the list of tasks in this section.

21.3.10.1 **Cleaning the ID Surface**

IRP The individual coil end user should use due diligence to ensure the coiled tubing string being used is properly cleaned before each operation and tested to suit each pending operation.

21.3.10.1.1 General Procedure

IRP The general procedure for cleaning the ID of a coiled tubing string should include, at minimum, the following:

1. Mechanical cleaning to remove heavy rust and scale (skip this step for coiled tubing strings containing cable).
2. Flushing with clean fresh water.
3. Chemical cleaning to remove light rust and scale.
4. Neutralizing the ID.

21.3.10.1.2 Mechanical Cleaning

IRP The procedure for mechanical cleaning of coiled tubing strings should include, at minimum, the following steps:

1. Select two mechanical coiled tubing cleaning pigs appropriately designed and sized for cleaning the coiled tubing ID.

   Note: Common wiper darts and foam plugs are not acceptable.

2. Insert the two cleaning pigs into the coiled tubing string separated by approximately the length of one wrap around the reel.
3. Pump both cleaning pigs through the coiled tubing string using clean fresh water or a water/antifreeze mixture. Pump at a flow rate that will ensure turbulent flow.

21.3.10.1.3 Flushing

IRP Flushing procedures shall be as follows:

- **Continue to pump clean fresh water or a water/antifreeze mixture after the trailing pig exits the coiled tubing string.**
- **The volume should be the greater of one full string volume or until the discharge is suitably clear, whichever is greater.**
- **Pump at a flow rate that will ensure turbulent flow.**

21.3.10.1.4 Chemical Cleaning

IRP The procedures for chemical cleaning of coiled tubing strings should include the following:

- Use hydrochloric acid (HCl) or other chemical designed to chemically clean the ID of the string.
- Use a volume of chemical suitable for the inner surface area of the specific coiled tubing string..
- After pumping the cleaner through switch to clean fresh water or water/antifreeze mixture and continue pumping until the pH of the discharge is greater than six.

21.3.10.1.5 Neutralizing the Surface pH

IRP After chemically cleaning with acid the tubing surface shall be neutralized to eliminate any low pH spots that can lead to corrosion failures (pitting).

IRP The procedures for neutralizing the tubing surface pH should include the following:

- Use a neutralizer with a pH greater than nine and less than eleven.
- Use an adequate volume of neutralizer to achieve a pH of greater than six in the discharge.
- After pumping the neutralizer through the coiled tubing switch to clean fresh water or a water/antifreeze mixture and continue pumping until the discharge has pH greater than seven and less than nine.

21.3.10.1.6 Preparation for Storage

IRP Cleaned coiled tubing string that will not be used within 48 hours shall have an internal and external corrosion inhibitor applied prior to storing.

21.3.10.2 Corrosion Protection

IRP If external corrosion protection is required, the coiled tubing manufacturer or end user shall uniformly apply a full-body coating of corrosion inhibitor to the exterior of the coiled tubing string.

IRP If internal corrosion protection is required the following shall apply:

- **The volume of the inhibitor shall be adequate to coat the entire surface of the coiled tubing string based on the chemical manufacturer's recommendations.**
- **After the hydrostatic test new strings or at the end of a wellsite treatment, the coiled tubing manufacturer or end user shall trap a volume of inhibitor between two foam pigs and then pump the combination around the tubing with nitrogen (the objective is to apply a uniform coating to the interior surface of the tubing). See Figure 23.**
- **The nitrogen flow rate shall be as low as practical to maximize the contact between the inhibitor and the ID surface. The manufacturer shall select foam plugs that fit tightly inside the ID of the tubing.**

Figure 23. Pig and Inhibitor Placement

IRP If required by the coiled tubing string purchase specification, the coiled tubing manufacturer should pressurize the coiled tubing string with nitrogen after internal corrosion inhibitor coating.

Note: The positive nitrogen pressure will prevent evaporation of the inhibitor, minimize the oxygen level inside the coiled tubing string and prevent moisture and other contaminants from entering the string. Oxygen is a primary contributor to internal corrosion

21.3.10.3 Managing Slack for Internal Electric Cable

IRP If a length of tubing is to be removed from a coiled tubing string containing electrical cable, the end user should ensure the total length of electric cable inside the coiled tubing string is at least 0.5 to 1.0% greater than the remaining length of the coiled tubing.

IRP If electrical cable is protruding from the end of the coiled tubing string before a coiled tubing operation, the end user should verify that the length of cable inside the coiled tubing string is at least one percent greater than length of the coiled tubing string before cutting back the excess. Otherwise, the end user should attempt to pump the excess cable into the coiled tubing string to achieve at least one percent excess length.

21.3.11String-Life Management System

21.3.11.1 Well Servicing Category 1A and 1B/Drilling Class I and II

IRP The coiled tubing string-life management system for Well Servicing Class I and Drilling Class I and II wells should be adequate to prevent a string failure of the coiled tubing string due to accumulated low-cycle fatigue.

21.3.11.2 All Other Well Servicing Categories and Drilling Classes

IRP The coiled tubing string-life management system for all other Well Servicing and Drilling classes shall be a computer-based system for tracking the cumulative low-cycle fatigue in each segment of a coiled tubing string.

IRP The maximum segment length for tracking the cumulative low-cycle fatigue in each segment of a coiled tubing string shall be 15.2 m (50 ft.).

The fatigue limits outlined below apply to computer-based systems only.

21.3.11.2.1 Fatigue Limits for Base Tubing

IRP A coiled tubing string should be removed from service if the accumulated fatigue in the base tubing of any section of the string exceeds the applicable percentage limit of its predicted working life as per Table 21.

Table 21. Fatigue Limits for Base Tubing

Service Type	Fatigue Limit
Non-sour	100%
Sour with continuous application of H_2S inhibitor	40%
Sour without continuous application of H_2S inhibitor	15%

Note: It is recognized that work is ongoing to develop more accurate fatigue limits for various coiled tubing grades, both with and without inhibitor protection, in sour environments. As additional data become available the fatigue limits applied may change.

21.3.11.2.2 Fatigue Limits for Welds

IRP A coiled tubing string should be removed from service if the accumulated fatigue in a weld exceeds the applicable percentage limit of the predicted working life for the adjacent base metal as per Table 22.

Table 22. Fatigue Limits for Welds

Weld Type	Fatigue Limit (% of Predicted Working Life of Adjacent Metal)	Effective Sour Limit[12]	
		With Inhibitor	Without Inhibitor
Bias weld with uniform wall thickness	90%	36%	13%
Bias weld with different wall thickness	80%	32%	12%
Tube-to-tube butt weld with uniform wall thickness – orbital	45%	18%	7%
Tube-to-tube butt weld with uniform wall thickness – manual	35%	14%	5%
Tube-to-tube butt weld with different wall thickness – orbital	25%	10%	4%
Tube-to-tube butt weld with different wall thickness – manual	15%	6%	2%

Not Recommended

Note: Welds with fatigue limits falling in the shaded area are not recommended.

[12] The effective sour limit column applies the derating factors from Table 10 to the fatigue limits in Table 24 to reflect the degradation in sour conditions.

21.3.11.2.3 Fatigue Limits for Mechanical Splices

IRP The end user of a mechanical splice (tube-to-tube connector) for a coiled tubing string shall be responsible for determining the fatigue limit for the mechanical splice before the intended service operation.

IRP A mechanical splice should be retired from service before its accumulated fatigue reaches this predetermined limit.

21.3.12 Protecting Against H_2S Damage

IRP The end user should use a documented method to minimize coiled tubing string damage during sour service operations from hydrogen embrittlement (HE), hydrogen induced cracking (HIC) and sulphide stress cracking (SSC).

21.3.12.1 Requirements by Well Category/Drilling Class

IRP The end user should apply an H_2S inhibitor to the exterior of the coiled tubing string for the following:

- Well Servicing Category 2 operations with sour conditions.
- Drilling Class III and IV wells with sour conditions drilled underbalanced.

Note: Addition of an H_2S scavenger to the circulated fluid for these classes is **not** an acceptable alternative to application of an H_2S inhibitor as the section of coiled tubing adjacent to the perforations will be exposed to H_2S before it can be neutralized.

IRP The end user shall apply an H_2S inhibitor to the exterior of the coiled tubing string for the following:

- **Well Servicing Category 3, 4 or 5 with sour conditions or any Critical Sour operations.**
- **Drilling Class V and VI sour conditions wells drilled underbalanced.**

Note: Addition of an H_2S scavenger to the wellbore fluid for these classes is **not** an acceptable substitute for application of an H_2S inhibitor.

21.3.12.2 H_2S Inhibitor Properties

IRP H_2S inhibitors shall be as follows:

- A fit-for-purpose anti-cracking agent. Products that only protect the coiled tubing against surface corrosion are not recommended.
- Compatible with the other fluids used during the operation.

- Compatible with all materials it could contact in the wellbore, pressure control equipment, downhole check valves and BHA components. The end user should be able to demonstrate H_2S inhibitor compatibility before starting the coiled tubing operation.

21.3.12.3 H_2S Inhibitor Application

IRP H_2S inhibitors should be applied by the end user using a documented method for applying the H_2S inhibitor to the exterior of the coiled tubing during the coiled tubing operation.

IRP The end user should be able to demonstrate that the application method effectively coats the entire exterior of the coiled tubing with H_2S inhibitor.

21.3.12.4 H_2S Inhibitor Effectiveness

IRP The end user should be able to demonstrate the effectiveness of the H_2S inhibitor and its application method for protecting the coiled tubing string against damage from HE, HIC and SSC in the expected wellbore conditions during the coiled tubing operation.

IRP Inhibitor qualification testing should measure the following:

- Ductility of the treated coiled tubing material exposed to the sour conditions.
- Rate of hydrogen diffusion through the treated coiled tubing material.
- SSC resistance of the treated coiled tubing material.
- HIC resistance of the treated coiled tubing material.
- Low cycle fatigue life with strain at least 2% and strain rate at least 1.0 sec^{-1} after exposure to the wellbore conditions.

21.4 Fluids and Circulating Systems

The following IRPs and guidelines address many aspects of fluids and circulating systems:

- IRP 1: Critical Sour Drilling
- IRP 4: Well Testing and Fluid Handling
- IRP 8: Pumping of Flammable Fluids
- IRP 14: Non-Water Based Drilling Fluids
- Enform Fire and Explosion Hazard Management Guideline

Consult these IRPs for recommended practices for fluids and circulating systems for coiled tubing operations.

This fluids and circulating systems section contains additional requirements for critical sour wells for well servicing and underbalanced drilling, over and above the requirements of IRPs 1, 4, 8 and 14. These are listed to ensure consistency of standards with IRP 2: Completing and Servicing Critical Sour Wells and IRP 6: Critical Sour Underbalanced Drilling so the requirements for coiled tubing units, service rigs and drilling rigs are in agreement.

IRP If there appears to be a conflict among these recommendations, the most stringent recommendation shall apply.

For bonding and grounding requirements see 21.1.5.2: General Safety Requirements.

21.4.1 Well Servicing Category Critical Sour Operations

21.4.1.1 Surface Equipment

21.4.1.1.1 Pressure Rating

Consider design working pressure limits of equipment during equipment selection to ensure it is capable of safe operations at the anticipated pressures.

IRP Circulating pumps, manifolds, discharge lines and return lines shall have a working pressure equal to or greater than 1.2 times the shut-in tubing pressure.

21.4.1.1.2 Backup Pumps

A pump failure could lead to uncontrolled flow.

IRP On a well where a hard shut in is not possible during pumping operations, a backup pump with manifold shall be on location to maintain control of the well if the primary fluid pump fails.

IRP On a well that can be shut in, a contingency plan shall be place to bring a backup pump with manifold on site if the primary fluid pump fails.

21.4.1.1.3 Fluid Pump

IRP The fluid pump shall have a discharge rate of sufficient capability (pump rate and worst case pressure) to control the well.

IRP For winter operation the pump, manifold and lines shall be adequately heated to prevent freezing.

21.4.1.1.4 Fluid Storage Tank

IRP The fluid storage tank shall provide for accurate fluid gauging.

IRP For winter operation the tank shall be adequately heated to prevent freezing.

Note: Fluid storage tanks with properly maintained steam coils will prevent freezing and steam contamination of fluid.

IRP If scavenger, inhibitor or other chemicals are required, an adequate and accurate means of mixing into the storage tank or flow stream should be used.

21.4.1.1.5 Closed System Circulation

Sour effluent cannot be emitted to the atmosphere.

IRP Sour effluent shall be directed through temporarily installed separation equipment to closed storage vessels equipped with vapour recovery systems or directed to an existing flowline capable of handling sour-produced fluids.

IRP Fluid-gas separators (rig degassers) shall not be used on open rig tanks.

21.4.1.1.6 Sour Fluid Storage

Sour fluid storage tanks are required for storage of all sour fluids.

IRP Storage tanks containing sour fluids or sour gasified fluids shall be as follows:

- Grounded and bonded.
- Purged before storing sour fluids.

- Have a mechanical gauge for gauging the tank level.
- Equipped with connections for circulating the tank to add scavenger or for unloading.
- Equipped with steam coils during winter operations to prevent fluids from freezing and steam contamination.
- Have a flame arrestor installed on the storage tank vent line at the base of the flare stack.

21.4.1.2 Completion and Workover Fluids

The primary functions of completion or workover fluids are to control formation pressure, transport movable solids and minimize formation damage. Selection of completion and workover fluids is determined based on site-specific operations and well conditions. Completion and workover fluids can range from complex high-density viscosified fluids to fluids such as fresh water, brines or hydrocarbon-based fluids.

IRP Precautions shall be taken to prevent explosion or ignition when using hydrocarbon or flammable fluids (see IRP 8: Pumping Flammable Fluids).

Hydrocarbon use can pose the following risks to well control:

- Reduced warning sign of a kick
- Increases solubility of H_2S
- Slowed reaction time of scavengers.

Injection of hydrocarbon or flammable fluid into an air-filled or partially air-filled well may provide favourable conditions for explosion or fire given a suitable ignition source.

21.4.1.2.1 Dissolved Sulphide

A decrease in pH in a water-based fluid is an indicator that sulphides may be present in the fluid. Sulphides in the pumped fluid can damage the coiled tubing from the inside in the same way sulphides in the wellbore can damage the outside of the tubing.

IRP The presence of dissolved sulphides in the completion or workover fluid shall be determined.

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

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

IRP Dissolved sulphides in the completion fluids shall be monitored by an individual competent in performing the chosen test method.

21.4.1.2.2 Completion Fluid Volume and Storage

IRP All fluid volumes on location shall be monitored and recorded at the following times:

- The start of each crew change
- Before and after filling the hole
- Before and after circulating
- Before and after tripping

IRP The minimum fluid volume on location shall be the volume of fluid required for well control as follows:

- the hole volume plus
- a surface backup volume of 100% of the hole volume factoring in the fact that you can’t get all of the fluid out of the tank (tank bottom).

IRP Before starting an operation there shall be 200% of active hole volume on surface. 100% of active hole volume shall be maintained on surface at all times.

IRP Kill fluid density shall provide a minimum of 1,400 kPa overbalance of the formation pressure.

Completion fluid storage capacity on location may include all appropriate storage vessels.

IRP For winter operations storage tanks shall be adequately heated to prevent freezing.

Storage tanks equipped with properly maintained steam coils will prevent freezing and steam contamination of fluids.

21.4.1.2.3 Handling

IRP Written procedures and fluid specifications for safe handling and mixing of the completion/workover fluid shall be on location.

IRP Transportation of dangerous goods (TDG), workplace hazardous materials information system (WHMIS) and applicable provincial occupational health and safety regulations must be followed.

IRP Safety data sheets (SDSs) shall be current and adhered to on site.

IRP Exposure monitoring and control must be as per the SDS and local jurisdictional regulations.

21.4.2 Critical Sour Underbalanced Drilling Operations

The design of circulating media systems is an integral part of pre-planning and programming for a critical sour underbalanced well.

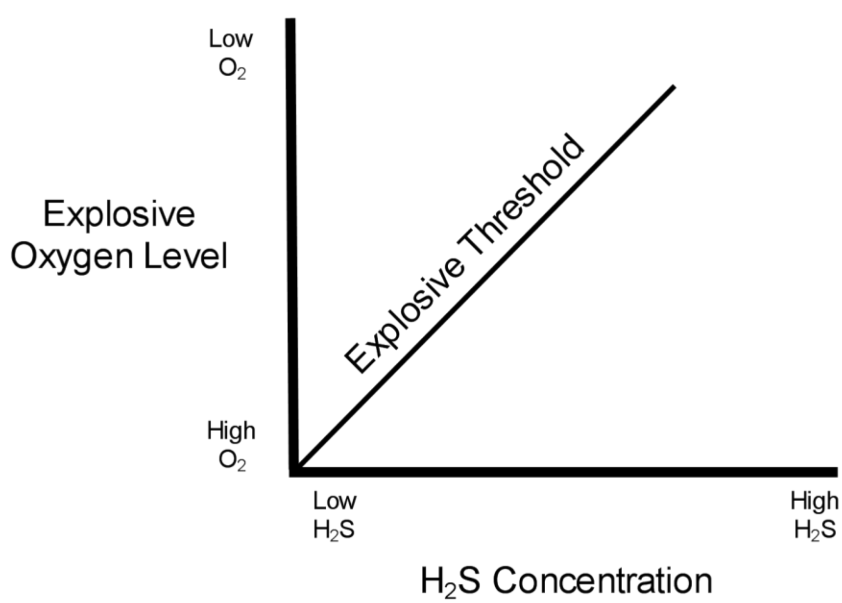
For purposes of this IRP the circulating media includes both injected and produced fluids as well as their mixtures.

21.4.2.1 **Circulating Media Properties**

21.4.2.1.1 Flammability and Explosive Limits

Hydrocarbons, when mixed with appropriate levels of oxygen, result in an explosive condition. Explosive conditions are not present in a closed circulating system where no oxygen is contained in the circulating stream. However, oxygen may be introduced into the circulating stream at specific points (e.g., at the gas injection equipment). As the percentage of oxygen within the circulating stream increases, the mixture's susceptibility to ignition increases. The presence of H_2S reduces the oxygen levels required to create a potentially explosive condition (as depicted in Figure 26 and described in SPE Paper 37067: High Pressure Flammability of Drilling Mud/Condensate/Sour Gas Mixtures in De-oxygenated Air for Use in Underbalanced Drilling).

Figure 26. Impact of O_2 and H_2S Concentrations on Explosive Threshold



IRP Explosive limits shall be established for all circulating media systems that have the potential to introduce oxygen into the circulating stream.

IRP If explosive limits are not clearly defined, systems which have the potential to introduce oxygen to the circulating stream shall not be used.

IRP Explosive limits shall be documented and posted next to the oxygen monitoring system for all circulating streams that contain oxygen.

IRP Steps shall be taken to ensure that these limits are never reached throughout underbalanced drilling operations.

21.4.2.1.2 Hydrates

Hydrates can form in a gas well or a high gas content oil well as it is being drilled underbalanced when the wellbore is exposed to the appropriate pressure and temperature conditions. Hydrates limit the ability to produce fluids, inject fluids and, ultimately, control the well safely.

IRP Measures shall be taken to prevent hydrate formation unless it can be proven that hydrates cannot be formed in the gas stream expected to flow from the well while drilling underbalanced.

These measures include, but are not limited to, the use of surface line heaters and the injection of fluids to appropriately control the freezing point of the circulated/produced fluid stream.

Hydrate plugs are an ice-like crystalline structure made up of water and hydrocarbon gases. Due to the chemical composition of this structure, its freezing point is well above the normal freezing point of fresh water. These plugs can form when a gas/water mixture flows through a pressure drop that causes a localized cooling effect. A solid structure may start building up and, if not controlled, can completely bridge off the flowing area. Pressure drops may occur at various locations within a circulating path such as inside tubulars, across choke manifolds, across flow path diameter changes, BOPs, etc.

IRP If methanol is introduced into the system, consideration shall be given to changes in flammability limits and the potential for a sudden release of the hydrate plug.

21.4.2.1.3 Carrying Capacity

The flow regime of multi-phase circulating streams is typically more complex than for single-phase circulating streams. A proper understanding of cuttings transport in this environment is necessary to ensure adequate hole cleaning while drilling with a multi-phase system. Inadequate hole cleaning could result in the circulation returns path becoming packed off which limits the ability to circulate and results in a potential reduction of well control. Losing the ability to circulate due to cuttings pack-off will also likely result in a stuck coiled tubing string.

A properly designed and implemented underbalanced circulation system will help ensure adequate hole cleaning.

IRP A multi-phase flow simulation of the returning flow stream shall be completed to ensure adequate hole cleaning.

21.4.2.1.4 Separation Qualities

Separation of oil, water, gases and solids contained in the circulating media at surface is necessary during an underbalanced drilling operation. Inadequate separation may result in a variety of problems including inconsistencies in circulating fluid properties that result in flow modelling inaccuracies, loss of accurate injection/production volume measurements and fluid carryover to the flare stack.

IRP Steps shall be taken to ensure that separation of solids, gases and liquids at surface is sufficient such that the ability to effectively circulate liquids downhole is not compromised.

Formation of emulsions may be a concern with specific circulating media/produced fluids combinations. This may result in pumping difficulties which, in extreme cases, could result in plugged suction lines. Fluid density control may also be compromised when emulsions form.

IRP Operational practices such as the use of demulsifiers, line heaters and constant removal of emulsified fluids should be considered where emulsion formation is anticipated to be a problem.

IRP If demulsifiers or other chemicals are introduced into the system, consideration shall be given to changes in flammability limits.

The use of viscosified or hydrocarbon-based fluids in underbalanced drilling operations may result in gas entrainment. Gas entrainment may result in vapour-locking of fluid pumps, lack of fluid density control and recirculation of produced gases. Where the system is open to the atmosphere (e.g., open mud tanks, drill pipe on connections) entrained gas may break out causing hazards to workers.

IRP Areas where the system is open to the atmosphere must be monitored and operations stopped if worker regulatory exposure limits are exceeded.

Refer to Section 6.7 of IRP 6: Critical Sour Underbalanced Drilling for more information on separation systems.

21.4.2.1.5 Compatibility with Other Systems

The presence of acid gases (i.e., H_2S, CO_2), acid fluids, oxygen and electrolytes in the circulating system can result in corrosive conditions. Corrosion of metals or degradation of rubbers, elastomers and seals can lead to failure of components which could result in safety or environmental concerns.

IRP The compatibility of the circulating media, both injected and produced, with other components of the circulating system shall be reviewed to address the potential for corrosion and degradation of the circulating system components both at surface and downhole.

IRP The chemical composition of any additives to be used in the circulating media shall be examined to ensure they do not contain, alone or in combination with produced fluids, constituents that could result in premature failure of elastomers, seals or other well control elements

See 21.6 Elastomeric Seals for detailed requirements for elastomers and information about seals.

IRP If H_2S recirculation is anticipated, operational issues regarding H_2S compatibility with metallic components, elastomers and fluids handling/storage equipment shall be addressed.

Sour fluids may be stripped of H_2S by employing a properly designed scrubber system.

IRP A scrubber system should be used for drilling fluids containing H_2S that are to be reinjected into the wellbore.

21.4.2.2 Kill Fluids

Operational or safety considerations may require the killing of a critical sour well that is being drilled underbalanced.

IRP A minimum of 1.5 hole volumes of kill fluid shall be available for immediate circulation to the wellbore at all times.

IRP The kill fluid shall provide for a minimum 1,500 kPa overbalance when spotted.

IRP Kill fluid system contingency plans shall be in place to manage degradation of the kill fluid (gel strength if weighting material is required), lost circulation issues and the effects of winter operations.

IRP A backup pump with manifold shall be on location to maintain control of the well if the primary fluid pump fails on a well where a hard shut in is not possible during pumping operations.

IRP A contingency plan shall be in place to bring a backup pump with manifold on site if the fluid primary pump fails on a well that can be shut in.

21.4.2.3 Weighting or Lost Circulation Material

IRP If weighting or lost circulation material (LCM) is required to kill the well, consideration should be given to the ability to successfully circulate these materials through the BHA.

Circulating subs above flow restrictions may be necessary.

21.4.2.4 Corrosion and Erosion

See the Glossary for definitions of corrosion and erosion as used in this IRP.

Potential agents for initiating corrosion include carbon dioxide, hydrogen sulphide, chlorides and oxygen. All of these can be introduced into the circulating system during wellbore or surface circulation of the circulating media. Corrosion results in pitting, embrittlement, stress cracking and black sulphide coating. Factors that affect corrosion rates include pressure, temperature and pH.

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.

IRP Steps shall be taken to minimize the corrosive or erosive potential of the circulating media and produced fluids when such conditions exist.

These steps may include the following:

- Minimizing/eliminating oxygen, carbon dioxide, hydrogen sulphide and chlorides in the injection stream.
- Adding scavengers and/or inhibitors into the injection stream.
- The use of corrosive resistant materials.

IRP The effectiveness of corrosion control steps shall be established before starting critical sour underbalanced drilling operations.

21.4.2.5 Monitoring

21.4.2.5.1 H_2S

Recommendations for H_2S monitoring are discussed in IRP 1: Critical Sour Drilling and IRP 2: Completing and Servicing Critical Sour Wells.

IRP H_2S monitoring shall be as per IRP1, IRP2 and applicable Occupational Health and Safety regulations.

21.4.2.5.2 Oxygen

IRP The oxygen content of any injection stream that has the potential to introduce oxygen into the circulating stream shall be monitored to ensure that explosive limits are never reached during critical sour underbalanced drilling operations.

IRP Continuous read-out monitors shall be used and calibration reports shall be available on site.

21.4.2.5.3 Flow Rate

IRP Circulation parameters shall be monitored to ensure that the system capabilities are not exceeded. Parameters that require monitoring include, but are not limited to, the following:

- **Gas and liquid production rates**
- **Injection pressures**
- **Wellhead annular pressure**
- **Bottomhole annular pressure**
- **Surface volumes**

21.4.2.5.4 Corrosion

IRP A corrosion monitoring program shall be in place and be appropriate for the corrosion risks of the fluid being used.

IRP During drilling under corrosive conditions, the circulating media shall be monitored to provide an indication of corrosion and to determine the effectiveness of corrosion control measures being used.

IRP If operating under potentially corrosive conditions, corrosion indicators (i.e., rings, coupons or suitable alternatives) shall be installed at appropriate/practical circulating stream locations (e.g., surface piping, drill pipe, BHA) to measure corrosion rates.

IRP Corrosion indicators shall be regularly inspected to establish corrosion rates.

IRP Consideration should be given to precautionary steps (e.g., regularly tripping to inspect the coiled tubing string/BHA to establish the severity of downhole corrosive conditions) when drilling in an area where the corrosive environment is not thoroughly understood.

Note: Each trip will add fatigue to the coiled tubing string.

21.4.2.5.5 Erosion

IRP Surface equipment exposed to high pressures or high flow velocities shall be inspected using industry accepted practices and on a regular basis to monitor for materials erosion.

21.4.2.6 Fluid Handling

21.4.2.6.1 Handling System

IRP Circulated liquids shall be contained in a closed-loop system unless H_2S levels can be reduced to meet occupational exposure limits (which would then allow the use of open tanks).

21.4.2.6.2 On-Site Storage Capacity

IRP Sufficient storage capacity shall be available to temporarily store produced fluids during drilling operations.

IRP Flush production shall be considered in determining storage requirements. Alternatively, provisions for fluid injection or offsite fluids transport shall be in place if on-site facilities do not have the capacity to handle the necessary volumes.

IRP Consideration should be given to providing excess storage capacity in the event of unforeseen circumstances (e.g., inclement weather conditions) which may compromise proper fluid handling abilities.

IRP Sour fluid volumes stored on location should be minimized for added safety of on-site personnel.

21.4.2.6.3 Transport

IRP Spill contingency plans for storage, loading, unloading and transporting fluids shall be included in the operator's site-specific ERP.

Refer to existing industry documents (e.g., IRP 4: Well Testing and Fluid Handling) and regulatory requirements regarding the transportation of hazardous fluids.

21.4.2.6.4 Waste Treatment/Disposal

IRP A waste management plan for produced liquids and drilled solids shall be developed before starting underbalanced drilling operations.

IRP The waste management plan should consider the volume of solids that will be generated and their residual oil, chloride and H_2S content.

IRP If a third party waste handler will be used for disposal, they should be contacted in advance to determine their sour fluids and sour solids handling capabilities.

21.4.2.7 Equipment

21.4.2.7.1 Emergency Shutdown Valve

IRP The working pressure of the emergency shutdown valve (ESD) components shall be equal to or greater than the anticipated maximum anticipated operating pressure of the well control equipment (MAOP).

IRP The ESD should be installed as close to the BOP stack as possible to minimize the potential of failure between the stack and the ESD.

IRP A valve position indicator should be installed and equipped with a visual and audible alarm system to be actuated when the ESD is in the closed position.

Caution: Closing the ESD with an incompressible fluid under high pressure may cause instantaneous pressure spikes.

21.4.2.7.2 Primary Flowline

IRP The primary flowline installed between the ESD and the choke manifold should be as straight as possible to minimize friction and erosion.

IRP A uniform piping inside diameter should be maintained to minimize turbulence within the flowline.

Butt weld unions and flanges also help to minimize turbulence.

IRP Appropriate ports should be installed for chemical injection.

IRP Consideration should be given to the installation of a secondary flowline connected to the manifold and separator.

21.4.2.7.2.1 Pressure Rating

IRP The primary flowline downstream of the ESD to the first control valve must have a working pressure rating equal to or greater than the anticipated SITHP.

21.4.2.7.2.2 Internal Diameters

IRP The primary flowline components between the flow diverter and the separator, with the exception of the choke manifold, shall not have an internal diameter of diminishing size.

IRP The ID of the piping downstream of the choke manifold should be larger than the ID of the piping upstream.

21.4.2.7.2.3 Erosion Calculations

IRP Erosion calculations shall be performed to determine proper flowline sizing, taking into account abrasion, corrosion (cushion tees), slug flow (line jacking), liquid/gas velocities and solids loading.

21.4.2.7.2.4 Inspection and Certification

IRP Third party pre-job inspections shall include a thickness inspection and a hydrostatic pressure test.

IRP The pressure test shall be equal to 1.5 times the working pressure rating of the piping.

IRP Mill documentation of the piping metallurgy shall be available at the wellsite.

21.4.2.7.2.5 Wellsite Testing and Certification

IRP The flowline downstream of the BOP stack to the first control valve shall be

- **hydrostatically pressure-tested for a minimum of 10 minutes to a low pressure of 1,400 kPa and to the anticipated SITHP and**
- **tested with an inert gas medium for a minimum of 10 minutes to a low pressure of 1,400 kPa and to a pressure equal to 90% of the anticipated SITHP if the circulating medium is a gaseous fluid or the wellbore effluent is expected to contain free gas.**

Refer to IRP 6: Critical Sour Underbalanced Drilling section 6.2 for well control equipment pressure test requirements.

IRP Pressure testing of the flowline piping shall conform to the regulatory requirements of the local jurisdiction and the pressure testing criteria set out in IRP 4: Well Testing and Fluid Handling.

21.4.2.7.2.6 Wellsite Inspection

The intent of wellsite inspection is to ensure that wear spots are identified prior to pipe failure. Refer to IRP 6: Critical Sour Underbalanced Drilling for operability recommendations (including erosion calculations).

IRP Piping shall be thickness-tested (ultrasonically) at predetermined erosion spots to determine loss of piping thickness.

IRP Records of the inspection shall be kept at the wellsite.

IRP The inspection frequency shall be increased if wear becomes noticeable.

IRP High rate gas wells shall be monitored on a continuous basis.

21.4.2.7.3 Choke Manifold

IRP The choke manifold must have a pressure rating equal to or greater than the anticipated SITHP. It shall include two chokes and isolation valves for each choke and flow path.

IRP All components within the choke manifold must conform to NACE MR0175/ISO 15156 specifications.

21.4.2.7.4 Downstream Inlet Piping

IRP All piping downstream of the choke manifold, up to and including the separator inlet, must conform to NACE MR0175/ISO 15156 specifications and have a working pressure equal to or greater than the designed operating pressure of the separator.

21.4.2.7.5 Sample Catcher

IRP The sample catcher shall be purged with either an inert gas or a sweet gas before geological sample recovery.

IRP The sample recovery procedure shall be considered a sour operation. Personnel shall take appropriate precautions when recovering samples.

IRP The purged sour gas shall be vented into the vapour recovery system.

21.4.2.7.6 Injection Line Bleed-off

IRP The injection line bleed-off components must comply with NACE MR0175/ISO 15156 specifications and have a working pressure equal to or greater than the anticipated SITHP.

21.4.2.7.7 Separator

IRP Separator equipment components that will come into contact with sour gas must comply with NACE MR0175/ISO 15156 specifications.

IRP The separator must be certified by applicable provincial regulatory bodies supporting compliance to pressure vessel and electrical standards.

IRP Current documentation shall be available at the wellsite that verifies the function testing of the pressure relief valves.

IRP Assurance of correct sizing of the pressure relief valves shall be supported with gas flow calculations available at the wellsite.

IRP The separator equipment capacity should be determined by considering the hole size, depth, reservoir pressure, anticipated flow rates, H_2S concentration and expected solids recovery.

21.4.2.7.8 Fluids Handling

IRP All fluids handling equipment, except storage tanks, must conform to NACE MR0175/ISO 15156 specifications.

NACE MR0175/ISO 15156 specifications do not apply to storage tanks because fluids are stored below 350 kPa.

IRP The fluids handling system and the separator capacity should be based upon maximum potential production at maximum drawdown.

Note: In a prolific gas reservoir this may not be possible so an adequate manifold system for holding back pressure would be mandatory.

Short-term near-wellbore flush production can result in flow rates that can significantly exceed expected rates.

IRP If the well to be drilled is in an area with little production experience or is a significant step location, the fluids handling system and the separator size should be selected to provide for excess capacity.

IRP For the drilling of a sour gas reservoir where the potential exists for production rates larger than the sizing of the separator vessel and at a relatively high flowing wellhead pressure, a high pressure separator should be used or, at minimum, a second manifold should be considered to step down any potential large surface circulating pressures (instead of using one manifold and taking the entire pressure drop across a single system). The second manifold should be installed in series no closer than 10 pipe IDs from the previous manifold. Chokes that are highly erosion-resistant should be used.

The reason for these recommendations is to minimize the degree of pressure drop across one restriction thereby minimizing erosion. In an oil well, these steps may not be warranted if the anticipated bottomhole pressures would not cause high flowing wellhead pressures. In this case an industry-accepted manifold and separation vessel would be sufficient.

IRP Regulatory fluids handling requirements of the local jurisdiction must be adhered to.

For additional sour fluids requirements in Alberta, or in the absence of any local jurisdictional requirements, consult AER Directive 36 – Addendum: Drilling and Blowout Prevention Requirements and Procedures.

IRP 22: Underbalanced and Managed Pressure Drilling Operations Using Jointed Pipe provides additional information on fluids handling.

21.4.2.7.9 Pump Lines

IRP Pump lines and related components used for pumping fluid down the coiled tubing shall have a working pressure rating that would allow the well to be killed. Therefore, the pressure rating shall be equal to or greater than the friction pressure of the fluid being pumped down the coil plus the anticipated SITHP.

IRP Elastomers shall be compatible with the fluid circulating medium and the service conditions.

IRP Pump line equipment shall include two check valves (with a bleed-off line between them) installed between the pump and coiled tubing reel and have a working pressure equal to or greater than the anticipated SITHP.

IRP A pressure relief valve, adequately sized for the anticipated pump rates, shall be included.

21.4.3 Use of Air

In cases of inconsistency between the recommended practices on the use of air contained in this IRP and applicable legislation, the legislative requirements prevail.

> **Note:** Use of air is a corrosion and explosion risk. Ensure proper mitigation plans are in place.

IRP Pumping of air shall only be permitted on a well meeting the following criteria:

- **The reservoir pressure of the zone is less than 5,500 kPa.**
- **There is no hydrogen sulphide present in a representative sample of the gas.**
- **The well is a gas well or the well produces heavy oil**
  - **with a density greater than 920 kg/m3,**
  - **a gas-oil ratio of less than 70 sm3/m3 and**
  - **the well produces by primary recovery or is included in a water-flood scheme.**

Air may be used when drilling through non-hydrocarbon bearing zones. For further information on the use of air in Drilling Operations consult the IRP 22: Underbalanced and Managed Pressure Drilling Operations Using Jointed Pipe.

IRP Air shall not be used on any well containing H_2S.

Further information can be found in IRP 4: Well Testing and Fluid Handling.

IRP Local jurisdictional requirements must be adhered to if the well contains any liquids.

In Alberta, or in the absence of any local jurisdictional requirements, consult the AER.

IRP An assessment of the operations shall be done using the tools and methods outlined in the Enform Fire and Explosion Hazard Management Guideline before starting operations.

IRP Local jurisdictional regulations should also be consulted for the assessment.

In Alberta, or in the absence of any local jurisdictional requirements, consult the following:

- AER Directive 33: Well Servicing and Completions Operations - Interim Requirement Regarding the Potential for Explosive Mixtures and Ignition in Wells
- AER Directive 60: Upstream Petroleum Industry Flaring, Incinerating, and Venting Section 8.1

IRP Issues pertinent to coiled tubing operations that shall be considered in this assessment include, but are not limited to, the following:

- Well pressure
- Pumping pressure
- Depth
- Flammable liquids in wellbore
- Ignition sources
- Presence or absence of water
- Purge of wellbore after operation

IRP Air shall only be flowed back to an open tank.

IRP With the coiled tubing in the well, pressure shall not be bled back through the coil if pumping air and the BHA does not contain a barrier (e.g., check valve).

21.5 QA for Well Pressure Control Equipment

The recommended practices for a quality assurance program for well pressure control equipment listed below have been summarized from IRP 2: Completing and Servicing Critical Sour Wells and recognize the need to ensure that the well pressure control or pressure-containing equipment used is suitable for its intended service.

Well operators and service providers are responsible for ensuring that any well pressure control equipment conforms to regulatory requirements and the recommended practices in this and other IRPs.

21.5.1 Quality Assurance Program

IRP **A quality assurance program shall be implemented, in particular for well pressure control equipment not manufactured in compliance with an applicable API specification and API Spec Q1: Quality Program 1.**

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

21.5.2 Manufacturing API Well Pressure Control Equipment

IRP **Well pressure control equipment used in critical sour wells made to API specifications shall be manufactured by an API-licensed manufacturer.**

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

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

API Spec Q1: Specification for Quality Programs and ISO 9001 detail all aspects of quality assurance programs.

21.5.3 Manufacturing Non-API Well Pressure Control Equipment

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

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

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

21.5.4 Shop Servicing and Repairs

Servicing and repairs include cleaning, replacement of components or reworking of any API-specified dimension within the tolerances indicated in the applicable API specification. Remanufacture refers to rework of original equipment manufacturer (OEM) specified dimensions or welding.

IRP Shop servicing and repairs shall be done by either an API-licensed manufacturer or a company that meets the requirements in 21.5.3 Manufacturing of Non-API Well Pressure-Containing Equipment.

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

21.5.5 Quality Control for Non-API Well Pressure Control Equipment

21.5.5.1 **Minimum Quality Control Measures**

IRP The minimum quality control measures set out in Table 23 shall be used to ensure the non-API well pressure control equipment is suitable for critical sour well operations.

Table 23. Minimum Quality Control Measures and Methods

Quality Control Measure	Method
Mechanical Tests	Tests commonly run are tensile and hardness.
Non-destructive examination	Methods commonly used are ultrasonics, magnetic particle, dye penetration and visual.
Dimensional verification	To be in conformance with design specifications.
Chemistry verification	To be in conformance with design specifications.
Traceability to end user	Traceability of component from raw material through manufacturing processes to end user.
Wellsite traceability	Component(s) to be marked in such a fashion so that on-site personnel can verify that the component delivered to the wellsite is suitable for sour service.

21.5.5.2 Non-Destructive Test Methods

IRP Non-Destructive test methods for evaluating materials for critical sour operations should be as per Table 24.

Table 24. Non-Destructive Test Methods to Evaluate Materials for Critical Sour Operations

Test Type	Related Standard(s)	Usage
Chemical analysis	ASTM E751/751M	To establish the hardenability of the material and the likelihood of having hard-heat-affected weld zones which would be susceptible to SCC. To determine the material type and its conformance to Tables I, II, and III of NACE MR0175/ISO 15156. To confirm compliance with the 1% Nickel content restriction of NACE MR0175/ISO 15156.
Eddy current inspection	ASME Section V ASTM E309	To detect cracks and volumetric defects in tubular products (although variations in test equipment do allow for the inspection of other types of components).
Hardness testing	ASTM E10 ASTM E18	To confirm compliance with the hardness restrictions of NACE MR0175/ISO 15156.
Liquid penetrant inspection	ASME Section V ASTM E165/E165M	To detect surface defects on non-magnetic components (although it may be used for magnetic components). Several types are available with widely varying sensitivities. One of the more sensitive methods should be used for the detection of SCC.
Magnetic particle inspection	ASME Section V ASTM E709	To detect surface defects and near surface linear discontinuities in magnetic components. Wet fluorescent techniques should be used for small, fine cracking (e.g., SCC).

21.5.5.3 Destructive Test Methods

IRP Destructive test methods for evaluating materials for critical sour operations should be as per Table 25.

Table 25. Destructive Test Methods to Evaluate Materials for Critical Sour Operations

Test Type	Related Standard(s)	Usage
Band testing	ASTM A370	To measure a weld’s or material’s ability to deform under load without cracking or suddenly failing (usually used for weld procedure and welder qualification testing).
Impact testing	ASTM A370	To establish a relative measure of the material’s or weld’s resistance to fracture at low temperatures under high and suddenly applied loads.
Tensile testing	ASTM A370	To establish the yield and tensile strength of a material or weld as well as its ductility and whether it complies with the minimum specified values for that particular grade.

21.6 Elastomeric Seals

The elastomer recommended practices in this section have been developed with consideration for well completion and servicing activities and environments recognizing the need for seal integrity under a variety of service conditions.

This section should help coiled tubing service providers select elastomers for well pressure seals (e.g., stripper rubbers, lubricator O-rings, BOP ram seals, BHA O-rings). Seal design, plastic seals and metal-to-metal seals are outside the scope of this IRP so manufacturers should be consulted.

Further details on the requirements for elastomeric seals in critical sour underbalanced drilling can be found in IRP 6: Critical Sour Underbalanced Drilling. Refer to Appendix C for supporting information regarding elastomeric seals and a basic reference for elastomer selection.

21.6.1 Service Conditions

IRP Service providers should determine the compatibility for the intended service between the seal material and the seal design. The following factors should be considered:

- Seal movement. Differences between static (BOP) and dynamic (stripper) seals should be taken into consideration in the selection.
- Service period. The length of service should be considered when selecting seal materials as seal material will often perform satisfactorily for a short service period but would be unsuitable for extended service periods.
- Seal maintenance. A wellhead seal may be relatively inaccessible and therefore require long-term performance whereas a wireline lubricator seal can be changed out after each job.
- Changing service conditions. Seal selection should be based worst-case conditions that may occur during the planned service or drilling operation such as increasing H_2S or temperature.

Note: For a given generic type of elastomer (e.g., nitrile) manufacturers may have different formulations or compounds each with different chemical resistance and temperature ratings.

Service providers should be aware of the various fluids to be handled and their individual or combined effect on sealing materials. These fluids include the anticipated well production fluids and any other fluid encountered during workovers or any chemical additives introduced to the well.

IRP **Compatibility of any elastomeric seal with the intended service environment shall be determined when selecting materials and equipment for the completion, servicing or drilling of any well.**

IRP **Compatibility shall include consideration of the effect of any fluid or substance that elastomer seals may be exposed to as well as ambient temperatures at which seals are required to perform.**

Note: Many types of elastomeric seals are susceptible to attach and degradation due to corrosion and H_2S cracking inhibitors. Proper elastomer selection is critical.

IRP Manufacturer-supplied performance properties and recommendations should also be used to verify compatibility.

21.6.2 Testing and Evaluation

IRP **Specific testing of seals based on anticipated field conditions shall be performed if available information is not adequate for the service application.**

IRP To evaluate the suitability of elastomers and other seal materials for a particular well, the user should first refer to the equipment manufacturer's recommendations. These recommendations should be based on materials testing and experience.

IRP **The end user shall be satisfied that information or data on seal materials meet the intended service requirements.**

IRP A field-specific testing program should be considered to verify the manufacturer's recommendations or to determine an elastomer's suitability.

IRP Storage and handling should be included in the quality control program because many elastomers have a shelf life due to sensitivity to sunlight and humidity.

21.6.3 Quality Control

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

IRP **The well operator shall ensure that records are kept that identify the elastomer materials in use for first-line well pressure control seals.**

Keeping these records is recommended because there are no standard markings on most elastomer seals to indicate the elastomer material.

21.7 Well Servicing Operations

This section addresses coiled tubing operations for well servicing.

21.7.1 Pre-Rig Up

IRP Before rigging up any coiled tubing equipment on site the operating company and service company representatives shall review the equipment service log and ensure the following:

- **The coiled tubing pipe to be used has sufficient serviceability to safely complete the job with a reasonable contingency factor.**
- **The coiled tubing string used can complete the job within operating limits (e.g., tensile strength, burst, collapse, torsional yield, etc.).**
- **The three-year BOP equipment certification has been completed (this includes all riser, lubricator, flow spools, cross-overs, strippers, etc., from the wellhead to the upper stripper).**
- **The accumulator specifications are available and accumulator sizing calculations have been performed.**
- **All equipment, including the coiled tubing pipe and BOP system, has been checked for compatibility with the formation fluids and treating fluids.**
- **If the shear ram is installed, it is capable of severing the coiled tubing pipe and any internal/external hardware being used (e.g., wireline-installed coiled tubing).**
- **For cold weather operations, consideration has been given to heating (or other appropriate actions) of the BOPs to ensure that the response time and sealing efficiency is satisfactory.**

For critical sour operations inspection/testing requirements for the coiled tubing pipe see 21.3.6.2 Full-Length NDE of Coiled Tubing Strings.

IRP The operating company representative shall provide a documented site-specific orientation to the service company representatives before starting operations. Items to be reviewed shall include the following:

- **General safety issues**
- **Identification of any hazards on location (e.g., rat holes, high pressure piping, etc.)**
- **Muster stations**
- **Egress routes**

IRP The operating company and service company shall review the well parameters including, but not limited to, the following:

- **Asphaltenes and waxes**
- **Condensate**
- **Depth**
- **Formation or treatment fluids**
- **Gas composition (especially air, H_2S and CO_2 concentrations)**
- **Hydrate formation potential**
- **Emergency response plan (if required)**
- **Scales (e.g., Iron sulphide, naturally occurring radioactive material (NORM) and others)**
- **Pressures**
- **Relevant well equipment and detail (e.g., trajectory, ID restrictions, etc.)**
- **Salinity of produced water**
- **Wind direction**

IRP The operating company and service company shall review proposed equipment layout and spacing requirements recognizing all regulatory requirements. See IRP 20: Wellsite Design Spacing Recommendations.

IRP Including a landing nipple at the bottom of the string should be considered when running velocity strings.

An isolation dart can then be landed prior to pulling the string to minimize the possibility of a release should the string part above the well control equipment on recovery. This is strongly recommended on sour wells.

21.7.2 Rig Up

IRP A safety/operations meeting shall be held with all on-site personnel to discuss the following:

- **Pressure testing**
- **Detailed operations to be performed**
- **Delegation of responsibilities**
- **BOP Drill requirements**
- **Emergency response plans**

- **Other operational or site-specific considerations**

IRP All hydraulic lines, testing lines and kill lines shall be organized and kept tidy so they prevent interference with an emergency evacuation of the area.

IRP All equipment attached to the wellhead shall be adequately supported to limit transverse movement.

IRP Factors affecting crane operations should be considered (e.g., injector height, equipment weight and wind conditions).

IRP Stabilizing guy lines should be installed to rig anchors or a secure anchor point as deemed necessary by the rig up geometry.

IRP If liquid CO_2 is to be pumped, contingency plans shall be in place to deal with ice plugs in the surface piping (e.g., treating iron, coiled tubing).

21.7.3 Pressure Tests

IRP A full pressure and function test must be performed upon initial rig up on every well. If the duration of operations on that particular well exceeds 7 days, the full function and pressure test must be repeated at least once every 7 days.

IRP With the coiled tubing BOP components and auxiliary equipment installed on the wellhead, the BOP system must be pressure tested as follows:

- **A low-pressure test of 1,400 kPa must be conducted on each pressure seal (ram preventer) for ten minutes. This test shall be conducted first.**
- **A high-pressure test must be conducted on each ram preventer, annular preventer and stuffing box for ten minutes. The pressure required shall be the lessor of the wellhead pressure rating or 1.1 times the estimated maximum potential of MASP or MAOP, whichever is greater. For critical sour wells use 1.3 times the estimated maximum potential MASP or 1.1 times MAOP, whichever is greater.**

A documented stump test is acceptable if a pressure test of the connecting flange is completed after installation on the well.

Operations in Pressure Category 0 wells do not require a pressure test.

IRP Any connection between the stripper and the wellhead which is disconnected (broken) after the initial pressure test shall be retested before resuming operations. This includes lubricators, strippers, BOP components and valves.

IRP A produced hydrocarbon shall not be considered an acceptable pressure testing medium.

IRP The following components of the BOP system shall be pressure tested for ten minutes to the lessor of the wellhead pressure rating or 1.1 times the estimated maximum potential MASP or MAOP, whichever is greater (for critical sour wells use 1.3 times the estimated maximum potential MASP or 1.1 times MAOP, whichever is greater):

- **Each individual sealing element in the BOP stack.**
- **The connection between the BOP stack and the wellhead.**
- **All auxiliary equipment including lubricators and pressure windows.**
- **The bleed-off and kill lines.**
- **All valves in the bleed-off manifold (if applicable).**

IRP The following components of the BOP system shall be pressure tested for ten minutes to the lessor of the wellhead pressure rating or 1.1 times the maximum anticipated pump pressure (for critical sour wells use 1.3 times the maximum anticipated pump pressure):

- **The reel isolation valve**
- **The rotary swivel (pressure tested to the greater of the criteria above or maximum anticipated wellhead treatment pressure).**
- **The coiled tubing pipe (pressure tested to the greater of the criteria above or maximum anticipated wellhead treatment pressure).**

IRP The downhole equipment composing a part of the coiled tubing pipe above the isolation device (e.g., check valves) shall be pressure tested for ten minutes to the lessor of the wellhead pressure rating or 1.1 times the maximum anticipated pressure differential that will be experienced during the job (for critical sour wells use 1.3 times the maximum anticipated pressure differential that will be experienced during the job).

Adjustable chokes do not require testing.

IRP For a satisfactory pressure test using a liquid, all tests shall maintain a stabilized pressure of at least 90% of the test pressure over a 10 minute interval.

IRP For a satisfactory pressure test using an inert gas or air, not more than 5% of the value of the test pressure is to be recorded to have leaked off during the test period. If more than 5% has leaked off, then the length of the test shall be increased to determine the nature of the pressure decline.

IRP If air is to be used as a test medium, all regulatory requirements must be met and the appropriate hazard assessments carried out.

IRP Where well classification or the greater of reservoir pressure and SITHP is not clear through past operations, pressure tests should be conducted to the wellhead pressure rating.

21.7.4 Equipment Records

Equipment records are records detailing information about the history of the equipment used during coiled tubing operations.

IRP A coiled tubing contractor shall have a pipe management system ensuring that a program is in place using a records log to predict when a coiled tubing pipe shall be removed from service.

IRP Records should be kept of the following:

- All operations conducted with the coiled tubing pipe being used.
- Fluid types and/or gases pumped.
- Depth run into the well and any repetitively cycling.

See 21.3.9.2 Post-Production Records and 21.3.11 String-Life Management System for further details.

21.7.5 Operating Practices

IRP The coiled tubing unit shall not be left unattended while the lubricator or injector head assembly is connected to the wellhead.

IRP A pull test shall be performed on the coiled tubing pipe to BHA connection before running into the well and the intensity of the pull shall be based on the expected operational requirements.

IRP Coiled tubing pipe shall not exceed operating limits while in the hole.

IRP Factors such as differential pressure across coiled tubing pipe and axial load should be taken into consideration. These accumulative factors affect total stress level on the coiled tubing pipe.

IRP The following procedures should be considered to bring the well under control in the event of a serious wellhead leak between the coiled tubing BOP stack and the master valve:

1. Ensure everyone on location is safe.

2. Evaluate if the coiled tubing can be pulled from the hole so the master valve can be closed to bring the well under control.
3. Evaluate if the well can be safely killed and brought under control.

IRP The following procedures should be considered for Well Servicing Category 2, 3, 4 and 5 if the procedures above cannot be performed:

1. Identify the depth of the bottom portion of the coiled tubing pipe.
2. Pull the bottom of the coiled tubing pipe high enough in the vertical portion of the hole to ensure that when the coiled tubing pipe is cut the top of the coil will fall below the lowest master valve.
3. Activate the slip rams.
4. Ensure tension is pulled into the coiled tubing pipe above the slip rams then activate the shear rams and shear the pipe.
5. Open the slip rams and allow the coiled tubing pipe to fall below the lower master valve.
6. Shut in Master Valve and secure the well.

IRP When performing a BOP Drill the slip rams should not be closed on the coiled tubing as this will add stress risers that could lead to premature failure of the coiled tubing in the hole. This applies to the BOP Drill only. In emergency situations the slip rams should be closed if the situation merits it.

Note: Stress risers will make the coiled string significantly more susceptible to failure in sour gas environments.

21.7.6 Bottomhole Assemblies

IRP When working in sour conditions all parts of the BHA from the end connector down to the check valves and all load bearing parts should meet the requirements of NACE MR0175/ISO 15156.

IRP When working on Critical Sour wells all parts of the BHA from the end connector down to the check valves and all load bearing parts shall meet the requirements of NACE MR0175/ISO 15156.

21.8 Drilling Operations

This section addresses coiled tubing operations for drilling.

21.8.1 General Requirements

21.8.1.1 Service Log

IRP The operating company and service company shall review the equipment service log and ensure the following:

- **The coiled tubing drill string to be used has sufficient serviceability to safely complete the job with a reasonable contingency factor.**
- **The three-year BOP equipment certification has been completed. This includes all equipment from the bottom of the BOP to the top of the wellhead.**
- **The accumulator specifications are available and accumulator sizing calculations have been performed and documented.**
- **The well control equipment conforms with the applicable well classification as per jurisdictional requirements.**
- **All equipment, including the coiled tubing drill string and BOP system, has been checked for compatibility with the formation fluids and treating fluids.**
- **If installed, a shear ram BOP is capable of severing the coiled tubing drill string and any internal or external hardware (e.g., wireline-installed coiled tubing).**
- **For cold weather operations, consideration has been given to heating (or other appropriate actions) of the BOPs to ensure that the response time and sealing efficiency is satisfactory.**

21.8.1.2 Orientation

IRP The operating company representative shall provide orientation to the service company representatives before starting operations. Items to be reviewed shall include the following:

- **General safety issues**
- **Identification of any hazards on location (e.g., rat holes, high pressure piping, etc.)**
- **Muster stations**
- **Egress routes**

IRP The operating and service companies shall review the well parameters including, but not limited to, the following:

- **Asphaltenes and waxes**
- **Condensate**
- **Depth**
- **Formation and drilling fluids**
- **Gas composition (especially air, H_2S and CO_2 concentrations)**
- **Hydrate formation potential**
- **Emergency response plan (if required)**
- **Scales (e.g., Iron sulphide, naturally occurring radioactive material (NORM) and others)**
- **Pressures**
- **Relevant well equipment and detail (e.g., trajectory, ID restrictions, etc.)**
- **Salinity of produced water**
- **Wind direction**

21.8.1.3 Equipment Layout and Spacing

IRP The operating company and service company shall review proposed equipment layout and spacing requirements recognizing all local regulatory requirements. See IRP20: Wellsite Design Spacing Recommendations.

21.8.1.4 Coiled Tubing Mechanical Properties

IRP The coiled tubing drill string used shall be able to complete the job within operating limits (e.g., tensile strength, burst, collapse, torsional yield, etc.).

21.8.1.5 Inhibitors

IRP Inhibitors shall be present in sufficient quantities to protect the exposed materials (e.g., coiled tubing drill string, downhole equipment, etc.) during operations where the coiled tubing drill string is exposed to a corrosive media.

IRP When selecting an inhibition program consideration shall be given to the total circulation system (e.g., the presence of water, salinity, oxygen content, H_2S, CO_2 and temperature).

21.8.2 Underbalanced Drilling

21.8.2.1 **Pressure Limits**

IRP Coiled tubing drill string differential pressure limits shall be established for each underbalanced drilling operation. These limits shall take into account the following:

- **Tube diameter**
- **Ovality**
- **Wall thickness**
- **Applied loads**
- **Anticipated operating conditions**

21.8.2.2 **Fatigue Cycles**

IRP The following shall be posted in the coiled tubing operating unit for underbalanced drilling operations:

- Fatigue cycles remaining in the coiled tubing drill string at the anticipated circulating pressures
- Fatigue cycles remaining in the coiled tubing drill string at the lessor of the maximum operating pressure or 25% above the anticipated circulating pressures.

Specifying fatigue cycles remaining at 25% above the anticipated circulating pressure accounts for situations where the circulating pressure is higher than predicted due to higher than anticipated reservoir pressures or flow rates.

21.8.2.3 **Swivel Isolation Valve**

IRP A valve between the coiled tubing drill string and the reel swivel shall be included on all underbalanced wells.

21.8.3 Critical Sour Underbalanced Drilling Considerations

The connector system comprises all of the items carrying loads from the BHA to the coiled tubing drill string and the condition of the coiled tubing drill string at the interface with the connector.

These precautions are meant to ensure that neither the pipe nor the BHA/connector twists off under stall conditions. Unless information exists to the contrary, it should be assumed that the motor stall torque is twice the maximum operating torque.

21.8.3.1 Torsional Yield

IRP The torsional rating of the coiled tubing drill string shall be greater than two times the downhole motor stall torque for critical sour underbalanced drilling operations.

IRP The torsional rating of the coiled tubing drill string BHA, including any connectors, shall be their original specification less 20% for all critical sour underbalanced drilling. This rating shall be greater than 1.5 times the downhole motor stall torque (i.e., Operational rating = 80% of original spec = at least 1.5 x stall torque).

IRP The coiled tubing owner shall test the coiled tubing drill string connector system to prove fitness for sour service. The coiled tubing owner shall determine which tests are appropriate for the operation.

21.8.3.2 Stress Analysis

IRP Technical personnel competent in tubing force and circulation analysis shall be on location during all coiled tubing critical sour underbalanced drilling operations.

IRP Coiled tubing drill string stress analysis (including drag predictions) shall be completed before starting critical sour underbalanced drilling operations.

IRP Coiled tubing drill string design shall take into account appropriate factors such as desired overpull, drag and wellbore profile.

IRP Operating limits shall be established and clearly posted in the coiled tubing drill string operating unit for the following:

- **Maximum coiled tubing drill string pull weights**
- **Set down loads**
- **Circulating pressures**

21.8.3.3 Pipe Inspection

IRP Pipe inspection of the coiled tubing drill string shall be carried out before use in critical sour underbalanced drilling (see 21.3.6 Non-Destructive Examinations).

IRP Inspection results shall be used in conducting tubing force analysis and in calculating circulation limits. At minimum, the following should be measured:

- **Coiled tubing drill string OD**
- **Minimum wall thickness**
- **Ovality**

21.8.3.4 On-Site Documentation

IRP The coiled tubing operator shall keep records on coiled tubing drill string cycle life, pipe management and well conditions on site during critical sour underbalanced drilling operations.

21.8.4 Rig Up

IRP A safety/operations meeting shall be held with the operators representatives, coiled tubing crew and all personnel on site to discuss the following:

- **Pressure testing**
- **Detailed operations to be performed**
- **Delegation of responsibilities**
- **BOP Drill requirements**
- **Emergency response plans**
- **Other appropriate considerations**

IRP All hydraulic lines, testing lines and kill lines shall be organized so they prevent interference with an emergency evacuation of the area.

IRP All equipment attached to the wellhead shall be adequately supported to limit lateral movement.

IRP Each individual coiled tubing or crane operation should be evaluated for the potential to cause lateral movement of the equipment rigged onto the wellhead.

IRP Factors affecting crane operations should be considered (e.g., injector height, equipment weight, wind conditions).

IRP Stabilizing guy lines should be installed to rig anchors or a secure anchor point as deemed necessary by the rig up geometry.

21.8.5 Pressure Tests

A pressure control system is defined as the blowout prevention system and includes all equipment from the top wellhead flange to the uppermost piece of pressure control equipment (i.e., BOP, snubbing, pressure deployment). The pressure containing system includes the following:

- BOP stack
- Snubbing stack
- Coiled tubing stack
- Pressure deployment system (including all bleed lines)

For purposes of this IRP, maximum potential SITHP is equal to the original reservoir pressure minus the gas gradient. If no gradient is available use 85% of the original reservoir pressure. The pressure may be reduced to 85% of the current reservoir pressure if a qualified reservoir specialist endorses a reduction based on factual data.

21.8.5.1 General Requirements

IRP Pressure tests must be carried out in adherence with the applicable jurisdiction for the well location.

IRP For a satisfactory pressure test using a liquid, all tests shall maintain a stabilized pressure of at least 90% of the test pressure over a 10 minute interval.

IRP For a satisfactory pressure test using an inert gas or air, not more than five percent of the value of the test pressure is to be recorded to have leaked off during the test period. If more than five percent has leaked off then the length of the test shall be increased to determine the nature of the pressure decline.

IRP In the absence of any specific jurisdictional requirements, AER Directive 36: Drilling Blowout Prevention Requirements and Procedures should be consulted.

IRP Before drilling out intermediate or production casing, the coiled tubing drill string, valves and piping to the circulating pump shall be pressure tested to the working pressure of the required class of BOPs.

IRP A produced hydrocarbon shall not be considered an acceptable pressure testing medium.

In most overbalanced drilling cases the drilling circulating pressure exceeds the required pressure test requirements and is an acceptable method of pressure testing the coiled tubing drill string.

21.8.5.2 Underbalanced Drilling

IRP The coiled tubing drill string shall be pressure tested on all wells above Drilling Class I.

IRP The coiled tubing drill string, valves and piping to the circulating pump shall be pressure tested to the greater of the maximum anticipated circulating pressure plus 10% or the working pressure of the required class of BOPs.

21.8.5.3 Critical Sour Underbalanced Drilling

The intent of the pressure test requirements is that the BHA can be pressure-deployed at the highest possible anticipated pressure.

Refer to IRP 6: Critical Sour Underbalanced Drilling for more information about the general requirements for critical sour underbalanced drilling.

21.8.5.3.1 Wellsite Testing

IRP Pressure testing of the pressure containing-system conducted at the wellsite must conform to regulatory requirements.

IRP If the circulating medium is a gaseous fluid or if drilling a critical sour gas well, a gas pressure test with an inert gas shall be conducted on all pressure control equipment (in addition to a hydrostatic pressure test).

21.8.5.3.2 Pressure Control System

IRP The pressure control system shall be hydrostatically pressure tested for a minimum of ten minutes to a low pressure of 1,400 kPa and a high pressure equal to the maximum potential SITHP.

> **Note:** This requirement reflects the additional rigor required in the planning and design of critical sour underbalanced drilling.

IRP The pressure control system shall then be pressure tested with an inert gas if the circulating medium is a gaseous fluid or if the wellbore effluent is expected to contain free gas for a minimum of ten minutes to a low pressure of 1,400 kPa and a pressure equal to 90% of the maximum potential SITHP.

IRP Documentation of the hydrostatic and gas pressure tests shall be kept at the wellsite throughout the duration of the critical sour underbalanced drilling operation.

IRP If any connections in the pressure containing system are broken (disconnected) during operations, those connections shall be pressure tested again before operations can continue.

IRP All tests conducted on the annular-type preventers shall be conducted with the element closed on pipe.

Test plugs may be used to isolate the BOP system from the production casing during pressure tests if no casing valve is present.

Refer to Section 6.5 of IRP 6: Critical Sour Underbalanced Drilling for casing pressure testing requirements.

21.8.5.3.3 Coiled Tubing Drill String

IRP Immediately before tripping the coiled tubing drill string into the hole, the double check valve in the BHA shall be bench-tested with an inert gas. Low pressure test is to 1,400 kPa for a minimum of 10 minutes. High pressure test is to 1.1 times the maximum potential SITHP for a minimum of 10 minutes.

IRP The coiled tubing drill string between the double check valve and the rotating joint on the coiled tubing reel should be pressure tested for a minimum of 10 minutes to both 1,400 kPa and the greater of 1.1 times the maximum potential SITHP or maximum anticipated coiled tubing injection pressure.

IRP The pressure control devices in the BHA during pressure deployment operations into the hole shall be pressure tested from the bottom up using wellbore pressure at surface.

IRP If the pressure control devices in the BHA do not hold pressure from below during pressure deployment operations into the hole, the coiled tubing drill string shall be pulled from the hole and the existing barriers replaced and pressure tested again before pressure deployment operations into the hole continue.

IRP If any connections in the coiled tubing drill string between the double check valve and the rotating joint on the coiled tubing reeled unit are broken (disconnected) during operations, those connections shall be pressure tested again as outlined in this section before the coiled tubing drill string can be run back into the well.

21.8.6 Operating Practices

21.8.6.1 General Requirements

IRP The designated senior supervisor on site shall inspect the coiled tubing drill string end connector and document the inspection before running in the well.

IRP If the coiled tubing drill string loses the ability to contain pressure it shall be pulled to surface as soon as is practical and safe.

IRP When the injector head is supported by a crane the coiled tubing unit shall not be left unattended while the injector head assembly is connected to the wellhead.

IRP When performing a BOP Drill the slip rams should not be closed on the coiled tubing as this will add stress risers that could lead to premature failure of the coiled tubing in the hole. This applies to the BOP Drill only, in emergency situations the slip rams should be closed if the situation merits it.

Note: Stress risers will make the coiled string significantly more susceptible to failure in sour gas environments.

21.8.6.2 Underbalanced Drilling

IRP A pull test shall be performed on the connection between the coiled tubing drill string and the BHA before running into the well. The intensity of the pull shall be based on the expected operational requirements.

Pressure testing a blanked end connector is an acceptable alternative to a pull test provided sufficient axial force is generated.

Coiled tubing separation is defined as a separation above the highest disconnect in the coiled tubing string. This separation may be intentional or as a result of material failure.

IRP The well shall be killed immediately in the event of any coiled tubing separation within the wellbore while drilling a critical sour well.

IRP The following procedures should be considered to bring the well under control in the event of a serious wellhead leak between the coiled tubing BOP stack and the wellbore isolation valve:

1. Ensure everyone on location is safe.
2. Evaluate if the coiled tubing drill string can be pulled from the well so the wellbore isolation valve can be closed to bring the well under control.
3. Evaluate if the well can be safely killed and brought under control.

IRP The following procedures should be considered for a well where a shear ram is installed if the procedures above cannot be performed:

1. Identify the depth of the bottom portion of the coiled tubing drill string.
2. Pull the bottom of the coiled tubing drill string high enough in the vertical portion of the hole to ensure when the coiled tubing is cut the top of the coiled tubing drill string will fall below the wellbore isolation valve.
3. Activate the slip rams.
4. Ensure tension is pulled into the coiled tubing drill string above the slip rams then activate the shear rams and shear the pipe.
5. Open the slip rams and allow the coiled tubing drill string to fall below the wellbore isolation valve.
6. Shut in Wellbore Isolation Valve and secure the well.

21.8.6.3 Night Time Operations

IRP For snubbing, stripping and pressure deployment to be allowed after dark, the lighting at the wellsite shall be sufficient to

- **enable work to be conducted safely,**
- **allow personnel to leave the wellsite safely,**
- **initiate emergency shutdown procedures and**
- **perform a rescue.**

21.8.7 Bottomhole Assemblies

IRP When working in sour conditions all parts of the BHA from the end connector down to the check valves should meet the requirements of NACE MR0175/ISO 15156.

IRP When working in sour conditions all load bearing parts of the BHA should meet NACE MR0175/ISO 15156.

IRP When working on critical sour or special sour wells all parts of the BHA from the end connector down to the check valves and all load bearing parts shall meet the requirements of NACE MR0175/ISO 15156.

Appendix A: Revision Log

IRP21 was originally sanctioned in September of 2010.

2016 Revision

The 2016 revision was a limited scope review of IRP21 made the modifications listed in Table 26.

Table 26. 2016 Revisions

Change	Section(s)	Description
Reformat to current DACC Template and Style Guide	All	Document reformatted to match the current DACC style guide (2015 version). Key updates include: • Formatting IRP statements and using range of obligation words in all IRP statements (must, shall, should). • All metric UOM rounded to two decimal places • All metric measurements shown before imperial (where present). The exception is where items are manufactured in imperial units – then imperial comes first. • Removal of IRP statements from Appendices in Appendix B (IRP statements don't belong in the appendices. Text modified to just regular text as the section that references Appendix B has detailed recommendations/IRPs pertinent to the topic.).
Editorial Review	All	• Consistent wording, terminology, structure • Active voice • Merging related IRPs into one bulleted list to reduce bolding • Cleanup/numbering of headings • Update references to current versions
Definitions of Well Servicing Pressure Categories	21.1.2.1, All	• Updated the generic set of Well Servicing Pressure Categories that encompasses requirements from all jurisdictions and then uses those consistently throughout the IRP • Bring IRP classes into alignment with global API Standards • Use new categories in remainder of document
Update well control equipment configurations requirements	21.2.3	• Bring into alignment with the global API standard • Updated diagrams • New table of equipment (Table 15)
Update Pressure testing IRPs to use MSAP/MAOP rather than SITHP	21.7.3	• Adjusted to reflect new pressure categories and calculation methods

Appendix B: Non-Destructive Examination of Coiled Tubing Strings

The following are detailed recommended practices regarding non-destructive examination of coiled tubing strings.

The recommended and best practices below are meant to complement and be consistent with IRP 2: Completing and Servicing Critical Sour Wells.

Bias or Butt Welds

Radiographic Testing

RT should be conducted in accordance with ASTM E94 and ASTM E1032 using an ASTM rectangular image quality indicator (IQI).

The IQI should be in accordance with Table 27 for the appropriate wall thickness. The 2T hole should be clearly discernible in each radiograph of each weld.

Table 27. ASTM Image Quality Indicator

Nominal Wall Thickness (t)		ASTM Designation	Essential Hole
inches	mm		
t ≤ 0.150	t ≤ 3.810	10	2T
0.150 < t ≤ 0.250	3.810 < t ≤ 6.350	12	2T
0.250 < t ≤ 0.375	6.350 < t ≤ 9.525	15	2T

Ultrasonic Shear Wave Testing

Ultrasonic shear wave testing (UT) should be conducted in accordance with ASTM E164. The UT unit should be standardized using a reference standard both before and immediately after performing the UT inspection.

The reference standard should contain at least one electron discharge machined (EDM) notch having the following dimensions:

- Length ≤ 6.35 mm (0.250 inch)
- Width = 0.25 mm (0.010 inch)
- Depth = 5% of the specified nominal wall thickness of the base metal (with a minimum notch depth of 0.25 mm (0.010 inch)).

Liquid Penetrant Testing

Liquid penetrant testing should be performed in accordance with ASTM E165.

Acceptance Criteria

The acceptance criteria for non-destructive evaluation of welds should be as follows:

- For RT: no indications in excess of the essential IQI hole.
- For UT: no indication greater than 50% of the reference amplitude.
- For PT: no relevant indications are allowed (regardless of size).

Full Length NDE of Coiled Tubing Strings

NDE Procedure and Equipment

The following automated methods are acceptable for full length NDE of coiled tubing strings:

- Ultrasonic inspection in accordance with ASTM E273
- Electromagnetic Inspection (EMI) in accordance with ASTM E570
- Eddy current inspection in accordance with ASTM E309

The NDE procedure shall require standardization (calibration) of the inspection unit with a reference standard both prior to and immediately following the inspection, as well as any time a malfunction of the unit is suspected.

The NDE equipment should be adjusted to produce well defined indications from the reference indicators when the reference standard is scanned by the inspection unit in a manner simulating the actual inspection of the product.

The signals from the reference indicators should be clearly labelled and separated on the record obtained from the NDE equipment.

If the NDE equipment is capable of alerting the operator for indications exceeding a specific limit (threshold), the limit should be set at the average minimum signal level observed while scanning the reference standard.

The running speed of the coiled tubing through the NDE equipment should be adjusted to allow 100% coverage of the inspected length.

All indications from NDE exceeding threshold limits should be documented in the NDE report and maintained in the coiled tubing string records.

NDE System Capability Records

The NDE service provider should maintain NDE system records verifying the system capabilities in detecting the reference indicators used to establish the equipment test sensitivity. The verification and records should cover, at minimum, the following:

- Coverage calculation (i.e., scan plan) including wall thickness verification
- Capability for the intended wall thickness
- Repeatability
- Transducer orientation that provides detection of defects typical of the manufacturing process
- Documentation demonstrating that defects typical of the manufacturing process are detected using the NDE method
- Threshold setting parameters
- NDE system operating procedures
- NDE equipment description
- NDE personnel qualification information
- Dynamic test data demonstrating the NDE system/operation capabilities under dynamic production inspection/test conditions

NDE Reference Standards

The reference standards used to standardize automated UT, eddy current or magnetic flux leakage units should meet the requirements of this section.

Dimensions and Properties

These dimensions and properties apply to automated UT, Eddy current and magnetic flux leakage units.

Specified nominal outside diameter is the same as the coiled tubing string being inspected.

Specified nominal wall thickness ≥ the coiled tubing string being inspected.

For tapered coiled tubing strings, two reference standards should be used corresponding to the maximum and minimum specified wall thickness of the coiled tubing string to be inspected.

Standardization of the NDE unit should be performed on the thicker standard with the thinner standard used as a check.

Reference Indicators

Each reference standard should include the reference indicators described in the following sections. Individual reference indicators should be separated sufficiently on the reference standard so as to generate distinct recordable signals from the NDE equipment.

Through Drilled Holes

This information applies to automated UT, Eddy current and magnetic flux leakage units.

The NDE reference standard should include at least one through-drilled hole. Through-drilled holes should be drilled perpendicular to the surface of the reference standard at the weld zone edge:

- 1.59 mm (0.063 inch) – both new and used coiled tubing
- 0.79 mm (0.031 inch) – used when agreed upon between customer and inspector

Longitudinal Notches

This information applies to automated UT and magnetic flux leakage units.

IRP The outer surface of the NDE reference standard should include at least one longitudinal EDM notch with the following dimensions:

- Length = 6.35 mm (0.25 inch) at full depth
- Depth = maximum of 10% of the specified nominal wall thickness (with a minimum depth of 0.305 mm (0.012 inch))
- Width = 0.254 mm (0.010 inch)

IRP For coiled tubing strings with OD = 38.10 mm (1.5 inches) the inner surface of the NDE reference standard should include at least one longitudinal EDM machined notch with the following dimensions:

- Length = 6.35 mm (0.25 inch) at full depth
- Depth = maximum of 10% of the specified nominal wall thickness (with a minimum depth of 0.305 mm (0.012 inch))
- Width = 0.254 mm (0.010 inch)

Transverse Notches

This information applies to automated UT and magnetic flux leakage units.

The outer surface of the NDE reference standard should include at least one transverse EDM notch with the following dimensions:

- Length = 6.35 mm (0.25 inch) at full depth
- Depth = 10% of the specified nominal wall thickness (maximum); the minimum depth = 0.31 mm (0.012 inch)
- Width = 0.25 mm (0.010 inch)

For coiled tubing strings with OD = 38.10 mm (1.5 inches) the inner surface of the NDE reference standard should include at least one transverse EDM machined notch with the following dimensions:

- Length = 6.35 mm (0.25 inch) at full depth
- Depth = maximum of 10% of the specified nominal wall thickness (with a minimum depth of 0.31 mm (0.012 inch))
- Width = 0.25 mm (0.010 inch)

Wall Loss Area for Used Coiled Tubing

This information applies to automated UT and magnetic flux leakage units.

The outer surface of the NDE reference standard for used coiled tubing should include a wall loss area covering 645.2 – 967.7 mm^2 (1.00-1.50 $inch^2$) with the following depth:

- 0.13 mm (0.005 inch) for specified nominal wall thickness 2.79 mm (0.110 inch)
- 0.20 mm (0.008 inch) for specified nominal wall thickness ≥ 2.79 mm (0.110 inch)

The wall loss area should make a smooth transition to the surrounding material (i.e., no sharp edges).

Prove-Up of NDE Indications

Any indication that produces a signal equal to or greater than the reference standard is to be treated as follows:

Any indication that produces a signal equal to or greater than the reference standard should be marked with a non-damaging method.

Any indication that produces a signal equal to or greater than the reference standard shall be evaluated and proved-up with RT, UT, PT and/or magnetic particle testing (MT) as appropriate and accepted by customer. All prove-up of indications and repairs of blemishes should be documented in the NDE report.

Non-Sour Service Coiled Tubing Strings

If the prove-up of an indication from NDE on a coiled tubing string for non-sour service confirms a physical blemish, the coiled tubing string should not be acceptable for non-sour service operations unless one of the following conditions is met:

1. The external blemish can be removed as per the Repair of Blemishes section below. If the wall thickness after the repair is less than 90% of the specified nominal wall thickness, the user of the coiled tubing string should provide compelling evidence the coiled tubing string is suitable for the intended service as per the requirements of 21.3.2 Evaluating Suitability and 21.3.3 Assessing Mechanical Strength.
2. The section of tubing containing the blemish can be cut out of the coiled tubing string. If necessary the cut ends of the string can be spliced together with a butt weld or mechanical connector.
3. The user of the coiled tubing string provides compelling evidence that leaving the blemish in place will not render the coiled tubing string unsuitable for the intended service as per the requirements of 21.3.2 Evaluating Suitability and 21.3.3 Assessing Mechanical Strength.

Sour Service Coiled Tubing Strings

If the prove-up of an indication from NDE on a coiled tubing string for sour service confirms a physical blemish, the coiled tubing string should not be acceptable for sour service operations unless one of the following conditions is met:

1. The external blemish can be removed as per the Repair of Blemishes section below. The minimum allowable wall thickness after the repair should be 90% of the specified nominal wall thickness.
2. The section of tubing containing the blemish can be cut out of the coiled tubing string. If the service is not critical sour the cut ends of the string can be spliced together as per 21.3.5 Welding Coiled Tubing Strings.

Repair of Blemishes

Blemish repairs should be as follows:

- A blemish revealed by NDE should be repaired by removing material parallel to the tubing axis.
- Material should not be removed at any angle transverse to the tubing axis. Even shallow scratches at small angles to the tubing axis can serve as effective crack initiation sites.
- Files, belt sanders or cylindrical rotary stones should be used for repairing blemishes to the coiled tubing string instead of flat rotary grinding disks.
- Bulk material should be removed over a length at least twice the tubing OD.

- The exposed surface should be as smooth as possible and free of irregularities.
- The edges of the repaired area should make a smooth transition to the undisturbed material.
- After the bulk material removal the exposed surface should be polished manually in the longitudinal direction. Use progressively finer emery cloth, beginning with 180-240 grit and ending with 400-600 grit.

Re-Inspection of Repaired Surfaces

The repaired area should be re-inspected with RT, UT, PT and/or MT as deemed appropriate. Each repaired area should be subjected to UT compression wave inspection to verify the remaining wall thickness.

Acceptance Criteria for Repaired Surfaces

The acceptance criteria for surfaces repaired by polishing should be as follows:

- No visible flaws or cracks (regardless of size).
- No indication that produces a signal equal to or greater than the reference standard.
- No dents.
- No visible scratches having a transverse component.
- Surface finish equal to or smoother than the surrounding undisturbed material.
- Coiled tubing string re-evaluated as per 21.3.2 Evaluating Suitability and 21.3.3 Assessing Mechanical Strength.

NDE Documentation

The complete results of all NDE performed on a coiled tubing string should be documented by the NDE technician who performed the inspection. Documentation includes the following:

- Serial number of the coiled tubing string.
- Size, weight and material of the coiled tubing string.
- NDE methods used and details of NDE equipment including serial numbers of all calibration standards and the last date of their verification.
- NDE procedures followed including reference number and revision level or date.
- Results of the NDE including all indications noted and the results of the ultimate prove-up of each indication.
- Printed name and signature of the NDE technician performing the inspection.
- Date of the inspection.

Appendix C: Elastomers

Design

Sealing materials normally include elastomers or elastomers with plastics. Plastics are normally used in conjunction with elastomers for anti-extrusion backup. See the Glossary for definitions of elastomers and plastics as used in this IRP.

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

Material Selection

Two important parameters for seal material selection are temperature (service and ambient) and the fluids to be encountered for the intended application. Pressure will affect seal mechanical design and operating parameters more than it affects the seal material. Rapid depressurization of the system can also cause rupture of the seal material (explosive decompression).

Temperature

Elastomers and plastics have upper and lower temperature limitations that are usually published by the seal manufacturer and are available through them or the equipment supplier.

The general chemical resistance of elastomers at low temperatures may be critical for BOPs or other equipment. Supplementary heating could be required for the BOP element based on equipment manufacturer’s guidelines or government regulations.

The T5 temperature (as measured using ASTM D1053-92a test method) or the TR10 plus 5 temperature (measured using ASTM D1329 test method) may be used as estimates of a minimum operating temperature for an elastomer. The Glass Transition Temperature (Tg) of the elastomer is also used to help determine the low temperature capability.

Fluids

Fluid exposures can cause changes in the seal material. Some of these changes are reversible and others are not. For example, the seal swelling caused by gas or oil permeation may reverse itself once the elastomer is removed from the exposure environment. Nitrogen or natural gas impregnation of the elastomers may lead to irreversible damage such as blistering or tearing. H_2S exposure can cause additional cross-linking of the elastomer which results in embrittlement which is also irreversible.

The aromatic component of mineral-oil-based fluids that can be present in crude oil, invert emulsion muds and fracturing oil can swell and weaken some elastomers. Alcohol, such as methanol, causes some elastomers to lose their resilience. Amine-based corrosion inhibitors and sulphur solvent chemicals such as dimethyl disulphide (DMDS) are very aggressive to many elastomers. Negative effects of these chemicals can vary depending on the elastomer, service, and concentration of chemicals. This effect may be difficult to predict and may require specific testing to determine adverse effects.

Testing and Evaluation

No oilfield industry testing and evaluation standard exists for elastomers used in oilfield equipment and so the manufacturer’s standards are often used. However, API does have specific test requirements for verifying elastomer performance for wellhead and drill-through equipment. These tests are based on standard test environments and equipment temperature and pressure ratings.

NACE TM0187: Evaluating Elastomeric Materials in Sour Gas Environments and NACE TM0296: Evaluating Elastomeric Materials in Sour Liquid Environments are good examples of generic test procedures and methods.

Storage Conditions

Inventory control is especially important because most elastomers look alike. Even in the same generic category such as nitrile, small chemical and dimensional variances made by manufacturers will drastically change the elastomer effectiveness for the given application.

API and ISO are recommended sources of further quality control information on elastomers.

Properties and Uses

Table 28 outlines the typical properties for common oilfield elastomers. The purpose of this table is to aid in elastomer selection. It should not be considered an exhaustive list.

Table 28. Properties of Common Oilfield Elastomers

Generic Category[13]	ASTM Designation	Hardness Range (Shore A)	H_2S Resistance	Liquid Hydrocarbon Resistance	Temperature Rating (°C)[14]	Common Trade Name Examples	Comments
Natural rubber	NR	25-100	Fair	Poor	-60 – 80		Sometimes used for BOP elements Good low temperature points
Polychloroprene	CR	30-95	Fair	Fair	-50 to 90	Neoprene	High swelling in oil Good low temperature properties Better H_2S resistance than NBR
Epichlorohydrin	CO	50-85	Fair	Fair	-40 to 150	Hydrin 100 Herclor H	Good low temperature properties Has limited resistance to methanol
Ethylene propylene diene	EPDM	65-90	Good	Poor	-50 to 150	Nordel	Good high temperature Used mainly for geothermal applications Excellent water resistance Large swelling in oil (unsuitable for general oilfield)
Nitrile	NBR	40-95	Poor	Good	-50 to 120	Buna N Hycar	Most common oilfield elastomer Used commonly for packer, BOP elements Low temperature rating can vary Various levels of acrylonitrile available
Hydrogenated nitrile	HNBR	40-90	Fair	Good	-50 to 120		Improved H_2S and amine resistance over standard nitrile
Fluorocarbon	FKM	60-90	Fair	Good	-30 to 200	Viton Fluorel	Common oilfield elastomer often replaces NBR for higher

[13] There is no intent to limit the choice of elastomers to these materials only.

[14] Not all elastomer products in a generic category will have the full temperature range given.

Generic Category[13]	ASTM Designation	Hardness Range (Shore A)	H_2S Resistance	Liquid Hydrocarbon Resistance	Temperature Rating (°C)[14]	Common Trade Name Examples	Comments
							temperatures Can harden in amine inhibitors and sulphur solvents Has limited methanol resistance
Tetrafluoro-ethylene-propylene	TFEP	60-95	Good	Fair	0 to 200	Aflas	Excellent general thermo-chemical resistance Poor mechanical properties below 0 °C Moderate swelling in hydrocarbons Better in amine inhibitors than FKM Mainly downhole applications
Perfluoro-elastomer	FFKM	65-95	Good	Good	-20 to 230	Kalrez Chemraz	Excellent general thermo-chemical resistance Poor mechanical properties below 0 °C Superior amine and hydrocarbon resistance Mainly used downhole for O-ring or chevron-ring packing

Symbols, Acronyms and Abbreviations

Symbols

The following symbols are used in the figures in IRP 21.

Check Valve

Hydraulically Controlled Remote (HCR) Valve (can be either inside or outside of the manual valve)

Manually Operated Valve

Acronyms and Abbreviations

The following acronyms and abbreviations are used in IRP 21.

ADI Automated Dimensional Inspection

AER Alberta Energy Regulator

API American Petroleum Institute

ASME American Society of Mechanical Engineers

ASNT American Society for Nondestructive Testing

ASTM American Society of Testing and Materials

BCOGC British Columbia Oil and Gas Commission

BHA Bottomhole Assembly

BOP Blowout Preventer

CAODC Canadian Association of Oilwell Drilling Contractors

CAPP Canadian Association of Petroleum Producers

CMTR Certified Material Test Reports

CO_2 Carbon Dioxide

CT Coiled Tubing

DACC Drilling and Completions Committee

DMDS Dimethyl Disulphide

EDM Electron Discharge Machined

EMI Electromagnetic Inspection

ESD Emergency Shut Down (Valve)

H_2S Hydrogen Sulphide

HAZ Heat-affected Zone

HE Hydrogen Embrittlement

HIC Hydrogen Induced Cracking

HCl Hydrochloric Acid

HCR Hydraulically Controlled Remote (Valve)

HRC Rockwell “C” Hardness

ID Inside Diameter

IQI Image Quality Indication

IRP Industry Recommended Practice

ISO International Standards Organization

LCM Lost Circulation Material

LPI Liquid Penetrant Inspection

MAOP Maximum Anticipated Operating Pressure

MASP Maximum Anticipated Surface Pressure

MPI Magnetic Particle Inspection

MQP Manufacturing Quality Plan

MSDS Materials Safety Data Sheet (now SDS)

MT Magnetic Testing

N_2 Nitrogen Gas

NACE National Association of Corrosion Engineers

NDE Non-destructive Examination

NORM Naturally Occurring Radioactive Material

OD Outside Diameter

OEM Original Equipment Manufacturer

PPE Personal Protective Equipment

PQR Procedure Qualification Record

PSAC Petroleum Services Association of Canada

PT Penetrant Testing

QMS Quality Management System

RT Radiographic Testing

SCC Stress Corrosion Cracking

SDS Safety Data Sheet

SITHP Shut-in Tubing Head Pressure

SMYS Specified Minimum Yield Strength

SPE Society of Petroleum Engineers

SSC Sulphide Stress Cracking

TDG Transportation of Dangerous Goods

Tg Gas Transition Temperature

UT Ultrasonic Shear Wave Testing

VME von Mises Equivalent

WHMIS Workplace Hazardous Materials Information System

WPS Weld Procedure Specification

Glossary

IRP 21 uses the following definitions:

BOP Drill A drill to determine the crew's ability to detect a well kick and to perform a shut-in for the operation in progress.

Circulating Media Circulating media includes both injected and produced fluids as well as their mixtures

Calibration Comparison and adjustment to a standard of known accuracy.

Coiled Tubing Continuously manufactured steel tubular product spooled onto a take-up reel.

Conformance Compliance with specified requirements.

Corrosion The destruction of metal by chemical or electrochemical means. Potential agents for initiating corrosion include carbon dioxide, hydrogen sulphide, chlorides and oxygen. All of these can be introduced into the circulating system during wellbore or surface circulation of the circulating media. Corrosion results in pitting, embrittlement, stress cracking and black sulphide coating. Factors that affect corrosion rates include pressure, temperature and pH.

Critical Lift A non-routine crane lift requiring detailed planning and additional or unusual safety precautions. All lifts involving an occupied man basket are considered critical lifts. Certain jurisdictions may have alternative definitions.

Critical Sour Well/Special Sour Well (Well Servicing and Drilling) Each meets the conditions defined by the applicable jurisdictional regulator. These terms refer to the current definition from the AER (critical sour) and BCOGC (Class C/Special Sour).

Coiled Tubing String-Life Management System A manual tracking or computer-based modelling system for predicting the remaining working life of a coiled tubing string.

Discharge Lines The treatment life from downstream of the discharge of the high pressure pump.

Drilling Consult local jurisdictional regulations regarding the specific definition of drilling operations. In Alberta consult AER Directive 36: Drilling Blowout

Prevention Requirements and Procedures section 23.1. See also Well Servicing Operations.

Elastomer An elastomer is a material that can be stretched repeatedly to at least twice its original length and upon release of stress will return with force to its original length**.**

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**.**

Flow Nipple A non-pressure containing device with a side outlet that guides flow back of drilling fluids to the surface mud system. May also referred be to as a **Bell Nipple**.

Hard Shut-In To close in a well with the BOP having the choke or choke line valve closed.

Hydrostatic Proof-Testing of Coiled Tubing Strings Pressure tests performed on a string of coiled tubing at a facility (manufacturer, end user, etc.). These tests typically follow any string maintenance being performed on the coil. It is separate from any subsequent testing performed during rig-up or other operations at a wellsite.

Maximum Anticipated Operating Pressure (MAOP) For a given piece of equipment, the highest calculated pressure that a given equipment component will be subjected to during the execution of the prescribed service and/or during a contingency operation.

Maximum Anticipated Surface Pressure (MASP) The highest pressure predicted to be encountered at the surface of a well. This pressure prediction should be based upon formation pressure minus a wellbore filled with native formation fluid at current conditions. If formation fluid is unknown, this pressure prediction should be based upon formation pressure minus a wellbore filled with dry gas from the surface to the completion interval.

Ovality The distortion on the cross-sectional profile of a coiled tubing string. The mechanical performance of oval tubing deteriorates as the degree of ovality increases. The most critical effect is the ability of the tube to resist collapse under differential pressure. String ovality limits are generally determined by the maximum diameter that can pass through the primary pressure-control equipment. In high-pressure operations, the ovality limits will generally be reduced to maintain an adequate safety margin against string collapse. (Source: SLB Oilfield Glossary).

Plastic Plastics (e.g., Teflon, Ryton or PEEK) are polymers that are stronger and have better chemical resistance than elastomers but do not have the resilience (rebound) properties of elastomers.

Predicted Life to Failure The fatigue life of a string calculated by a computer model where all safety limits are removed.

Predicted Working Life The fatigue life of a string calculated by a computer with a known safety factor in place.

Pressure Control System A pressure control system is defined as the blowout prevention system and includes all equipment from the top wellhead flange to the uppermost piece of pressure control equipment. The pressure containing system includes the BOP stack, snubbing stack, coiled tubing stack and pressure deployment system (including all bleed lines).

Quality Conformance to specified requirements.

Quality Assurance Planned, systematic and preventative actions that are required to ensure that materials, products or services will meet specified requirements.

Quality Control Inspection, test or examination to ensure that materials, products or services conform to specified requirements.

Remanufacture Rework of original equipment manufacturer (OEM) specified dimensions or welding.

Return Line The line from the discharge from the well (flow tee or other) up to the primary choke manifold.

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

Shop Servicing A 3-year certification that fulfills the requirements of AER Directive 36: Drilling Blowout Prevention Requirements and Procedures Appendix 5.

Sour Conditions Partial pressure of H_2S in a wet gas phase of the wellbore fluids 0.05 psia (per NACE MR 0175/ISO 15156).

Sour Well For purposes of IRP 21, a well is considered sour if it has any concentration of H_2S (H_2S > 0 ppm) (as per AER Directive 71: Emergency Preparedness and Response Requirements for the Petroleum Industry)

String Separation A separation above the highest disconnect in the coiled tubing string. This separation may be intentional or as a result of material failure.

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

Well Servicing Operations Those operations that have the ability to do a hard shut-in with no casing limitation relative to reservoir pressure. Configuration/operation includes a master valve and cemented casing. Everything else is drilling.

References

The following documents are referenced in IRP 21.

Alberta Regulations

These following documents are available through the Alberta Energy Regulator (www.aer.ca).

- Directive 033: Well Servicing and Completions Operations - Interim Requirement Regarding the Potential for Explosive Mixtures and Ignition in Wells
- Directive 036: Drilling Blowout Prevention Requirements and Procedures
- Directive 036 (Addendum): Drilling Blowout Prevention Requirements and Procedures (replaces ID 94-3)
- Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting
- Alberta Oil and Gas Conservation Regulations and Rules

API

The following document is available through www.API.org:

- API Recommended Practice 16ST (R2014) Coiled Tubing Well Control Equipment Systems, First Edition.
- API Spec Q1 Quality Program1: Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry, Includes Errata (February 2014), Errata 2, 9th Edition. March 2014.

ASME

The following documents are available from www.ASME.org:

- ASME Boiler and Pressure Vessel Code, Section V: Nondestructive Examination. July 2015.
- ASME Boiler and Pressure Vessel Code, Section IX: Welding and Brazing Qualifications. July 2015.

ASNT

The following document is available from www.ASNT.org:

- SNT-TC-1A (2011) Personnel Qualification and Certification in Nondestructive Testing

ASTM

The following documents are available through ASTM (www.astm.org):

- ASTM A370: ASTM A370 - 15 Standard Test Methods and Definitions for Mechanical Testing of Steel Products
- ASTM A450/440M: ASTM A450/A450M - 15 Standard Specification for General Requirements for Carbon and Low Alloy Steel Tubes
- ASTM D1053: ASTM D1053 – 92A Standard Test Methods Rubber Property - Stiffening at Low Temperatures: Flexible Polymers and Coated Fabrics. 2012.
- ASTM D1329: ASTM D1329 – 08 Standard Test Method for Evaluating Rubber Property - Retraction at Lower Temperatures (TR Test)
- ASTM E10: ASTM E10-15 Standard Test Method for Brinell Hardness of Metallic Materials Volume 03.01
- ASTM E1030/E1030M: ASTM E1030/E1030M - 15 Standard Test Method for Radiographic Examination of Metallic Castings Volume 03.03
- ASTM E1032: ASTM E1032 - 12 Standard Test Method for Radiographic Examination of Weldments Volume 03.03
- ASTM E140: ASTM E140 – 12be1 Standard Hardness Conversion Tables for Metals Relationship Among Brinell Hardness, Vickers Hardness, Rockwell Hardness, Superficial Hardness, Knoop Hardness, and Scleroscope Hardness Volume 03.01
- ASTM E164: ASTM E164 - 13 Standard Practice for Contact Ultrasonic Testing of Weldments Volume 03.03
- ASTM E165/165M: ASTM E165 - 12 Standard Practice for Liquid Penetrant Examination for General Industry Volume 03.03
- ASTM E18: ASTM E18 - 15 Standard Test Methods for Rockwell Hardness of Metallic Materials Volume 03.01
- ASTM E273: ASTM E173-15 Standard Practice for Ultrasonic Testing of the Weld Zone of Welded Pipe and Tubing Volume 03.03
- ASTM E309: ASTM E309-11 Standard Practice for Eddy-Current Examination of Steel Tubular Products Using Magnetic Saturation Volume 03.03
- ASTM E384: ASTM E384 – 11e1 Standard Test Method for Knoop and Vickers Hardness of Materials Volume 03.01

- ASTM E570: ASTM E570-15 Standard Practice for Flux Leakage Examination of Ferromagnetic Steel Tubular Products Volume 03.03
- ASTM E709: ASTM E709-15 Standard Guide for Magnetic Particle Testing Volume 03.03
- ASTM E751/E751M: ASTM E751/E751M – 12 Standard Practice for Acoustic Emission Monitoring During Resistance Spot-Welding Volume 03.03
- ASTM E8/E8M: ASTM E8/E8M – 15A Standard Test Methods for Tension Testing of Metallic Materials Volume 03.01
- ASTM E94: ASTM E94 – 04 (2010) Standard Guide for Radiographic Examination Volume 03.03

Enform

The following documents are available from Enform (www.enform.ca):

- Enform Fire and Explosion Hazard Management Guideline
- Enform Lease Lighting Guideline
- IRP 1: Critical Sour Drilling
- IRP 2: Completing and Servicing Critical Sour Wells
- IRP 4: Well Testing and Fluid Handling
- IRP 6: Critical Sour Underbalanced Drilling
- IRP 7: Standards for Wellsite Supervision of Drilling, Completion and Workovers
- IRP 8: Pumping of Flammable Fluids
- IRP 14: Non Water Based Drilling and Completion/Well Servicing Fluids
- IRP 22: Underbalanced and Managed Pressure Drilling Operations Using Jointed Pipe

NACE

The following documents are available through NACE (www.nace.org):

- NACE TM0187 2011: Standard Test Method for Evaluating Elastomeric Materials in Sour Gas Environments
- NACE TM0296-2014: Standard Test Method for Evaluating Elastomeric Materials in Sour Liquid Environments
- NACE Standard MR0175/ISO 15156: Materials for use in H_2S-containing Environments in oil and gas production

Other References

Other references include the following:

- Alberta OHS publication GS006: Best Practice – Working Safely in the Heat and Cold (available through work.alberta.ca under Occupational Health and Safety, Publications, Education and Promotion).
- BC Oil and Gas Commission Drilling and Production Regulations can be found on the Legislation page of the BCOGC website.
- CAODC Technical Information Bulletin T-02-08 regarding electrical bonding and grounding (available through www.caodc.ca).
- Manitoba Drilling and Production Regulations can be found on the Government of Manitoba Website under the Manitoba Mineral Resources Acts and Regulations page.
- Saskatchewan regulations are found in Saskatchewan Oil and Gas Conservation Regulations (OGCR) and can be found on the Government of Saskatchewan Website under the Publications Centre for the Queens Printer. Publication name is the Oil and Gas Conservation Regulations.
- SPE Paper 37067: High Pressure Flammability of Drilling Mud/Condensate/Sour Gas Mixtures in De-oxygenated Air for Use in Underbalanced Drilling (available through www.spe.org)