DACC

DRILLING AND COMPLETION COMMITTEE

IRP 15: Snubbing Operations

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

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Preface

15.0.1 Purpose

The purpose of this document is to provide easily accessible snubbing operation guidelines for all personnel involved in the development, planning and execution of the snubbing program. IRP 15 is intended to supplement existing standards and regulations and establish guidelines where none previously existed.

15.0.2 Audience

The intended audience of this document includes oil and gas company engineers, field consultants, snubbing personnel, service rig personnel and regulatory bodies.

15.0.3 Scope and Limitations

This IRP includes the following pertinent information about snubbing:

- Snubbing program requirements
- Downhole and surface equipment specifications
- Personnel requirements
- Hazard assessment information
- Joint safety meeting requirements
- Operational procedures

IRP 15 applies to both rigless and rig-assisted snubbing operations. Most of the information in the document pertains to both but when a recommended practice or process is specific to one or the other the document clearly differentiates.

IRP 15 refers to other relevant standards where appropriate. A full list of the documents referred to in this IRP and other useful reference material is provided in the References section at the end of the document.

15.0.4 Revision Process

Industry recommended practices (IRPs) are developed by the Drilling and Completions Committee (DACC) with the involvement of both the upstream petroleum industry and relevant regulators. IRPs provide a unique resource outside of direct regulatory intervention.

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

A history of revisions to this document can be found in Appendix A: Revision History.

15.0.5 Sanction

The following organizations have sanctioned this document:

Canadian Association of Oilwell Drilling Contractors (CAODC)

Canadian Association of Petroleum Producers (CAPP)

Petroleum Services Association of Canada (PSAC)

Explorers & Producers Association of Canada (EPAC)

15.0.6 Acknowledgements

The following individuals helped develop this edition of IRP 15 through a subcommittee of DACC. We are grateful for each participant's efforts. We also wish to acknowledge the support of the employers of individual committee members.

Table 1. Development Committee

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15.0.7 Range of Obligations

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

Table 2. Range of Obligation

Term	Usage
Must	A specific or general regulatory and/or legal requirement that must be followed. Statements are bolded for emphasis.
Shall	An accepted industry practice or provision that the reader is obliged to satisfy to comply with this IRP. Statements are bolded for emphasis.
Should	A recommendation or action that is advised.
May	An option or action that is permissible within the limits of the IRP.
Can	Possibility or capability.

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Table 3. Copyright Permissions

Copyrighted Information	Used in	Permission from
Snubbing Services: Map 1 – Occupation Ladder and Typical Work Environments	Appendix C	PHRCC
Heat Stress Quick Card	Appendix G	OSHA
Table 1: Cooling Power of Wind on Exposed Flesh Expressed as Equivalent Temperature, 1998 Threshold Limit Values	Appendix H	ACGIH
Table 2: TLVs Work Warm-Up Schedule for Four Hour Shift (Under Discretion of Supervisor on Site) – 1998 TLVs	Appendix H	ACGIH
Allowable Tensile Loads	Appendix I	Petro-Canada
Pipe Buckling Forces	Appendix J	Petro-Canada
Glossary	Glossary	API, Schlumberger

15.0.9 Background

Snubbing is an upstream petroleum industry operation using specialized hydraulic (snubbing) equipment and qualified personnel. Specifically, it is the act of moving tubulars in or out of a pressurized wellbore with blowout preventers (BOPs) that are closed and containing the pressure in the well.

Snubbing equipment, whether rig-assist or rigless, is designed and required to perform two functions:

1. Well control of annulus pressure. Pressure is maintained by the use of stripping blow out preventer (the configuration of which will vary by well or job requirements).

2. Movement of tubulars into and out of a well. Movement is controlled by mechanical means with enough advantage to overcome the force the well pressure exerts.

Snubbing applications include, but are not limited to, the following:

- Completions
- Work overs and recompletions
- Stripping
- Fishing and other remedial operations
- Stimulation
- Underbalanced drilling

The following crews or personnel may be involved during snubbing operations:

- Coiled tubing crews
- Downhole tool specialists
- Drilling rig crews
- Electric line and slick line crews
- Well owner company representatives
- Pumping services personnel
- Safety supervisors
- Service rig crews
- Snubbing personnel
- Well fracturing and stimulation crews
- Well testing crews

15.1 Snubbing Program

It is the primary contractor's responsibility to prepare a written snubbing program outlining the well site operations to be performed during snubbing. The snubbing program may be job-specific or part of the overall well program.

IRP All snubbing operations should follow the snubbing program under the direction of the primary contractor.

IRP The snubbing program should include the 10 components outlined below:

- Job Objectives
- Well History
- Risk Assessment
- Surface Equipment
- Downhole Equipment
- Pre-Job Engineering Calculations
- Mitigation of Explosive Potential
- Snubbing Procedures
- Snubbing Vendor Selection
- Supervisory Control

15.1.1 Job Objectives

Include job objectives and a brief summary of the work to be done. A checklist such as the Sample Job Information/Dispatch Sheet provided in Appendix B can be used to gather this information.

15.1.2 Well History

Identify any previous and potential problems that could impact the decision to include snubbing as part of the work to be done. Summarize the history in an easy-to-use format as background information for well site personnel.

Include, at a minimum, the following information:

- Spud and rig release dates
- Well location and directions to the lease
- Well type (i.e., gas, oil, etc.)
- Kelly bushing (KB), cubic feet (CF) and ground level (GL) elevations
- Plug back total depth (PBTD) and total depth (TD)

- Sweet or sour (including H_2S concentrations and release rates)
- Wellhead and rig blowout preventer (BOP) data (i.e., size, type, working pressure, compressive load rating)
- Casing and tubing specifications and condition
- Bottom hole assembly (BHA) description and specifications
- Cementing information
- Stimulation information for each zone
- Depths of perforations
- Pressure and flow rate information for each associated formation
- Reservoir temperature
- Sand face and sand production
- Wellhead absolute open flow (AOF)
- Hydrate potential
- Hydrocarbon production in a condensate type reservoir
- Surface casing vent flow (if present the gas needs to be piped away from the well)

15.1.3 Risk Assessment

Review each snubbing operation to evaluate the risks and assess the need for snubbing. Each situation has unique circumstances.

Reasons to snub include the following:

- Productivity loss due to reservoir sensitivity to kill fluids.
- The zone is so depleted there is not enough pressure to flow back kill fluids from the reservoir.
- The zone is so permeable, fractured or over pressured that it is very difficult to keep the well killed.
- Significant production loss due to the time required to kill the well or surrounding wells.

Hazard control and mitigation processes can significantly reduce operational risks to personnel, the environment and assets. Refer to 15.6 Hazard Assessment for information about specific risks and safeguards. Site-specific conditions may present additional hazards that should be considered.

> **Note:** For workers positioned in the derrick or on the tubing board, the hazards or risks introduced by a live well or snubbing operation exist in the majority of live well operations, including use of a self-contained snubbing work over unit or underbalanced and

managed drilling operations. See IRP 22: Underbalanced and Managed Pressure Drilling Operations Using Jointed Pipe for more information.

New technology, approaches, procedures and engineering may be effective in reducing the identified hazards and risks to acceptable levels. Industry is encouraged to continuously seek risk reduction solutions to increase worker safety. Any deviations to the risk control/mitigation safeguard considerations outlined in the Hazard Register (see Table 8 in 15.6 Hazard Assessments) for any worker while conducting snubbing operations requires formal written dispensation and approval by the PSAC Snubbing Committee prior to implementation.

IRP A demonstrable, methodical and step-wise process for evaluating the effectiveness of any new measures implemented to control/mitigate risks to a worker positioned in the derrick or on the tubing board shall be completed prior to industry acceptance. (i.e., An IRP 15 revision).

15.1.4 Emergency Response Plan (ERP)

The primary contractor's generic or corporate ERP must be used along with any site-specific plans developed in the well program. Site-specific plans should control well-specific hazards identified during the history review (see 15.1.2 Well History), risk assessment (see 15.1.3 Risk Assessment) or pre-job meetings.

IRP Regulatory requirements must be consulted for ERP content.

15.1.5 Surface Equipment

Review 15.3 Surface Equipment and identify the surface equipment required for the snubbing program. Consider the following:

- Well classification
- Tubing and casing sizes and working pressures
- Well pressure
- Hydrogen sulphide content of the gas
- Type of well fluids and any impact they could have on steel or elastomers
- Sizes and configuration of the BHAs to be snubbed
- Wellhead and rig BOP size and pressure rating
- Bleed-off/flare systems
- Kill systems
- Monitoring systems (e.g., ram savers or indicator lights)
- Rig derrick layout and compatibility
- Egress routing

- Equipment spacing
- General lease layout

15.1.6 Downhole Equipment

Review 15.2 Downhole Equipment and identify the downhole equipment required for the snubbing program.

The two main considerations are as follows:

1. The blanking mechanism installed in the tubing string to prevent flow up the tubing during snubbing operations (see 15.2.1 Wireline Practices and Procedures).
2. The BHA to be snubbed in or out of the well as part of the tubing string.

15.1.7 Bottom hole Equipment

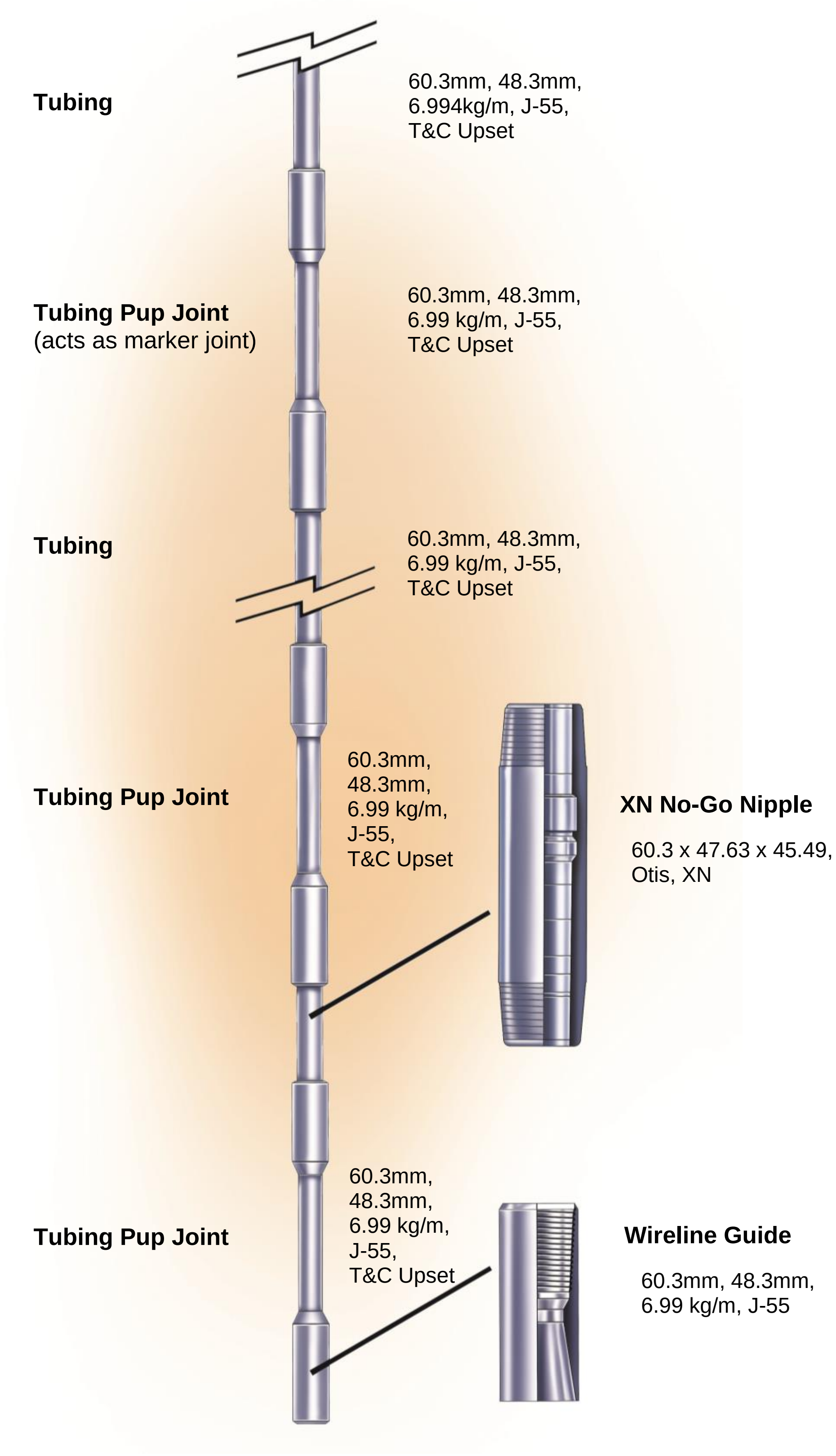
IRP The bottom hole equipment configuration should be compatible with the surface equipment in terms of lengths and diameters and allow ease of operation for staging the BHA in or out of the well.

IRP The following guidelines should be considered in the snubbing program planning:

- The BHA equipment should maintain lengths and configurations that are “snubbing friendly.” This means:
  - Tools (e.g., packers, sliding sleeves, profile nipples, jars, collars, expansion joints, etc.) are short enough that they can be easily staged through the snubbing stack and spaced out with pup joints of sufficient length to provide areas for slips and rams to close and hold on.
  - Inside diameters are maintained to allow plug removal or installation.
- The design should be simple to aid in release and removal of the BHA, particularly if the well is prone to issues such as sand production, scale deposition, corrosion or hydrates. Packers that are one-quarter-turn to set in compression and pick up to release are preferred.
- The metallurgy, elastomers, pressure ratings and type of packing materials selected must be compatible with the well pressure, gas, fluids and pressures.
- Any tubing string to be snubbed in a well shall have at least one plug seating profile in the string located at the bottom (or one pup joint up) with a pup joint installed above the profile. This connection must never be broken until pressure below the plug is bled off. Another pup joint (to act as a marker joint) should be placed in the string one joint above the profile nipple/pup assembly that will have the snubbing plug installed. See Figure 1 below for the typical recommended bottom hole equipment configuration.

- A no-go profile should be installed below selective profiles of the same profile size.
- Profiles of increasing ID shall be installed in ascending order.

Figure 1. Typical Recommended Bottomhole Equipment Configuration



15.1.8 Pre-Job Calculations

The pre-job calculations define safe operating parameters of the BHA, tubing, casing, wellhead and other surface or downhole pressure containing and mass supporting equipment. For wells with a history of corrosion, the reduced wall thickness must be estimated or measured and reduced mechanical properties applied to snubbing pressure and load conditions. Record the calculations in the snubbing program to ensure all equipment selected is suitable for the service to which it will be exposed.

IRP Pre-job calculations shall be performed and documented before commencement of snubbing operations. The calculations shall be re-executed if well parameters or activities change significantly and those changes were not considered in the original calculations.

IRP The following calculations and procedures shall be performed:

- **Snub forces must be calculated, recorded and signed off in the PSAC daily safety meeting report.**
- **Safe stroke lengths must be calculated to prevent tubing and BHA buckling. Every snubbing jack must be able to limit the snub forces and length of stroke by a mechanical, hydraulic or computerized limiting device to work within the safe parameters of the tubing.**
- **Maximum pulling forces and maximum allowable string weights must be determined. The true weight on the string below the pressure containing BOP is more than is indicated on the weight indicator by the hydraulic force exerted on the tubing by the well pressure (neglecting friction).**
- **Wellbore pressures must be monitored to prevent tubing collapse, over pressuring of wellhead or stack components or reduced values for safe unsupported stroke length.**
- **Pipe light and heavy stages must be calculated to ensure safe movement of the tubing string and the changeover point determined. Buoyancy should be considered.**
- **BHA lengths and diameters must be measured and stripping BOP stacks appropriately assembled to ensure safe installation or recovery of tubulars, BHAs, larger OD tools, connections and tubing hangers.**
- **Hydraulic forces acting on tubing hangers must be calculated to ensure safe securement of the well when the tubing hanger is landed (i.e. lift force acting against locking screws).**
- **Rotary torque must be calculated for all milling, drilling or rotating operations. A mechanical, hydraulic or computerized lockout device must be installed to limit the amount of torque applied in relation to the physically achievable length of stroke of the jack. Stress on the jack cylinders must be limited to within safe working parameters.**
- **Tubing connection torques should be established to ensure no damage is done to the string by over torqueing.**

IRP The following personnel shall be included or carry specific responsibilities in order to ensure the accuracy of pre-job engineering calculations:

- **All personnel involved in the snubbing operation should be included in a discussion of the calculation parameters at a pre-job safety meeting.**
- **The snubbing operator should perform all calculations.**
- **The snubbing supervisor should conduct a review of the calculations.**
- **The well site supervisor should confirm the completion of the calculations.**

IRP All pre-job calculations shall be verified on-site by the appropriate field personnel prior to commencement of any snubbing operation.

Refer to Appendix I: Allowable Tensile Loads (Petro-Canada) and Appendix J: Pipe Buckling Forces (Petro-Canada) for additional information.

15.1.8.1 Forces Acting on String

IRP The forces acting on a tubing or work string shall be analyzed to determine the force needed to run the string into the well.

Generally there are five forces acting on the string:

1. Upward force created by the differential of well pressure vs. atmospheric pressure on the maximum cross-section of the tubing and tool string at the sealing surface.
2. Gravitational force (weight) of the string.
3. Frictional force for passing through BOPs.
4. Force applied by the snubbing unit (snubbing force).
5. Force from pipe drag on the casing in directional, slant or dog-legged wells.

Refer to Appendix J: Pipe Buckling Forces (Petro-Canada) for additional information.

15.1.8.2 Calculations Required

IRP The following calculations shall be performed:

- **Maximum snubbing force required.**
- **Depth of neutral point.**
- **Critical buckling load of the tubing string for the support conditions provided by the snubbing unit.**
- **Collapse point of the tubing.**

15.1.9 Mitigation of Explosive Potential

Evaluate situations with the potential for fire or explosion and provide instructions to eliminate or reduce the risk.

There are two primary causes of fires and explosions:

1. Practices that allow air to contacts well gas or flammable liquids at a concentration that forms an explosive wellbore mixture.
2. Situations that allow gas or flammable fluids to be bought to surface or escape to the atmosphere.

The two main areas where air can be mixed with gas at explosive concentrations during snubbing are in the casing and in the tubing.

15.1.9.1 Explosive Mixtures in the Casing

An explosive mixture can accumulate in the casing if it is swabbed dry before it is perforated in an underbalanced condition and the zone flows gas into the air-filled casing. This is aggravated if the well has been shut in after perforating, which allows the pressure to increase. Snubbing tubing into or out of this environment could detonate an explosion.

IRP The well shall be flowed to flare at a controlled rate until the air is displaced from the casing before the well can be shut in and the snubbing started.

15.1.9.2 Explosive Mixtures in the Tubing

Air will usually be present in the tubing after it has been snubbed into the hole and before the snubbing plug is pulled. Explosive mixtures can be created if well gas from the annulus is introduced into the tubing to equalize the pressure above and below the snubbing plug before removal.

IRP A fluid spacer shall be pumped into the tubing before the annular gas is equalized into the tubing.

- **The spacer will keep the air under the fluid from contacting the gas above during wireline plug removal.**
- **The volume required will vary with well pressure but generally one half to one cubic metre of fluid (e.g., methanol, glycol or a water mixture) will suffice.**
- **An alternative to the spacer would be to equalize the pressure with an inert gas such as nitrogen. There may be situations where the annulus has been displaced to nitrogen. This can simplify the equalization process.**

- **For hydrate-prone wells, a methanol spacer should be placed in the wireline lubricator before gas or nitrogen pressure is equalized into the lubricator.**

IRP Oxygen shall be purged from the lubricator with nitrogen or sweet annular gas to prevent creation of an explosive mixture.

- **An oxygen monitor can be used to ensure that the sweet annular gas used for purging or pressuring is oxygen-free.**
- **This can be done by slowly feeding the gas into the top of the lubricator through a purge sub and flowing the oxygen out the bleed-off valve at the bottom of the lubricator.**
- **Oxygen levels must be checked at the bleed-off to determine completion of purge.**
- **The lubricator must then be pressured to the equivalent of the wellhead pressure before an attempt is made to open the wellhead working valve or BOP rams.**

IRP The BOP stack shall be purged of any explosive gases if there are iron sulphides present.

- **Iron sulphides, produced by deteriorating metal in hydrogen sulphide environments, can spontaneously ignite on contact with oxygen.**
- **Water can be used to purge and keep tools wet.**

15.1.9.3 Surface Fires and Explosions

IRP The following recommendations and guidelines for surface fires and explosions shall be considered for the snubbing program:

- **Follow the plug selection and setting recommendations in 15.2 Downhole Equipment to minimize the risk of gas flowing to surface from the tubing due to snubbing plug failure.**
- **Follow the procedures in 15.8 Operational Practices and Procedures and use all available monitoring technology to reduce the risk of tubing compression or tension failure from pulling or pushing into a closed ram or slip at surface.**
- **The well may be displaced to nitrogen, fluid or other inert product before snubbing to minimize the risk of surface fires and explosions caused by gas flows from the annulus. This will help reduce deterioration of the ram elements and seal elastomers due to prolonged exposure to well gas and fluids at elevated pressures. The nitrogen provides an inert buffer to enhance the reliability of the equipment and is non-flammable.**
- **The tubing shall be properly purged either before or during the snubbing operation to avoid surface explosions and fires caused by gas or liquid**

hydrocarbons being brought to the surface inside a tubing string being snubbed out.

Four possible options and considerations for purging procedures are listed below:

1. Swab the tubing as dry as possible and pump some fresh water down the tubing. Allow sufficient time lapse for the inversion of the water and hazardous fluids. Normally, the time to trip the tubing until reaching “wet” pipe or shutting down overnight (depending on timing) is sufficient. When wet pipe is reached swab it dry again. Use a mud can to wet trip water only that cannot be swabbed or recovered with other acceptable methods.
2. Use a pump-through type wireline plug such as an Otis TKXN, TKX, TXN, or TX to enable tubing displacement by pumping water or nitrogen. If the full displacement of the tubing is not practical, then swab the tubing as dry as possible and when reaching wet pipe at the end of the tubing string, purge with water or nitrogen.
3. Pump in a methanol cushion and equalize the shut-in casing pressure (SICP) into the tubing. Flow annulus until the shut-in tubing pressure (SITP) drops. The higher tubing pressure will be great enough to displace the liquids from the tubing through the pump-through type plug.
4. Fluid from the tubing may be displaced using coiled tubing and air or nitrogen. Air must not be used if liquid hydrocarbons are present.

15.1.9.4 Other Reference Material

The potential for explosive mixtures in the wellbore is not unique to snubbing. Other operations such as swabbing, testing, wireline and coiled tubing may be exposed to the same risk.

For more information refer to the following documents:

- IRP 4: Well Testing and Fluid Handling includes information on air entrainment and explosive mixtures and direction on the effective use of LEL detection equipment (for detecting explosive mixtures) and also discusses purge procedures (of value when developing snubbing programs).
- CAPP Flammable Environments Guideline includes information on explosive atmospheres.
- AER Directive 033: Well Servicing and Completions Operations - Interim Requirement Regarding the Potential for Explosive Mixtures and Ignition in Wells

See the References section for information about where to find these documents.

15.1.10 Snubbing Procedures

Include a written description of what operations are to be performed and what will be accomplished with the snubbing program.

IRP Snubbing procedures should be appropriate to the task to be completed.

These procedures may be drawn from any or all of the following sources:

- 15.8 Operational Practices and Procedures.
- The snubbing contractor's corporate specifications.
- The primary contractor's internal specifications.

15.1.11 Snubbing Vendor Selection

IRP A review of the following criteria shall be completed for each prospective vendor:

- **Equipment Specifications**
- **Policy and Operational Procedures**
- **Personnel Qualifications (including training and competency certification)**
- **Safety record**
- **Certificate of Recognition (COR/SECOR)**
- **WCB clearance**
- **Regulatory compliance**
- **Ability to provide technical and operational support**
- **Proof of insurance**

15.1.12 Supervisory Control

Clearly identify the chain of command for all snubbing operations.

15.1.12.1 General Supervisory Control of Wellbore

The well belongs to the well owner as primary contractor but there is often uncertainty as to who takes direction from whom during snubbing operations.

IRP The primary contractor's on-site supervisor shall maintain supervisory control of the wellbore at all times.

15.1.12.2 Specific Well Control Issues

15.1.12.2.1 Moving Tubing or Tools through the BOP Stack

IRP Any operator needing to move the tubing string or use any wellhead or support equipment shall communicate their intentions to all other related service personnel to ensure all wellhead equipment is appropriately opened or closed.

IRP The primary BOPs shall be under the direct supervision and operation of a worker who can competently respond to a well control emergency during any snubbing operation involving the movement of tubing or tools through the BOP stack. Minimum components of this competence include the following:

- **The worker should be an employee of the contractor owning the primary BOP stack.**
- **The worker must hold a valid Energy Safety Canada Well Service Blow Out Prevention certificate.**

15.1.12.2.2 Rig-Assisted Snubbing Operations

IRP All snubbing work to be performed shall involve both of the snubbing operator and the service rig driller.

The snubbing operator and the service rig driller have to work closely together to complete tasks safely and efficiently. They are both responsible for maintaining well control and coordinating tubing string movement.

15.1.12.3 Supportive Practices

The following two practices support effective supervisory control and well control:

1. All supervisors and workers on location involved in the snubbing operation must review and agree on procedures before beginning any task. This will provide a routine for work to be done safely and efficiently. If the scope of work changes another meeting regarding the new task must be held and documented. For more information on joint safety meetings see 15.7 Joint Safety Meetings.
2. Any safety devices available to preserve the safety of on-site workers must be installed and operational and necessary personnel trained in their use. Some examples of safety devices are shown in Table 4.

Table 4. Example Safety Devices

Safety Device	Purpose
Ram Indicator Systems	Provide a visual aid and mechanically limit the ability to function service rig hoisting equipment while primary or secondary pipe rams are closed.
Snub and Left Force Pressure Adjustment Equipment	Mechanically limit the ability to part, bend or buckle tubing during jacking.
Crown Savers	Mechanically limit the ability of the driller to strike the rig crown with the block assembly.
Escape Equipment	Allows all workers on location a safe, efficient egress in case of an incident or unplanned release.
Floor Saver on Stiff Mast Snubbing Units	Mechanically prevents the travelling plate from striking the work floor.

15.2 Downhole Equipment

The information in this section is used to aid in the selection of downhole equipment during snubbing program development (see 15.1.6 Downhole Equipment). It is also used by on-site field personnel at the pre-job stage to verify the accuracy of the equipment provided and that the equipment remains appropriate to the planned activities.

15.2.1 Wireline Practices and Procedures

15.2.1.1 Wireline Practices

IRP The following wireline practices should be used during snubbing:

1. Run a tubing-drift gauge ring to establish tubing drift and tag the profile.
2. Run a brush through the profile if sand or scale is present to clean it before plug installation. Ensure the brush is made of a material that will not score the polished bore of the profile.
3. Set a profile-locking plug such as an Otis TKXN, TXN, TKX, TX, PXN, PX, PR, or PRN.
4. Verify the plug integrity before setting the slip stop to ensure the plug is set properly.
5. Bleed down the tubing pressure in stages to ensure plug integrity and monitor for 10 minutes per stage.

If the pressure does not bleed off then pull the assembly and assess the problem. Corrective action may include one of the following:

- Re-brush or re-clean the profile and rerun
- Try another profile
- Install a non-profile plug such as a permanent bridge plug

15.2.1.2 Wireline Plug Practices and Procedures

IRP Hook-wall plugs, G pack-offs and similar plugs shall only be used for snubbing on wells and conditions where they can be used with a surface valve.

IRP The following wireline plug practices and procedures shall be used during snubbing:

- **All wire line plugs and tools shall be installed and removed by qualified wire line personnel in the manner identified in the snubbing program.**

- **Plugs installed in profiles at surface shall be pressure tested from below to 1.3 times the bottom hole pressure. The pressure test shall be documented on the daily tour sheet.**

15.2.1.2.1 Profile plugs

- Care shall be taken to correctly match the plug specified to the profiles installed in the tubing string.
- A permanent tubing bridge plug should be set if the profiles no longer work or are not there.
- Any leaking plug shall be removed before a bridge plug is set.
- The condition of the tubing ID will affect the seal of the bridge plug element when it is set. Install a second plug if seal effectiveness is in doubt.
- Acceptable single barriers used with slip stops are wireline set selective plugs (e.g., an Otis-style TKX, TX, PX or PR) or a no-go locking plug (e.g., an Otis TKXN, TXN, PXN, or PRN, interference-style locks).
- A downhole shut-off valve, permanent bridge plug or tubing end plug can be used without a slip stop. Additional guidelines are as follows:
    - If the plug has an equalizing prong, the prong should be a locking style or be pinned in place.
    - Use of a pump-through type wire line plug such as an Otis TKXN, TKX, TXN, or TX enables tubing displacement by pumping water or nitrogen. It can also utilize wellbore gas and differential pressure between tubing and casing pressure by equalizing tubing and then flowing the casing.
- A fluid column in the tubing may be used to reduce the effects of increased differential pressure across a single plug. Avoid the use of highly flammable or hydrocarbon based fluids.

15.2.1.2.2 Non-Profile plugs

- Tubing end plugs are suitable for snubbing in final tubing installations.
- Downhole shut-off valves are suitable when the tubing is to be round-tripped.
- Tubing end plugs are an acceptable alternative when dual barriers are required and are recommended for final tubing string installations where there is no equipment below the tubing end.

15.2.1.2.3 Slip Stops

IRP The following slip stop practices and procedures should be used during snubbing:

- A slip stop shall be installed immediately above the fish-neck of the equalizing prong as a second measure to prevent upward movement and subsequent dislodging.

- The slip stop shall be set immediately above injection or pump-through style plugs (e.g., TKXN, TKX, TXN or TX) to help hold them in place.
- The ID of the slip carrier for Otis-style plugs shall be restricted enough to prevent the fish-neck of the prong from entering and tagging the slip stop body (which could cause a release of the slip stop).
- The slip stop for Baker-style plugs shall have an extension fastened to the bottom of the body that is of sufficient ID and length to pass over the fish-neck of the plug and exert downward force to the lock mandrel. Downward force applied to the fish-neck of a Baker-style plug may cause a release.

15.2.1.2.4 Dual Barriers

IRP The following dual barrier practices and procedures should be used during snubbing:

- High pressure gas may be trapped between the plugs when dual barriers have been installed. Use caution and care to ensure that the pressure is relieved between the barriers.
- For snubbing out, the lower plug installed should be an injection or pump-through style and the upper plug should be a blanking style. This will allow the pressure to bleed continuously through the plug into the wellbore as the tubing is withdrawn from the well.
- The lower plug should be negative pressure tested after installation by bleeding off the tubing pressure.
- The upper plug’s pressure integrity should be determined by filling the tubing with fluid, pressure testing and swabbing the tubing dry after. Nitrogen can be used if the tubing cannot be easily swabbed or hydrates are a concern.
- Reverse the order of the plugs described above when snubbing in.

Note: A slip stop is not considered a barrier.

15.2.1.2.5 Downhole ¼ Turn Valves

IRP The following downhole ¼ turn valve practices and procedures should be used during snubbing:

- Downhole shut-off valves may be used if rotating the tubing to manipulate the valve can be performed effectively.
- The downhole ¼ turn valve shall be pressure tested and charted equal to the requirements for a plug set in a profile at the surface after being serviced and before each use.

15.2.3 Engineering Specifications

Wireline companies and well owners have several downhole equipment supply options. Downhole equipment performance is influenced by quality control during manufacturing and the condition of the equipment at the time of plug installation. The failure of a plug to hold pressure could be related to the plug being manufactured or repaired to a condition that is “out of spec” or set in a profile that is out of spec. It is as important to ensure that the downhole equipment being installed is within manufacturer tolerances as it is to install the equipment properly.

15.2.4 Certification

IRP All downhole equipment (e.g., tubing plugs and profiles) shall be certified by the original equipment manufacturer (OEM) as being suitable for the environment that the equipment will be exposed to (e.g., pressure rating, wellbore fluids, etc.).

Equipment not from an OEM may be substituted if it is accompanied by a letter of conformance or compliance or is approved by a certifying professional engineer as being suitable for the application.

The certifying professional engineer shall have the following credentials:

- **Previous experience or training with pressure control equipment.**
- **Practical working knowledge of downhole completion equipment.**
- **Experience with general quality control standards.**
- **Professional engineering status in the jurisdiction of practice.**

The end user is responsible for selecting appropriate materials for the well environment or accepting manufacturer recommendations. It is the responsibility of the well owner to ensure the materials comply with the requirements and are certified by the manufacturer.

15.3 Surface Equipment

The information in this section is used to aid in the selection of surface equipment during snubbing program development (see 15.1.5 Surface Equipment). It is also used by on-site field personnel at the pre-job stage to verify the accuracy of the equipment provided and that the equipment remains appropriate to the planned activities.

Surface equipment specifications refer to the following:

- All wellbore pressure-containing components of the snubbing unit.
- All BOPs, bleed-offs, equalizing spools, spacer spools, plug valves and equalizing lines.
- Hydraulic systems incorporated to facilitate pipe-tripping operations.
- Lifting and rigging systems for rigless snubbing operations.
- The design requirements for functioning the well containment systems on the snubbing unit.

15.3.1 Requirements

15.3.1.1 Primary BOP Equipment

The primary BOP equipment is operated by the snubbing unit operators in rigless operations and by the service rig crew in rig-assist operations.

IRP Regulatory requirements of the applicable jurisdiction must be followed for all primary BOP equipment.

IRP If a well has H_2S of 1% or more or BHP of 21,000 KPA or more, one of the following well control methods should be applied:

1. Install a shear ram as the lowermost primary BOP.
2. Connect a pump and tank to the wellbore and keep a minimum of one hole volume of fluid on site.

The use of substances that are incompatible with certain polymers (e.g., aromatic fracturing oil, methanol and CO_2) will contribute to annular seal failures and potentially compromise equipment performance. This can be mitigated by limiting the use of primary annular preventers previously exposed to such substances. Having a surface blanket of fluid or inert gas will also mitigate the chance of exposure. Once exposed, the annular seals and element should undergo a visual inspection and pressure test before being returned to use.

IRP Primary BOP controls must be readily accessible.

- **Employers shall perform a risk assessment to determine the optimal placement of BOP controls for their specific operations.**
- **All primary well control BOPs must be connected to an accumulator that meets the requirements of the regulations of the applicable jurisdiction and shall be isolated from the snubbing accumulator system.**
- **For primary BOP applications refer to Schedule 10 of AER Directive 37: Service Rig Inspection Manual (Alberta) and/or section 8.144 of the Oil and Gas Conservation Regulations (Saskatchewan).**

15.3.1.2 Auxiliary Wellhead Equipment

A full-opening valve may be installed below the primary BOPs as a safe alternative to snubbing in a tubing hanger in the following situations:

- When well owner policy dictates that the tubing hanger be landed for dual barrier securement overnight.
- For rigless operations.
- When there is no tubing.
- When multiple tubing sizes necessitate ram changes and pressure testing of the BOP equipment.
- For well conditions with high pressure aromatic-rich gas that can cause premature elastomer failure.
- For well conditions with highly sour and/or corrosive well fluids that can cause premature metal failure.

15.3.1.3 Snubbing Equipment

15.3.1.3.1 Rig-Assist and Rigless Snubbing Equipment

For the purposes of this IRP, a rig assist or rigless snubbing unit is defined as having the following components:

- Two BOPs, usually one stripping ram and one annular. An extra stripping ram is used on wells with a surface pressure higher than 21mPa and rigless snubbing units will also include primary BOP equipment.
- One or more working spools with ports for bleeding off and equalizing wellbore pressure between BOPs.
- A slip assembly made up of one or two sets of snubbing slips (to control upward movement of the tubing string) and one or two conventional (heavy) slips (to aid in transition to and in pipe heavy stripping).
- A mechanical system to move tubulars or pipe in or out of a well (e.g., cable, cylinders and rack-and-pinion systems)

- A power pack that supplies power to the hydraulic system. On mobile units the truck motor may supply power to the hydraulic system when the truck is stationary.

The following requirements apply to surface snubbing equipment:

- The snubbing unit shall be able to control tubulars at wellbore pressure.
- Surface pressure should be reduced if greater than the working pressure of the snubbing stack. Surface pressure and stress on the snubbing stack can be reduced using control measures such as a column of fluid or flowing the well.
- The mechanical system shall be strong enough to overcome the maximum hydraulic lift force on tools and tubing at surface (see 15.1.8 Pre-Job Calculations for information regarding pressure-area calculations).
- The maximum surface pressure shall be used for pressure-area calculations.
- All components of the snubbing unit hydraulic system (i.e., hoses, fittings, directional valves, piping) shall have a working pressure rating equal to or greater than the working pressure rating of the hydraulic system.
- The hydraulic tank design shall include sufficient venting to allow escape of gas in the event of a BOP wellbore seal failure.
- The accumulator and jack circuits shall not use silver solder fittings.
- The snubbing unit shall have gauges, labeled and visible from the operator's position, which accurately indicate the following:
    - Wellbore pressure
    - Push/pull force
    - Accumulator pressures
    - Operating pressure
    - Annular closing pressure
    - Slip pressure
- The panel in the snubbing basket shall house all the manually operated controls for the slips, BOPs and jack and there must be a lockout system for these controls (see 15.3.1.7 Lockout Equipment).
- The snubbing unit may use a proven technology (e.g., interlock systems) to ensure one set of the appropriate slips is closed at all times during snubbing operations. If this technology is used there shall be written procedures, training and demonstrated competency in its use.
- The rig assist snubbing unit shall include a system to prevent the snubbing operator from accidentally closing a snubbing slip while the service rig is tripping out of the hole.

15.3.1.4 Snubbing Unit Accumulator Requirements

The snubbing unit accumulator requirements are as follows:

- The design shall include a usable fluid volume that, with the annular preventer closed, allows two functions of a single gate preventer and two functions of the actuators for the bleed-off/equalizing plug valves. A minimum pressure of 8,400 KPA shall be maintained on the snubbing unit accumulator circuit after performing these functions.
- The snubbing unit accumulator shall be able to maintain closure of the annular preventer for a minimum of ten minutes while maintaining a minimum of 8,400 KPA with no power to the recharge pump.

  Note: 8,400 KPA remaining on the accumulator system may not be sufficient to close specific types of 10,000 psi BOPs. The OEM manual for the BOP should be consulted to confirm that the accumulator has sufficient closing volume for the BOP it is matched with.

- The snubbing unit accumulator shall have a low-pressure warning system.

15.3.1.5 BOP Requirements for Rig-assisted Snubbing

The BOP Requirements for rig-assisted snubbing are as follows:

- Primary BOPs should be equipped with ram-savers that prevent the movement of pipe when a ram BOP is closed.
- The BOP ram shall be equipped with either ram-indicators or ram-savers to prevent or restrict the movement of pipe by the service rig when the snubbing ram is closed.
- A ram-saver device that limits the ability of the service rig to pull pipe when a BOP ram is closed should be seriously considered.
- A visual indicator that clearly indicates the position of the BOP ram(s) to the snubbing operator and driller shall be used if a ram-saver device is not used.

  Note: It is critical that the ram-savers or the indicator system be fully functional before commencing tripping operations (see 15.8.12 Tripping).

15.3.1.6 BOP Requirements for Rigless Snubbing

The BOP Requirements for rigless snubbing are as follows:

- Primary BOPs shall be equipped with either ram indicators that alert the operator to the position of the primary rams or ram-savers that prevent the movement of pipe when the ram is closed.
- The BOP ram shall be equipped with ram indicators that clearly indicate the position of the BOP ram(s) to the snubbing operator.

Note: It is critical that the ram-savers or the indicator system be fully functional before commencing tripping operations (see 15.8.12 Tripping).

15.3.1.7 Lockout Equipment

IRP A lockout system shall be in place to prevent equipment from becoming energized if there is potential for workers to be injured while they are inside the range of motion of that equipment.

IRP Snubbing service providers shall have lockout procedures on site for workers to follow.

IRP Snubbing unit components that shall have lockouts include, but are not limited to, the following:

- **Power Tongs**
- **Slip Controls**
- **Snubbing BOP Controls**
- **Jack Control**
- **Annular**

15.3.1.7.1 Power Tongs

The requirements and procedures to lockout power tongs are as follows:

- Open faced tongs shall be fitted with a gate to be closed during operation
- All tongs shall have means to eliminate hydraulic flow through the tong motor when lockout is needed.
- The lockout device shall be used during die changes and other maintenance or repair.

15.3.1.7.2 Slip Controls

The slip control panel lockout should be used when:

- The snubbing operator leaves the basket.
- Other service contractors are in the basket and the tubing string will not be moving.
- Maintenance is being performed where workers could be injured if the slips are inadvertently activated.

15.3.1.7.3 Snubbing BOP Controls

The snubbing BOP panel lockout should be used when:

- The operator leaves the basket.
- Other service contractors are in the basket and the tubing string will not be moving.
- Maintenance is being performed where workers could be injured.

15.3.1.7.4 Jack Control

Jack control shall include a mechanical or hydraulic lockout device to prevent inadvertent movement of the jack plate while workers are on or under the jack plate.

15.3.1.7.5 Annular

A lockout shall be in place to prevent the annular control from being opened unintentionally or by mistake. This lockout must provide a step before the control can be opened.

15.3.1.8 Reverse Circulation Sand Cleanout Equipment

Typical sand cleanout equipment consists of the following:

- A 15 m by 50 mm double or triple-braided hose
- An emergency shutdown (ESD) valve
- Several slim hole valves
- A tubing swivel
- A Chiksan or heavy-walled elbow

IRP All surface sand cleanout equipment shall have a working pressure equal to or greater than the bottom hole pressure.

The reverse circulation sand cleanout equipment requirements are as follows:

- Flow back lines from the tubing and the snubbing unit bleed off line shall be connected in such a way that if the upper snubbing BOP needs to be opened at any time, the snubbing stack can be bled off to zero beforehand.
    - Sources of pressure include back pressure from the test vessel or line pressure from the flowing tubing.
    - The lines shall terminate according to well owner policy or applicable jurisdictional regulation.
- All the surface equipment used for sand cleanouts shall be dedicated solely for that purpose and shall be in addition to normal rig inventory.
- The valves shall be lubricated and pressure tested after each use.

- Valves shall be sent for repair and recertification to OEM specifications when leaks are detected.
- The equipment owner should maintain a logbook to help predict when repair or replacement of valves will be needed. The log book entries should include the following:
  - Serial number for each valve
  - Date of use
  - Volume of sand flowed through the valve body
  - The working pressure the valve was exposed to
- Hose ends shall be equipped with integral crimped ends.
- Hoses will typically bubble before failing and shall be replaced, not repaired, when this occurs.
- The swivel and Chiksan should be inspected for erosion wear after each use and repaired as needed.
- All components of the sand cleanout system shall be hydraulically pressure tested to at least 10% above the maximum anticipated operating pressure (but not above the working pressure) before use.
- For reverse sand cleanouts, a remote-activated fail-close shut-off shall be installed on a valve upstream of all flow back equipment at the top of the tubing string. This device shall be function tested before use.

15.3.2 Configuration

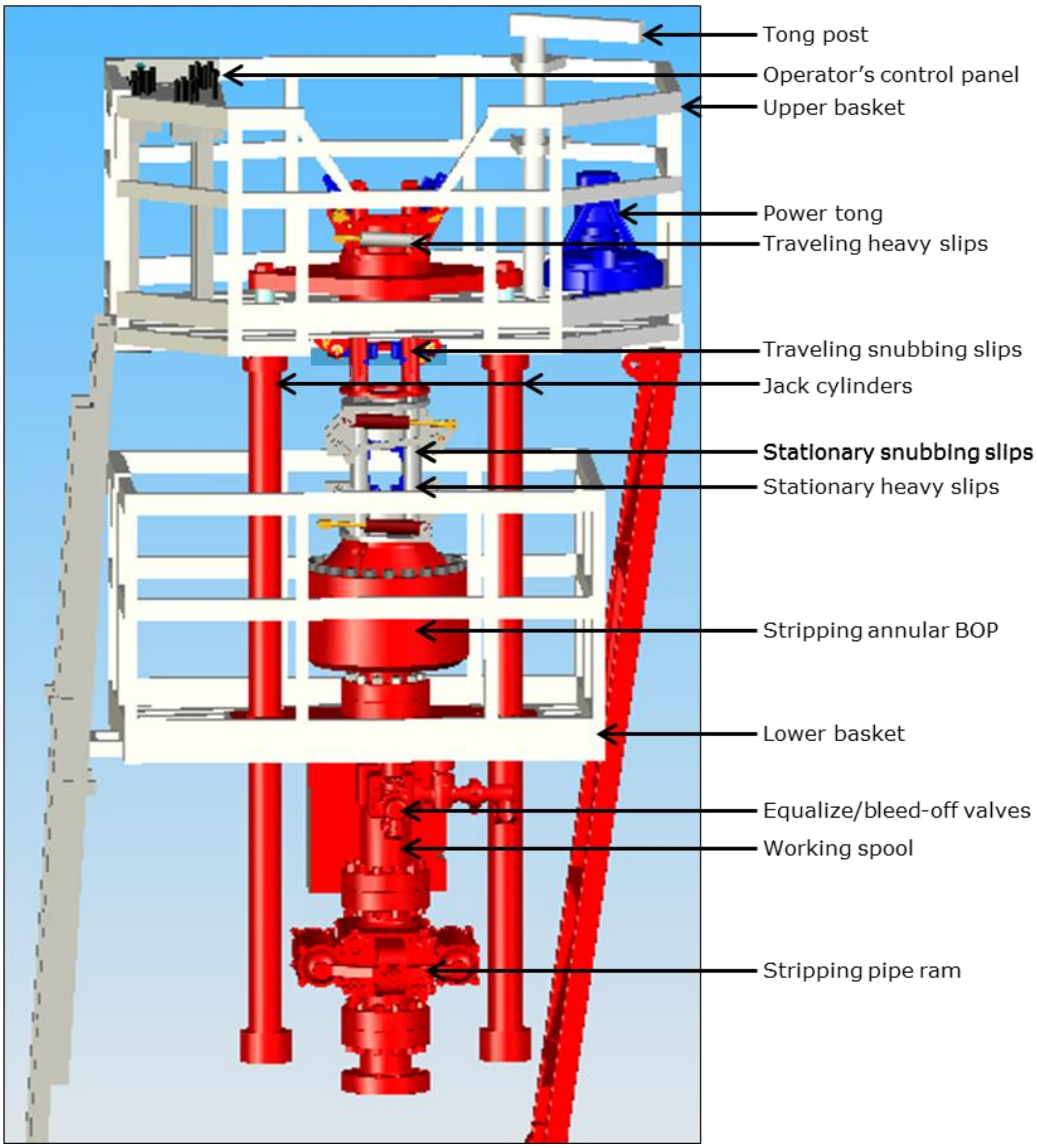
The following are general guidelines and recommendations for the configuration of surface equipment:

- All snubbing units shall be equipped with engineered fall protection and arrest devices as per applicable occupational health and safety regulations. Risk assessment, training and procedures are required for the use of egress systems.
- Careful consideration is needed when assemblies are being designed for snubbing operations. If there are odd-shaped items to be run or pulled, a spool shall be placed in the snubbing BOP assembly with sufficient length to cover the item. This spool then becomes a lubricator.
- All components exposed to the wellbore environment in sour wells must meet NACE standards.
- Double valves shall be used on critical sour wells for the snubbing unit and the bleed-off and equalize loops.
- On any well deemed critical sour or high risk, shear rams with sufficient accumulator and nitrogen back-up shall be installed in the lowest ram in the primary BOP stack. For more information see IRP 2: Completing and Servicing Critical Sour Wells.

- Diesel engines equipped with exhaust regeneration can create exhaust temperatures in excess of 1000° F. Consider securing the well when engines within 25 m (75 ft.) are regenerating. Refer to IRP 20 Well site Design Spacing Recommendations and AER Directive 37: Service Rig Inspection Manual Section 250 for more information about equipment spacing.

Although each well and snubbing operation will be unique, Figure 2 depicts a typical configuration for a snubbing unit with the components labeled for reference.

Figure 2. Typical Snubbing Configuration



15.3.3 Engineering and Design Specifications

All snubbing equipment in use must be certified by a certified professional engineer using the appropriate and applicable standards from the following:

- American National Standards Institute (ANSI)
- American Petroleum Institute (API)
- American Society of Mechanical Engineers (ASME)
- Canadian Standards Association (CSA)
- National Association of Corrosion Engineers (NACE) if the equipment will be exposed to H_2S

The certifying professional engineer will have the following:

- Previous experience or training with pressure control equipment
- Practical working knowledge of surface equipment
- Experience with general quality control standards
- Professional engineering status in the jurisdiction of practice

15.3.4 Certification and Inspection

Certificates are part of due diligence and help field personnel know the type and condition of the equipment they are using. A document with an engineer's stamp constitutes certification for equipment. A copy of the certificates shall be on site and up to date.

15.3.4.1 CAODC Recommended Practices and Certifications

IRP The equipment identified in the following CAODC recommended practices shall have certifications:

- **RP 3.0 – Service Rigs Inspection and Certification of Masts**
- **RP 3.0A – Service Rigs Inspection and Certification of Substructures, Draw works and Carriers**
- **RP 4.0 – Service Rigs Overhead Equipment Inspection and Certification**
- **RP 6.0 – Drilling Blowout Preventer Inspection and Certification**
- **RP 7.0 – Service Rigs Well Servicing Blowout Preventer Inspection and Certification**

Specific components include, but are not limited to, the following:

- Pipe rams
- Annulars

- Slip bowls
- Jack structure
- Overhead equipment including:
    - Pick-up elevators
    - Short bails
    - Overhead Slings
    - Pick-up nubbins
    - Spreader bars
    - Winch line weights (if equipped)
- Equalize lines
- Chokes
- Pancake flanges
- Hoses and piping
- Equalize hoses (if equipped)
- Fall arrest equipment (covered in OH&S, not RP's)
- Ram blocks
- Accumulator bottles
- Tubing winches (if equipped)
- Spool lifting brackets (if equipped)
- Spools (including the working spool between BOPs)

The certification schedules in the CAODC RPs and detailed below are the minimum required intervals for recertification of surface equipment and should be done more frequently if recommended by the OEM. All equipment must be maintained to manufacturer specifications.

AER Directive 037: Service Rig Inspection Manual outlines procedures and items checked by AER staff when inspecting service rigs in Alberta.

15.3.4.2 Snubbing Unit Pressure Containment Equipment

All wellbore pressure containing equipment must be hydrostatically tested to the maximum working pressure of the components every three years. Documentation must be kept with the unit and at the base of operations.

IRP Snubbing unit equipment certification shall include, but is not limited to, the equipment and recertification intervals in Table 5 Snubbing Unit Equipment Recertification Schedule.

Table 5. Snubbing Unit Equipment Recertification Schedule

Equipment	Recertification Interval
Equalize line (steel or hose)	1 Year
Calibration Interval for Critical Gauges	3 Years
Load cells	1 Year
Annular	3 Years
Bleed-off valves	3 Years
Equalize valves	3 Years
Load plate	3 Years
Ram blocks	3 Years
Rams	3 Years
Spacer spools	3 Years
Stripping heads	3 Years
T-block and/or flow cross	3 Years
Tubing safety valves	3 Years
Work spool	3 Years

15.3.4.3 Hoisting Equipment

IRP Hoisting equipment certifications shall include, but are not limited to, the following:

- **All components of the hoisting equipment must have an engineered rating sufficient for the lift.**
- **All welded components of the hoisting equipment must have an engineered rating and be non-destructive (ND) tested at the time of manufacture and at six-year intervals thereafter.**
- **Wire rope equipment must follow all wire rope manufacturer rejection criteria.**
- **Tubing transfer elevators must have an engineered rating, be certified every three years and incorporate a double latch or secondary safety lock to prevent inadvertent opening.**

IRP Hoisting equipment certification must include, but is not limited to, the equipment and recertification intervals in Table 6 Hoisting Equipment Recertification Schedule.

Table 6. Hoisting Equipment Recertification Schedule

Equipment	Recertification Interval
Slings	1 Year
Pick-up elevators	3 Years
Shackles	3 Years
Sheaves	3 Years
Elevator links	6 Years
Pick-up subs	6 Years
Rack and pinion	6 Years
Spreader bar	6 Years
Stand-up hoists	6 Years
Tong raising ram assembly	6 Years

15.3.4.4 Snubbing Unit Structure

IRP All snubbing equipment structural components shall be inspected every 24,000 hours of operation. All equipment shall have a log book of accumulated operating hours since the last Level IV Inspection. If this log book does not exist inspection frequency shall be every six calendar years.

Unit structure certification requirements include, but are not limited to, the following:

- The unit structure must have an engineered rating and all welds of load-bearing components must have an engineered weld procedure.
- All load-bearing components of the unit shall be ND tested according to the inspection schedule.
- Snubbing jack certification shall include maximum push/pull ratings and be clearly visible on the jack itself (such as a rating plate or label affixed to the unit).

Unit structure certification shall include, but is not limited to, the equipment and recertification intervals in the following table:

Table 7. Unit Structure Recertification Schedule

Equipment	Recertification Interval
Fall arrest support	6 Years
Jack cylinder	6 Years
Load plate (not part of BOP system)	6 Years
Rotary bearing assembly	6 Years
Slip bowls	6 Years
Slip windows	6 Years
Support legs and/or angle iron	6 Years
Traveling plate	6 Years
Window plate	6 Years
Load bolts and nuts	as per engineered requirement

15.3.4.5 Wellhead and Stack Stabilization Equipment

IRP Certification requirements for wellhead and stack stabilization equipment shall be as follows:

- **The certification for all stabilization systems must be specified by the design engineer and followed by the snubbing company.**
- **The recertification interval is a maximum of three years if the system contains wellbore pressure.**
- **The Recertification interval is a maximum of six years if the system does not contain wellbore pressure.**

15.3.4.6 Snubbing Unit Inspections

IRP Snubbing unit inspections must be completed after each rig-up and every seven days of operation or weekly after initial rig-up.

Refer to the Snubbing Unit Inspection checklist in Appendix D.

15.4 Equipment for Rigless Operations

The nature of rigless snubbing operations means that there are some equipment requirements that are specific to rigless operations.

15.4.1.1 Cranes and Pickers

The majority of rigless snubbing operations involve a picker or a crane to position snubbing equipment on the well (rigging up).

IRP Lifting and hoisting regulations must be considered for each province of operation.

15.4.1.2 Wellhead and Stack Stabilization

IRP All wellhead/snubbing BOP stack stabilization systems must be engineered with the following minimum parameters:

- **Maximum load rating**
- **Maximum wind speed loading to ensure stability**
- **Maximum BOP/snubbing stack heights**

These parameters must be available on site as documentation or a manufacturer data plate must be mounted on the structure.

Operating procedures shall be available and followed to ensure stabilization is maintained equally on all components of the system.

15.5 Personnel Requirements

15.5.1 Snubbing Worker Competencies

IRP Snubbing personnel should be certified under the Petroleum Competency Program (PCP) Standards of Competence for Snubbing Services.

These standards were revised effective January 1, 2006. During their implementation period, snubbing companies will begin implementing these revised standards, and oil and gas companies are advised to use personnel certified under these standards to ensure competent snubbing personnel.

Definitions related to the PCP program are listed below:

- Petroleum Competency Program: The Petroleum Human Resources Council of Canada (PHRCC) developed the PCP. This program identifies standards of competence for specific petroleum-related occupations and supports assessment of those standards. For further information see the PSAC website (Occupational Competencies – PCP Program), as well as Alberta Apprenticeship and Industry Training summary and related regulation.
- Standard of Competence: A standard of competence is a written specification of the knowledge and skills required by a worker to be applied over the range of circumstances demanded by a job.
- Snubbing Services Career Ladder and Standards of Competence: The snubbing industry has identified a ladder of six occupations for snubbing services within the context of the PCP:

    1. Assistant Operator
    2. Snubbing Operator Level 1
    3. Snubbing Operator Level 2
    4. Snubbing Operator Level 3
    5. Snubbing Supervisor Level 1
    6. Snubbing Supervisor Level 2

  Note: The snubbing industry has identified the standards of competence for each occupation identified above.

  Note: Refer to Appendix C for a chart illustrating this career ladder.

- Worker Competencies: The occupation ladder and standards of competence for the snubbing services sector provide a framework for assessing and certifying a worker's competence. In addition to these defined standards, companies will most likely have their own performance criteria and qualifications based on their particular corporate culture and strategic objectives. Companies may use different equipment and operating procedures so workers are certified in that context.

- Assessment and Certification: Individuals are certified competent in an occupation when they fulfill the requirements of the Standards of Competence for Snubbing Services combined with the ability and desire to apply those skills at an acceptable level of performance over the range of circumstances demanded by each job. Worker competence is assessed by snubbing assessors trained through the PCP. Snubbing assessors evaluate competence using a systematic approach for determining the skill levels of employees. A certificate of competence is issued only when there is clear evidence that a worker meets the Standard of Competence.

15.5.2 Training for Multiple Contractors

Snubbing operations involve non-snubbing personnel. Training requirements for non-snubbing personnel are listed below. These training requirements are in addition to applicable jurisdictional legislation and regulations.

15.5.2.1 Well site Supervisors

IRP The well site supervisor should have a clear understanding of the following:

- Snubbing calculations
- Snubbing procedures
- Equipment and personnel requirements
- Industry Recommended Practices including compliance with IRP 7: Competencies for Critical Roles in Drilling and Completion Operations
- Hazards specific to snubbing

IRP The well site supervisor should have thorough knowledge of the snubbing program and ensure all services coming on site have the required training for the equipment.

15.5.2.2 Rig and On-site Service Personnel

IRP Rig personnel and all other on-site service personnel should be trained in all applicable IRPs and industry standards and be made aware of the following:

- Hazards specific to snubbing
- Job scope
- Snubbing procedures

IRP Rig and other on-site service personnel shall be involved in development of the ERP and be aware of their roles in it.

15.5.3 Crew Management

Job scope will dictate the number and type of snubbing personnel required on location. Personnel requirements are at the discretion of the snubbing contractor.

IRP The snubbing supervisor is responsible for crew fatigue management and shall ensure work shifts are either:

1. **scheduled within the parameters of applicable legislation or**
2. **scheduled such that a shift does not extend to more than 15 hours (including crew travel) with an 8-hour rest period between shifts whichever is less.**

15.5.4 Supervision of New Workers

IRP Employees with little or no snubbing experience shall be closely supervised during all work activities.

IRP Any new workers on site shall be identified in the pre-job safety meeting and any expectations of those workers shall be outlined to all other workers on location.

IRP Supervision shall be present and instructive until workers understand and can use all information presented to them (as outlined in the common core and assistant operator occupations in the PCP Standards of Competence for Snubbing Services. See 15.1.1 Snubbing Worker Competencies above).

15.5.5 Crew Training

Additional general crew training requirements are as follows.

IRP All crew members required by jurisdiction or site owner policy to use fall protection equipment (e.g., harnesses, lifelines or lanyards) must possess fall protection certification.

IRP If a boiler that requires a certified operator is in operation, at least one person on site must possess a Special Oilfield Boiler Certificate.

Other training available for the enhancement of crew competency includes the following:

- First Line Supervisor’s Blowout Prevention
- Safety and Regulatory Awareness
- Fire extinguisher use and maintenance
- Basic firefighting

- Fluid handling/pumping duties (from CAODC Derrickhand Competency)
- Training to address AER Directive 33: Well Servicing and Completions Operations – Interim Requirement Regarding the Potential for Explosive Mixtures and Ignition in Wells

15.5.6 Rigless Snubbing

The crew requirements specific to rigless snubbing are as follows.

IRP All members of a rigless crew shall have the following minimum training and certifications:

- **H_2S Alive**
- **WHMIS**
- **Applicable Industry, Company and Site Orientations (e.g., PSCD, eGSO, online requirements)**

IRP All drivers of mobile rigless equipment shall have the following minimum training and certifications:

- **Appropriate operator's license with air endorsement where required**
- **Transportation of Dangerous Goods (TDG) training**

Note: Additional training such as General Oilfield Driver Improvement (GODI), Heavy Hauler, Hours of Service, Fatigue Management and Cargo Securement are available and may be required for drivers based on jurisdiction or operating status.

IRP The operator of a snubbing unit in a rigless application shall be competent in accordance with the PHRCC Occupational Ladder or equivalent. In addition the operator shall possess the following minimum training and certifications:

- **Blowout Prevention – Well Servicing**
- **Fall Protection for Rig Work**
- **Standard First Aid**

IRP The operator of a crane or well head boom truck shall meet the training requirements of the jurisdiction.

IRP The supervisor of a rigless snubbing operation shall be competent in accordance with the PHRCC Occupational Ladder or equivalent. In addition the supervisor shall possess the following minimum training and certifications:

- **Blowout Prevention – Well Servicing**
- **Fall Protection for Rig Work**
- **Standard First Aid**

IRP At least one crew member of a rigless operation shall possess the following training and certifications or equivalent:

- **Detection and Control of Flammable Substances**
- **Fall Rescue for Rig Work**

IRP All crane or picker operators must hold a certification either as an apprentice/journeyman Wellhead Boom Truck operator or NCCCO Crane Operator.

Review the CAODC SRCP: Derrickhand Manual for pumping and fluid handling requirements.

15.6 Hazard Assessments

Snubbing contractors shall refer to the following resources for hazard assessment:

- The hazard information in 15.6.2 Hazards below.
- Task Analyses or Job Procedures (JSAs)
- PSAC Snubbing Pre-Job Safety Meeting Report and Snubbing Hazard Assessment

15.6.1 Procedures

IRP The snubbing contractor shall take the following actions during hazard assessment:

- **Discuss the job scope with all on-site personnel**
- **Identify hazards**
- **Assign risk factors to each hazard**
- **Discuss hazard control measures with on-site personnel**

IRP For any deviation from the job scope the snubbing contractor shall take the following actions:

- **Stop all operations**
- **Complete a new hazard assessment**
- **Re-evaluate personnel requirements**

IRP The well site supervisor must ensure that all the personnel on location participate in, and document their involvement in, the hazard assessment (as applicable to the job scope and their role).

15.6.2 Hazards

Some of the industry recognized hazards that present considerable risk to workers during live well operations are identified in Table 8. The column for likelihood in this register is used as follows:

- Almost Certain – Event is expected to occur if no controls/mitigations in place
- Likely – Event will probably occur if no controls/mitigations in place
- Moderate – Event should occur if no controls/mitigations in place
- Unlikely - Event could occur at some time if no controls/mitigations in place

Table 8. Hazard Register

Hazard Scenario	Consequence	Likely-hood	Risk Rank	Required Safeguards and Considerations for Control / Mitigation
1. Inability of worker to safely egress from above the rig/work floor in emergency situations (see 15.8.11 Snubbing with Personnel in the Derrick or on the Tubular Racking Board).	Harm to personnel	Moderate	High	1. For any work requiring workers to be positioned in the derrick or on the tubular racking board follow the guidelines outlined in 15.8.11 Snubbing with Personnel in the Derrick or on the Tubular Racking Board. 2. Employment of an auto-mechanical pipe handler / pipe racking system.
2. Uncontrolled flow up the tubing/work string due to loss of integrity of a plug and/or tubing/work string	Harm to personnel	Moderate	High	See 15.2.1 Wireline Practices and Procedures
3. Uncontrolled flow up the annulus through the BOP stack due to loss of stripping element/device integrity: • Pulling into closed pipe rams • Pulling into closed snubbing slips • Exceeding tensile or compressive (buckling) loading of the tubing/work string • Excessive wear to and/or fluid compatibility deterioration of stripping element(s).	Harm to personnel Environmental damage Asset damage	Moderate	High	1. Ram saver with a) visual alarms or b) throttle interrupt connected to the rig throttle that interrupts the rig throttle when the snubbing rams are closed. Note: This system shall also be “fail safe” so any malfunction activates the alarms and throttle interrupt. 2. Ram saver on primary rams. 3. Slip lockout for snubbing slips when tripping out pipe heavy that does not interfere with the operator’s ability to close all slips in an emergency. 4. Jack pressure adjust in the basket 5. Documented snub force calculations 6. Follow Appendix J: Pipe Buckling Forces (Petro-Canada) 7. Implementation of a stripping element/device servicing procedure with an enforced “no leak” policy. 8. Conduct fluid compatibility tests with stripping elements and primary BOP elements prior to well site operations.
4. Uncontrolled release of projectiles up tubing / work string and annulus. Projectiles including:	Harm to personnel	Moderate	High	1. Slip interlock device which prevents one set of slips from opening until the other has been closed.

Hazard Scenario	Consequence	Likely-hood	Risk Rank	Required Safeguards and Considerations for Control / Mitigation
• Launched tubing • Plug and/or prong release • Hydrates				2. See 15.2.1 Wireline Practices and Procedures
5. Fire and explosion of well hydrocarbon.	Harm to personnel Environmental damage Asset damage	Unlikely	High	Consider displacement of well over to an inert gas or fluid.
6. Inadequate communication between service rig driller and snubbing unit operator	Harm to personnel	Almost Certain	High	1. Familiarization trials shall be conducted to verify adequate communication protocols and competencies. 2. Written rig floor work instructions and procedures required.
7. Pressure release from wellbore	Harm to personnel Environmental damage Asset damage	Almost Certain	High	1. Live well operations inherently have positive pressure at surface in the wellbore, thus all equipment pressure ratings shall be in accordance with this IRP. 2. Consider flowing of the well to relieve pressures to a more manageable / controllable level and/or to eliminate pipe light scenarios.

Additional hazards to consider are as follows:

- Damaged or corroded tubing, profiles or other BHAs
- Severe hydrate problems
- Sand production
- Presence of scales such as iron sulphides
- Extreme hydrogen sulphide concentrations
- Volatile or corrosive reservoir fluids
- Extreme pressure
- Explosive mixtures in downhole and surface equipment
- Incomplete lockout of adjacent surface equipment including cathodic protection, flow line, electrical supplies, pilot lights, engines without kill switches, etc.
- Complex BHAs that cannot be snubbed safely due to varying diameters or excessive lengths
- Extreme weather conditions
- Simultaneous Operations and adjacent well activity

15.7 Joint Safety Meetings

15.7.1 Scheduling

The purpose of the Joint Safety Meeting is to familiarize all personnel involved with snubbing operations, snubbing program and safety procedures. The importance of teamwork and communication should be emphasized. The well site supervisor should coordinate multiple contractors on site.

IRP Joint safety meetings shall be held and documented before starting a job.

IRP Additional meetings shall be held and documented in the following situations:

- When new services arrive on location to perform work
- When the scope of work or program changes
- When there is a change in well conditions (e.g., hydrates, pressure fluctuations, etc.)
- When there is a near miss or a hazard identified

Note: The contractor shift change during extended-hour operations is considered a change in operations so a joint safety meeting is required. The agenda must include a complete debriefing and communication regarding any hazards encountered in the previous shift.

15.7.2 Agenda

IRP Safety meeting topics shall include, but are not limited to, the following:

- **Procedure review and risk assessment (discussed between the snubbing contractor, well site supervisor and all other services on site).**
- **Specific safety and operational requirements.**
- **Personnel and equipment evaluation and selection.**
- **Supervisory control of the well pertaining to pipe movement and functioning of surface equipment (see 15.1.12 Supervisory Control).**
- **Well shut-in procedures, responsibilities and egress.**
- **Communication procedures for operations (e.g., hand signals, radios, etc.).**
- **Supervision of inexperienced personnel during operations (see 15.5.4 Supervision of New Workers).**

IRP The PSAC Snubbing Pre-job Safety Meeting Report and Snubbing Hazard Assessment provide an extensive topic list that shall be used as a guide for safety meetings.

15.7.3 Guidelines for Effective Meetings

IRP Each service supervisor shall ensure his personnel understand the scope of the job and what was discussed at the joint safety meeting

The following are guidelines for holding effective joint safety meetings:

- Involve all personnel to ensure active participation
- Rotate chairperson duty should among competent supervisors
- Ensure clear communication among meeting participants
- Requested feedback or perform tests to evaluate understanding

15.8 Operational Practices and Procedures

The following practices and procedures are recommended as a reference for creating safe operating procedures. The practices and procedures are based on incident reviews and typical operational practices and procedures used in industry.

IRP Each snubbing contractor must have a customized version of these basic practices and procedures, specific to their equipment and job at hand, for review in the pre-job safety meeting.

15.8.1 Well Designation Verification

IRP The well designation shall be verified by the crew on location to ensure it is the same as the original program (job scope). Equipment and/or personnel changes shall be made to accommodate any differences from the original program.

Refer to the following for additional information:

- 15.1 Snubbing Program
- 15.2 Downhole Equipment
- 15.3 Surface Equipment
- 15.4 Equipment for Rigless Operations
- 15.5 Personnel Requirements

15.8.2 Pre-Job Calculation Verification

IRP The following calculations shall be verified as appropriate to the job scope before starting operations:

- **Pressure**
- **Volume**
- **Pipe-buckling**

The information in Appendix I: Allowable Tensile Loads (Petro-Canada) and Appendix J: Pipe-Buckling Forces (Petro-Canada) can be used for this purpose.

IRP The well site supervisor should be consulted to confirm or reassess operations if the results of the verified calculations differ from the original program.

15.8.3 Emergency Egress Systems

Conduct a proper assessment of emergency egress systems. Requirements may vary for rig-assisted and rigless snubbing operations and by jurisdiction.

Consider the following minimum requirements for emergency egress systems for any location over three metres high:

- There is unimpeded access to the system (example being a clear path, safe reaching distance, no obstructions, etc.).
- A fall protection system is in place where a fall of three metres or greater may occur when accessing and using the egress system.
- A written fall protection plan is implemented when the height of the working platform is greater than 7.5 metres from ground level.
- The egress system allows all workers to escape in a safe and timely manner.
- An injured or incapacitated worker can safely use the egress system.
- The egress system is installed, regularly inspected and maintained according to manufacturer's specifications.
- The operation of the egress system is not adversely affected by environmental factors (e.g., ice, snow, dust, dirt, etc.) or wellbore affluent.
- All workers are competent in the use of the egress system.

IRP The egress system must adhere to local jurisdictional regulations.

15.8.4 Pressure Testing

15.8.4.1 General Pressure Testing Guidelines

IRP All primary well control equipment must be pressure tested as per regulations in the applicable jurisdiction.

IRP Pressure testing and pump operation shall be the responsibility of the service rig crew in rig-assist operations and the responsibility of the rigless crew in rigless operations.

IRP Pressure testing must be conducted and documented weekly, upon initial rig-up and any time after a seal, gasket or flange has been compromised.

IRP A safe means of pressure testing snubbing equipment shall be in place.

If there is a tubing hangar landed and/or a full-opening valve installed:

1. Perform a 10 minute low pressure test to 1,400 KPA.
2. Perform a 10 minute high pressure test to the lesser of the bottom hole or wellhead pressure rating.

Perform a 10-minute leak test to the wellbore shut-in pressure if there is no tubing hanger landed and/or no full opening valve is installed.

IRP When H_2S is at surface, daily pressure testing shall be performed before commencing work.

See IRP 2: Completing and Servicing Critical Sour Wells for detailed guidance on pressure testing for critical sour wells.

15.8.4.2 Preheat and Pressure Testing Guidelines for 10,000 psi BOPs

The 10,000 psi BOPs are used for rigless snubbing operations.

The following definitions from ANSI Specification for Drill-through Equipment/API Specification 16A apply to these units:

- Minimum Temperature: The lowest ambient temperature to which the equipment may be subjected.
- Maximum Temperature: The highest temperature of the fluid that may flow through the equipment.
- Shaffer Nitrile Packing Element temperature range: 4 °C to 77 °C (40 °F to 170 °F).

The following guidelines apply to pressure testing of 10,000 psi BOPs:

- Overhead equipment utilized for assembly of BOP on test stump requires Engineered Load Ratings.
- Accumulator manufacturer's recommended minimum operating temperature should be posted on accumulator.
- The accumulator volume calculations shall be performed in accordance with the manufacturer's specifications and the BOP specifications.
- As per AER Directive 037 Service Rig Inspection Manual Section 225, Class III BOP, Accumulator and Recharge Pump Check:
    - Record accumulator pressure.
    - Install test joint in test stump. (Spherical preventer or pipe ram preventer mechanical and pressure tests must be conducted with pipe in the BOP).
    - Shut down accumulator charge pump.
    - Close pipe rams.
    - Open pipe rams.
    - Close spherical preventer.

    - Record accumulator pressure.
    - Accumulator must be capable of providing, without recharging, fluid of sufficient volume & pressure to effect full closure of all preventers and retain a pressure of 8400 KPA on the accumulator system.

- As per AER Directive 037 Service Rig Inspection Manual Section 225, BOP Mechanical Test, Spherical closing time is 60 seconds. Closing time for Ram Preventers is 30 seconds.
- API Specification 16A states that the test fluid must be within the temperature ratings of the manufacturers written specifications.
- AER Directive 037 Service Rig Inspection Manual Section 260 (8.147)/IRP 2 Completing and Servicing Critical Sour Wells say: BOP equipment shall be fully assembled and tested prior to installation on the well. Each blowout preventer, the connection between the BOP and the wellhead, the safety valve, the bleed–off manifold and the bleed-off and kill lines shall be pressure tested for 10 minutes each to 1400 kPa low and to the working pressure of the BOP's or the formation pressure, whichever is less.

15.8.5 Contingency Practices and Procedures

Modern snubbing systems use known equipment and technology to reduce the potential for equipment failure. Snubbing systems have unique abilities to retain well control in case of equipment malfunction. Possible failures and recommended practices and procedures to address the failure are identified below.

15.8.5.1 Power Pack Failure

IRP The following steps should be followed to address power pack failure:

1. In the pipe heavy condition, if possible, position tubing at snubbing basket level and set slips as required. In the pipe light condition set slips as required.
2. Close and lock all available BOPs.
3. Install a stabbing valve in the open position then tighten and close the valve.
4. Evacuate and evaluate the situation.
5. Repair equipment to the original standard before resuming operations.

15.8.5.2 Snubbing Unit Accumulator Failure

Failure of the snubbing unit accumulator can result in failure of the secondary BOP system (including the stripping pipe rams and annular and, on most units, the hydraulically operated bleed-off and equalizing valves).

IRP Snubbing units should be equipped with nitrogen back-up systems designed so to allow the operator to maintain temporary well control in the event of accumulator failure.

Examples of accumulator failures include the following:

- Hydraulic pump failure
- Hydraulic/wellbore annular seal failure
- Accumulator bottle failure
- Hose or piping failure

IRP The accumulator low-pressure warning system shall function as follows to prevent incidents:

- **The system shall be function tested and deemed operational before any snubbing operations start.**
- **All warning lights shall be visible and audible alarms must be loud enough to be heard by equipment operators.**
- **The existence and purpose of this system shall be discussed in the presence of all personnel on site during the pre-job safety meeting.**

IRP The following steps shall be followed to address snubbing unit accumulator system failure:

1. **Close and lock the appropriate primary BOP and casing valves to ensure annulus is secure.**
2. **If the position of tubing or the BHA will not allow closure of the primary BOP or complete shut-off, manually close and lock snubbing pipe rams.**
3. **Position the tubing connection at working level in the snubbing unit basket if possible.**
4. **Install a stabbing valve into the tubing in the open position then tighten and close the valve.**
5. **Set slips as required and pull tension into stationary snubbing slips. Use mechanical slip locks.**
6. **Bleed off pressure in the snubbing stack above the primary BOP (including equalize line).**
7. **Assess the situation with all on-site personnel to ensure well securement before attempting any repairs.**

15.8.5.3 Slip Failure

IRP The following steps shall be followed to address slip failure:

1. **Close alternative slips immediately.**
2. **Evaluate the situation.**
3. **Close all available pipe rams.**
4. **Bleed off pressure in the stack; do not open the annular.**
5. **Install and close a stabbing valve in the tubing.**
6. **Repair, clean and replace slip dies and/or service the slips as required.**
7. **Test the load-supporting ability of the slip.**
8. **Inspect other slips for slip die conditions and repair as necessary.**
9. **Inspect the tubing for damage before resuming operations.**

15.8.5.4 Annular Seal Failure

IRP The following steps shall be followed to address annular seal failure:

1. **Close all pipe rams.**
2. **Bleed off pressure in the stack.**
3. **Position the tubing connection at working level.**
4. **Secure the wellbore.**
5. **Replace and repair annular seals as needed.**

15.8.6 Snubbing in the Dark

Sufficient lighting from enough angles to minimize shadows around active equipment and personnel is critical to safe night operations. As a guide, the immediate vicinity of the wellhead and active snubbing equipment including the stationary and traveling slips should be illuminated to approximately 50 lux. Operator panels should receive approximately 100 lux.

15.8.7 Weather Restrictions

Inclement weather (e.g., excessive wind, rain, snow, heat or cold) affects the safe operation of equipment and personnel. Weather is considered inclement when it impedes operators or prevents equipment from functioning at full capacity.

The final decision to continue or shut down is at the discretion of the supervisors on site. The decision should be made after consultation with operations management. Guidelines are listed below.

15.8.7.1 Equipment Restrictions

IRP The following guidelines and recommendations shall be considered for weather restrictions for equipment:

- **Tubing shall be ice and snow free before tripping begins.**
- **Upon moving onto location and rigging up, snubbing equipment shall be brought up to operating temperature before snubbing operations proceed.**
- **Sufficient heat and winterization shall be applied**
  1. **to all well control equipment so the equipment can operate as per manufacturer specifications and as per the requirements of the regulatory jurisdiction and**
  2. **to maintain BOP body temperature above –10 °C at all times when well control equipment is installed on the wellhead. This includes overnight when the BOPs are closed and locked.**
- **Snubbing unit hydraulics and engines need to be kept warm enough to maintain operating efficiency to prevent problems such as cavitating pumps, insufficient flows and pressures and BOP failures.**
- **Slips shall be free of ice and able to function properly.**
- **Manufacturer specifications shall be followed regarding the effects of temperature on equipment structural performance and capacity.**
- **Extra equipment may be required in order to continue operations (e.g., boilers, heaters, pre-fabs, tarps and electric BOP blankets).**

15.8.7.2 Personnel Protection

IRP The following guidelines and recommendations shall be considered for weather restrictions for personnel:

- **All warm-weather work shall be done in accordance with the safe work practices described in Appendix G: Heat Stress Quick Card from OSHA. Take into account the compounding effect of heat from weather, equipment and physical activity**
- **All cold-weather work shall be done in accordance with the charts on equivalent wind-chill temperatures and exposure consequences listed in Appendix H: Cold Weather Exposure Chart – ACGIH.**
- **Crews shall be protected against frostbite and should watch one another for signs of frostbite.**
- **Additional crew members may be needed to rotate duties.**
- **Respiratory equipment must be suitable for cold weather operations and be checked for efficiency.**
- **Personal Protective Equipment (PPE) must be suitable to the weather (e.g., wind guards, face guards, tarps and shelter covers).**

15.8.8 Arriving on Location and Rigging Up

IRP The following steps should be followed when arriving on location and rigging up:

1. Park the unit off location.
2. Change into proper PPE.
3. Introduce crews to all service company representatives and the rig manager. Verify snubbing qualifications.
4. Review the well program, including hazard assessment, and the timing to move the unit on site and rig up. Ensure proper lockouts have been done on equipment that could affect the operation.
5. Confirm that a snubbing equipment inspection has been completed within the last seven days. See Appendix D for the Snubbing Unit Inspection Checklist or Appendix E for a semi-annual inspection checklist.
6. Hold a pre-job safety meeting with all on-site personnel as per the PSAC Snubbing Pre-job Safety Meeting Report and Snubbing Hazard Assessment.
7. Ensure one person is responsible for coordinating rigging up and rigging out of equipment.
8. Ensure that all conflicting tasks are suspended during the rigging up/out of the snubbing unit.
9. Back the unit up to the wellhead using a guide. Guides should be competent snubbing operators or supervisors. For information on guiding refer to Energy Safety Canada's Workers' Guide to Hand Signals for Directing Vehicles.
10. Ensure emergency (maxi) brakes are applied and wheels are chock blocked.
11. Ensure equipment is grounded as per applicable jurisdiction regulations (see Appendix F: Electrical Grounding and Bonding for Service Rigs).
12. Engage the unit to hydraulic mode.
13. Prepare to hoist.
14. Clean and inspect BOP ring grooves and install correct ring gasket.
15. Clear area of all non-essential personnel.
16. Pick up the unit and lower it onto the primary BOP.
17. Tighten flange bolts.
18. Ensure equipment is spaced according to regulations.
19. Rig in auxiliary equipment.
20. Use extreme caution if snubbing power tongs need to be rigged up using the winch line or sand line. One person shall be assigned the task of operating controls.

15.8.9 Setting Jack Pressure

IRP The following steps shall be followed for setting Jack Pressure:

1. **Calculate the snub force versus buckling calculation for use in Step 8 (see 15.1.8 Pre-Job Calculations, Appendix I: Allowable Tensile Loads (Petro-Canada) and Appendix J: Pipe Buckling Forces (Petro-Canada).**
2. **Lower the BHA into the snubbing stack.**
3. **Close both sets of snubbing slips and pull into stationary snubbing slips with traveling heavy slips.**
4. **Close the annular and equalize the stack.**
5. **Unlock and open blind rams.**
6. **Lubricate the annular element, reposition the traveling plate for a short stroke and close the traveling snubbing slips.**
7. **Dial the jack pressure to zero and increase throttle to full capacity.**
8. **Push the jack controller to full "DOWN" and increase jack pressure until the pipe begins to snub. Do not exceed the snub force calculations from step one.**
9. **Snub using short strokes until the complete BHA is below the casing bowl.**
10. **Increase jack pressure as required to allow tubing couplings to be snubbed through the snubbing annular.**
11. **Decrease jack pressure as string weight increases and less snub force is required.**

15.8.10 Purging the Snubbing Stack

IRP Each snubbing company shall ensure that an effective plan is in place to purge their specific configuration of snubbing stack.

The following is a sample procedure:

1. Secure the BHA in the snubbing stack with slips and annular.
2. Close the equalize and bleed-off valves.
3. Open the casing valve to the equalize valve.
4. Check for leaks.
5. Equalize the stack slowly to 500 KPA.
6. Check for leaks.
7. Close the equalize valve.
8. Bleed off the stack slowly through the bleed-off valve.
9. Re-equalize the stack slowly to 500 KPA.
10. Close the equalize valve.

11. Bleed off the stack slowly through the bleed-off valve.
12. Equalize the stack slowly to full working pressure.
13. Check for leaks.
14. Remove the winch line from the BHA.
15. Unlock and open the blind rams or CSO valve.
16. Begin snubbing-in operation.

15.8.11 Rig-Assisted Snubbing with Personnel in the Derrick or on the Tubular Racking Board

There is risk of serious injury to any personnel positioned in the derrick or on the tubular racking board during rig-assisted snubbing operations if any of the safety precautions and recommendations of this IRP are not followed. It is the joint responsibility of the prime contractor, service rig company and snubbing service provider to ensure safety.

IRP If personnel are to be positioned in the derrick or on the tubular racking board during rig-assisted snubbing operations the following shall be completed before commencing operations:

- **Risk assessment of the operations under current conditions.**
- **Verification of all conditions outlined in the Service Rig/Rig Assist Snubbing Criteria Checklist in Appendix L (i.e., Primary BOPs, Egress Systems, Ram Savers, Slip Interlock, Tubing Isolation and Tubing Integrity).**
- **Verification that there are no hydrocarbons present at surface.**
- **Verification that the tubular racking board has a rear egress system in place that does not require the worker to disconnect from the primary fall arrest equipment used during rig assist tripping operations.**
- **Preparation and verification of a written agreement identifying responsibilities and liabilities with documented approval by the prime contractor, service rig company and snubbing service provider representatives to perform the operation.**
- **A safety meeting to review and discuss the safety procedures (e.g., egress systems, the other IRPs and conditions noted in this section, etc.).**
- **Confirmation of the workers' understanding of the safety meeting and associated hazards with documentation of the understanding in the Tour Sheets.**

IRP Any work requiring personnel positioned in the derrick or on the tubular racking board shall be conducted with a dual barrier in place.

IRP Workers shall only be positioned in the derrick or on the tubular racking board when there are no hydrocarbons present at surface via the use of

some form of surface hydrocarbon mitigating mechanism (e.g., surface blanket of fluid or inert gas).

IRP No workers shall be positioned in the derrick or on the tubular racking board when the tubing is pipe light.

IRP No workers shall be positioned in the derrick or on the tubular racking board when stripping rams are required to stage tubing in/out of the well.

Seed Appendix L for a sample checklist that prime contractors, rig companies and snubbing service providers can use to verify all of the necessary safety precautions and equipment required to perform this operation safely. See 15.1.3 Risk Assessment and 15.6 Hazard Assessments for risk and hazard information.

Note: WorkSafeBC does not accept positioning of personnel in the derrick or on the tubular racking board during rig assisted snubbing operations even where the foregoing IRPs have been undertaken. When working in BC prime contractors, rig companies and snubbing service providers should be aware of this restriction.

15.8.12 Tripping

IRP Tripping practices shall be as follows:

- **Develop procedures that clearly outline the responsibilities for work done by employees of multiple service companies.**
- **Use intrinsically safe communications technology to compensate for visual obstructions and noise.**
- **Use confirmation and repeat back communication methods between key operators (after first confirming hand signals between operators).**
- **To prevent potential incidents, stop movement of the tubing string or BHAs before**
  - **any worker climbs up or down the snubbing unit ladder,**
  - **any worker enters or exits the snubbing work floor or**
  - **any service rig/drilling rig workers who climb up or down the derrick ladder.**
- **Discuss a safe trip speed with the driller before the tubing is tripped in or out of the well.**
- **Function test the ram saver, throttle control and ram position indicator lights before all tripping operations. If the system does not function properly all tripping operations shall be stopped until the system is fixed.**
- **Well pressures will determine if the collars have to be staged in or out using the snubbing unit pipe rams and annular, or two sets of snubbing rams for higher pressure wells. Most snubbing work is done with external**

upset end (EUE) tubing. Guidelines for staging couplings through the stack using an annular as the upper BOP are as follows:

- **60.3 mm EUE at more than 13,800 KPA and less than 21,000 KPA**
- **73.0 mm EUE at more than 12,250 KPA and less than 21,000 KPA**
- **88.9 mm EUE at more than 4,000 KPA and less than 21,000 KPA**
- **A stripping pipe ram shall be used as the upper BOP at pressures above 21,000 KPA**

- **Pull or lower the first collar slowly through the annular at the start of the trip and after any breaks.**
- **Ensure the driller has a good visual of the snubbing unit heavy slips. Tarps should be positioned so they do not interfere with the driller's line of sight.**
- **Avoid picking up tubing over the snubbing operator's panel.**

IRP Tripping procedures shall be as follows:

1. **Maintain effective communications at all times.**
2. **Read and record well pressures.**
3. **Conduct safety meetings and hazard assessments with all personnel on site. Discuss methods for handling tubing (e.g. picking up tubing, etc.) and required procedures in case of plug loss/leaking.**
4. **Calculate lift on tubing string and set jack pressure as per pre-job calculations.**
5. **Purge the snubbing stack (see 15.8.10 Purging the Snubbing Stack).**
6. **Make up the BHA with a close stabbing valve in the top and place it in the stack.**
7. **Close and set the snubbing slips.**
8. **Equalize with wellbore pressure.**
9. **Add oil to the top of the annular element to reduce friction.**
10. **Set annular closing pressure to ensure ease of pipe movement and wellbore pressure control. Annular surge bottle pressure should be at 2,500 KPA (350 psi).**
11. **Snub the BHA in slowly through the BOP stack and wellhead, making sure to use the proper length of stroke to protect tubing from buckling (see Appendix J: Pipe Buckling Forces (Petro-Canada) for more information).**
12. **With the BHA snubbed in, pick up the next joint of tubing and make the connection. Snub in slowly. Continue to snub in at a safe and steady pace until the number of joints is close to pipe neutral. Refer to lift calculations performed at the beginning of the job. Test for pipe heavy frequently.**

IRP Tripping procedures using the rig blocks shall be as follows:

1. **Once the tubing string is pipe heavy, adjust jack pressure for pushing collars through the annular.**
2. **The driller shall run the tubing at a safe and steady speed that will allow the snubbing operator sufficient time to open and close the slips and will not put the snubbing crew in danger due to the blocks entering the snubbing basket.**

15.8.13 Landing and Snubbing the Tubing Hanger

IRP The snubbing supervisor and well owner company representative shall ensure tubing hanger lock-down screws are fully engaged and a pull test is completed before bleeding off pressure above.

15.8.13.1 Snubbing the Tubing Hanger with no Tailpipe

IRP Procedures for snubbing the tubing hanger into the well with no tailpipe shall be as follows:

- **Before a tubing hanger is landed in the pipe light stage, a call shall be made to the snubbing contractor's management team to inform them of the situation.**
- **If the tubing hanger is to be snubbed in or out of the well when pipe light, measurements and care should be taken to position the seal(s) of the hanger in a ram cavity or fluted spool when equalizing or bleeding off the stack**

15.8.13.2 Snubbing in the Tubing Hanger While Pipe Light

Practices for snubbing in the tubing hanger while pipe light shall be as follows:

- Follow a procedure that minimizes the chance of the hanger sealing off. Closely monitor the snub force and lift force gauges while bleeding off or equalizing slowly.
- If the tubing hanger is to be snubbed into the well with no tailpipe, contain well pressure with a plug at or below the hanger; not with a closed valve on top of the landing joint.
- Take the following actions when equalizing and/or bleeding off the snubbing stack with the tubing hanger (or any tool which could seal in the stack) contained between preventers:
  - Position the jack plate as low as possible and set the jack brake.
  - Ensure that the traveling snubbing and heavy slips are closed and the stationary snubbing slips are open.
  - If the tubing hanger (or any tool which could seal in the stack) has no tailpipe and the blind rams are closed and locked, do not open the annular after the stack has been bled off if either the snub force or lift force gauge does not read zero.

15.8.13.3 Snubbing in the Tubing Hanger with Typical PIPE HEAVY Method

The typical method for snubbing in the tubing hanger while pipe heavy is as follows:

1. Break the coupling off the last joint to be run below the tubing hanger.
2. Measure the distance from the lag screws on the casing bowl to the top of the slips on the snubbing unit. On higher pressure or square seal hangers, measure from the centre of the snubbing pipe ram cavity to slip top as well.
3. Screw and snug the stabbing valve into the top of the landing joint with pipe wrenches. Leave open.
4. Apply pipe dope to the pin end of the landing joint and screw into the top of the hanger.
5. Tighten landing joint with a pipe wrench.
6. Pick out of the slips with the blocks and stop.
7. Raise the jack plate over top of the tubing hanger.
8. Lower the hangar and stop just above the stationary slips.
9. Lower the jack plate and stop just above the top of the hanger.
10. Close the traveling snubbing slips to guide the hanger through the stationary slips and stop before tagging the annular top.

15.8.13.4 Snubbing in the Tubing Hanger with the Low Pressure Method

The typical method for snubbing in the tubing hanger with low pressure (less than 10 MPA surface) is as follows:

1. Close the snubbing pipe rams, bleed off the stack and open the annular.
2. Lower the hanger through the annular and close the annular to centre it as it is lowering into the stack. Read and record the string weight so it can be referred to later on.
3. Follow method a or b:

   Method (a): Raise the string until the hanger tags the bottom of the annular element and drop down approximately 15 cm. Stop.

   Method (b): Lower the string until the bottom of hanger is sitting with approximately one daN of weight on top of the snubbing pipe rams. Stop.
4. Confirm the string weight. Close the traveling snubbing slips and ask the driller to monitor the weight indicator and let the snubbing operator know immediately if anything changes.
5. Open the equalize valve just enough to allow the stack to be equalized very slowly. Watch the snub force gauge in case of increase
6. Follow method a or b:

   Method (a): Open the snubbing pipe rams and land the hanger.

Method (b): Tell the driller to pick up to string weight. Open the snubbing pipe rams and land the hanger, leaving the equalize valve in the open position

7. Push down with approximately 4,545 daN (10,000 lb. force) on the landing joint with the jack.
8. Have the rig crew tighten in the lag screws as per manufacturer specifications and when finished, close in the casing valve to the equalize line.
9. Bleed off the stack slowly. Stop halfway and monitor for two minutes for buildup. If pressure remains constant, bleed off to zero.
10. Before opening the annular, have the rig crew check the working spool to ensure the hanger seals are holding.
11. If pressure remains zero, open the annular and traveling snubbing slips, and break out/lay down the landing joint. Close and lock the blind rams.

15.8.13.5 Snubbing in the Tubing Hanger with the High Pressure or Wellbore Full of Fluid Method

The typical method for snubbing in the tubing hanger with high pressure (greater than 10 MPA surface) or a wellbore full of fluid is as follows:

1. Close the rig annular and bleed off the stack.
2. Open the annular and lower tubing string to position the hanger element in the snubbing pipe ram cavity.
3. Confirm the string weight. Close the traveling snubbing slips and ask the driller to monitor the weight indicator and let the snubbing operator know immediately if anything changes.
4. Equalize in 3,500 KPA increments and maintain good communication with the driller about the status of the string weight.
5. Watch the snub force and lift force gauges for increase. If there is increase reposition the tubing hanger as follows:
    - Lower the tubing string if there is an increase in snub force.
    - Raise the tubing string if an increase in lift force.
6. Once equalized, open the rig annular and land the hanger, leaving the equalize valve in the open position.
7. Push down with approximately 4,545 daN (10,000 lb. force) on the landing joint with the jack.
8. Have the rig crew tighten in the lag screws as per manufacturer specifications and when finished, close in the casing valve to the equalize line.
9. Perform pull test.
10. Bleed off the stack in 3,500 KPA increments. Monitor for build up for two minutes at each increment.

11. Before opening the annular, have the rig crew check the working spool to ensure the hanger seals are holding.
12. If pressure remains zero, open the annular and traveling snubbing slips and break out/lay down the landing joint. Close and lock the blind rams.

15.8.14 Removing the Tubing Hanger

The process for removing the tubing hanger is as follows:

1. Install the landing joint, close and load the traveling snubbing slips and pressure test.
2. Mark the landing joint at the top of the stationary slips (because they never move and during Step 3 the mark at the traveling snubbing slips will not be visible). Measure from the lag screws to the centre of the snubbing pipe ram cavity.
3. Push down with approximately 4,545 daN (10,000 lb. force) on the landing joint with the jack.
4. Equalize the stack to pressure below the hanger with wellbore effluent.
5. Unscrew the lag screws.

For **low pressure** proceed as follows for steps 6, 7 and 8:

6. Open the travelling snubbing slips and hoist the tubing string to tag the annular lightly. Stop and lower string approximately 15 cm.
7. Close the travelling snubbing slips and snubbing pipe rams.
8. Bleed off the stack to half the working pressure while having the driller monitor the weight indicator and snubbing operator monitor the snub force gauge.

For **high pressure** proceed as follows for steps 6, 7 and 8:

6. Open the travelling snubbing slips and hoist the tubing string to the snubbing pipe ram cavity using the measurement from Step 2.
7. Close the travelling snubbing slips and rig annular.
8. Bleed off the stack in 3,500 KPA increments while having the driller monitor the weight indicator and snubbing operator monitor the snub force gauge.

For **both high and low pressure** proceed as follows:

9. Once the stack has bled off and weight/force has not changed, open annular and traveling snubbing slips.
10. Raise jack plate above anticipated connection height and close traveling heavy slips.
11. Hoist string and once hanger has cleared the annular element, close the annular to center as it comes through the slips.
12. Once the hangar is at the connection height, open traveling heavy slips and lower jack plate over hanger.

13. Bottom out jack plate and close traveling heavy slips. Set string weight in traveling heavy slips.
14. Break out/lay down the tubing hanger and landing joint and replace with tubing coupling. Torque to manufacturer specifications.
15. For **low pressure**: Equalize the stack, open the pipe rams and continue tripping out of the hole.

    For **high pressure**: Equalize the stack, open the annular and continue tripping out of the hole.

15.8.15 Rigging Up on a Substructure

There are two major procedural differences between rigging up on a rig with a substructure and on a rig without:

1. Hoisting the unit to the work floor
2. Securing to the well

Hoisting the snubbing unit to the work floor may require extra equipment depending on the height of the substructure and the surrounding areas. On a short substructure where the unit can be spotted beside the V-door, extra slings may be all that are needed. On a high substructure or on a location where the unit cannot get positioned close to the floor, a crane or large picker will be needed to transfer the unit from the truck to the rig blocks at floor level.

Rig configurations vary. A site-specific procedure, including a hazard assessment, shall be developed with the involvement of all supervisors and operators on site.

IRP The following measurements and calculations should be completed before hoisting the unit to the work floor:

- Distance from the top flange of the uppermost rig BOP to the top of the work floor. A spacer spool will be needed to keep the bottom flange of the snubbing unit stripping pipe rams above the work floor.
- Distances in all directions from well centre and between the floor and any support in the derrick that may interfere with the snubbing unit and working platforms. These measurements should be taken before the unit is dispatched to aid operations management in unit selection.
- Potential string weight and wellhead load rating. A load displacement device may be needed to transfer string weight from the wellhead to the substructure.
- Derrick height and crown room for lifting sling length and selection.
- V-door dimensions including height from the catwalk to the work floor and distance from well centre to V-door on work floor. A lay-down machine or other auxiliary equipment may be required to facilitate safe, effective pipe handling.

The following is a sample procedure to use a guideline for hoisting the unit to the work floor:

1. Spot the unit and crane in positions where the crane operator will be able to lift the unit from the truck deck to the work floor.
2. Detach hoses and any other equipment from the unit to the truck.
3. Inspect all hoisting equipment including tags and certifications.
4. Install all rigging equipment to ensure safety and effectiveness. Do not use the snubbing unit lifting equipment at this time.
5. Clear all unnecessary personnel from the area. Instruct other workers to watch for line snags.
6. Raise the unit to the work floor.
7. Attach the snubbing unit lifting equipment to the rig blocks.
8. Transfer the unit weight from the crane to the rig blocks.
9. Unhook the crane when safe to do so.
10. Bolt down the unit and secure in the derrick.

15.8.16 Stripping Snubbing Unit On Over Existing Tubing Stump with no Tubing Hanger Landed

If a snubbing unit needs to be rigged up when there is a tubing string in the well, and it is not possible to land a tubing hanger, the unit may need to be stripped on over the existing tubing stump.

This can be done in either a pipe light or pipe heavy situation as long as the tubing is properly secured in the BOPs.

IRP A hazard assessment must be completed before beginning any stripping-on operation to address the following:

- **Tubing count**
- **Tubing weight**
- **Tubing tensile and buckling strengths**
- **Wellbore pressure**
- **Wellbore effluent (fluid or gas)**
- **Tubing plug requirements**
- **Other options**

Stripping-on risk can be significantly reduced with proper planning. Auxiliary equipment such as a hanger flange can be brought to location before the unit arrives and installed above the BOPs to replace the slips securing the tubing. Once the hanger flange is in place, the tubing string may be able to be moved to a safe working height if the string is pipe heavy. The unit can then be rigged up onto the hanger flange safely and easily.

Other equipment that may be provided by the snubbing contractor includes, but is not limited to, the following:

- Slings and hoisting devices
- C-plate for protecting slips and BOP ring grooves

Different contractors will have different procedures for their style of equipment and training. Dispatch personnel should be notified if the unit will need to be stripped on before it is dispatched so that any additional equipment or supervision requirements can be addressed.

15.8.17 Lubricating In

The process for lubricating in is as follows:

1. Remove snubbing equipment above the annular.
2. Space out BHA and place a locating pup on top. The locating pup should be long enough to locate the bottom coupling below the pipe rams to be used for securing and for the top coupling to be accessible above the annular.
3. Rig in wireline equipment and the BHA to be lubricated in (see 15.2.1 Wireline Practices and Procedures for plug requirements).
4. Purge and pressure test the lubricator assembly and equalize from the ground to full wellbore pressure.
5. Check that pressures above and below the closed ram is equal and then open the ram.
6. Lower and locate pup into the pipe rams (or whichever equipment is to be used for securing the assembly in the stack).
7. Close and lock the pipe rams.
8. Perform pull test with wireline to ensure the BHA is secured.
9. Bleed off pressure above the rams and monitor. If there is no pressure build-up in three to five minutes then close the annular. Rig out the wireline equipment. Install and close the stabbing valve. Rig in the snubbing equipment.
10. If pressure does not bleed off, refer to the lubricating-out procedure and start again (see 15.8.18 Lubricating Out).

Auxiliary equipment such as a hang-off flange or slip rams may be used for securing the BHA.

15.8.18 Lubricating Out

The process for lubricating out is as follows:

1. Locate and secure tubulars above the BHA in sealing and securing devices (e.g. snubbing pipe ram, slip rams or hang-off flange).
2. Bleed off the snubbing stack and close the snubbing annular.
3. Rig out the snubbing equipment above the snubbing annular and rig in wireline equipment.
4. Purge and pressure test the lubricator assembly and equalize from the ground to full wellbore pressure.
5. Ensure that the snubbing annular is open.
6. Open the securing device and raise the BHA above the blind rams or full-opening valve.
7. Close and lock the blind rams or close the full-opening valve.
8. Bleed off the lubricator and snubbing stack.
9. Resume operations.

15.8.19 Picking up Tubing

IRP All elevators used in pipe movement shall be double-latching elevators. Single latching elevators with an effective safety pin as the second safety device are also acceptable.

15.8.19.1 Pipe Light

The process for picking up tubing in a pipe light situation is as follows:

1. Latch the pick-up elevators as per manufacturer specifications on the joint to be hoisted.
2. Raise the joint to the snubbing basket and continue raising the joint until it is high enough for the connection to be made.
3. Repeat from Step 1 for each piece of tubing.

15.8.19.2 Pipe Heavy

The process for picking up tubing in a pipe heavy situation is as follows:

1. Latch the pick-up elevators as per manufacturer specifications on the joint to be hoisted.
2. Raise the joint to the snubbing basket and secure on the catwalk so it does not slide back and out of the basket.
3. Latch the rig elevators and raise the tubing from resting on the snubbing basket.

4. Lower the pick-up elevators to the catwalk and continue raising the joint until it is high enough for the connection to be made.
5. Repeat from Step 1 for each piece of tubing.

15.8.20 Laying Down Tubing

IRP **All elevators used in pipe movement shall be double-latching elevators. Single latching elevators with an effective safety pin as the second safety device are also acceptable.**

Note: Typical methods for laying down tubing are noted below. Other methods to handle tubing exist and their procedures may vary accordingly.

15.8.20.1 Pipe Light

The process for laying down tubing in a pipe light situation is as follows:

1. Latch the pick-up elevators as per manufacturer specifications onto the joint and install the safety pin.
2. Break the connection and lower the joint to the catwalk.
3. Raise the pick-up elevators to an agreed-upon working height for the worker in the snubbing basket to latch.

15.8.20.2 Pipe Heavy

The process for laying down tubing in a pipe heavy situation is as follows:

1. Break the connection with the power tongs and lower the tubing with the rig blocks.
2. Latch the pick-up elevators as per manufacturer specifications, install the safety pin and guide the pin end of the joint to the V-door (if the snubbing unit is equipped with a V-door).
3. Ensure the tubing is secured on the catwalk.
4. Transfer the tubing from the rig elevators to the pick-up elevators.
5. Ensure the worker tailing out the joint keeps it clear of the edge of the snubbing basket before the winch operator starts to lower the joint.
6. Lower the joint in the pick-up elevators to the ground and unlatch the pick-up elevators.
7. Latch the rig elevators onto the joint in the slips and hoist to the next connection.
8. Raise the pick-up elevators to an agreed-upon working height for the worker in the snubbing basket to latch when repeating Step 2.

15.8.21Snubbing BHA

IRP Proper stack configuration shall be confirmed when the BHA is to be snubbed.

IRP A properly sized safety valve must be in place and closed on top of the BHA when the BHA is to be snubbed.

15.8.22 Staging Couplings or Tool Joints

15.8.22.1 Practices for Staging Couplings or Tool Joints

IRP Recommended practices for staging couplings or tool joints shall include, but are not limited to, the following:

- Consistently inject methanol into the equalizing line.
- Develop a procedure for locating coupling position before closing the lower stripping ram. For example:
  - Marking the drill line
  - Picking a point of reference in the derrick
  - Counting jack strokes
- Ensure ram position indicators are visible and functioning properly before beginning staging operations.
- Choke equalize and bleed-off lines to minimize stress on flow equipment.
- Perform, at minimum, daily visual inspections of stripping BOP equipment.
- Set the BOP closing pressure to the minimum required for an effective seal to minimize wear on stripping ram fronts.

IRP The following practices shall be implemented when tubing couplings are staged:

- **Develop procedures to clearly outline the responsibilities for work done by employees of multiple service companies**
- **Use intrinsically safe communications technology to compensate for visual obstructions and noise.**
- **Use confirmation and repeat back communication methods between key operators (after first confirming hand signals between operators).**

15.8.22.2 External Upset End Tubing

Most snubbing work is done with external upset end (EUE) tubing. Pressure guidelines for staging couplings through the stack using an annular as the upper BOP are as follows:

- 60.3 mm EUE at more than 13,800 KPA and less than 21,000 KPA
- 73.0 mm EUE at more than 12,250 KPA and less than 21,000 KPA
- 88.9 mm EUE at more than 4,000 KPA and less than 21,000 KPA.
- A ram to ram staging kit at pressures above 21,000 KPA

15.8.22.3 Procedure for Staging Tubing Couplings in Well

Procedures for staging tubing couplings in a well are as follows:

1. Position the coupling above the upper stripping BOP.
2. Stop pipe movement.
3. Close the lower stripping BOP.
4. Bleed off between stripping BOPs.
5. Open the upper stripping BOP (not necessary if upper stripping BOP is annular).
6. Position the coupling below the upper stripping BOP.
7. Stop pipe movement.
8. Close the upper stripping BOP.
9. Equalize the pressure above and below the lower stripping BOP.
10. Open the lower stripping BOP.
11. Repeat from Step 1 for each tubing coupling.

See 15.3.1 Requirements for additional information about BOP requirements.

15.8.22.4 Procedure for Staging Tubing Couplings Out of Well

Procedures for staging tubing couplings out of a well are as follows:

1. Close the upper stripping BOP.
2. Position the coupling above the lower stripping BOP.
3. Stop pipe movement.
4. Close the lower stripping BOP.
5. Bleed off between stripping BOPs.
6. Open the upper stripping BOP (not necessary if the upper stripping BOP is annular).
7. Position the coupling above the upper stripping BOP.
8. Stop pipe movement.

9. Close the upper stripping BOP.
10. Equalize the pressure above and below the lower stripping BOP.
11. Open the lower stripping BOP.
12. Repeat from Step 1 for each tubing coupling.

15.8.23 Reverse Circulation Sand Cleanouts

IRP The following practices for reverse circulation sand cleanouts shall be followed:

- **Flow back lines from the tubing and the snubbing unit bleed off line need to be rigged-in in such a way that if the upper snubbing BOP needs to be opened at any time, the snubbing stack can be bled off to zero before opening the upper snubbing BOP.**
    - **Sources of pressure include back pressure from the test vessel or line pressure from the flowing tubing.**
    - **The lines must terminate according to well operator policy or applicable jurisdictional regulation.**
- **Sand cleanouts must not be done before sunrise or after sunset.**
- **A remote-actuated emergency shut-off system shall be in place for all sand cleanouts.**
- **Under no circumstances shall personnel participate in an air cleanout.**
- **If forward-circulation sand cleanouts are being considered, take appropriate measures to protect the primary and secondary BOP equipment and other surface equipment from erosion and plugging.**
- **Reverse circulation should not be conducted before sunrise or after sunset should. If deemed necessary, refer to 15.8.6 Snubbing in the Dark above for lighting information.**

IRP The following procedure for reverse circulation sand cleanouts shall be followed:

1. **Discuss wellbore details (e.g. sand top, perforation interval, etc.) with the well site supervisor.**
2. **Ensure appropriate equipment is available (e.g. proper number of valves, slim hole equipment, kelly hose, flow back equipment, emergency shut-in device, etc.) as detailed in 15.3.1.8 Reverse Circulation Sand Cleanout Equipment.**
3. **Install the stabbing valve and position pipe at a safe working height to start equalizing and wireline operations.**
4. **Remove the blanking plug or open the downhole valve.**

5. **Start flow/valve staging operations.**

15.8.24 Securing and Un-securing the Well

Whenever the well is being readied for work again and the snubbing slips and annular have been closed, the snubbing stack shall be bled off and opened to atmosphere before releasing the snubbing slips.

15.8.24.1 Supervision

IRP All on-site supervisors involved in the operation (well site supervisor, snubbing supervisor, rig manager, etc.) shall be present at the wellhead to verify the opening and closing of BOPs during securing and unsecuring.

15.8.24.2 Situations Where Securing Is Required

IRP For all well classes, all appropriate primary rams shall be locked from the time they were closed until the start of the next operation that requires them to be opened again.

IRP Access ports below the primary means of securement shall be used to check pressure before the primary rams are opened.

The following are some examples of when securing is necessary:

- For rigging up/out of snubbing equipment.
- Between trips and breaks.
- For overnight shut-ins.
- Whenever rams are closed to do any work on the BOPs or to rig in/out other services (e.g. wireline, coiled tubing, etc.).
- The primary rams shall be locked any time the integrity of the snubbing/secondary BOP stack is broken (e.g., to change over, for maintenance, etc.).

15.8.24.3 Overnight Shut-Ins

IRP Overnight shut-in operations shall be as follows:

- **Plan operations so that at the end of the day operations are pipe heavy or out of the hole.**
- **Dual mechanical barriers shall be used for annulus and tubing pressure control during shut-ins. Examples of adequate dual barriers are listed below:**
    - **Tubing hanger and pipe or blind ram combination in pipe heavy situations**

  - **Tandem pipe rams**
  - **Blinds and tubing/pipe ram combination**
  - **Blinds and orbit/gate valves**

- **Close and cap all wellhead valves**
- **Lock all rams and close and cap all bleed off and equalize valves. When two sets of rams are being used for annulus securement, access ports shall be used that will allow trapped pressure between rams to be identified before opening during unsecured operations.**
- **Suspend daily operations in a pipe heavy situation with the tubing hanger landed for wells containing wellbore effluent damaging to sealing components (e.g. carbon dioxide, hydrogen sulphide, fracturing oil, condensate, etc.).**

Note: A nightcap installed and closed on a closed safety valve is an adequate tubing barrier shut-in.

15.8.24.4 Well Securement Practices

There are three aspects of well control during snubbing operations:

1. Securing the tubing string from uncontrolled movement.
2. Controlling flow through the tubing.
3. Controlling the flow outside the tubing in the annulus.

Well securement procedures for all three involve redundancy and the ability to monitor for change.

IRP Well securement practices shall be as follows:

- **Tubing string movement should be secured using at least three sets of slips, two of which are inverted (called snubbing slips) to control upward force acting on the tubing string.**
  - **When the well is secured both sets of snubbing slips and one set of conventional (heavy slips) should be closed and all shall be locked.**
  - **Calculate whether the string is light or heavy before resuming operations after the well has been shut in. The calculations shall be confirmed correct with operating procedures before any slips are unlocked and functioned.**
- **Tubing flow while tripping shall be controlled with the use of downhole barriers such as tubing blanking plugs, floats or valves.**
  - **When tripping operations are stopped a working valve shall be installed at surface and closed.**

- **For prolonged shut-ins (such as overnight) the valve must be night capped with a ported plug/valve assembly.**
- **The tubing pressure shall be checked at the valve in the nightcap before resuming operations.**
- **The working valve shall remain installed in the tubing string for the initial pipe movement to assist with regaining well control if the plug lets go or begins to leak.**

- **Annulus control shall be maintained through the use of the stripping pipe rams and annular on the snubbing unit using the primary BOPs and gate or orbit valve (if available).**
    - **When operations are suspended with tubing in the hole (e.g. coffee breaks, changing rams, or servicing equipment) the annulus shall be shut in with the primary pipe rams (closed and locked), the snubbing unit stripping pipe rams (closed and locked) and annular (closed).**
    - **Pressure shall be bled off between all three BOPs.**
    - **For overnight shut-in all pipe rams shall be closed and locked but the snubbing annular shall be left open.**
    - **To complete well securement the casing valve to the equalize line must be closed, bled off and capped.**

15.8.24.5 Resuming Operations After the Well Has Been Secured

IRP The pressure build up between BOPs shall be checked to ensure BOPS have not leaked prior to resuming operations after shut in.

IRP Before opening any BOP

1. **the pressure above shall be equalized to the pressure below,**
2. **there shall be at least one set of snubbing slips and one set of heavy slips closed and**
3. **the snubbing annular shall be closed before the pipe rams are opened.**

IRP Senior snubbing personnel and the rig manager shall visually confirm that all rams are in the correct position and ram position indicators are fully functional before pipe movement is resumed.

IRP Senior snubbing personnel and the rig manager shall be at the wellhead to verify the opening and closing of BOPs and snubbing BHAs and during any rigging in and rigging out of other services and equipment.

15.8.25 Laying Down Snubbing Unit

IRP The procedures for laying down the snubbing unit shall be as follows:

1. **Ensure that one person is responsible for coordinating rigging up and rigging out of equipment.**
2. **Back the unit up to the wellhead using a guide. Guides should be competent snubbing operators or supervisors. For information on guiding refer to Energy Safety Canada's Workers' Guide to Hand Signals for Directing Vehicles.**
3. **Ensure the emergency (maxi) brakes are applied and wheels are chocked.**
4. **Re-engage the unit to hydraulic mode.**
5. **Inspect all lifting equipment before lifting.**
6. **Hook the hoisting device to pick up the sling and pull tension.**
7. **Rig out all support equipment.**
8. **Break out flange bolts and pick up the unit.**
9. **Attach the winch if applicable and lay down the unit on the truck.**
10. **Rig out the remaining equipment and prepare it for travel.**
11. **Move the snubbing truck away from the wellhead using a guide. Guides should be competent snubbing operators or supervisors.**
12. **Secure the equipment for traveling as per cargo Department of Transportation (DOT) securement regulations.**

Appendix A: Revision History

Table 9. Revision History

Edition	Sanction Date	Scheduled Review Date	Remarks / Changes
1	November 2003	2008	IRP 15 was initially sanctioned and published in November 2003
2	June 2007	2012	A review of IRP 15 began in April 2005, when industry stakeholders expressed interest in addressing how snubbing activities or equipment may have had a role in a number of recent upstream petroleum workplace incidents. This second edition of IRP 15 takes into account the content of the original document, but has been redeveloped completely
2.1	September 2011	2012	A review of the IRP was deemed necessary to clarify recertification schedule to match CAODC RP 3.0 and 4.0 as referenced in 1st Edition of IRP 15. Review and revise the document to address gaps introduced by new technology in industry (Rig Assist vs Self Contained Equipment). IRP statements were revised in order to adopt standardized range of obligation terminology.
3	September 2013		Additional development of the IRP was deemed necessary in order to address revised emergency egress system requirements and requirements unique to rigless snubbing operations. Formatting and text updated to match Style Guide.

<table>
<tr><th>Edition</th><th>Sanction Date</th><th>Scheduled Review Date</th><th>Remarks / Changes</th></tr>
<tr><td>4</td><td>2020</td><td>2025</td><td>Limited scope review modifications to allow personnel in the derrick or on the tubular racking board during snubbing operations:
15.1.9.3 Surface Fires and Explosions updated bullet 3 on displacement to include fluid or other inert product.
15.6.2 Hazards updated to include SimOps and adjacent well activity in the list of hazards to consider.
15.8.3 Egress Systems updated to add clarification that egress systems differ for rigless and rig-assisted snubbing operations and by jurisdiction. Add IRP that regulatory adherence is mandatory.
15.8.11 Rig-Assisted Snubbing with Personnel in the Derrick or on the Tubular Racking Board revised to allow under specific conditions.
Added Appendix L with the checklist for snubbing with personnel in the Derrick or on the tubular racking board
Formatting updates to bring up to current style guide and other fixes:
Updated DACC disclaimer
bring figure and table numbering to DACC style guide.
IRP must and shall updated to bold bulleted lists.
Fixes to hyperlinks.
Update Enform to Energy Safety Canada.
Update reference in 15.5.6 from Enform Derrickhand Competency guide to CAODC SRCP: Derrickhand Manual.</td></tr>
</table>

Appendix B: Sample Job Information / Dispatch Sheet

Date Call was Taken:		Call Taken by:	
Oil Company:		Company Rep:	
Location:		Contact #s:	
Area:			

Unit #: ________ Crew: ________________________ Job Status: ☐ Pending ☐ Confirmed

Required date and time on location: at

Rig Name and #:				Derrict Type:	☐ Single	☐ Double	☐ Triple
BOP Class:	☐ I	☐ II	☐ III	Derrick Height:	Ft	Substructure?	
Pressure Rating:	☐ 14 mpa	☐ 21 mpa	☐ 35 mpa	BOP Connection:	☐ R-45	☐ R-46	

Tubing Size:	mm	Tubing Type:		Depth:	m	Casing Size:	mm
Tubing Position:	☐ Catwalk	☐ Derrick	☐ Wellbore	Make-Up Torque:		Lb/ft	

Surface Pressure:	kPa	☐ Sweet	☐ Sour %	☐ Nitrogen	☐ CO_2
B.H. Pressure:	kPa	Fluid in Tubing?	Fluid in Casing?	Type:	
Tubing Plug Details:					

(BHP < 30,000 kPa: single plug and slip stop; Sour Wells and /or BHP > 30,000 kPa: dual plugs and slip stops)

Job Scope:

BHA Components	
Length	Description

Equipment Required:

☐ Tubing End Plug	______ mm	☐ Wireline Plug	______
☐ Lubricating Spool	______ m	☐ Short Elevator Bails	______ m
☐ Clean Out Kit	______ mm	☐ Hanger Flange	______ m
☐ High Torque Power Tongs	______	☐ Other:	______

Directions:

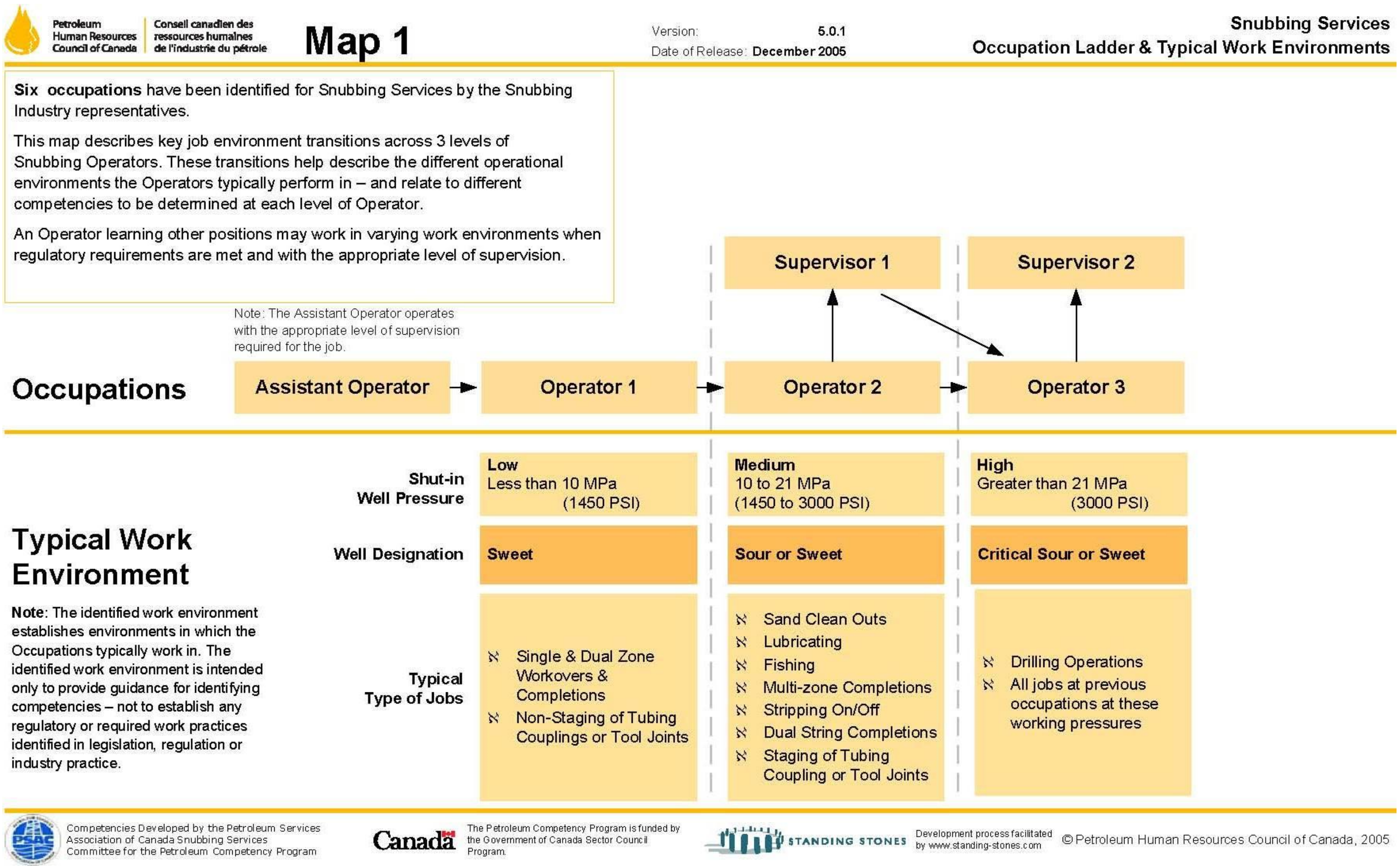
Accommodations:

☐ Home

☐ Hotel ______

☐ Camp ______

Appendix C: Snubbing Services: Map 1 – Occupational Ladder and Typical Work Environments



Appendix D: Snubbing Unit Inspection Checklist

Note: Each company is responsible for ensuring its checklist is adequate for its own equipment.

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

Snubbing Services

Snubbing Unit Inspection Checklist

Date:	Unit #:	Snubbing Unit Supervisor:

Oil & Gas Company + LSD:	Oil & Gas Company Rep:
Sweet or Sour Location:	Concentration:

Wellhead / BOP / Snubbing Equipment Measurements:

Snubbing Unit		m	Drilling Rig KB-GL:		m
		m	Drilling Rig KB-CF:		m
		m	Drilling Rig KB-THF:		m
		m	Snubbing Unit KB-GL:		m
		m	Snubbing Unit KB-CF:		m
		m	Snubbing Unit KB-THF:		m
		m	DRKB-SUKB Difference:		m
		m	Wellhead Ratings		
		m	Master Valve Turns to Open:		
		m	Casing Valve Turns to Open:		
Total Stack Height:		m	Tubing Hanger Lag Screws		Out
			Tubing Hanger Lag Screws		In

Inspection Details:

	Snubbing Jack	Y/N	Pass	Fail
1	All guards in place *			
2	Matting *			
3	Support jacks properly matted, locked and leveled			
4	Anchor chains properly rated *			
5	Anchor chains properly secured and tightened			
6	Anchor chain boomers *			
7	Handrailings in place on all walkways, work platforms and stairs			
8	Condition of handrails			
9	Toe plates installed on work floor handrails			
10	Housekeeping on work floor			
11	Condition of stairs from workfloor to ground			
12	Condition of snubbing basket access ladder			
13	Snubbing basket emergency egress system installed *			
14	Snubbing basket control panel clean *			
15	Control panel gauges functional *			
16	Hydraulic control lock-out devices in place *			
17	Emergency Engine Air kill in place			
18	Emergency Engine Air Kill functioned from snubbing basket			
19	Operator controls properly marked			
20	Snubbing and heavy slip assemblies *			
21	Jackplate rotary bearing *			
22	Jackplate rotary drive system *			
23	Rotary drive table lock present *			
24	Basket winch *			
25	Condition of winchline and safety hook			
26	Power tong raising ram *			
27	Power tongs *			
28	Hydraulic lock-out for power tong door present*			
29	Power tong back-up slings and chains present *			
30	Tong hoses, gauges and hydraulic fittings *			
31	Remote accumulator controls present *			
32	Primary BOPs function tested from remote and wellhead position			
33	Condition of snubbing jack main hydraulic power supply hoses			
34	Emergency Air Horn functioning properly?			
35	Primary Ram Saver Installed and Functioning			
36	Slip Interlock System installed and functioning?			

Comments / Explanations:

	Power Unit	Y/N	Pass	Fail
37	All guards in place *			
38	Handrailings in place where required			
39	Equipment free of leaks			
40	Hydraulic oil tank level			
41	Hydraulic tank is vented			
42	Hydraulic system control valves			
43	Housekeeping in and around truck			
44	Hand tools - clean and properly stored *			
45	Emergency Engine Air Kill in place			
46	Air kill function tested at power unit			
47	Engine exhaust outlet 7m away from well			
48	Secondary accumulator and BOP function tests completed			
49	Engine RPM at full throttle		RPM	

Comments / Explanations:

	Crane Truck	Y/N	Pass	Fail
50	Crane log books and inspection in place per juristiction			
51	Emergency Engine Air Kill in place			
52	Air kill function tested from drivers seat			
53	Engine exhaust outlet 7 m away from well			

Comments / Explanations:

	Electrical	Y/N	Pass	Fail
54	Proper grounding / bonding for all equipment			
55	Light bulbs enclosed with vapour proof and shatter-proof covers			
56	Light switches vapour proof			
57	All cords and ends *			
58	Electric motors within 8.5 m radius are explosion proof			
59	Proper clearance from power lines			

Comments / Explanations:

Inspection Details:

	Primary Blowout Preventer System	Y/N	Pass	Fail
60	Primary BOPs Installed:			
	Blind rams			
	Pipe Rams			
	Annular			
	Other			
61	All studs, nuts and bolts used in BOP stack			
62	Condition of rubber elements			
63	Fire sheathed hoses present and used within 7 m of wellhead			
64	Condition of fire sheathed hoses			
65	High pressure BOP lines identified			
66	BOP lines protected in crossing area			
67	BOPs adequately heated			
68	Safety valve with proper size and type of connection in place			
69	Safety valve closing wrench accessible			
70	Wellhead stabilizer properly matted			
71	Condition of stabilizer access stairs / ladders			
72	Stabilizer Handrails in place			
Comments / Explanations:				

	Primary Accumulator System	Y/N	Pass	Fail
73	Primary accumulator and BOP function tests completed			
74	Accumulator controls *			
75	Accumulator gauges *			
76	Controls and gauges properly labeled			
77	Accumulator information tag present			
78	Accumulator operating pressure			KPA
79	Accumulator manifold pressure			KPA
80	Nitrogen back-up system pressure			KPA
81	N_2 Working Pressure			
	Bottle #1			KPA
	Bottle #2			KPA
	Bottle #3			KPA
	Bottle #4			KPA
	Bottle #5			KPA
	Bottle #6			KPA
	Bottle #7			KPA
	Bottle #8			KPA
Comments / Explanations:				

	Pump and tank	Y/N	Pass	Fail
82	Condition of pump line and unions			
83	Pump line laid out and secured			
84	High pressure pump lines identified			
85	Kill line attached to well			
86	Pump manifold *			
87	Wellhead piping / valves *			
88	Pressure relief valve properly sized and rated			
89	Pressure relief valve set at or below rated system working pressure			KPA
90	Relief valve discharge properly fastened and vented			
91	Check valve in place on pump discharge			
92	Condition of kelly hoses			
93	Emergency Engine Air Kill in place *			
94	Air kill function tested			
95	Operators controls properly labeled			
96	Wind direction indicator			
97	All guards in place *			
98	Visual Inspection for leaks			
Comments / Explanations:				

	Health and Safety	Y/N	Pass	Fail
99	Occupational Health and Safety manual for appropriate jurisdiction on site			
100	Proper BOP regulations on site			
101	Clothing policy in place			
102	Hardhats in use			
103	Safety boots in use			
104	Protective clothing in use			
105	Protective eyewear / face protection in use			
106	Hearing protection in place			
107	Fire Extinguishers - Minimum 4 - 13.6kg			
108	Fire extinguishers *			
109	First Aid kit in place and adequately stocked			
110	First Aid Record book in place			
111	Eyewash station *			
112	High angle rescue kit			
113	Stretcher and basket *			
114	Emergency blanket in place			
115	Tube type H_2S detector in place			
116	Detector *			
117	H_2S detector tubes in place			
118	Gas detection monitors *			
119	SCBA bottles *			
120	Spare SCBA bottles in place and full			
121	Date of hydrostatic test on bottles			
	Bottle #1			
	Bottle #2			
	Bottle #3			
	Bottle #4			
	Bottle #5			
	Bottle #6			
	Bottle #7			
	Bottle #8			
122	Lease signage			
	No Smoking / Designated Smoking Area			
	H_2S Area			
	No Admittance without authorization			
123	Equipment Certifications up to date			
124	MSDS current and available			
Comments / Explanations:				

	Doghouse	Y/N	Pass	Fail
125	Doghouse properly matted and leveled			
126	Housekeeping around doghouse			
127	All equipment free of leaks			
128	Condition of catwalk and stairs			
129	Handrails and toe plates in use			
Comments / Explanations:				

	Environmental	Y/N	Pass	Fail
130	All equipment free of leakage - if no, are leaks properly contained			
131	Site free of material that may cause a fire hazard			
132	All trash cleaned up and properly disposed			
133	All waste disposed of as per ERCB guidelines			
Comments / Explanations:				

	Catwalk / Pipe racks	Y/N	Pass	Fail
134	Catwalk properly matted and leveled			
135	Pipe rack properly matted and leveled			
136	Pipe rack adjusting cylinders locked			
137	Condition of catwalk			
138	Condition of access stairs			
139	Clear egress at far end of catwalk (opposite wellhead)			
Comments / Explanations:				

Appendix E: Semi-Annual Snubbing Equipment Inspection Checklist

Note: Each company is responsible for ensuring its checklist is adequate for its own equipment.

SAFETY		Accept	Replace	Repair
Lockouts	tong	☐	☐	☐
	slip bank	☐	☐	☐
	BOP bank	☐	☐	☐
	jack handle	☐	☐	☐
	annular	☐	☐	☐
Safety Belts	one per man	☐	☐	☐
	inspected	☐	☐	☐
Fall Arrest system	cable	☐	☐	☐
	cable grab	☐	☐	☐
Wheel chock blocks		☐	☐	☐
Labels on all controls	legible	☐	☐	☐
	correct	☐	☐	☐
Emergency Air Shutoffs	basket	☐	☐	☐
	truck	☐	☐	☐
Escape poles	min.18 meters total	☐	☐	☐
	connectors	☐	☐	☐
	condition	☐	☐	☐
	ground stands	☐	☐	☐
Fire Extinguisher	Cab secured	☐	☐	☐
	certified	☐	☐	☐
	Truck secured	☐	☐	☐
	certified	☐	☐	☐
First Aid Kit	class II	☐	☐	☐
	inventory list	☐	☐	☐
	stocked to list	☐	☐	☐
PPE	CSA boots	☐	☐	☐
	hard hats	☐	☐	☐
	safety glasses	☐	☐	☐
	hearing protection	☐	☐	☐
	rain gear	☐	☐	☐
Safety pin in P/U elevators		☐	☐	☐
Two way radios		☐	☐	☐
Safety documentation		☐	☐	☐

TRUCK			Accept	Replace	Repair
Vehicle Document Book	Registration		☐	☐	☐
	Insurance		☐	☐	☐
	Safety Fitness cert		☐	☐	☐
	CVI report/sticker		☐	☐	☐
	Spec sheet		☐	☐	☐
	Maintenance book		☐	☐	☐
	Pretrip Safety		☐	☐	☐
	Log books		☐	☐	☐
	Exemption permit		☐	☐	☐
	Pre/post handbook		☐	☐	☐
IFTA sticker			☐	☐	☐
Triangle reflector kit			☐	☐	☐
Tire condition	even wear		☐	☐	☐
Tire pressures front		______	______	______	☐ ______
rear		______ ______ ______	☐ ______	☐ ______	☐ ______
Tire chains	size		☐	☐	☐
	condition		☐	☐	☐
Engine RPM at full throttle in basket			______	______	RPM
Lights			☐	☐	☐
Windows			☐	☐	☐
Windshield wipers			☐	☐	☐
Mirrors			☐	☐	☐
Horns	air		☐	☐	☐
	electric		☐	☐	☐
Gauges			☐	☐	☐
Brake Push rod travel			☐	☐	☐
Free from leakage	fuel		☐	☐	☐
	oil		☐	☐	☐
	air		☐	☐	☐
	air operating pressure		______	______	PSI
Load securement	jack tie downs		☐	☐	☐
	spools, hoses etc		☐	☐	☐
Boomers and shackles			☐	☐	☐

SNUBBING JACK COMPONENTS		Accept	Replace	Repair
Pipe rams	ram blocks	☐	☐	☐
	fronts and inserts	☐	☐	☐
	bore surface	☐	☐	☐
	ram indicator system	☐	☐	☐
Equalize & bleed off valves		☐	☐	☐
Equalize line	working valves	☐	☐	☐
	safety sling sleeves	☐	☐	☐
Annular BOP	visually inspect element	☐	☐	☐
	spare element available	☐	☐	☐
Tongs	directional pin	☐	☐	☐
	dies and blocks	☐	☐	☐
	brake band	☐	☐	☐
	external hardware	☐	☐	☐
	slings and ram	☐	☐	☐
Cylinders	pressure test	☐	☐	☐
	sealing surfaces	☐	☐	☐
Heavy and snubbing slips	Operating pressure	__________		PSI
(Identify any slips which have ***deficiencies*** *in the blanks provided)*				
________________ *slips*	bushings	☐	☐	☐
________________ *slips*	cylinder	☐	☐	☐
________________ *slips*	bore ID	☐	☐	☐
________________ *slips*	carrier travel	☐	☐	☐
________________ *slips*	bolts	☐	☐	☐
________________ *slips*	shear pins/stock	☐	☐	☐
________________ *slips*	die wear	☐	☐	☐
Basket condition	handrails & workfloor	☐	☐	☐
Hole cover		☐	☐	☐

HYDRAULIC SYSTEM		Accept	Replace	Repair
Hydraulic Oil		☐	☐	☐
Hydraulic Pumps	flow	☐	☐	☐
Accumulator System	bottle pressures	____	____	
	EUB Function test	☐	☐	☐
	IRP 15 bleed test	☐	☐	☐
	N2 backup pressure	________		PSI
	surge bottle pressure	________		PSI
	warning beacon	________		PSI
Accumulator pressure		________		PSI
BOP system pressure		________		PSI
Jack system pressure at truck		________		PSI
Filters	return	☐	☐	☐
	breather	☐	☐	☐
	suction	☐	☐	☐
	annular	☐	☐	☐
All hoses		☐	☐	☐
Gauges on panels on truck and in basket		☐	☐	☐
Valve banks		☐	☐	☐

Inspected by: ______________________________

In company with: ______________________________

Unit Number ______________ **Date** ______________

CERTIFICATIONS

ITEM	SERIAL NUMBER	EXPIRY DATE
Pipe ram BOP #1	____________	____________
BOP #2	____________	____________
Annular BOP	____________	____________
Working spool #1	____________	____________
Working spool #2	____________	____________
Spacer spool #1	____________	____________
Spacer spool #2	____________	____________
Stationary heavy slip	____________	____________
Stationary snubbing slip	____________	____________
Traveling snubbing slip	____________	____________
Traveling heavy slip	____________	____________
Jack structure	____________	____________
Pick up elevators	____________	____________
Pick up nubbin	____________	____________
Jack plate bolts	____________	____________
Short bales	____________	____________
Traveling plate & bearing	____________	____________
Load plate #1	____________	____________
Load plate #2	____________	____________
Cylinder #1/____________	____________	____________
Cylinder #2/____________	____________	____________
Fall arrest anchor	____________	____________
Eq & B\O flow Tee	____________	____________
EQ valve	____________	____________
B/O valve	____________	____________
Piston separator	____________	____________
Equalize line	____________	____________
Spreader Bar	____________	____________
Lifting slings	☐ certification available	____________

Appendix F: Electrical Grounding and Bonding for Service Rigs

The following information is taken from from Alberta Municipal Affairs Electrical Safety Information Bulletin CEC-10 (Rev-7) October 2009 pages 6 through 9. See References for more details and website link.

Grounding and Bonding at Oil and Gas Drilling or Servicing Operations

Rule 10-700(1) requires that grounding electrodes shall consist of a manufactured, field-assembled or in-situ type.

When setting up a service rig or a drilling rig, the use of manufactured or field-assembled electrodes as described in 10-700(2)(3) can be impractical. The following interpretation is considered acceptable for meeting the intent of <u>in-situ</u> type grounding electrode:

a) The rig guyline anchor (usually the closest one to the rig generator)

b) The well casing,

For equivalency to conventional electrodes, the portion of the anchor or well casing below 600 mm from finished grade should present an equivalent surface area in contact with earth as do manufactured electrodes.

<u>Grounding Conductor Size for AC Systems</u>

The following industry practices meet the grounding conductor size requirements of Rule 10-204 and 10-206 for applications where the generator ampacity is:

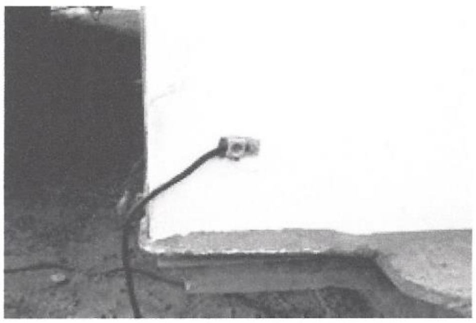
- up to 100 A - #8 AWG copper
- 101 to 200 A - #6 AWG copper
- 201 to 400 A - #3 AWG copper
- 401 to 600 A - #1 AWG copper
- 601 to 800 A - #1/0 AWG copper
- over 800 A - #2/0 AWG copper

<u>Bonding Non-electrical Equipment</u>

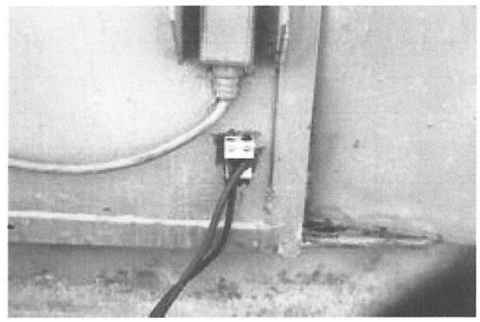
Although the CE Code does not specifically require that non-electrical equipment around drilling or service rig installations be bonded, the intent of Rule 10-406 is to have the metal parts of non-electrical equipment bonded to ground to prevent dangerous potentials in the event of electrical faults (see the Appendix B note to this Rule).

The nature of the activity around drilling operations (i.e., wet conditions and the potential for explosive atmospheres) is a strong factor to support the need for bonding non-electrical metal equipment to minimize shock hazards and potential static discharges.

EXAMPLES OF BONDING



Note single metal-to-metal connection



Note double metal-to-metal connection

Bonding Conductor Requirements

Rule 10-406 serves as a guideline for bonding non-electrical equipment to ground. To protect against loss of bonding, approved lugs are required for a positive connection. Due to possible mechanical damage to the bonding conductor, no smaller than AWG #6 copper should be used.

Grounding and Bonding Conductor Connections and Installation

Rule 10-906(1) and 10-908(1)(d) allows other equally substantial means for bonding or grounding conductor connections. For grounding and bonding of rigs, the use of a suitably rated copper or aluminum lugs with associated buss is acceptable. Pliers-style, screw-type or spring enabled booster cable clamps are not considered acceptable as they may be easily dislodged.

It is important that the installation and connections of the grounding and bonding conductors are reliable. The connections or lugs should make good metal-to-metal contact to the non-electrical equipment being bonded. The conductors should be well secured to the connectors. In addition, Rule 10-806 of the Canadian Electrical Code requires that the grounding conductor be without joint or splice throughout its length.

Extra precautions should be taken to ensure conductors and connectors are not subject to damage that could result in a loss of continuity. Contractors should incorporate measures to prevent circumstances within operations that could result in a loss of continuity. This may include altering traffic patterns, flagging or other means of protecting the grounding and bonding conductors and their connections.

Typical Grounding and Bonding Layout

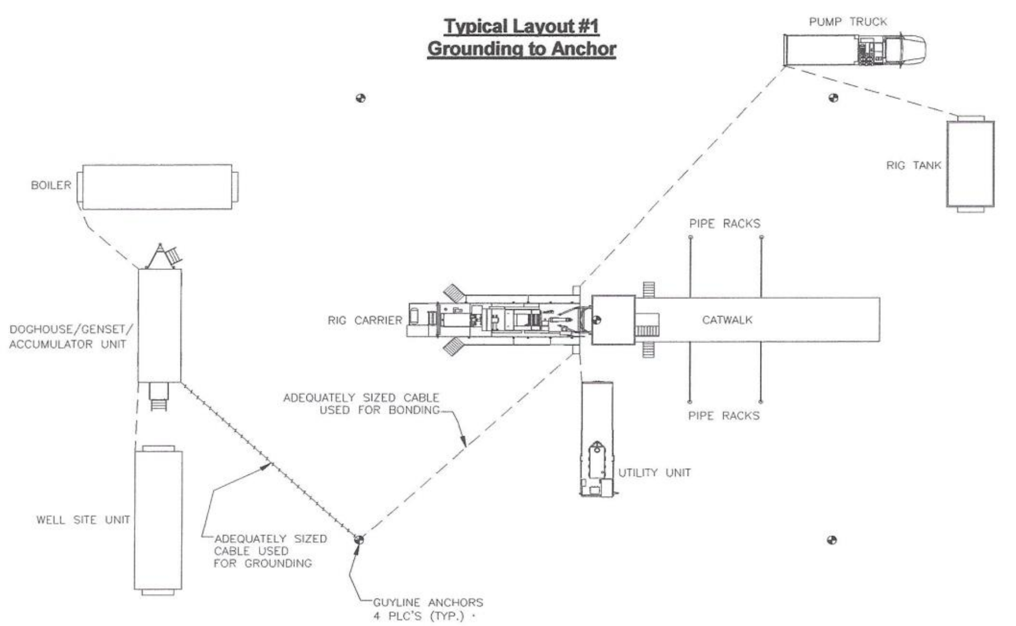
1) AC system ground conductor run without splice to an aluminum lug or buss attached to a rig anchor or the wellhead.
2) The remaining "non-electrical equipment" (i.e., rig, utility skid, mud pump, mud tank, generator building, boiler, etc.) bonded to ground with:

- a) a bonding conductor interconnecting each piece of equipment back to the ground electrode; or
- b) a bonding conductor from each piece of equipment to the ground electrode; or
- c) a combination of a) and b) above.

A #4 copper welding cable provides an excellent type of flexible cable for bonding purposes and AC system ground for most applications on service rigs.

Refer to the following diagrams as examples of typical rig grounding and bonding layouts.

Typical Layout #1
Grounding to Anchor



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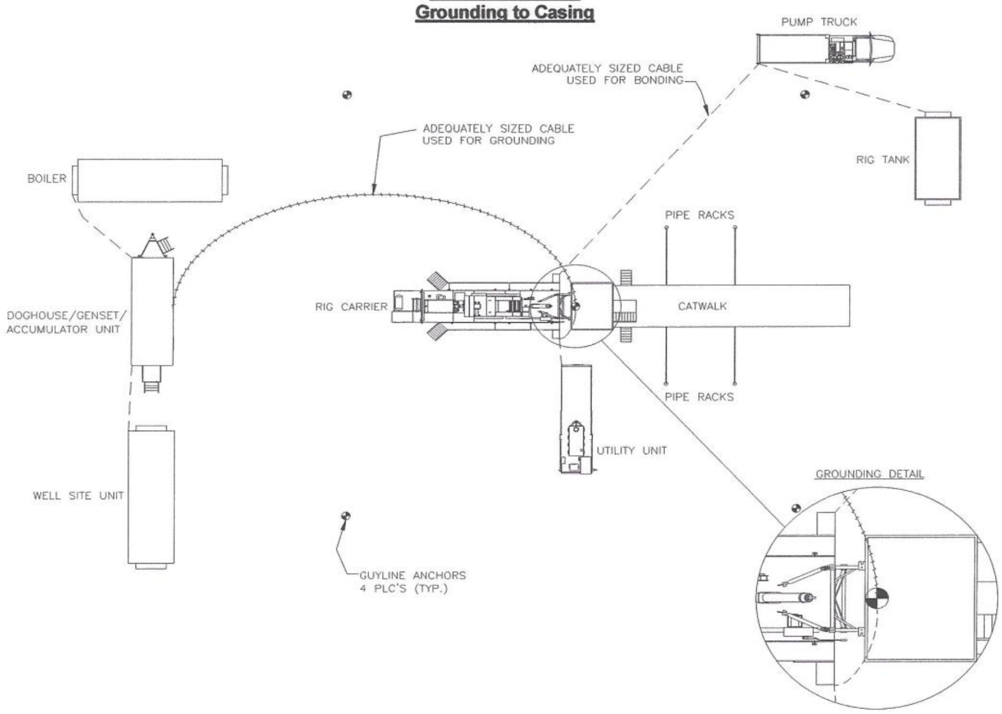
Typical Layout #2
Grounding to Casing



Appendix G: Heat Stress Quick Card

OSHA QUICK CARD™

Protect Yourself

Heat Stress

When the body is unable to cool itself by sweating, several heat-induced illnesses such as heat stress or heat exhaustion and the more severe heat stroke can occur, and can result in death.

Factors Leading to Heat Stress

High temperature and humidity; direct sun or heat; limited air movement; physical exertion; poor physical condition; some medicines; and inadequate tolerance for hot workplaces.

Symptoms of Heat Exhaustion

- Headaches, dizziness, lightheadedness or fainting.
- Weakness and moist skin.
- Mood changes such as irritability or confusion.
- Upset stomach or vomiting.

Symptoms of Heat Stroke

- Dry, hot skin with no sweating.
- Mental confusion or losing consciousness.
- Seizures or convulsions.

Preventing Heat Stress

- Know signs/symptoms of heat-related illnesses; monitor yourself and coworkers.
- Block out direct sun or other heat sources.
- Use cooling fans/air-conditioning; rest regularly.
- Drink lots of water; about 1 cup every 15 minutes.
- Wear lightweight, light colored, loose-fitting clothes.
- Avoid alcohol, caffeinated drinks, or heavy meals.

What to Do for Heat-Related Illness

- Call 911 (or local emergency number) at once.

While waiting for help to arrive:

- Move the worker to a cool, shaded area.
- Loosen or remove heavy clothing.
- Provide cool drinking water.
- Fan and mist the person with water.

For more complete information:

OSHA Occupational Safety and Health Administration
U.S. Department of Labor
www.osha.gov (800) 321-OSHA

OSHA 3154-07R-06

Appendix H: Cold Weather Exposure Chart – ACGIH

Table 1: Cooling Power of Wind on Exposed Flesh Expressed as Equivalent Temperature
1998 Threshold Limit Values, American Conference of Governmental Industrial Hygienists

Estimated Wind Speed (km/h)	Actual Temperature Reading (°C)												
	10	5	0	-5	-10	-15	-20	-25	-30	-35	-40	-45	-50
	Equivalent Wind Chill Temperature (°C)												
0	10	5	0	-5	-10	-15	-20	-25	-30	-35	-40	-45	-50
8	9	3	-2	-7	-12	-18	-23	-28	-33	-38	-44	-49	-54
16	4	-2	-7	-14	-20	-27	-33	-38	-45	-50	-57	-63	-69
24	2	-5	-11	-18	-25	-32	-38	-45	-52	-58	-65	-72	-78
32	0	-7	-14	-21	-28	-35	-42	-50	-56	-64	-71	-78	-84
40	-1	-8	-16	-24	-31	-38	-46	-53	-60	-67	-76	-82	-90
48	-2	-10	-17	-25	-33	-40	-48	-55	-63	-70	-78	-86	-94
56	-3	-11	-18	-26	-34	-42	-50	-58	-65	-73	-81	-89	-96
64	-3	-11	-19	-27	-35	-43	-51	-59	-66	-74	-82	-90	-98
(Wind speeds greater than 64 km/h have little additional effect.)	LITTLE DANGER In < 1 hour with dry skin. Maximum danger of false sense of security					DANGER Danger from freezing of exposed flesh within one minute		GREATEST DANGER Danger from freezing of exposed flesh within 30 seconds.					

Table 2: TLVs Work Warm-Up Schedule for Four Hour Shift (under discretion of supervisor on site) – 1998 TLVs, ACGIH										
Air Temperature	No Noticeable Wind		8 km/h Wind		16 km/h Wind		24 km/h Wind		32 km/h Wind	
°C (Approx.)	Max. Work Period	No. of Breaks*	Max. Work Period	No. of Breaks*	Max. Work Period	No. of Breaks*	Max. Work Period	No. of Breaks*	Max. Work Period	No. of Breaks*
-14° to -16°	Normal	1	Normal	1	Normal	1	Normal	1	Normal	1
-17° to -19°	Normal	1	Normal	1	Normal	1	Normal	1	75 min.	2
-20° to -22°	Normal	1	Normal	1	Normal	1	75 min.	2	55 min.	3
-23° to -25°	Normal	1	Normal	1	Normal	1	55 min.	3	40 min.	4
-26° to -28°	Normal	1	Normal	1	75 min.	2	40 min.	4	30 min.	5
-29° to -31°	Normal	1	75 min.	2	55 min.	3	30 min.	5		
-32° to -34°	75 min.	2	55 min.	3	40 min.	4				
-35° to -37°	55 min.	3	40 min.	4	30 min.	5		No Worker Exposure is Recommended		
-38° to -39°	40 min.	4	30 min.	5						
-40° to -42°	30 min.	5								
-43° and Below										

*Breaks are defined as a minimum of 15 minutes in a warm environment with the possibility to rehydrate and/or nourish.

This chart is for information purposes only. The snubbing supervisor on site must use his discretion as to whether the exposure times must be reduced or work stopped.

Appendix I: Allowable Tensile Loads – Petro-Canada

Allowable Tensile Loads as a Function of External or Internal pressure

API Bulletin 5C3, 6th edition, offers a number of equations to calculate pressures, stresses, and loads on casing and tubing. The objective of this section is to present charts that illustrate acceptable tensile loads as a function of internal or external pressure for those sizes and grades of tubing most likely to be snubbed or stripped by Petro-Canada. Note that this only considers tensile loads. Acceptable compressive loads are described in the Pipe Buckling Section.

API Equation 1, Yield Strength Collapse Pressure

API Bulletin 5C3, 6th edition, equation 1 calculates the yield strength collapse pressure with no axial load, and has the form Pyc=2*Sy*(D/t-t)/(D/t)^2.

API Equation 8, Collapse Pressure with Axial Tension Stress

API Bulletin 5C3, 6th edition, also offers a formula for calculating pipe limits with tensile load and external (collapse) pressure. Equation 8 (Collapse Pressure under Axial Tension Stress) has the form Yps=Yp*((1-0.75(Sa/Sy)^2)^.5-.5*Sa/Sy)*Sy, which is not really a determination of adjusted pressure. Fortunately, the formula can be re-written as Pca = Pcr {(1-.75(Sa/Sy)^2)^.5 - 0.5 (Sa/Sy)}

API 5C3, 6th edition, does not contain a formula for determining acceptable loads as a function of combined tension and internal pressure. The problem also cannot readily be solved using Von Mises triaxial stress with minimum wall thickness to determine acceptable tension loads, as the triaxial stress exceeds limits imposed by API equations 8, 31 and 46.The author has therefore chosen to use equations 30 & 31 to complete the load-pressure envelope.

API Equation 30, Pipe Body Yield Strength

API Bulletin 5C3, 6th edition, equation 30, calculates the pipe body yield strength for pipe of nominal wall thickness, and has the form Fyp = Sy * 3.14 * (D^2-d^2)/4.

External Upset Joint Strength is calculated with API equation 46, Load = Sy*PI (D2-d2)/4, which really means that external upset connections have the same strength as the pipe body. From pipe tables, non-upset pipe connection have about 60% of the pipe body yield strength, and integral joint connections have about 80% of the pipe body yield strength.

API Equation 31, Internal Yield Pressure

Hoop Stress: API 5C3, 6th edition, equation 31, states that the internal yield pressure for the pipe is calculated using the formula: Py = 0.875 *(2*Sy*t)/OD The factor 0.875 allows for minimum wall thickness.

Allowable Tension as a Function of Pressure Diagrams

The following charts plot allowable tension as a function of pressure. The objective of the charts is to illustrate the pressure-load envelope that is defined by API equations 1, 8, 30 and 31. The outer envelope has no safety factor, whereas the inner envelope applies safety factors for burst, collapse and tension that are deemed acceptable by Petro-Canada.

These calculations have been provided by Petro-Canada as a reference only. Reliance on this material alone to the exclusion of other professional advice, experience or resources is imprudent since each situation is unique.

Chart 1: Tubing OD 33.4 mm Grade J-55 Tubing Wt. 2.56 Kg/m Connection IJ

Allowable Tension as a Function of Pressure

Tubing OD:	**33.4** mm	Grade:	**J-55**
Tubing Wt.	**2.56** kg/m	Connection:	**IJ**

API equations:

Eqn. 1	Yield Strength Collapse Pressure	Pyc=2*Sy*((D/t-1)/(D/t)^2
Eqn. 8	Collapse Pressure w. Axial Tension	Pca=Pyc{((1-.75(Sa/Sy)^2)^.5-0.5(Sa/Sy)}
Eqn. 30	Pipe Body Yield Strength	Fyp = Sy * 3.14 * (D^2-d^2)/4
Eqn. 31	Internal Yield Pressure	Pyi = 0.875 * (2 * Sy * t) / D

	Inputs		Calculated	
Outside diameter (D)	**33.40** mm	Steel X-sectional area		318.6 mm^2
Inside diameter (d)	**26.64** mm	Fyp		120753 Newtons
Nom. wall thickness (t)	**3.38** mm	Pyi		67119 kPa
Steel yield strength (Sy)	**379** Mpa	Pyc		-68945 kPa
Joint Efficiency (JE)	**80** %			
Safety Factor, Tension	**1.25**		EUE = 100%	
Safety Factor, Burst	**1.20**	Joint	IJ = 80%	Yield
Safety Factor, Collapse	**1.10**	Efficiencies	NUE = 60%	Strengths

where:
D = Outside diameter
d = Inside diameter
t = nominal wall thickness
Sa = Axial stress
Sy = Yield stress of the steel
Pyi = Internal Yield Pressure
Pyc = Collapse rating, no axial stress
Pca = Adjusted collapse rating
Fyp = Pipe body yeld strength
1kPa = 100 dyne/mm^2
1 Newton = 100,000 dynes

Sy of J-55 = 379 Mpa
Sy of L-80 = 551 Mpa

Allowable Tension as a Function of Pressure

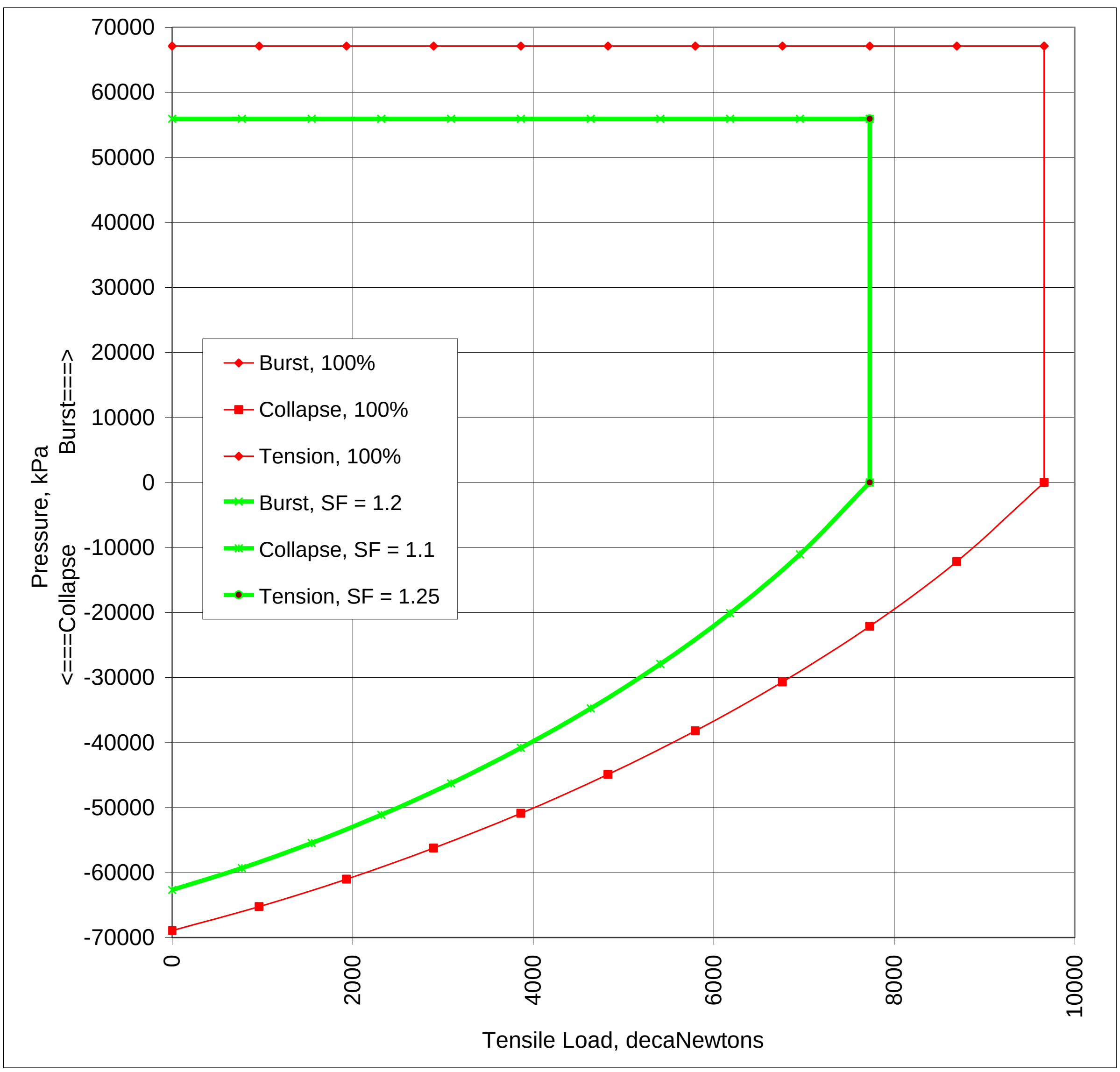


Chart 2: Tubing OD 33.4 mm Grade L-80 Tubing Wt. 2.56 Kg/m Connection IJ

Allowable Tension as a Function of Pressure

Tubing OD:	**33.4** mm	Grade:	**L-80**
Tubing Wt.	**2.56** kg/m	Connection:	**IJ**

API equations:

Eqn. 1	Yield Strength Collapse Pressure	Pyc=2*Sy*((D/t-1)/(D/t)^2	
Eqn. 8	Collapse Pressure w. Axial Tension	Pca=Pyc{((1-.75(Sa/Sy)^2)^.5-0.5(Sa/Sy)}	
Eqn. 30	Pipe Body Yield Strength	Fyp = Sy * 3.14 * (D^2-d^2)/4	
Eqn. 31	Internal Yield Pressure	Pyi = 0.875 * (2 * Sy * t) / D	

where:
D = Outside diameter
d = Inside diameter
t = nominal wall thickness
Sa = Axial stress
Sy = Yield stress of the steel
Pyi = Internal Yield Pressure
Pyc = Collapse rating, no axial stress
Pca = Adjusted collapse rating
Fyp = Pipe body yeld strength
1kPa = 100 dyne/mm^2
1 Newton = 100,000 dynes

	Inputs		Calculated		
Outside diameter (D)	**33.40** mm		Steel X-sectional area	318.6 mm^2	
Inside diameter (d)	**26.64** mm		Fyp	175553 Newtons	
Nom. wall thickness (t)	**3.38** mm		Pyi	97580 kPa	
Steel yield strength (Sy)	**551** Mpa		Pyc	-100234 kPa	
Joint Efficiency (JE)	**80** %				
Safety Factor, Tension	**1.25**		EUE = 100%		
Safety Factor, Burst	**1.20**	Joint	IJ = 80%	Yield	Sy of J-55 = 379 Mpa
Safety Factor, Collapse	**1.10**	Efficiencies	NUE = 60%	Strengths	Sy of L-80 = 551 Mpa

Allowable Tension as a Function of Pressure

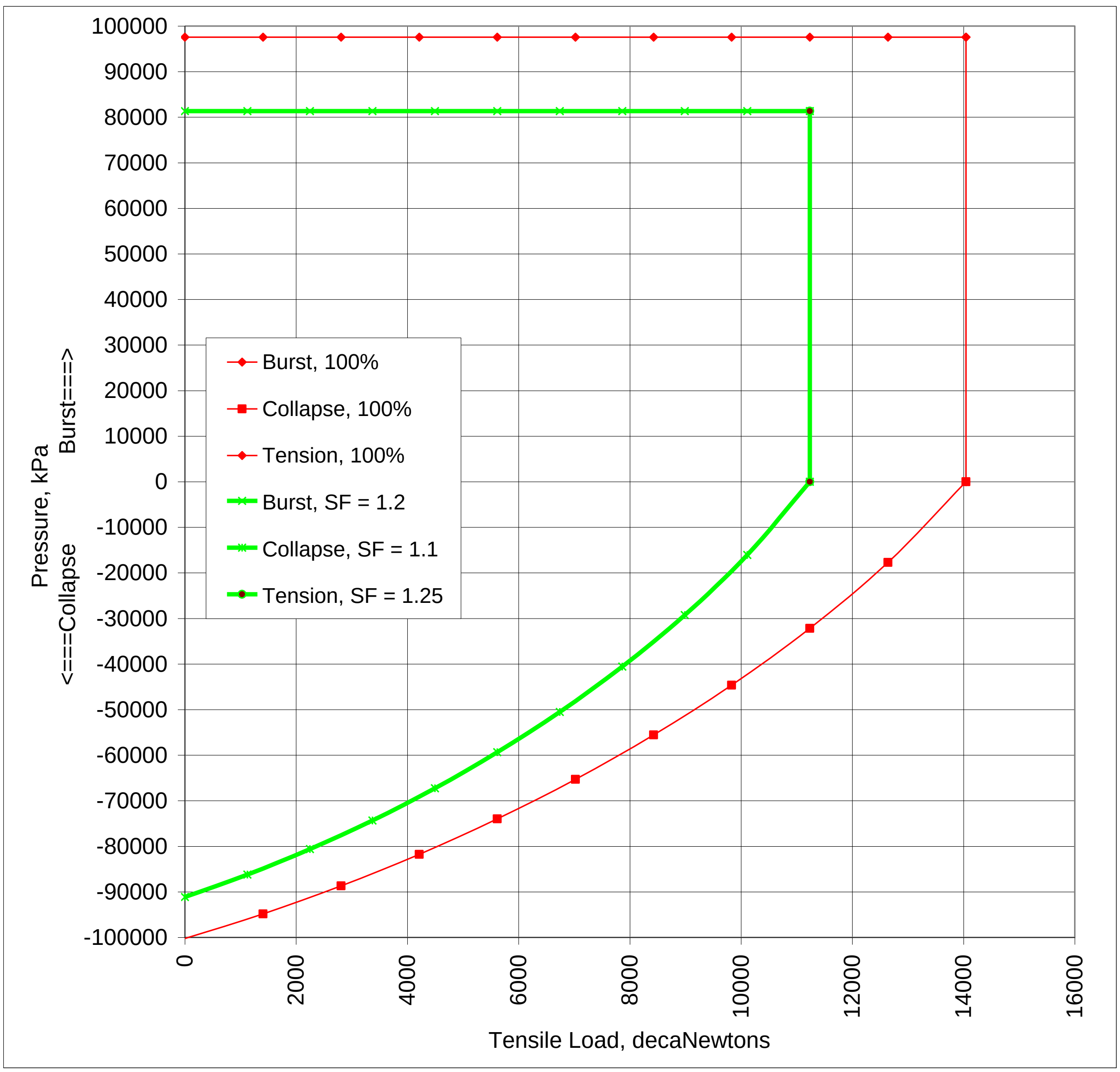


Chart 3: Tubing OD 42.2 mm Grade J-55 Tubing Wt. 3.47 Kg/m Connection IJ

Allowable Tension as a Function of Pressure

Tubing OD:	**42.2** mm	Grade:	**J-55**
Tubing Wt.	**3.47** kg/m	Connection:	**IJ**

API equations:

Eqn. 1	Yield Strength Collapse Pressure	Pyc=2*Sy*((D/t-1)/(D/t)^2	
Eqn. 8	Collapse Pressure w. Axial Tension	Pca=Pyc{((1-.75(Sa/Sy)^2)^.5-0.5(Sa/Sy)}	
Eqn. 30	Pipe Body Yield Strength	Fyp = Sy * 3.14 * (D^2-d^2)/4	
Eqn. 31	Internal Yield Pressure	Pyi = 0.875 * (2 * Sy * t) / D	

where:
D = Outside diameter
d = Inside diameter
t = nominal wall thickness
Sa = Axial stress
Sy = Yield stress of the steel
Pyi = Internal Yield Pressure
Pyc = Collapse rating, no axial stress
Pca = Adjusted collapse rating
Fyp = Pipe body yeld strength
1kPa = 100 dyne/mm^2
1 Newton = 100,000 dynes

	Inputs		Calculated	
Outside diameter (D)	42.20 mm	Steel X-sectional area	433.6 mm^2
Inside diameter (d)	35.05 mm	Fyp	164329 Newtons
Nom. wall thickness (t)	3.58 mm	Pyi	56188 kPa
Steel yield strength (Sy)	379 Mpa	Pyc	-58774 kPa
Joint Efficiency (JE)	80 %		
Safety Factor, Tension	1.25		EUE = 100%
Safety Factor, Burst	1.20	Joint	IJ = 80%
Safety Factor, Collapse	1.10	Efficiencies	NUE = 60%

Yield Strengths: Sy of J-55 = 379 Mpa; Sy of L-80 = 551 Mpa

Allowable Tension as a Function of Pressure

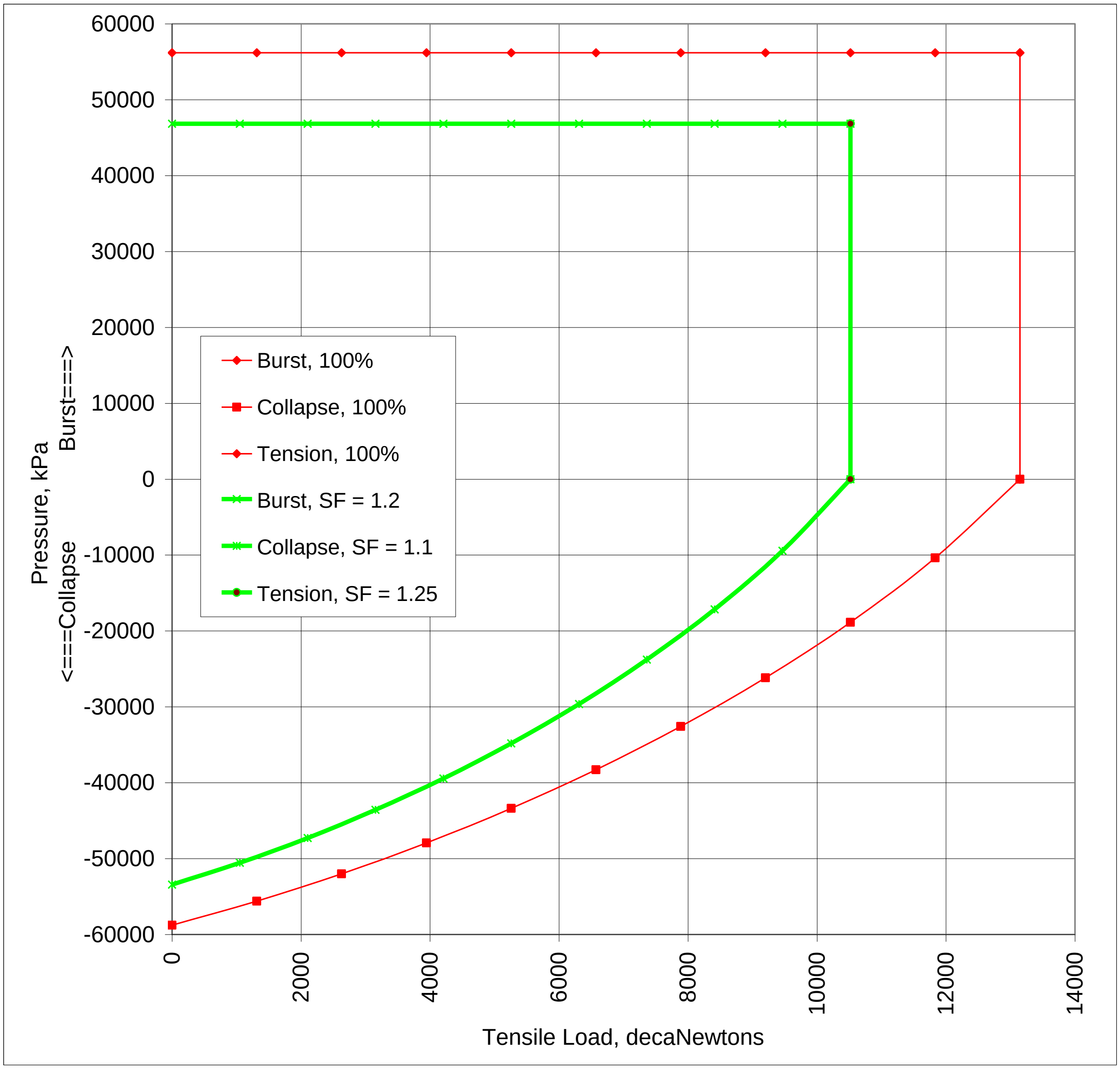


Chart 4: Tubing OD 42.2 mm Grade L-80 Tubing Wt. 3.47 Kg/m Connection IJ

Allowable Tension as a Function of Pressure

Tubing OD:	**42.2** mm	Grade:	**L-80**
Tubing Wt.	**3.47** kg/m	Connection:	**IJ**

API equations:

Eqn. 1	Yield Strength Collapse Pressure	Pyc=2*Sy*((D/t-1)/(D/t)^2
Eqn. 8	Collapse Pressure w. Axial Tension	Pca=Pyc{((1-.75(Sa/Sy)^2)^.5-0.5(Sa/Sy)}
Eqn. 30	Pipe Body Yield Strength	Fyp = Sy * 3.14 * (D^2-d^2)/4
Eqn. 31	Internal Yield Pressure	Pyi = 0.875 * (2 * Sy * t) / D

	Inputs		Calculated	
Outside diameter (D)	**42.20** mm	Steel X-sectional area	433.6	mm^2
Inside diameter (d)	**35.05** mm	Fyp	238905	Newtons
Nom. wall thickness (t)	**3.58** mm	Pyi	81687	kPa
Steel yield strength (Sy)	**551** Mpa	Pyc	-85448	kPa
Joint Efficiency (JE)	**80** %			
Safety Factor, Tension	**1.25**		EUE = 100%	
Safety Factor, Burst	**1.20**	Joint	IJ = 80%	Yield
Safety Factor, Collapse	**1.10**	Efficiencies	NUE = 60%	Strengths

where:
D = Outside diameter
d = Inside diameter
t = nominal wall thickness
Sa = Axial stress
Sy = Yield stress of the steel
Pyi = Internal Yield Pressure
Pyc = Collapse rating, no axial stress
Pca = Adjusted collapse rating
Fyp = Pipe body yeld strength
1kPa = 100 dyne/mm^2
1 Newton = 100,000 dynes

Sy of J-55 = 379 Mpa
Sy of L-80 = 551 Mpa

Allowable Tension as a Function of Pressure

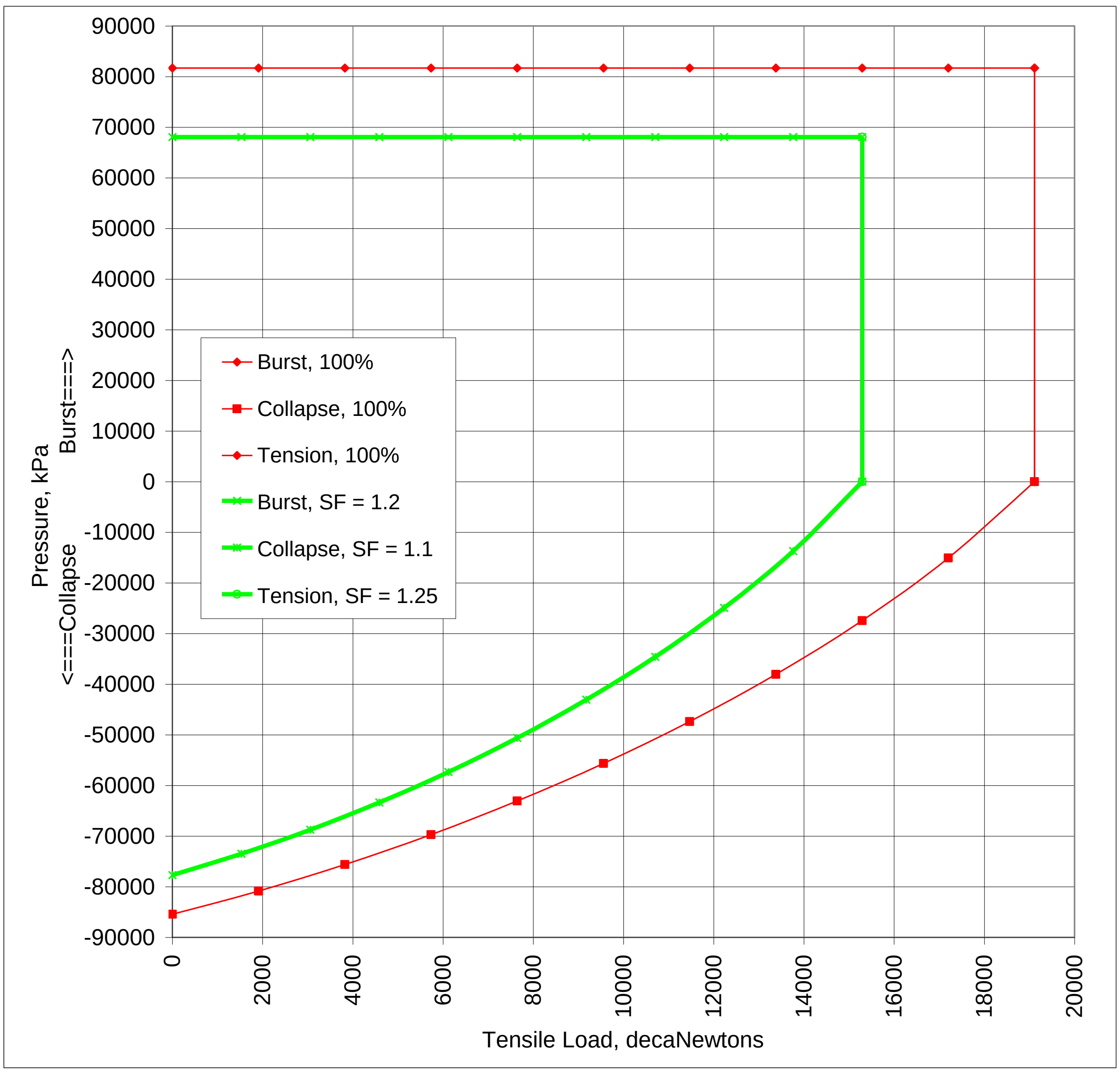


Chart 5: Tubing OD 48.3 mm Grade J-55 Tubing Wt. 4.11 Kg/m Connection IJ

Allowable Tension as a Function of Pressure

Tubing OD:	**48.3** mm	Grade:	**J-55**
Tubing Wt.	**4.11** kg/m	Connection:	**IJ**

API equations:

Eqn. 1	Yield Strength Collapse Pressure	Pyc=2*Sy*((D/t-1)/(D/t)^2
Eqn. 8	Collapse Pressure w. Axial Tension	Pca=Pyc{((1-.75(Sa/Sy)^2)^.5-0.5(Sa/Sy)}
Eqn. 30	Pipe Body Yield Strength	Fyp = Sy * 3.14 * (D^2-d^2)/4
Eqn. 31	Internal Yield Pressure	Pyi = 0.875 * (2 * Sy * t) / D

	Inputs		Calculated	
Outside diameter (D)	**48.30** mm	Steel X-sectional area	518.8	mm^2
Inside diameter (d)	**40.89** mm	Fyp	196627	Newtons
Nom. wall thickness (t)	**3.71** mm	Pyi	50877	kPa
Steel yield strength (Sy)	**379** Mpa	Pyc	-53685	kPa
Joint Efficiency (JE)	**80** %			
Safety Factor, Tension	**1.25**		EUE = 100%	
Safety Factor, Burst	**1.20**	Joint	IJ = 80%	
Safety Factor, Collapse	**1.10**	Efficiencies	NUE = 60%	

where:
D = Outside diameter
d = Inside diameter
t = nominal wall thickness
Sa = Axial stress
Sy = Yield stress of the steel
Pyi = Internal Yield Pressure
Pyc = Collapse rating, no axial stress
Pca = Adjusted collapse rating
Fyp = Pipe body yeld strength
1kPa = 100 dyne/mm^2
1 Newton = 100,000 dynes

Yield Strengths
Sy of J-55 = 379 Mpa
Sy of L-80 = 551 Mpa

Allowable Tension as a Function of Pressure

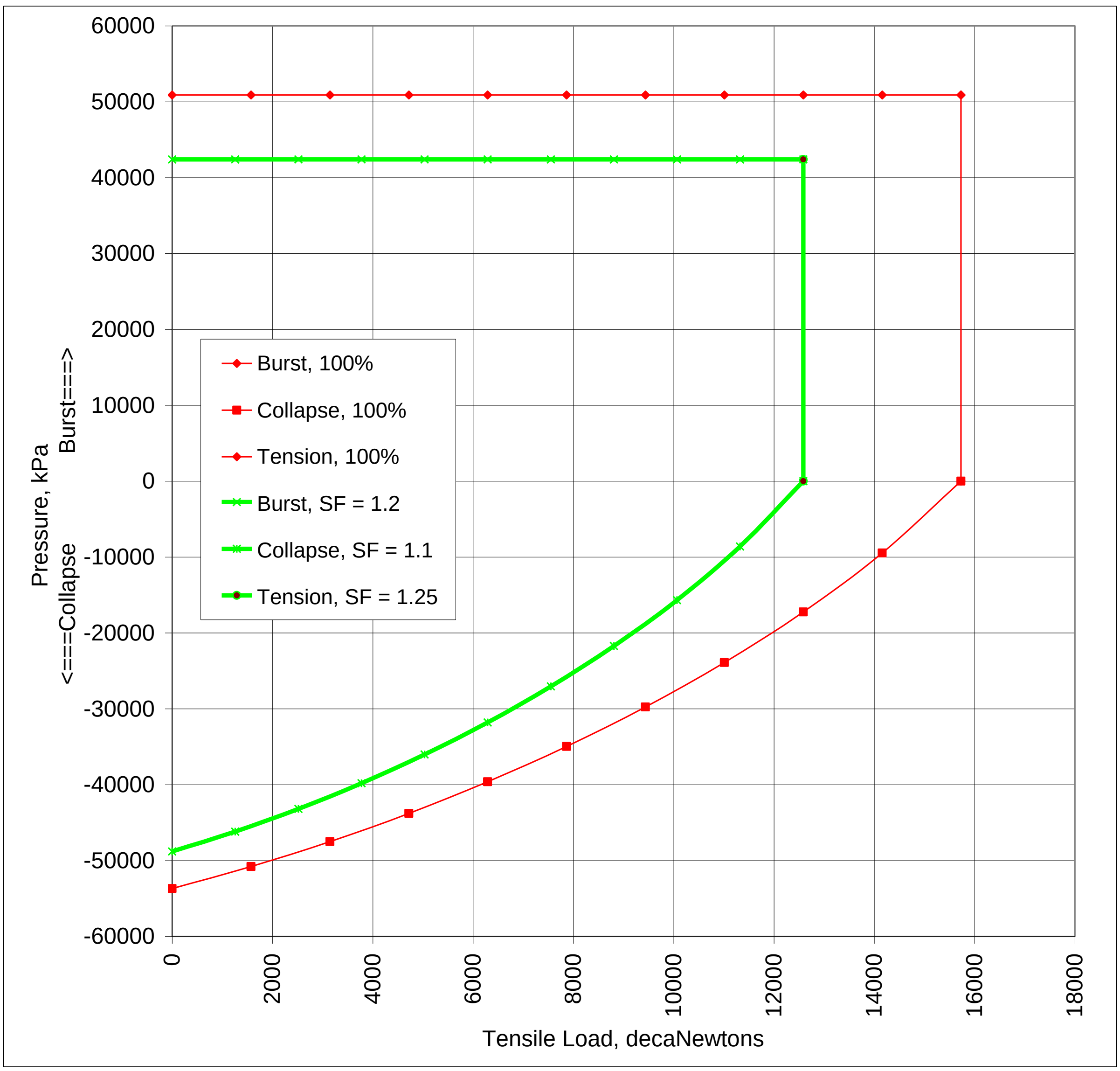


Chart 6: Tubing OD 48.3 mm Grade L-80 Tubing Wt. 4.11 Kg/m Connection IJ

Allowable Tension as a Function of Pressure

Tubing OD:	**48.3** mm	Grade:	**L-80**
Tubing Wt.	**4.11** kg/m	Connection:	**IJ**

API equations:

Eqn. 1	Yield Strength Collapse Pressure	Pyc=2*Sy*((D/t-1)/(D/t)^2
Eqn. 8	Collapse Pressure w. Axial Tension	Pca=Pyc{((1-.75(Sa/Sy)^2)^.5-0.5(Sa/Sy)}
Eqn. 30	Pipe Body Yield Strength	Fyp = Sy * 3.14 * (D^2-d^2)/4
Eqn. 31	Internal Yield Pressure	Pyi = 0.875 * (2 * Sy * t) / D

Inputs			Calculated		
Outside diameter (D)	**48.30**	mm	Steel X-sectional area	518.8	mm^2
Inside diameter (d)	**40.89**	mm	Fyp	285861	Newtons
Nom. wall thickness (t)	**3.71**	mm	Pyi	73966	kPa
Steel yield strength (Sy)	**551**	Mpa	Pyc	-78048	kPa
Joint Efficiency (JE)	**80**	%			
Safety Factor, Tension	**1.25**		EUE = 100%		
Safety Factor, Burst	**1.20**		Joint Efficiencies: IJ = 80%		
Safety Factor, Collapse	**1.10**		NUE = 60%		

where:
D = Outside diameter
d = Inside diameter
t = nominal wall thickness
Sa = Axial stress
Sy = Yield stress of the steel
Pyi = Internal Yield Pressure
Pyc = Collapse rating, no axial stress
Pca = Adjusted collapse rating
Fyp = Pipe body yeld strength
1kPa = 100 dyne/mm^2
1 Newton = 100,000 dynes

Yield Strengths
Sy of J-55 = 379 Mpa
Sy of L-80 = 551 Mpa

Allowable Tension as a Function of Pressure

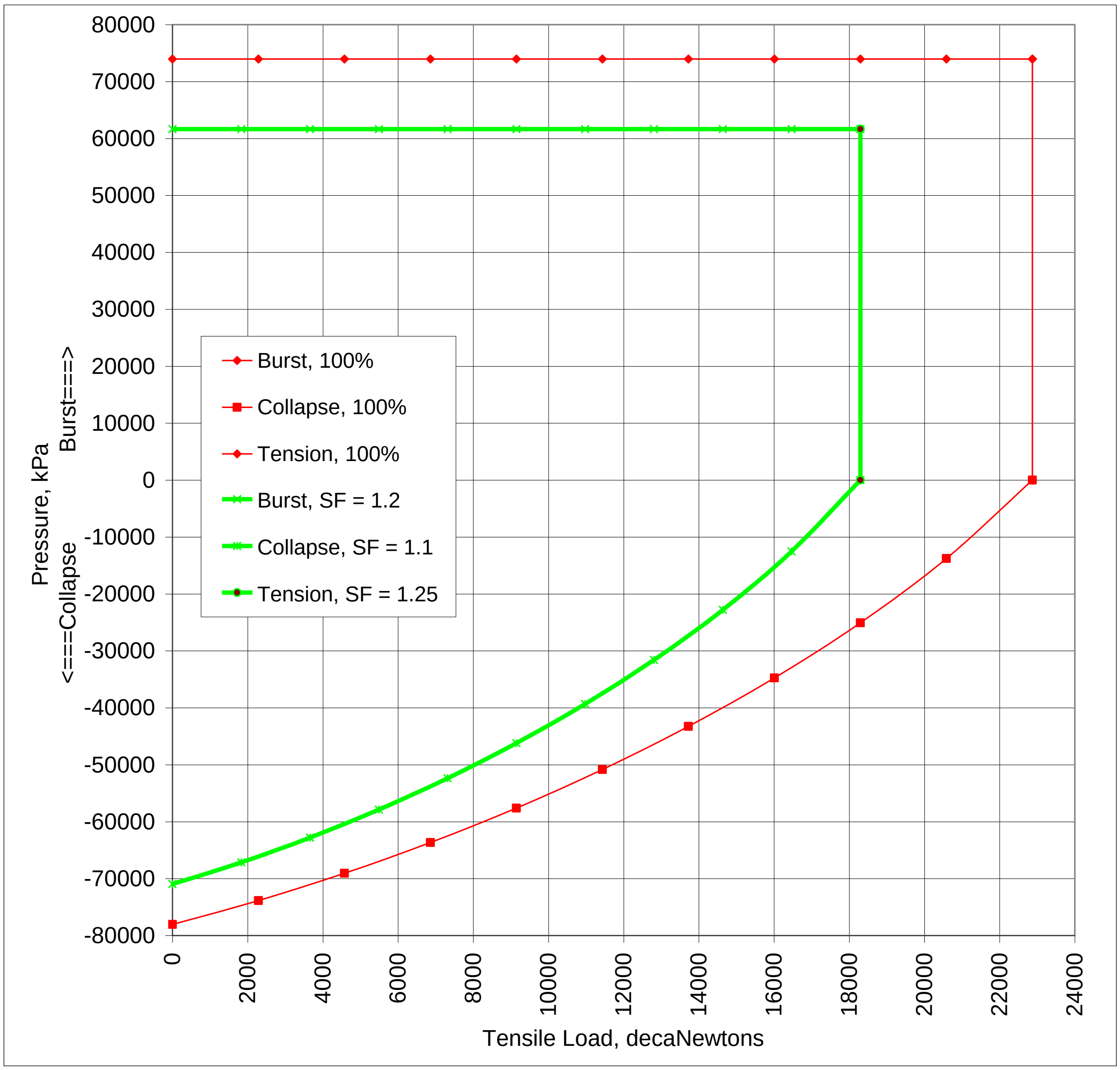


Chart 7: Tubing OD 52.4 mm Grade J-55 Tubing Wt. 4.85 Kg/m Connection IJ

Allowable Tension as a Function of Pressure

Tubing OD:	**52.4** mm	Grade:	**J-55**
Tubing Wt.	**4.85** kg/m	Connection:	**IJ**

API equations:

Eqn. 1	Yield Strength Collapse Pressure	Pyc=2*Sy*((D/t-1)/(D/t)^2	
Eqn. 8	Collapse Pressure w. Axial Tension	Pca=Pyc{((1-.75(Sa/Sy)^2)^.5-0.5(Sa/Sy)}	
Eqn. 30	Pipe Body Yield Strength	Fyp = Sy * 3.14 * (D^2-d^2)/4	
Eqn. 31	Internal Yield Pressure	Pyi = 0.875 * (2 * Sy * t) / D	

	Inputs	Calculated		
Outside diameter (D)	52.40 mm	Steel X-sectional area	602.3 mm^2	
Inside diameter (d)	44.48 mm	Fyp	228280 Newtons	
Nom. wall thickness (t)	3.96 mm	Pyi	50123 kPa	
Steel yield strength (Sy)	379 Mpa	Pyc	-52955 kPa	
Joint Efficiency (JE)	90 %			
Safety Factor, Tension	1.25		EUE = 100%	
Safety Factor, Burst	1.20	Joint	IJ = 80%	Yield
Safety Factor, Collapse	1.10	Efficiencies	NUE = 60%	Strengths

where:
D = Outside diameter
d = Inside diameter
t = nominal wall thickness
Sa = Axial stress
Sy = Yield stress of the steel
Pyi = Internal Yield Pressure
Pyc = Collapse rating, no axial stress
Pca = Adjusted collapse rating
Fyp = Pipe body yeld strength
1kPa = 100 dyne/mm^2
1 Newton = 100,000 dynes

Sy of J-55 = 379 Mpa
Sy of L-80 = 551 Mpa

Allowable Tension as a Function of Pressure

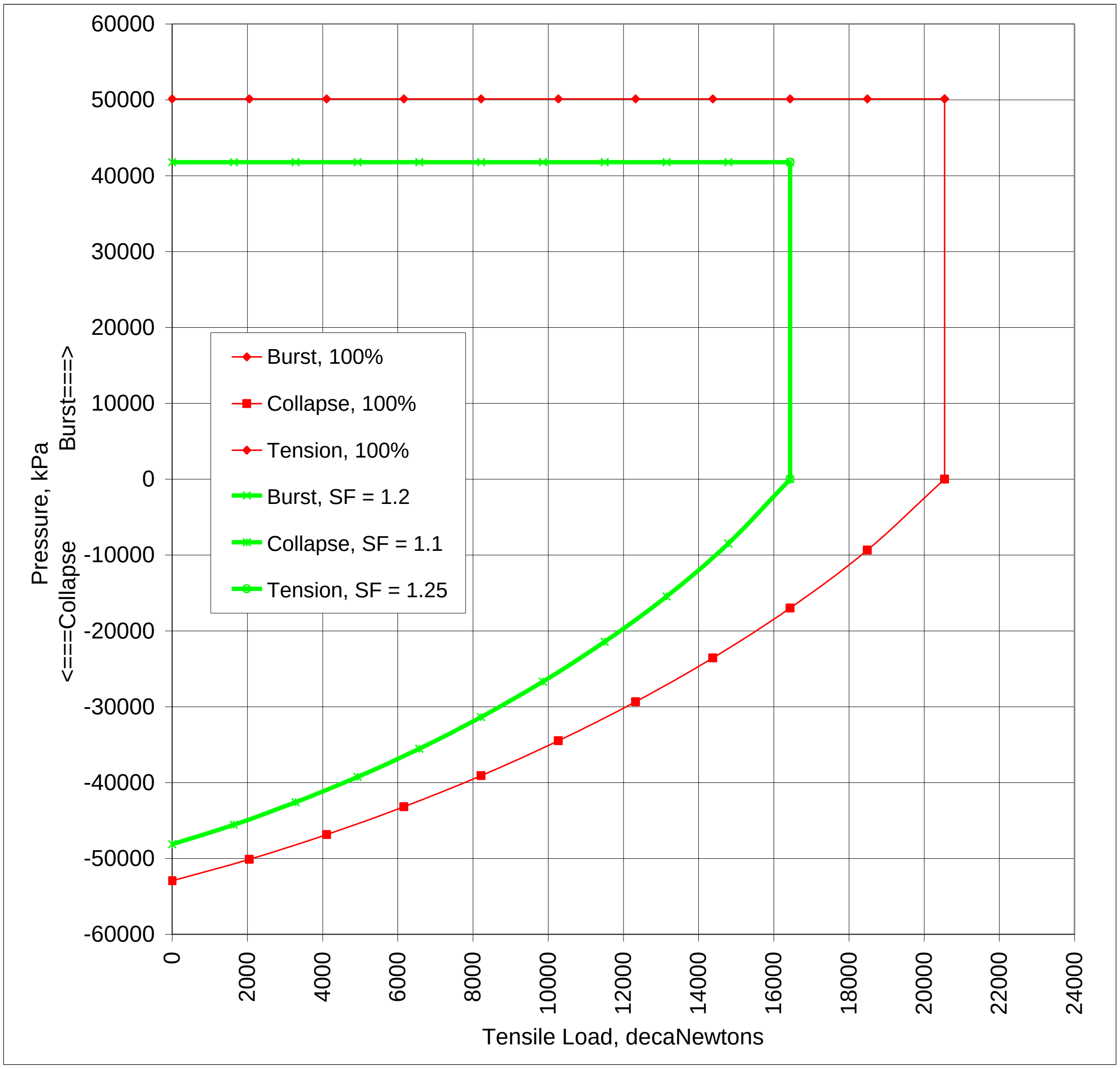


Chart 8: Tubing OD 52.4 mm Grade L-80 Tubing Wt. 4.85 Kg/m Connection IJ

Allowable Tension as a Function of Pressure

Tubing OD:	**52.4** mm	Grade:	**L-80**
Tubing Wt.	**4.85** kg/m	Connection:	**IJ**

API equations:

Eqn. 1	Yield Strength Collapse Pressure	Pyc=2*Sy*((D/t-1)/(D/t)^2
Eqn. 8	Collapse Pressure w. Axial Tension	Pca=Pyc{((1-.75(Sa/Sy)^2)^.5-0.5(Sa/Sy)}
Eqn. 30	Pipe Body Yield Strength	Fyp = Sy * 3.14 * (D^2-d^2)/4
Eqn. 31	Internal Yield Pressure	Pyi = 0.875 * (2 * Sy * t) / D

where:
D = Outside diameter
d = Inside diameter
t = nominal wall thickness
Sa = Axial stress
Sy = Yield stress of the steel
Pyi = Internal Yield Pressure
Pyc = Collapse rating, no axial stress
Pca = Adjusted collapse rating
Fyp = Pipe body yeld strength
1kPa = 100 dyne/mm^2
1 Newton = 100,000 dynes

	Inputs		Calculated	
Outside diameter (D)	52.40 mm		Steel X-sectional area	602.3 mm^2
Inside diameter (d)	44.48 mm		Fyp	331880 Newtons
Nom. wall thickness (t)	3.96 mm		Pyi	72871 kPa
Steel yield strength (Sy)	551 Mpa		Pyc	-76987 kPa
Joint Efficiency (JE)	90 %			
Safety Factor, Tension	1.25			
Safety Factor, Burst	1.20			
Safety Factor, Collapse	1.10			

	EUE = 100%		
Joint	IJ = 80%	Yield	Sy of J-55 = 379 Mpa
Efficiencies	NUE = 60%	Strengths	Sy of L-80 = 551 Mpa

Allowable Tension as a Function of Pressure

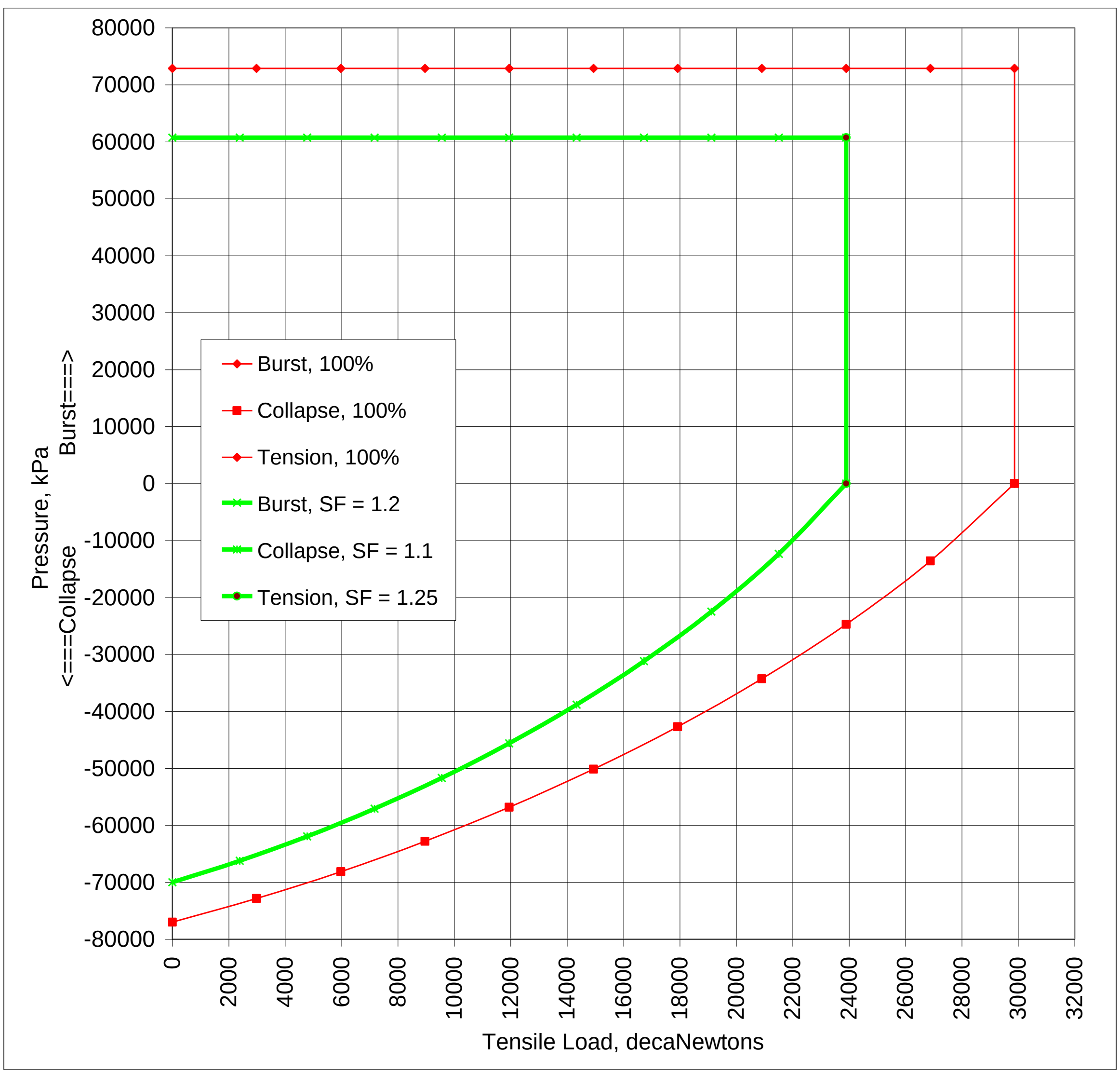


Chart 9: Tubing OD 60.3 mm Grade J-55 Tubing Wt. 6.99 Kg/m Connection EUE

Allowable Tension as a Function of Pressure

Tubing OD:	**60.3** mm	Grade:	**J-55**
Tubing Wt.	**6.99** kg/m	Connection:	**EUE**

API equations:

Eqn. 1	Yield Strength Collapse Pressure	Pyc=2*Sy*((D/t-1)/(D/t)^2
Eqn. 8	Collapse Pressure w. Axial Tension	Pca=Pyc{((1-.75(Sa/Sy)^2)^.5-0.5(Sa/Sy)}
Eqn. 30	Pipe Body Yield Strength	Fyp = Sy * 3.14 * (D^2-d^2)/4
Eqn. 31	Internal Yield Pressure	Pyi = 0.875 * (2 * Sy * t) / D

	Inputs	Calculated		
Outside diameter (D)	60.30 mm	Steel X-sectional area	838.9 mm^2	
Inside diameter (d)	50.67 mm	Fyp	317937 Newtons	
Nom. wall thickness (t)	4.82 mm	Pyi	52961 kPa	
Steel yield strength (Sy)	379 Mpa	Pyc	-55694 kPa	
Joint Efficiency (JE)	100 %			
Safety Factor, Tension	1.25		EUE = 100%	
Safety Factor, Burst	1.20	Joint	IJ = 80%	Yield
Safety Factor, Collapse	1.10	Efficiencies	NUE = 60%	Strengths

where:
D = Outside diameter
d = Inside diameter
t = nominal wall thickness
Sa = Axial stress
Sy = Yield stress of the steel
Pyi = Internal Yield Pressure
Pyc = Collapse rating, no axial stress
Pca = Adjusted collapse rating
Fyp = Pipe body yeld strength
1kPa = 100 dyne/mm^2
1 Newton = 100,000 dynes

Sy of J-55 = 379 Mpa
Sy of L-80 = 551 Mpa

Allowable Tension as a Function of Pressure

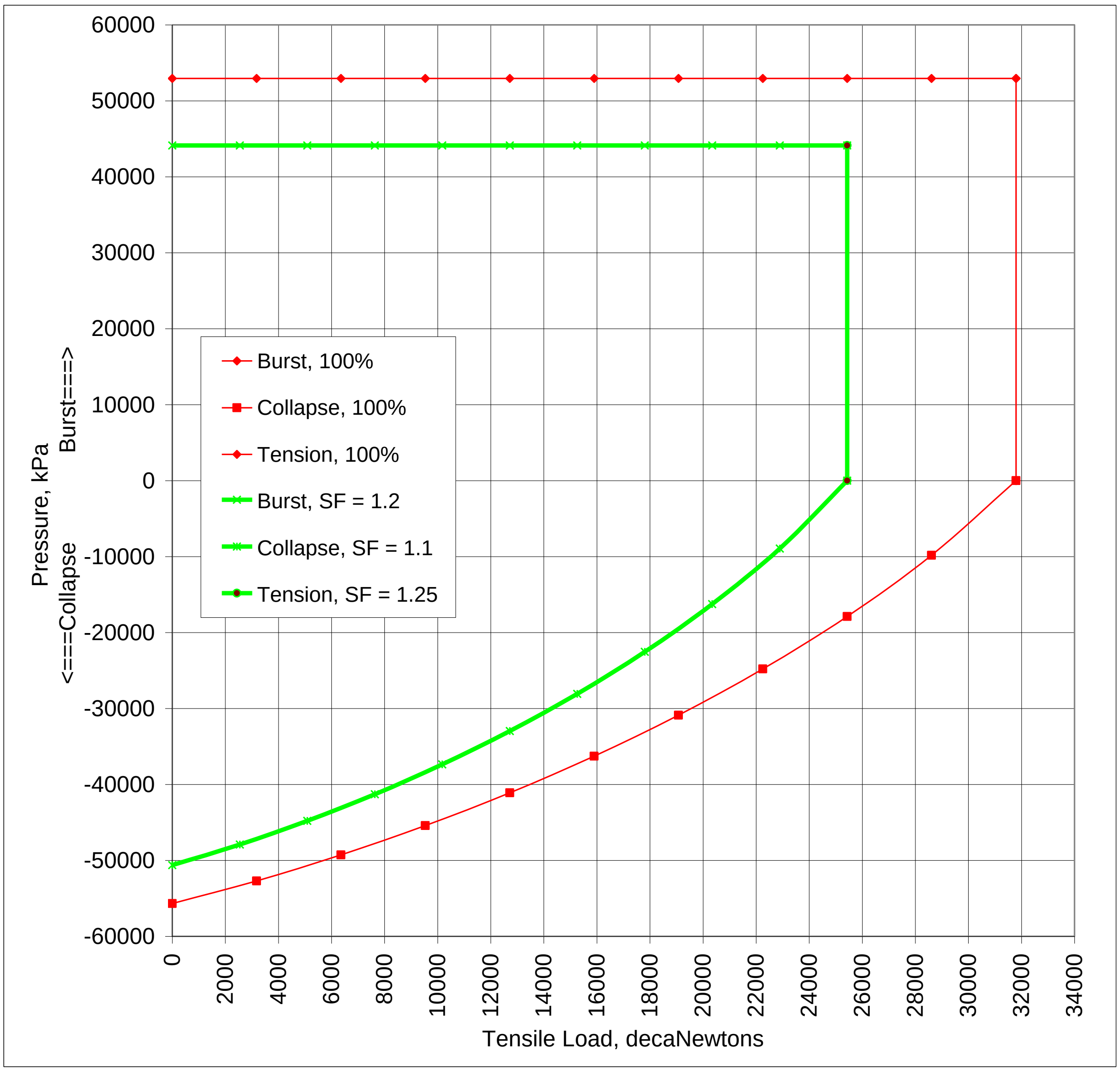


Chart 10: Tubing OD 60.3 mm Grade I-80 Tubing Wt. 6.99 Kg/m Connection EUE

Allowable Tension as a Function of Pressure

Tubing OD:	**60.3** mm	Grade:	**L-80**
Tubing Wt.	**6.99** kg/m	Connection:	**EUE**

API equations:

Eqn. 1	Yield Strength Collapse Pressure	Pyc=2*Sy*((D/t-1)/(D/t)^2
Eqn. 8	Collapse Pressure w. Axial Tension	Pca=Pyc{((1-.75(Sa/Sy)^2)^.5-0.5(Sa/Sy)}
Eqn. 30	Pipe Body Yield Strength	Fyp = Sy * 3.14 * (D^2-d^2)/4
Eqn. 31	Internal Yield Pressure	Pyi = 0.875 * (2 * Sy * t) / D

	Inputs		Calculated	
Outside diameter (D)	**60.30** mm	Steel X-sectional area		838.9 mm^2
Inside diameter (d)	**50.67** mm	Fyp		462225 Newtons
Nom. wall thickness (t)	**4.82** mm	Pyi		76996 kPa
Steel yield strength (Sy)	**551** Mpa	Pyc		-80969 kPa
Joint Efficiency (JE)	**100** %			
Safety Factor, Tension	**1.25**		EUE = 100%	
Safety Factor, Burst	**1.20**	Joint	IJ = 80%	Yield
Safety Factor, Collapse	**1.10**	Efficiencies	NUE = 60%	Strengths

where:
D = Outside diameter
d = Inside diameter
t = nominal wall thickness
Sa = Axial stress
Sy = Yield stress of the steel
Pyi = Internal Yield Pressure
Pyc = Collapse rating, no axial stress
Pca = Adjusted collapse rating
Fyp = Pipe body yeld strength
1kPa = 100 dyne/mm^2
1 Newton = 100,000 dynes
Sy of J-55 = 379 Mpa
Sy of L-80 = 551 Mpa

Allowable Tension as a Function of Pressure

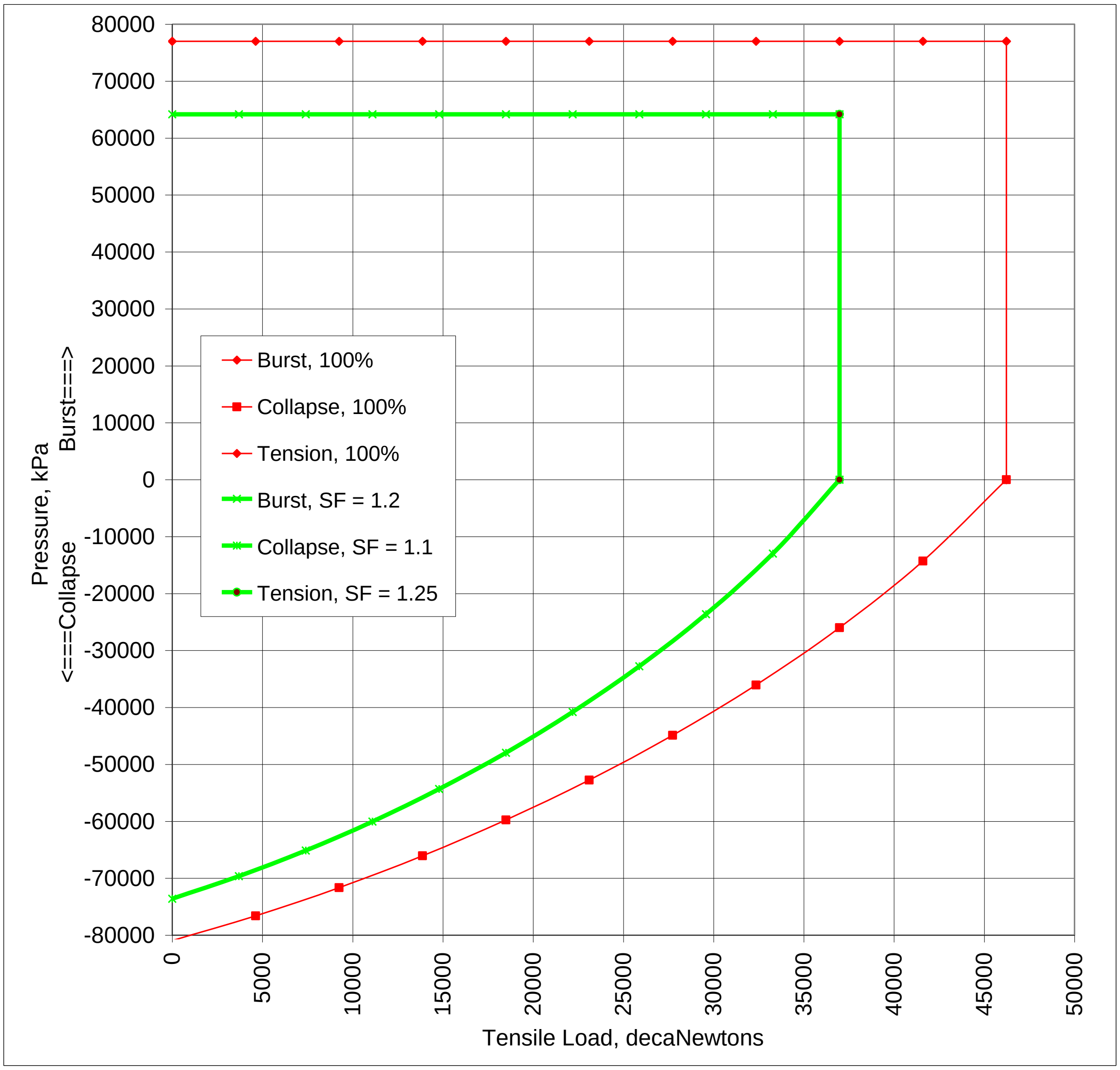


Chart 11: Tubing OD 73.0 mm Grade J-55 Tubing Wt. 9.67 Kg/m Connection EUE

Allowable Tension as a Function of Pressure

Tubing OD:	**73.0** mm	Grade:	**J-55**
Tubing Wt.	**9.67** kg/m	Connection:	**EUE**

API equations:

Eqn. 1	Yield Strength Collapse Pressure	Pyc=2*Sy*((D/t-1)/(D/t)^2
Eqn. 8	Collapse Pressure w. Axial Tension	Pca=Pyc{((1-.75(Sa/Sy)^2)^.5-0.5(Sa/Sy)}
Eqn. 30	Pipe Body Yield Strength	Fyp = Sy * 3.14 * (D^2-d^2)/4
Eqn. 31	Internal Yield Pressure	Pyi = 0.875 * (2 * Sy * t) / D

where:
D = Outside diameter
d = Inside diameter
t = nominal wall thickness
Sa = Axial stress
Sy = Yield stress of the steel
Pyi = Internal Yield Pressure
Pyc = Collapse rating, no axial stress
Pca = Adjusted collapse rating
Fyp = Pipe body yeld strength
1kPa = 100 dyne/mm^2
1 Newton = 100,000 dynes

	Inputs		Calculated	
Outside diameter (D)	73.00	mm	Steel X-sectional area	1165.7 mm^2
Inside diameter (d)	62.00	mm	Fyp	441810 Newtons
Nom. wall thickness (t)	5.50	mm	Pyi	49971 kPa
Steel yield strength (Sy)	379	Mpa	Pyc	-52807 kPa
Joint Efficiency (JE)	100	%		
Safety Factor, Tension	1.25			
Safety Factor, Burst	1.20			
Safety Factor, Collapse	1.10			

Joint Efficiencies: EUE = 100%, IJ = 80%, NUE = 60%

Yield Strengths: Sy of J-55 = 379 Mpa, Sy of L-80 = 551 Mpa

Allowable Tension as a Function of Pressure

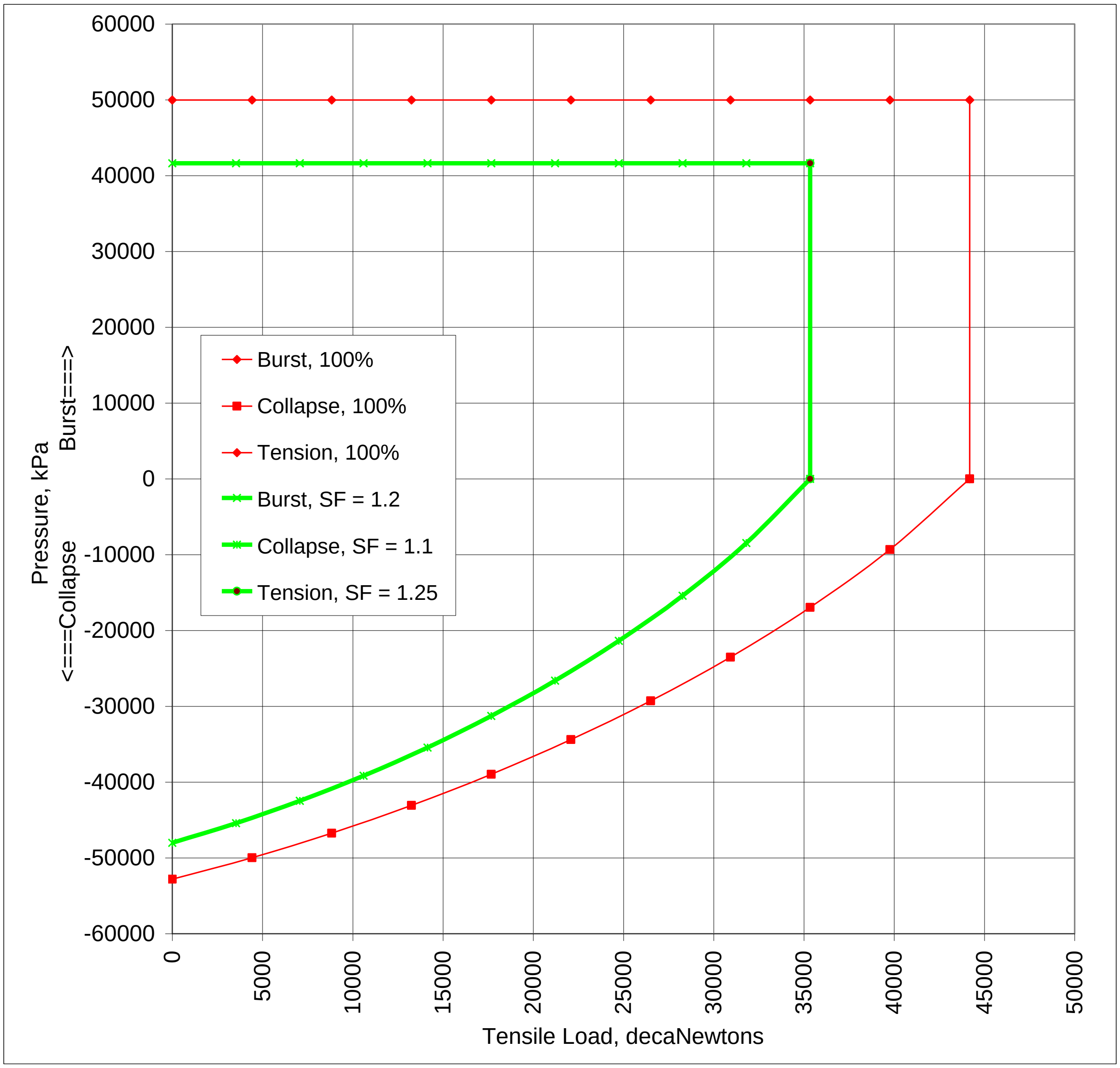


Chart 12: Tubing OD 73.0 mm Grade L-80 Tubing Wt. 9.67 Kg/m Connection EUE

Allowable Tension as a Function of Pressure

Tubing OD:	**73.0** mm		Grade:	**L-80**
Tubing Wt.	**9.67** kg/m		Connection:	**EUE**

API equations:

Eqn. 1	Yield Strength Collapse Pressure	Pyc=2*Sy*((D/t-1)/(D/t)^2
Eqn. 8	Collapse Pressure w. Axial Tension	Pca=Pyc{((1-.75(Sa/Sy)^2)^.5-0.5(Sa/Sy)}
Eqn. 30	Pipe Body Yield Strength	Fyp = Sy * 3.14 * (D^2-d^2)/4
Eqn. 31	Internal Yield Pressure	Pyi = 0.875 * (2 * Sy * t) / D

	Inputs		Calculated	
Outside diameter (D)	73.00 mm	Steel X-sectional area		1165.7 mm^2
Inside diameter (d)	62.00 mm	Fyp		642314 Newtons
Nom. wall thickness (t)	5.50 mm	Pyi		72649 kPa
Steel yield strength (Sy)	551 Mpa	Pyc		-76772 kPa
Joint Efficiency (JE)	100 %			
Safety Factor, Tension	1.25		EUE = 100%	
Safety Factor, Burst	1.20	Joint	IJ = 80%	Yield
Safety Factor, Collapse	1.10	Efficiencies	NUE = 60%	Strengths

where:
D = Outside diameter
d = Inside diameter
t = nominal wall thickness
Sa = Axial stress
Sy = Yield stress of the steel
Pyi = Internal Yield Pressure
Pyc = Collapse rating, no axial stress
Pca = Adjusted collapse rating
Fyp = Pipe body yeld strength
1kPa = 100 dyne/mm^2
1 Newton = 100,000 dynes
Sy of J-55 = 379 Mpa
Sy of L-80 = 551 Mpa

Allowable Tension as a Function of Pressure

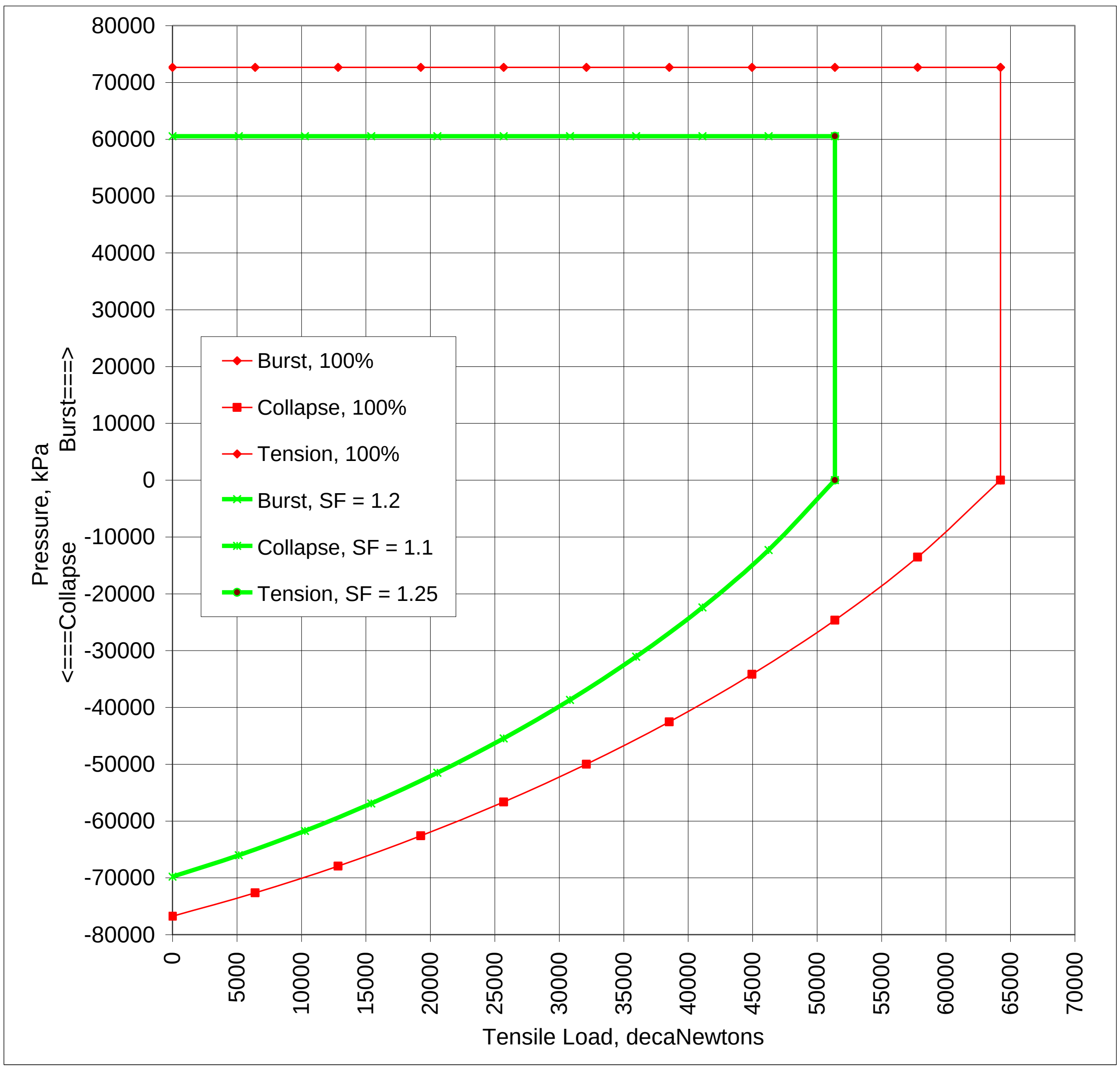


Chart 13: Tubing OD 88.9 mm Grade J-55 Tubing Wt. 13.84 Kg/m Connection EUE

Allowable Tension as a Function of Pressure

Tubing OD:	**88.9** mm		Grade:	**J-55**
Tubing Wt.	**13.84** kg/m		Connection:	**EUE**

API equations:

Eqn. 1	Yield Strength Collapse Pressure	Pyc=2*Sy*((D/t-1)/(D/t)^2
Eqn. 8	Collapse Pressure w. Axial Tension	Pca=Pyc{((1-.75(Sa/Sy)^2)^.5-0.5(Sa/Sy)}
Eqn. 30	Pipe Body Yield Strength	Fyp = Sy * 3.14 * (D^2-d^2)/4
Eqn. 31	Internal Yield Pressure	Pyi = 0.875 * (2 * Sy * t) / D

	Inputs		Calculated	
Outside diameter (D)	**88.90** mm	Steel X-sectional area		1669.9 mm^2
Inside diameter (d)	**76.00** mm	Fyp		632877 Newtons
Nom. wall thickness (t)	**6.45** mm	Pyi		48121 kPa
Steel yield strength (Sy)	**379** Mpa	Pyc		-51005 kPa
Joint Efficiency (JE)	**100** %			
Safety Factor, Tension	**1.25**		EUE = 100%	
Safety Factor, Burst	**1.20**	Joint	IJ = 80%	Yield
Safety Factor, Collapse	**1.10**	Efficiencies	NUE = 60%	Strengths

where:
D = Outside diameter
d = Inside diameter
t = nominal wall thickness
Sa = Axial stress
Sy = Yield stress of the steel
Pyi = Internal Yield Pressure
Pyc = Collapse rating, no axial stress
Pca = Adjusted collapse rating
Fyp = Pipe body yeld strength
1kPa = 100 dyne/mm^2
1 Newton = 100,000 dynes

Sy of J-55 = 379 Mpa
Sy of L-80 = 551 Mpa

Allowable Tension as a Function of Pressure

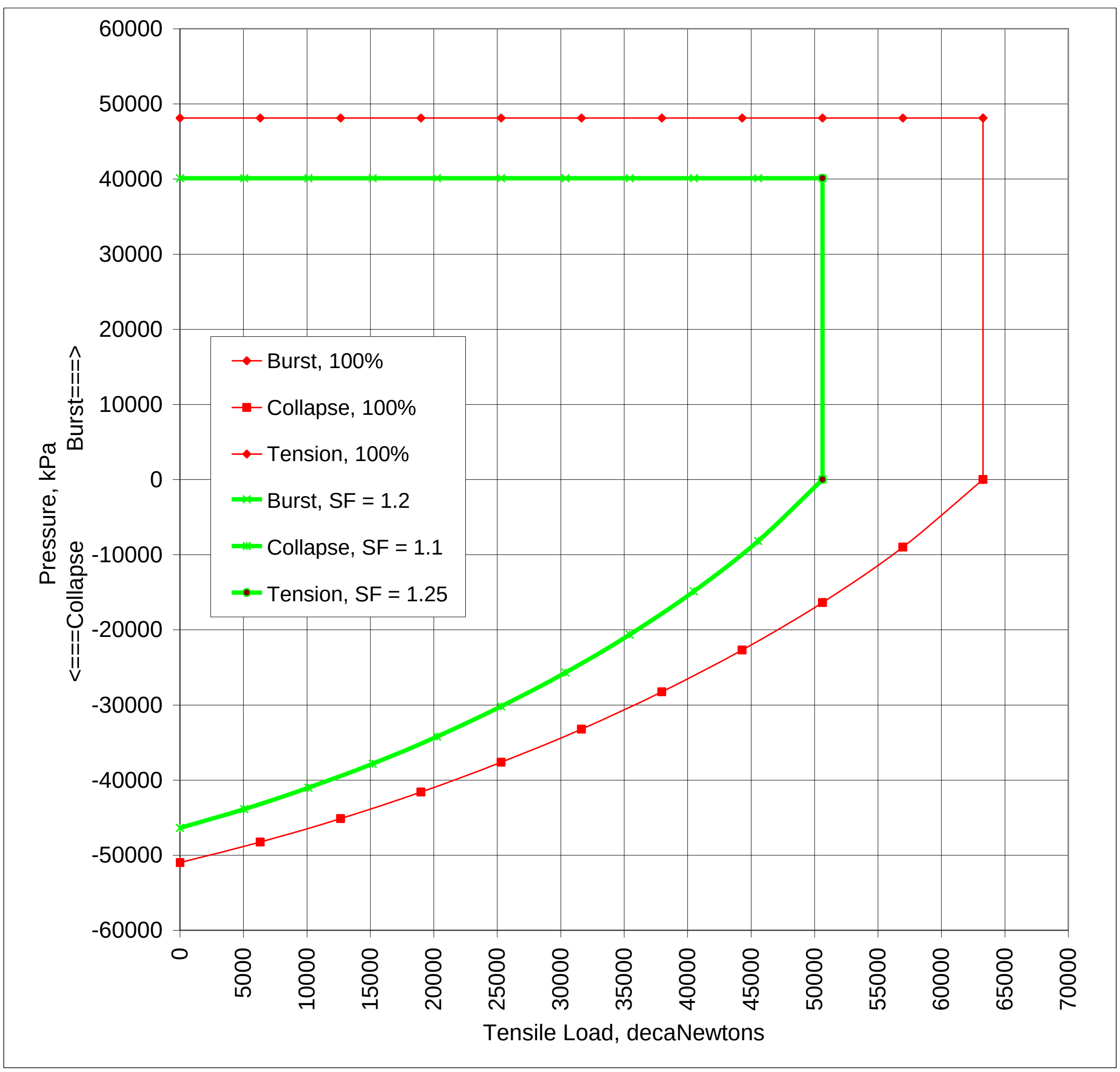


Chart 14: Tubing OD 88.9 mm Grade L-80 Tubing Wt. 13.84 Kg/m Connection EUE

Allowable Tension as a Function of Pressure

Tubing OD:	**88.9** mm		Grade:	**L-80**
Tubing Wt.	**13.84** kg/m		Connection:	**EUE**

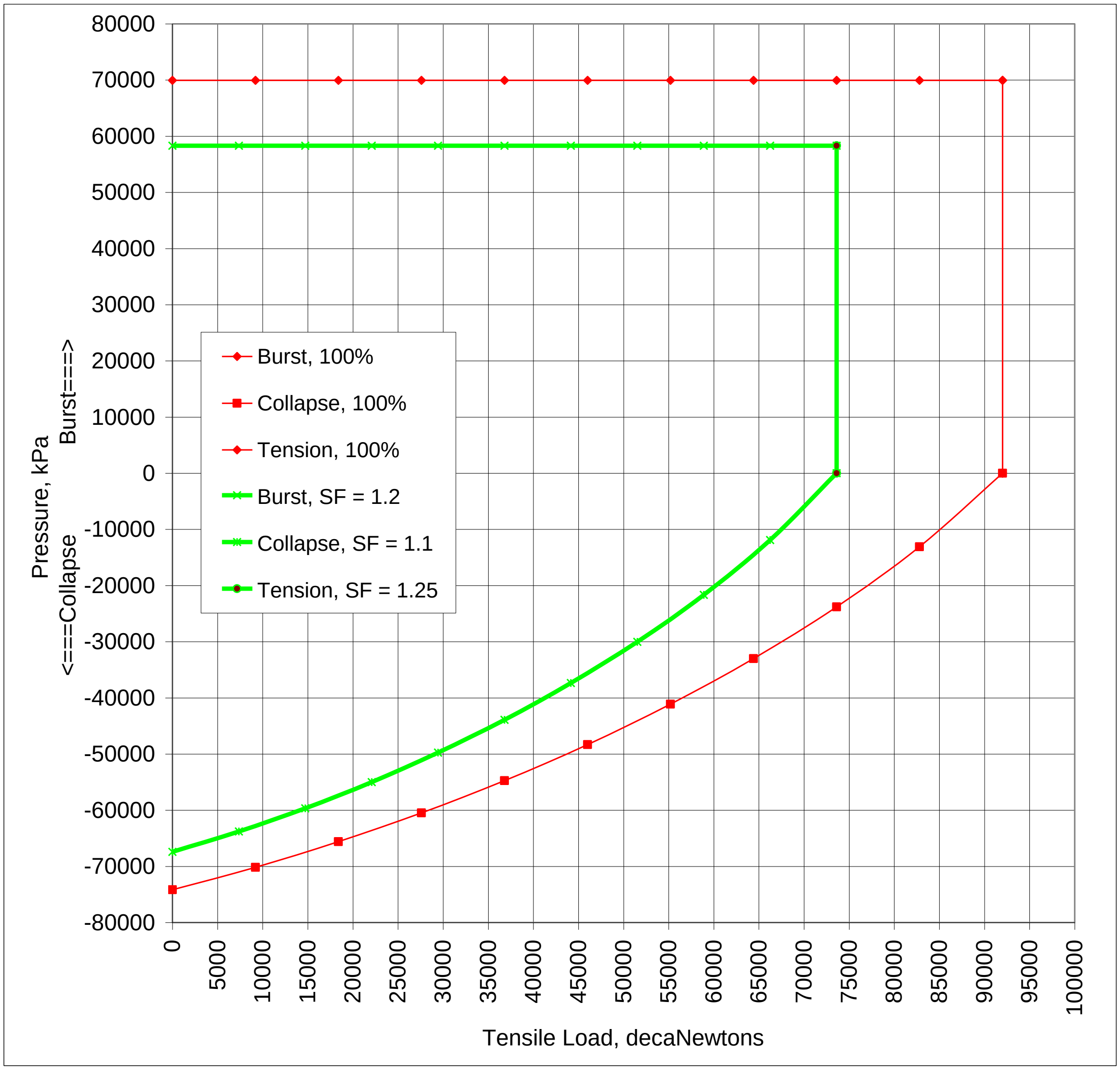
API equations:

Eqn. 1	Yield Strength Collapse Pressure	Pyc=2*Sy*((D/t-1)/(D/t)^2	
Eqn. 8	Collapse Pressure w. Axial Tension	Pca=Pyc{((1-.75(Sa/Sy)^2)^.5-0.5(Sa/Sy)}	
Eqn. 30	Pipe Body Yield Strength	Fyp = Sy * 3.14 * (D^2-d^2)/4	
Eqn. 31	Internal Yield Pressure	Pyi = 0.875 * (2 * Sy * t) / D	

where:
D = Outside diameter
d = Inside diameter
t = nominal wall thickness
Sa = Axial stress
Sy = Yield stress of the steel
Pyi = Internal Yield Pressure
Pyc = Collapse rating, no axial stress
Pca = Adjusted collapse rating
Fyp = Pipe body yeld strength
1kPa = 100 dyne/mm^2
1 Newton = 100,000 dynes

	Inputs		Calculated	
Outside diameter (D)	**88.90** mm	Steel X-sectional area	1669.9 mm^2	
Inside diameter (d)	**76.00** mm	Fyp	920093 Newtons	
Nom. wall thickness (t)	**6.45** mm	Pyi	69960 kPa	
Steel yield strength (Sy)	**551** Mpa	Pyc	-74153 kPa	
Joint Efficiency (JE)	**100** %			
Safety Factor, Tension	**1.25**		EUE = 100%	
Safety Factor, Burst	**1.20**	Joint	IJ = 80%	Yield Strengths: Sy of J-55 = 379 Mpa
Safety Factor, Collapse	**1.10**	Efficiencies	NUE = 60%	Sy of L-80 = 551 Mpa

Allowable Tension as a Function of Pressure

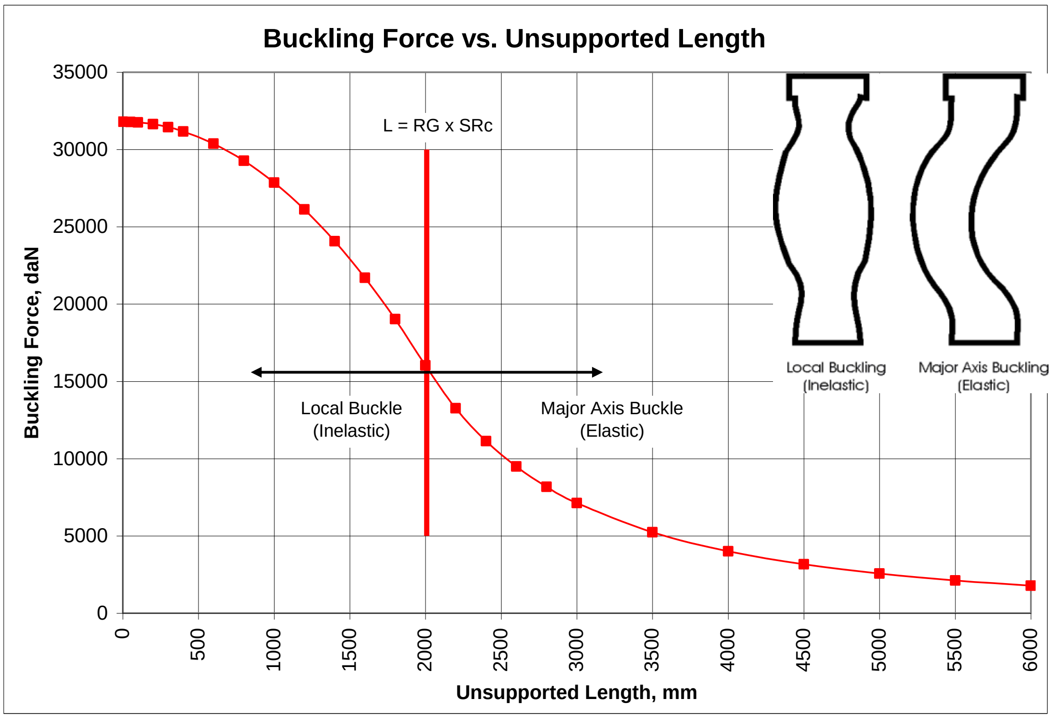


Appendix J: Pipe Buckling Forces – Petro-Canada

Pipe Buckling (pipe light condition)

The allowable length of unsupported pipe above the snubbing annular (or stripping pipe rams) must be determined. The length of unsupported tubing increases when the snubbing annular is open. The upwards force generated by wellbore pressures increases when a tubing connection is in the snubbing annular.

Tubing OD	**60.30** mm	Grade	**J-55**
Tubing weight	**6.99** kg/m	Connection	**EUE**



Use Johnson's Equation for Short Column Buckling (Local Buckling)

Flb =Sy*As*(1-(L/RG)^2/(2*(SRc)^2))

Use Euler's Equation for Long Column Buckling (Major Axis Buckling)

Feb =(3.14)^2*E*I/(L)^2

Where:

- As = Steel cross sectional area
- Sy = Yield stress of steel
- I = Moment of Inertia
- RG = Radius of Gyration
- SR = Slenderness ratio for a given length
- SRc = Critical slenderness ratio
- L = Unsupported Length

The safety factor applied to the above equations depends on the strength of the tubing connection.

These calculations have been provided by Petro-Canada as a reference only. Reliance on this material alone to the exclusion of other professional advice, experience or resources is imprudent since each situation is unique.

Pipe Buckling Forces

There are five vertical forces acting on the tubing string while snubbing

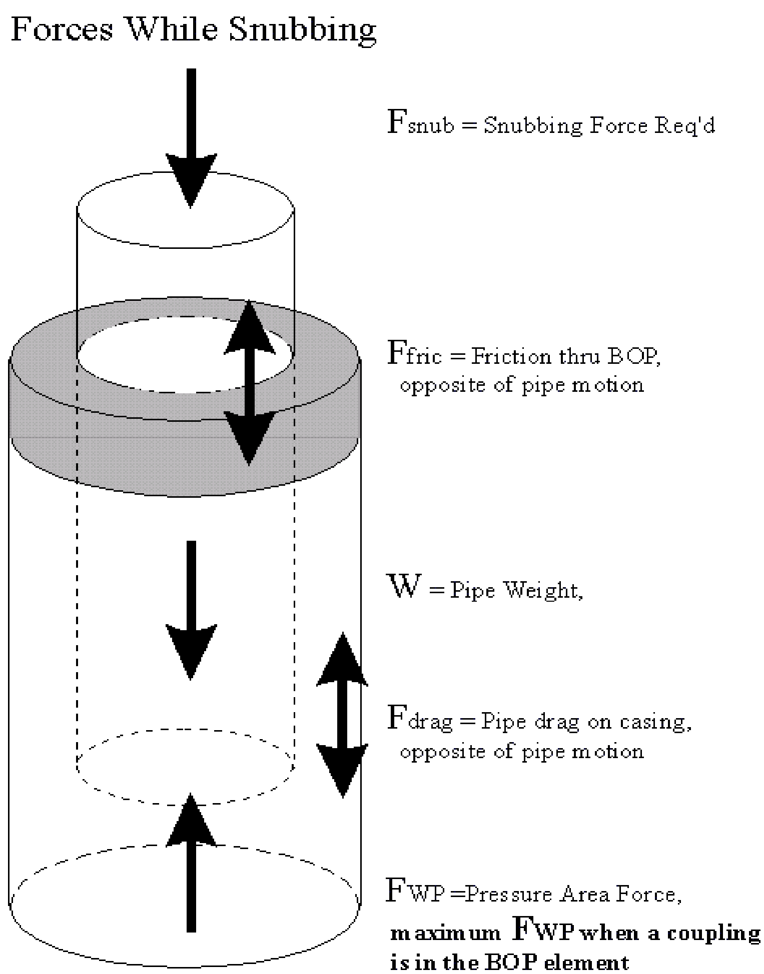
1. Force resulting from well pressure acting on the cross section of the tubing string or coupling (Fwp)

2. Gravitational force or weight of the tubing string (W).

3. Frictional force to push pipe through the BOPs (Ffric).

4. Force caused by pipe drag on the casing (Fdrag)

5. Force applied by the snubbing unit (Fsnub).



Fsnub is the force required to push the tubing into the wellbore.

Maximum Fsnub occurs when pipe is being started into the wellbore, as there is no pipe weight to counter pressure. Fsnub = Fwp + Ffric.

Force due to friction through the annular BOP is a function of how much hydraulic pressure is applied to the annular, which in turn is a function of the well pressure. Conservatively assume that Ffric = 20% of Fwp.

The upwards force generated by wellbore pressures increases when a tubing connection is in the snubbing annular.

These calculations have been provided by Petro-Canada as a reference only. Reliance on this material alone to the exclusion of other professional advice, experience or resources is imprudent since each situation is unique.

Connection Strength vs. Pipe Body Strength

J55 Pipe yield stress **379** Mpa

Tubing Diameter mm	Weight kg/m	Coupling Type	Coupling Diameter mm	Coupling X-sect. Area mm^2	Pipe OD mm	Pipe ID mm	Area OD mm^2	Area ID mm^2	Pipe Body Strength daN	Connection Strength daN	Ratio
33.4	2.56	IJ	39.4	1222	33.4	26.64	876	557	12075	9800	0.812
42.2	3.47	IJ	47.8	1799	42.2	35.05	1398	964	16433	13600	0.828
48.3	4.11	IJ	53.6	2262	48.3	40.89	1831	1313	19663	16400	0.834
52.4	4.85	IJ	59.1	2751	52.4	44.48	2155	1553	22828	21800	0.955
60.3	7.00	EUE	77.8	4767	60.3	50.67	2854	2015	31794	31900	1.003
73.0	9.69	EUE	93.2	6840	73.0	62.00	4183	3018	44181	44300	1.003
88.9	13.87	EUE	114.3	10288	88.9	76.00	6204	4534	63288	63400	1.002

L80 Pipe yield stress **551** Mpa

Tubing Diameter mm	Weight kg/m	Coupling Type	Coupling Diameter mm	Coupling X-sect. Area mm^2	Pipe OD mm	Pipe ID mm	Area OD mm^2	Area ID mm^2	Pipe Body Strength daN	Connection Strength daN	Ratio
33.4	2.56	IJ	39.4	1222	33.4	26.64	876	557	17555	14200	0.809
42.2	3.47	IJ	47.8	1799	42.2	35.05	1398	964	23891	19700	0.825
48.3	4.11	IJ	53.6	2262	48.3	40.89	1831	1313	28586	23900	0.836
52.4	4.85	IJ	59.1	2751	52.4	44.48	2155	1553	33188	31800	0.958
60.3	7.00	EUE	77.8	4767	60.3	50.67	2854	2015	46222	46400	1.004
73.0	9.69	EUE	93.2	6840	73.0	62.00	4183	3018	64231	64500	1.004
88.9	13.87	EUE	114.3	10288	88.9	76.00	6204	4534	92009	92200	1.002

Comments regarding API 5CT and pipe wall thickness:
Some operators use a minimum wall thickness that is 12.5% less than the nominal wall thickness when doing buckling calculations, but this appears to be overly conservative. API 5CT , section 8, states that there is a mass tolerance of +6.5 / -3.5 % on casing and tubing. There is an OD tolerance of +/- 0.79 mm on tubing, but most pipe manufacturers appear to be making pipe slightly oversize, rather than undersize to ensure that the pipe meets drift specifications.

Comments regarding long column buckling (Euler buckling)
Euler's buckling equation takes the form:

– Fcr = n•π^2•E•I/(L^2)

Where: n = 1 for a column that is pivoted at both ends, n = 4 for fixed ends, n = 2 when one end is free and the other is rounded, and n = ¼ when one end is fixed and the other is free..

All snubbing calculations appear to use a value of n=1 in determining major axis buckling. It is reasonable to assume, however, that the pipe is somewhat fixed when being held in the annular preventer and travelling pipe light slips.

These calculations have been provided by Petro-Canada as a reference only. Reliance on this material alone to the exclusion of other professional advice, experience or resources is imprudent since each situation is unique.

Buckling Tables Explanation

Before starting a snubbing job, it is necessary to determine the expected snubbing force, Fsnub, and the allowable unsupported length of tubing.

Step 1 Referring to the figures on worksheets entitled Low Pressure Snubbing Arrangement and High Presure Snubbing Arrangement, determine the distance between the snubbing annular and the lowest attainable position for the travelling, pipe light slips.

Step 2 Refer to the buckling worksheet appropriate for the size, weight and grade of tubing that will be snubbed. There are 14 worksheets, corresponding to the most likely tubing, connection & grade combinations likely to be snubbed by Petro-Canada.

Tubing Diameter mm	Tubing Weight kg/m	Tubing Grade
33.4	2.56	J-55 or L-80
42.2	3.47	J-55 or L-80
48.3	4.11	J-55 or L-80
52.4	4.85	J-55 or L-80
60.3	6.99	J-55 or L-80
73.0	9.69	J-55 or L-80
88.9	13.87	J-55 or L-80

Use the tables or charts to determine the allowable unsupported length as a function of wellbore pressure for the tubing, plus when a connection is in the annular BOP (or stripping pipe rams if the annular is open).

The smaller diameters, 33.4, 42.2, 48.3 & 52.4 mm are likely to have Integral Joint connections. 33.4, 42.2 & 48.3 mm IJ connections have about 83% of the strength of the pipe body. Use the 60% curve for these three tubing sizes. The 52.4 mm IJ connection has ± 95% of the strength of the pipe body. Use the 65% curve for 52.4 mm IJ tubing.

The larger diameters, 60.3, 73.0 and 88.9 mm are likely to have EUE or premium connections. EUE and premium connections have 100% of the strength of the pipe body. Use the 70% curve for these 3 sizes.

If the tubing is N-80 (non sour spec), is old, the wellbore pressure is greater than 5000 psi (35 MPa) or if there is an H_2S concentration greater than 1.0% (10,000 ppm), reduce the unsupported length by 25%.

Step 3 If the wellbore conditions and snubbing lengths are such that snubbing forces will exceed the limits illustrated in the buckling calculation worksheets, it will probably be necessary to add liquid to the wellbore so as to reduce the wellbore pressure and snubbing force required.

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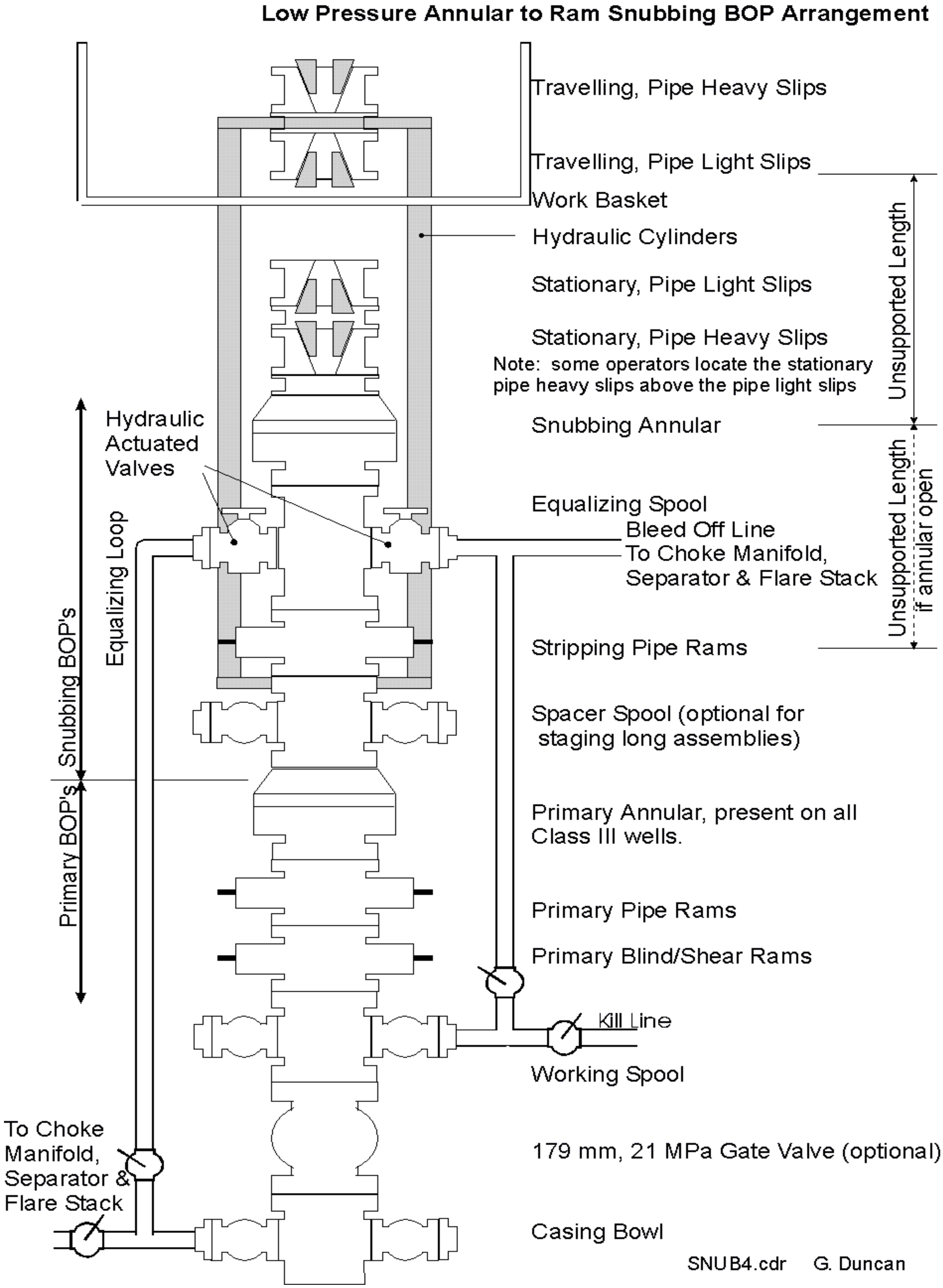

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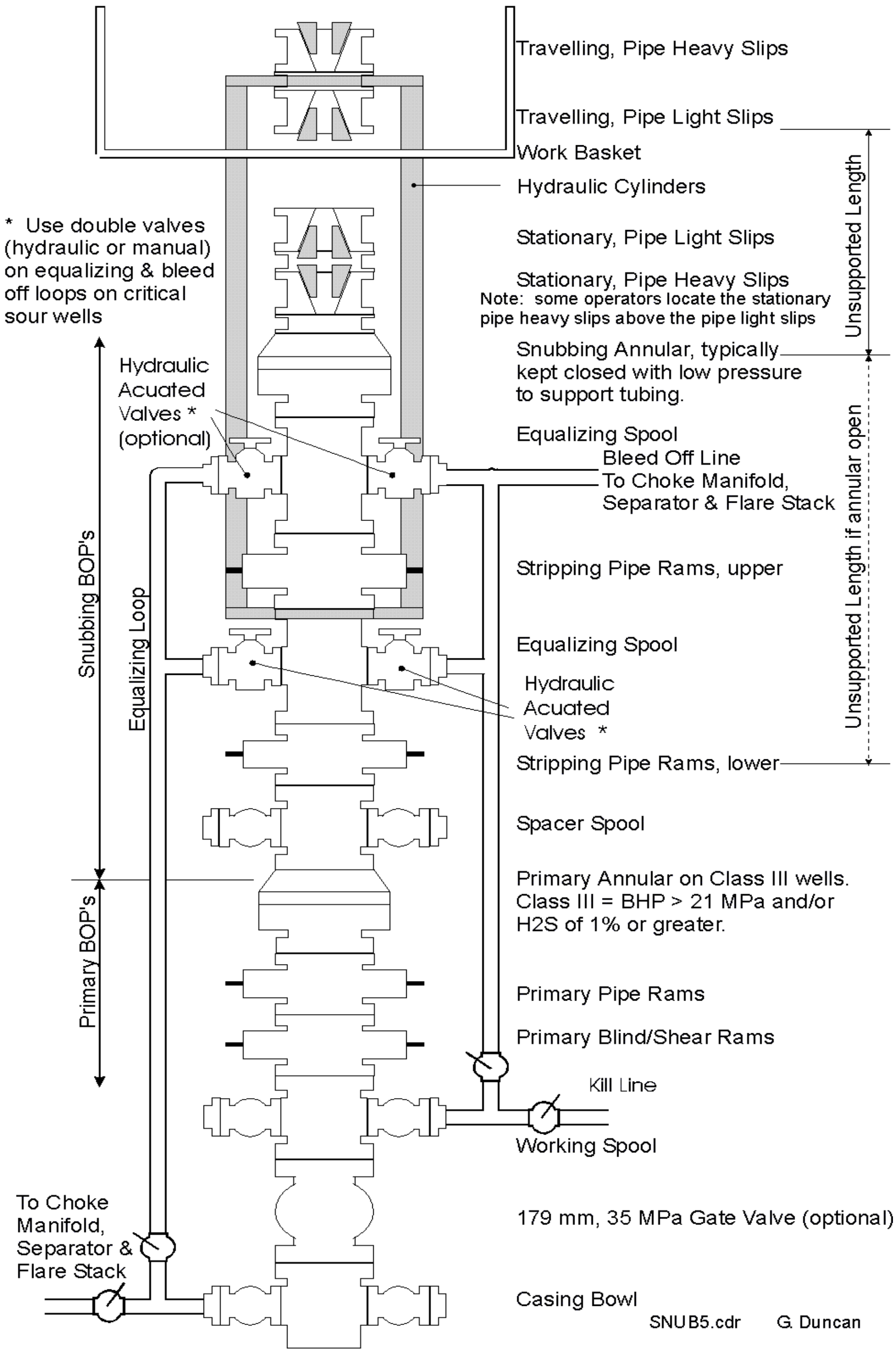
High Pressure Ram to Ram Snubbing BOP Arrangement



These calculations have been provided by Petro-Canada as a reference only. Reliance on this material alone to the exclusion of other professional advice, experience or resources is imprudent since each situation is unique.

Chart 15: Tubing OD 33.4 mm Grade J-55 Tubing Wt. 2.56 Kg/m Connection IJ

Pipe Buckling Calculations

Tubing OD **33.40** mm   Tubing weight **2.56** kg/m
Grade **J-55**   Connection **IJ**

	INPUT		
Pipe OD	OD	**33.40**	mm
Pipe ID	ID	**26.64**	mm
Cplg OD	CplgOD	**39.40**	mm
Pipe yield stress	Sy	**379**	MPa
Modulus Elasticity	E	**200**	GPa
	CALCULATED		
Area, pipe OD	Ao	876	mm^2
Area, pipe ID	Ai	557	mm^2
Area, steel	As	319	mm^2
Moment of Inertia	I	36346	mm^4
Radius of Gyration	RG	10.68	mm
Critical Slenderness Ratio	SRc	102.0	
Cplg x-sect area	Acplg	1222	mm^2
	EQUATIONS		
Area, pipe OD	Ao	=3.14*(OD^2)/4	
Area, pipe ID	Ai	= 3.14*(ID^2)/4	
Area, steel	As	=Ao-Ai	
Moment of Inertia	I	=3.14*(OD^4-ID^4)/64	
Radius of Gyration	RG	=(I/As)^.5	
Crit.slenderness ratio	SRc	=3.14*(2*E/Sy)^.5	
Slenderness ratio	SR	=L/r	
Local Buckle (Johnson's Eqn, short column)	Flb	=Sy*As*(1-(L/RG)^2/(2*(SRc)^2))	
Major Axis Buckle (Euler Eqn, long column, pinned ends)	Feb	=(3.14)^2*E*I/(L)^2	
Buckling Load	Fb	=IF(SR>SRc,Feb,Flb)	

Snubbing Force vs Wellbore Pressure

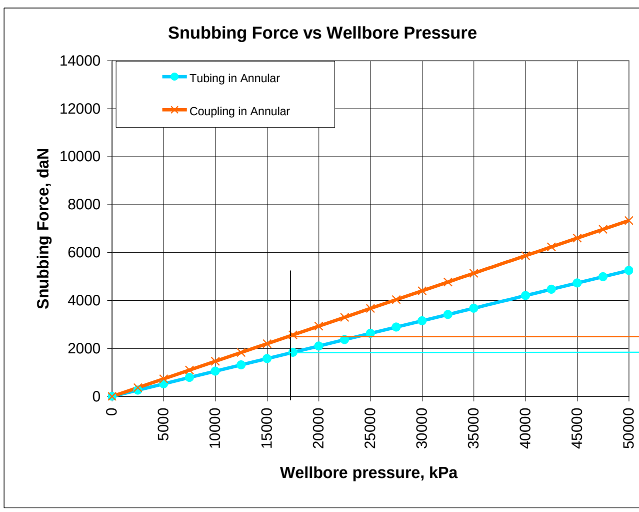
Wellbore Pressure kPa	Snubbing Force: Tubing in Annular, daN	Snubbing Force: Coupling in Annular, daN	Transition to pipe heavy, m.	Length at which cplg. neutral, m.
0	0	0	0.0	0.0
2500	263	367	104.6	146.0
5000	525	733	209.2	292.1
7500	788	1100	313.8	438.1
10000	1051	1467	418.4	584.1
12500	1314	1834	523.1	730.2
15000	1576	2200	627.7	876.2
17500	1839	2567	732.3	1022.2
20000	2102	2934	836.9	1168.3
22500	2364	3301	941.5	1314.3
25000	2627	3667	1046.1	1460.3
27500	2890	4034	1150.7	1606.4
30000	3153	4401	1255.3	1752.4
32500	3415	4768	1359.9	1898.4
35000	3678	5134	1464.5	2044.5
40000	4203	5868	1673.8	2336.6
42500	4466	6235	1778.4	2482.6
45000	4729	6601	1883.0	2628.6
47500	4992	6968	1987.6	2774.7
50000	5254	7335	2092.2	2920.7

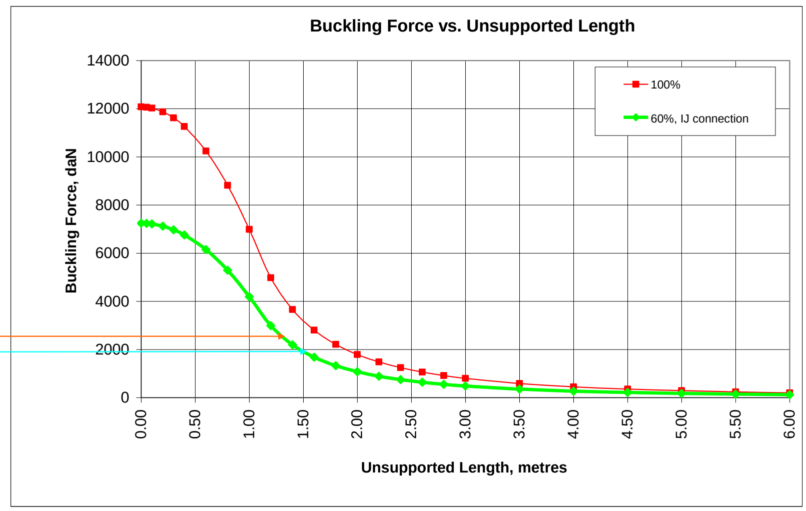
Note: Above snubbing forces include 20% for friction through the annular BOP
Fwp = WP (kPa) * X-area (mm^2) / 10000
Fsnub = Fwp + Ffric = 1.2 x Fwp
units: decaNewtons

Above calculations assume annulus gas has a specific gravity = 1.0 (air sg = 1.0)

Buckling Force as a Function of Unsupported Length

Unsupported Length (mm)	Unsupported Length (metres)	Slenderness Ratio	Buckling Force, daN IJ 100%	Buckling Force, daN IJ **60%**
0	0.00	0.00	12075	**7245**
50	0.05	4.68	12063	**7238**
100	0.10	9.36	12024	**7215**
200	0.20	18.73	11872	**7123**
300	0.30	28.09	11618	**6971**
400	0.40	37.45	11261	**6757**
600	0.60	56.18	10244	**6147**
800	0.80	74.90	8820	**5292**
1000	1.00	93.63	6989	**4193**
1200	1.20	112.35	4977	**2986**
1400	1.40	131.08	3657	**2194**
1600	1.60	149.80	2800	**1680**
1800	1.80	168.53	2212	**1327**
2000	2.00	187.25	1792	**1075**
2200	2.20	205.98	1481	**888**
2400	2.40	224.70	1244	**747**
2600	2.60	243.43	1060	**636**
2800	2.80	262.15	914	**549**
3000	3.00	280.88	796	**478**
3500	3.50	327.69	585	**351**
4000	4.00	374.51	448	**269**
4500	4.50	421.32	354	**212**
5000	5.00	468.13	287	**172**
5500	5.50	514.95	237	**142**
6000	6.00	561.76	199	**119**





Example: Wellbore pressure = 17,500 kPa   Tubing snubbing force = 1839 daN   Coupling snubbing force = 2567 daN

Allowable unsupported length with tubing in annular BOP 1.5 metres
Allowable unsupported length, coupling in annular BOP 1.3 metres

These calculations have been provided by Petro-Canada as a reference only. Reliance on this material alone to the exclusion of other professional advice, experience or resources is imprudent since each situation is unique.

Chart 16: Tubing OD 33.4 mm Grade L-80 Tubing Wt. 2.56 Kg/m Connection IJ

Pipe Buckling Calculations

Tubing OD **33.40** mm Tubing weight **2.56** kg/m
Grade **L-80** Connection **IJ**

	INPUT	
Pipe OD	OD	**33.40** mm
Pipe ID	ID	**26.64** mm
Cplg OD	CplgOD	**39.40** mm
Pipe yield stress	Sy	**551** MPa
Modulus Elasticity	E	**200** GPa
	CALCULATED	
Area, pipe OD	Ao	876 mm^2
Area, pipe ID	Ai	557 mm^2
Area, steel	As	319 mm^2
Moment of Inertia	I	36346 mm^4
Radius of Gyration	RG	10.68 mm
Critical Slenderness Ratio	SRc	84.6
Cplg x-sect area	Acplg	1222 mm^2
	EQUATIONS	
Area, pipe OD	Ao	=3.14*(OD^2)/4
Area, pipe ID	Ai	= 3.14*(ID^2)/4
Area, steel	As	=Ao-Ai
Moment of Inertia	I	=3.14*(OD^4-ID^4)/64
Radius of Gyration	RG	=(I/As)^.5
Crit.slenderness ratio	SRc	=3.14*(2*E/Sy)^.5
Slenderness ratio	SR	=L/r
Local Buckle (Johnson's Eqn, short column)	Flb	=Sy*As*(1-(L/RG)^2/(2*(SRc)^2))
Major Axis Buckle (Euler Eqn, long column, pinned ends)	Feb	=(3.14)^2*E*I/(L)^2
Buckling Load	Fb	=IF(SR>SRc,Feb,Flb)

Snubbing Force vs Wellbore Pressure

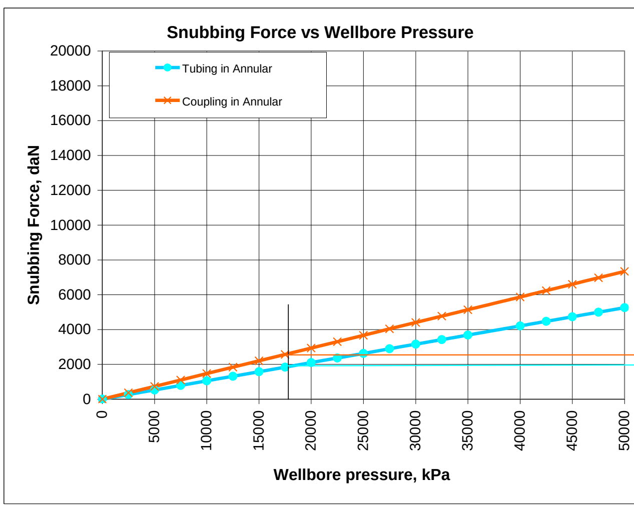
Wellbore Pressure kPa	Snubbing Force Tubing in Annular, daN	Coupling in Annular, daN	Transition to pipe heavy, m.	Length at which cplg. neutral, m.
0	0	0	0.0	0.0
2500	263	367	104.6	146.0
5000	525	733	209.2	292.1
7500	788	1100	313.8	438.1
10000	1051	1467	418.4	584.1
12500	1314	1834	523.1	730.2
15000	1576	2200	627.7	876.2
17500	1839	2567	732.3	1022.2
20000	2102	2934	836.9	1168.3
22500	2364	3301	941.5	1314.3
25000	2627	3667	1046.1	1460.3
27500	2890	4034	1150.7	1606.4
30000	3153	4401	1255.3	1752.4
32500	3415	4768	1359.9	1898.4
35000	3678	5134	1464.5	2044.5
40000	4203	5868	1673.8	2336.6
42500	4466	6235	1778.4	2482.6
45000	4729	6601	1883.0	2628.6
47500	4992	6968	1987.6	2774.7
50000	5254	7335	2092.2	2920.7

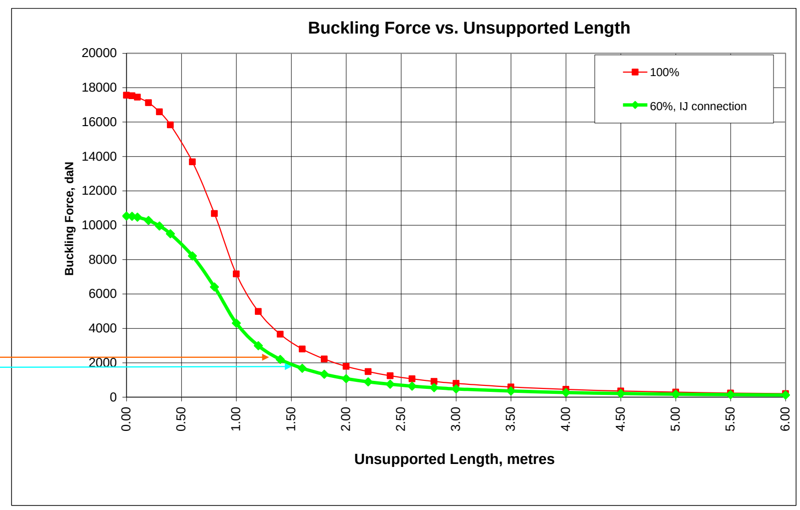
Note: Above snubbing forces include 20% for friction through the annular BOP
Fwp = WP (kPa) * X-area (mm^2) / 10000
Fsnub = Fwp + Ffric = 1.2 x Fwp
units: decaNewtons

Above calculations assume annulus gas has a specific gravity = 1.0 (air sg = 1.0)

Buckling Force as a Function of Unsupported Length

Unsupported Length (mm)	Unsupported Length (metres)	Slenderness Ratio	Buckling Force, daN IJ 100%	**60%**
0	0.00	0.00	17555	**10533**
50	0.05	4.68	17528	**10517**
100	0.10	9.36	17448	**10469**
200	0.20	18.73	17125	**10275**
300	0.30	28.09	16588	**9953**
400	0.40	37.45	15835	**9501**
600	0.60	56.18	13685	**8211**
800	0.80	74.90	10675	**6405**
1000	1.00	93.63	7167	**4300**
1200	1.20	112.35	4977	**2986**
1400	1.40	131.08	3657	**2194**
1600	1.60	149.80	2800	**1680**
1800	1.80	168.53	2212	**1327**
2000	2.00	187.25	1792	**1075**
2200	2.20	205.98	1481	**888**
2400	2.40	224.70	1244	**747**
2600	2.60	243.43	1060	**636**
2800	2.80	262.15	914	**549**
3000	3.00	280.88	796	**478**
3500	3.50	327.69	585	**351**
4000	4.00	374.51	448	**269**
4500	4.50	421.32	354	**212**
5000	5.00	468.13	287	**172**
5500	5.50	514.95	237	**142**
6000	6.00	561.76	199	**119**





Example: Wellbore pressure = 17,500 kPa Tubing snubbing force = 1839 daN
Coupling snubbing force = 2567 daN

Allowable unsupported length with tubing in annular BOP 1.5 metres
Allowable unsupported length, coupling in annular BOP 1.3 metres

These calculations have been provided by Petro-Canada as a reference only. Reliance on this material alone to the exclusion of other professional advice, experience or resources is imprudent since each situation is unique.

Chart 17: Tubing OD 42.2 mm Grade J-55 Tubing Wt. 3.47 Kg/m Connection IJ

Pipe Buckling Calculations

Tubing OD	**42.20** mm	
Grade	**J-55**	
Tubing weight	**3.47** kg/m	
Connection	**IJ**	

	INPUT	
Pipe OD	OD	**42.20** mm
Pipe ID	ID	**35.05** mm
Cplg OD	CplgOD	**47.90** mm
Pipe yield stress	Sy	**379** MPa
Modulus Elasticity	E	**200** GPa
	CALCULATED	
Area, pipe OD	Ao	1398 mm^2
Area, pipe ID	Ai	964 mm^2
Area, steel	As	434 mm^2
Moment of Inertia	I	81550 mm^4
Radius of Gyration	RG	13.71 mm
Critical Slenderness Ratio	SRc	102.0
Cplg x-sect area	Acplg	1807 mm^2
	EQUATIONS	
Area, pipe OD	Ao	=3.14*(OD^2)/4
Area, pipe ID	Ai	= 3.14*(ID^2)/4
Area, steel	As	=Ao-Ai
Moment of Inertia	I	=3.14*(OD^4-ID^4)/64
Radius of Gyration	RG	=(I/As)^.5
Crit.slenderness ratio	SRc	=3.14*(2*E/Sy)^.5
Slenderness ratio	SR	=L/r
Local Buckle (Johnson's Eqn, short column)	Flb	=Sy*As*(1-(L/RG)^2/(2*(SRc)^2))
Major Axis Buckle (Euler Eqn, long column, pinned ends)	Feb	=(3.14)^2*E*I/(L)^2
Buckling Load	Fb	=IF(SR>SRc,Feb,Flb)

Snubbing Force vs Wellbore Pressure

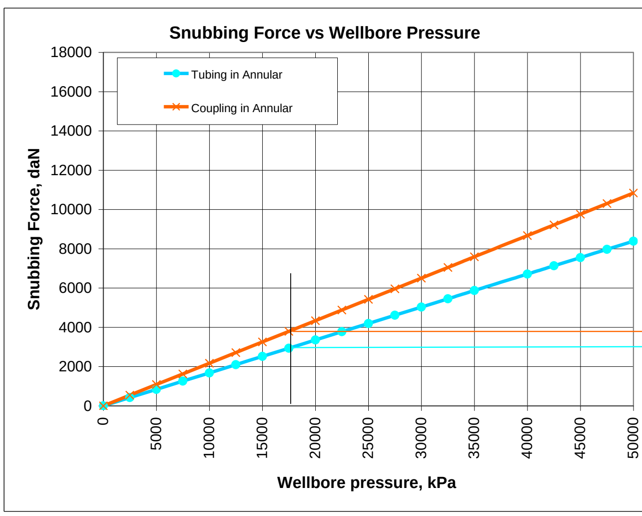
Wellbore Pressure kPa	Snubbing Force: Tubing in Annular, daN	Snubbing Force: Coupling in Annular, daN	Transition to pipe heavy, m.	Length at which cplg. neutral, m.
0	0	0	0.0	0.0
2500	419	542	123.2	159.2
5000	839	1084	246.4	318.5
7500	1258	1626	369.6	477.7
10000	1678	2168	492.8	636.9
12500	2097	2710	616.0	796.2
15000	2516	3252	739.2	955.4
17500	2936	3794	862.4	1114.7
20000	3355	4336	985.6	1273.9
22500	3774	4878	1108.8	1433.1
25000	4194	5421	1232.0	1592.4
27500	4613	5963	1355.2	1751.6
30000	5033	6505	1478.4	1910.8
32500	5452	7047	1601.6	2070.1
35000	5871	7589	1724.8	2229.3
40000	6710	8673	1971.2	2547.8
42500	7130	9215	2094.4	2707.0
45000	7549	9757	2217.6	2866.3
47500	7968	10299	2340.8	3025.5
50000	8388	10841	2464.0	3184.7

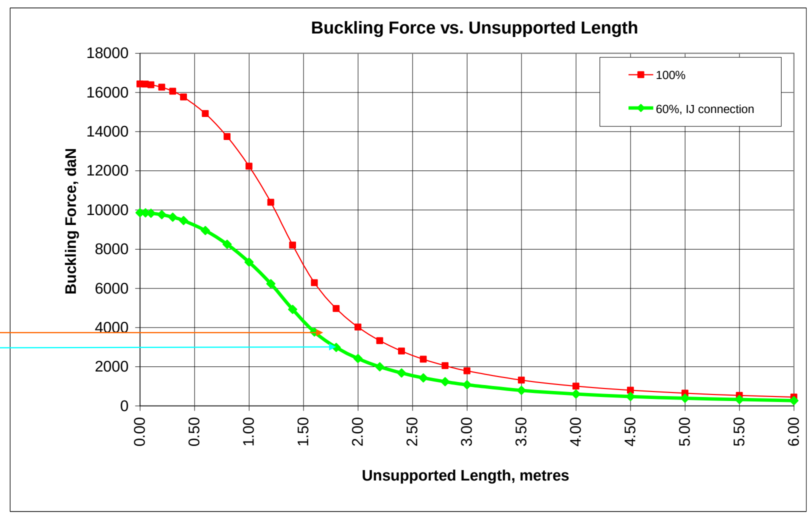
Note: Above snubbing forces include 20% for friction through the annular BOP
Fwp = WP (kPa) * X-area (mm^2) / 10000
Fsnub = Fwp + Ffric = 1.2 x Fwp
units: decaNewtons

Above calculations assume annulus gas has a specific gravity = 1.0 (air sg = 1.0)

Buckling Force as a Function of Unsupported Length

Unsupported Length (mm)	Unsupported Length (metres)	Slenderness Ratio	Buckling Force, daN 100%	IJ 60%
0	0.00	0.00	16433	**9860**
50	0.05	3.65	16422	**9853**
100	0.10	7.29	16391	**9835**
200	0.20	14.58	16265	**9759**
300	0.30	21.87	16055	**9633**
400	0.40	29.17	15761	**9457**
600	0.60	43.75	14922	**8953**
800	0.80	58.33	13746	**8248**
1000	1.00	72.92	12235	**7341**
1200	1.20	87.50	10388	**6233**
1400	1.40	102.08	8205	**4923**
1600	1.60	116.67	6282	**3769**
1800	1.80	131.25	4963	**2978**
2000	2.00	145.83	4020	**2412**
2200	2.20	160.42	3323	**1994**
2400	2.40	175.00	2792	**1675**
2600	2.60	189.58	2379	**1427**
2800	2.80	204.17	2051	**1231**
3000	3.00	218.75	1787	**1072**
3500	3.50	255.21	1313	**788**
4000	4.00	291.66	1005	**603**
4500	4.50	328.12	794	**476**
5000	5.00	364.58	643	**386**
5500	5.50	401.04	532	**319**
6000	6.00	437.50	447	**268**





Example:	Wellbore pressure = 17,500 kPa	Tubing snubbing force =	2936 daN	Allowable unsupported length with tubing in annular BOP	1.8 metres
		Coupling snubbing force =	3794 daN	Allowable unsupported length, coupling in annular BOP	1.6 metres

These calculations have been provided by Petro-Canada as a reference only. Reliance on this material alone to the exclusion of other professional advice, experience or resources is imprudent since each situation is unique.

Chart 18: Tubing OD 42.2 mm Grade L-80 Tubing Wt. 3.47 Kg/m Connection IJ

Pipe Buckling Calculations

Tubing OD	**42.20** mm	Tubing weight	**3.47** kg/m
Grade	**L-80**	Connection	**IJ**

	INPUT		
Pipe OD	OD	**42.20** mm	
Pipe ID	ID	**35.05** mm	
Cplg OD	CplgOD	**47.90** mm	
Pipe yield stress	Sy	**551** MPa	
Modulus Elasticity	E	**200** GPa	
	CALCULATED		
Area, pipe OD	Ao	1398 mm^2	
Area, pipe ID	Ai	964 mm^2	
Area, steel	As	434 mm^2	
Moment of Inertia	I	81550 mm^4	
Radius of Gyration	RG	13.71 mm	
Critical Slenderness Ratio	SRc	84.6	
Cplg x-sect area	Acplg	1807 mm^2	
	EQUATIONS		
Area, pipe OD	Ao	=3.14*(OD^2)/4	
Area, pipe ID	Ai	= 3.14*(ID^2)/4	
Area, steel	As	=Ao-Ai	
Moment of Inertia	I	=3.14*(OD^4-ID^4)/64	
Radius of Gyration	RG	=(I/As)^.5	
Crit.slenderness ratio	SRc	=3.14*(2*E/Sy)^.5	
Slenderness ratio	SR	=L/r	
Local Buckle (Johnson's Eqn, short column)	Flb	=Sy*As*(1-(L/RG)^2/(2*(SRc)^2))	
Major Axis Buckle (Euler Eqn, long column, pinned ends)	Feb	=(3.14)^2*E*I/(L)^2	
Buckling Load	Fb	=IF(SR>SRc,Feb,Flb)	

Snubbing Force vs Wellbore Pressure

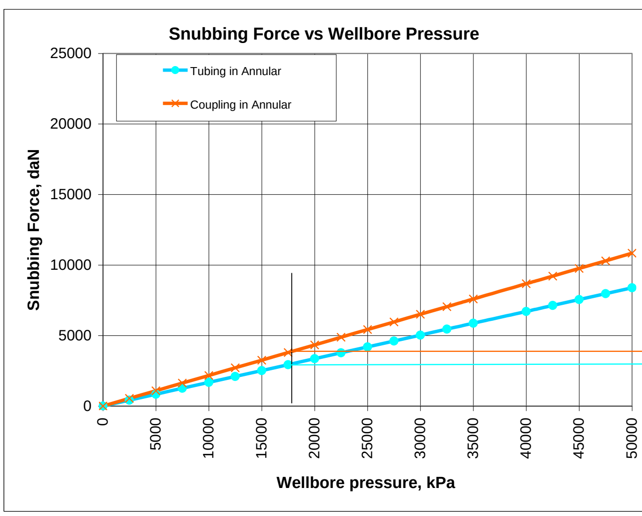
Wellbore Pressure kPa	Snubbing Force Tubing in Annular, daN	Snubbing Force Coupling in Annular, daN	Transition to pipe heavy, m.	Length at which cplg. neutral, m.
0	0	0	0.0	0.0
2500	419	542	123.2	159.2
5000	839	1084	246.4	318.5
7500	1258	1626	369.6	477.7
10000	1678	2168	492.8	636.9
12500	2097	2710	616.0	796.2
15000	2516	3252	739.2	955.4
17500	2936	3794	862.4	1114.7
20000	3355	4336	985.6	1273.9
22500	3774	4878	1108.8	1433.1
25000	4194	5421	1232.0	1592.4
27500	4613	5963	1355.2	1751.6
30000	5033	6505	1478.4	1910.8
32500	5452	7047	1601.6	2070.1
35000	5871	7589	1724.8	2229.3
40000	6710	8673	1971.2	2547.8
42500	7130	9215	2094.4	2707.0
45000	7549	9757	2217.6	2866.3
47500	7968	10299	2340.8	3025.5
50000	8388	10841	2464.0	3184.7

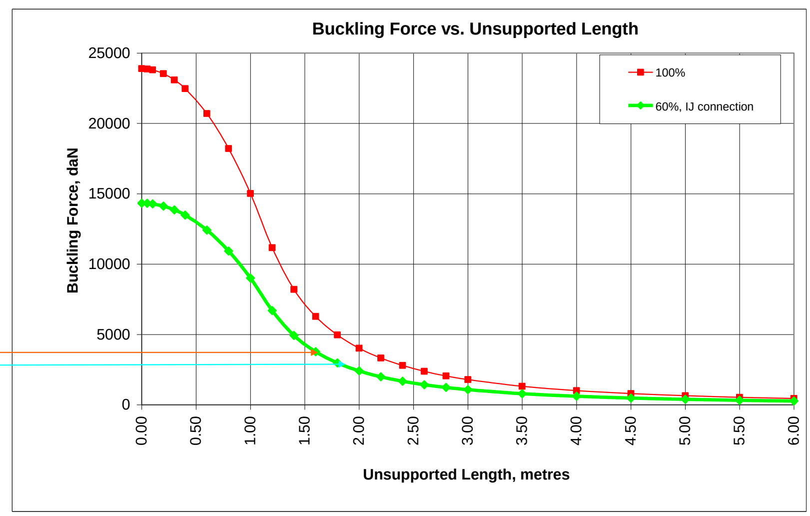
Note: Above snubbing forces include 20% for friction through the annular BOP
Fwp = WP (kPa) * X-area (mm^2) / 10000
Fsnub = Fwp + Ffric = 1.2 x Fwp
units: decaNewtons

Above calculations assume annulus gas has a specific gravity = 1.0 (air sg = 1.0)

Buckling Force as a Function of Unsupported Length

Unsupported Length (mm)	Unsupported Length (metres)	Slenderness Ratio	Buckling Force, daN 100%	IJ 60%
0	0.00	0.00	23891	**14334**
50	0.05	3.65	23868	**14321**
100	0.10	7.29	23802	**14281**
200	0.20	14.58	23536	**14121**
300	0.30	21.87	23092	**13855**
400	0.40	29.17	22471	**13482**
600	0.60	43.75	20696	**12418**
800	0.80	58.33	18212	**10927**
1000	1.00	72.92	15017	**9010**
1200	1.20	87.50	11167	**6700**
1400	1.40	102.08	8205	**4923**
1600	1.60	116.67	6282	**3769**
1800	1.80	131.25	4963	**2978**
2000	2.00	145.83	4020	**2412**
2200	2.20	160.42	3323	**1994**
2400	2.40	175.00	2792	**1675**
2600	2.60	189.58	2379	**1427**
2800	2.80	204.17	2051	**1231**
3000	3.00	218.75	1787	**1072**
3500	3.50	255.21	1313	**788**
4000	4.00	291.66	1005	**603**
4500	4.50	328.12	794	**476**
5000	5.00	364.58	643	**386**
5500	5.50	401.04	532	**319**
6000	6.00	437.50	447	**268**





Example:	Wellbore pressure = 17,500 kPa	Tubing snubbing force =	2936 daN	Allowable unsupported length with tubing in annular BOP	1.8 metres
		Coupling snubbing force =	3794 daN	Allowable unsupported length, coupling in annular BOP	1.6 metres

These calculations have been provided by Petro-Canada as a reference only. Reliance on this material alone to the exclusion of other professional advice, experience or resources is imprudent since each situation is unique.

Chart 19: Tubing OD 48.3 mm Grade J-55 Tubing Wt. 4.11 Kg/m Connection IJ

Pipe Buckling Calculations

Tubing OD	**48.30** mm	Tubing weight	**4.11** kg/m
Grade	**J-55**	Connection	**IJ**

	INPUT	
Pipe OD	OD	**48.30** mm
Pipe ID	ID	**40.89** mm
Cplg OD	CplgOD	**53.60** mm
Pipe yield stress	Sy	**379** MPa
Modulus Elasticity	E	**200** GPa
	CALCULATED	
Area, pipe OD	Ao	1831 mm^2
Area, pipe ID	Ai	1313 mm^2
Area, steel	As	519 mm^2
Moment of Inertia	I	129860 mm^4
Radius of Gyration	RG	15.82 mm
Critical Slenderness Ratio	SRc	102.0
Cplg x-sect area	Acplg	2262 mm^2
	EQUATIONS	
Area, pipe OD	Ao	=3.14*(OD^2)/4
Area, pipe ID	Ai	= 3.14*(ID^2)/4
Area, steel	As	=Ao-Ai
Moment of Inertia	I	=3.14*(OD^4-ID^4)/64
Radius of Gyration	RG	=(I/As)^.5
Crit.slenderness ratio	SRc	=3.14*(2*E/Sy)^.5
Slenderness ratio	SR	=L/r
Local Buckle (Johnson's Eqn, short column)	Flb	=Sy*As*(1-(L/RG)^2/(2*(SRc)^2))
Major Axis Buckle (Euler Eqn, long column, pinned ends)	Feb	=(3.14)^2*E*I/(L)^2
Buckling Load	Fb	=IF(SR>SRc,Feb,Flb)

Snubbing Force vs Wellbore Pressure

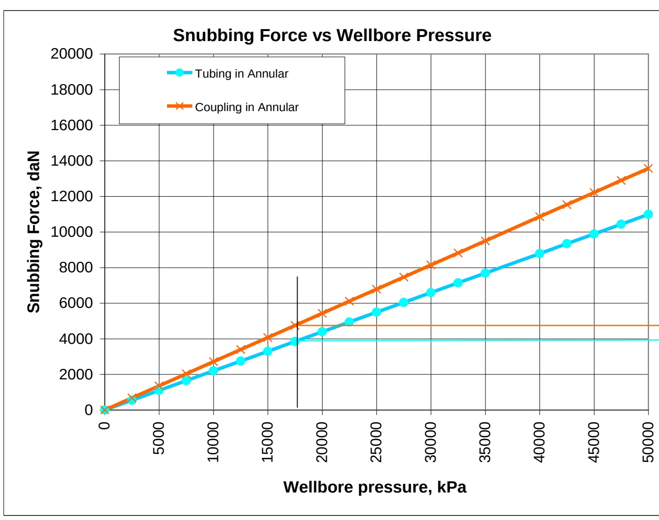
Wellbore Pressure kPa	Snubbing Force: Tubing in Annular, daN	Snubbing Force: Coupling in Annular, daN	Transition to pipe heavy, m.	Length at which cplg. neutral, m.
0	0	0	0.0	0.0
2500	549	679	136.3	168.3
5000	1099	1357	272.5	336.7
7500	1648	2036	408.8	505.0
10000	2198	2715	545.0	673.4
12500	2747	3394	681.3	841.7
15000	3296	4072	817.6	1010.0
17500	3846	4751	953.8	1178.4
20000	4395	5430	1090.1	1346.7
22500	4945	6109	1226.4	1515.1
25000	5494	6787	1362.6	1683.4
27500	6043	7466	1498.9	1851.8
30000	6593	8145	1635.1	2020.1
32500	7142	8824	1771.4	2188.4
35000	7692	9502	1907.7	2356.8
40000	8790	10860	2180.2	2693.5
42500	9340	11539	2316.5	2861.8
45000	9889	12217	2452.7	3030.1
47500	10439	12896	2589.0	3198.5
50000	10988	13575	2725.2	3366.8

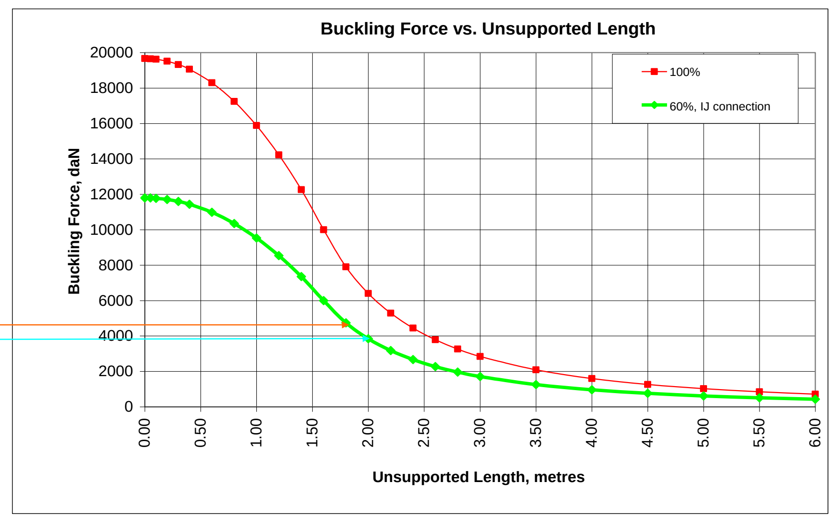
Note: Above snubbing forces include 20% for friction through the annular BOP
Fwp = WP (kPa) * X-area (mm^2) / 10000
Fsnub = Fwp + Ffric = 1.2 x Fwp
units: decaNewtons

Above calculations assume annulus gas has a specific gravity = 1.0 (air sg = 1.0)

Buckling Force as a Function of Unsupported Length

Unsupported Length (mm)	Unsupported Length (metres)	Slenderness Ratio	Buckling Force, daN: 100%	Buckling Force, daN: IJ 60%
0	0.00	0.00	19663	**11798**
50	0.05	3.16	19653	**11792**
100	0.10	6.32	19625	**11775**
200	0.20	12.64	19512	**11707**
300	0.30	18.96	19323	**11594**
400	0.40	25.28	19059	**11435**
600	0.60	37.92	18304	**10982**
800	0.80	50.57	17247	**10348**
1000	1.00	63.21	15888	**9533**
1200	1.20	75.85	14227	**8536**
1400	1.40	88.49	12265	**7359**
1600	1.60	101.13	10000	**6000**
1800	1.80	113.77	7903	**4742**
2000	2.00	126.41	6402	**3841**
2200	2.20	139.06	5291	**3174**
2400	2.40	151.70	4446	**2667**
2600	2.60	164.34	3788	**2273**
2800	2.80	176.98	3266	**1960**
3000	3.00	189.62	2845	**1707**
3500	3.50	221.22	2090	**1254**
4000	4.00	252.83	1600	**960**
4500	4.50	284.43	1265	**759**
5000	5.00	316.03	1024	**615**
5500	5.50	347.64	847	**508**
6000	6.00	379.24	711	**427**





Example:	Wellbore pressure = 17,500 kPa	Tubing snubbing force =	3846 daN	Allowable unsupported length with tubing in annular BOP	2.0 metres
		Coupling snubbing force =	4751 daN	Allowable unsupported length, coupling in annular BOP	1.8 metres

These calculations have been provided by Petro-Canada as a reference only. Reliance on this material alone to the exclusion of other professional advice, experience or resources is imprudent since each situation is unique.

Chart 20: Tubing OD 48.3 mm Grade L-80 Tubing Wt. 4.11 Kg/m Connection IJ

Pipe Buckling Calculations

Tubing OD	**48.30** mm	
Grade	**L-80**	
Tubing weight	**4.11** kg/m	
Connection	**IJ**	

	INPUT		
Pipe OD	OD	**48.30**	mm
Pipe ID	ID	**40.89**	mm
Cplg OD	CplgOD	**53.60**	mm
Pipe yield stress	Sy	**551**	MPa
Modulus Elasticity	E	**200**	GPa
	CALCULATED		
Area, pipe OD	Ao	1831	mm^2
Area, pipe ID	Ai	1313	mm^2
Area, steel	As	519	mm^2
Moment of Inertia	I	129860	mm^4
Radius of Gyration	RG	15.82	mm
Critical Slenderness Ratio	SRc	84.6	
Cplg x-sect area	Acplg	2262	mm^2
	EQUATIONS		
Area, pipe OD	Ao	=3.14*(OD^2)/4	
Area, pipe ID	Ai	= 3.14*(ID^2)/4	
Area, steel	As	=Ao-Ai	
Moment of Inertia	I	=3.14*(OD^4-ID^4)/64	
Radius of Gyration	RG	=(I/As)^.5	
Crit.slenderness ratio	SRc	=3.14*(2*E/Sy)^.5	
Slenderness ratio	SR	=L/r	
Local Buckle (Johnson's Eqn, short column)	Flb	=Sy*As*(1-(L/RG)^2/(2*(SRc)^2))	
Major Axis Buckle (Euler Eqn, long column, pinned ends)	Feb	=(3.14)^2*E*I/(L)^2	
Buckling Load	Fb	=IF(SR>SRc,Feb,Flb)	

Snubbing Force vs Wellbore Pressure

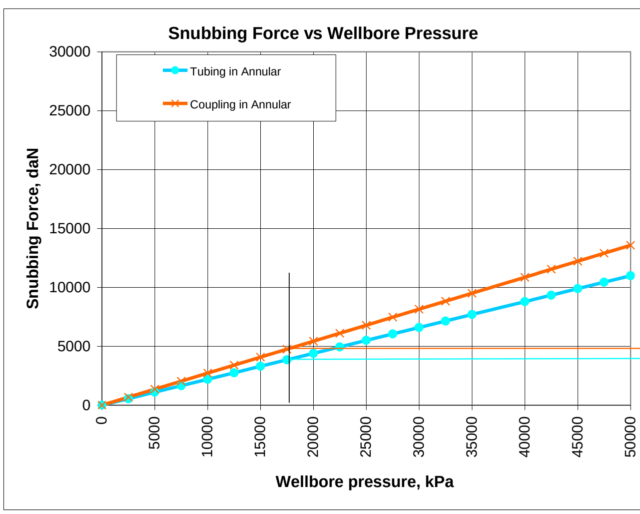
Wellbore Pressure kPa	Snubbing Force Tubing in Annular, daN	Snubbing Force Coupling in Annular, daN	Transition to pipe heavy, m.	Length at which cplg. neutral, m.
0	0	0	0.0	0.0
2500	549	679	136.3	168.3
5000	1099	1357	272.5	336.7
7500	1648	2036	408.8	505.0
10000	2198	2715	545.0	673.4
12500	2747	3394	681.3	841.7
15000	3296	4072	817.6	1010.0
17500	3846	4751	953.8	1178.4
20000	4395	5430	1090.1	1346.7
22500	4945	6109	1226.4	1515.1
25000	5494	6787	1362.6	1683.4
27500	6043	7466	1498.9	1851.8
30000	6593	8145	1635.1	2020.1
32500	7142	8824	1771.4	2188.4
35000	7692	9502	1907.7	2356.8
40000	8790	10860	2180.2	2693.5
42500	9340	11539	2316.5	2861.8
45000	9889	12217	2452.7	3030.1
47500	10439	12896	2589.0	3198.5
50000	10988	13575	2725.2	3366.8

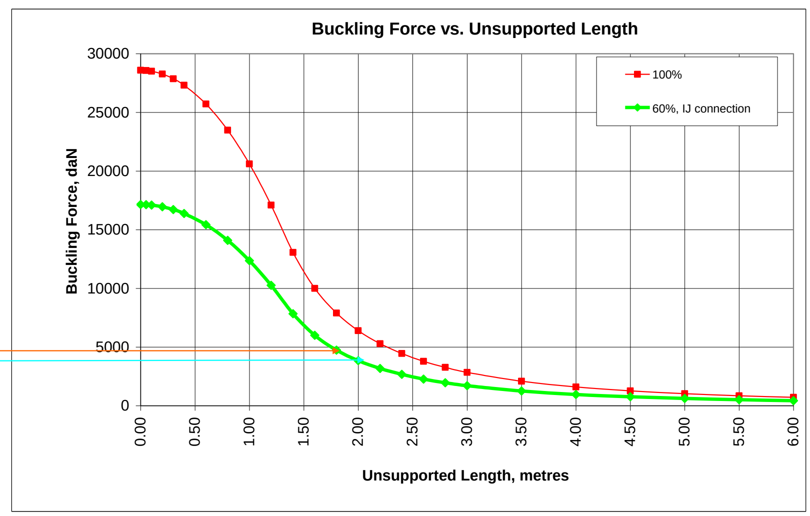
Note: Above snubbing forces include 20% for friction through the annular BOP
Fwp = WP (kPa) * X-area (mm^2) / 10000
Fsnub = Fwp + Ffric = 1.2 x Fwp
units: decaNewtons

Above calculations assume annulus gas has a specific gravity = 1.0 (air sg = 1.0)

Buckling Force as a Function of Unsupported Length

Unsupported Length (mm)	Unsupported Length (metres)	Slenderness Ratio	Buckling Force, daN IJ 100%	Buckling Force, daN IJ 60%
0	0.00	0.00	28586	**17152**
50	0.05	3.16	28566	**17140**
100	0.10	6.32	28506	**17104**
200	0.20	12.64	28267	**16960**
300	0.30	18.96	27868	**16721**
400	0.40	25.28	27310	**16386**
600	0.60	37.92	25714	**15428**
800	0.80	50.57	23480	**14088**
1000	1.00	63.21	20608	**12365**
1200	1.20	75.85	17098	**10259**
1400	1.40	88.49	13065	**7839**
1600	1.60	101.13	10003	**6002**
1800	1.80	113.77	7903	**4742**
2000	2.00	126.41	6402	**3841**
2200	2.20	139.06	5291	**3174**
2400	2.40	151.70	4446	**2667**
2600	2.60	164.34	3788	**2273**
2800	2.80	176.98	3266	**1960**
3000	3.00	189.62	2845	**1707**
3500	3.50	221.22	2090	**1254**
4000	4.00	252.83	1600	**960**
4500	4.50	284.43	1265	**759**
5000	5.00	316.03	1024	**615**
5500	5.50	347.64	847	**508**
6000	6.00	379.24	711	**427**





Example:	Wellbore pressure = 17,500 kPa	Tubing snubbing force =	3846 daN	Allowable unsupported length with tubing in annular BOP	2.0 metres
		Coupling snubbing force =	4751 daN	Allowable unsupported length, coupling in annular BOP	1.8 metres

These calculations have been provided by Petro-Canada as a reference only. Reliance on this material alone to the exclusion of other professional advice, experience or resources is imprudent since each situation is unique.

Chart 21: Tubing OD 52.4 mm Grade J-55 Tubing Wt. 4.85 Kg/m Connection IJ

Pipe Buckling Calculations

Tubing OD	**52.40** mm	Tubing weight **4.85** kg/m
Grade	**J-55**	Connection **IJ**

	INPUT	
Pipe OD	OD	**52.40** mm
Pipe ID	ID	**44.48** mm
Cplg OD	CplgOD	**59.10** mm
Pipe yield stress	Sy	**379** MPa
Modulus Elasticity	E	**200** GPa
	CALCULATED	
Area, pipe OD	Ao	2155 mm^2
Area, pipe ID	Ai	1553 mm^2
Area, steel	As	602 mm^2
Moment of Inertia	I	177844 mm^4
Radius of Gyration	RG	17.18 mm
Critical Slenderness Ratio	SRc	102.0
Cplg x-sect area	Acplg	2751 mm^2
	EQUATIONS	
Area, pipe OD	Ao	=3.14*(OD^2)/4
Area, pipe ID	Ai	= 3.14*(ID^2)/4
Area, steel	As	=Ao-Ai
Moment of Inertia	I	=3.14*(OD^4-ID^4)/64
Radius of Gyration	RG	=(I/As)^.5
Crit.slenderness ratio	SRc	=3.14*(2*E/Sy)^.5
Slenderness ratio	SR	=L/r
Local Buckle (Johnson's Eqn, short column)	Flb	=Sy*As*(1-(L/RG)^2/(2*(SRc)^2))
Major Axis Buckle (Euler Eqn, long column, pinned ends)	Feb	=(3.14)^2*E*I/(L)^2
Buckling Load	Fb	=IF(SR>SRc,Feb,Flb)

Snubbing Force vs Wellbore Pressure

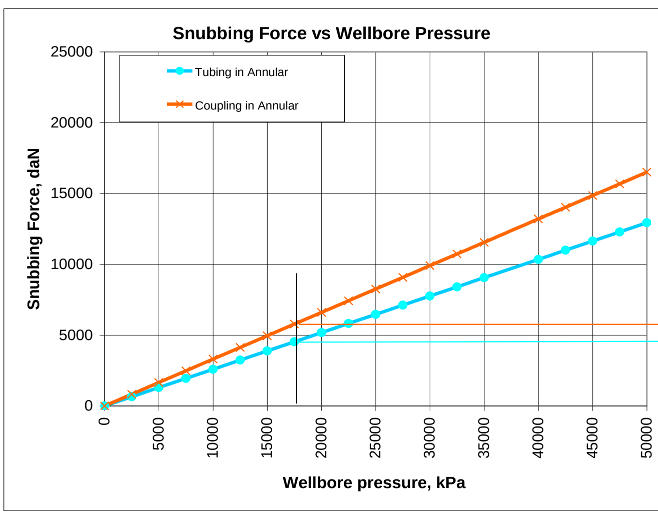
Wellbore Pressure kPa	Snubbing Force Tubing in Annular, daN	Coupling in Annular, daN	Transition to pipe heavy, m.	Length at which cplg. neutral, m.
0	0	0	0.0	0.0
2500	647	825	135.9	173.4
5000	1293	1650	271.8	346.9
7500	1940	2476	407.7	520.3
10000	2587	3301	543.6	693.7
12500	3233	4126	679.5	867.2
15000	3880	4951	815.4	1040.6
17500	4526	5776	951.4	1214.0
20000	5173	6601	1087.3	1387.5
22500	5820	7427	1223.2	1560.9
25000	6466	8252	1359.1	1734.3
27500	7113	9077	1495.0	1907.8
30000	7760	9902	1630.9	2081.2
32500	8406	10727	1766.8	2254.7
35000	9053	11552	1902.7	2428.1
40000	10346	13203	2174.5	2775.0
42500	10993	14028	2310.4	2948.4
45000	11639	14853	2446.3	3121.8
47500	12286	15678	2582.2	3295.3
50000	12933	16504	2718.1	3468.7

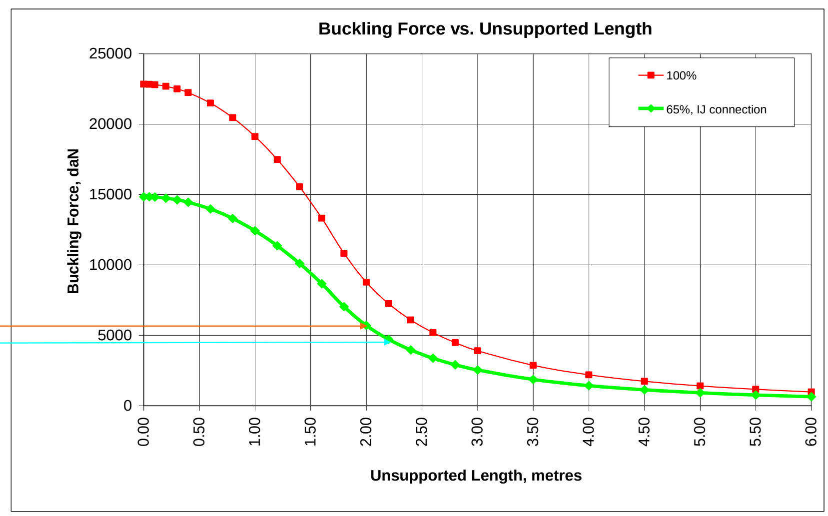
Note: Above snubbing forces include 20% for friction through the annular BOP
Fwp = WP (kPa) * X-area (mm^2) / 10000
Fsnub = Fwp + Ffric = 1.2 x Fwp
units: decaNewtons

Above calculations assume annulus gas has a specific gravity = 1.0 (air sg = 1.0)

Buckling Force as a Function of Unsupported Length

Unsupported Length (mm)	Unsupported Length (metres)	Slenderness Ratio	Buckling Force, daN 100%	IJ 65%
0	0.00	0.00	22828	**14838**
50	0.05	2.91	22819	**14832**
100	0.10	5.82	22791	**14814**
200	0.20	11.64	22679	**14742**
300	0.30	17.46	22494	**14621**
400	0.40	23.28	22234	**14452**
600	0.60	34.92	21491	**13969**
800	0.80	46.56	20450	**13293**
1000	1.00	58.20	19113	**12424**
1200	1.20	69.84	17479	**11361**
1400	1.40	81.47	15547	**10105**
1600	1.60	93.11	13318	**8657**
1800	1.80	104.75	10824	**7036**
2000	2.00	116.39	8767	**5699**
2200	2.20	128.03	7246	**4710**
2400	2.40	139.67	6088	**3957**
2600	2.60	151.31	5188	**3372**
2800	2.80	162.95	4473	**2908**
3000	3.00	174.59	3897	**2533**
3500	3.50	203.69	2863	**1861**
4000	4.00	232.78	2192	**1425**
4500	4.50	261.88	1732	**1126**
5000	5.00	290.98	1403	**912**
5500	5.50	320.08	1159	**754**
6000	6.00	349.18	974	**633**





Example:	Wellbore pressure = 17,500 kPa	Tubing snubbing force =	4526 daN	Allowable unsupported length with tubing in annular BOP	2.2 metres
		Coupling snubbing force =	5776 daN	Allowable unsupported length, coupling in annular BOP	2.0 metres

These calculations have been provided by Petro-Canada as a reference only. Reliance on this material alone to the exclusion of other professional advice, experience or resources is imprudent since each situation is unique.

Chart 22: Tubing OD 52.4 mm Grade L-80 Tubing Wt. 4.85 Kg/m Connection IJ

Pipe Buckling Calculations

Tubing OD **52.40** mm Tubing weight **4.85** kg/m
Grade **L-80** Connection **IJ**

	INPUT	
Pipe OD	OD	**52.40** mm
Pipe ID	ID	**44.48** mm
Cplg OD	CplgOD	**59.10** mm
Pipe yield stress	Sy	**551** MPa
Modulus Elasticity	E	**200** GPa
	CALCULATED	
Area, pipe OD	Ao	2155 mm^2
Area, pipe ID	Ai	1553 mm^2
Area, steel	As	602 mm^2
Moment of Inertia	I	177844 mm^4
Radius of Gyration	RG	17.18 mm
Critical Slenderness Ratio	SRc	84.6
Cplg x-sect area	Acplg	2751 mm^2
	EQUATIONS	
Area, pipe OD	Ao	=3.14*(OD^2)/4
Area, pipe ID	Ai	= 3.14*(ID^2)/4
Area, steel	As	=Ao-Ai
Moment of Inertia	I	=3.14*(OD^4-ID^4)/64
Radius of Gyration	RG	=(I/As)^.5
Crit.slenderness ratio	SRc	=3.14*(2*E/Sy)^.5
Slenderness ratio	SR	=L/r
Local Buckle (Johnson's Eqn, short column)	Flb	=Sy*As*(1-(L/RG)^2/(2*(SRc)^2))
Major Axis Buckle (Euler Eqn, long column, pinned ends)	Feb	=(3.14)^2*E*I/(L)^2
Buckling Load	Fb	=IF(SR>SRc,Feb,Flb)

Snubbing Force vs Wellbore Pressure

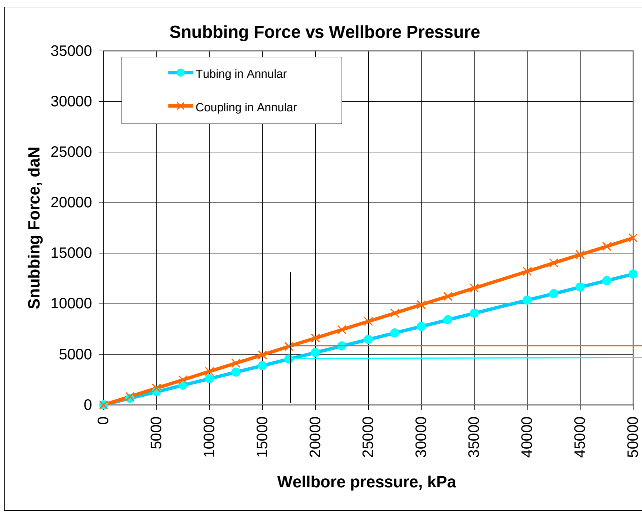
Wellbore Pressure kPa	Snubbing Force: Tubing in Annular, daN	Snubbing Force: Coupling in Annular, daN	Transition to pipe heavy, m.	Length at which cplg. neutral, m.
0	0	0	0.0	0.0
2500	647	825	135.9	173.4
5000	1293	1650	271.8	346.9
7500	1940	2476	407.7	520.3
10000	2587	3301	543.6	693.7
12500	3233	4126	679.5	867.2
15000	3880	4951	815.4	1040.6
17500	4526	5776	951.4	1214.0
20000	5173	6601	1087.3	1387.5
22500	5820	7427	1223.2	1560.9
25000	6466	8252	1359.1	1734.3
27500	7113	9077	1495.0	1907.8
30000	7760	9902	1630.9	2081.2
32500	8406	10727	1766.8	2254.7
35000	9053	11552	1902.7	2428.1
40000	10346	13203	2174.5	2775.0
42500	10993	14028	2310.4	2948.4
45000	11639	14853	2446.3	3121.8
47500	12286	15678	2582.2	3295.3
50000	12933	16504	2718.1	3468.7

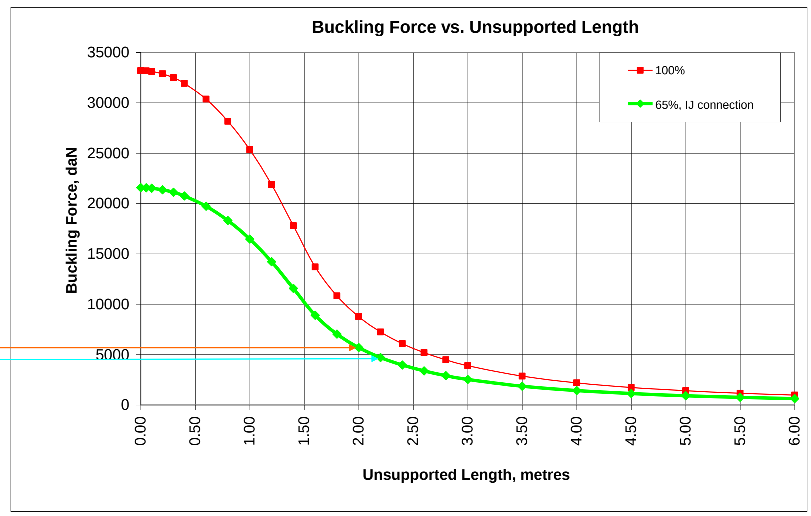
Note: Above snubbing forces include 20% for friction through the annular BOP
Fwp = WP (kPa) * X-area (mm^2) / 10000
Fsnub = Fwp + Ffric = 1.2 x Fwp
units: decaNewtons

Above calculations assume annulus gas has a specific gravity = 1.0 (air sg = 1.0)

Buckling Force as a Function of Unsupported Length

Unsupported Length (mm)	Unsupported Length (metres)	Slenderness Ratio	Buckling Force, daN 100%	Buckling Force, daN IJ 65%
0	0.00	0.00	33188	**21572**
50	0.05	2.91	33168	**21559**
100	0.10	5.82	33109	**21521**
200	0.20	11.64	32874	**21368**
300	0.30	17.46	32481	**21113**
400	0.40	23.28	31932	**20756**
600	0.60	34.92	30361	**19735**
800	0.80	46.56	28163	**18306**
1000	1.00	58.20	25336	**16468**
1200	1.20	69.84	21881	**14223**
1400	1.40	81.47	17798	**11569**
1600	1.60	93.11	13699	**8904**
1800	1.80	104.75	10824	**7036**
2000	2.00	116.39	8767	**5699**
2200	2.20	128.03	7246	**4710**
2400	2.40	139.67	6088	**3957**
2600	2.60	151.31	5188	**3372**
2800	2.80	162.95	4473	**2908**
3000	3.00	174.59	3897	**2533**
3500	3.50	203.69	2863	**1861**
4000	4.00	232.78	2192	**1425**
4500	4.50	261.88	1732	**1126**
5000	5.00	290.98	1403	**912**
5500	5.50	320.08	1159	**754**
6000	6.00	349.18	974	**633**





Example: Wellbore pressure = 17,500 kPa

Tubing snubbing force = 4526 daN
Coupling snubbing force = 5776 daN

Allowable unsupported length with tubing in annular BOP 2.2 metres
Allowable unsupported length, coupling in annular BOP 2.0 metres

These calculations have been provided by Petro-Canada as a reference only. Reliance on this material alone to the exclusion of other professional advice, experience or resources is imprudent since each situation is unique.

Chart 23: Tubing OD 60.3 mm Grade J-55 Tubing Wt. 6.99 Kg/m Connection EUE

Pipe Buckling Calculations

Tubing OD **60.30** mm Tubing weight **6.99** kg/m
Grade **J-55** Connection **EUE**

	INPUT	
Pipe OD	OD	**60.30** mm
Pipe ID	ID	**50.67** mm
Cplg OD	CplgOD	**77.80** mm
Pipe yield stress	Sy	**379** MPa
Modulus Elasticity	E	**200** GPa
	CALCULATED	
Area, pipe OD	Ao	2854 mm^2
Area, pipe ID	Ai	2015 mm^2
Area, steel	As	839 mm^2
Moment of Inertia	I	325253 mm^4
Radius of Gyration	RG	19.69 mm
Critical Slenderness Ratio	SRc	102.0
Cplg x-sect area	Acplg	4767 mm^2
	EQUATIONS	
Area, pipe OD	Ao	=3.14*(OD^2)/4
Area, pipe ID	Ai	= 3.14*(ID^2)/4
Area, steel	As	=Ao-Ai
Moment of Inertia	I	=3.14*(OD^4-ID^4)/64
Radius of Gyration	RG	=(I/As)^.5
Crit.slenderness ratio	SRc	=3.14*(2*E/Sy)^.5
Slenderness ratio	SR	=L/r
Local Buckle (Johnson's Eqn, short column)	Flb	=Sy*As*(1-(L/RG)^2/(2*(SRc)^2))
Major Axis Buckle (Euler Eqn, long column, pinned ends)	Feb	=(3.14)^2*E*I/(L)^2
Buckling Load	Fb	=IF(SR>SRc,Feb,Flb)

Snubbing Force vs Wellbore Pressure

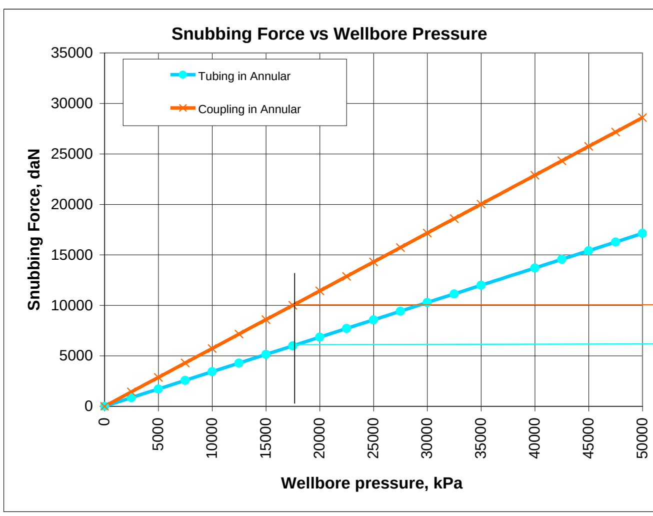
Wellbore Pressure kPa	Snubbing Force: Tubing in Annular, daN	Snubbing Force: Coupling in Annular, daN	Transition to pipe heavy, m.	Length at which cplg. neutral, m.
0	0	0	0.0	0.0
2500	856	1430	124.9	208.5
5000	1713	2860	249.8	417.1
7500	2569	4290	374.6	625.6
10000	3425	5720	499.5	834.2
12500	4281	7150	624.4	1042.7
15000	5138	8580	749.3	1251.2
17500	5994	10010	874.1	1459.8
20000	6850	11440	999.0	1668.3
22500	7707	12870	1123.9	1876.8
25000	8563	14300	1248.8	2085.4
27500	9419	15730	1373.6	2293.9
30000	10276	17160	1498.5	2502.5
32500	11132	18590	1623.4	2711.0
35000	11988	20020	1748.3	2919.5
40000	13701	22880	1998.0	3336.6
42500	14557	24310	2122.9	3545.1
45000	15413	25740	2247.8	3753.7
47500	16270	27170	2372.6	3962.2
50000	17126	28600	2497.5	4170.8

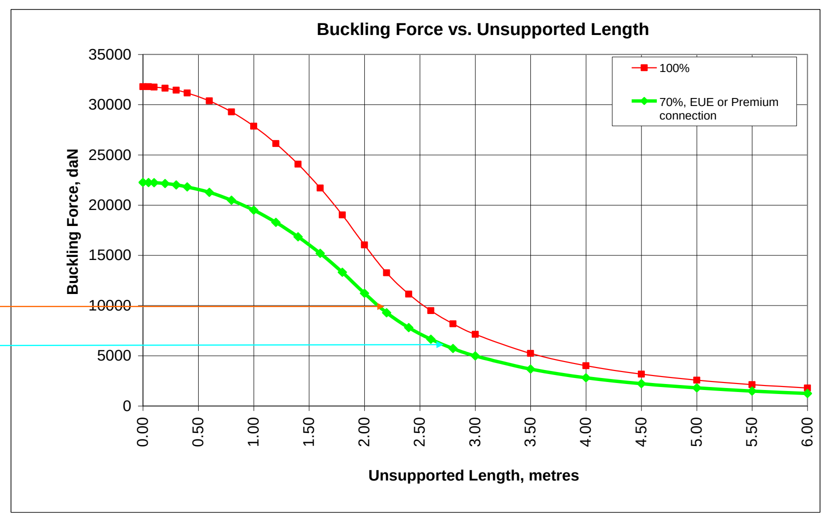
Note: Above snubbing forces include 20% for friction through the annular BOP
Fwp = WP (kPa) * X-area (mm^2) / 10000
Fsnub = Fwp + Ffric = 1.2 x Fwp
units: decaNewtons

Above calculations assume annulus gas has a specific gravity = 1.0 (air sg = 1.0)

Buckling Force as a Function of Unsupported Length

Unsupported Length (mm)	Unsupported Length (metres)	Slenderness Ratio	Buckling Force, daN 100%	Buckling Force, daN EUE 70%
0	0.00	0.00	31794	**22256**
50	0.05	2.54	31784	**22249**
100	0.10	5.08	31754	**22228**
200	0.20	10.16	31636	**22145**
300	0.30	15.24	31439	**22007**
400	0.40	20.31	31163	**21814**
600	0.60	30.47	30375	**21263**
800	0.80	40.63	29272	**20490**
1000	1.00	50.79	27854	**19497**
1200	1.20	60.94	26120	**18284**
1400	1.40	71.10	24071	**16850**
1600	1.60	81.26	21707	**15195**
1800	1.80	91.41	19028	**13319**
2000	2.00	101.57	16033	**11223**
2200	2.20	111.73	13251	**9276**
2400	2.40	121.89	11135	**7794**
2600	2.60	132.04	9488	**6641**
2800	2.80	142.20	8181	**5727**
3000	3.00	152.36	7126	**4988**
3500	3.50	177.75	5236	**3665**
4000	4.00	203.14	4009	**2806**
4500	4.50	228.54	3167	**2217**
5000	5.00	253.93	2565	**1796**
5500	5.50	279.32	2120	**1484**
6000	6.00	304.71	1782	**1247**





Example: Wellbore pressure = 17,500 kPa
Tubing snubbing force = 5994 daN
Coupling snubbing force = 10010 daN
Allowable unsupported length with tubing in annular BOP 2.7 metres
Allowable unsupported length, coupling in annular BOP 2.2 metres

These calculations have been provided by Petro-Canada as a reference only. Reliance on this material alone to the exclusion of other professional advice, experience or resources is imprudent since each situation is unique.

Chart 24 Tubing OD 60.3 mm Grade L-80 Tubing Wt. 6.99 Kg/m Connection EUE

Pipe Buckling Calculations

Tubing OD	**60.30** mm	
Grade	**L-80**	
Tubing weight	**6.99** kg/m	
Connection	**EUE**	

	INPUT	
Pipe OD	OD	**60.30** mm
Pipe ID	ID	**50.67** mm
Cplg OD	CplgOD	**77.80** mm
Pipe yield stress	Sy	**551** MPa
Modulus Elasticity	E	**200** GPa
	CALCULATED	
Area, pipe OD	Ao	2854 mm^2
Area, pipe ID	Ai	2015 mm^2
Area, steel	As	839 mm^2
Moment of Inertia	I	325253 mm^4
Radius of Gyration	RG	19.69 mm
Critical Slenderness Ratio	SRc	84.6
Cplg x-sect area	Acplg	4767 mm^2
	EQUATIONS	
Area, pipe OD	Ao	=3.14*(OD^2)/4
Area, pipe ID	Ai	= 3.14*(ID^2)/4
Area, steel	As	=Ao-Ai
Moment of Inertia	I	=3.14*(OD^4-ID^4)/64
Radius of Gyration	RG	=(I/As)^.5
Crit.slenderness ratio	SRc	=3.14*(2*E/Sy)^.5
Slenderness ratio	SR	=L/r
Local Buckle (Johnson's Eqn, short column)	Flb	=Sy*As*(1-(L/RG)^2/(2*(SRc)^2))
Major Axis Buckle (Euler Eqn, long column, pinned ends)	Feb	=(3.14)^2*E*I/(L)^2
Buckling Load	Fb	=IF(SR>SRc,Feb,Flb)

Snubbing Force vs Wellbore Pressure

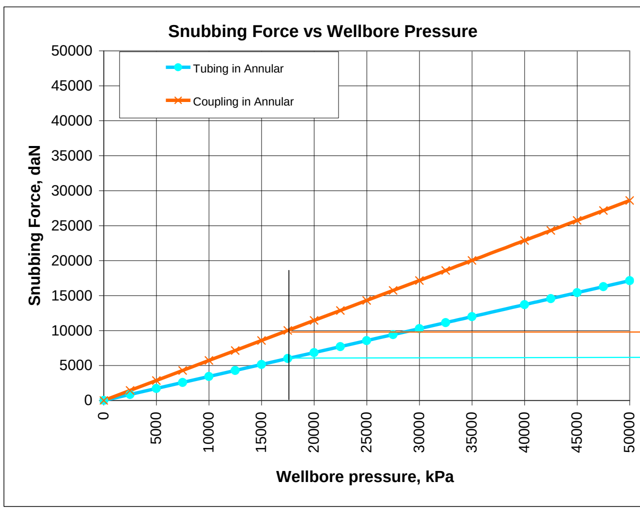
Wellbore Pressure kPa	Snubbing Force Tubing in Annular, daN	Snubbing Force Coupling in Annular, daN	Transition to pipe heavy, m.	Length at which cplg. neutral, m.
0	0	0	0.0	0.0
2500	856	1430	124.9	208.5
5000	1713	2860	249.8	417.1
7500	2569	4290	374.6	625.6
10000	3425	5720	499.5	834.2
12500	4281	7150	624.4	1042.7
15000	5138	8580	749.3	1251.2
17500	5994	10010	874.1	1459.8
20000	6850	11440	999.0	1668.3
22500	7707	12870	1123.9	1876.8
25000	8563	14300	1248.8	2085.4
27500	9419	15730	1373.6	2293.9
30000	10276	17160	1498.5	2502.5
32500	11132	18590	1623.4	2711.0
35000	11988	20020	1748.3	2919.5
40000	13701	22880	1998.0	3336.6
42500	14557	24310	2122.9	3545.1
45000	15413	25740	2247.8	3753.7
47500	16270	27170	2372.6	3962.2
50000	17126	28600	2497.5	4170.8

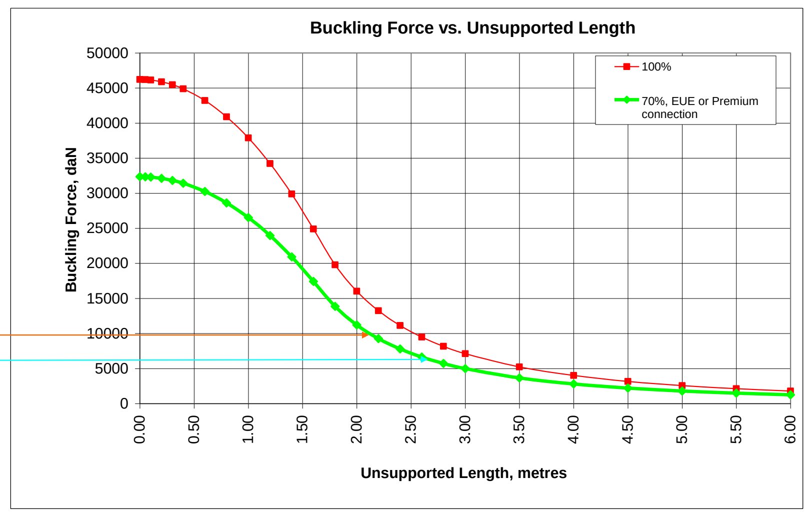
Note: Above snubbing forces include 20% for friction through the annular BOP
Fwp = WP (kPa) * X-area (mm^2) / 10000
Fsnub = Fwp + Ffric = 1.2 x Fwp
units: decaNewtons

Above calculations assume annulus gas has a specific gravity = 1.0 (air sg = 1.0)

Buckling Force as a Function of Unsupported Length

Unsupported Length (mm)	Unsupported Length (metres)	Slenderness Ratio	Buckling Force, daN 100%	Buckling Force, daN EUE 70%
0	0.00	0.00	46222	**32356**
50	0.05	2.54	46202	**32341**
100	0.10	5.08	46139	**32297**
200	0.20	10.16	45889	**32123**
300	0.30	15.24	45473	**31831**
400	0.40	20.31	44890	**31423**
600	0.60	30.47	43224	**30257**
800	0.80	40.63	40893	**28625**
1000	1.00	50.79	37895	**26526**
1200	1.20	60.94	34230	**23961**
1400	1.40	71.10	29900	**20930**
1600	1.60	81.26	24903	**17432**
1800	1.80	91.41	19795	**13857**
2000	2.00	101.57	16034	**11224**
2200	2.20	111.73	13251	**9276**
2400	2.40	121.89	11135	**7794**
2600	2.60	132.04	9488	**6641**
2800	2.80	142.20	8181	**5727**
3000	3.00	152.36	7126	**4988**
3500	3.50	177.75	5236	**3665**
4000	4.00	203.14	4009	**2806**
4500	4.50	228.54	3167	**2217**
5000	5.00	253.93	2565	**1796**
5500	5.50	279.32	2120	**1484**
6000	6.00	304.71	1782	**1247**





Example: Wellbore pressure = 17,500 kPa
Tubing snubbing force = 5994 daN
Coupling snubbing force = 10010 daN
Allowable unsupported length with tubing in annular BOP 2.7 metres
Allowable unsupported length, coupling in annular BOP 2.2 metres

These calculations have been provided by Petro-Canada as a reference only. Reliance on this material alone to the exclusion of other professional advice, experience or resources is imprudent since each situation is unique.

Chart 25: Tubing OD 73.0 mm Grade J-55 Tubing Wt. 9.67 Kg/m Connection EUE

Pipe Buckling Calculations

Tubing OD **73.00** mm
Grade **J-55**
Tubing weight **9.67** kg/m
Connection **EUE**

	INPUT		
Pipe OD	OD	**73.00**	mm
Pipe ID	ID	**62.00**	mm
Cplg OD	CplgOD	**93.20**	mm
Pipe yield stress	Sy	**379**	MPa
Modulus Elasticity	E	**200**	GPa
	CALCULATED		
Area, pipe OD	Ao	4183	mm^2
Area, pipe ID	Ai	3018	mm^2
Area, steel	As	1166	mm^2
Moment of Inertia	I	668325	mm^4
Radius of Gyration	RG	23.94	mm
Critical Slenderness Ratio	SRc	102.0	
Cplg x-sect area	Acplg	6840	mm^2
	EQUATIONS		
Area, pipe OD	Ao	=3.14*(OD^2)/4	
Area, pipe ID	Ai	= 3.14*(ID^2)/4	
Area, steel	As	=Ao-Ai	
Moment of Inertia	I	=3.14*(OD^4-ID^4)/64	
Radius of Gyration	RG	=(I/As)^.5	
Crit.slenderness ratio	SRc	=3.14*(2*E/Sy)^.5	
Slenderness ratio	SR	=L/r	
Local Buckle (Johnson's Eqn, short column)	Flb	=Sy*As*(1-(L/RG)^2/(2*(SRc)^2))	
Major Axis Buckle (Euler Eqn, long column, pinned ends)	Feb	=(3.14)^2*E*I/(L)^2	
Buckling Load	Fb	=IF(SR>SRc,Feb,Flb)	

Snubbing Force vs Wellbore Pressure

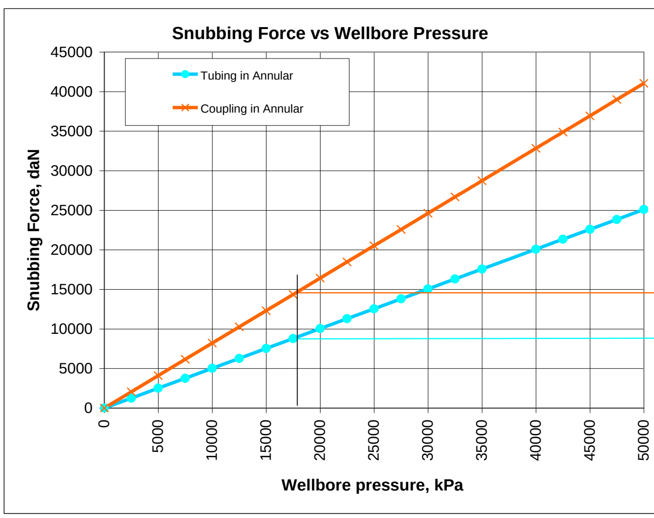
Wellbore Pressure kPa	Snubbing Force: Tubing in Annular, daN	Snubbing Force: Coupling in Annular, daN	Transition to pipe heavy, m.	Length at which cplg. neutral, m.
0	0	0	0.0	0.0
2500	1255	2052	132.3	216.3
5000	2510	4104	264.6	432.7
7500	3765	6156	396.9	649.0
10000	5020	8208	529.2	865.3
12500	6275	10261	661.5	1081.6
15000	7530	12313	793.8	1298.0
17500	8785	14365	926.1	1514.3
20000	10040	16417	1058.4	1730.6
22500	11295	18469	1190.6	1946.9
25000	12550	20521	1322.9	2163.3
27500	13805	22573	1455.2	2379.6
30000	15060	24625	1587.5	2595.9
32500	16315	26678	1719.8	2812.2
35000	17570	28730	1852.1	3028.6
40000	20080	32834	2116.7	3461.2
42500	21335	34886	2249.0	3677.5
45000	22590	36938	2381.3	3893.9
47500	23845	38990	2513.6	4110.2
50000	25100	41042	2645.9	4326.5

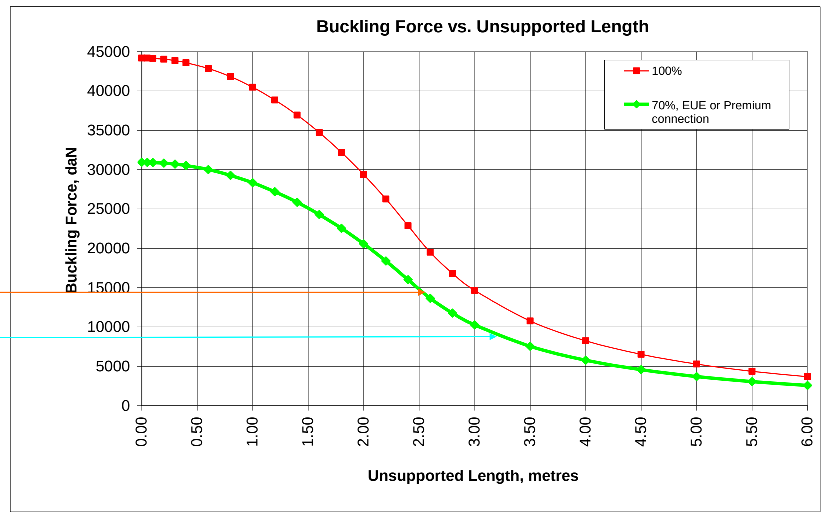
Note: Above snubbing forces include 20% for friction through the annular BOP
Fwp = WP (kPa) * X-area (mm^2) / 10000
Fsnub = Fwp + Ffric = 1.2 x Fwp
units: decaNewtons

Above calculations assume annulus gas has a specific gravity = 1.0 (air sg = 1.0)

Buckling Force as a Function of Unsupported Length

Unsupported Length (mm)	Unsupported Length (metres)	Slenderness Ratio	Buckling Force, daN EUE 100%	Buckling Force, daN EUE 70%
0	0.00	0.00	44181	**30927**
50	0.05	2.09	44172	**30920**
100	0.10	4.18	44144	**30901**
200	0.20	8.35	44033	**30823**
300	0.30	12.53	43848	**30693**
400	0.40	16.71	43589	**30512**
600	0.60	25.06	42848	**29994**
800	0.80	33.41	41811	**29268**
1000	1.00	41.76	40478	**28335**
1200	1.20	50.12	38849	**27194**
1400	1.40	58.47	36923	**25846**
1600	1.60	66.82	34702	**24291**
1800	1.80	75.18	32184	**22529**
2000	2.00	83.53	29370	**20559**
2200	2.20	91.88	26259	**18381**
2400	2.40	100.23	22853	**15997**
2600	2.60	108.59	19495	**13647**
2800	2.80	116.94	16810	**11767**
3000	3.00	125.29	14643	**10250**
3500	3.50	146.17	10758	**7531**
4000	4.00	167.06	8237	**5766**
4500	4.50	187.94	6508	**4556**
5000	5.00	208.82	5272	**3690**
5500	5.50	229.70	4357	**3050**
6000	6.00	250.59	3661	**2563**





Example: Wellbore pressure = 17,500 kPa
Tubing snubbing force = 8785 daN
Coupling snubbing force = 14365 daN
Allowable unsupported length with tubing in annular BOP 3.2 metres
Allowable unsupported length, coupling in annular BOP 2.5 metres

These calculations have been provided by Petro-Canada as a reference only. Reliance on this material alone to the exclusion of other professional advice, experience or resources is imprudent since each situation is unique.

Chart 26: Tubing OD 73.0 mm Grade L-80 Tubing Wt. 9.67 Kg/m Connection EUE

Pipe Buckling Calculations

Tubing OD	**73.00** mm	
Grade	**L-80**	
Tubing weight	**9.67** kg/m	
Connection	**EUE**	

	INPUT	
Pipe OD	OD	**73.00** mm
Pipe ID	ID	**62.00** mm
Cplg OD	CplgOD	**93.20** mm
Pipe yield stress	Sy	**551** MPa
Modulus Elasticity	E	**200** GPa
	CALCULATED	
Area, pipe OD	Ao	4183 mm^2
Area, pipe ID	Ai	3018 mm^2
Area, steel	As	1166 mm^2
Moment of Inertia	I	668325 mm^4
Radius of Gyration	RG	23.94 mm
Critical Slenderness Ratio	SRc	84.6
Cplg x-sect area	Acplg	6840 mm^2
	EQUATIONS	
Area, pipe OD	Ao	=3.14*(OD^2)/4
Area, pipe ID	Ai	= 3.14*(ID^2)/4
Area, steel	As	=Ao-Ai
Moment of Inertia	I	=3.14*(OD^4-ID^4)/64
Radius of Gyration	RG	=(I/As)^.5
Crit.slenderness ratio	SRc	=3.14*(2*E/Sy)^.5
Slenderness ratio	SR	=L/r
Local Buckle (Johnson's Eqn, short column)	Flb	=Sy*As*(1-(L/RG)^2/(2*(SRc)^2))
Major Axis Buckle (Euler Eqn, long column, pinned ends)	Feb	=(3.14)^2*E*I/(L)^2
Buckling Load	Fb	=IF(SR>SRc,Feb,Flb)

Snubbing Force vs Wellbore Pressure

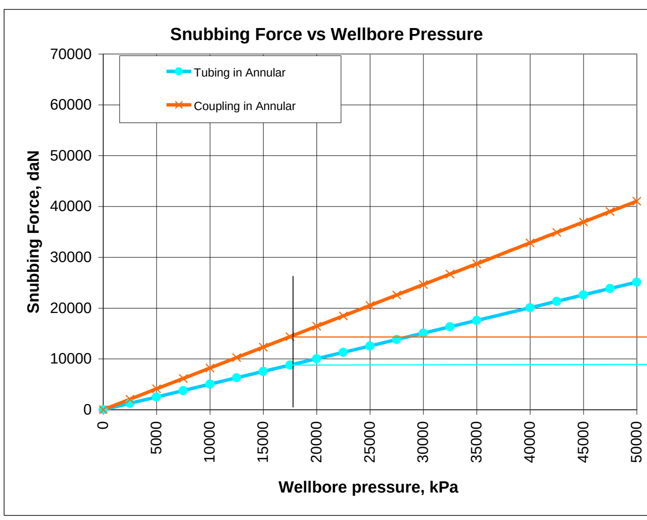
Wellbore Pressure kPa	Snubbing Force: Tubing in Annular, daN	Snubbing Force: Coupling in Annular, daN	Transition to pipe heavy, m.	Length at which cplg. neutral, m.
0	0	0	0.0	0.0
2500	1255	2052	132.3	216.3
5000	2510	4104	264.6	432.7
7500	3765	6156	396.9	649.0
10000	5020	8208	529.2	865.3
12500	6275	10261	661.5	1081.6
15000	7530	12313	793.8	1298.0
17500	8785	14365	926.1	1514.3
20000	10040	16417	1058.4	1730.6
22500	11295	18469	1190.6	1946.9
25000	12550	20521	1322.9	2163.3
27500	13805	22573	1455.2	2379.6
30000	15060	24625	1587.5	2595.9
32500	16315	26678	1719.8	2812.2
35000	17570	28730	1852.1	3028.6
40000	20080	32834	2116.7	3461.2
42500	21335	34886	2249.0	3677.5
45000	22590	36938	2381.3	3893.9
47500	23845	38990	2513.6	4110.2
50000	25100	41042	2645.9	4326.5

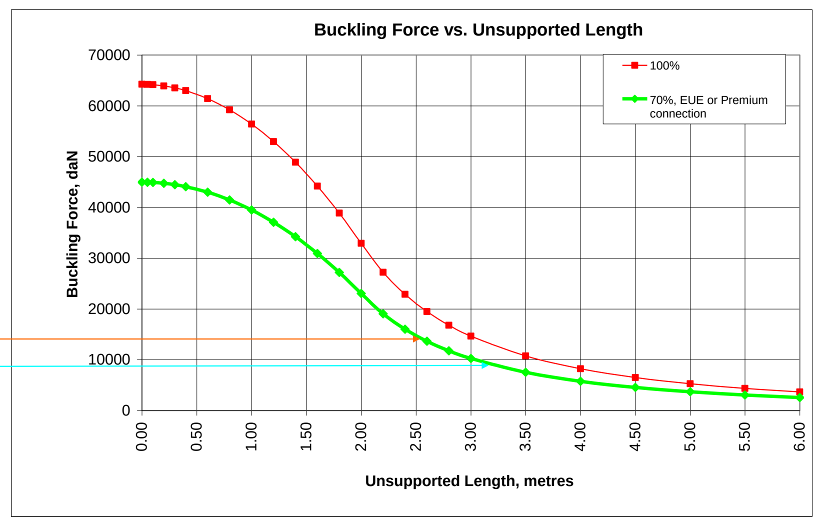
Note: Above snubbing forces include 20% for friction through the annular BOP
Fwp = WP (kPa) * X-area (mm^2) / 10000
Fsnub = Fwp + Ffric = 1.2 x Fwp
units: decaNewtons

Above calculations assume annulus has a specific gravity = 1.0 (air sg = 1.0)

Buckling Force as a Function of Unsupported Length

Unsupported Length (mm)	Unsupported Length (metres)	Slenderness Ratio	Buckling Force, daN 100%	Buckling Force, daN EUE 70%
0	0.00	0.00	64231	**44962**
50	0.05	2.09	64212	**44948**
100	0.10	4.18	64153	**44907**
200	0.20	8.35	63918	**44743**
300	0.30	12.53	63527	**44469**
400	0.40	16.71	62979	**44085**
600	0.60	25.06	61414	**42990**
800	0.80	33.41	59223	**41456**
1000	1.00	41.76	56405	**39484**
1200	1.20	50.12	52962	**37073**
1400	1.40	58.47	48892	**34224**
1600	1.60	66.82	44196	**30937**
1800	1.80	75.18	38874	**27212**
2000	2.00	83.53	32926	**23048**
2200	2.20	91.88	27229	**19060**
2400	2.40	100.23	22880	**16016**
2600	2.60	108.59	19495	**13647**
2800	2.80	116.94	16810	**11767**
3000	3.00	125.29	14643	**10250**
3500	3.50	146.17	10758	**7531**
4000	4.00	167.06	8237	**5766**
4500	4.50	187.94	6508	**4556**
5000	5.00	208.82	5272	**3690**
5500	5.50	229.70	4357	**3050**
6000	6.00	250.59	3661	**2563**





Example:	Wellbore pressure = 17,500 kPa	Tubing snubbing force =	8785 daN	
		Coupling snubbing force =	14365 daN	
		Allowable unsupported length with tubing in annular BOP	3.2 metres	
		Allowable unsupported length, coupling in annular BOP	2.5 metres	

These calculations have been provided by Petro-Canada as a reference only. Reliance on this material alone to the exclusion of other professional advice, experience or resources is imprudent since each situation is unique.

Chart 27: Tubing OD 88.9 mm Grade J-55 Tubing Wt. 13.84 Kg/m Connection EUE

Pipe Buckling Calculations

Tubing OD **88.90** mm
Grade **J-55**

Tubing weight **13.84** kg/m
Connection **EUE**

	INPUT	
Pipe OD	OD	**88.90** mm
Pipe ID	ID	**76.00** mm
Cplg OD	CplgOD	**114.30** mm
Pipe yield stress	Sy	**379** MPa
Modulus Elasticity	E	**200** GPa
	CALCULATED	
Area, pipe OD	Ao	6204 mm^2
Area, pipe ID	Ai	4534 mm^2
Area, steel	As	1670 mm^2
Moment of Inertia	I	1427648 mm^4
Radius of Gyration	RG	29.24 mm
Critical Slenderness Ratio	SRc	102.0
Cplg x-sect area	Acplg	10288 mm^2
	EQUATIONS	
Area, pipe OD	Ao	=3.14*(OD^2)/4
Area, pipe ID	Ai	= 3.14*(ID^2)/4
Area, steel	As	=Ao-Ai
Moment of Inertia	I	=3.14*(OD^4-ID^4)/64
Radius of Gyration	RG	=(I/As)^.5
Crit.slenderness ratio	SRc	=3.14*(2*E/Sy)^.5
Slenderness ratio	SR	=L/r
Local Buckle (Johnson's Eqn, short column)	Flb	=Sy*As*(1-(L/RG)^2/(2*(SRc)^2))
Major Axis Buckle (Euler Eqn, long column, pinned ends)	Feb	=(3.14)^2*E*I/(L)^2
Buckling Load	Fb	=IF(SR>SRc,Feb,Flb)

Snubbing Force vs Wellbore Pressure

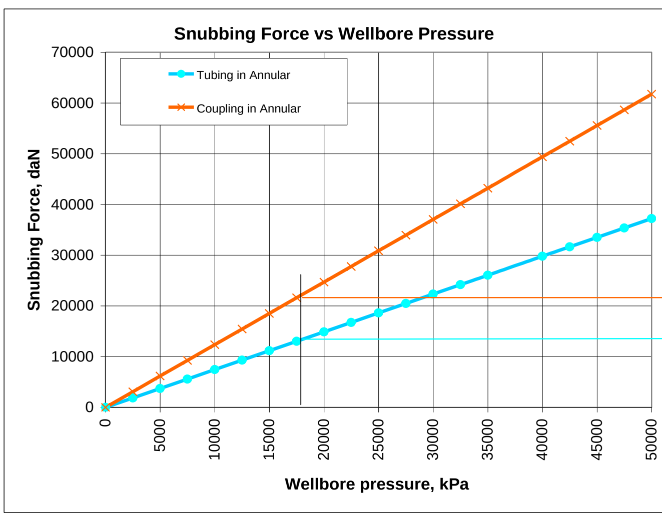
Wellbore Pressure kPa	Snubbing Force Tubing in Annular, daN	Coupling in Annular, daN	Transition to pipe heavy, m.	Length at which cplg. neutral, m.
0	0	0	0.0	0.0
2500	1861	3086	137.1	227.3
5000	3722	6173	274.2	454.7
7500	5584	9259	411.3	682.0
10000	7445	12346	548.3	909.3
12500	9306	15432	685.4	1136.7
15000	11167	18519	822.5	1364.0
17500	13028	21605	959.6	1591.3
20000	14890	24692	1096.7	1818.7
22500	16751	27778	1233.8	2046.0
25000	18612	30865	1370.8	2273.3
27500	20473	33951	1507.9	2500.6
30000	22334	37038	1645.0	2728.0
32500	24196	40124	1782.1	2955.3
35000	26057	43211	1919.2	3182.6
40000	29779	49384	2193.4	3637.3
42500	31641	52470	2330.4	3864.6
45000	33502	55557	2467.5	4092.0
47500	35363	58643	2604.6	4319.3
50000	37224	61730	2741.7	4546.6

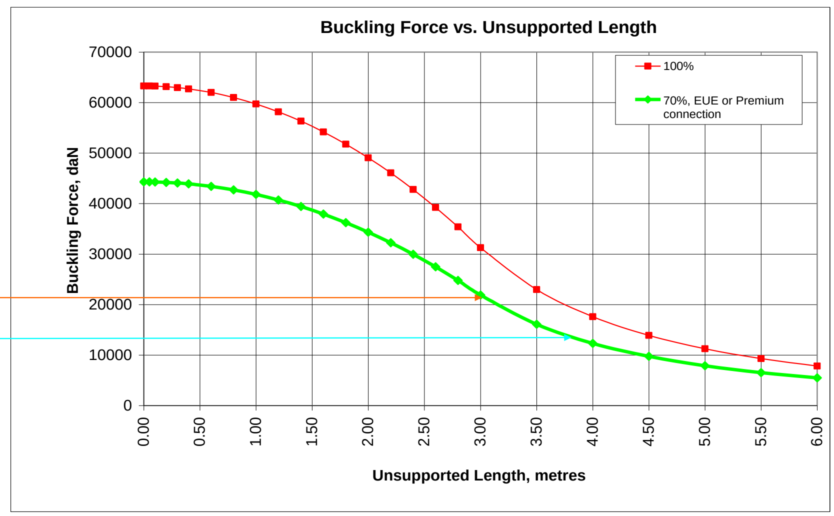
Note: Above snubbing forces include 20% for friction through the annular BOP
Fwp = WP (kPa) * X-area (mm^2) / 10000
Fsnub = Fwp + Ffric = 1.2 x Fwp
units: decaNewtons

Above calculations assume annulus gas has a specific gravity = 1.0 (air sg = 1.0)

Buckling Force as a Function of Unsupported Length

Unsupported Length (mm)	Unsupported Length (metres)	Slenderness Ratio	Buckling Force, daN 100%	EUE 70%
0	0.00	0.00	63288	**44301**
50	0.05	1.71	63279	**44295**
100	0.10	3.42	63252	**44276**
200	0.20	6.84	63145	**44202**
300	0.30	10.26	62968	**44077**
400	0.40	13.68	62719	**43903**
600	0.60	20.52	62007	**43405**
800	0.80	27.36	61011	**42708**
1000	1.00	34.20	59731	**41812**
1200	1.20	41.04	58166	**40716**
1400	1.40	47.88	56316	**39421**
1600	1.60	54.72	54182	**37927**
1800	1.80	61.56	51763	**36234**
2000	2.00	68.40	49060	**34342**
2200	2.20	75.24	46072	**32251**
2400	2.40	82.08	42800	**29960**
2600	2.60	88.92	39243	**27470**
2800	2.80	95.76	35402	**24781**
3000	3.00	102.60	31280	**21896**
3500	3.50	119.70	22981	**16087**
4000	4.00	136.80	17595	**12317**
4500	4.50	153.90	13902	**9732**
5000	5.00	171.00	11261	**7883**
5500	5.50	188.10	9306	**6515**
6000	6.00	205.20	7820	**5474**





Example: Wellbore pressure = 17,500 kPa
Tubing snubbing force = 13028 daN
Coupling snubbing force = 21605 daN
Allowable unsupported length with tubing in annular BOP 3.8 metres
Allowable unsupported length, coupling in annular BOP 3.0 metres

These calculations have been provided by Petro-Canada as a reference only. Reliance on this material alone to the exclusion of other professional advice, experience or resources is imprudent since each situation is unique.

Chart 28: Tubing OD 88.9 mm Grade L-80 Tubing Wt. 13.84 Kg/m Connection EUE

Pipe Buckling Calculations

Tubing OD	**88.90** mm	Tubing weight	**13.84** kg/m
Grade	**L-80**	Connection	**EUE**

	INPUT	
Pipe OD	OD	**88.90** mm
Pipe ID	ID	**76.00** mm
Cplg OD	CplgOD	**114.30** mm
Pipe yield stress	Sy	**551** MPa
Modulus Elasticity	E	**200** GPa
	CALCULATED	
Area, pipe OD	Ao	6204 mm^2
Area, pipe ID	Ai	4534 mm^2
Area, steel	As	1670 mm^2
Moment of Inertia	I	1427648 mm^4
Radius of Gyration	RG	29.24 mm
Critical Slenderness Ratio	SRc	84.6
Cplg x-sect area	Acplg	10288 mm^2
	EQUATIONS	
Area, pipe OD	Ao	=3.14*(OD^2)/4
Area, pipe ID	Ai	= 3.14*(ID^2)/4
Area, steel	As	=Ao-Ai
Moment of Inertia	I	=3.14*(OD^4-ID^4)/64
Radius of Gyration	RG	=(I/As)^.5
Crit.slenderness ratio	SRc	=3.14*(2*E/Sy)^.5
Slenderness ratio	SR	=L/r
Local Buckle (Johnson's Eqn, short column)	Flb	=Sy*As*(1-(L/RG)^2/(2*(SRc)^2))
Major Axis Buckle (Euler Eqn, long column, pinned ends)	Feb	=(3.14)^2*E*I/(L)^2
Buckling Load	Fb	=IF(SR>SRc,Feb,Flb)

Snubbing Force vs Wellbore Pressure

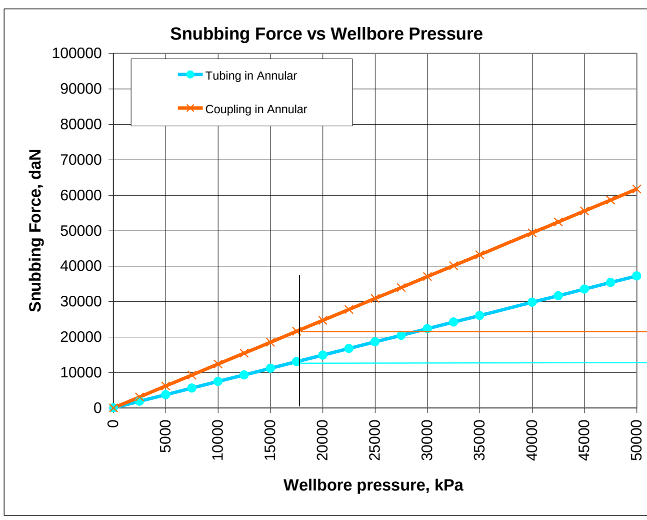
Wellbore Pressure kPa	Snubbing Force: Tubing in Annular, daN	Snubbing Force: Coupling in Annular, daN	Transition to pipe heavy, m.	Length at which cplg. neutral, m.
0	0	0	0.0	0.0
2500	1861	3086	137.1	227.3
5000	3722	6173	274.2	454.7
7500	5584	9259	411.3	682.0
10000	7445	12346	548.3	909.3
12500	9306	15432	685.4	1136.7
15000	11167	18519	822.5	1364.0
17500	13028	21605	959.6	1591.3
20000	14890	24692	1096.7	1818.7
22500	16751	27778	1233.8	2046.0
25000	18612	30865	1370.8	2273.3
27500	20473	33951	1507.9	2500.6
30000	22334	37038	1645.0	2728.0
32500	24196	40124	1782.1	2955.3
35000	26057	43211	1919.2	3182.6
40000	29779	49384	2193.4	3637.3
42500	31641	52470	2330.4	3864.6
45000	33502	55557	2467.5	4092.0
47500	35363	58643	2604.6	4319.3
50000	37224	61730	2741.7	4546.6

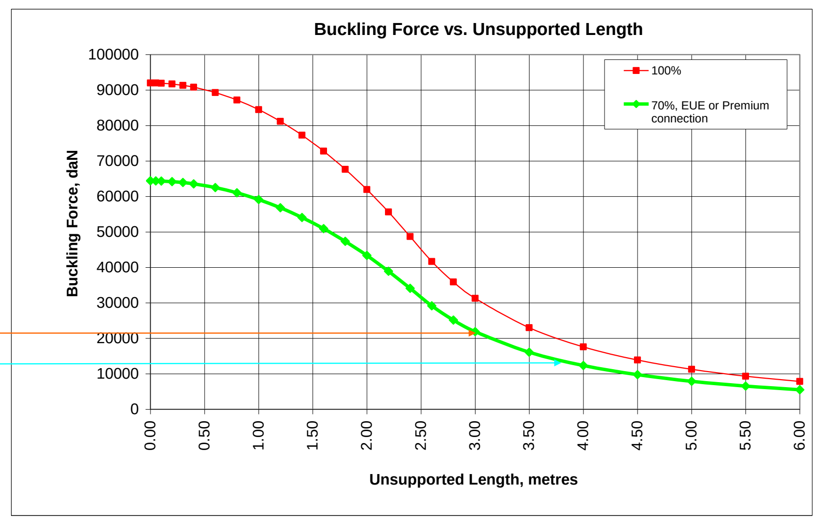
Note: Above snubbing forces include 20% for friction through the annular BOP
Fwp = WP (kPa) * X-area (mm^2) / 10000
Fsnub = Fwp + Ffric = 1.2 x Fwp
units: decaNewtons

Above calculations assume annulus gas has a specific gravity = 1.0 (air sg = 1.0)

Buckling Force as a Function of Unsupported Length

Unsupported Length (mm)	Unsupported Length (metres)	Slenderness Ratio	Buckling Force, daN EUE 100%	Buckling Force, daN EUE 70%
0	0.00	0.00	92009	**64406**
50	0.05	1.71	91990	**64393**
100	0.10	3.42	91934	**64354**
200	0.20	6.84	91709	**64196**
300	0.30	10.26	91333	**63933**
400	0.40	13.68	90806	**63564**
600	0.60	20.52	89303	**62512**
800	0.80	27.36	87198	**61039**
1000	1.00	34.20	84491	**59144**
1200	1.20	41.04	81184	**56829**
1400	1.40	47.88	77274	**54092**
1600	1.60	54.72	72764	**50935**
1800	1.80	61.56	67651	**47356**
2000	2.00	68.40	61938	**43357**
2200	2.20	75.24	55623	**38936**
2400	2.40	82.08	48707	**34095**
2600	2.60	88.92	41645	**29152**
2800	2.80	95.76	35908	**25136**
3000	3.00	102.60	31280	**21896**
3500	3.50	119.70	22981	**16087**
4000	4.00	136.80	17595	**12317**
4500	4.50	153.90	13902	**9732**
5000	5.00	171.00	11261	**7883**
5500	5.50	188.10	9306	**6515**
6000	6.00	205.20	7820	**5474**





Example:	Wellbore pressure = 17,500 kPa	Tubing snubbing force =	13028 daN	Allowable unsupported length with tubing in annular BOP	3.8 metres
		Coupling snubbing force =	21605 daN	Allowable unsupported length, coupling in annular BOP	3.0 metres

These calculations have been provided by Petro-Canada as a reference only. Reliance on this material alone to the exclusion of other professional advice, experience or resources is imprudent since each situation is unique.

Appendix K: Tubing Plug and Burst Disc Recommendations

X – Single Burst Disc **XX – Two Burst Discs**	Tubing end plug	Single locking plug & slip stop	Single permanent plug	Dual locking plugs & slip stop	Dual permanent plugs	Dual float assembly	Downhole shutoff valve (1/4 turn)	Regular burst disc & Combination burst disc (10k or 15k)
Sweet, less than 14 MPA differential	**X**	**X**	**X**			**X**	**X**	**X**
Sour, greater than 14 MPA differential and less than 500 ppm H_2S	**X**	**X**	**X**			**X**		**X**
Sweet, between 14 – 21 MPA differential	**X**	**X**	**X**			**X**	**X**	**X**
Sour, between 14-21 MPA differential and less than 500 ppm H_2S	**X**	**X**	**X**			**X**		**X**
Pre-Spud sign off required on all scenarios below								
Sour, less than 21 MPA differential, greater than 500 ppm H_2S	**X**			**X**	**X**	**X**		**XX***
Sweet, greater than 21 MPA differential	**X**			**X**	**X**	**X**		**XX***
Sour, greater than 21 MPA differential, less than 500 ppm H_2S	**X**			**X**	**X**	**X**		**XX***
Sour, greater than 21 MPA differential, greater than 500 ppm H_2S	**X**			**X**	**X**	**X**		**XX***

*Recommended distance between two plugs for dual barrier: 3-10m. When tubing fill is required and the ability to obtain <21MPa across a single barrier is not possible, the burst disc should be set as the lower barrier and a pump through plug as the second, upper barrier.

Burst Discs

When receiving, handling, transporting and running burst discs of any size and style (single or dual barrier) the following minimum recommendations should be applied:

1. Compliance letter (i.e. manufacturing, seal specifications (sour service, temp rates, etc.) shall accompany each burst disc.
2. Individual Identification such as a serial # stamped on the body. This insures that the test chart and all other relevant paper work are fully traceable to the individual burst disc body.
3. Each burst disc must be individually pressure tested (not less than 10 minutes) and real time charted. The test charts must be available upon request to the Oil/Gas Company and/or the Snubbing personnel.
4. Safe Trip Packaging: All burst discs must be safe trip packaged for pickup and delivery to the customer. Such packaging must have proof of its ability to protect the burst discs in day to day handling and transportation.
5. Transportation: While transporting the burst disc from the supplier to the end user the transport company should follow proper load securement protocol.
6. OEM specifications should be followed when making up a burst disc into a BHA. DO NO APPLY TORQUE THROUGH THE BODY OF THE BURST DISC.
7. If tubing bill is required to displace oxygen or to prevent collapse while running in hole, dual burst discs are not recommended as the hydrostatic pressure may burst the uppermost disc prematurely or the differential across the void between the two burst discs could cause the tubing to collapse.

Appendix L: Checklist for Snubbing with Personnel on the Derrick or Tubular Racking Board

This checklist is a sample of the written agreement between the prime contractor, rig company and snubbing service provider to proceed with snubbing operations with personnel on the derrick or tubular racking board. It has been compiled as a summary of the IRP 15 requirements that need to be met in order to perform this operation safely.

This checklist can be downloaded from the IRP 15 page of the Energy Safety Canada website (www.energysafetycanada.com).

Figure 3. Service Rig Assist Snubbing Criteria Checklist

Service Rig-Rig Assist Snubbing Criteria Checklist

This checklist identifies the criteria to be satisfied before standing tubing with a worker in the derrick or on the tubular racking board during snubbing operations. Refer to IRP15[1] Section 15.8.11 for more information.

Well Operations

- No Hydrocarbons present at surface
- No workers on the tubing board when the tubing is pipe light
- No workers on the tubing board when stripping rams are required to stage tubing in/out of the well

Primary Blow Out Preventers

- ☐ All primary BOP's have been pressure tested to jurisdictional regulations
- ☐ Primary pipe rams have a functional, tested and documented ram saver
- ☐ BOP configuration meets requirements of IRP 15 Snubbing Operations

Egress System

- ☐ Tubing board has a rear egress system in place that does not require the worker to disconnect from primary fall arrest equipment used during tripping operations
- ☐ Snubbing basket has egress systems in place that meets the criteria outlined in IRP15 section 15.8.3 Emergency Egress Systems

Ram Saver

- ☐ Audible alarm indicating secondary ram position change (open/close)
- ☐ Visual indicator on secondary ram position
- ☐ Throttle interrupt that cuts the rig throttle when secondary rams begin to close
- ☐ Ram Saver system is functional, tested and documented

Slip Interlock

- ☐ In place on all snubbing slips and heavy slips
- ☐ Slip Interlock in use, functional, tested and documented

Tubing Isolation

- ☐ Plug installed meets requirements found in IRP 15 with dual barrier
- ☐ Plug and seal integrity has been confirmed by a documented/recorded pressure test for 10 minutes

Tubing Integrity

- ☐ Number of joints to be snubbed is calculated and communicated to all workers
- ☐ Maximum stroke length to be used while snubbing has been calculated
- ☐ BOP and slip configuration has been confirmed to be acceptable for calculated buckling force exerted on the tubing string while snubbing
- ☐ Tubing type and grade has been confirmed acceptable for maximum well pressure expected, including surface pressure for buckling calculations and bottom hole pressure for resistance to buckling/collapse

Working pressure (wellhead)	
Plug Type Used	

Number of joints to be snubbed	
Tubing size and grade	

Service Rig Company & No.	Rig Manager (print)	Rig Manager (sign)	Date
Snubbing Service Provider & No.	Snubbing Supervisor (print)	Snubbing Supervisor (sign)	Date
Prime Contractor & Location	Wellsite Supervisor (print)	Wellsite Manager (sign)	Date

[1] IRPs are available from Energy Safety Canada at www.energysafetycanada.com

Appendix M: Acronyms and Abbreviations

ACGIH American Conference of Governmental Industrial Hygienists

ANSI American National Standards Institute

AOF Absolute Open Flow

API American Petroleum Institute

ASME American Society of Mechanical Engineers

ASTM American Society of Testing and Materials

BHA Bottom hole Assembly

BOP Blowout Preventer

CAODC Canadian Association of Oil well Drilling Contractors

CAPP Canadian Association of Petroleum Producers

CF Cubic Feet

COR Certificate of Recognition

CSA Canadian Standards Association

DACC Drilling and Completions Committee

DOT Department of Transportation

ERP Emergency Response Plan

ESD Emergency Shutdown Valve

EUE External Upset End.

GL Ground Level

GODI General Oilfield Driver Improvement

H2S Hydrogen Sulphide.

ID Inside Diameter

IRP Industry Recommended Practice

JSA Job Safety Analysis

KB Kelly Bushing

MPI Magnetic Particle Inspection

NACE National Association of Corrosion Engineers

OD Outside Diameter

OEM Original Equipment Manufacturer

OSHA Occupational Safety and Health Administration

PBTD Plug Back Total Depth

PCP Petroleum Competency Program

PHRCC Petroleum Human Resources Council of Canada

PPE Personal Protective Equipment

PR Type of Plug

PRN Type of Plug

PSAC Petroleum Services Association of Canada

PX Type of Plug

PXN Type of Plug

RP Recommended Practice

SABA Supplied Air Breathing Apparatus (a type of respiratory equipment)

SCBA Self-Contained Breathing Apparatus (a type of respiratory protective equipment)

SEPAC Small Explorers and Producers Association of Canada

SICP Shut-In Casing Pressure

SITP Shut-In Tubing Pressure

SRCP Service Rig Competency Program (CAODC)

STARS Shock Trauma Air Rescue Society

TD Total Depth

TDG Transportation of Dangerous Goods

TKX Type of Plug

TKXN Type of Plug

TLV Threshold Limit Value

TX Type of Plug

TXN Type of Plug

WCB Workers' Compensation Board

Appendix N: Glossary

Accumulator A small tank or pressure vessel to hold air, gas, or liquid under pressure for use in a hydraulic or air-actuated system; stores a source of pressure for use at a regulated rate in mechanisms or equipment in a plant or in drilling or production operations; can also be a vessel or tank that receives and temporarily stores a liquid used in a continuous process in a gas plant.

Annular preventer A device which can seal around any object in the borehole or upon itself; compression of a reinforced elastomer packing element by hydraulic pressure causes the seal**.**

Balance Point The point when the weight of the pipe equals the forces created by the well pressure acting on the cross-sectional area of the pipe; also known as the transition point or snub point.

Bleeding off To equalize or relieve pressure from a vessel or system.

Bleed-off The section of manifold containing the valves and piping necessary to bleed off pressure from a vessel or system; bleed-off lines may be exposed to widely fluctuating pressures, must be adequately secured, and consideration must be given to safe handling or disposal of resulting fluids.

Blowout preventer A large valve at the top of a well that may be closed if there is loss of control of formation gas/fluids.

Bottomhole assembly Tools deployed on the tubing, usually at the bottom of the string.

Bridge plug A downhole tool located and set to isolate the lower part of the wellbore; may be permanent or retrievable, enabling the lower wellbore to be permanently sealed from production or temporarily isolated from a treatment conducted on an upper zone.

Buckling load The load that will cause a distortion, bend, or kink in the pipe.

Catwalk A platform used as a staging area for rig and drill string tools, components that are about to be picked up and run, or components that have been run and are being laid down.

Cavitating Pulsating movement.

Certificate (for equipment) A document with an engineer’s stamp.

Chiksan A type of swivel joint.

Choke A device with an orifice used to control fluid flow rate or downstream system pressure.

Classification See well classification.

Coiled tubing A jointless hollow steel cylinder that can be uncoiled or coiled as required; used in well completion and servicing instead of traditional tubing (joined sections of pipe).

Collar A threaded coupling used to join two lengths of pipe such as production tubing or casing.

Competency See worker competency.

Condensate The liquid hydrocarbons produced with natural gas that are separated from the gas by cooling and various other means; the liquid recovery from a well classified as a gas well; generally in the gaseous state under reservoir conditions but becomes liquid either in passing up the hole or at the surface.

Contingency procedure A procedure for an unforeseen event, incident, or emergency.

Coupling A connection device for fastening two lengths of tubing.

Critical sour well Defined by jurisdiction's regulatory agency; generally includes all the elements of a sour well plus the added concerns of residents near the well site and environmental issues.

Crown saver An upward limiting device for traveling assembly on rig; prevents the blocks from striking the crown.

Designation See well designation.

Detent The function of a hydraulic control that maintains it in the open or closed position.

Division See well division.

Elastomer Often used interchangeably with the term "rubber"; primary uses are for seals, adhesives and molded flexible parts.

Equalizing prong Part of tubing plug.

External upset end An extra thick wall at the threaded end of drill pipe or tubing; does not have a uniform OD throughout its length but is enlarged at each end.

Expansion joint A device or completion component designed to enable relative movement between two fixed assemblies in the event of thermal expansion or contraction; expansion joints within the completion assembly prevent any movement or forces being transmitted to fixed components such as packers or tubing hangers.

Explosive mixture A gas and air mixture that will form an ignitable mixture.

Explosive potential Any time there is an explosive mixture present with a potential source of ignition.

Fishing The application of tools, equipment, and techniques for the removal of tools, casing, or other items lost or stuck in a wellbore; key elements of fishing include an understanding of the dimensions and nature of the items to be removed, the wellbore conditions, the tools and techniques employed, and the process by which the recovered items will be handled at surface.

Fishneck The groove in the top of many wireline tools to allow other tools to clamp the tool and remove it from the wellbore.

Fluid spacer A column of fluid in wellbore, usually above a tubing plug.

Frac oil Oil injected into a well in a fracturing operation which may then be recovered through production.

Fracing (Fracturing) A stimulation treatment routinely performed on oil and gas wells in low-permeability reservoirs; process of pumping into a closed wellbore with powerful hydraulic pumps to create enough downhole pressure to crack or fracture the formation.

Frictional force The force for passing through BOPs.

G pack-off A retrievable non-profile setting plug.

Gravitational force The force from the weight of the string.

Grounding Conducting electricity harmlessly into the ground in case of a fault.

Hang-off flange A sealed flange used to support a string of tubing or drill pipe; prevents movement.

Hook-wall plug A retrievable non-profile setting plug.

Hydrates Compounds in which natural gas molecules are trapped within a crystal structure; form in cold climates, such as permafrost zones and deep water; can form in pipelines and in gas gathering, compression, and transmission facilities at reduced temperatures and high pressures.

Hydraulic snubbing unit The most widely used snubbing unit; sometimes called hydraulic work over unit; hydraulic pressures act on cylinders to produce a force that is transmitted to the work string so the snubbing unit performs the operation of pushing pipe into or pulling pipe from a pressurized well; traveling slips transmit the lifting or snubbing force from jack to pipe.

Hydrogen sulphide A gaseous compound, commonly known by its chemical formula, H_2S; frequently found in oil and gas reservoirs; has a distinctive rotten egg odor at low parts per million; is extremely poisonous and corrosive and quickly deadens the olfactory nerve so that its odor is no longer a warning signal.

Interlock system A device that physically prevents activation of the system used for controlling the operation of machinery or equipment.

Iron sulphide A compound containing iron and sulphur; examples are ferric sulphide, ferrous sulphide, and iron disulphide.

Jack Hydraulic cylinders used to provide the force to move the pipe up or down.

Jar (Jarring device) A downhole tool used to deliver a heavy blow or impact to a downhole tool assembly or tool string; commonly used to operate downhole tools, to dislodge a stuck tool string, or in fishing to free stuck objects.

Joint safety meeting A safety meeting coordinated by well site supervisor with the multiple contractors on location.

Kelly bushing A device fitted to the rotary table through which the kelly passes and by means of which the torque of the rotary table is transmitted to the kelly and to the drill stem; sometimes called drive bushing.

KCl water Potassium chloride water; a non-invasive kill fluid.

Kill fluid Mud whose density is high enough to produce a hydrostatic pressure at the point of influx in a wellbore and shut off flow into the well.

Kill lines High-pressure pipe leading from an outlet on the BOP stack to the high-pressure rig pumps.

Lift force gauge A gauge that measures hydraulic pressure required to lift a string of tubing.

Load plate The interface between snubbing jack structure and snubbing BOP stack.

Lock mandrel – component of downhole plug or profile setting plug.

Lock-out system The system used to prevent the powering or operating of equipment inadvertently or by mistake until locks or tags are removed by the authorized person; also called tag-out.

Lubricating Running tools (packers, sleeves, etc.) into or pulling tools out of a pressurized wellbore while maintaining a seal with a lubricator and pack-off head.

Marker joint A joint of tubing that serves as a position or depth indicator; in most cases, significantly shorter than other joints in the string so that it is easily noticeable on correlation logs or when retrieving a work string. (from Schlumberger)

Metallurgy The science and technology of a metal.

Monkey board A tubular racking board.

Mud can Equipment used to contain fluids and direct them away from the drill pipe when breaking connections.

ND tested Non-destructive tested.

Neutral point The point on a string of tubulars at which there are neither tension nor compression forces present.

New worker An employee with little or no snubbing experience.

No-go locking plug A type of downhole plug; cannot be passed through.

No-go profile A type of a downhole profile; used with no-go locking plug.

One-man tight Tightened by one worker only.

Operating pressure The actual pressure to which a particular system or system component is subjected during normal operations.

Out of spec No longer meeting OEM specifications.

Packer A downhole device used to isolate the annulus from the production conduit, enabling controlled production, injection, or treatment; usually incorporates a means of securing the packer against the casing, such as a slip arrangement, and a means of creating a reliable hydraulic seal to isolate the annulus, typically by means of an expandable elastomeric element.

Pancake flange A blanking flange used to prevent flow.

Perforation A tunnel created from the casing into the reservoir formation, through which oil or gas is produced.

Pick-up elevators A hoisting device used to handle a single joint of tubing.

Pick-up nubbin A rigging attachment used to attach snubbing unit pick-up sling to rig elevators.

Pipe heavy See stripping.

Pipe light See snubbing.

Pipe dope A specially formulated blend of lubricating grease and fine metallic particles that prevents metal damage and seals the roots of threads; applied to tool joints when a connection is made.

Pipe ram The closing and sealing component on a BOP whose end is contoured to seal around pipe to close the annular space.

Pipe-drag force The force from pipe drag on the casing in directional, slant, or dog-legged wells.

Plug valve A type of quick-opening valve constructed with a central core or plug; can be opened or closed with one quarter turn of the plug.

Power pack The assembly of components and controls necessary to provide a hydraulic power supply.

Power tong Pneumatically or hydraulically operated tools that serve to spin the pipe up tight, and in some instances, to apply final make-up torque.

Pressure-area force The force from well pressure acting on the maximum cross-section of the tubing string.

Primary BOP The main blowout preventer in well servicing or drilling operation.

Prime contractor (Primary contractor) The directing contractor for a multi-employer workplace.

Prime mover The source of power for a pump or other device, usually gas engines or electric motors.

Profile brush A wireline tool used to clean profile nipple before plug installation.

Profile nipple A device of smaller ID than the tubing string installed in tubing string where wireline-conveyed tools can be seated.

Pup joint A joint of tubular shorter than standard length.

Purging The practice where a vessel, container, or piping system is evacuated of its gas and/or fluid contents and replaced with another gas and/or fluid; general purpose is to remove explosive and/or flammable gas/fluid from a closed system before opening the system to the atmosphere or before entry to the system by a worker.

Push/pull force The upward or downward force exerted by the mechanical system used to control tubular movement.

Ram The closing and sealing component on a BOP; rams are of three types: blind, pipe, and shear. Pipe rams, when closed, have a configuration such that they seal around the pipe; shear rams cut through drill pipe and then form a seal; blind rams seal on each other with no pipe in the wellbore.

Ram indicator system The system used to indicate whether rams are open or closed.

Ram saver A device used to ensure movement of pipe cannot occur when rams are closed.

Rig-assist The style of snubbing unit that works with a service or drilling rig.

Rigless The style of snubbing unit that is self-contained.

Round-tripping The complete operation of removing string from wellbore and running it back in the hole.

Sand cleanout – process of removing sand or similar fill from a wellbore.

Separator The production equipment used to separate free liquid components of the well production stream from gaseous elements; separation is accomplished principally by gravity, the heavier liquids falling to the bottom and the gas rising to the top; also a process vessel employed to separate liquids of distinctly different physical properties which result in layering or vapor phasing.

Shackles The rigging component used for attaching lifting components.

Shear ram A BOP element with hardened tool steel blades capable of cutting the pipe; normally used as a last resort to regain pressure control of a well that is flowing.

Sheave A pulley; usually refers to either the pulleys permanently mounted on the top of the rig (the crown blocks), or the pulleys used for running wireline tools into the wellbore.

Shut-off valve An automatically operated valve used for isolating a process component or process system.

Shut-in casing pressure The pressure measurement recorded for the space between the surface casing and the producing casing during a well test shut-in phase.

Shut-in tubing pressure The shut-in pressure measurement recorded for the tubing during a well test shut-in phase.

Slickline Commonly used to differentiate operations performed with single-strand wire or braided lines; a single-strand wireline used to run and retrieve tools and flow-control equipment in oil and gas wells; a thin nonelectric cable used for selective placement and retrieval of wellbore hardware, such as plugs, gauges and valves.

Sliding sleeves A completion device that can be operated to provide a flow path between the production conduit and the annulus; incorporate a system of ports that can be opened or closed by a sliding component that is generally controlled and operated by slickline tool string.

Slim hole valve A full-opening safety valve with an OD smaller than the ID of the casing string.

Slings A flat, wide piece of material used for moving material with a type of hoist, crane, etc.; also a wire rope loop for use in lifting heavy equipment.

Slip A wedge-shaped piece of metal with teeth or other gripping elements used to prevent pipe from slipping down into the wellbore or for otherwise holding the pipe in place; rotary slips fit around the drill pipe and wedge against the master bushing to support the pipe; power slips are pneumatically or hydraulically actuated devices operated by the driller at this station and which dispenses with the manual handling of slips when making a connection.

Slip bowl A load bearing component of a slip design into which the slip die carriers seat to prevent pipe movement.

Slip pressure The hydraulic pressure required to function the slips.

Slip stop A wireline tool used to prevent plug from moving.

SNUB FORCE gauge A gauge that measures hydraulic pressure required to push a string of tubing into the well.

Snubbing The process of running or pulling pipe where the force created by well pressure acting on the cross-sectional area of the pipe is greater than the weight of the pipe; the well pressure is attempting to force the tubing out of the well, and is known as “pipe light” situation.

Snubbing BOP A secondary well control device.

Snubbing force The force applied by the snubbing unit.

Snubbing jack The components of a hydraulic snubbing unit that provide the vertical movement required to run or retrieve the work string; can apply extremely high forces to the tubing string and the wellhead to which they are attached.

Snubbing program A written program prepared by prime contractor—either job-specific or part of the total well program—of the operations to be followed at the well site during snubbing.

Snub point See balance point.

Sour well A well having an H_2S content of 10 ppm or greater; respiratory protective equipment (e.g. SABA, SCBA) must be worn by personnel exposed to this environment.

Spacer spools The auxiliary equipment used to lubricate tool assemblies in or out the well.

Spool A short section of pipe with flanged ends, used to separate and support the various valves in the stack; spools act as spacers for the valves in the BOP.

Spool lifting bracket A device used to move spacer spools with a winch.

Spreader bar An overhead lifting component used to facilitate effective hoisting of the snubbing unit.

Spud To start the well drilling process by removing rock, dirt, and other sedimentary material with the drill bit.

Stabbing valve A valve connected to the work string in case the well starts to flow when running or retrieving the string; to protect against tubing plug or backpressure valve failure.

Staging The act of moving pipe connections in or out of the well using of multiple BOPs and an equalize/bleed-off loop.

Standard of competence Written specification by PCP of the knowledge and skills required by a worker to be applied over the range of circumstances demanded by a job.

Stand-up hoists The hoist used to move a snubbing jack from horizontal to vertical position.

Stationary slips The lower sets of slips attached to the jack plate that secures the pipe while the traveling slips are not engaged; include a slip bowl for light pipe (holding the pipe from moving upwards), and a slip bowl for heavy pipe (holding the pipe from moving downwards).

Stimulation The treatment performed to restore or enhance the productivity of a well; see also fracturing.

Strippers The secondary ram preventers used to stage tubing connections through the BOP stack; the inner seals of these BOPs have usually been modified to accept stripper or wear inserts.

Stripping The process of running or pulling pipe where the weight of the pipe exceeds the forces created by the well pressure acting on the cross-sectional area of the pipe; the pipe will fall into the well, and is known as "pipe heavy" situation; pipe can be stripped into or out of a live well through a pack-off element/flow diverter or additional annular.

Stripping pipe ram A ram-type BOP used to provide primary pressure control in high-pressure snubbing operations; used when the wellhead pressure is higher than the limitations of a stripper bowl.

Substructure The foundation on which the derrick and engines sit; contains space for storage and well control equipment.

Swabbing The process of unloading liquids from production tubing to initiate flow from the reservoir.

Sweet well A well having H_2S content of 10 ppm or less, and having no harmful of toxic substances and no corrosive or erosive agents.

Tailpipe The tubulars and completion components run below a production packer; can provide a facility for plugs and other temporary flow-control devices, improve downhole hydraulic characteristics, and provide a suspension point for downhole gauges and monitoring equipment.

Tong ram – device used for vertical positioning of snubbing tongs.

Tongs The large wrenches used for turning to make up or break out drill pipe, casing, tubing and other pipe; variously called casing tongs, rotary tongs, etc., according to the use for which they are designed.

Tool joint A heavy coupling element having coarse, tapered threads and seating shoulders designed to sustain the weight of the drill stem, withstand the strain of repeated makeup and breakout, and provide a leak proof seal; tool joints may be welded to the drill pipe, screwed onto the pipe, or a combination of screwed on and welded.

Tour A work shift of a crew.

Tour sheets A field invoice.

Traveling slips The upper sets of slips attached to the traveling assembly, which moves vertically up and down as the cylinder rods are extended and retracted; grip the pipe to transmit snubbing or lifting force from the jack to the pipe; most snubbing units are equipped with two sets.

Tripping The process of removing the string from the hole and running it back in again.

Tubing end plug A non-retrievable type of plug installed in end of tubing and expelled into the well cellar.

Tubing hanger A device included in the wellhead hook-up and contained in the tubing head which, by use of a mandrel or slips, suspends and holds the tubing string.

Tubing-drift gauge ring A wireline tool used to confirm ID of the tubing string.

Underbalanced drilling Drilling that allows a well to flow oil, gas, and formation fluids to surface as it is being drilled; differs from conventional/overbalanced drilling where one of the prime considerations is preventing hydrocarbons from flowing during drilling.

Unsecuring Resuming operations after a well has been secured.

V-door An opening at floor level in a side of a derrick or mast; opposite the drawworks and used as an entry to bring in drill pipe, casing, and other tools from the pipe rack.

Well classification The class name given to wells by industry and regulatory bodies based on their characteristics; includes the terms “sweet” and “sour.”

Well designation The term used in headings in this IRP that encompasses both well classifications and well designations; also a term used by the PCP referring to their well designations of “sweet,” “sour or sweet,” and “critical sour or sweet,” and upon which this IRP’s well divisions have been built.

Well division The categories assigned to wells for the purpose of this IRP; includes Divisions 1, 2, and 3.

Wellbore effluent A type of gas or fluid discharged from the well.

Well site supervisor A supervisor employed by prime contractor.

Wet tripping Also called wet string, wet pipe; act of pulling a string of pipe from a well with ID full of fluid.

Wireline Well-intervention operations conducted using single-strand or multistrand wire or cable for intervention in oil or gas wells.

Wireline lubricator The assembly of pressure-control equipment used on wireline operations to house the tool string in preparation for running into the well or for retrieval of the tool string on completion of the operation.

Worker competency PCP occupation ladder and standards of competence for the snubbing services sector, which provide a framework for assessing and certifying a worker's competence.

Appendix O: References

The list of information sources and documents provided below includes any documents specifically referred to within this IRP and several additional sources that are useful for reference for basic information on occupational health and safety. Specific snubbing references will vary from jurisdiction to jurisdiction. This list is not exhaustive and any web addresses listed are current at the time of publication of this IRP but are subject to change.

Edition	Remarks / Changes
ACGIH Table 1: Cooling Power of Wind on Exposed Flesh Expressed as Equivalent Temperature, 1998 Threshold Limit Values Table 2: TLVs Work Warm-Up Schedule for Four Hour Shift (Under Discretion of Supervisor on Site) – 1998 TLVs	www.acgih.org
Government of Alberta | Alberta Energy Regulator	www.aer.ca
Government of Alberta | Employment, Immigration and Industry	www.hre.gov.ab.ca
Government of Alberta | Municipal Affairs | Canadian Electrical Code – Electrical Safety Information Bulletin CEC-10 [rev-7] October 2009 (Referenced in Appendix F)	http://www.municipalaffairs.alberta.ca/documents/ss/STANDATA/electrical/454-CEC-10unsigned.pdf
Workers' Compensation Board | Alberta	www.wcb.ab.ca
EII | Workplace Health and Safety	www.hre.gov.ab.ca
British Columbia Oil and Gas Commission	www.ogc.gov.bc.ca
CAODC RP 3.0 Service Rigs Inspection and Certification of Masts RP 3.0A Service Rigs Inspection and Certification of Substructures, Drawworks, and Carriers RP 4.0 Service Rigs Overhead Equipment Inspection and Certification RP 6.0 Drilling Blowout Preventer Inspection and Certification RP 7.0 Service Rigs Well Servicing Blowout Preventer Inspection and Certification	www.caodc.ca
CAPP Flammable Environments Guideline, Dec 2004.	www.capp.ca
Energy Safety Canada IRP 2: Completing and Servicing Critical Sour Wells IRP 4: Well Testing and Fluid Handling IRP 7: Competencies for Critical Roles in Drilling and Completion Operations Workers Guide to Hand Signals for Directing Vehicles Lease Lighting Guideline	www.energysafetycanada.com

Manitoba Industry, Economic Development, and Mines	www.gov.mb.ca/edm/petroleum
Manitoba Labour and Immigration | Workplace Safety and Health	www.gov.mb.ca/labour/safety
Government of Newfoundland and Labrador | Mines and Energy	www.nr.gov.nl.ca/mines&en
US Department of Labor | OSHA Heat Stress Quick Reference	www.ohsa.gov
Petroleum Human Resources Council of Canada (PHRCC) PCP Standards of Competence for Snubbing Services Snubbing Services: Map 1 – Occupation Ladder and Typical Work Environments	www.petrohrsc.ca
Petroleum Services Association of Canada (PSAC) PSAC Snubbing Pre-job Safety Meeting Report and Snubbing Hazard Assessment	www.psac.ca
Saskatchewan Industry and Resources	www.ir.gov.sk.ca
Saskatchewan Labour | Occupational Health & Safety	www.labour.gov.sk.ca/safety
WorkSafeBC	www.worksafebc.com
Workers' Compensation Board of Manitoba	www.wcb.mb.ca
Workplace Health, Safety, and Compensation Commission of New Brunswick	www.whscc.nb.ca
Workplace Health, Safety, and Compensation Commission of Newfoundland and Labrador	www.whscc.nf.ca