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Introduction

This recommended practice is provided to meet the need for assembly and operation of coiled tubing well control equipment and systems.

Coiled tubing well control practices typically rely on mechanical barriers as the primary means for well control.

1 Scope

1.1 General

This recommended practice (RP) addresses coiled tubing well control equipment assembly and operation as it relates to well control practices. Industry practices for performing well control operations using fluids for hydrostatic pressure balance are not addressed in this RP.

This document covers well control equipment assembly and operation used in coiled tubing intervention and coiled tubing drilling/milling applications performed through:

— christmas trees constructed in accordance with API 6A and/or API 11IW,
— a surface flow head or surface test tree constructed in accordance with API 6A,
— a fracture stimulation wellhead assembly (with at least two gate valves installed for isolation)
— drill pipe or workstrings with connections manufactured in accordance with API 5CT, API 5DP and/or API 7-1.

1.2 Operations Not Covered in this Document

The following operations are not covered in the scope of this document:

a) coiled tubing well intervention operations without the christmas tree (or surface test tree) in place,
b) coiled tubing drilling operations without the christmas tree (or surface test tree) in place,
c) coiled tubing less than 1/2 in. outside diameter (OD) used in well intervention operations,
d) coiled tubing intervention operations within pipelines and flowlines,
e) open-water coiled tubing intervention operations,
f) reverse circulation of solids-laden fluids or gas through the coiled tubing workstring
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2 Normative References

The following referenced documents are indispensible in the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any addenda) applies.

API Specification 5ST, Specification for Coiled Tubing
API Specification 6A, Specification for Wellhead and Christmas Tree Equipment
API Technical Report 6AF1, Technical Report on Capabilities of API Flanges under Combinations of Load
API Technical Report 6AF2, Technical Report on Capabilities of API Integral Flanges under Combination of Loading
API Specification 7K, Specification for Drilling and Well Servicing Equipment
API Specification 16A, Specification for Drill-through Equipment
API Specification 16C, Specification for Choke and Kill Systems
API Specification 16D, Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment
API Specification 20E, Alloy and Carbon Steel Bolting for use in the Petroleum and Natural Gas Industries
API Specification 20F, Stainless Steel and Corrosion Resistant Alloy Bolting for use in the Petroleum and Natural Gas Industries
ASME B31.3 ¹, Process Piping
NACE MR0175/ISO 15156 ², Sulfide Stress Cracking Resistant-Metallic Materials for Oilfield Equipment

² NACE International (formerly the National Association of Corrosion Engineers), 1440 South Creek Drive, Houston, Texas 77218-8340, www.nace.org.
3 Terms, Definitions and Abbreviations

3.1 Terms and Definitions

3.1.1 accumulator
A pressure vessel charged with a non-reactive or inert gas used to store hydraulic fluid under pressure for operation of well control equipment.

3.1.2 accumulator bank
An assemblage of multiple accumulators sharing a common manifold.

3.1.3 accumulator precharge
An initial inert gas charge in an accumulator, which is further compressed when the hydraulic fluid is pumped into the accumulator thereby storing potential energy.

3.1.4 actuation test
function test
The closing and opening of a well control component to assure mechanical functioning.

3.1.5 adapter
A pressure-containing piece of equipment having end connections of different API size designation and/or pressure ratings, used to connect other pieces of equipment of different API size designation and/or pressure ratings.

3.1.6 annular preventer
A device with a generally toroidal shaped steel-reinforced elastomer packing element that is hydraulically operated to close and seal around any coiled tubing size and CT BHA or to provide full closure of the wellbore.

3.1.7 anti-buckle guide
A device located between the top of the stripper assembly and the bottom of the injector gripper blocks that provides lateral support to the coiled tubing as it is pushed into the well control stack preventing or reducing the tendency for the tubing to buckle in this area.

3.1.8 articulated line
Pump, choke, and kill lines assembled as a unit with rigid pipe, swivel joints, and end connections designed to accommodate specified relative movement between end terminations.

3.1.9 backflow
Fluid flow in a direction opposite to the intended direction of flow.
3.1.10 back-pressure valve
A flow check device that is installed on the deployed end of the coiled tubing string and prevents well fluids from flowing out of the well through the ID of the CT Workstring.

NOTE In coiled tubing services, a back-pressure valve is typically disconnected from the end with applied internal coiled tubing pressure or with a mechanical release mechanism (shear-out sub).

3.1.11 barrier element (CT)
Pressure and flow-containing device or system used in coiled tubing well control that contributes to well integrity by preventing the unintended communication of pressure and the flow of fluids (liquid, gas or both).

3.1.12 bend cycle
The coupling of two tube bending events.

NOTE Consists of one straightening event and one bending event, where the material strain is equal in magnitude.

3.1.13 bleed-off line
The assembly of valves and piping used to release trapped pressure from the pump line(s) or kill line(s).

3.1.14 blind ram
The ram assembly in a well control stack which is designed to seal opposing elastomeric elements against each other in an unobstructed bore to isolate pressure below the ram in the well control stack.

NOTE Not designed to seal against the coiled tubing.

3.1.15 bolting
All threaded fasteners including studs, tap end studs, double ended studs, headed bolts, cap screws, screws and nuts.

3.1.16 bottomhole assembly
BHA
The assemblage of tools and equipment installed on the end of the coiled tubing workstring used to perform a prescribed service in the wellbore.

3.1.17 bottomhole assembly connector
BHA connector
CT end connector
A mechanical device used to attach the bottomhole assembly tools to the coiled tubing workstring.

3.1.18 choke
A device with either a fixed or variable aperture used to control the rate of flow of liquids and/or gas.

3.1.19 choke line
High-pressure line connected to the well control stack for the transmission of well fluids to the choke manifold during well control operations.
3.1.20
choke line valve
Valve(s) connected to and a part of the well control stack that controls the flow to the choke line and manifold.

3.1.21
choke manifold
Assembly of valves, chokes, gauges, pressure sensors and lines used to control the rate of flow from the well during well intervention and well control operations.

3.1.22
christmas tree
A combination of valves and fittings assembled above the top of the tubing hanger on a completed well to contain well pressure and control the flow of hydrocarbons and other fluids.

3.1.23
circulation (conventional)
The movement of fluid from the pump(s) through the coiled tubing workstring which discharges through the CT BHA deployed within the well and returns to surface up the annular space in the wellbore.
NOTE  The flow of fluids may exit the well control stack through the flow cross/flow tee or production flowline in the christmas tree.

3.1.24
circulation (reverse)
The movement of fluid from the pump(s) into the annular space between the coiled tubing workstring OD and the ID of the wellbore which is directed into the CT BHA and returns to surface through the ID of the coiled tubing workstring.
NOTE  The flow of fluids exit through the CT reel swivel and is directed through surface piping to the choke line and choke device(s).

3.1.25
closing ratio
Area of the actuator piston(s) exposed to the close operating pressure, divided by the cross-sectional area of the piston shaft exposed to wellbore pressure.

3.1.26
closure bolting
Bolting used to assemble or join wellbore pressure-containing parts, including end and outlet connections.
Note  Examples include flange bolting, bonnet bolting, end connection bolting on the well control stack and ram door bolting.

3.1.27
coiled tubing workstring
Continuously milled carbon or alloy steel tubular product spooled onto a reel that is used in well intervention operations.

3.1.28
coiled tubing connector
tube-to-tube connector
A mechanical device used to join two segments of coiled tubing together. This type of connection may be rigid or spoolable.
3.1.29
**collapse**
The flattening of CT due to the application of differential pressure (external to internal), with or without an axial tensile load.

3.1.30
**competent person**
Person with characteristics or abilities gained through training, experience or both, as measured against the manufacturer’s or equipment owner’s established requirements.

3.1.31
**concentric well intervention operations**
Well intervention operations conducted within conventional tubing or tubing-less well completions.

NOTE These operations are normally performed with the christmas tree in place using a coiled tubing unit, wireline unit, hoisting unit, hydraulic workover (snubbing) unit or small jointed-tubing rig.

3.1.32
**connection**
Flanges, and studded connections manufactured in accordance with API specifications, including dimensional requirements.

3.1.33
**control console**
An enclosure displaying an array of switches, push buttons, lights, valves, various pressure gauges and/or meters to control or monitor coiled tubing operation functions.

3.1.34
**control fluid**
Hydraulic fluid (at atmospheric pressure) to be used for operation of the well control components, injector, stripper assembly and CT reel.

3.1.35
**cross flow cross**
A pressure-containing fitting with a minimum of four openings.

NOTE Usually all four openings are oriented at 90 degrees to one another in the same plane.

3.1.36
**deployment bar**
Pressure isolated bar(s) installed in the bottomhole assembly (BHA) used for the safe insertion and removal of tool strings in two or more sections with surface pressure present, if the tool string length exceeds the available height of the well control stack above the tree.

3.1.37
**diametral growth**
The enlargement of the coiled tubing diameter due to the effects of applied internal pressure when the coiled tubing is subjected to bend-cycling events.

3.1.38
**energized fluid**
A fluid having compressed gas potential energy.
3.1.39  
extective hydraulic actuator pressure  
The pressure determined by subtracting the ram piston balance pressure from the observed hydraulic actuator system pressure acting on a given ram.

3.1.40  
fatigue  
The process of progressive localized permanent structural change occurring in a material subjected to conditions which produce fluctuating stresses that may culminate in cracks or complete failure after a sufficient number of fluctuations.

3.1.41  
flange  
A protruding rim, with holes to accept bolts and having a sealing mechanism, used to join pressure containing equipment together by bolting one flange to another.

3.1.42  
flexible line  
An assembly of a pipe body and end-fittings.

3.1.43  
flow check device  
A valve that permits fluid to flow freely in one direction and contains a mechanism to automatically prevent flow in the reverse direction.

3.1.44  
force (pressure-affected cross-section)  
$F_{\text{PACS}}$  
Force created by differential pressure acting across an energized sealing element on the pressure-affected cross-sectional area of a tubular member, such as a coiled tubing or snubbing workstring.

3.1.45  
force (snub)  
Sum of $F_{\text{PACS}}$ and stripper friction acting on the CT workstring which must be overcome by the CT injector to deploy the CT workstring into a wellbore with surface pressure present.

3.1.46  
force (thrust)  
Sum of snub force and secondary reactive axial force(s) acting on the CT workstring which must be overcome by the injector to deploy the CT into a wellbore with surface pressure present.

3.1.47  
full-opening valve  
A valve capable of passing a sphere of the valve’s nominal size through the closure mechanism when the valve is in its fully opened position.

NOTE  The closure mechanism may or may not be of the same size as the end connections.
3.1.48
function
The operation of a well control component, choke or kill valve, or any other component in one direction.

EXAMPLE Closing the blind ram is one function, and opening the blind ram is a separate function.

3.1.49
gauge and test port connection
Hole drilled and tapped into API 6A equipment through which internal pressure may be measured or through which pressure may be applied to test the sealing mechanism.

3.1.50
hydrostatic pressure
Pressure that is exerted at any point in the wellbore due to the weight of the column of fluid above that point.

3.1.51
intervention
Well servicing operations conducted within a completed wellbore.

3.1.52
kill
The act of balancing the formation pressure in a wellbore with the hydrostatic pressure derived from a vertical column of fluid with a given density.

Note: The formation is a subsurface completion interval which serves as the source for production of accumulated hydrocarbons or the injection of disposal fluids.

3.1.53
kill line
A high-pressure line run from the pump(s) to a connection below the blind ram or shear-blind ram that allows fluid to be pumped into the well or annulus with the designated ram closed during well control operations.

3.1.54
kill line inlet
An inlet on the well control stack that provides a flow path to pump fluids into the sheared coiled tubing segment suspended within the wellbore or within the annulus between the coiled tubing string and the completion tubulars.

3.1.55
leakage
Visible passage of the pressurized fluid from the inside to the outside of the pressure containment area of the equipment being tested and/or the loss of test pressure observed on the pressure-recording device.

3.1.56
lubricator
An assembly of tube sections generally constructed with quick union-type integral seal end connections.

NOTE This term is applied to the assembly of pressure-control tubular sections installed between the stripper assembly and the upper-most well control stack-sealing ram and is typically used to house the BHA tool string.
3.1.57
maintenance
Disassembly, inspection, reassembly, replacement of components and testing of equipment performed in accordance with equipment owner’s maintenance program and the manufacturer’s guidelines.

3.1.58
manifold
An assemblage of pipe, hydraulic hoses, valves and fittings by which fluid from one or more sources is selectively directed to various systems or components.

3.1.59
original equipment manufacturer
OEM
Design owner or manufacturer of the traceable assembled equipment, single equipment unit or component part.

Note   If any alterations to the original design and/or assembled equipment or component part are made by anyone other than the OEM, the assembly, part, or component is not considered an OEM product. The party that performs these alterations is then designated as the OEM.

3.1.60
other end connector
OEC
Connectors that are not specified in an API dimensional specification, including API flanges, pressure-containing hydraulic latch quick-connects and hubs with non-API gasket preparations and manufacturer’s proprietary connections.

3.1.61
ovality
The change in roundness of a tube body due to external forces derived from bend-cycling activities.

3.1.62
pipe-heavy
Condition occurring during concentric well intervention operations where the well pressure applied against the cross-sectional area of the tube acting at the stripper element or pressure isolation ram creates an upward acting force that is less than the buoyancy-compensated weight of the deployed workstring.

NOTE 1   In this condition, mechanical assistance is required to support the weight of the tubing during deployment or retrieval operations.

NOTE 2   Buoyancy compensation of the workstring is a function of the weight of the fluid internal to the workstring, the weight of the fluid displaced by the workstring and the air weight of the workstring.

3.1.63
pipe-light
Condition occurring during concentric well intervention operations where the well pressure applied against the cross-sectional area of the tube acting at the stripper element or pressure isolation ram creates an upward acting force that is greater than the buoyancy-compensated weight of the deployed workstring.

NOTE 1   In this condition, mechanical assistance is required to apply thrust to the tubing during deployment or to maintain control of the workstring when retrieving from the well.

NOTE 2   Buoyancy compensation of the workstring is a function of the weight of the fluid internal to the workstring, the weight of the fluid displaced by the workstring and the air weight of the workstring.
3.1.64
pipe ram
The ram assembly in a well control stack which is designed to close and seal around the coiled tubing workstring, isolating pressure in the annular space below the ram.

3.1.65
pipe-slip ram
The combination ram assembly in the well control stack designed to secure the coiled tubing within the slip inserts and isolate pressure in the annular space below the combination ram in a single operation.

3.1.66
power fluid
Pressurized hydraulic control fluid used to operate the well control equipment components.

3.1.67
pressure
Ratio of force to the area over which that force is distributed (i.e. pound force to an area (in.²), measured in “psi”)

  absolute pressure
  Internal pressure that the equipment is designed to contain and/or control, or that is zero-referenced against a perfect vacuum.
  NOTE Measured in psia.

  differential pressure
  Difference in pressure between any two points (p1 and p2); measured in “psid”.

  gauge pressure
  Pressure measured relative to the ambient pressure
  NOTE e.g. atmospheric for surface application, hydrostatic for subsea application
  NOTE Measured in psig.

3.1.68
pressure-containing part
Part exposed to wellbore fluids whose failure to function as intended would result in a release of wellbore fluid to the environment or to other areas within the well control equipment assembly.

  NOTE 1 Examples include bodies and bonnets.
  NOTE 2 Examples of items that are not included are actuator cylinders and cylinder heads.

3.1.69
pressure-controlling bolting
Bolting used to assemble or join pressure-controlling part(s)

  NOTE Examples include bolting on ram, seat or seal retainer bolting, shear-blind ram blade bolting

3.1.70
pressure-controlling part
Part intended to control or regulate the movement of wellbore fluids

  NOTE Examples include packing elements, rams, and replaceable seats within a pressure containing part.
3.1.71
**pressure-retaining bolting**
Bolting used to assemble or join pressure-retaining parts whose failure would result in a release of wellbore fluid to the environment.

*NOTE*  Examples are studs and nuts on top of a pressure-containing hydraulic latch connector.

3.1.72
**pressure-retaining part**
Part not exposed to wellbore fluids whose failure to function as intended will result in a release of wellbore fluid to the environment.

3.1.73
**pump line**
A high-pressure line between the pump(s) and the coiled tubing service reel or kill line.

*NOTE*  This line is typically configured to pump fluid into the wellbore through the coiled tubing workstring or into the wellbore annulus when connected to the kill line.

3.1.74
**quick union**
End connections that employ O-rings seals to hold pressure, while allowing thread make-up of the union connection by hand.

*NOTE*  Used to join sections of lubricator and connect the stripper assembly to the top of the ram-type well control equipment.

3.1.75
**ram piston balance pressure**
Amount of hydraulic actuator pressure required to create a force equal to that generated by wellbore pressure acting on the cross-sectional area of the ram piston rod.

*NOTE*  Typically determined by dividing the MASP by the closing ratio of the ram for ram performance testing purposes.

3.1.76
**rapid gas decompression**
RGD
Sudden depressurization of compressed gas in a system.

*NOTE*  The rapid decrease in gas pressure causes the gas to expand rapidly and can cause blistering or internal damage to gas saturated elastomeric materials.

3.1.77
**rated working pressure**
RWP
The maximum internal pressure the equipment component is designed to contain and/or control.

*NOTE 1*  Indicative of wellbore wetted rated components or actuator systems

*NOTE 2*  Should not be confused with test pressure.

3.1.78
**relief valve**
A device that is built into a hydraulic or pneumatic system to mechanically relieve (dump) any excess of the predetermined pressure setting.
3.1.79 repair
Replacement of parts or correction of damaged components that does not include machining, welding, heat treating or other manufacturing operation.

3.1.80 reservoir
A storage tank for control fluids used to operate the well control equipment operating system and other hydraulically actuated devices.

3.1.81 response time
The time required to function a well control component closed and establish an effective pressure seal.

3.1.82 shear ram
The ram assembly in a well control stack which is designed to shear the coiled tubing and any spoolable components inside the coiled tubing (including wire, tubing, and/or cable).

NOTE The shear ram blade is designed to maintain sufficient flow area at the cut to facilitate through-coiled tubing pumping and well kill operations.

3.1.83 shear-blind ram (standard)
The combination ram assembly in the well control stack which is designed to shear the coiled tubing and any spoolable components inside the coiled tubing (including wire, tubing, and/or cable) and seal the wellbore in a single operation. The shear-blind ram blade is designed to maintain sufficient flow area at the cut to facilitate through-coiled tubing pumping and well kill operations.

3.1.84 shear-blind ram (dedicated)
The combination shear-blind ram assembly in the well control stack which is installed as close to the wellhead as possible and operated through the dedicated accumulator circuit on the well control closing unit.

3.1.85 slip ram
The ram assembly in a well control stack which is equipped with tubing slips inserts that, when engaged, prevents movement of the coiled tubing but does not isolate pressure or control flow.

3.1.86 spacer spool(s)
Pressure-containing pieces of equipment having flanged end connections which serves to space out the well control stack components with equal sized end connections.

NOTE Spacer spools may be located above or below the well control ram stack.

3.1.87 spoolable component
Continuous manufactured length of tubular or stranded wire product installed within the ID of the CT workstring.

NOTE Spoolable components include wireline, capillary tubing and fiber optic line.
3.1.88  
spoolable connector  
A tube-to-tube connector used to join segments of the CT workstring and capable of surviving bending forces encountered during deployment and retrieval which maintaining pressure sealing integrity.

3.1.89  
stabilized pressure  
State in which the pressure change rate has decreased to within acceptable limits before beginning the hold period during a pressure test.  
NOTE Pressure changes can be caused by such things as variations in temperature, setting of elastomer seals, or compression of air or fluids, etc.

3.1.90  
stack rated working pressure  
The pressure containment rating of the ram components in a stack.  
NOTE In the event that the rams are rated at different pressures, the stack maximum rated working pressure (RWP) is considered equal to the lowest rated ram component pressure.

3.1.91  
stored hydraulic fluid  
Fluid volume recoverable from the accumulator system between the maximum designed accumulator operating pressure and the pre-charge pressure.

3.1.92  
stripper  
A pressure-controlling device with a resilient elastomeric element used to effect a seal in the annulus formed between the coiled tubing OD and stripper ID bore.  
NOTE This device is primarily used to isolate well pressure from the atmosphere when deploying or retrieving coiled tubing strings in wellbores with surface pressure present.

3.1.93  
swivel (CT reel)  
A pressure-containing component comprised of rigid elements joined by seal(s) and bearings that allow for the rotation of the rigid elements on the CT reel.  
NOTE The swivel is mounted on the axis of the coiled tubing reel and can freely rotate in the direction of the reel motion.

3.1.94  
swivel (articulated line)  
A pressure-containing component comprised of rigid elements joined by seal(s) and bearings that allow for the rotation of the rigid elements on the pump and/or kill lines.  
NOTE The swivel is not intended to allow the articulated line to rotate freely after the line has been installed.

3.1.95  
system pressure test  
The integrity test used to verify the ability of the pipe and pressure containment equipment in service to maintain a pressure seal.

3.1.96  
tee  
flow tee  
A pressure-containing fitting with three openings.  
NOTE Two openings, opposite one another, form the run portion of the tee, and one opening at 90 degrees to the line of the run forms the branch.
3.1.97  
unassisted flow  
sustained flow
A flow capable from a wellbore with any formation open to the casing and tubing that can produce to the surface without the use of artificial lift.

3.1.98  
usable hydraulic fluid capacity
The fluid volume recoverable from the accumulator system between the maximum designated accumulator operating pressure to a pressure 200 psig above the pre-charge pressure.

3.1.99  
utility bolting
All bolting that is required to mount equipment and accessories to the well control equipment that is not closure bolting, pressure-retaining or pressure-controlling.

Note: Examples include bolting on lifting eyes, pad eyes (non welded), wear bushing, nameplate, clamps for tubing, guards.

3.1.100  
visual position indicator
Visible means of determining the position of a valve, ram, connector or annular activation to indicate full open or full close positions.

3.1.101  
well control barrier
A tested mechanical device, or combination of tested mechanical devices, capable of preventing uncontrolled flow of wellbore effluents to the surface.

NOTE: The use of a weighted fluid is not considered a barrier in this document, which relies on tested mechanical equipment for well control.

3.1.102  
well control stack
An integral body or an assembly of well control components including ram-type components, stripper assemblies, annular components, spools, and valves connected to the top of the wellhead or tree to control well fluids.
3.2 Abbreviations

For the purposes of this Recommended Practice, the following abbreviations apply.

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<th>Abbreviation</th>
<th>Meaning</th>
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<td>CR</td>
<td>closing ratio</td>
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<td>CT</td>
<td>coiled tubing</td>
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<td>( F_{PACS} )</td>
<td>force acting on the pressure-affected cross-section</td>
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<tr>
<td>( H_2S )</td>
<td>hydrogen sulfide</td>
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<tr>
<td>ID</td>
<td>inside diameter</td>
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<tr>
<td>IOM</td>
<td>installation, operation and maintenance</td>
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<tr>
<td>MASP</td>
<td>maximum anticipated surface pressure</td>
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<tr>
<td>NDE</td>
<td>nondestructive examination</td>
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<td>National Institute of Standards and Technology (US)</td>
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<td>OEC</td>
<td>other end connection</td>
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4 Well Control Equipment

4.1 General
Coiled tubing well control equipment is designed to allow safe well intervention services to be performed under pressure. However, well pressure should be kept at a minimum to avoid unnecessary wear and tear on the well-control equipment. With the exception of CT ram and stripper assemblies, all CT well control stack support equipment shall be manufactured in accordance with API 16A, API 16C, and API 6A, where applicable. The selection of well control equipment for a given application should be consistent with the manufacturers’ recommendations.

4.2 Coiled Tubing Operations

4.2.1 General
Well control equipment shall be identified, installed, tested, and used to promote and maintain control of the well at all times. The following issues should be reviewed to ensure compliance with this requirement:

a) maximum anticipated surface pressure (MASP);

b) maximum anticipated operating pressure (MAOP);

c) well control barriers;

d) CT operational pressure categories;

e) well control stack configurations;

f) bore size, rated working pressure (RWP), and connections of well control equipment.

4.2.2 Maximum Anticipated Surface Pressure
The maximum anticipated surface pressure (MASP) is the highest surface pressure possible in the well which may be encountered while the well control equipment is installed.

4.2.3 Maximum Anticipated Operating Pressure
The 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.

NOTE The MAOP may be equal to or greater than the MASP.

4.2.4 Coiled Tubing Well Control Barriers
A CT well control barrier is defined as a tested mechanical device, or combination of tested mechanical devices, capable of preventing uncontrolled flow of wellbore effluents to the surface. Tested barrier elements incorporated in the well control stack and BHA shall demonstrate reliable and repeatable pressure and flow control performance through mechanical testing prior to being used for the prescribed service.
The following mechanical devices, or combination of mechanical devices, are CT well control barriers:

- a) the combination of a pipe ram sealing component and a flow check assembly installed within the CT BHA;
- b) a single blind ram and single shear ram;
- c) a shear-blind combination ram.

NOTE: A barrier envelope is a combination of barrier elements used in coiled tubing well control that together constitute a method of pressure containment and prevents uncontrolled flow of fluids to surface. Where more than one of the barrier items described above are incorporated within the well control stack, the well control stack may be classified as a barrier envelope.

NOTE: The flow check assembly installed on the end of the CT workstring in combination with a pipe ram sealing component in the well control stack constitutes only one barrier, regardless of the number of pipe ram 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 in the number of barriers in the stack.

### 4.2.5 Coiled Tubing Operational Pressure Categories

Minimum stack RWP should be selected to allow for a kill program to be implemented. The difference between the MASP and minimum stack pressure rating in Table 1 is a recommended pressure margin. Different kill margins may be applied, provided that 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. MAOP or MASP which exceeds the limits of Pressure Category (PC) 4 pressure category are beyond the scope of this document.

<table>
<thead>
<tr>
<th>Pressure Category (PC)</th>
<th>MASP Range psig</th>
<th>Minimum Rated Working Pressure of Stack(^b) psig</th>
<th>Minimum Number of Barriers</th>
</tr>
</thead>
<tbody>
<tr>
<td>PC-0</td>
<td>0(^a)</td>
<td>3000</td>
<td>1</td>
</tr>
<tr>
<td>PC-1</td>
<td>1 to 1500</td>
<td>3000</td>
<td>2</td>
</tr>
<tr>
<td>PC-2</td>
<td>1501 to 3500</td>
<td>5000</td>
<td>2</td>
</tr>
<tr>
<td>PC-3</td>
<td>3501 to 7500</td>
<td>10,000</td>
<td>2</td>
</tr>
<tr>
<td>PC-4</td>
<td>7501 to 12,500</td>
<td>15,000</td>
<td>2</td>
</tr>
</tbody>
</table>

\(^a\) PC-0 applies to those wells demonstrated as incapable of unassisted flow to surface (based on local regulatory agency guidelines).

\(^b\) The minimum RWP of the stack shall be equal to or greater than the MAOP.
4.2.6   Well Control Stack Configurations

4.2.6.1   General

4.2.6.1.1   The configuration of the well control stack will vary depending upon many factors, including, but not limited to, MAOP, MASP, CT string design, and execution of the prescribed service. All annular preventer, stripper and ram-type well control components and hydraulically-operated valves (where required) in the well control stack shall be controlled from a remote station.

4.2.6.1.2   Excluding PC 0, the standard well control stack configuration for all pressure categories shall include the following components. The recommended order of the components (from the top down) is shown as follows:

1) one stripper well control component (see 4.3.1),
2) one blind ram well control component (see 4.3.2.1),
3) one shear ram well control component (see 4.3.3),
4) one kill line inlet (see 4.3.8),
5) one slip ram well control component (see 4.3.4),
6) one pipe ram well control component (see 4.3.2.2).

4.2.6.2   Pressure Category 0 (0 psig)

The PC-0 well control components that meet the barrier requirements of Table 1 are described as follows (from top down).

a) For returns taken through the tree or wellhead below the well control stack, one pipe ram well control component in combination with a flow check assembly installed within the CT BHA.

b) For returns taken through the flow cross or flow tee installed in the well control stack:
   — one pipe ram well control component in combination with a flow check assembly installed within the CT BHA,
   — one flow tee or flow cross,
   — one pipe ram (or pipe-slip ram) well control component.

In lieu of the use of a flow check assembly, one blind ram and one shear ram or a combi shear-blind ram well control component shall be installed.

4.2.6.3   Pressure Categories 1 - 4

The acceptable options for arrangement of well control stack equipment which will meet this recommended practice for Pressure Categories 1 through 4 seen in Table 1 are shown in Table 2, with example illustrations of well control stack options seen in Annex A of this document.
Table 2 — CT Well Control Stack Equipment Configuration

<table>
<thead>
<tr>
<th>Well Control Equipment Component</th>
<th>PC - 1</th>
<th>PC - 2</th>
<th>PC - 3</th>
<th>PC - 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stripper Assembly (1ST in Service)</td>
<td>Required</td>
<td>Required</td>
<td>Required</td>
<td>Required</td>
</tr>
<tr>
<td>Stripper Assembly (2nd in Service)</td>
<td>Optional</td>
<td>Optional</td>
<td>Optional</td>
<td>Required</td>
</tr>
<tr>
<td>Stack-to-Stripper Connection</td>
<td>Quick Union, Flanged or OEC¹</td>
<td>Quick Union, Flanged or OEC¹</td>
<td>Quick Union, Flanged or OEC¹</td>
<td>Flanged</td>
</tr>
<tr>
<td>Blind Ram Component a</td>
<td>Required</td>
<td>Required</td>
<td>Required</td>
<td>Required</td>
</tr>
<tr>
<td>Shear Ram Component a</td>
<td>Required</td>
<td>Required</td>
<td>Required</td>
<td>Required</td>
</tr>
<tr>
<td>Kill Line Inlet Connection c</td>
<td>Required</td>
<td>Required</td>
<td>Required</td>
<td>Required</td>
</tr>
<tr>
<td>Slip Ram Component b</td>
<td>Required</td>
<td>Required</td>
<td>Required</td>
<td>Required</td>
</tr>
<tr>
<td>Pipe Ram Component b (Primary)</td>
<td>Required</td>
<td>Required</td>
<td>Required</td>
<td>Required</td>
</tr>
<tr>
<td>Flow Cross/ Flow Tee</td>
<td>Optional</td>
<td>Optional</td>
<td>Optional</td>
<td>Optional</td>
</tr>
<tr>
<td>Pipe Ram Component b,c (Secondary)</td>
<td>Required</td>
<td>Required</td>
<td>Required</td>
<td>Required</td>
</tr>
<tr>
<td>Dedicated Shear-Blind Ram c</td>
<td>Required</td>
<td>Required</td>
<td>Required</td>
<td>Required</td>
</tr>
</tbody>
</table>

NOTE 1: a pressure-containing hydraulic latch connection may be used above the uppermost ram-type well control component.

NOTE a: a manufacturer’s single combination of the blind and shear ram (see 4.3.5) may be used.

NOTE b: a manufacturer’s single combination of the slip and pipe ram (see 4.3.6) may be used.

NOTE c: On a dual combination-ram stack, a kill line inlet shall be installed between the combination shear-blind ram position, and the combination pipe-slip ram positions.

4.2.6.3.1 If a dual combination well control stack is used to supplement the standard well control stack configuration, the well control component order could change. In this configuration, the combination pipe-slip ram assembly will typically be located below the combination shear-blind ram assembly.

4.2.6.3.2 The recommendations for flow tee/cross choke(s) and valve assemblies are specified in Section 8, with the recommendations for kill line(s) and valve assemblies provided in Section 9.

4.2.7 Bore Size, Rated Working Pressure, and Connections of Well Control Equipment

4.2.7.1 The bore of well control stack components (with the exception of the stripper assembly) should be greater than the maximum predicted width of collapsed CT (see 5.5).

4.2.7.2 In cases where the bore of well tubulars could deter the removal of collapsed CT, contingency plans should be in place.
4.2.7.3 End connections and outlet connections in the well control stack shall be in accordance with **API 6A** and/or **API 16A**. Flange connections or other non-threaded end connectors may be used.

External supports (e.g. guy wires, crane, support structure) shall be used to reduce the bending and transmitted loads from the equipment onto the connections. The following shall apply to connections for the specified pressure category.

a) PC-0—All connections shall have a minimum pressure rating of 3000 psig.

b) PC-1—All connections from the tree to the uppermost required ram component in the well control stack configuration should be flanged and shall have a minimum pressure rating of 3000 psig. Flanged or other connection types used above the uppermost ram component shall have a minimum pressure rating of 3000 psig. Where surface wellhead and tree construction prevents use of a flange connection, an installation plan for use of other end connectors (OEC) shall be available and reviewed. For tree construction with a threaded connection only, the threaded connection shall meet the minimum pressure rating of 3000 psig and should be restricted to the connection between the tree and well control stack.

c) PC-2—All connections from the tree to the uppermost required ram component in the well control stack configuration shall be flanged with a minimum pressure rating of 5000 psig. Flanged or other connection types used above the uppermost ram component shall have a minimum pressure rating of 5000 psig. Where surface wellhead and tree construction prevents use of a flange connection, an installation plan for use of OECs shall be available and reviewed. For tree construction with a threaded connection only, the threaded connection shall meet the minimum pressure rating of 5000 psig and should be restricted to the connection between the tree and well control stack.

d) PC-3—All connections from the tree to the uppermost required ram component in the well control stack configuration shall be flanged with a minimum pressure rating of 10,000 psig. Flanged or other connection types used above the uppermost ram component shall have a minimum pressure rating of 10,000 psig.

e) PC-4—All connections from the tree to the stripper assembly in the well control stack configuration shall be flanged with a minimum pressure rating of 15,000 psig.

4.2.7.4 With the exception of PC-4 operations, other types of connections may be used above the uppermost ram component provided they are in accordance with **API 6A** and/or **API 16A**.

4.2.7.5 All studs, bolts, and nuts used in connection with flanges shall be selected in accordance with **API 20E** or **API 20F** as seen in **ANNEX B**. The installation of the flange fastener components shall be performed in a cross-flange pattern to the appropriate torque values by a competent person.

4.2.7.6 Ring gaskets shall meet the requirements of **API 6A**.

4.2.7.7 Ring gaskets shall not be reused.

4.2.8 Pressure Barrier Protection Below the Well Control Stack Equipment

4.2.8.1 For rig-up of PC-1 through PC-4 CT well control stacks onto a christmas tree, surface test tree or other connection to a wellbore exposed to produced fluids, the wellbore shall be isolated by at least two tested mechanical barriers (valves) installed below the well control stack to establish safe operating conditions for installation of well control equipment.

4.2.8.2 Where rig up onto drill pipe or a jointed tubing workstring is required, the drill pipe or workstring shall be isolated by at least one mechanical barrier rated for the pressure end load (such as full-open safety valve, etc.), with a risk assessment performed to evaluate onsite conditions and determine the most appropriate means for providing a second barrier.
Note: A pressure end load is an axial force resulting from internal pressure applied to the area defined by the maximum seal diameter.

4.2.8.3 Where the isolation valve on the tree immediately below the CT well control stack connection is designed to be directional (seals pressure from below only), a separate two-way sealing valve should be installed above the tree directional-sealing valve to allow for proper pressure testing of the well control stack.

4.3 Well Control Components

4.3.1 Stripper Assembly (Pressure controlling device)

The stripper assembly component is a pressure controlling device designed to isolate well pressure and effluents from the atmosphere during CT operations. The purpose of the stripper assembly is to seal around the outside diameter (OD) surface of the CT workstring in both static and dynamic operating conditions.

4.3.1.1 For all CT operations where surface wellhead pressure is expected, at least one stripper assembly shall be installed in the well control stack to serve as the means for controlling wellhead pressure under dynamic CT operating conditions.

4.3.1.2 In all CT operations where surface wellhead pressure is expected, lateral support for the CT, such as an anti-buckle guide, shall be incorporated to decrease the risk of catastrophic buckling failure between the injector and the entry position of the stripper assembly packer element. The anti-buckle guide may be an integral part designed into the stripper assembly or incorporated as a separate item attached to the stripper assembly. The intent for use of an anti-buckle guide is to minimize the unsupported column length between the entry position of the CT into the stripper packer element and the lowest fully-supported gripper blocks within the injector chains to reduce the risk of catastrophic buckling failure.

A tubing force analysis shall be conducted to confirm that the CT segment above the energized stripper element will not experience catastrophic buckling due to force acting on the pressure-affected cross-section (\(F_{pacs}\)) generated by the differential pressure occurring across the sealing stripper element. The results of the tubing force analysis should be used to determine the maximum allowable thrust force to be applied to the CT workstring during snubbing operations (see 5.4).

4.3.1.3 For PC-4 CT operations (pressure greater than 7,501 psig), a second stripper shall be installed in the CT well control stack.

4.3.1.4 Where two stripper assemblies are installed within the well control stack, the stripper assembly which is protected with an anti-buckle guide shall be designated as the “first-in-service” stripper which is intended to be used as the primary dynamic pressure control component. The “second-in-service” stripper assembly used to provide additional pressure containment should be as close to the “first-in-service” stripper assembly as practically possible.

4.3.1.5 Where service applications require applied snub force to be imparted through the “second-in-service” stripper, a tubing force analysis shall be performed to quantify the risk for potential catastrophic buckling failure of the unsupported column length above the “second-in-service” stripper assembly packer element due to \(F_{pacs}\) generated by the differential pressure occurring across the energized stripper element (see 5.4).

Note: For general CT well intervention service, the uppermost stripper assembly in the well control stack should be designated as “first-in-service”.

4.3.1.6 Each stripper assembly in the well control stack shall serve as a single pressure control component. In normal operations, the two stripper assemblies shall not be used in combination to regulate wellhead pressure or trap pressure between the two sealing elements.
4.3.1.7 The general operational arrangement for each stripper assembly used in CT operations shall be subjected to a risk analysis to determine the following:

a) The stripper assembly packer elements shall allow for removal and replacement during the well intervention program with the CT workstring deployed within the wellbore.

b) The stripper assembly lateral support bushings shall allow for removal and replacement during the well intervention program with the CT workstring deployed within the wellbore.

c) The stripper assembly components should provide sufficient mechanical support and wear resistance to complete the CT workstring deployment and retrieval program for the prescribed service conditions without having to replace the packer elements or support bushings.

d) The stripper assembly shall provide a dynamic pressure seal on the OD surface of the CT workstring at the maximum speed that the CT workstring is to be deployed or retrieved from the wellbore.

e) The maximum running speed for the stripper assembly using a specified OD size of CT workstring shall be determined by the User based on the following conditions:

   i. Surface wellhead pressure
   ii. Surface wellhead temperature
   iii. Tube body roughness and general CT OD surface lubrication
   iv. Wellbore fluids immediately below the stripper (liquids, gas, \( \text{H}_2\text{S} \), etc)
   v. Stripper element chemistry (Nitrile, Buna-N, Viton, Polyurethane, etc)

4.3.1.8 Where an annular preventer is used in CT operations, the annular preventer is primarily used for sealing on areas of the CT BHA or the OD surface of deployment bars/through-tubing screens when the diameter of the assembly is different than the OD of the CT workstring. In these applications, the annular preventer is used only as a static annular seal component (similar to a pipe ram) and is not intended to provide the same dynamic pressure sealing service as expected from the CT stripper assembly.

4.3.1.9 In CT operations where an annular preventer is installed in the well control stack for pressure containment when deploying the CT BHA, a pressure sealing window shall be installed above the annular preventer to allow the stripper assembly to seal on the CT workstring when performing the prescribed service with surface pressure present.
4.3.1.10
As the stripper assembly elastomeric sealing element is considered a consumable component, the elastomeric sealing element installed in each stripper assembly within the well control stack shall be inspected prior to initiating well intervention operations. If the elastomeric sealing element is observed to be damaged or worn, the stripper assembly elastomeric sealing element shall be replaced prior to conducting well intervention operations.

4.3.2 Pressure Sealing Rams (Blind and Pipe)

4.3.2.1 The blind ram is designed to seal the wellbore and isolate pressure when the bore of the ram is unobstructed. In CT operations, the blind ram (Figure 1) is normally the upper-most ram well control component in the standard well control stack configuration (see Annex A).

![Blind Ram](image)

**Figure 1 — Blind Ram**

4.3.2.2 The pipe ram is designed to isolate annulus pressure between the CT OD surface and the inside diameter (ID) of the well control stack bore. The pipe ram shall be sized for the CT OD in use and shall be configured with guides to center the CT workstring in the well control stack bore. The pipe ram (Figure 2) is normally the bottom ram well control component in the standard well control stack configuration (see Annex A).

The pipe ram should hold at least the kill pressure margin differential pressure from above the ram.
NOTE: For the differential pressure seal from above the ram, a bubble tight seal is not required and some percentage of leakage may be acceptable. The User should consult with the ram manufacturer to determine how much pressure the pipe ram design is expected to contain above the closed pipe ram.
4.3.3 Shear Ram

The shear ram shall be capable of shearing the CT workstring body (and any spoolable components inside the CT workstring) at MASP of the well without tensile loads applied to the tubing or spoolable components inside the CT workstring. The shear ram (Figure 3) is normally located immediately below the blind ram in the standard well control stack configuration (see Annex A). The shear ram shall be sized appropriate for the OD of the CT workstring used in the prescribed service.

Figure 3—Shear Ram

4.3.3.2 The shear ram shall be capable of two or more cuts of the CT workstring OD size, wall thickness and grade in service. The shear cut shall provide an opening in the lower cut end of at least 30% of the original ID cross-sectional area to facilitate subsequent through-tubing pumping and well killing operations. The geometry of the shear cut should also enable fishing operations.

4.3.3.3 The shear ram shall be capable of shearing the CT workstring when the tubing is secured within the slip ram or pipe-slip ram.

4.3.3.4 The closing pressure required to shear the CT workstring at MASP of the well \( P_{\text{crit}} \) shall be less than the retained pressure within the well control accumulator system at the projected point where the shear ram is to be closed (see H.2.3.2). The value of \( P_{\text{crit}} \) shall not exceed the manufacturer’s RWP for the ram operating system.

4.3.3.5 The shear ram blades shall be replaced after each CT workstring shearing operation as soon as practically possible.
4.3.4 Slip Ram

4.3.4.1 The slip ram shall be sized for the OD of the CT workstring used in the prescribed service and shall be configured with guides to center the CT workstring in the well control stack bore. The slip ram (Figure 4) is normally located immediately above the pipe rams in the standard well control stack configuration (see Annex A).

![Slip Ram](image)

**Figure 4 — Slip Ram**

4.3.4.2 The slip ram shall be capable of holding the maximum anticipated hanging weight of the CT workstring in the pipe-heavy condition without movement of the tubing within the slip inserts. In addition, the slip ram shall be capable of holding the CT workstring in the pipe-light condition to the force equal to the MASP multiplied by the cross-sectional area of the tube body without movement of the tubing within the slip inserts.

4.3.4.3 The tests to be conducted to determine closing pressure required to secure the CT workstring within the slip inserts at MASP of the well (P_{slip}) are defined in ANNEX E and shall not exceed the manufacturer’s RWP for the ram operating system.

4.3.5 Shear-blind Combination Ram

4.3.5.1 The shear-blind ram is a combination ram which incorporates two ram functions into a single well control ram component (Figure 5). Shearing and sealing shall be achieved in a single operation. The shear-blind ram shall be capable of shearing the CT workstring body (and any spoolable components inside the CT workstring) at the MASP of the well without tensile loads applied to the tubing or any of the spoolable components inside the CT workstring.
Upon completion of the shear-blind ram actuation, the ram seals shall isolate the wellbore without requiring movement of the CT workstring. The shear-blind ram shall be sized appropriate for the OD of the CT workstring used in the prescribed service.

![Figure 5 — Shear-blind Combination Ram](image)

**4.3.5.2** The shear-blind ram shall be capable of two or more shear and seal operations for the CT workstring OD size, wall thickness and grade in service. The shear-blind cut shall provide an opening in the lower cut end of at least 30% of the original ID cross-sectional area to facilitate subsequent through-tubing pumping and well killing operations. The geometry of the shear-blind ram cut should also enable fishing operations.

**4.3.5.3** The shear-blind rams shall be capable of shearing the CT when the tubing is secured within a slip or pipe-slip ram located below the shear-blind ram.

**4.3.5.4** The closing pressure required to shear the CT workstring and seal the wellbore at the MASP of the well ($P_{cr1}$) shall be less than the retained pressure within the well control accumulator system at the projected point where the shear-blind ram is to be closed (see ANNEX H.2.3.6). The value of ($P_{cr1}$) shall not exceed the manufacturer’s RWP for the ram operating system.

**4.3.5.5** The shear-blind ram blades and required components shall be replaced after each CT workstring shearing operation as soon as practically possible.
4.3.6 Pipe-slip Combination Ram

4.3.6.1 The pipe-slip ram is a combination ram which incorporates two ram functions into a single well control ram component, holding the CT workstring and isolating annulus pressure between the surface of the CT OD and the ID of the well control stack bore in a single ram operation (Figure 6).

![Figure 6 — Pipe-slip Combination Ram](image)

4.3.6.2 The pipe-slip ram shall be sized for the OD of the CT workstring used in the prescribed service and shall be configured with guides to center the CT workstring in the well control stack bore.

4.3.6.3 The pipe-slip ram shall be capable of sealing the annulus while holding the maximum anticipated hanging weight of the CT workstring without movement of the tubing within the slip inserts. In addition, the pipe-slip ram shall be capable of sealing the annulus while holding the CT workstring in the pipe-light condition to the force equal to the MASP multiplied by tube cross-sectional area without movement of the tubing within the slip inserts.

The pipe-slip ram should hold at least the kill pressure margin differential pressure from above the ram.

NOTE For the differential pressure seal from above the ram, a bubble tight seal is not required and some percentage of leakage may be acceptable. The User should consult with the ram manufacturer to determine how much pressure the pipe-slip ram design is expected to contain above the closed pipe-slip ram.

4.3.6.4 The closing pressure required to secure the CT workstring within the slip inserts and seal the annulus at MASP of the well ($P_{slip}$) is defined in ANNEX E and shall not exceed the manufacturer’s RWP for the ram operating system.

4.3.7 Ram Position

Each ram-type well control equipment component shall be equipped with a visual position indicator to determine the ram position for each ram component (as open or closed).
4.3.8 Kill Line Inlet

The kill line inlet shall be a flanged connection sized for at least a 2-inch nominal flange and a RWP at least equivalent to the well control ram body. The location of the integral kill line inlet is normally between the shear ram and slip ram in the standard well control stack configuration and between the shear-blind ram and pipe-slip ram in the dual combination ram well control stack configuration.

The kill line inlet should be used only as a flow path to pump fluids into the wellbore during well intervention services, pressure testing of the well control stack, and/or to equalize pressure across sealing rams.

4.3.9 Installation, Operation and Maintenance

The coiled tubing well control equipment components assembled within the stack consist of pressure-containing, pressure controlling and pressure-retaining parts critical to safe and effective operation.

4.3.9.1 The installation, operation and maintenance (IOM) of pressure-containing parts, pressure-controlling parts and pressure-retaining parts within each stack component shall be performed by a competent person.

4.3.9.2 A record of the maintenance, repair history and/or remanufacture file for each well control stack component assembly shall be retained by serial number or unique identification number and available for review by the User.

Note Remanufacture involves disassembly, reassembly and testing of equipment where machining, welding heat treating or other manufacturing operations are employed.

4.3.9.3 Replacement parts (consumables) shall be in conformance with the relevant API standards and satisfy the design/operating requirements as specified by the original equipment manufacturer (OEM).

4.3.9.4 Operation of the well control stack components shall be conducted by a competent person, following the operating practices specified by the OEM.

4.3.9.5 The IOM manuals (either hard copy or electronic storage) shall be available onsite for the well control equipment in service.

4.4 Additional Well Control Components

4.4.1 Well Control Elastomers

Elastomers used in well control equipment which are exposed to well fluids and/or corrosive gases shall be qualified for use in the well intervention service. See Section 7 for review of the elastomers and materials referenced in this document.

4.4.2 Equalizing Device

The well control stack shall have a means for equalizing pressure between cavities across each pressure-sealing ram set prior to opening the rams.

4.4.3 Ram Locking System

All pressure sealing and slip-type well control stack ram components shall have a system for locking the rams in the closed position. The ram locking system shall be capable of holding the rams in the closed position and meet the individual performance requirements in the absence of closing pressure applied by the accumulator system.
4.4.4 Spacer Spools, Adapter Spools, Crossover Connectors and Lubricators

4.4.4.1 Spacer spools, adapter spools, crossover connectors and lubricators may be used when the CT BHA is too long to be contained within the well control stack or when the work environment necessitates spacing out the well control equipment. The spacer spools, adapter spools, and lubricators shall meet or exceed all requirements stipulated in API 6A, 4.2.5 and 4.2.7, with fasteners and bolting meeting the requirements of 4.2.7.5.

4.4.4.2 Spacer spools, adapter spools, and lubricators shall be capable of withstanding the applied loads and combination of loads shown below (as a minimum):

a) compression loads generated by the weight of the injector and well control equipment on top of the assembly plus loads resulting from the buoyed weight of the CT workstring suspended in the well;
b) bending loads generated by the reel back tension, dynamic motion and wind loads;
c) loads due to internal pressure.

4.4.4.3 External supports (e.g. guy wires, crane, support structure) shall be used to reduce the bending and transmitted loads from the equipment onto the connections. Where the bending loads cannot be completely mitigated, the flanged connections shall be subject to derating as per API 6AF1 and API 6AF2.

4.4.4.5 The location of the stripper assemblies shall not restrict the ability to fully retrieve the CT BHA above the upper-most ram in the well control stack.

4.4.4.6 When bottomhole assemblies are too long to be contained within the well control stack, alternate methods or processes meeting the barrier requirements of Table 1 shall be acceptable. Alternate methods may include use of deployment bars, remotely-actuated connectors, etc.

4.4.5 Flow Cross or Flow Tee

The flow cross or flow tee is typically located below the standard well control stack configuration. If a flow cross or flow tee is installed, the flanged flow cross or flanged flow tee shall be in accordance with API 6A and/or API 16A and fasteners/bolting shall meet the requirements of 4.2.7.5.

4.4.6 Well Control Stack Pressure-Containing Welds

Spacer spools, adapter spools, lubricators, flow crosses and flow tees having welded end connections shall conform to the following:

a) All welds of wellbore pressure-containing and or load bearing components shall be performed in accordance with the applicable API standards and performed by a welder qualified/certified to the specific welding procedure and practice.
b) All welding of wellbore pressure-containing components shall comply with the welding requirements of NACE MR0175/ISO 15156.
c) Verification of compliance shall be established through the implementation of a written WPS and the support PQR from the repair facility.
d) Welding shall be performed in accordance with a WPS, written and qualified in accordance with ASME BPVC, Section IX, Article II.
e) All welded end connections shall be subjected to nondestructive examination (NDE) inspection (x-ray or ultrasound shear wave) and the records of the latest NDE inspection shall be available for review.

Note A pressure-containing weld is a weld whose absence or failure will reduce or compromise the pressure-containing integrity of the component.
4.5 Well Control Equipment for Hydrogen Sulfide Service

All well control equipment, inclusive of surface piping, manifolds, valves, and fittings exposed to hydrogen sulfide (H₂S) shall be in accordance with NACE MR 0175/ISO 15156. Shear blades and Slip inserts need not meet the requirements of NACE MR 0175.
5 Coiled Tubing Workstring and Connectors

5.1 Coiled Tubing Workstring

The CT workstring is an integral part of the well control equipment system. The pipe ram cannot establish an effective barrier and the stripper assembly cannot establish an effective pressure controlling seal unless the CT workstring within the wellbore maintains pressure integrity and the tube geometry remains within the sealing tolerance of the well control equipment. The CT workstring consists of the full length of coiled tube and all tube-to-tube connections (including welded connectors and spoolable connectors). Where used as a well control barrier component, the CT connector shall provide an effective pressure seal.

The CT workstring and tube-to-tube connections shall be in accordance with the CT well control stack pressure ratings shown in Table 1 as integral parts of the well control system.

5.1.1 Welding on Coiled Tubing Workstrings During the Manufacturing Process

As per API Spec 5ST, all coiled tubing strings are manufactured having a longitudinal seam weld created using the high frequency induction (HFI) welding practices. Further, the reference end connection (attaching the CT workstring to the CT reel piping) is typically constructed by welding a “slip-on” type Figure 1502 union onto the end of the CT workstring. The welding practices typically associated with the manufacture of a CT workstring shall comply with the following:

a) Verification of compliance shall be established through the implementation of a written WPS and the support PQR from the manufacturing facility.

b) Welding shall be performed in accordance with a WPS, written and qualified in accordance with ASME BPVC, Section IX, API 1104 or the manufacturer’s documented welding requirements. The weld record shall include the qualification/certification of the welder for the respective welding practice.

c) The longitudinal welded seam shall have NDE performed using either ultrasonic or electromagnetic methods in accordance with API Spec 5ST.

(d) The tube-to-reference end fitting weld shall have NDE performed using the liquid penetrant method as a minimum.

5.1.2 Welding on Coiled Tubing Workstrings After the Manufacturing Process

Welding performed on “post-manufactured” CT workstrings include repair welds (tube-to-tube) and end connection welds (at the CT reference end or the CT BHA end connection). The welding practices typically associated with the “post-manufacture” of a CT workstring shall comply with the following:

a) Verification of compliance shall be established through the implementation of a written WPS and the support PQR from the manufacturing or repair facility.

b) Welding shall be performed in accordance with a WPS, written and qualified in accordance with ASME BPVC, Section IX, API 1104 or the manufacturer’s documented welding requirements. The weld record shall include the qualification/certification of the welder for the respective welding practice.

c) The tube-to-tube weld shall have NDE performed using either radiographic (x-ray) or ultrasonic shear wave methods in accordance with API Spec 5ST.

d) The tube-to-CT BHA end fitting weld shall have NDE performed using the liquid penetrant method (for slip-on fittings) or volumetric methods (radiographic or ultrasonic shear wave) for tube-to-tube end connections.
5.2 Coiled Tubing String Selection

5.2.1 General

The CT material properties and tube body geometry typically change as a result of bend-cycling throughout the service life of the workstring. The material yield strength typically decreases due to work softening (typically described as the Baushinger Effect) and reduces the performance capability of the tube. The changes in tube body geometry can include ovality, diametral growth and wall thinning. The changes in tube body geometry are typically not uniform along the length of the string.

To comply with this Recommended Practice, the CT workstring shall be designed and constructed to meet or exceed the manufacturing standards of API Spec 5ST.

The CT workstring should be selected such that the combined stresses of pressure and tension do not exceed the working limits, based on the material properties.

5.2.2 Ovality and Diametral Growth

As the CT workstring is used in service, the cross-section of the tube body becomes oval. When the CT workstring is subjected to bend-cycling with internal pressure present, the diameter of the tube body will increase. The effects of ovality and diametral growth on well control includes:

a) a reduction in collapse pressure rating compared to that of round tube;
b) a reduction in the ability of the pipe ram (or pipe-slip ram) and stripper assembly to establish an effective pressure seal on the circumference of the tube body;
c) greater difficulty in installation of the CT bottomhole assembly connector (BHA connector);
d) a reduction in pressure integrity of the flow check assembly seals on the OD of the CT body;
e) a reduction in the gripping performance of the slip ram (see 4.3.4) or pipe-slip ram (see 4.3.6);
f) decreased clearance between the CT body, the stripper bushings and/or anti-buckle guide.

Closing well control rams on tubing with excessive diametral growth and/or ovality may result in significant damage to the CT body. At any time that the well control stack rams are closed onto the CT body, an effort should be made to inspect the CT OD surface area affected by the ram closure to determine whether the tube body suffered excessive damage or if the remaining condition is acceptable for continued service.

5.2.3 Wall Thinning

When the CT workstring is used in service, the wall thickness may be reduced through corrosion, erosion, mechanical wear, diametral growth or permanent lengthening of the string. The effects of tube body wall thinning on well control includes:

a) a reduction in collapse and burst pressure rating of the tube,
b) a reduction in the load carrying capability of the tube,
c) a reduction in the gripping performance of the slip ram (see 4.3.4) or pipe-slip ram (see 4.3.6),
d) a reduction in the buckling resistance of the tube body,
e) a reduction in bend cycle fatigue life.
5.3 Axial Tensile Forces Applied to Coiled Tubing Workstrings

For all CT operations, the magnitude of axial tensile forces which are expected to be applied to the CT workstring during planned operations shall be identified. This analysis serves as the basis for determining if the CT workstring can be deployed within the safe working limits of the tri-axial stress envelope to avoid ductile overload and mechanical separation failure.

5.3.1 The forces expected during deployment and retrieval of the CT workstring within a wellbore with surface pressure present shall include, but are not limited to:

a) Force generated by surface wellhead pressure acting against the cross-sectional area of the outside diameter of the CT occurring at the base of the energized stripper assembly element (\( F_{\text{Pacs}} \))

b) Buoyed weight of the CT workstring deployed within the wellbore

c) Force generated by friction between the CT OD surface and energized stripper element (\( F_{\text{Stripper}} \))

d) Force generated by friction between the CT OD surface and ID surface of wellbore tubulars (\( F_{\text{Drag}} \))

5.3.2 Depending upon the prescribed service, ancillary forces may also be present which result in additional reactive axial tensile loads on the CT workstring. These axial tensile loads include pulling forces experienced during mechanical CT workstring operations. Where these forces are anticipated and predictable (fishing, jarring, shifting sleeves, etc.), the magnitude of these forces shall be determined and added to the predicted axial tensile force loading. The result is the maximum axial tensile force load expected to be applied to the CT workstring.

5.3.3 A tubing force analysis shall be conducted to predict the maximum tri-axial stress safe working limit threshold for the CT workstring based on, but not limited to the following:

a) The buoyed weight of the CT workstring at the maximum deployed position within the wellbore.

b) The nominal dimensions of the CT workstring (OD and wall thickness) and CT grade.

c) Ancillary tri-axial stresses which may be generated by pressure internal to the CT workstring.

d) Force generated by friction between the CT OD surface and energized stripper element (\( F_{\text{Stripper}} \))

e) Force generated by friction between the CT OD surface and ID surface of wellbore tubulars (\( F_{\text{Drag}} \))

f) Ancillary mechanical force generated during the planned operation

g) Torque force generated by reaction of CT BHA tools which apply torque to the CT connector as a result of the prescribed service (downhole motors, ratcheting devices, etc).

5.3.4 For the designated CT workstring size and properties, the predicted maximum axial tensile force load for the prescribed service shall be less than the calculated maximum safe tri-axial stress working load limit threshold to avoid ductile overload force conditions. This tri-axial load analysis shall include each tapered CT workstring segment with wall thicknesses less than the maximum wall thickness segment deployed which may be subjected to the critical axial tensile loads during the prescribed service.

5.3.5 Where the CT injector is capable of developing an axial tensile force which exceeds the maximum safe tri-axial stress working load limits for CT workstring ductile overload, the injector power control circuit shall be equipped with a means for limiting the force which can cause the CT workstring to exceed the tri-axial stress limits applied, limiting conditions which may result in ductile overload and mechanical separation failure.
5.4 Axial Compressive Forces Applied to Coiled Tubing Workstrings

For CT operations where surface wellhead pressure is expected, the magnitude of axial compressive forces expected to be applied to the CT workstring during planned operations shall be identified. This analysis serves as the basis for determining if the CT workstring can be deployed within the safe working limits of the tri-axial stress envelope to avoid catastrophic buckling failure.

5.4.1 The forces opposing deployment of the CT workstring into a wellbore with surface pressure present shall include, but are not limited to:

a) Force generated by surface wellhead pressure acting against the cross-sectional area of the outside diameter of the CT occurring at the base of the energized stripper assembly element (\( F_{Pacs} \))

b) Force generated by friction between the CT OD surface and energized stripper element (\( F_{Stripper} \))

The combination of the aforementioned forces is typically referred to as “snub force”, which represents the magnitude of dynamic reactive axial compressive force acting on the CT workstring to oppose deployment into the wellbore with surface pressure present.

5.4.2 Ancillary forces may also be present which apply additional reactive axial compressive forces on the CT workstring. Where these forces are anticipated and predictable (deployment of CT BHA tools with tight annular clearances), the magnitude of these forces shall be determined and added to the predicted snub force loading. The result is the total axial compressive force, typically referred to as “thrust force”.

5.4.3 A tubing force analysis shall be conducted to predict the maximum tri-axial stress safe working limit threshold for catastrophic buckling of the CT workstring based on the following:

a) The unsupported column length between the lowest fully-supported gripper block in the injector and the lateral support component above the stripper bushings (or anti-buckle guide as seen in 4.3.1.2).

b) The nominal dimensions of the CT workstring (OD and wall thickness) and CT grade.

c) Ancillary tri-axial stresses which may be generated by pressure internal to the CT workstring.

5.4.4 For the designated CT workstring size and properties, the predicted thrust force shall be less than the calculated maximum tri-axial stress safe working load limit threshold for catastrophic buckling failure above the energized stripper assembly element.

5.4.5 Where the CT injector is capable of developing a thrust force which exceeds maximum safe tri-axial stress working load limit threshold for the CT workstring, the injector power control circuit shall be equipped with a means for limiting the force which can cause catastrophic buckling failure of the CT workstring.
5.5 Coiled Tubing Collapse

Collapse of the CT body is the flattening of the tube due to the application of differential pressure (external to internal), with or without an axial tensile load. A collapsed CT workstring inside the wellbore will not cause wellbore effluents to be released to the atmosphere. However, if the collapsed portion of the string is positioned across the well control stack, the change in tube body geometry negatively impacts the performance of the pipe ram, slip ram and/or the pipe-slip ram. A contingency plan should be considered on how to perform well control activities in the event of CT collapse.

A method used to predict the width of a plastically-collapsed tube is shown in Equation (1):

\[
W_{Col} = 0.95 \left[ D + 0.5708 D \left( 1 - \frac{2t}{D} \right) \right]
\]

where

- \( W_{Col} \) is the predicted collapse width of coiled tube body (inches),
- \( D \) is the outside diameter of coiled tube body (inches),
- \( t \) is the wall thickness of coiled tube body (inches).

For a given CT string OD size, the predicted collapse width increases when the wall thickness decreases. See Table 3 for examples of collapse width predictions and minimum stack bore sizes.

<table>
<thead>
<tr>
<th>Coiled Tube Size (in.)</th>
<th>( D/t ) Ratio</th>
<th>Predicted Collapse Width (in.)</th>
<th>Minimum Bore Size (in.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.250 OD × 0.087 wall</td>
<td>14.4</td>
<td>1.771</td>
<td>2 3/16</td>
</tr>
<tr>
<td>1.500 OD × 0.095 wall</td>
<td>15.8</td>
<td>2.135</td>
<td>2 3/16</td>
</tr>
<tr>
<td>1.750 OD × 0.109 wall</td>
<td>16.1</td>
<td>2.493</td>
<td>2 3/16</td>
</tr>
<tr>
<td>2.000 OD × 0.125 wall</td>
<td>16.0</td>
<td>2.849</td>
<td>3 1/16</td>
</tr>
<tr>
<td>2.375 OD × 0.145 wall</td>
<td>16.4</td>
<td>3.387</td>
<td>4 1/16</td>
</tr>
<tr>
<td>2.625 OD × 0.156 wall</td>
<td>16.8</td>
<td>3.748</td>
<td>5 1/8</td>
</tr>
<tr>
<td>2.875 OD × 0.156 wall</td>
<td>18.4</td>
<td>4.121</td>
<td>5 1/8</td>
</tr>
<tr>
<td>3.500 OD × 0.203 wall</td>
<td>17.2</td>
<td>5.003</td>
<td>5 1/8</td>
</tr>
</tbody>
</table>

Note: See ANNEX B of API RP 5C8 for a method of predicting collapse of coiled tubing under designated operating conditions.
5.6 Bend Cycle Fatigue

The CT workstring is exposed to cyclical stresses above the material yield strength as part of normal day-to-day operations. These yield stresses occur as the CT workstring is subjected to bend cycles on the CT reel and over the tubing guide arch. During the service of a CT workstring, the repeated bend cycling activities contribute to the accumulation of fatigue damage and impact the service life of the workstring. Further, the addition of internal pressure during bend cycle events significantly reduces the service life of the CT workstring.

5.6.1 A fatigue prediction model shall be used to estimate the remaining bend-cycle fatigue life of the CT workstring selected for the prescribed service. The bend-cycle fatigue life model shall represent the remaining life projected for the CT workstring based on bending cycles occurring at the CT service reel and injector tubing guide arch coupled with internal pressure at a minimum. The bend-cycle fatigue life model may also incorporate results of wall thickness NDE inspections or theoretical wall loss predictions.

5.6.2 The bend-cycle fatigue life chart should be up-to-date, representing the condition of the CT workstring immediately prior to implementing the prescribed service.

5.6.3 The CT workstring shall not exceed the determined maximum bend-cycle fatigue life for well intervention operations, based on the model calculations for the prescribed conditions. Anticipation for the expected workload for a CT workstring should ensure that it will not exceed the maximum bend-cycle fatigue life during operations.

5.7 Coiled Tubing String Management

To manage the integrity of the CT system, the following information shall be recorded, tracked and available for review by the User onsite:

— string design, material traceability and string identification (mill serial number);

— Tag installed on CT workstring confirming string identification and material traceability information

— most recent projected CT fatigue life chart;

— string history (including repairs, storage, re-spooling, corrosion prevention practices and maintenance);

— service history (including pumping of abrasive and/or corrosive fluids and/or exposure to H₂S and/or CO₂ environments) and NDE inspections.
6. **Downhole Flow Check Assembly**

6.1 **General**

The downhole flow check assembly is a well control barrier component and consists of a pressure-sealing CT BHA connector and a pressure-sealing flow check device. A downhole flow check assembly shall be run within the CT BHA unless the specific job design criteria preclude the use of this assembly.

6.2 **Coiled Tubing Bottomhole Assembly Connectors**

6.2.1 The CT BHA connectors serve as the means to attach the BHA to the CT workstring. When used as a barrier component, the CT BHA connector shall be capable of establishing an effective pressure seal between the CT workstring and the connector body, as well as the connector body and attached components. The CT BHA connector shall maintain the pressure seal and withstand the expected combined loads during the prescribed service.

6.2.2 The components used to assembly the CT BHA connector shall be traceable to material records and elastomeric seal chemistry which can confirm that the components are appropriate for the operating conditions to be experienced during the prescribed service. The traceability records shall include material properties and manufacturing/heat treatment practices which may affect the performance of the connector.

6.2.3 Where the CT BHA serves as a barrier component, the following steps shall be taken to ensure that the CT BHA connector is capable of performing the proposed service:

a) The CT BHA connector shall be disassembled and the mechanical parts of the connector body visually inspected for erosion or mechanical wear due to general service.

b) UT inspection shall be performed on all areas of the mechanical CT BHA connector components to determine the remaining body wall thickness and confirm that sufficient material remains to perform the intended service. The frequency of UT inspection shall be based on the recommendations of the connector OEM and/or the equipment owners maintenance system.

c) All elastomeric seal glands and contact surfaces within the mechanical CT BHA connector components which are used for pressure containment shall be inspected to confirm that the glands and contact surfaces are clean and free from corrosion damage (pitting, wall loss, scarring, etc).

d) All CT BHA connector elastomeric seals shall be replaced to enhance reliability of pressure sealing integrity of the connector on the CT workstring body. The chemistry of the elastomeric sealing elements shall be confirmed as appropriate for the fluids expected to be in contact with the seals.

e) Documentation of the aforementioned inspection results shall be provided to the User to confirm that the CT BHA connector is capable of maintaining pressure containment of fluids within the component throughout the well intervention operation. Documentation shall include the qualification of the individual(s) performing the inspection and maintenance.

f) Where a pressure test was conducted on the CT BHA connector to confirm pressure containment capability of the sub body and threaded end connections, these pressure test records should be provided with the component and be made available for review onsite.

g) For CT BHA connector rebuild activities on onsite, items a, c and d shall be performed, with documentation records (6.2.3 Item e) updated prior to the CT BHA connector being returned to service.
6.2.4 Where the CT BHA connector is designed to be welded onto the end of the CT workstring, documentation shall be provided to confirm that the welding procedure used to join the connector to the end of the CT workstring is in compliance with practices approved by the CT workstring manufacturer (see 5.1.2). Further, NDE inspection records (radiographic or ultrasonic shear wave body wall) shall be provided prior to initiating well intervention operations to confirm that the weld area is free from defects and/or cracks occurring as a consequence of downhole service.

6.3 Downhole Flow Check Devices

6.3.1 A flow check device is a pressure-controlling pump-through device that prevents backflow of well fluids within the ID of the CT workstring. Where the flow check assembly is used to serve as a barrier component, a dual flow check device shall be installed.

6.3.2 For CT installations (including, but not limited to CT string hang-off and straddle assemblies), the following flow isolation devices may be used in lieu of a flow check device to satisfy flow check requirements:

a) pump-off plugs;
b) plugs (wireline deployed, pump down, etc.);
c) flow actuated valves (e.g. storm chokes);
d) burst discs;
e) pump-out back-pressure valves.

6.3.3 The components used to assembly the CT BHA flow check device shall be manufactured in accordance with API 7NRV (Specification for Drill String Non-Return Valves) providing traceability of material and elastomeric seal records which can be used to confirm that the components are appropriate for the operating conditions to be experienced during the prescribed service. The traceability records shall include material properties and manufacturing/heat treatment practices which may affect the performance of the downhole flow check device.

6.3.4 Where the CT BHA serves as a barrier element, the following steps shall be taken to ensure that the CT BHA flow check device is capable of performing the proposed service:

a) The CT BHA flow check device shall be disassembled and the mechanical parts of the component visually inspected for erosion or mechanical wear due to general service.
b) UT inspection shall be performed on all areas of the mechanical CT BHA flow check device components to determine the remaining body wall thickness and confirm that sufficient material remains to perform the intended service. The frequency of UT inspection shall be based on the recommendations of the flow check device OEM and/or the equipment owners maintenance system.
c) All elastomeric seal glands and contact surfaces within the mechanical CT BHA flow check device components which are used for pressure containment shall be inspected to confirm that the glands and contact surfaces are clean and free from corrosion damage (pitting, wall loss, scarring, etc).
d) All CT BHA flow check device elastomeric seals shall be replaced to enhance reliability of pressure sealing integrity of the flow check device. The chemistry of the elastomeric sealing elements shall be confirmed as appropriate for the fluids expected to be in contact with the seals.
e) Each flow check device installed in the CT BHA sub shall be subjected to pressure testing to the RWP as designated by the manufacturer. The pressure test record for each flow check device installed shall be available for review by the User onsite.
f) Documentation of the aforementioned inspection results shall be provided to the User to confirm that the CT BHA flow check device is capable of maintaining pressure containment and fluids between the wellbore and the CT workstring. Documentation shall include the qualification of the individual(s) performing the inspection and maintenance.

g) For rebuild activities on location, items a, c, d and e shall be performed, with documentation records (Item f) updated prior to the CT BHA flow check device being returned to service.

6.3.5 Where a flow check assembly cannot be used, a well control contingency plan shall be available and reviewed. The contingency plan shall adhere to the well control barrier requirements of 4.2.4 and Table 1.

7 Elastomers and Seals

7.1 General

Elastomers and seals used in well control equipment shall be appropriate for all liquids, gases and/or treatment chemicals anticipated to be encountered. The sealing assembly and seal gland shall be suitable for the pressure rating of the equipment component in service. The provider of the well control equipment shall provide a record of the seals used to ensure that recommended elastomers and seals are installed. Degradation of the elastomers physical and mechanical properties can result in loss of pressure containment.

7.1.1 The equipment manufacturer should be consulted regarding selection of the elastomer for a prescribed service. While noting that there is no universal elastomer compound that is suitable for all operating conditions, elastomer selection criteria shall at least include the following performance parameters:

a) rapid gas decompression (RGD),
b) chemical compatibility,
c) temperature performance range,
d) extrusion resistance,
e) abrasion/erosion resistance, and
f) pressure rating.

NOTE The listed criteria are not exclusive and are interrelated. See API 6J for additional information on testing of oilfield elastomers.

7.2 Rapid Gas Decompression

Some elastomers are more resistant to the effects of RGD than others. Seal performance in RGD is highly dependent on both the materials and seal geometries (seal assembly and seal gland) employed. It should be noted that while special decompression resistant grades of material are commercially available, some seal geometries (e.g. exposed and relaxed seals on rams) are always susceptible to damage by RGD.

The decompression rate is critical below 1000 psig as most seal damage will occur below this pressure. Unless otherwise recommended by the manufacturer, the decompression rate should not exceed 75 psig per minute when the pressure within the well control stack is below 1000 psig. The depressurization rate to 1000 psig should not exceed a rate that contributes to mechanical damage of the seal assembly.

NOTE Carbon dioxide (CO₂) can increase susceptibility to RGD damage in some materials.
7.3 Chemical Compatibility

Incompatibility issues may result in degradation of performance of the sealing elements. Incompatibility with fluids may lead to softening or hardening depending on the fluid and material involved. The use of solvents normally leads to softening and the potential for mechanical damage, including extrusion. Elevated temperatures will increase chemical activity.

7.3.1 Documentation shall be provided to the User to confirm that the “pumped-fluid wetted” surfaces of the fluid circulation system elastomer seals and “wellbore-wetted” surfaces of the well control stack component elastomer seals are compatible with the fluid chemistry (high-density brines, Xylene, MeoH, etc).

7.3.2 Operational procedures may be used to minimize the detrimental effects of chemical exposure to elastomers within the well control stack. These options include but are not limited to:

a) continuous injection of inert fluids or inhibitors across the well control stack rams to displace chemically active fluids,

b) operational procedures that prevent chemically active fluids from entering the well control stack,

c) application of a protective coating.

7.4 Temperature Performance Range

7.4.1 The elastomers must perform across the range of temperatures encountered during operations. Exceeding the temperature capability of an elastomer can result in softening or hardening, and/or other changes in physical properties. Changes at low temperature are typically reversible physical changes, while those at elevated temperature are normally chemical and irreversible.

7.4.2 Temperature changes may arise from, but are not limited to, the following:

a) ambient temperature extremes before, during and after the operations;

b) wellbore temperatures;

c) bleed down operations causing cooling due to the Joule-Thompson effect;

d) heated treatment fluids;

e) cryogenic fluids.

7.4.3 Operational procedures may be used to keep the elastomers within the OEM temperature range limits. These options include:

a) continuous injection of cooling fluids (in hot environments) or heated fluids (in cold environments) across the well control stack rams and piping, and

b) controlling the external operating environment of the well control stack and piping.

7.5 Extrusion Resistance

For some seal glands, the seal geometry requires mechanical support from either thermoplastic or metallic anti-extrusion devices, as per the manufacturer’s recommendations, to avoid extrusion damage.
7.6 Abrasion/Erosion Resistance

Abrasion and erosion issues can compromise the sealing integrity of the elastomers. To minimize the effects of abrasion/erosion:

a) ensure that the well control stack rams are retracted and out of the fluids flow path when not closed,
b) select elastomer material appropriate for the stripper operating conditions,
c) consider abrasion by pumped fluids when using elastomer-lined piping systems (high-pressure pump line hoses).

7.7 Pressure Rating

The elastomers shall be suitable for the pressure rating of the equipment component in service.

7.8 Other Considerations

7.8.1 Exposure

If the well control stack elastomers have been exposed to conditions which exceed the limits of the elastomers (e.g. RGD, temperature, chemical), the pressure-sealing components with the exposed elastomers should be replaced at the earliest opportunity.

7.8.2 Fatigue Life of Well Control Stack Ram Packers

The fatigue life of the elastomers is determined using API 16A (operational characteristics test procedure: fatigue test). The fatigue life of the ram elastomers should exceed the anticipated cycle frequency during the well intervention operation.

7.8.3 Age Control and Storage of Non-Metallic Seals

All elastomers shall be stored in their original opaque and sealed packaging as per OEM recommendations to avoid exposure to oxygen, ultraviolet light, heat and ozone which are damaging to some types of elastomers. For storage of elastomers, the following should apply:

a) Age control;
b) Indoor storage;
c) Maximum temperature not to exceed 120°F;
d) protected from direct natural light;
e) stress conditions (see text below)
f) stored away from contact with liquids;
g) protected from ozone and radiographic damage.

Packaging and storage of nonmetallic seals shall not impose tensile or compressive stresses sufficient to cause permanent deformation or other damage.

The manufacturer should provide written requirements for preservation of nonmetallic seals in storage.
7.8.4 Product Marking

Manufacturers’ marking on well control elastomers or packaging should include the following:

a) manufacturer,
b) durometer hardness,
c) generic type of compound,
d) date of manufacture (cure date),
e) part number, and 
f) shelf life.

When replacing the elastomeric seals, the packaging identification shall be compared to the OEM documentation to ensure that the replacement seals meet the manufacturers requirements.

7.8.5 Equipment in Storage

Elastomers can degrade while in stored equipment. Stored equipment should be tested before use and elastomers replaced as necessary.
8 Choke Manifolds and Choke Lines

8.1 Purpose

This section pertains to the choke manifold and choke line components temporarily installed to perform the CT well intervention operation. The choke line and manifold provide a means to control pressure and flow originating from the wellbore and/or CT well control stack. The choke line and manifold consists of, but not limited to, piping, fittings, connections, valves, pressure monitoring device(s) and adjustable choke(s). Choke lines, choke line valves and manifold components shall be in accordance with API 16C.

8.2 Choke Line Installation

Choke lines shall be installed using rigid piping and flexible lines. See Figure C-1 through Figure C-3 in ANNEX C as examples of choke line assemblies used in CT operations. The choke line shall be identified as the piping assembly and flow control components installed between the well control stack and the inlet to the choke body or choke manifold. Choke line installations should be constructed as straight as possible to minimize erosion and incorporate targeted tees and/or fluid cushions in accordance with API 16C.

Choke line components shall be manufactured to conform with API 16C and should be installed in accordance with the following:

a) All components shall have a RWP equal to or greater than the minimum well control stack pressure rating designated by the operational pressure category.

b) For all pressure categories, end connections shall be integral or welded and in accordance with API 6A and/or API 16C.

c) At least one full-opening valve shall be installed between the CT well control stack and choke line. For any well capable of unassisted flow, at least two full-opening valves shall be installed between the CT well control stack and the choke line. Full-opening choke line valves shall not be used to throttle or choke flow.

d) For any well capable of unassisted flow, all connections between the CT well control stack and the first full-opening valve shall be a flanged connection.

e) For PC-3 and PC-4 operations, at least one full-opening valve installed between the well control stack and the choke line shall be remotely operated.

f) The minimum recommended size for choke lines is 2-inch nominal diameter, with an ID not less than 1.875 inches.

g) All gauge and test port connections, including isolation valve(s), shall be rated for the pressure service and be in accordance with API 6A.

8.3 Choke Manifold Installation

The choke manifold shall be identified as the assembly of piping and flow control components used to direct flow from the choke line to one or more choke devices. See Figure C-4 through Figure C-9 in ANNEX C for examples of choke manifold assemblies used in CT operations.

If a by-pass line is installed in the choke manifold, the by-pass line shall be equipped with at least two full-opening valves.
NOTE A by-pass line is a pressure-containing branch of the choke line manifold which redirects fluid flow upstream of the choke(s) and provides a means for unchoked flow to the atmosphere.

When used, choke manifold components shall be manufactured to conform with API 16C and should be installed in accordance with the following.

a) Manifold equipment subject to well and/or pump pressure (normally upstream of and including the chokes) shall have a RWP equal to or greater than the minimum CT well control stack pressure rating designated by the operational pressure category.

b) For all pressure categories, end connections subject to well and/or pump pressure (normally upstream of and including the chokes) shall be in accordance with API 6A and/or API 16C. For PC-2 operations and above, line pipe threads are not allowed.

c) For all pressure categories, at least one full-opening valve shall be installed between the choke line and each adjustable choke. Full-opening choke line valves shall not be used to throttle or choke flow.

d) In a multi-choke manifold, two full-opening valves shall be installed between the choke line and each choke device when it is expected that repairs may be conducted on one choke while flowing through the alternate choke.

e) For PC-4 operations, the adjustable chokes and their adjacent inboard valve shall be remotely controlled.

f) Pressure monitoring device(s) should be installed so that wellbore and/or choke pressure(s) may be monitored. The connections should conform to API 6A.

9 Kill Lines

9.1 Purpose

The kill line system provides an alternate means for pumping into the wellbore. Kill line components shall be in accordance with API 16C.

9.2 Kill Line Installation

A kill line assembly is comprised of full-opening valve(s) and a flow check device. See Figure D-1 in ANNEX D for an example of a kill line assembly. Kill lines shall be constructed using rigid piping, flexible lines or articulated line assemblies to conform with API 16C. Kill line installations should be constructed to minimize erosion in accordance with API 16C.

9.2.1 Kill line components shall be manufactured to conform with API 16C and should be installed in accordance with the following:

a) All components shall have a RWP equal to or greater than the minimum CT well control stack pressure rating designated by the operational pressure category.

b) For all pressure categories, end connections shall be integral or welded and in accordance with API 6A and/or API 16C.

c) At least one full-opening valve plus an inline flow check device shall be installed between the CT well control stack and pump line. For any well capable of unassisted flow, at least two full-opening valves and a flow check device shall be installed between the CT well control stack and the pump line. In both cases, the full-opening valves shall be located between the CT well control stack and the inline flow check device.
d) For any well capable of unassisted flow, all connections between the CT well control stack and the first full-opening valve shall be a flanged connection.

e) The minimum recommended size for kill lines is 2-inch nominal diameter, with an ID not less than 1.875 inches.

f) All gauge and test port connections, including isolation valve(s), shall be rated for the pressure service and in accordance with API 6A.

g) Over pressure protection shall be provided to ensure that pump pressure cannot exceed the RWP of the kill line(s).

9.3 Bleed-off Lines

Bleed-off line components shall be manufactured to conform with API 16C and:

a) be constructed of rigid piping, and

b) be located between the kill line valves and the flow check device.

The bleed-off line should be oriented at 90 degrees from the piping.

10 Pump Lines

10.1 Purpose

The pump line system provides a means of pumping into the CT workstring and/or wellbore to perform circulating or bull-heading operations. The pump line connects the fluid pumps to the CT reel and kill line(s) on the well control stack.

10.2 Pump Line(s) Installation

Pump lines shall be constructed of materials compatible with the fluid(s) pumped. Pump line installations should be constructed to minimize erosion in accordance with API 16C.

Pump lines should be installed and operated in compliance with the following:

a) All components shall have a RWP greater than or equal to the MAOP of the operation.

b) For all pressure categories, end connections shall be in accordance with API 6A.

c) For liquid pumping services, hoses used for the pump line shall be in accordance with API 7K. For nitrogen pumping services, flexible lines (hoses) used for pump line shall be in accordance with API 16C or API 7K.

d) A full-opening valve shall be installed between the reel swivel and the CT. In addition, a full-opening valve shall be installed between the pump line and the CT reel swivel.

e) An inline flow check device should be installed for each pump line.

f) All gauge and test port connections, including isolation valve(s), shall be rated for the pressure service and conform to API 6A.

g) Over pressure protection shall be provided to ensure that pump pressure cannot exceed the RWP of the pump lines.
10.3  Conventional Circulation Through Coiled Tubing Reel Swivel and Piping

Where conventional circulation operations are planned, the CT reel swivel becomes a pressure containing component integral to the pump line. In this scenario, the swivel body and elastomers are subjected to pumped fluids which are under the control of the User. As such, chemistry, compressibility and volatility documentation should be available to the User to confirm that the fluids to be pumped through the CT workstring will not adversely affect the swivel body materials and elastomeric seals. The selection of the reel swivel for a given application (fluid, temperature, and pressure) should be consistent with the manufacturers’ recommendations.

10.3.1 In preparation for conventional circulation operations, documentation shall be provided to confirm that the CT reel swivel is designed with appropriate elastomers and structural materials to maintain pressure integrity and fluid containment for the rated fluid chemistries to be circulated for the prescribed service. Documentation shall be provided to the User to confirm that the “pumped-fluid wetted” surfaces of the swivel body material and elastomeric seals are compatible with the fluid chemistry (high-density brines, Xylene, MeoH, etc).

10.3.2 The maintenance history of the CT reel swivel for pumping services should be reviewed to determine when the swivel was last repacked or repaired. Considerations for repacking the CT reel swivel include:

a) Length of time since last repacking (concerns for elastomeric seal outgassing and loss of seal elasticity)

b) Mechanical abrasion of the seals due to rotation of the CT reel (includes issues related to high-speed reel rotation)

c) Chemical reaction due to extended time in service between elastomeric seals and volume of pumped fluids

d) Effects of long-term exposure to nitrogen gas under pressure (gas impregnation and possible explosive decompression effects occurring upon completion of service application)

10.3.3 Where documentation recommended in 10.3.1 and 10.3.2 are not available, the following steps shall be taken to ensure that the pump line swivel component is capable of performing the proposed service:

a) The CT reel swivel shall be disassembled and the swivel body mechanical parts visually inspected for erosion or mechanical wear due to general service.

b) The areas of swivel mechanical components where changes in fluid flow direction typically occur within the component shall be UT inspected to determine remaining body wall thickness to confirm whether sufficient material remains to perform the intended service with the expected surface pressure to be contained within the swivel.

c) All areas of the swivel mechanical components where elastomeric seals are used for pressure containment shall be inspected to confirm that the glands are clean and free from corrosion damage (pitting, wall loss, scarring, etc).

d) All swivel elastomeric seals shall be replaced to enhance reliability of pressure sealing integrity of the swivel at the rotating shaft. The chemistry of the elastomeric sealing elements shall be confirmed as appropriate for the fluids expected to flow through the CT reel swivel. Documentation shall include the qualification of the individual(s) performing the inspection and maintenance.

e) The pump line piping upstream of the CT reel swivel shall be constructed in compliance with Section 10 recommended practices.

10.4 Bleed-off Lines

When a flow check device is installed in the pump line, a bleed-off line shall be installed as follows:

a) the bleed-off line shall be constructed of rigid piping,

b) the bleed-off line shall be located at a point upstream of the in-line flow check device,

c) the bleed-off line should be oriented at 90 degrees from the piping.
11 General Description of Coiled Tubing Surface Equipment

11.1 General

This section describes the minimum surface equipment necessary for handling CT except for the pressure control equipment (see Section 4). This section also provides assembly and performance guidelines for each component. A CT unit should be capable of carrying out all aspects of the proposed work and meet the performance guidelines as shown below. All surface equipment shall be designed and configured for operation in the ambient conditions at the job site. All surface equipment shall be operated within manufacturers ratings and specifications.

11.2 Typical Coiled Tubing Unit Components

In addition to the pressure control equipment, a typical CT unit incorporates the following equipment and components:

a) injector,
b) tubing guide arch,
c) CT reel,
d) power supply/prime mover,
e) monitoring equipment,
f) control system,
g) hoses and hose reel(s), as required.

The equipment described in this section covers only opposed-gripper injector systems.

11.3 Injector

The injector is the mechanical device that moves and supports the CT workstring in the operating environment. The chains, sprockets, and other moving parts of the injector should be covered with safety guards.

11.3.1 Tubing Size Range

The tubing size range refers to the sizes of CT workstring that the injector is capable of running.

11.3.2 Pulling Force

The pulling force is the tensile force that the injector can apply to the CT workstring immediately above the stripper. The injector should be capable of a pulling force that is greater than the maximum force expected for the service, including frictional drag. The hydraulic system for the injector should have a means of limiting the maximum pulling force to a predetermined value (thrust force and pulling force).

11.3.3 Thrust Force

The thrust force is the compressive force the injector can apply to the CT workstring immediately below the gripper mechanism. The injector should be capable of a thrust force greater than the maximum force expected for the intended service, including stripper and wellbore tubular contact drag. The hydraulic system for the injector should have a means of limiting the maximum thrust force to a predetermined value. Precautions should be taken to minimize the unsupported length of CT workstring between the injector and the stripper assembly to prevent catastrophic tube buckling failure due to thrust force (see 4.3.1.2).
11.3.4  Traction

Traction refers to the gripping force, which is the product of the force applied normal to the CT workstring axis and the coefficient of friction between the gripper and CT OD surfaces. Traction refers to the gripping force needed to maintain control and prevent slippage between the CT workstring and the gripping mechanism.

In the event of power supply or prime mover failure, the traction system shall have provisions to maintain control of the CT workstring.

11.3.5  Injector Support

The injector shall be stabilized to prevent bending moments which could cause damage to the wellhead, tree, or well-control stack (see 4.4.3).

11.3.6  Braking System

The injector shall have a braking system that prevents the CT workstring from moving uncontrollably. The hydraulic counter-balance valves decelerate the CT workstring and limit drift speed when hydraulic pressure is released. The injector shall also have a secondary friction brake that is set automatically or manually when the injector is stopped. Both of these braking systems shall be capable of holding the injector’s rated pulling and thrust forces, independently of each other.

11.3.7  Chains and Gripper Blocks

The most common type of gripper mechanism uses gripper blocks attached to counter-rotating chains. The friction between the gripper blocks and the CT workstring contributes to the traction controlling the CT workstring forces. Gripper block design should minimize the damage to the CT workstring.

NOTE  Other gripper mechanisms exist (e.g. clam shell, grooved wheel, etc.) but are not described here.

11.3.8  Chain Tension

Chain tension is the force applied to the chains to keep them taut and avoid chain buckling. The injector shall be equipped with a chain tensioning system.

11.3.9  Dampeners

Dampeners are gas-charged accumulators included in the chain traction and optionally in tension systems. Dampeners should be installed in the chain traction where sudden pressure surges in the system may occur.

11.3.10  Drive Motors

Drive motors are used to provide the dynamic torque needed to rotate the injector chains. The drive motors should have the capability to apply incremental amounts of thrust and pulling force.

11.3.11  Weight Sensor

The CT injector shall have a weight sensor which represents the axial loads in the CT workstring above the stripper assembly. The weight sensor shall be capable of showing the full range of thrust and pulling forces expected for the prescribed service. These load readings shall be displayed to the CT unit equipment operator at the control console.
11.4  Tubing Guide Arch

11.4.1  General

Most types of injectors utilize a tubing guide arch located on top of the injector that guides the CT workstring from the CT reel into the top of the injector. The tubing guide arch may be constructed with a series of rollers or slide pads which guide the CT workstring as it travels through the injector.

11.4.2  Radius

The tubing guide arch radius is defined as the minimum radius of curvature of the centerline of the CT workstring on the inner rollers or the slide pad.

For CT used for well intervention service, the tubing guide arch radius should be at least 40 times the CT outside diameter.

11.4.3  Rig-up Geometry (Lead-in and Fleet Angles)

The CT workstring should enter and exit the tubing guide arch tangentially to the curve of the tubing guide arch. An abrupt change in the lead-in bending angle could cause damage to the CT workstring.

The fleet angle is defined as the angle between a line passing through the center of the tubing guide arch and the center of the CT reel, and a line passing through the center of the tubing guide arch and the position of the CT workstring on the CT reel.

Spooling of the CT workstring back and forth across the width of the reel changes the fleet angle. The end of the tubing guide arch should not interfere with the CT workstring as it passes through this fleet angle. Guide arches may be constructed with a flared end or a swiveling base to accommodate the changing fleet angle.

11.5  Coiled Tubing Reel

11.5.1  General

The CT reel:

a) serves as the storage mechanism during transport;

b) serves as the spooling device during operations;

c) provides the means for continuous circulation;

d) provides the means for transmittal of electrical, hydraulic and other signals; and,

e) provides the means for pumping of balls, darts and other devices.

11.5.2  Reel Dry Weight

The dry weight is the weight of the CT reel assembly plus the weight of the empty CT workstring on the CT reel.

11.5.3  Reel Wet Weight

The wet weight is the CT reel dry weight plus the weight of any liquids inside the CT workstring.
11.5.4 Core Radius

The core radius of the CT reel defines the smallest bending radius for the CT workstring. For CT used in well intervention service, the core radius should be at least 20 times the CT outside diameter.

11.5.5 Coiled Tubing Reel Motor

The CT reel motor shall provide sufficient torque to spool the wet weight of the CT workstring on the CT reel. The tension created by the CT reel motor on the CT workstring between the reel and the injector is called the CT reel back tension. The CT reel back tension is not intended to aid the injector in pulling the CT workstring, but to keep the CT taut on the CT reel.

11.5.6 Coiled Tubing Reel Brake

The CT reel shall have a brake that is used to keep the CT reel drum stationary and can be manual and/or automatic.

11.5.7 Levelwind

The levelwind is used to aid the spooling of the CT workstring onto the CT reel. The levelwind assembly should be used to maintain spooling efficiency of the CT workstring on the service reel.

11.5.8 Coiled Tubing Reel Swivel and Piping

11.5.8.1 The CT reel is equipped with a swivel and piping to allow:
   a) continuous circulation through the CT workstring while the CT reel is rotating, and
   b) pumping of balls, darts, and other devices.

11.5.8.2 The CT reel piping between the swivel and the CT workstring end connection shall include a full-opening valve to isolate the CT workstring from the CT reel swivel and ball-launcher fixture.

NOTE: see 10.3 for recommendations regarding CT reel swivel service concerns in conventional circulation operations.

11.6 Power Supply/Prime Mover

The power supply/prime mover provides hydraulic, mechanical, pneumatic, and/or electrical power to operate all of the CT unit equipment and may be built in different configurations.

11.7 Monitoring Equipment

11.7.1 The following gauges/displays shall be used to monitor critical well control parameters on CT well intervention services:
   a) weight sensor display,
   b) measured depth counter,
   c) circulating pressure gauge,
   d) wellhead pressure gauge,
11.7.2 Where applicable, the following gauges should be used to monitor operating parameters on CT well intervention services:

a) traction hydraulic pressure,
b) chain tension hydraulic pressure,
c) CT reel back-tension hydraulic pressure.

11.8 Control System

d) "dedicated SBR" well control operating system pressure gauge (accumulator pressure),
h) "dedicated SBR" well control stack ram pressure gauge.

i) “First-in-service” stripper operating system pressure gauge

j) “Second-in-service” stripper operating system pressure gauge

11.8.1 Where applicable, the following controls should be used to operate the CT equipment:

a) “primary” well control system hydraulic pressure enable,
b) “primary” well control system hydraulic ram open/close for each ram
c) “dedicated SBR” well control system hydraulic pressure enable,
d) “dedicated SBR” well control system hydraulic ram open/close for each ram,
e) well control system emergency pressure supply,
f) “First-in-service” stripper operating hydraulic pressure,
g) “Second-in-service” stripper operating hydraulic pressure,
h) injector motor hydraulic pressure,
i) injector brake hydraulic pressure,
j) traction hydraulic pressure,
k) chain tension hydraulic pressure,
l) CT reel back-tension hydraulic pressure,
m) CT reel brake hydraulic pressure.
11.9 Hoses and Hose Reel(s)

All hydraulic and pneumatic hoses and hose reels used to operate the CT Unit shall comply with the following:

a. All hoses shall be appropriately sized for the equipment component in service to minimize frictional pressure losses due to expected fluid flow and rated for the working pressure of the system, as installed.

b. End connections and extension connectors shall be selected to minimize restrictions in the fluid flow path and should be sized appropriately for the diameter of hose in service. Use of end connections and extension connectors which are larger in size than the diameter of the hose is acceptable where the connector is joined to the hose through a single crossover bushing. Assembly of threaded connections using sealing tape or non-soluble thread preparations shall require care in use and be subjected to subsequent flushing to avoid plugging or malfunction of system components.

c. Where quick-disconnect unions are used as end connections for the hoses, the quick-disconnect should be sized appropriately for the diameter of hose in service. Use of quick-disconnect unions which are larger in size than the diameter of the hose is acceptable where the quick-disconnect unions are joined to the hoses through a single crossover bushing. Assembly of multiple quick-disconnect unions to crossover from one hose size to another shall not be permitted.

d. Where hose reels are used to connect components on the CT Unit, piping and hose metal components shall be burr-free, clean and free of loose scale and other foreign material prior to assembly. Assembly of threaded connections using sealing tape or non-soluble thread preparations shall require care in use and be subjected to subsequent and periodic flushing to avoid plugging or malfunction of system components.

e. Each hose connected to the hose reel should be inspected for leakage prior to initiating CT well intervention operations by applying the designated maximum system pressure expected for the prescribed service. All rotating seal assemblies shall be visually inspected during the hose leakage test.
12 Well Control Equipment Testing

12.1 General

The well control equipment including, but not limited to, the well control stack, flow lines, kill lines, manifolds, valves and spacer spool segments, shall be tested in accordance with 12.2 through 12.7.

12.2 Performance Testing—Slip Ram, Pipe-Slip Ram, Shear Ram and Shear-Blind Ram

The performance tests for the slip ram, pipe-slip ram, shear ram and shear-blind ram shall be conducted to demonstrate that the well control component is fit for purpose. Documentation from the latest performance test results shall be available for review and include the projected performance of the slip ram, pipe-slip ram, shear ram and shear-blind ram at the MASP for the prescribed service.

12.2.1 Slip Ram Performance Test

The slip ram shall be tested to confirm the ability of the slip inserts to secure the segment of the designated CT workstring without movement to the maximum projected axial load (hang weight) applied to the CT workstring during the well intervention activity. The slip ram performance test protocol and performance requirements shall be in accordance with ANNEX E.

12.2.2 Pipe-Slip Ram Performance Test

The pipe-slip ram shall be tested to confirm the ability of the slip inserts to hold the segment of the designated CT string without movement to the maximum projected axial load applied to the CT string during the well intervention activity. The pipe-slip ram performance test protocol and performance requirements shall be in accordance with ANNEX E.

12.2.3 Shear Ram Performance Test

The shear ram shall be tested to confirm the ability of the ram, shear blade inserts and ram actuator (including booster, if installed) to properly sever the segment of the designated CT workstring with the cut ends having the appropriate geometry and remaining cross-sectional area to conduct a circulation kill program down the CT workstring remaining suspended in the slip rams. The shear ram performance test protocol and performance requirements shall be in accordance with ANNEX F.

12.2.4 Shear-Blind Ram Performance Test

The shear-blind ram shall be tested to confirm the ability of the ram, shear blade inserts, sealing elements and ram actuator (including booster, if installed) to properly sever the segment of the designated CT workstring with the cut ends having the appropriate geometry and remaining cross-sectional area to conduct a circulation kill program down the CT workstring remaining suspended in the slip ram or pipe-slip ram. Further, the shear-blind ram shall demonstrate the ability to seal the ID bore of the well control stack to the MASP of the well. The shear-blind ram performance test protocol and performance requirements shall be in accordance with ANNEX F.

12.2.5 Pressure-sealing Ram Locks

The ram locking system on the pressure sealing rams (blind ram, pipe ram, shear-blind ram and pipe-slip ram) shall be performance tested to confirm that the rams remain closed and maintain the pressure seal to the established test criteria after removal of hydraulic actuator pressure applied to the rams. The ram locking performance tests shall be conducted at a minimum test frequency of 180 days to the RWP of the ram component. Records documenting the performance pressure tests using only the ram locking system shall be available for review.
12.2.6 Frequency of Actuation Test

An actuation test of a well control component consists of a close and open sequence. The test of the well control component shall be performed:

a) upon initial installation of the well control equipment and hydraulic pressure control system,

b) following any action compromising the integrity of the hydraulic control system connected to the specific component,

c) at least once every seven days.

12.2.7 Well Control Hydraulic System Test

12.2.7.1 This test is required to demonstrate the ability and verify the pressure integrity of the prime mover hydraulic system to actuate the individual well control component(s) as designed. Each component shall be actuated and the actuation visually confirmed. This test shall be performed on location prior to commencing the job and shall be documented on the job log.

12.2.7.2 The minimum pressure of the well control equipment operating system shall be that required to perform the specified ram function at atmospheric pressure plus that required to overcome the wellbore pressure (based on the ram piston balance pressure). The accumulator response time test (see 13.6.3) shall be performed on location and shall be documented on the job log.

12.2.7.3 A hydraulic system shall supply the volume required to operate the well control stack functions at MASP.

12.3 Performance Load Test—Flow Check Assembly Connector

The CT BHA flow check assembly shall be installed on the CT workstring following the manufacturer’s recommended procedure prior to pressure testing the device. The CT BHA connector on the flow check assembly shall be pull tested to the maximum anticipated force/load (including contingencies) expected at the connector.

12.4 Pressure Testing

All well control equipment components shall be pressure tested. The pressure test sequence consists of a low-pressure test, followed by a high-pressure test. The pressure test fluid should be water or some other solids-free liquid with a flash point greater than 100 °F.

12.4.1 Low-pressure Test

Well control components shall be subjected to a low-pressure test (250 psig to 350 psig). The pressure shall be maintained at stabilized pressure with no leakage for at least five minutes.

All low-pressure tests shall be between 250 psig and 350 psig. Any initial pressure above 350 psig shall be bled back to a pressure between 250 psig and 350 psig before starting the test. If the initial pressure exceeds 500 psig, the pressure shall be bled back to zero and the test reinitiated. Note that a pressure of 500 psig or greater could energize a seal that may continue to hold pressure after bleeding down and, therefore, not be representative of an acceptable low-pressure test.
12.4.2 High Pressure Test

Well control components shall be subjected to a pressure equal to the MAOP or 1.1 times MASP, whichever is greater, but not to exceed the 5% or 500 psig of the RWP of the components, whichever is less. The pressure drop shall meet the documented criteria with a stable pressure or decreasing decay rate during the evaluation period. The pressure shall not decrease below the intended test pressure. The pressure shall be stabilized with no leakage for a minimum of 10 minutes.

12.4.3 Types of Well Control Equipment Pressure Tests

The following are descriptions of the types of pressure tests.

a) Ram/valve pressure test: a pressure integrity test used to verify the ability of the well control component to maintain the designated pressure seal(s) when closed.

Note: The ram/valve pressure test may simultaneously demonstrate the pressure-sealing integrity of other affected well control equipment or ram components.

b) System pressure test: a full-body pressure integrity test used to verify the pressure sealing capability of all pressure containment components assembled for the operation. The stripper assembly typically serves as the upper pressure containment device for the system pressure test.

c) Connection pressure test: a pressure integrity test used to confirm the pressure-sealing integrity of one or more connections within the system.

12.4.4 Conventional CT Well Control Equipment Pressure Test Frequency

Pressure test frequency for the well control equipment shall be as follows.

a) Ram/valve pressure test:
   - initial installation of the well control equipment and hydraulic pressure control system,
   - following any action compromising the pressure seals.

b) System pressure test: initial installation of the well control equipment and hydraulic pressure control system on each designated well.

c) Connection pressure test:
   - initial installation of the well control equipment if not included in the ram/valve pressure test,
   - following any action that requires disconnecting a pressure seal.

The ram/valve and system pressure tests shall be performed at least once every seven days. A period of more than seven days between tests should be allowed when well operations (such as, but not limited to, stuck CT workstring) lasting more than seven days prevent testing. However, the pressure tests shall be performed at the earliest opportunity following the seven day period.
12.4.5  “Well Hopping” Coiled Tubing Well Control Equipment Pressure Test Frequency

In campaign programs where several concentric well intervention operations are planned, the grouping of wells within close proximity of each other provides a unique opportunity in performing safe and effective pressure testing in a time-efficient manner. The term “well hopping” refers to the practice of conducting well intervention operations within a group of wells where the objective of the intervention program within a given wellbore is completed within the 7-day pressure test frequency as recommended in 12.4.4 and the CT well control stack is then moved to an adjacent wellbore and well intervention operations are conducted with pressure testing requirements following 12.4.4 (c) only.

12.4.5.1 Where “well hopping” operations are anticipated, see ANNEX G for the testing process which will meet the pressure testing frequency recommendations of this Standard.

12.4.6 Pressure Testing Contingencies

12.4.6.1 When operational conditions (i.e. CT workstring in the wellbore) prevent a connection pressure test to the designated test pressure, an applied pressure equal to the current well pressure may be used. These tests only apply to connections located above the upper-most sealing ram in the well control stack.

12.4.6.2 When change-out of the stripper element and/or related repair is required with the CT workstring positioned across the well control stack, a modified pressure test at an applied pressure equal to or greater than the current well pressure should be conducted upon completion of the replacement.

12.4.6.3 The post stripper element change-out/repair activity pressure test should be held for a minimum of ten minutes at stabilized pressure.

12.4.6.4 Prior to reentering the wellbore on subsequent runs, a pressure test shall be conducted on the affected component.

12.4.7 Pressure Test: Coiled Tubing BHA Flow Check Assembly

Prior to installation onto the CT BHA, an internal pressure test of the flow check assembly shall be performed to the RWP of the flow check assembly or 1.1 times the MASP of the well, whichever is less at the test frequency recommended in 12.4.4.

To confirm performance of the flow check device(s) following installation on the CT workstring, an external flow check test shall be performed to the lesser of the maximum differential pressure expected at the flow check assembly or within the collapse pressure limitations of the CT workstring exposed to the pressure test. The flow check test shall demonstrate the ability to establish a pressure seal and prevent backflow through the CT workstring.
12.5 Test Documentation

The following applies to test records.

a) All well control equipment test activities, including test results, remedial actions taken and testing sequence shall be documented on the daily operations log and recorded in a separate pressure test log. The results of all well control equipment pressure tests should be recorded using an analog chart recorder or digital data acquisition system and include as a minimum:

1) the well control component(s) incorporated within the pressure test,
2) the stabilized pressure observed for the low-pressure test and duration of each test,
3) the stabilized pressure observed for the high-pressure test and duration of each test,
4) resulting outcome of the pressure test (passed or failed),
5) resolution of failed pressure tests (repairs implemented and or replacement of components)

b) The CT equipment owner should be informed of well control equipment failures in the field. The CT equipment owner should alert the manufacturer.

12.6 General Testing Considerations

All on-site personnel should be alerted when pressure test operations are being conducted. Only necessary personnel should remain in the test area. The following considerations should be noted:

a) only personnel authorized by the well owner or designee shall go into the test area to inspect for leaks when the well control equipment is under pressure,

b) repairs or any other work shall be performed only after pressure has been released and potential trapped pressure has been bled at every available outlet,

c) pressure should be released through pressure release (bleed-off) lines.

12.7 Pressure Test Devices

Pressure gauges, chart recorders, and or data acquisition equipment shall be used to record the pressure test of the well control equipment. For all pressure tests, pressure measurements made with bourdon tube-type pressure measurement devices shall be made at not less than 25 % and not greater than 75 % of the full pressure span of the gauge or device.

The graduations of the test gauge scale should have sufficient resolution for conducting the pressure test. Where chart recorders are used, the chart recorder time clock should be set for a four-hour period or less.

For recording pressure tests using a digital data acquisition system, the pressure sensor accuracy shall be equal to or better than ±0.5% of the full range of the sensor. The monitoring system shall be at least as accurate as the sensor. The update (scan) rate of the monitoring system shall be equal to or faster than 1 Hz and calibrated in accordance with ASTM D5720-95.
13 Well Control Equipment Operating System

13.1 General

13.1.1 The well control equipment operating system provides a source of pressurized hydraulic control fluid (power fluid) to operate the well control equipment components.

13.1.2 The well control equipment operating system shall be an independent hydraulic circuit dedicated exclusively for the operation of well control equipment components.

13.1.3 The well control operating system may be configured through one of the following Options:

   Option A: A “primary” well control stack accumulator bank and a separate, independent “dedicated” shear-blind ram well control component accumulator bank integral to a stand-alone Closing Unit.

   Option B: A “primary” well control stack accumulator bank integral to a CT Unit hydraulic power system, with a stand-alone Closing Unit to provide the “dedicated” shear-blind ram well control component accumulator bank.

   Option C: A “primary” well control stack accumulator bank and a separate, independent “dedicated” shear-blind ram well control component accumulator bank integral to a CT Unit hydraulic power system.

Options for the CT well control operating system that do not conform with aforementioned Options A, B or C may be permitted where a risk assessment has been performed and the management of change addresses deviations to ensure that performance requirements seen in Section 13 have been met.

13.2 Functional Requirements

13.2.1 Option A

The stand-alone well control stack operating system shall be constructed and operated in accordance with the latest version of API 16D, where the “primary” well control stack accumulator bank is separate and independent of the “dedicated” shear-blind ram well control component accumulator bank.

13.2.1.1 The operating system for the “first-in-service” stripper assembly shall be located on the control console panel and operated through the hydraulic circuit described in 13.7.1.

13.2.1.2 The remote operating panel for the stand-alone closing unit controlling the well control stack components with shall be located within or immediately adjacent to the CT control console cabin.

13.2.1.3 The pressure and volume capacity of the “primary” and “dedicated” shear-blind ram well control equipment operating systems shall be sufficient to perform all required functions of the respective operating system, as seen in 13.6.2.1 (primary) and 13.6.2.2 (dedicated).

13.2.1.4 The response time provided by the stand-alone closing unit for the CT well control stack components shall meet or exceed the requirements of 13.6.3.

13.2.2 Option B

The “primary” well control stack operating system integrated within a CT Unit shall consist of a pump system used exclusively to provide power fluid to the accumulator bank. The energy source shall be designed with the capability of independently operating the well control equipment components as required.
13.2.2.1 The “primary” well control stack accumulator bank shall be designed as integral to a CT Unit hydraulic power system, with a stand-alone Closing Unit supplied to provide the means to operate the “dedicated” shear-blind ram well control component accumulator bank.

13.2.2.2 The stand-alone well control operating system shall be constructed and operated in accordance with the latest version of API 16D, where the well control stack accumulator bank of the stand-alone Closing Unit serves as the operating system for the “dedicated” shear-blind ram well control component.

13.2.2.3 All controls and monitoring devices for the “primary” well control stack operating system shall be integrally mounted within the control console cabin.

13.2.2.4 The operating system for the “first-in-service” stripper assembly should be located on the control console panel and operated through the hydraulic circuit described in 13.7.1.

13.2.2.5 The remote operating panel for the stand-alone closing unit controlling the “dedicated” shear-blind ram well control stack component shall be located within or immediately adjacent to the CT control console cabin.

13.2.2.6 The pressure and volume capacity of the “primary” and “dedicated” shear-blind ram well control equipment operating systems shall be sufficient to perform all required functions of the respective operating system as seen in 13.6.2.1 (primary) and 13.6.2.2 (dedicated).

13.2.3 Option C

The “primary” well control stack operating system and “dedicated” shear-blind ram operating system integrated within a CT Unit shall consist of one or more pumps used exclusively to provide power fluid to the “primary” accumulator bank and the “dedicated” accumulator bank.

13.2.3.1 The “primary” well control stack accumulator bank and the “dedicated” shear-blind ram well control component accumulator bank shall be designed as integral to a CT Unit hydraulic power system and both accumulator banks may be charged from a single pump system where sufficient check valve isolation protection is provided to ensure that the “dedicated” accumulator bank operates totally independent from the “primary” accumulator bank. Further, the system shall be designed to ensure that a failure of one accumulator bank cannot drain the fluid and pressure from the other accumulator system.

13.2.3.2 All controls and monitoring devices for the “primary” well control stack operating system and the “dedicated” shear-blind ram operating system shall be integrally mounted within the control console.

13.2.3.3 The operating system for the “first-in-service” stripper assembly and “second-in-service” stripper assembly shall be located on the CT Unit control console panel and operated through the hydraulic circuit described in 13.7.1.

13.2.3.4 The pressure and volume capacity of the “primary” and “dedicated” shear-blind ram well control equipment operating systems shall be sufficient to perform all required functions of the respective operating system as seen in 13.6.2.1 (primary) and 13.6.2.2 (dedicated).

13.3 Well Control Equipment Operating System Components

The well control equipment operating system contains the following components:

a) reservoir,

b) accumulator bank pump system (pressurizes the hydraulic control fluid).
c) primary accumulator bank (stores power fluid),

d) dedicated accumulator bank (stores power fluid),

e) stripper assembly operating system (pressurizes the hydraulic control fluid),

f) control panel, manifold and hoses (for transmission of power fluid to well control stack components), and

g) hydraulic control fluid.

h) alarm systems

NOTE When pressurized, hydraulic control fluid is referred to as power fluid.

### 13.4 Reservoir

**13.4.1** The hydraulic fluid requirements (reservoir) for the Option A “primary” and “dedicated” well control operating systems integral to a stand-alone closing unit system (Par. 13.2.1) shall be at least two-times the stored hydraulic fluid capacity of the accumulator bank(s), in addition to the volume of the control valve manifold and well control equipment components.

**13.4.2** The hydraulic requirements (reservoir) for the Option B “primary” well control operating system integral to the CT Unit operating system (Par. 13.2.2) shall be at least two-times the stored hydraulic fluid capacity of the “primary” accumulator bank(s), in addition to the volume of the control valve manifold and well control equipment components. To meet the requirements, the reservoir hydraulic fluid may be derived from the fluid stored within the CT power pack hydraulic system tank or from an independent reservoir dedicated to provide fluid to the “primary” accumulator systems.

**13.4.3** The hydraulic requirements (reservoir) for the Option C “primary” well control operating system and “dedicated” shear-blind ram operating system (Par. 13.2.3) integral to the CT Unit operating system shall be at least two-times the stored hydraulic fluid capacity of both of the accumulator bank(s), in addition to the volume of the control valve manifold and well control equipment components. To meet the requirements, the reservoir hydraulic fluid may be derived from the fluid stored within the CT power pack hydraulic system tank or from an independent, isolated reservoir which can provide a separate fluid chemistry dedicated to the accumulator systems.

**13.4.4** The hydraulic system tank containing the hydraulic fluid reservoir shall be equipped with pressure relief valves or vents to avoid over-pressurization. The hydraulic system tank shall be equipped with an inspection/cleanout port, a means to determine hydraulic fluid level, pump suction port(s) and fluid returns port(s) from the well control stack components and accumulator bank(s).

### 13.5 Pump System and Pump Sizing

**13.5.1** The pump system(s) provides power fluid to their respective well control equipment components. The pump system(s) shall be capable of meeting the following requirements:

- a) Charge the accumulator systems (primary and dedicated) to exceed the minimum component operating pressure needed to function each well control stack component to meet the performance requirements of Section 12;

- b) The pump system for the “primary” and/or “dedicated” accumulator bank(s) installed integral to the CT Unit shall charge the accumulator circuit from precharge pressure to $P_{\text{max}}$ within 10 minutes;
c) If air-actuated hydraulic pumps are used to charge the accumulator system, the air-actuated hydraulic pumps shall be capable of charging the accumulators to the system working pressure with 75-psig minimum air pressure supply.

d) If air-actuated hydraulic pumps are used to operate the stripper assembly system, the air-actuated hydraulic pumps shall be capable of operating the stripper assembly circuit to the system working pressure with 75-psig minimum air pressure supply.

13.5.2 The pump system(s) shall be protected by at least one device designed to regulate the pump discharge pressure and a second, independent pump system pressure relief valve set at a pressure no greater than 1.1 times the RWP of the hydraulic circuit. Devices used to prevent pump system overpressurization shall be installed directly in the pump discharge line and shall not have isolation valves or any other means that defeat their intended purpose. Rupture discs or relief valves that do not automatically reset are not allowed.

13.6 Accumulator Bank and Accumulator Sizing

13.6.1 General

Each accumulator bank in service ("primary" and "dedicated") shall have two or more bottles that store hydraulic fluid under pressure. The stored energy within each accumulator bank is used to function well control components, independent of the pump system.

13.6.1.1 The accumulator bank piping shall have the means to isolate the pump(s) from the accumulator bank manifold.

13.6.1.2 Each accumulator system shall be protected by at least one pressure relief valve set at a pressure no greater than 1.1 times the RWP of the hydraulic circuit. Pressure relief valve(s) shall be installed directly in the accumulator manifold circuit downstream of the pump line check valves and shall not have isolation valves or any other means that defeat their intended purpose. Rupture discs or relief valves that do not automatically reset are not allowed.

13.6.2 Accumulator Volumetric Capacity

13.6.2.1 The "primary" accumulator bank shall have sufficient usable hydraulic fluid capacity (with the pump system inoperative) to operate all well control equipment components connected to the "primary" bank through a complete close-open-close sequence. After completing the close-open-close sequence, the pressure remaining in the accumulator bank shall be at least 200 psig above the pre-charge pressure (see 13.6.5). The volumetric capacity of the well control equipment accumulator bank and pre-charge pressure should be calculated using the method in Annex H.

13.6.2.2 The "dedicated" accumulator bank shall have sufficient usable hydraulic fluid capacity (with the pump system inoperative) to operate the dedicated shear-blind ram through a complete close-open-close sequence. After completing the close-open-close sequence, the pressure remaining in the accumulator bank shall be at least 200 psig above the pre-charge pressure (see 13.6.5). The volumetric capacity of the well control equipment accumulator bank and pre-charge pressure should be calculated using the method in Annex H.
13.6.2.3 Where an accumulator bank is provided for the stripper assembly operating system, the accumulator bank shall have sufficient usable hydraulic fluid capacity (with the pump system inoperative) to operate the stripper assembly through a complete close-open-close sequence. The volumetric capacity of the well control equipment accumulator bank and pre-charge pressure should be calculated using the methods seen in Annex H.

13.6.3 Accumulator Bank - Well Control Stack Operating System Response Time

The response time is measured from initial component actuation to confirmed closure of the component and establishment of an effective pressure seal. The function of a well control component may be confirmed through observation of the visual position indicator (closed or opened), or when recovery of the decrease in operating system pressure due to frictional pressure losses in the control lines is observed. If confirmation of pressure seal-off is required, a pressure test below the ram component or across the valve shall be performed.

13.6.3.1 Every pipe ram designated to serve as the annulus-sealing mechanism in the event of a stripper assembly malfunction or failure shall have a response time of 10 seconds or less for closure and sealing on the OD CT.

13.6.3.2 The operating system for all remaining “primary” well control stack ram components shall provide a response time of 30 seconds or less for closure and completion of function.

13.6.3.3 The operating system for the “dedicated” shear-blind ram shall provide a response time of 10 seconds or less to complete shearing and sealing functions.

13.6.3.4 The closing time using only the accumulator system shall be confirmed through testing onsite and evaluated to determine whether the closing time is appropriate for the intended service (see Annex I for an example CT accumulator drawdown test form).

13.6.4 Stabilized Operating Pressure

The stabilized operating pressure of the accumulator bank and manifold shall be greater than the value of $P_{crit}$ (see Annex H), but not to exceed the maximum allowable working pressure of the well control operating system components. The stabilized operating pressure of the accumulator bank shall be the pressure observed at least 30 minutes after initial pressurization.

13.6.5 Accumulator Precharge

The accumulator precharge pressure provides the minimum stored potential energy needed to propel the power fluid from within the accumulators. The precharge pressure shall be calculated (see Annex H for examples) to meet the minimum operating requirements of the well control equipment and the operating environment without exceeding the RWP of the accumulator. Precharge practices shall conform to the following.

a) The accumulator shall be pre-charged with inert gas only.

b) The precharge pressure should be recorded and accompanied by a temperature reading of the accumulator body. The precharge pressure and body temperature of record should be taken after the accumulator has reached thermal equilibrium (typically 30 minutes) after precharge activities.

b) Precharge pressure should be at least 25% of $P_{maximum}$. 
13.7 Stripper Assembly Operating System

13.7.1 The pump system employed to operate the stripper assembly shall be configured with a minimum of two pumps having independent power sources. The pump system may be configured with the following pressure-delivery systems:

a. an air-actuated hydraulic pump
b. a hydraulic hand pump
c. a regulated pump
d. an accumulator system charged through the control console priority pressure circuit. This accumulator circuit is in addition to the existing priority circuit accumulator and shall be used exclusively for the stripper assembly circuit.

13.8 Control Panel, Manifold and Hoses

13.8.1 The well control equipment operating system shall be equipped with one or more control panels. The main control panel is typically located within or near the CT equipment operators control console. The control manifold directs power fluid to and from the well control equipment components. All hydraulic components of the control panel and manifold shall have a RWP greater than or equal to the maximum allowable working pressure of the operating system.

13.8.2 The control panel shall provide the following:

a) Two-step operations to function well control stack rams. All control valves for the well control stack should be protected to avoid unintentional operation.

b) Control valves clearly marked to indicate:
   — the well control component operated, and
   — the position of the control valves (i.e. open, close, neutral).

c) Displays to monitor accumulator pressure, ram component pressure, operating system hydraulic pump pressure and rig air pressure (for all systems using air-operated pumps and air operated panels).

d) An isolation valve in the power fluid circuit installed upstream of each of the “primary” and “dedicated” well control ram operating valves to minimize losses of power fluid volume and pressure when not in use (due to control valve leakage). During normal operations, the isolation valve should remain closed and opened only to function the well control ram components.

NOTE Each ram control valve should be in the open position (not the neutral position) during the well servicing operations.

13.8.3 Allowable end connections include (but are not limited to) American National Standard Taper Pipe Thread, SAE industrial O-ring boss port connections, and SAE four-bolt flange connections. Pipe and pipe fittings shall conform as specified in ASME B31.3 or an equivalent standard. All welded connections on the hydraulic control manifold shall be welded by a welder qualified in accordance with ASME Section IX per a weld procedure specification that has been qualified in accordance to ASME Section IX.
13.8.4 Hydraulic and pneumatic hoses used to operate the CT barrier components assembled in the well control stack shall comply with 11.9 and include the following:

a. All hoses shall be appropriately sized for the equipment component in service to minimize frictional pressure losses due to expected fluid flow and rated for the working pressure of the system, as installed.

b. The hose assembly shall be tested to 1.5 times the RWP. The testing shall include end connections if permanently attached.

c. All control hoses directly connecting to well control stack barrier components located in a division one (1) area, as defined by API 500 or a Zone 1 area defined by API 505, shall comply with the fire test requirements of API 16D.

d. The minimum length of each fire-resistant control hose directly connecting to well control stack barrier components shall be determined by API 500 or API 505. The end connection joining the fire-resistant hose to the remainder of conventional hydraulic control hose should be through a threaded fitting having fire-resistant qualification.

e. All well control equipment operating hoses and monitoring cables shall be supported through briddles or brackets which are secured to the stack to eliminate axial tensile loading on the end connections during any stage of well intervention service.

f. All well control stack barrier operating hoses and monitoring cables shall remain connected throughout the well intervention operation and be pre-deployed in a manner where movement of the well control stack does not require changes in any of the mechanical components or connections providing hydraulic flow or signal communication (hose reels, points of severe turns, bending or kinking of lines, etc.).

13.9 Hydraulic Control Fluid

13.9.1 The hydraulic control fluid shall comply with the recommendations of the equipment manufacturer and meet or exceed local requirements for environmental safety.

13.9.2 Where operating conditions dictate use of synthetic fluids (extreme cold temperatures, etc), a reservoir tank separate from the CT Unit hydraulic control fluid shall be installed and used exclusively for the well control equipment operating system.

13.10 Accumulator Circuit Alarm Systems

13.10.1 Each tank used to serve as a hydraulic fluid reservoir for the accumulator systems (“primary” and “dedicated”) shall be equipped with fluid level alarms to indicate a “low fluid level” condition.

13.10.2 Each pump system shall be equipped with a low-pressure alarm to indicate a “low power fluid pressure” condition.

13.10.3 Each accumulator bank (“primary” and “dedicated”) shall be equipped with a low-pressure alarm to indicate a “low power fluid pressure” condition for each isolated accumulator bank.

13.10.4 Each air-actuated hydraulic pump system shall be equipped with a low-pressure alarm to indicate a “low air pressure” condition.

13.10.5 All alarm systems described in Par. 13.10 above shall provide both visual and audible alert devices located within the CT control console to identify the accumulator system experiencing the defined alarm condition.
14 Pre-job Planning and Preparation

14.1 General

This section provides guidelines that can be used to help plan and execute CT operations. Well owners, service providers, and equipment manufacturers may require or recommend additional well servicing practices and/or site-specific considerations. Regulatory authorities may require certain operational, safety and environmental conditions be met. In addition, well control certification and other operational training may be required.

14.2 Well Control Contingencies

The purpose of well control contingency planning is to minimize response time in the event of an unplanned well control incident.

Well control contingency actions are responses to conditions which threaten well security and/or personnel safety. These responses should be based on personnel training, familiarity with the equipment, knowledge of the wellbore, and site conditions. Contingency responses to certain well control events which may arise during CT well intervention operations are shown in Annex J.

14.3 Job Planning

A planning meeting should be held with all involved parties to clearly define operational objectives. The scope of work, services, required equipment, materials, and well intervention procedures should be outlined. A health, safety and environmental (HSE) plan should be in place to cover items such as well site orientation, job safety analysis (JSA), material safety data sheets (MSDSs), and the pre-job safety meeting.

The information in 14.3.1 through 14.3.5 should be considered in preparation for CT well intervention service applications.

14.3.1 Wellbore—Physical Characteristics

Wellbore physical characteristics include the following:

a) casing sizes, weights, grades, depths, and connection type;
b) tubing sizes, weights, grades, depths, and connection type;
c) dimensions, depths, and description of downhole completion equipment;
d) directional survey;
e) type and density of fluids in the wellbore;
f) description of current completion including wellbore diagram;
g) location and dimension of obstructions or restrictions;
h) specifications of wellhead and related surface equipment;
i) location and type of wellbore safety devices;
j) known wellbore problems;
k) current casing and/or tubing pressure capacities;
l) well history (workovers, wireline work, problems, etc.).
14.3.2 Reservoir—History and Current Parameters

Reservoir history and current parameters include the following:

a) reservoir type and characteristics;
b) reservoir temperature;
c) description and location of all zones communicating with the wellbore;
d) initial and current static and flowing tubing pressures;
e) initial and current static and flowing bottomhole pressures;
f) maximum potential shut-in pressure;
g) type(s) of produced fluids and maximum potential production rates;
h) condition which can promote erosion, corrosion, scale, or other problems;
i) known field problems.

14.3.3 Location—Physical, Environmental, and Regulatory Factors

Onshore or marine location factors include the following:

a) type of facility (floating, fixed platform, satellite, or caisson);
b) location plan and constraints;
c) emergency shutdown and evacuation contingency plans;
d) crane capacity and reach;
e) pollution prevention and containment;
f) other operations in near proximity, including non-petroleum activities such as farming, fishing, hunting, tourism, etc.;
g) handling and disposal of fluids and materials;
h) logistical support;
i) governmental and regulatory agency regulations;
j) property owner concerns.

14.4 Location—Equipment Layout

Location equipment layout considerations include the following:

a) location constraints (load limit, overhead obstructions, and site dimensions);
b) identification and classification of hazardous areas;
c) dimensions and weights of service equipment;
d) placement and orientation of equipment;
e) location and description of remote control operator panels and emergency shutdown devices (ESD);
f) escape routes and accessibility;
g) tiedown locations;
h) lodging and subsistence.
14.4.1 Well Control Equipment

Well control equipment considerations include the following:

a) type, size, configuration, and pressure rating of well control equipment required (see Section 4 and ANNEX A);
b) personnel assignments and responsibilities;
c) pump, choke, and kill line requirements, pressure ratings, and configurations (see Sections 8, 9 and 10);
d) pumping of energized fluids and/or corrosive fluids;
e) hydrate prevention considerations (i.e. glycol or methanol water mix);
f) choke manifold requirements, pressure rating, and configuration (see Section 8);
g) CT requirements, pressure and tensile rating, configuration, and history (see Section 5);
h) pumping unit requirements, pressure rating and configuration;
i) bottomhole and flow check assembly dimensional information (see Section 6);
j) review of on-site pressure testing procedure (see Section 12);
k) tree connection, spacer spools, and crossover spool requirements (see Section 4);
l) accumulator system capacity and pressure requirements (see Section 13 and Annex H).

14.5 Personnel Requirements

14.5.1 Personnel shall have certification as required by governmental and regulatory agencies. The crew should be qualified and competent to perform the required operation.

14.5.2 CT crews shall have approved and/or accredited training in the following areas, as appropriate:

a) well control;
b) personal protective equipment;
c) health safety and environment.

14.6 Job Review

A pre-job meeting should be held at the well site with all personnel involved either directly or indirectly in the operation.

The pre-job meeting should include, but not be limited to the following:

a) identification of the on-site representative in charge;
b) discussion of the detailed written job procedure and areas of responsibility;
c) a review of the expected hazards (particularly chemicals, flammable fluids, and energized fluids), contingencies, and emergency procedures at the well site;
d) discussion of the pressure and operating limits of equipment and service;
 e) a review of the procedure for pressure and function testing of surface equipment;
f) a review of the wellhead, downhole tubular, and downhole completion assembly schematics, noting all potential obstructions; a copy of the downhole completion schematic and BHA diagrams should be in the control cabin at all times;
g) a review of the type and location of required personal protective equipment;

h) a review of the type and location of fire extinguishers and other fire-fighting equipment;

i) a review of emergency well control equipment-operating procedures;

j) identification of a smoking area (signs to be posted on land locations);

k) a review of the location of hoses or showers, eye baths and self-contained breathing apparatus (SCBA) sets as applicable for the planned operations;

l) where applicable, designation of a primary driver and secondary driver for emergency transportation.

14.7 Equipment Rig-up Considerations

The following is a partial list of items which should be considered when rigging up for CT operations.

a) If possible, spot equipment upwind or crosswind of the wellhead. The CT unit should be aligned with the wellhead so the crane is not on the reel-wellhead line.

b) Check wind speed. Consideration should be given to gusting, sudden wind direction shifts, debris, sand, or heavy rain.

c) Verify that proper legs or support equipment is in use for stabilizing the injector and well control stack.

d) Secure the injector to minimize movement and bending moments.

e) Ensure that the well owner or designee is aware of and has authorized all wellhead operations. The number of turns required to open the master valve should be recorded.

f) Verify the compatibility of the adapter from the wellhead to the well control stack.

g) Zero the counters with the BHA at a suitable reference point and record the reference point.

h) Function-test all equipment.

i) Check space available for optimum equipment rig up.

j) Zero the weight indicator.

k) Secure the choke, kill, and pump lines to prevent excessive whip or vibration.

14.8 Coiled Tubing Service Considerations

The following are planning considerations for CT service.

a) The intentional pumping or production of hydrocarbon gas through CT is not recommended.

b) Pumping of flammable liquids shall follow a written procedure.

c) Pumping of energized fluids and/or corrosive fluids shall follow a written procedure.

d) The well control stack kill line should not be used as the return line for circulating well fluids during normal operations.

e) In cold weather operations and/or on gas filled wells, glycol, methanol-water mixtures, or other fluids should be used to prevent freezing or the formation of hydrates. Where this is not practical, equipment and or operational procedures should be implemented that prevent freezing or the formation of hydrates.
ANNEX A
(Informative)

Coiled Tubing Well Control Stack Arrangements
for Designated Pressure Categories
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RECOMMENDED COIL TUBING WELL CONTROL STACK EQUIPMENT CONFIGURATION (PC–1, PC–2, PC–3)
TRIPLE RAM ASSEMBLY, DUAL COMBI WITH DEDICATED SBR

<table>
<thead>
<tr>
<th>PRESSURE CATEGORY</th>
<th>MINIMUM RATE</th>
</tr>
</thead>
<tbody>
<tr>
<td>PC–1</td>
<td>3000 PSIG</td>
</tr>
<tr>
<td>PC–2</td>
<td>5000 PSIG</td>
</tr>
<tr>
<td>PC–3</td>
<td>10,000 PSIG</td>
</tr>
</tbody>
</table>

COILED TUBING (SEE SECTION 9)
ANTI-BUCKLE GUIDE
(SEE PAR. 4.3.1.2)

SINGLE STRIPPER ASSEMBLY
(PRESSURE CONTROLLING DEVICE)
(SEE PAR. 4.3.1)

LUBRICATOR W/ QUICK UNIONS
(SEE PAR. 4.4.4)

CROSSOVER CONNECTOR
(SEE PAR. 4.4.4)

TRIPLE RAM ASSEMBLY

SHEAR-BLIND RAM
(SEE PAR. 4.3.3)

SLIP RAM
(SEE PAR. 4.3.4
AND TABLE 2 NOTE B)

PIPE RAM
(SEE PAR. 4.3.2.2
AND TABLE 2 NOTE B)

KILL LINE ASSEMBLY
(SEE PAR. 9.2 & ANNEX D)

FLOW CROSS / TEE
(OPTIONAL)
(SEE PAR. 4.4.5)

FULL-OPENING VALVES
(SEE PAR. 8.2)

DEDICATED SHEAR-BLIND RAM
(SEE PAR. 4.3.3)
NOTE: THE DEDICATED SBR SHALL BE OPERATED EXCLUSIVELY THROUGH THE DEDICATED ACCUMULATOR CIRCUIT.

PIPE SLIP RAM
(SEE PAR. 4.3.6)

KILL LINE ASSEMBLY
(SEE PAR. 9.2 & ANNEX D)

DUAL COMBI RAM ASSEMBLY

SHA WITH FLOW CHECK ASSEMBLY
(SEE SECTION 6)

FIGURE A–4
RECOMMENDED COIL TUBING WELL CONTROL STACK EQUIPMENT CONFIGURATION (PC–1, PC–2, PC–3)
DUAL COMBI RAM ASSEMBLY, DUAL COMBI WITH DEDICATED SBR

<table>
<thead>
<tr>
<th>PRESSURE CATEGORY</th>
<th>MINIMUM RATE WORKING PRESSURE</th>
</tr>
</thead>
<tbody>
<tr>
<td>PC–1</td>
<td>3000 PSIG</td>
</tr>
<tr>
<td>PC–2</td>
<td>5000 PSIG</td>
</tr>
<tr>
<td>PC–3</td>
<td>10,000 PSIG</td>
</tr>
</tbody>
</table>

COILED TUBING (SEE SECTION 5)

ANTI-BUCKLE GUIDE (SEE PAR. 4.3.1, 2)

SINGLE STRIPPER ASSEMBLY (PRESSURE CONTROLLING DEVICE) (SEE PAR. 4.3.1)

LUBRICATOR W/ QUICK UNIONS (SEE PAR. 4.4.4)

CROSSOVER CONNECTOR (SEE PAR. 4.4.4)

DUAL COMBI RAM ASSEMBLY

PIPE SLIP RAM (SEE PAR. 4.3.6)

FLOW CROSS/TEE (OPTIONAL) (SEE PAR. 4.4.5)

FULL-OPENING VALVES (SEE PAR. 8.2)

DEDICATED SHEAR-BLIND RAM (SEE PAR. 4.3.5)

NOTE: THE DEDICATED SBR SHALL BE OPERATED EXCLUSIVELY THROUGH THE DEDICATED ACCUMULATOR CIRCUIT.

PIPE SLIP RAM (SEE PAR. 4.3.6)

KILL LINE ASSEMBLY (SEE PAR. 9.2 & ANNEX D)

[FOR PC–3 OPERATIONS, SEE PAR 8.2(c)]

REMOTE OPERATOR

FULL-OPENING VALVES (SEE PAR. 8.2)

KILL LINE ASSEMBLY (SEE PAR. 9.2 & ANNEX D)

[FOR PC–3 OPERATIONS, SEE PAR 8.2(c)]

REMOTE OPERATOR

CHoke LINE ASSEMBLY (SEE PAR. 8.2 & ANNEX C)

FIGURE A–6
RECOMMENDED COIL TUBING WELL CONTROL STACK EQUIPMENT CONFIGURATION (PC-4)
QUAD RAM ASSEMBLY, SINGLE PIPE RAM + DEDICATED SBR

PRESSURE CATEGORY
MINIMUM RATE WORKING PRESSURE
PC-4 15,000 PSIG

COILED TUBING (SEE SECTION 5)
ANTI-BUCKLE GUIDE (SEE PAR. 4.3.1.2)

FIRST IN-SERVICE STRIPPER ASSEMBLY
(PRESSURE CONTROLLING DEVICE)
(SEE PAR. 4.3.1)

SECOND IN-SERVICE STRIPPER ASSEMBLY
(PRESSURE CONTROLLING DEVICE)
(SEE PAR. 4.3.1)

FLANGED SPACER SPOOL
(SEE PAR. 4.4.4)

CROSSOVER CONNECTOR
WHEN REQUIRED
(SEE PAR. 4.4.4)

QUAD RAM ASSEMBLY

BLIND RAM (SEE PAR. 4.3.2.1)
SHEAR RAM (SEE PAR. 4.3.3)
SLIP RAM (SEE PAR. 4.3.4)
PIPE RAM (SEE PAR. 4.3.2.2)

[SEE PAR 8.2(a)] REMOTE OPERATOR
FLOW CROSS / TEE
(OPTIONAL)
(SEE PAR. 4.4.5)
FULL-OPENING VALVES
(SEE PAR. 8.2)

[SEE PAR 8.2(a)] REMOTE OPERATOR
CHOKING LINE ASSEMBLY
(SEE PAR. 8.2 & ANNEX C)
FULL-OPENING VALVES
(SEE PAR. 8.2)

SINGLE RAM ASSEMBLY

DEDICATED SHEAR-BLIND RAM
(SEE PAR. 4.3.5)
NOTE: THE DEDICATED SBR SHALL
BE OPERATED EXCLUSIVELY THROUGH
THE DEDICATED ACCUMULATOR CIRCUIT.

BHA WITH FLOW CHECK ASSEMBLY
(SEE SECTION 8)

FIGURE A-7
RECOMMENDED COIL TUBING WELL CONTROL STACK EQUIPMENT CONFIGURATION (PC-4)

TRIPLE ASSEMBLY, SINGLE PIPE RAM + DEDICATED SBM

PRESSURE CATEGORY
PC-4

MINIMUM RATE WORKING PRESSURE
15,000 PSIG

COILED TUBING (SEE SECTION 5)

ANTI-BUCKLE CLUSE
(SEE PAR. 4.3.1.2)

FIRST IN-SERVICE STRIPPER ASSEMBLY
(PRESSURE CONTROLLING DEVICE)
(SEE PAR. 4.3.1)

SECOND IN-SERVICE STRIPPER ASSEMBLY
(PRESSURE CONTROLLING DEVICE)
(SEE PAR. 4.3.1)

FLANGED SPACER SPOOL
(SEE PAR. 4.4.6)

CROSSOVER CONNECTOR
( WHEN REQUIRED)
(SEE PAR. 4.4.4)

TRIPLE RAM ASSEMBLY

SHEAR-BLIND RAM
(SEE PAR. 4.3.5)

SLIP RAM (SEE PAR. 4.3.4
AND TABLE 2 NOTE b)

PIPE RAM (SEE PAR. 4.3.2.2
AND TABLE 2 NOTE b)

[SEE PAR 8.2(a)] REMOTE
OPERATOR

FLOW CROSS / TEE
(OPTIONAL)
(SEE PAR. 4.4.5)

FULL-OPENING VALVES
(SEE PAR. 8.2)

FULL-OPENING VALVES
(SEE PAR. 8.2)

PIPE RAM (SEE PAR. 4.3.2.2)

SINGLE RAM ASSEMBLY

DEDICATED SHEAR-BLIND RAM
(SEE PAR. 4.3.5)

NOTE: THE DEDICATED SBM SHALL
BE OPERATED EXCLUSIVELY THROUGH
THE DEDICATED ACCUMULATOR CIRCUIT.

EHA WITH FLOW CHECK ASSEMBLY
(SEE SECTION 6)

FIGURE A-9
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ANNEX B

(Informative)

Coiled Tubing Well Control Stack Equipment Bolting Requirements

B.1 Bolt for Surface CT Well Control Equipment Service

B.1.1 General

The OEMs and Users shall have a documented procedure for the qualification of bolting manufacturers, that satisfies the requirements of API 20E and API 20F in accordance to Table B-1. Exposed bolting shall meet the hardness requirements of NACE MR-0175/ISO 15156. The OEMs shall have documented specifications which include the thread form and dimensions of studs, nuts and bolts. When plating or coating is specified, API 20E plating and coating requirements shall be required.

<table>
<thead>
<tr>
<th>Table B-1 – Bolting Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Material</td>
</tr>
<tr>
<td>Pressure-Controlling Bolting</td>
</tr>
<tr>
<td>Alloy Steel and Carbon Steel</td>
</tr>
<tr>
<td>Stainless Steel and CRA</td>
</tr>
<tr>
<td>Closure Bolting</td>
</tr>
<tr>
<td>Alloy Steel and Carbon Steel</td>
</tr>
<tr>
<td>Stainless Steel and CRA</td>
</tr>
<tr>
<td>Pressure-Retaining Bolting</td>
</tr>
<tr>
<td>Alloy Steel and Carbon Steel</td>
</tr>
<tr>
<td>Stainless Steel and CRA</td>
</tr>
<tr>
<td>Utility Bolting</td>
</tr>
<tr>
<td>Stainless Steel and CRA</td>
</tr>
</tbody>
</table>

NOTE:  
(1) General requirement listed in B.1 apply to all bolting  
(2) General requirement listed in B.2 apply to all bolting  
(3) Need to conform to API 6A for material class and material testing  
(4) Based on Manufacturers written specification

Bolting manufactured from proprietary materials shall conform to API 20E or API 20F, with the exception that the materials meet the manufacturer’s written specifications for chemical composition and mechanical properties.

Refer to Table B-1 for bolting requirements.

B.1.2 Pressure-controlling Bolting

Alloy steel and carbon steel bolting shall be in conformance with API 20E BSL-1 minimum and API 6A (for Material Class and mechanical testing).

Stainless steel and CRA bolting shall be in conformance with API 20F BSL-2 minimum.

B.1.3 Closure Bolting

Alloy steel and carbon steel closure bolting shall be conformance with API 20E BSL-2 minimum and API 6A (for material class, and mechanical testing).

Stainless steel and CRA closure bolting shall be in conformance with API 20F BSL-2 minimum.
B.1.4 Pressure–retaining Bolting

Alloy steel and carbon steel pressure–retaining bolting shall be in conformance with API 20E BSL-2 minimum and API 6A (for material class and mechanical testing).

Stainless steel and CRA pressure–retaining bolting shall be in conformance with API 20F BSL-2 minimum.

B.1.5 Utility Bolting

Alloy steel and carbon steel bolting shall be in conformance with the manufacturer’s specification.

Stainless steel and CRA bolting shall be in conformance with manufacturer’s specification.

B.2 Bolting for Offshore Surface Service

B.2.1 General

The OEMs and Users shall have a documented procedure for the qualification of bolting manufacturers that follows the requirements of API 20E and API 20F.

Bolting manufactured from alloy steel or carbon steel shall be limited to 34 HRC maximum due to concerns about hydrogen embrittlement.

Exposed bolting shall meet the requirements of NACE MR0175/ISO 15156. The OEMs shall have documented specifications that include the thread form and dimensions of studs, nuts and bolts.

When plating or coating is specified, API 20E plating and coating requirement shall be required.

Bolting manufactured from proprietary materials shall conform to manufacturer’s written specification and the requirements of API 20E or API 20F, with the exception that the material meets the manufacturer’s specified chemical composition and mechanical properties.

Refer to Table B-1 for bolting requirements.

B.2.2 Pressure-controlling Bolting

Alloy steel and carbon steel bolting shall conform to API 20E BSL-2 minimum and API 6A (for material class and mechanical testing).

Stainless steel and CRA bolting shall conform to API 20F BSL-2 minimum and API 6A (for material class and mechanical testing).

Bolting that attaches the shear ram blade or shear-blind ram blade to the ram block shall conform to:

— the requirements of API 20E BSL-3 or API 20F BSL-3 and API 6A as appropriate for the material type;
— the manufacturer’s written specification and requirements for the chemical composition and mechanical properties.
B.2.3 Closure Bolting

Alloy steel and carbon steel closure bolting shall conform to API 20E BSL-3 and API 6A (for material class, and mechanical testing).

Stainless steel and CRA closure bolting shall conform to API 20F BSL-3 and API 6A (for material class and mechanical testing).

B.2.4 Pressure–retaining Bolting

Alloy steel and carbon steel pressure–retaining bolting shall conform to API 20E BSL-2 minimum and API 6A (for material class and mechanical testing).

Stainless steel and CRA pressure–retaining bolting shall conform to API 20F BSL-2 minimum.

B.2.5 Utility Bolting

Alloy steel and carbon steel bolting shall conform to the manufacturer’s specifications.

Stainless steel and CRA bolting shall conform to the manufacturer’s specifications.
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Figure C.2—(Title)
ANNEX C
(Informative)

Coiled Tubing Well Control Choke Manifold and Choke Line Configurations

Key
1 choke line valves at well control stack flow cross/flow tee
2 flanged connection [see 8.2 d]]
3 choke line (in accordance with API 16C)
4 pressure gauge
5 manual adjustable choke
6 flow back iron (not covered in this document)

\[a\] Rated working pressure [see 8.3 a]].

Figure C-1 — Single Inline Choke Installation (PC-1 and PC-2) — for Returns Taken Through the Flow Cross or Flow Tee Installed in the Well Control Stack
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**Figure C-2 — Single Inline Choke Installation (PC-3) — for Returns Taken Through the Flow Cross or Flow Tee Installed in the Well Control Stack**

**Key**
1. choke line valves at well control stack flow cross/flow tee
2. flanged connection [see 8.2 di]
3. choke line (in accordance with API 16C)
4. pressure gauge
5. manual adjustable choke
6. flow back iron (not covered in this document)

NOTE As per 8.2 e), One choke line valve installed on the well control stack should be remotely controlled.

*a Rated working pressure [see 8.3 a].

---

**Diagram Description**

1. Choke line valves
2. Flow cross/flow tee
3. Choke line
4. Pressure gauge
5. Manual adjustable choke
6. Flow back iron (not covered in this document)

---

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Figure C-3 — Single Inline Choke Installation (PC-4) — for Returns Taken Through the Flow Cross or Flow Tee Installed in the Well Control Stack

Key
1 choke line valves at well control stack flow cross/flow tee
2 flanged connection [see 8.2 d)]
3 choke line (in accordance with API 16C)
4 pressure gauge
5 remote adjustable choke
6 flow back iron (not covered in this document)

NOTE  As per 8.2 e), One choke line valve installed on the well control stack should be remotely controlled.

a Rated working pressure [see 8.3 a)].
C-4 — Dual Choke Manifold Installation (PC-1 and PC-2) — for Returns Taken Through the Flow Cross or Flow Tee Installed in the Well Control Stack
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Key
1 choke line valves at well control stack flow cross/flow tee
2 flanged connection [see 8.2 d)]
3 choke line (in accordance with API 16C)
4 pressure gauge
5 remote adjustable choke
6 remote adjustable choke or positive choke
7 remote operated valves
8 flow back line (not covered in this document)
9 by-pass line (optional)
10 flow back line (not covered in this document)

NOTE 1 As per 8.2 e), One choke line valve installed on the well control stack should be remotely controlled.

NOTE 2 Choke manifold arrangement where no repairs are to be performed on chokes during live operations [see 8.3 d)].

a Rated working pressure [see 8.3 a]).

C-6 — Dual Choke Manifold Installation (PC-4) — for Returns Taken Through the Flow Cross or Flow Tee Installed in the Well Control Stack
NOTE Choke manifold arrangement where repairs may be performed on chokes during live operations [see 8.3 d)].

a Rated working pressure [see 8.3 a)].
b A second valve is required if manifold is joined to a common flow-back line.

Figure C-7 — Dual Choke Manifold Installation (PC-1 and PC-2) — for Returns Taken Through the Flow Cross or Flow Tee Installed in the Well Control Stack
Key
1. choke line valves at well control stack flow cross/flow tee
2. flanged connection [see 8.2 d)]
3. choke line (in accordance with API 16C)
4. pressure gauge
5. manual adjustable choke
6. manual adjustable choke or positive choke
7. flow back line (not covered in this document)
8. by-pass line (optional)
9. flow back line (not covered in this document)

NOTE 1 As per 8.2 e), One choke line valve installed on the well control stack should be remotely controlled

NOTE 2 Choke manifold arrangement where repairs may be performed on chokes during live operations see [8.3 d)].

a. Rated working pressure [see 8.3 a]).
b. A second valve is required if manifold is joined to a common flow-back line.

C-8 — Dual Choke Manifold Installation (PC-3) — for Returns Taken Through the Flow Cross or Flow Tee Installed in the Well Control Stack
Key
1 choke line valves at well control stack flow cross/flow tee
2 flanged connection [see 8.2 d)]
3 choke line (in accordance with API 16C)
4 pressure gauge
5 remote adjustable choke
6 remote adjustable choke or positive choke
7 remote operated valves
8 flow back line (not covered in this document)
9 by-pass line (optional)
10 flow back line (not covered in this document)

NOTE 1 As per 8.2 e), One choke line valve installed on the well control stack should be remotely controlled.

NOTE 2 Choke manifold arrangement where repairs may be performed on chokes during live operations [see 8.3 d]).

a Rated working pressure [see 8.3 a])

b A second valve is required if manifold is joined to a common flow-back line.

C-9 — Dual Choke Manifold Installation (PC-4) — for Returns Taken Through the Flow Cross or Flow Tee Installed in the Well Control Stack
ANNEX D
(Informative)

Coiled Tubing Well Control Kill Line and Pump Line Configurations

Key
1 kill line valves at well control stack kill line inlet
2 flanged connection [see 9.2.1 a)]
3 bleed line valve
4 kill line (in accordance with API 16C)

5 flow check device
6 pump line
7 pressure gauge
8 pump

a Rated working pressure [see 9.2.1 a)]
b Rated working pressure [see 10.2 a)]

Figure D-1 — Kill Line and Pump Line Installation (All PC Conditions)
ANNEX E
(Normative)

Coiled Tubing Well Control Stack Mechanical Ram Performance Tests
Slip Ram and Pipe-Slip Ram

E.1 Slip Ram Performance Test

The slip ram tests are conducted to confirm the capability of the ram to secure the axial load of the CT Workstring without movement when performing well control activities.

E.1.1 The slip ram performance tests shall be conducted using a segment of CT which meets the following conditions:

a. Material yield strength equal to or greater than the material yield strength of the CT Workstring
b. Outside diameter equivalent to the CT string selected for the prescribed service
c. The slip ram test shall be performed with the ram ID bore at atmospheric pressure

E.1.2 CT “Pipe-Heavy” Slip Ram Tests Using Thickest Wall Segment of CT Workstring

E.1.2.1 Prior to initiating the “pipe-heavy” slip ram test, the following test information shall be defined:

a. MASP
b. Maximum specified hanging weight (axial tensile load) for the CT Workstring

E.1.2.2 In the pipe-heavy slip ram test, the ram shall hold a segment of CT equivalent to the thickest wall segment of the CT workstring without movement within the slip inserts to the maximum specified hanging weight of the CT workstring. The axial tensile test load shall be applied from below the closed slip ram. The slip ram tests shall be considered successful when the maximum specified hanging weight is held for a minimum of 15 minutes after stabilization has occurred (after tube body stretch and alignment within the slip inserts reaches equilibrium).

E.1.2.3 For the test of record, the hydraulic pressure applied to the slip ram actuator shall be adjusted to represent the effective hydraulic actuator pressure applied for the specified MASP. The effective hydraulic actuator pressure is determined by subtracting the ram piston balance pressure from the accumulator system pressure retained after closing the slip ram (without assistance of the accumulator system pumps), not to exceed the RWP of the ram actuator.

E.1.2.4 The slip ram lock test shall be conducted to confirm that the axial tensile load remains secured without movement within the slip inserts by the mechanical locks on the ram actuator engaged at the effective hydraulic actuator pressure after the hydraulic actuator pressure is released. The slip ram lock tests shall be considered successful when the maximum specified hanging weight is held for a minimum of 15 minutes after stabilization has occurred (after tube body stretch and alignment within the slip inserts reaches equilibrium).

E.1.2.5 A visual and dimensional inspection shall be conducted on the affected segment to confirm that the combined load of the hydraulic ram actuator and axial tensile load does not cause damage to the tubing beyond the indentation of the slip teeth.

E.1.2.6 The pipe-heavy slip ram performance tests with applied hydraulic pressure and with the locks engaged (hydraulic actuator pressure released) shall be conducted with a minimum test frequency of 180 days.
E.1.3 CT “Pipe-Heavy” Slip Ram Tests With Maximum Hydraulic Actuator Pressure Applied

This test addresses conditions which are likely to occur in well control activities, where pressure applied to the slip ram actuator may increase to the maximum accumulator system pressure after the pipe rams are closed and pressure in the well control stack above the closed pipe ram decreases to atmospheric pressure. This pipe-heavy slip ram test shall be conducted to evaluate damage to the CT segment at the maximum accumulator system pressure when coupled with the maximum specified hanging weight of the CT Workstring.

E.1.3.1 In the pipe-heavy slip ram test, the ram shall hold a segment of CT equivalent to the thickest wall segment of the CT workstring without movement within the slip inserts to the maximum specified hanging weight of the CT workstring. The axial tensile test load shall be applied from below the closed slip ram.

E.1.3.2 The pipe-heavy slip ram test shall be conducted to the maximum hydraulic system pressure applied to the slip ram actuator. The maximum hydraulic system pressure shall be the pressure expected from the accumulator system without ram piston balance pressure adjustment, not to exceed the RWP of the ram actuator.

E.1.3.3 A visual and dimensional inspection shall be conducted on the affected segment to confirm that the combined load of the hydraulic ram actuator and axial tensile load does not cause damage to the tubing beyond the indentation of the slip teeth.

E.1.3.4 The pipe-heavy slip ram performance test with the maximum hydraulic actuator pressure applied shall be conducted at least once for each CT OD size, grade and maximum wall thickness in service with the designated slip ram. The record of this test, along with the reported damage to the CT OD surface shall be available for review by the User.

E.1.4 CT “Pipe-Light” Slip Ram Tests Using Thinnest Wall Segment of CT Workstring

E.1.4.1 Prior to initiating the “pipe-light” slip ram test, the MASP to be used for the test shall be defined.

E.1.4.2 In the pipe-light slip ram test, the slip ram shall hold a segment of CT equivalent to the thinnest wall segment of the CT workstring without movement within the slip inserts to a force greater than or equal to MASP multiplied by the cross-sectional area of the tube body. The axial compressive load should be applied from below the closed slip ram. The slip ram test shall be considered successful when the specified upward acting compressive force is held for a minimum of 15 minutes after stabilization has occurred (after tube body compression and alignment within the slip inserts reaches equilibrium).

If the “pipe-light” slip ram tests are conducted with an axial tensile load applied from above the closed slip ram (as opposed to an axial compressive load applied from below), this test may not be representative of the performance of the specific design of the ram. As such, the direction of applied axial load shall also be reported.

E.1.4.3 For the test of record, the hydraulic pressure applied to the slip ram actuator shall be adjusted to represent the effective hydraulic actuator pressure applied for the specified MASP. The effective hydraulic actuator pressure is determined by subtracting the ram piston balance pressure from the accumulator system pressure retained after closing the slip ram (without assistance of the accumulator system pumps), not to exceed the RWP of the ram actuator.

E.1.4.4 The slip ram lock test shall be conducted to confirm that the specified upward acting compressive force remains secured without movement within the slip inserts by the mechanical locks on the ram actuator engaged at the effective hydraulic actuator pressure after the hydraulic actuator pressure is released. The slip ram lock tests shall be considered successful when the specified axial load is held for a minimum of 15 minutes after stabilization has occurred (after tube body compression and alignment within the slip inserts reaches equilibrium).
E.1.4.5 A visual and dimensional inspection shall be conducted on the affected segment to confirm that the combined load of the hydraulic ram actuator and axial tensile load does not cause damage to the tubing beyond the indentation of the slip teeth.

E.1.4.6 The pipe-light slip ram performance tests with applied hydraulic pressure and with the locks engaged (hydraulic actuator pressure released) shall be conducted with a minimum test frequency of 180 days.

E.1.5 CT “Pipe-Light” Slip Ram Tests With Maximum Hydraulic Actuator Pressure Applied

This test addresses conditions which are likely to occur in well control activities, where pressure applied to the slip ram actuator may increase to the maximum accumulator system pressure after the pipe rams are closed and pressure in the well control stack above the closed pipe ram decreases to atmospheric pressure. This pipe-light slip ram test shall be conducted to evaluate damage to the CT segment at the maximum accumulator system pressure when coupled with the maximum calculated upward compressive force acting on the CT Workstring from below the closed pipe ram.

E.1.5.1 In the pipe-light slip ram test, the ram shall hold a segment of CT equivalent to the thinnest wall segment of the CT workstring without movement within the slip inserts to the maximum specified upward force applied to the CT workstring. The axial compressive test load should be applied from below the closed slip ram. The slip ram test shall be considered successful when the specified upward acting compressive force is held for a minimum of 15 minutes after stabilization has occurred (after tube body compression and alignment within the slip inserts reaches equilibrium).

If the “pipe-light” slip ram tests are conducted with axial tensile load applied from above the closed slip ram (as opposed to an axial compressive load applied from below), this test may not be representative of the performance of the specific design of the ram. As such, the direction of applied axial load shall also be reported.

E.1.5.2 The pipe-light slip ram test shall be conducted to the maximum hydraulic system pressure applied to the slip ram actuator. The maximum hydraulic system pressure shall be the pressure expected from the accumulator system without ram piston balance pressure adjustment, not to exceed the RWP of the ram actuator.

E.1.5.3 A visual and dimensional inspection shall be conducted on the affected segment to confirm that the combined load of the hydraulic ram actuator and axial load does not cause damage to the tubing beyond the indentation of the slip teeth.

E.1.5.4 The pipe-light slip ram performance test with the maximum hydraulic actuator pressure applied shall be conducted at least once for each CT OD size, grade and minimum wall thickness in service with the designated slip ram. The record of this test, along with the reported damage to the CT OD surface shall be available for review by the User.

E.1.6 The test report data for each of the slip ram “pipe-heavy” and “pipe-light” load tests shall include:

a. CT specimen OD, average wall thickness, material yield strength from MTR and designated grade of tube
b. manufacturer of slip ram assembly, including model, ID bore, RWP and serial number
c. model of ram assembly actuator, including maximum allowable hydraulic operating pressure of actuator
d. effective hydraulic actuator pressure applied to slip ram actuator (when adjusted for the specified MASP)
e. maximum hydraulic actuator pressure applied to slip ram actuator (for maximum hydraulic pressure test)
f. serial number and/or part number of slip ram and slip insert
g. condition of slip inserts upon completion of each slip ram test
h. digital record of hydraulic actuator pressure from start to end of each test, including documentation of test period where axial load is retained using only the ram locks (hydraulic actuator pressure is bled to zero)
i. record of axial load retained on the CT segment
j. Date and location of test

The value of hydraulic pressure applied to the slip ram actuator reported for the pipe-heavy tests shall be based on the tests identified in either E.1.2 (when adjusted for the specified MASP) or E.1.3 (for maximum hydraulic pressure test). The value of hydraulic pressure applied to the slip ram actuator reported for the pipe-light tests shall be based on the tests identified in either E.1.4 (when adjusted for the specified MASP) or E.1.5 (for maximum hydraulic pressure test).

E.1.7 The hydraulic actuator pressure shall be recorded using a digital data acquisition system. The pressure sensor accuracy shall be equal to or better than 0.5% of the full range of the sensor. The monitoring system shall be at least as accurate as the sensor. The update (scan) rate of the monitoring system shall be equal to or faster than 1Hz and operated in accordance with ASTM D-5720.

E.2 Pipe-Slip Ram

The pipe-slip ram tests are conducted to confirm the capability of the ram to secure the axial load of the CT Workstring without movement when performing well control activities.

E.2.1 The pipe-slip ram performance tests shall be conducted using a segment of CT which meets the following conditions:

a. Material yield strength equal to or greater than the material yield strength of the CT string
b. Outside diameter equivalent to the CT string selected for the prescribed service
c. The slip ram test shall be performed with the ram ID bore at atmospheric pressure

E.2.2 CT “Pipe-Heavy” Pipe-Slip Ram Tests Using Thickest Wall Segment of CT Workstring

E.2.2.1 Prior to initiating the "pipe-heavy" pipe-slip ram test, the following test information shall be defined:

a. MASP
b. Maximum specified hanging weight (axial tensile load) for the CT Workstring

E.2.2.2 In the pipe-heavy pipe-slip ram test, the ram shall hold a segment of CT equivalent to the thickest wall segment of the CT workstring without movement within the slip inserts to the maximum specified hanging weight of the CT workstring. The axial tensile test load shall be applied from below the closed slip ram. The pipe-slip ram tests shall be considered successful when the specified axial tensile load is held for a minimum of 15 minutes after stabilization has occurred (after tube body stretch and alignment within the slip inserts reaches equilibrium).

E.2.2.3 For the test of record, the hydraulic pressure applied to the pipe-slip ram actuator shall be adjusted to represent the effective hydraulic actuator pressure applied for the MASP. The effective hydraulic actuator pressure is determined by subtracting the ram piston balance pressure from the accumulator system pressure retained after closing the pipe-slip ram (without assistance of the accumulator system pumps), not to exceed the RWP of the ram actuator.

E.2.2.4 The pipe-slip ram lock test shall be conducted to confirm that the axial tensile load remains secured without movement within the slip inserts by the mechanical locks on the ram actuator engaged at the effective hydraulic actuator pressure after the hydraulic actuator pressure is released. The pipe-slip ram lock tests shall be considered successful when the specified axial tensile load is held for a minimum of 15 minutes after stabilization has occurred (after tube body stretch and alignment within the slip inserts reaches equilibrium).
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E.2.2.5 A visual and dimensional inspection shall be conducted on the affected segment to confirm that the combined load of the hydraulic ram actuator and axial tensile load does not cause damage to the tubing beyond the indentation of the slip teeth.

E.2.2.6 The pipe-heavy pipe-slip ram performance tests with applied hydraulic pressure and with the locks engaged (hydraulic actuator pressure released) shall be conducted with a minimum test frequency of 180 days.

E.2.3 CT “Pipe-Heavy” Pipe-Slip Ram Tests With Maximum Hydraulic Actuator Pressure Applied

This test addresses conditions which are likely to occur in well control activities, where pressure applied to the pipe-slip ram actuator may increase to the maximum accumulator system pressure after the pipe-slip element creates a seal on the CT Workstring and pressure in the well control stack above the closed pipe-slip ram decreases to atmospheric pressure. This pipe-heavy pipe-slip ram test shall be conducted to evaluate damage to the CT segment at the maximum accumulator system pressure when coupled with the specified hanging weight of the CT string.

E.2.3.1 In the pipe-heavy pipe-slip ram test, the ram shall hold a segment of CT equivalent to the thickest wall segment of the CT workstring without movement within the slip inserts to the maximum specified hanging weight of the CT workstring. The axial tensile test load shall be applied from below the closed pipe-slip ram.

E.2.3.2 The pipe-heavy pipe-slip ram test shall be conducted to the maximum hydraulic system pressure applied to the pipe-slip ram actuator. The maximum hydraulic system pressure shall be the pressure expected from the accumulator system without ram piston balance pressure adjustment, not to exceed the RWP of the ram actuator.

E.2.3.3 A visual and dimensional inspection shall be conducted on the affected segment to confirm that the combined load of the hydraulic ram actuator and axial tensile load does not cause damage to the tubing beyond the indentation of the slip teeth.

E.2.3.4 The pipe-heavy pipe-slip ram performance test with the maximum hydraulic actuator pressure applied shall be conducted at least once for each CT OD size, grade and maximum wall thickness in service with the designated pipe-slip ram. The record of this test, along with the reported damage to the CT OD surface shall be available for review by the User.

E.2.4 CT “Pipe-Light” Pipe-Slip Ram Tests Using Thinnest Wall Segment of CT Workstring

E.2.4.1 Prior to initiating the “pipe-light” slip ram test, the User shall provide the MASP to be used for the test.

E.2.4.2 In the pipe-light pipe-slip ram test, the ram shall hold a segment of CT equivalent to the thinnest wall segment of the CT workstring without movement within the slip inserts to a force greater than or equal to MASP multiplied by the cross-sectional area of the tube body. The axial compressive load should be applied from below the closed pipe-slip ram. The pipe-slip ram tests shall be considered successful when the specified axial load is held for a minimum of 15 minutes after stabilization has occurred (after tube body compression and alignment within the slip inserts reaches equilibrium).

If the "pipe-light" pipe-slip ram tests are conducted with axial tensile load applied from above the closed pipe-slip ram (as opposed to an axial compressive load applied from below), this test may not be representative of the performance of the specific design of the ram. As such, the direction of applied axial load shall also be reported.
E.2.4.3 For the test of record, the hydraulic pressure applied to the pipe-slip ram actuator shall be adjusted to represent the effective hydraulic actuator pressure applied for the specified MASP. The effective hydraulic actuator pressure is determined by subtracting the ram piston balance pressure from the accumulator system pressure retained after closing the slip ram (without assistance of the accumulator system pumps), not to exceed the RWP of the ram actuator.

E.2.4.4 The pipe-slip ram lock test shall be conducted to confirm that the axial tensile load remains secured without movement within the slip inserts by the mechanical locks on the ram actuator engaged at the effective hydraulic actuator pressure after the hydraulic actuator pressure is released. The slip ram lock tests shall be considered successful when the specified axial load is held for a minimum of 15 minutes after stabilization has occurred (after tube body compression and alignment within the slip inserts reaches equilibrium).

E.2.4.5 A visual and dimensional inspection shall be conducted on the affected segment to confirm that the combined load of the hydraulic ram actuator and axial tensile load does not cause damage to the tubing beyond the indentation of the slip teeth.

E.2.4.6 The pipe-light pipe-slip ram performance tests with applied hydraulic pressure and with the locks engaged (hydraulic actuator pressure released) shall be conducted with a minimum test frequency of 180 days.

E.2.5 CT “Pipe-Light” Pipe-Slip Ram Tests With Maximum Hydraulic Actuator Pressure Applied

This test addresses conditions which are likely to occur in well control activities, where pressure applied to the pipe-slip ram actuator may increase to the maximum accumulator system pressure after the pipe-slip element creates a seal on the CT Workstring and pressure in the well control stack above the closed pipe-slip ram decreases to atmospheric pressure. This pipe-light pipe-slip ram test shall be conducted to evaluate damage to the CT segment at the maximum accumulator system pressure when coupled with the specified maximum upward compressive force acting on the CT Workstring.

E.2.5.1 In the pipe-light pipe-slip ram test, the ram shall hold a segment of CT equivalent to the thinnest wall segment of the CT workstring without movement within the slip inserts to the specified upward force applied to the CT workstring. The axial compressive test load should be applied from below the closed pipe-slip ram.

If the "pipe-light" pipe-slip ram tests are conducted with axial tensile load applied from above the closed pipe-slip ram (as opposed to an axial compressive load applied from below), this test may not be representative of the performance of the specific design of the ram. As such, the direction of applied axial load shall also be reported.

E.2.5.2 The pipe-light pipe-slip ram test shall be conducted to the maximum hydraulic system pressure applied to the pipe-slip ram actuator. The maximum hydraulic system pressure shall be the pressure expected from the accumulator system without ram piston balance pressure adjustment, not to exceed the RWP of the ram actuator.

E.2.5.3 A visual and dimensional inspection shall be conducted on the affected segment to confirm that the combined load of the hydraulic ram actuator and axial load does not cause damage to the tubing beyond the indentation of the slip teeth.

E.2.5.4 The pipe-light pipe-slip ram performance test with the maximum hydraulic actuator pressure applied shall be conducted at least once for each CT OD size, grade and minimum wall thickness in service with the designated pipe-slip ram. The record of this test, along with the reported damage to the CT OD surface shall be available for review by the User.
The test report data for each of the pipe-slip ram “pipe-heavy” and “pipe-light” load tests shall include:

a. CT specimen OD, average wall thickness, material yield strength from MTR and designated grade of tube
b. manufacturer of slip ram assembly, including model, ID bore, RWP and serial number
c. model of ram assembly actuator, including maximum allowable hydraulic operating pressure of actuator
d. effective hydraulic actuator pressure applied to slip ram actuator (when adjusted for the specified MASP)
e. maximum hydraulic actuator pressure applied to slip ram actuator (for maximum hydraulic pressure test)
f. serial number and/or part number of slip ram and slip insert
g. condition of slip inserts upon completion of each slip ram test
h. digital record of hydraulic actuator pressure from start to end of each test, including documentation of test period where axial load is retained using only the ram locks (hydraulic actuator pressure is bled to zero)
i. record of axial load retained on the CT segment
j. Date and location of test

The value of hydraulic pressure applied to the pipe-slip ram actuator reported for the pipe-heavy tests shall be based on the tests identified in either E.2.2 (when adjusted for the specified MASP) or E.2.3 (for maximum hydraulic pressure test). The value of hydraulic pressure applied to the slip ram actuator reported for the pipe-light tests shall be based on the tests identified in either E.2.4 (when adjusted for the specified MASP) or E.2.5 (for maximum hydraulic pressure test).

The hydraulic actuator pressure shall be recorded using a digital data acquisition system. The pressure sensor accuracy shall be equal to or better than 0.5% of the full range of the sensor. The monitoring system shall be at least as accurate as the sensor. The update (scan) rate of the monitoring system shall be equal to or faster than 1Hz and operated in accordance with ASTM D-5720.
ANNEX F
(Normative)

Coiled Tubing Well Control Stack Mechanical Ram Performance Tests
Shear Ram and Shear-Blind Ram

F.1 SHEAR RAM PERFORMANCE TESTING

F.1.1 The shear ram performance tests shall be conducted with a minimum test frequency of 180 days using a segment of CT which meets the following conditions:

a. Material yield strength equal to or greater than the material yield strength of the thickest wall segment of the CT workstring

b. CT specimen OD and wall thickness equivalent to the thickest wall segment of the CT workstring selected for the prescribed service

c. Test specimen shall include equivalent samples of all spoolable components (e.g., wireline, capillary tube, fiber optic line) installed inside the CT workstring selected for the service application

d. Where wireline is likely to be run internal to the CT workstring for the purpose of conducting free-point and/or pipe recovery operations, the shear test should include a sample of the wireline expected to be used.

e. The shear ram test shall be performed with the ram ID bore at atmospheric pressure without tension applied to the CT specimen or the internal spoolable components (e.g., wireline, capillary tube, fiber optic line)

F.1.2 One shear ram test shall be conducted with the CT specimen secured within the slip ram. At least one additional shear test shall be conducted with the CT specimen positioned off-center of the ID bore, perpendicular to the axis of the ram shaft at the edge of the shear blade cutting surface.

F.1.3 The test report data for each shear test shall include:

a. CT specimen OD, average wall thickness, material yield strength from MTR and designated grade of tube

b. description of each of the internal spoolable components and material yield strength(s) taken from MTR’s

c. manufacturer of shear ram assembly, including model, ID bore, RWP and serial number

d. model of ram assembly actuator, including maximum allowable hydraulic operating pressure of actuator

e. serial number and/or part number of shear blade, along with description of blade cutting profile

f. observed shear ram hydraulic actuator “close” pressure applied to shear ram actuator at the point in time of the shearing event for each cut test

h. condition of shear blade upon completion of each shear test

g. observed shear ram hydraulic actuator “open” pressure at the point in time of the shearing event for each cut test

i. digital record of hydraulic actuator pressure from start to end of each test, including peak CT shear pressure.

F.1.4 The hydraulic actuator pressure shall be recorded using a digital data acquisition system. The pressure sensor accuracy shall be equal to or better than ±0.5% of the full range of the sensor. The monitoring system shall be at least as accurate as the sensor. The update (scan) rate of the monitoring system shall be equal to or faster than 20Hz and operated in accordance with ASTM D-5720.
F.2  SHEAR-BLIND RAM PERFORMANCE TESTING

F.2.1  The shear-blind ram performance tests shall be conducted with a minimum test frequency of 180 days using a segment of CT which meets the following conditions:

   a. Material yield strength equal to or greater than the material yield strength of the thickest wall segment of the CT workstring

   b. CT specimen OD and wall thickness equivalent to the thickest wall segment of the CT workstring selected for the prescribed service

   c. Test specimen shall include equivalent samples of all spoolable components (e.g., wireline, capillary tube, fiber optic line) installed inside the CT workstring selected for the service application

   d. Where wireline is likely to be run internal to the CT workstring for the purpose of conducting free-point and/or pipe recovery operations, the shear-blind test should include a sample of the wireline expected to be used.

   e. All shear-blind ram tests shall be performed with the ID bore at atmospheric pressure without tension applied to the CT specimen or the internal spoolable components (e.g., wireline, capillary tube, fiber optic line)

F.2.2  Where the shear-blind ram is to be used to cut the CT workstring to facilitate through-tubing pumping and well kill operations, at least one shear-blind ram test shall be conducted with the CT secured within the slip ram or pipe-slip ram located below the shear-blind ram.

F.2.3  Immediately following the initial shear-blind ram cut test, the shear-blind ram shall remain closed and a pressure test conducted in accordance with 12.4.1 and 12.4.2. The hydraulic pressure applied to the shear-blind actuator for the pressure test shall be adjusted to represent the effective actuator pressure applied to the rams for the specified MASP.

F.2.4  The ram locking system on the shear-blind ram actuator shall be performance tested to confirm that the rams remain closed and maintain the pressure seal to the established test criteria after removal of applied ram actuator hydraulic pressure to the rams.

F.2.5  At least one additional shear tests shall be conducted with the CT specimen positioned off-center of the ID bore, perpendicular to the axis of the ram shaft at the edge of the shear blade cutting surface.

F.2.6  Immediately following the second shear-blind ram cut test, the shear-blind ram shall remain closed and a pressure test conducted in accordance with 12.4.1 and 12.4.2. The hydraulic pressure applied to the shear-blind actuator for the pressure test shall be adjusted to represent the effective actuator pressure applied to the rams for the specified MASP.

F.2.7  The ram locking system on the shear-blind ram actuator shall be performance tested to confirm that the rams remain closed and maintain the pressure seal to the established test criteria after removal of applied ram actuator hydraulic pressure to the rams.
F.2.8 The test report data for each shear-blind ram cut and seal test shall include:

a. CT specimen OD, average wall thickness, material yield strength from MTR and designated grade of tube
b. description of each of the internal spoolable components and material yield strength(s) taken from MTR's
c. manufacturer of shear-blind ram assembly, including model, ID bore, RWP and serial number
d. model of ram assembly actuator, including maximum allowable hydraulic operating pressure of actuator
e. serial number and/or part number of shear-blind blade, along with description of blade cutting profile
f. observed shear-blind ram hydraulic actuator "close" pressure applied to shear ram actuator at the point in time of the shearing event for each cut test
g. observed shear-blind ram hydraulic actuator "open" pressure at the point in time of the shearing event for each cut test
h. condition of shear-blind blade upon completion of each shear test
i. digital record of hydraulic actuator pressure from start to end of each test, including peak CT shear pressure
j. Post-shear pressure test record (circular charts or digital data acquisition)

F.2.9 The hydraulic actuator pressure shall be recorded using a digital data acquisition system. The pressure sensor accuracy shall be equal to or better than ±0.5% of the full range of the sensor. The monitoring system shall be at least as accurate as the sensor. The update (scan) rate of the monitoring system for the shearing tests shall be equal to or faster than 20Hz and operated in accordance with ASTM D-5720. The update (scan) rate of the monitoring system for the post-shear pressure tests shall be equal to or faster than 1 Hz and operated in accordance with ASTM D-5720.
ANNEX G  
(Informative)  
Coiled Tubing “Well-Hopping” Well Control Stack Pressure Testing

G.1 General  
“Well-hopping” pressure testing practices are intended to address CT operations conducted on platform drilled (offshore) or pad drilled (onshore) wells where the proposed CT well intervention operation will be completed prior to the seven-day pressure test frequency timeline (see 12.4.4) and another CT well intervention operation is planned in a well adjacent to the initial well.

In CT well intervention applications where each well in the campaign is completed within a 12-hour to 36-hour period, there is a concern that rapid degradation of CT well control barrier components will occur due to abrasion/erosion of the elastomer seals and/or deformation of the sealing elements when subjected to a higher frequency of pressure testing than intended to confirm performance capability of the barriers (see 12.4.4).

The “well-hopping” pressure testing practices seen in this Annex are to be conducted only where the CT Unit control console, service tubing reel and Closing Unit are placed on location and remain in their original position on location (not moved during the “well-hopping” well intervention campaign).

G.2 Recommended “Well-Hopping” Well Control Stack Pressure Test Procedure

In order to meet the intent of safety and high confidence in well control stack component performance, the following process is recommended to be used when conducting Well Hopping pressure testing practices. The following steps are considered as minimum actions for conducting “well-hopping” operations and the actual operations employed should meet or exceed these steps based on a risk assessment.

G.2.1 In preparation for “well-hopping” operations, the initial pressure test of record for the well control stack components should be conducted to meet the highest MASP or MAOP conditions projected for the group of wells to be included in the 7-day test period protocol.

G.2.2 An assessment of the well intervention operations to be performed should be conducted to ensure that wellbore-wetted fluids in each wellbore within the specified “well hopping” group are compatible with the elastomeric seals installed in the well control equipment components to be used in the prescribed services.

G.2.3 If any well control components requires replacement due to failure or job scope, then the replaced component and all affected components should be pressure tested following 12.4.4.

G.2.4 The “well-hopping” procedure should be conducted in the following manner to ensure the safe and effective pressure containment of the CT well control stack components when moved from the current wellbore to the subsequent wellbore in the program:

a. The CT Unit control console and service tubing reel should be aligned with the wells within the intervention group such that no movement of the Control Console, Service Tubing Reel or stand-alone Closing Unit is moved or disturbed when disconnecting the CT well control stack on the current well and installation on the subsequent well.

b. Equipment used to raise the well control stack should be located in the optimum position to enable the lift equipment to reach each wellbore within the prescribed “well-hopping” group.
c. Disconnection of the well control stack from the current well installation should be limited to the flanged connection located below all well control stack components, with minimal vibration or mechanical disturbance.

d. Disconnection of the kill line(s) and choke/returns lines affected by the move should be located at the deck (or ground) level to eliminate shock loads to the suspended well control equipment and flow isolation valve connections.

e. All well control stack operating hoses and monitoring cables should remain connected and be pre-deployed in a manner where movement of the well control stack does not require changes in any of the mechanical components or connections providing hydraulic flow or signal communication (hose reels, points of severe turns, bending or kinking of lines, etc.).

f. All well control equipment operating hoses and monitoring cables should be supported through bridles or brackets secured to the stack in a manner which eliminates axial tensile loading on the end connections expected to occur during the move or during any stage of well intervention service.

g. Movement of the well control stack from the current tree to the subsequent tree should be provided by dedicated lifting equipment and handled in a controlled environment which will ensure that no contact or collision with other equipment components can occur. The suspended hoses and cables should remain in a relaxed condition (as suspended from the bridles/brackets secured to the stack). During this stage of stack movement, the CT BHA may be inspected and/or replaced.

h. Connection of the well control stack from the current well installation to the subsequent wellbore should be limited to the flanged tree connection located below all well control stack components. The flanged tree connection shall be installed using bolts which comply with API 20E or API 20F (see ANNEX B) and mechanically-fastened to the recommended torque with minimal vibration or mechanical disturbance to the stack.

i. Re-connection of the kill line(s) and choke/returns lines should occur at the deck (or ground) level to eliminate shock loads to the suspended well control equipment and flow isolation valves.

j. Post-installation pressure tests shall be conducted following 12.4.4 (c), as applicable

G.2.5 The "well-hopping" procedural steps seen in ANNEX G.2 should be reported and recorded in the pressure test log, along with relevant documentation providing a layout of the "well-hopping" group of wells, location of the CT Unit in relation to the group of wells and P&ID layout for the well control equipment, choke lines and kill line(s).
ANNEX H
(informative)

Accumulator Sizing Calculations

H.1 General

The accumulator sizing calculations offered in this ANNEX are intended to guide the User in determining the minimum volume of power fluid needed and minimum accumulator system pressure needed to meet the performance requirements for the given well control stack components. The minimum accumulator volume calculation \( V_{\text{acc}} \) is used to determine the minimum volume needed to function the well control components, but may not provide sufficient volume to meet the performance requirements as defined by \( P_{\text{max}} \). As such, the accumulator sizing calculations offered in this ANNEX should be considered as an iterative process, where the minimum accumulator system volume may be determined through the greater of \( V_{\text{acc}} \) and \( P_{\text{max}} \) calculations.

H.2 Volumetric Capacity Calculations

H.2.1 General

The following is an example of how volumetric capacity of the well control “primary” and “dedicated” accumulator systems may be calculated.

H.2.2 Accumulator Volume

H.2.2.1 The volume of usable hydraulic fluid \( (V_{\text{use}}) \) per accumulator is the difference between the calculated volume of compressed nitrogen at 200 psig above the precharge pressure \( (V_{\theta p+200}) \) and its maximum compressed volume after hydraulic fluid has been pumped into the accumulator \( (V_{\theta \text{max}}) \). \( V_{\theta p} \) is equivalent to the volume of a single accumulator. The total usable hydraulic fluid volume \( (V_{\text{totuse}}) \) is equal to the usable hydraulic fluid capacity \( (V_{\text{use}}) \) per accumulator multiplied by the number of accumulators \( (N_A) \) in the hydraulic system [see Equation (H.1) and Equation (H.2)].

\[
V_{\text{use}} = V_{\theta p+200} - V_{\theta \text{max}} \quad \text{(H.1)}
\]

\[
V_{\text{totuse}} = V_{\text{use}} \times N_A \quad \text{(H.2)}
\]

H.2.2.2 The total usable hydraulic fluid capacity \( (V_{\text{use}}) \) shall be greater than or equal to the minimum volume of hydraulic fluid needed to perform the well control stack close-open-close operating cycles desired and have 200 psig above precharge remaining in the respective accumulator system.

Primary Accumulator System Requirements

H.2.2.3 The volume of fluid needed to operate each individual set of rams (close and open) in the “primary” accumulator system is a function of the ram piston area, the piston rod area, and the stroke length of the ram. Once these volumes are determined, the total volume of hydraulic fluid needed for a close-open-close operating sequence \( (V_{\text{COC}}) \) on a multi-ram stack operated through the “primary” accumulator system can be determined using Equation (H.3).

\[
V_{\text{COC}} = 2(V_{\text{close slips}} + V_{\text{close pipe}} + V_{\text{close shears}} + V_{\text{close blind}} + \ldots) + (V_{\text{open slips}} + V_{\text{open pipes}} + V_{\text{open shears}} + V_{\text{open blind}} + \ldots) \quad \text{(H.3)}
\]
H.2.2.4 Once the minimum volume needed for actuating the multi-ram stack through the close-open-close sequence has been determined, the minimum required “primary” accumulator bank volume \( V_{acc} \) may be found using Equation (H.4).

\[
V_{acc} = \frac{V_{COC}}{\rho@P_p \left( \frac{1}{\rho@P_{p+200}} - \frac{1}{\rho@P_{max}} \right)}
\]  

(H.4)

where

\( \rho@P_p \) is the nitrogen density at precharge pressure and temperature;

\( \rho@P_{p+200} \) is the nitrogen density at the precharge pressure plus 200 psig and minimum operating temperature or the precharge temperature, whichever is the least; and

\( \rho@P_{max} \) is the nitrogen density at the minimum charged accumulator system pressure and maximum operating temperature.

The density of nitrogen for the various pressures at the temperature of interest can be found in the NIST Chemistry WebBook (http://webbook.nist.gov/chemistry/fluid).

H.2.2.5 Once the minimum “primary” accumulator system volume has been determined, the number of accumulators in the “primary” accumulator bank, \( N_A \), should be selected such that:

\[
N_A \times V_{app} \geq V_{acc}
\]  

(H.5)

NOTE: 13.6.1 stipulates the requirement of a minimum of two accumulator bottles for each accumulator system.

Dedicated Shear-Blind Ram Accumulator System Requirements

H.2.2.6 The volume of fluid needed to operate the dedicated shear-blind ram (close and open) in the “dedicated” accumulator system is a function of the ram piston area, the piston rod area, and the stroke length of the ram. Once this volume is determined, the total volume of hydraulic fluid needed for a close-open-close operating sequence \( V_{COC} \) of the dedicated shear-blind ram operated through the “dedicated” accumulator system can be determined using Equation (H.6).

\[
V_{COC} = (V_{close\ SBR} + V_{open\ SBR} + V_{close\ SBR})
\]  

(H.6)

H.2.2.7 Once the minimum volume needed for actuating the dedicated shear-blind ram through the close-open-close sequence has been determined, the minimum required “dedicated” accumulator bank volume \( V_{acc} \) may be found using Equation (H.7).

\[
V_{acc} = \frac{V_{COC}}{\rho@P_p \left( \frac{1}{\rho@P_{p+200}} - \frac{1}{\rho@P_{max}} \right)}
\]  

(H.7)
where

\[ \rho_{@P_p} \]
\[ \text{is the nitrogen density at precharge pressure and temperature;} \]
\[ \rho_{@P_p + 200} \]
\[ \text{is the nitrogen density at the precharge pressure plus 200 psi and minimum operating} \]
\[ \text{temperature or the pre-charge temperature, whichever is the least; and} \]
\[ \rho_{@P_{\text{max}}} \]
\[ \text{is the nitrogen density at the minimum charged accumulator system pressure and maximum} \]
\[ \text{operating temperature.} \]

The density of nitrogen for the various pressures at the temperature of interest can be found in the NIST Chemistry WebBook (http://webbook.nist.gov/chemistry/fluid).

H.2.2.8 Once the minimum “dedicated” accumulator system volume has been determined, the number of accumulators in the “dedicated” accumulator bank, \( N_A \), should be selected such that:

\[ N_A \times V_{@P} \geq V_{\text{acc}} \]  

(H.8)

NOTE: 13.6.1 stipulates the requirement of a minimum of two accumulator bottles for an accumulator system.

H.2.3 Accumulator Pressures

H.2.3.1 The variable \( (P_p) \) is the pre-charge pressure of the nitrogen in the accumulator prior to filling with hydraulic fluid. \( P_{\text{charged}} \) is the minimum accumulator bank pressure needed to perform the specified ram functions and effectively shear the CT. \( P_{\text{crit}} \) is the hydraulic system pressure needed to shear the CT and is dependent upon the size of the CT, wall thickness, material grade, type of rams, and the surface wellbore pressure within the well control stack.

H.2.3.2 \( P_{\text{crit}} \) is calculated by adding the ram piston balance pressure to the hydraulic pressure required to shear the CT at atmospheric pressure (see ANNEX F). \( P_{\text{crit}} \) may be calculated using Equation (H.9).

\[ P_{\text{crit}} = P_{\text{shear @ 0 psig}} + (P_{\text{MASP}}/CR) \]  

(H.9)

Primary Accumulator System Requirements

In a well control event, the order of rams to be closed using the primary accumulator system will be dictated by the situation at hand. However, for evaluating the minimum accumulator bank pressure needed to shear the CT workstring at MASP from the “primary” accumulator system, the order of ram function is:

a) close slip ram,

b) close pipe ram, and

e) close shear ram.

H.2.3.3 In the event that the hydraulic pump system becomes inoperative (due to pump or power pack failure), the closing of the slip ram, pipe ram and shear ram will reduce the usable hydraulic fluid in the accumulator bank by a volume, \( V_{\text{close}} \), equal to the capacity of the slip ram, pipe ram and shear ram actuators.

H.2.3.4 With the values of \( P_{p}, \rho_{@P_p}, T_{@P_p}, P_{\text{crit}}, T_{@P_{\text{max}}} \) and \( V_{\text{close}} \) known, the value of \( P_{\text{max}} \) for an accumulator bank with a given pre-charge pressure can be calculated. The calculated value of \( P_{\text{max}} \) in this instance represents the minimum accumulator bank pressure needed to close the slip ram, pipe ram and effectively shear the CT at MASP using the “primary” accumulator system. Therefore, it is recommended that the hydraulic system pressure be greater than \( P_{\text{max}} \).

The value of \( P_{\text{max}} \) may be determined iteratively using Equation (H.10) and Equation (H.11).
\[ P_{\text{max}} = \frac{T_{\@ P_{\text{max}}} Z_{\@ P_{\text{max}}}}{2.61 \left( \frac{1}{\rho_{\@ P_{\text{crit}}}} - \frac{1}{\rho_{\@ P_{p}}} \left( \frac{V_{\text{close}}}{V_{@ P_{p}} N_{A}} \right) \right)} \]  

(H.10)

\[ Z_{\@ P_{\text{max}}} = \frac{2.61 P_{\text{max}}}{T_{\@ P_{\text{max}}} \rho_{\@ P_{\text{max}}}} \]  

(H.11)

where

- \( P_{\text{max}} \) is the minimum required accumulator bank pressure as defined in H.2.3.4 (psia);
- \( \rho_{\@ P_{\text{crit}}} \) is the nitrogen density at \( P_{\text{crit}} \) and minimum operating temperature or the pre-charge temperature, whichever is the least (lbm/ft^3);
- \( \rho_{\@ P_{p}} \) is the nitrogen density at the pre-charge pressure and temperature (lbm/ft^3);
- \( T_{\@ P_{\text{max}}} \) is the maximum operating temperature (°R);
- \( Z_{\@ P_{\text{max}}} \) is the compressibility factor of nitrogen at \( P_{\text{max}} \) and \( T_{\text{max}} \).

The conversion factors for pressure and temperature are shown as follows:

a) absolute pressure (psia) is gauge pressure (psig) plus 14.7 psi,

b) degrees Rankine (°R) is degrees Fahrenheit (°F) plus 460.

**H.2.3.5** Alternatively, **Equation (H.12)** can be used to calculate the density that the nitrogen in the “primary” accumulator bank will have at the minimum required pressure \( P_{\text{max}} \) and temperature \( T_{\@ P_{\text{max}}} \). \( P_{\text{max}} \) can then be determined from the data reference noted in H.1.3.4 by looking up the pressure required to cause the calculated density at the minimum anticipated operating temperature.

\[ P_{\@ P_{\text{max}}} = \frac{1}{\left( \frac{1}{\rho_{\@ P_{\text{crit}}}} - \frac{1}{\rho_{\@ P_{p}}} \left( \frac{V_{\text{close}}}{V_{@ P_{p}} N_{A}} \right) \right)} \]  

(H.12)

**NOTE**  **Equation (H.10), Equation (H.11), and Equation (H.12)** do not take into account adiabatic cooling which occurs when the nitrogen volume expands during the ram closing functions. As a result, the pressure observed at the completion of the ram component closure is expected to be less than the value calculated above.
Dedicated Shear-Blind Ram Accumulator System Requirements

H.2.3.6 For a well control event where the dedicated shear-blind ram is actuated, the minimum accumulator bank pressure needed to shear the CT workstring at MASP from the “dedicated” accumulator system is evaluated for a single function of the shear-blind ram. In the event that the hydraulic pump system becomes inoperative (due to pump or power pack failure), the closing of the dedicated shear-blind ram will reduce the usable hydraulic fluid in the accumulator bank by a volume, \( V_{\text{close}} \), equal to the capacity of the shear-blind ram actuator.

H.2.3.7 With the values of \( P_p \), \( V@P \), \( T@P \), \( P_{\text{crit}} \), \( T@P_{\text{max}} \), and \( V_{\text{close}} \) known, the value of \( P_{\text{max}} \) for an accumulator bank with a given pre-charge pressure can be calculated. The calculated value of \( P_{\text{max}} \) in this instance represents the minimum accumulator bank pressure needed to close the shear-blind ram, shear the CT and effectively seal the ID bore at MASP using the “dedicated” accumulator system. Therefore, it is recommended that the hydraulic system pressure be greater than \( P_{\text{max}} \).

The value of \( P_{\text{max}} \) may be determined iteratively using Equation (H.13) and Equation (H.14).

\[
P_{\text{max}} = \frac{T@P_{\text{max}} Z@P_{\text{max}}}{2.61 \left( \frac{1}{\rho@P_{\text{crit}}} - \frac{1}{\rho@P} \frac{V_{\text{close}}}{V@P N_A} \right)} \tag{H.13}
\]

\[
Z@P_{\text{max}} = \frac{2.61 P_{\text{max}}}{T@P_{\text{max}} \rho@P_{\text{max}}} \tag{H.14}
\]

where

- \( P_{\text{max}} \) is the minimum required accumulator bank pressure as defined in H.2.3.7 (psia);
- \( \rho@P_{\text{crit}} \) is the nitrogen density at \( P_{\text{crit}} \) and minimum operating temperature or the pre-charge temperature, whichever is the least (lbm/ft\(^3\));
- \( \rho@P \) is the nitrogen density at the pre-charge pressure and temperature (lbm/ft\(^3\));
- \( T@P_{\text{max}} \) is the maximum operating temperature (°R);
- \( Z@P_{\text{max}} \) is the compressibility factor of nitrogen at \( P_{\text{max}} \) and \( T_{\text{max}} \).

H.2.3.8 Alternatively, Equation (H.15) can be used to calculate the density that the nitrogen in the “dedicated” accumulator bank will have at the minimum required pressure \( P_{\text{max}} \) and temperature \( T@P_{\text{max}} \). \( P_{\text{max}} \) can then be determined from the data reference noted in H.1.3.4 by looking up the pressure required to cause the calculated density at the minimum anticipated operating temperature.

\[
\rho@P_{\text{max}} = \frac{1}{\left( \frac{1}{\rho@P_{\text{crit}}} - \frac{1}{\rho@P} \frac{V_{\text{close}}}{V@P N_A} \right)} \tag{H.15}
\]
NOTE  Equation (H.13), Equation (H.14), and Equation (H.15) do not take into account adiabatic cooling which occurs when the nitrogen volume expands during the ram closing functions. As a result, the pressure observed at the completion of the ram component closure is expected to be less than the value calculated above.

H.2.3.9 If the hydraulic system operating pressure and pre-charge pressure adjustments do not meet the accumulator bank pressure requirements, the nitrogen volume \((V_{@p} \times N_A)\) in the accumulator bank should be increased. Since \(V_{@p}\) is equal to the nominal accumulator(s) size, a larger accumulator or additional accumulators may provide the increase in nitrogen bladder volume desired.

H.2.3.10 For onsite operations, the stabilized accumulator system pressure reading of record \((P_{max})\) shall be obtained 30 minutes after initial pressurization (to allow the accumulator bank to reach thermal equilibrium).

H.3 Minimum Accumulator Volume Example Calculations

H.3.1 General

A well control stack system needs a volume of 10.715 gal to perform the requisite close-open-close functions of all ram components. A nitrogen pre-charge of 1200 psig will be applied to the accumulators and the minimum planned charge pressure is 2950 psig. The pre-charge will be performed at a temperature of 70°F which is also the minimum anticipated operating temperature. The maximum anticipated operating temperature is 100°F.

From the NIST Chemistry WebBook (http://webbook.nist.gov/chemistry/fluid):

\[
\begin{align*}
\text{— density of nitrogen at 1200 psig and 70°F: } & \quad \rho_{@p} = 5.9996 \text{lbf/ft}^3; \\
\text{— density of nitrogen at 1400 psig and 70°F: } & \quad \rho_{@p} + 200 = 6.9659 \text{lbf/ft}^3; \\
\text{— density of nitrogen at 2950 psig and 100°F: } & \quad \rho_{@P_{max}} = 12.959 \text{lbf/ft}^3; \\
\end{align*}
\]

and,

\[
V_{acc} = \frac{10.715}{\frac{5.9996}{6.9659} + \frac{1}{12.959}} = 26.90 \text{ gal}
\]

\(V_{COC}\) is 10.715 gal.

Substituting into Equation (H.4) gives

\[(H.16)\]

which is the minimum accumulator bank volume required to ensure a close-open-close sequence can be performed at the anticipated conditions and have 200 psi remaining in the accumulator bank. For an accumulator bank using 10-gal accumulators, then \(N_A\) will be three or greater to meet or exceed the calculated value of \(V_{acc}\).

H.3.2 Minimum Operating Pressure Example Calculation

The volume required to close the slip, pipe and shear rams is 1.45 gal.

The hydraulic pressure required to shear the CT size and grade for the prescribed service at atmospheric pressure was observed to be 1800 psig. The MASP for the given well was determined to be 6125 psig and the closing ratio of the shear ram was found to be 12.25. Using Equation (H.6), the value for \(P_{crit}\) was found to be 2300 psig.

\[
P_{crit} = 1800 \text{ psig} + (6125 \text{ psig}/12.25) = 2300 \text{ psig}
\]

\[(H.17)\]
With a minimum required pressure of 2300 psig to shear the coiled tube ($P_{\text{crit}}$) at MASP and a volume of 1.45 gal to close the slip, pipe and shear rams, the minimum operating pressure in the accumulator system may be found using Equation (H.9).

From the NIST Chemistry WebBook (http://webbook.nist.gov/chemistry/fluid):

Density of nitrogen at 2300 psig and 70°F: $11.112 \text{ lbm/ft}^3 = \rho_{\text{crit}}$

$$\rho_{\text{acc}} = \frac{\rho_{\text{crit}} \times 1.45 \text{ gal} \times 10^3 \text{ in}^3}{2300 \text{ psig}} = 12.205 \text{ lb/ft}^3$$

From the data reference, the pressure required for the nitrogen to have a density of 12.205 lbm/ft$^3$ at 70°F is 2568.7 psia which is the minimum recommended hydraulic pressure the accumulator bank should be operated at to ensure that there is sufficient pressure available to shear the coiled tube at MASP.
**ANNEX I**
(Informative)

**Example Coiled Tubing Well Control Accumulator System Drawdown Test Form**

I.1 The following form is provided to offer guidance in conducting coiled tubing well control equipment accumulator system drawdown tests and recording the performance data. The recommended test steps are intended to confirm that sufficient power fluid and actuator pressure are available to effectively perform the required ram function for the given CT workstring and wellbore pressure.

I.2 “Primary” Well Control Stack Drawdown Test Form – Stack Configuration A

<table>
<thead>
<tr>
<th>Primary CT Accumulator System</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Number of Accumulator Bottles</th>
<th>Nominal Volume of Bottles</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Average Precharge Pressure</th>
<th>Psig</th>
<th>Average Temperature at Precharge</th>
<th>°F</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Maximum Charge Pump Pressure</th>
<th>Psig</th>
<th>Ambient Temperature</th>
<th>°F</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>30-Minute Stabilized Operating Pressure Reading</th>
<th>Psig</th>
<th>Observed Temperature at the 30-Minute Operating Pressure Reading</th>
<th>°F</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Observed Operating Pressure Upon Open of Isolation Valve</th>
<th>Psig</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Component</th>
<th>Status</th>
<th>Observed Pressure</th>
<th>Function Time</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Slip Ram</td>
<td>Close</td>
<td>Psig</td>
<td>Seconds</td>
<td>Compared with Slip Ram Test Data</td>
</tr>
<tr>
<td>Pipe Ram</td>
<td>Close</td>
<td>Psig</td>
<td>Seconds</td>
<td></td>
</tr>
<tr>
<td>Shear Ram</td>
<td>Close</td>
<td>Psig</td>
<td>Seconds</td>
<td>Compared with Shear Ram Test Data</td>
</tr>
<tr>
<td>Blind Ram</td>
<td>Close</td>
<td>Psig</td>
<td>Seconds</td>
<td></td>
</tr>
<tr>
<td>Component</td>
<td>Status</td>
<td>Observed Pressure</td>
<td>Function Time</td>
<td>Comments</td>
</tr>
<tr>
<td>---------------------</td>
<td>--------</td>
<td>-------------------</td>
<td>---------------</td>
<td>----------</td>
</tr>
<tr>
<td>Pipe Safety Ram</td>
<td>Close</td>
<td>Psig</td>
<td>Seconds</td>
<td></td>
</tr>
<tr>
<td>Shear Ram</td>
<td>Open</td>
<td>Psig</td>
<td>Seconds</td>
<td></td>
</tr>
<tr>
<td>Pipe Safety Ram</td>
<td>Open</td>
<td>Psig</td>
<td>Seconds</td>
<td></td>
</tr>
<tr>
<td>Pipe Ram</td>
<td>Open</td>
<td>Psig</td>
<td>Seconds</td>
<td></td>
</tr>
<tr>
<td>Slip Ram</td>
<td>Open</td>
<td>Psig</td>
<td>Seconds</td>
<td></td>
</tr>
<tr>
<td>Blind Ram</td>
<td>Open</td>
<td>Psig</td>
<td>Seconds</td>
<td></td>
</tr>
<tr>
<td>Slip Ram</td>
<td>Close</td>
<td>Psig</td>
<td>Seconds</td>
<td></td>
</tr>
<tr>
<td>Pipe Ram</td>
<td>Close</td>
<td>Psig</td>
<td>Seconds</td>
<td></td>
</tr>
<tr>
<td>Shear Ram</td>
<td>Close</td>
<td>Psig</td>
<td>Seconds</td>
<td></td>
</tr>
<tr>
<td>Blind Ram</td>
<td>Close</td>
<td>Psig</td>
<td>Seconds</td>
<td></td>
</tr>
<tr>
<td>Pipe Safety Ram</td>
<td>Close</td>
<td>Psig</td>
<td>Seconds</td>
<td></td>
</tr>
</tbody>
</table>
I.3 "Dedicated" Shear-Blind Ram Accumulator Drawdown Test Form

<table>
<thead>
<tr>
<th>“Dedicated” CT SBR Accumulator System</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of Accumulator Bottles</td>
<td>Nominal Volume of Bottles</td>
</tr>
<tr>
<td>Average Precharge Pressure Psig</td>
<td>Average Temperature at Precharge °F</td>
</tr>
<tr>
<td>Maximum Charge Pump Pressure Psig</td>
<td>Ambient Temperature °F</td>
</tr>
<tr>
<td>30-Minute Stabilized Operating Pressure Reading Psig</td>
<td>Observed Temperature at the 30-Minute Operating Pressure Reading °F</td>
</tr>
<tr>
<td>Observed Operating Pressure Upon Open of Isolation Valve Psig</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Component</th>
<th>Status</th>
<th>Observed Pressure</th>
<th>Function Time</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shear-Blind Ram</td>
<td>Close</td>
<td>Psig</td>
<td>Seconds</td>
<td>Compared with SBR Test Data</td>
</tr>
<tr>
<td>Shear-Blind Ram</td>
<td>Open</td>
<td>Psig</td>
<td>Seconds</td>
<td></td>
</tr>
<tr>
<td>Shear-Blind Ram</td>
<td>Close</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
ANNEX J
(Informative)

Coiled Tubing Well Control Contingencies and Drills

J General

The following are a series of equipment operation contingencies related to CT well control events. The following cases are offered to provide a common sequence of expected personnel reactions to the well control events described for use in well control drills and training for non-H_{2}S service. Although the following responses are considered to be typical, the appropriate emergency response shall be determined on a case-by-case basis. Once the initial emergency well control incident is contained, a risk assessment should be conducted to evaluate the appropriate next steps to be conducted in the recovery process.

J.1 Case A—Stripper Assembly Leak

Situation: CT workstring is deployed at a given depth within a wellbore with pressure at surface. A leak is observed at the stripper assembly and additional hydraulic pressure applied to the stripper assembly does not re-establish the pressure seal. See Table J.1 for the recommended steps to follow in addressing this event.

Table J.1—Personnel Actions to Address a Stripper Assembly Leak

<table>
<thead>
<tr>
<th>Step</th>
<th>Activity (Order may vary according to circumstances)</th>
<th>CT Supervisor</th>
<th>CT Operator</th>
<th>Pump Operator</th>
<th>CT Helper</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Halt movement of CT workstring within injector. Set brakes on the injector and tubing reel.</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Open the primary accumulator circuit pressure isolation valve on console. Close the slip ram and pipe ram.</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Assess fluid pumping activities to determine the most appropriate course of action.</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Secure the well as required for the operation.</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Monitor CT pump pressure if pumping operations are to be continued.</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Continue to monitor wellhead pressure.</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Assess pressure containment situation above the closed pipe ram to determine most appropriate course of action.</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>If continued circulation of wellbore fluids is not required, the second pipe ram should be close (if installed).</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>If installed, the 2nd-In-Service Stripper Assembly should be energized.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Confirm closure of slip ram and pipe rams (report position of indicator pins) and manually lock rams as soon as safe working conditions permit access to the well control stack.</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Bleed off trapped pressure from well control stack cavity above the closed pipe rams.</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>Replace worn or damaged stripper assembly elements and affected components as needed and return the</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
</tbody>
</table>
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<table>
<thead>
<tr>
<th>Step</th>
<th>Activity</th>
<th>CT Supervisor</th>
<th>CT Operator</th>
<th>Pump Operator</th>
<th>CT Helper</th>
</tr>
</thead>
<tbody>
<tr>
<td>11</td>
<td>Line up pump to kill line. Conduct “post-repair” pressure test from below the stripper assembly.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>Equalize pressure across the pipe rams. Unlock the pipe rams and the slip ram.</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>Open the pipe rams (first) and the slip ram (second).</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>14</td>
<td>Upon completion of the accumulator pressure recharge ($P_{\text{max}}$), close the primary accumulator circuit pressure isolation valve on the console. Record $P_{\text{max}}$ pressure.</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>15</td>
<td>Release the injector brake and tubing reel brake.</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>16</td>
<td>Pick up CT workstring to position the segment of tubing affected by the slip ram closure above the stripper assembly. Inspect OD of tube body for damage.</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>17</td>
<td>If damage is observed where the slip ram and pipe ram were closed on the CT workstring, determine the risks of continuing operations with the damaged tubing.</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>18</td>
<td>Based on the risk assessment from Step 17, resume well servicing operations or pull out of the wellbore and replace the CT workstring.</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
</tbody>
</table>

---

**J.2 Case B—Leak in Coiled Tubing Workstring Between Tubing Guide Arch and Service Reel**

Situation: A leak is observed in the CT workstring between the tubing guide arch and the service reel. The CT workstring remaining within the wellbore is capable of withstanding the tri-axial stress of the annulus fluid pressure with zero psig internal pressure present (conditions will not induce collapse of CT string). See Table J.2 for the recommended steps to follow in addressing this event.

---

**Table J.2—Personnel Actions to Address a CT Workstring Leak Between the Tubing Guide Arch and Service Reel**

<table>
<thead>
<tr>
<th>Step</th>
<th>Activity (Order may vary according to circumstances)</th>
<th>CT Supervisor</th>
<th>CT Operator</th>
<th>Pump Operator</th>
<th>CT Helper</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Halt movement of CT workstring within injector. Set brakes on the injector and tubing reel.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Stop pumping operations through the CT workstring and monitor CT workstring pressure.</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Secure the well as required for the operation.</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Continue to monitor wellhead pressure.</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td></td>
<td>Assess situation to determine course of action. If there is no flow through the CT ID, go to <strong>Step 16</strong>. If there is slight flow through the CT Workstring ID and the assessment concludes that the CT workstring can be safely pulled out of the well, go to <strong>Step 16</strong>. If there is sustained flow and the assessment concludes that CT workstring movement is not recommended, continue with <strong>Step 6</strong>.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>---</td>
<td>---</td>
<td>---</td>
<td>---</td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Open the primary accumulator circuit pressure isolation valve on the console. Close the slip ram and the pipe ram(s).</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Confirm closure of the slip ram and the pipe rams (report position of indicator pins) and manually lock the rams as soon as safe working conditions permit access to the well control stack.</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Release injector brake and tubing reel brake. Slack-off buoyed CT workstring weight onto the closed slip ram.</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Cut the CT workstring using the shear ram. Open the shear ram immediately after the cut is completed.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Pick up the CT workstring approximately one foot with the injector to locate the sheared end of CT above the blind ram position.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>Close the blind ram.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>Set injector brake and tubing reel brake.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>Confirm closure of the blind ram (report position of indicator pins) and manually lock the ram as soon as safe working conditions permit access to the well control stack.</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>Upon completion of the primary accumulator pressure recharge ($P_{\text{max}}$), close the primary accumulator circuit pressure isolation valve on the console. Record $P_{\text{max}}$ pressure.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>14</td>
<td>Ensure pressure is bled-off above the blind ram (observe wellhead pressure readings). Go to <strong>Step 19</strong>.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>15</td>
<td>Pull CT workstring out of the well to secure the damaged tubing on the tubing reel. Note that <strong>Step 16</strong> may be switched with <strong>Step 17</strong> depending upon the situation at hand.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>16</td>
<td>Make provisions to displace hazardous fluids in CT workstring with a safe liquid if needed. Initiate pumping operations and displace hazardous fluids in CT workstring with a safe liquid.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>17</td>
<td>Continue to pull CT workstring out of the well while monitoring the CT leak and well control condition.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>18</td>
<td>Monitor well conditions and wait on instructions from the Company Representative.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
J.3 Case C—Leak in Coiled Tubing Workstring Between Tubing Guide Arch and Stripper Assembly

Situation: A leak is observed in the CT workstring between the tubing guide arch and the stripper assembly (within the injector body). The CT workstring remaining within the wellbore is capable of withstanding the tri-axial stress of the annulus fluid pressure with zero psig internal pressure present (conditions will not induce collapse of the CT workstring). See Table J.3 for the recommended steps to follow in addressing this event.

Table J.3—Personnel Actions to Address a CT Workstring Leak Between the Tubing Guide Arch and Stripper Assembly

<table>
<thead>
<tr>
<th>Step</th>
<th>Activity (Order may vary according to circumstances)</th>
<th>CT Supervisor</th>
<th>CT Operator</th>
<th>Pump Operator</th>
<th>CT Helper</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Halt movement of CT workstring within injector. Set brakes on the injector and tubing reel.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Stop pumping operations through the CT workstring and monitor CT pressure.</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Secure well as required for the operation.</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>4</td>
<td>Continue to monitor wellhead pressure</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>5</td>
<td>Assess situation to determine course of action.</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td></td>
<td>If there is no flow, go to Step 23.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>If there is slight flow and the assessment concludes that the CT workstring can be safely moved, go to Step 6.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>If there is sustained flow and the assessment concludes that CT workstring movement is not recommended, continue with Step 6.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Open the primary accumulator circuit pressure isolation valve on the console. Close the slip ram and the pipe ram(s).</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>7</td>
<td>Confirm closure of the slip ram and pipe ram (report position of indicator pins) and manually lock the rams as soon as safe working conditions permit access to the well control stack.</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Release injector brake and tubing reel brake. Slack off buoyed workstring weight onto the closed slip ram.</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Cut the CT workstring using the shear ram. Open the shear ram immediately after the cut is completed.</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>Pick up CT workstring approximately one foot with the injector to place the CT sheared end above the blind ram position.</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>Close the blind ram.</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>Set injector brake and tubing reel brake.</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>Confirm closure of the blind ram (report position of indicator pins) and manually lock the ram as soon as safe working conditions permit access to the well control stack.</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
</tbody>
</table>
Upon completion of the primary accumulator pressure recharge ($P_{\text{max}}$), close the primary accumulator circuit pressure isolation valve on the console. Record $P_{\text{max}}$ pressure.

Ensure pressure is bled-off above the blind ram (observe wellhead pressure readings). Go to Step 23.

Release the injector brake and tubing reel brake.

Run the CT workstring into the well to position the leak below the stripper assembly and above the pipe ram.

Set the injector brake and tubing reel brake.

Open the primary accumulator circuit pressure isolation valve on the console. Close the slip ram and the pipe ram.

Confirm closure of the slip ram and the pipe ram (report position of indicator pins) and manually lock the rams as soon as safe working conditions permit access to the well control stack.

Upon completion of the primary accumulator pressure recharge ($P_{\text{max}}$), close the primary accumulator circuit pressure isolation valve on the console. Record $P_{\text{max}}$ pressure.

Make provisions to displace hazardous fluids in CT workstring with a safe liquid if needed. Initiate pumping operations and displace hazardous fluids contained in CT with a safe liquid.

Monitor well conditions and wait on instructions from the Company Representative.
J.4 Case D—Coiled Tubing Workstring Parts Between Tubing Guide Arch and Service Reel

Situation: The CT workstring suffers a separation failure between the tubing guide arch and the service reel. The CT workstring segment remaining within the wellbore is capable of withstanding the tri-axial stress of the annulus fluid pressure with zero psig internal pressure present (conditions will not induce collapse of CT workstring). See Table J.4 for the recommended steps to follow in addressing this event.

Table J.4—Personnel Actions to Address a CT Workstring Separation Failure Between the Tubing Guide Arch and Service Reel

<table>
<thead>
<tr>
<th>Step</th>
<th>Activity (Order may vary according to circumstances)</th>
<th>CT Supervisor</th>
<th>CT Operator</th>
<th>Pump Operator</th>
<th>CT Helper</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Halt movement of CT within injector. Set brakes on the injector and tubing reel.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Stop pumping operations through the CT workstring.</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Secure well as required for the operation.</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Open the primary accumulator circuit pressure isolation valve on the console. Close the slip ram and the pipe ram(s).</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Confirm closure of the slip ram and the pipe rams (report position of indicator pins) and manually lock rams as soon as safe working conditions permit access to the well control stack.</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Assess situation to determine course of action If there is no flow through the CT ID, go to Step 17. If there is sustained flow, continue with Step 7.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Release injector brake and tubing reel brake. Slack off buoyed workstring weight onto the closed slip ram.</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Cut the CT workstring using the shear ram. Open the shear ram immediately after the cut is completed.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Pick up CT approximately one foot with the injector to locate the sheared end of CT above the blind ram position.</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>Close the blind ram.</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>Set the injector brake and tubing reel brake.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>Confirm closure of the blind ram (report position of indicator pins) and manually lock ram as soon as safe working conditions permit access to the well control stack.</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>Upon completion of the primary accumulator pressure recharge ($P_{\text{max}}$), close the primary accumulator circuit pressure isolation valve on the console. Record $P_{\text{max}}$ pressure.</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>14</td>
<td>Ensure that pressure is bled off above the blind ram (observe wellhead pressure readings).</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
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<table>
<thead>
<tr>
<th>Step</th>
<th>Activity</th>
<th>CT Supervisor</th>
<th>CT Operator</th>
<th>Pump Operator</th>
<th>CT Helper</th>
</tr>
</thead>
<tbody>
<tr>
<td>15</td>
<td>Secure spooled segment of CT workstring to tubing reel.</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>16</td>
<td>Make provisions to displace hazardous fluids in CT workstring with a safe liquid if needed. Initiate pumping operations and displace hazardous fluids contained in CT with a safe liquid.</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>17</td>
<td>Monitor well conditions and wait on instructions from the Company Representative</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
</tbody>
</table>

### J.5 Case E—Coiled Tubing Workstring Parts Between Stripper Assembly and Injector

Situation: The CT workstring suffers a tensile separation failure between the stripper assembly and the injector chain drive section. The following sequence applies if the coiled tubing is considered sufficiently off-bottom to allow for the coiled tubing to fall below the christmas tree and the separated tubing segment cannot be controlled with the injector. If the CT workstring is still controlled by the injector, refer to J.4, Case D. See Table J.5 for the recommended steps to follow in addressing this event.

Table J.5—Personnel Actions to Address a Tensile Separation Failure of the CT Workstring Between the Stripper Assembly and Injector

<table>
<thead>
<tr>
<th>Step</th>
<th>Activity</th>
<th>CT Supervisor</th>
<th>CT Operator</th>
<th>Pump Operator</th>
<th>CT Helper</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Halt movement of CT workstring within injector. Set brakes on the injector and tubing reel.</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Stop pumping operations through the CT workstring.</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Secure the well as required for the operation.</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>4</td>
<td>Assess situation to determine course of action. Confirm reduction in weight indicator reading and attempt to determine where the CT segment has fallen. If the failed end of the CT workstring has fallen into the well (below the blind ram), go to Step 12. If the failed end of the CT workstring remains across the blind ram and there is no flow through the CT ID, go to Step 17. If the failed end of the CT workstring remains across the blind ram and there is sustained flow, continue with Step 5.</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Open the primary accumulator circuit pressure isolation valve on the console. Close the slip ram and the pipe ram(s).</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Confirm closure of the slip ram and the pipe rams (report position of indicator pins) and manually lock rams as soon as safe working conditions permit access to the well control stack.</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>7</td>
<td>If flow is halted, go to Step 17. If flow continues through the stripper assembly, continue with Step 8.</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Step</td>
<td>Instruction</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
<td>---</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Open the dedicated SBR accumulator circuit pressure isolation valve on the console. Close the shear-blind ram.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Cut the CT workstring using the shear-blind ram.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>Confirm closure and seal of the shear-blind ram (report position of indicator pins). Manually lock the SBR as soon as safe working conditions permit access to the well control stack.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>Upon completion of the dedicated accumulator pressure recharge ($P_{\text{max}}$), close the dedicated accumulator circuit pressure isolation valve on the console. Record $P_{\text{max}}$ pressure. Go to Step 17.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>Open the primary accumulator circuit pressure isolation valve on the console. Close the blind ram.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>Confirm closure of the blind ram (report position of indicator pins) and manually lock the ram as soon as safe working conditions permit access to the well control stack.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>14</td>
<td>Upon completion of the primary accumulator pressure recharge ($P_{\text{max}}$), close the primary accumulator circuit pressure isolation valve on the console. Record $P_{\text{max}}$ pressure.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>15</td>
<td>Ensure that pressure is bled off above the blind ram (observe wellhead pressure readings).</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>16</td>
<td>Monitor well conditions and wait on instructions from the Company Representative.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
J.6  Case F—Coiled Tubing Workstring Buckle Between Injector and Stripper Assembly

Situation: The CT workstring failed between the injector and the stripper through catastrophic buckling due to excessive thrust load. The coiled tubing may be mechanically stuck within the well and may not be able to clear the stripper. Upon pick-up, the coiled tubing may suffer a separation failure.

See Table J.6 for the recommended steps to follow in addressing this event.

Table J.6—Personnel Actions to Address a Compressive CT Workstring Buckling Failure Between the Injector and Stripper

<table>
<thead>
<tr>
<th>Step</th>
<th>Activity (Order may vary according to circumstances)</th>
<th>CT Supervisor</th>
<th>CT Operator</th>
<th>Pump Operator</th>
<th>CT Helper</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Halt movement of CT workstring within injector. Set brakes on the injector and the tubing reel.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Stop pumping operations through the CT workstring and monitor CT pressure. Check for spike in pump pressure.</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Open the primary accumulator circuit pressure isolation valve on console. Close the slip ram and the pipe rams.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Increase stripper assembly hydraulic pressure.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Secure the well as required for the operation.</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>6</td>
<td>Assess situation to determine course of action. If no flow is observed, go to Step 11. If flow is observed above the stripper assembly, continue with Step 7.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Open the slip ram and the pipe rams.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Open the dedicated SBR accumulator circuit pressure isolation valve on console.</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Cut the CT workstring using the dedicated shear-blind ram.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>Confirm closure of the dedicated shear-blind rams (report position of indicator pins) and manually lock rams as soon as safe working conditions permit access to the well control stack.</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>11</td>
<td>Attempt to close the christmas tree valve and secure the well. Count the number of valve handle turns to confirm proper closure.</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>12</td>
<td>Monitor well conditions and wait on instructions from the Company Representative</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
J.7 Case G—Leak Between Tree and Well Control Stack Pressure-Sealing Rams

Situation: A leak is observed in the well control stack components between the surface tree connection and the lowest pressure-sealing well control stack ram component. The CT workstring is currently deployed at a given off-bottom depth within a wellbore completed in a hydrocarbon-bearing reservoir and continued flow from the well will transport hydrocarbons to the surface. See Table J.7 for the recommended steps to follow in addressing this event.

Table J.7—Personnel Actions to Address a Leak Between the Surface Tree Connection and the Lowest Pressure-sealing Well Control Stack Ram Component

<table>
<thead>
<tr>
<th>Step</th>
<th>Activity</th>
<th>CT Supervisor</th>
<th>CT Operator</th>
<th>Pump Operator</th>
<th>CT Helper</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Halt movement of CT workstring within injector. Set brakes on the injector and the tubing reel.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Assess situation to determine course of action.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Assess fluid pumping activities to determine appropriate course of action.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Continue to monitor CT workstring pump pressure (if pumping operations are to be maintained).</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Continue to monitor wellhead pressure.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Secure well as required for the operation.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Consult with Company Representative to determine if it is safe to pull CT workstring out of the well or if emergency well control practices should be implemented. If the well can be safely killed, go to Step 12. If it deemed safe to pull the CT workstring out of the well, go to Step 16. If the options above are unacceptable, go to Step 8.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Confirm that the CT workstring has room to fall within the wellbore and prepare for an emergency “shear &amp; drop” procedure.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Open the dedicated SBR accumulator circuit pressure isolation valve on console.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>Cut the CT workstring using the shear-blind ram.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>Close the crown valve on the christmas tree. Count number of valve handle turns to confirm proper closure. Go to Step 18.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>Coordinate with Company Representative to determine appropriate pumped fluid kill program and preparations needed to implement the program.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>Line up pump(s) and tankage for resident and kill fluids.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>14</td>
<td>Implement the prescribed pumped fluid kill program.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Step</td>
<td>Description</td>
<td>Complete</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>------</td>
<td>-------------</td>
<td>----------</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>15</td>
<td>Complete pumped fluid kill program. Proceed to <strong>Step 18.</strong></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>16</td>
<td>Initiate CT workstring retrieval activities and pull the CT string out of the well.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>17</td>
<td>Close the christmas tree master valves and secure the well. Count number of valve handle turns to confirm proper closure.</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>18</td>
<td>Monitor well conditions and wait on instructions from the Company Representative</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
J.8 Case H—Leak Between Stripper and Well Control Stack Rams

Situation: A leak is observed in the well control stack components between the stripper assembly and the pipe ram component. The CT workstring is currently deployed at a given depth within a wellbore completed in a hydrocarbon-bearing reservoir and continued flow from the well will transport hydrocarbons to the surface. See Table J.8 for the recommended steps to follow in addressing this event.

Table J.8—Personnel Actions to Address a Leak in the Well Control Stack Between the Stripper Assembly and Pipe Ram Component

<table>
<thead>
<tr>
<th>Step</th>
<th>Activity (Order may vary according to circumstances)</th>
<th>CT Supervisor</th>
<th>CT Operator</th>
<th>Pump Operator</th>
<th>CT Helper</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Halt movement of CT workstring within injector. Set brakes on the injector and the tubing reel.</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Open the primary accumulator circuit pressure isolation valve on console. Close the pipe rams and the slip ram.</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Confirm closure of the pipe rams and slip ram (report position of the indicator pins) and manually lock rams as soon as safe working conditions permit access to the well control stack.</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Assess fluid pumping activities to determine appropriate course of action</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Secure well as required for the operation</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Continue to monitor wellhead pressure</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Assess situation to determine most appropriate follow-up course of action</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Consult with the Company Representative to determine if it is safe to pull the CT workstring out of the well or if emergency well control practices should be implemented.</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Monitor well conditions and wait on instructions from the Company Representative</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
</tbody>
</table>
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**TO BE POPULATED UPON COMPLETION OF THE DRAFT REVIEW**

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