Coiled Tubing Operations Manual

HALLIBURTON

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Section 1

Overview

Introduction

Standard job procedures enhance Halliburton operations worldwide by increasing safety, communication, and performance on the jobsite. The procedures included in this manual are designed to establish guidelines to match equipment to the type of work being performed.

"NV" No Variance Procedures

This manual provides Halliburton standard procedures and guidelines. The supervising Halliburton representative on location can make the decision to vary from these procedures if a better and safer way is appropriate—unless the procedure is labeled "NV."

Important	**The standard procedures marked "NV" (see example below) require approval from a Halliburton operations manager for variance to be acceptable.**

NV*	*"No variance" procedures are indicated by enclosure in these shaded areas.*

**No variance. Rule/process must be strictly followed.*

The standardized job procedures in this manual are supported and followed by technical information sections. Information from technical information sections will often be required when using the standardized job procedures.

This manual also provides additional information, such as references to existing policies, areas of responsibility, and other general information.

The Halliburton Management System

The process for operational procedures at Halliburton is broken down as follows:

PSL 1: Develop solutions—The primary goal in developing solutions is to identify the customer's needs, prepare a job design, and initiate a job file. It is crucial to the success of the job to begin with correct information. The person responsible for this should make every effort to gain the latest, most accurate information.

PSL 2: Prepare resources—The primary goal in preparing resources is to match the resources with the customer's needs. It is crucial that the resources match the job design and are capable of carrying out the job as identified in PSL 1.

PSL 3: Mobilize resources—The primary goal in mobilizing resources is to confirm that the right equipment has been properly prepared and is capable of meeting the customer's needs by carrying out the work successfully and professionally. It is crucial that all preventive maintenance schedules are current and documented.

PSL 4: Perform services/deliver products—The primary goal in PSL 4 is to deliver the right equipment, products, and personnel to the right location at the right time. It is crucial that a pre-site safety analysis is carried out before moving equipment onto location. It is also crucial that pertinent risk analyses are carried out throughout the job and that all pertinent HSE standards are followed.

PSL 5: Demobilize resources—The primary goal in PSL 5 is returning equipment, products, and personnel back to base in a safe and timely manner. It is crucial that any defects or irregularities are reported and corrected before the resources are scheduled for work again. It is also crucial that all preventive maintenance schedules are current and documented.

PSL 6: Complete reports and field tickets—The primary goal in PSL 6 is to ensure all pertinent paperwork has been accurately filled out and delivered. It is crucial that this paperwork is completed in a timely manner.

PSL 7: Review performance—The primary goal in PSL 7 is to ensure that the customer's goals were met to the best of Halliburton's ability. It is crucial that any realized opportunities to improve products and services are acted upon as soon as possible to improve future services.

Section

2

Coiled Tubing Safety

Introduction

Personnel safety, both on and off the wellsite, is a top priority at Halliburton.

Safe practices begin at the base before mobilization of personnel and equipment, continue at the wellsite, and are followed through demobilization. They are conveyed to all personnel through five key safety meetings conducted before each critical component of the job. These five components are as follows:

1. Pre-trip, or journey-management safety meeting
2. Wellsite, or pre-spot meeting
3. Pre-job, or pre-rig up meeting
4. Pre-rig down meeting
5. Demobilization, or journey-management safety meeting

NV*	*These meetings are to be attended by all HES personnel involved in that component. Safety meetings are to be documented and the documentation returned with the job packet at the completion of the job.*

**No variance. Rule/process must be strictly followed.*

The five safety meetings conducted in the "Toolbox/Tailgate" format are to cover HSE requirements for each job component. Additionally, observed unsafe conditions and/or practices are to be covered and noted using the HES, HOC, and JSA programs. The proper use of personnel protection equipment (PPE) is to be stressed at every safety meeting.

Safety Equipment Requirements

Safety equipment is provided on all Halliburton coiled tubing units to help minimize the risk to personnel and equipment from equipment malfunction or other causes. Due to the remote nature of most Halliburton work, it is imperative that this equipment be maintained according to HSE and HMS standards.

The following safety equipment shall be available on location during operation of Halliburton coiled tubing units.

Fire Extinguishers

All mobile vehicles shall have at least one mounted extinguisher not to exceed 4 lb. Where dry chemical extinguishers are used, they must be mounted on their side with the discharge hose located on the upper side. This is to avoid packing of the powder.

Provide at least one 10-lb capacity or larger fire extinguisher on all coiled tubing units. Fire extinguishers must be BCF dry chemical or Halon extinguishers. They should be strategically placed on location, where they are obtainable in an emergency. There should be at least one located in the front of the coil unit. It should be placed and marked to be visible for access and to avoid being run over.

The following rules apply to all Halliburton-supplied fire extinguishers:

- All fire extinguishers should have a gauge to check charge.
- There should be a tag noting the next scheduled inspection.
- Check daily to ensure that extinguishers are charged and in good order.
- Inspect extinguishers monthly to confirm proper location, that instructions are legible, that the extinguisher has not been operated, and that there is no physical damage.
- Inspect extinguishers yearly to confirm proper operation.
- Mounting brackets for fire extinguishers should be accessible and visible. If the extinguisher is kept in a toolbox, remove and place it in a visible, readily accessible area.
- In all cases, Halliburton's standards shall meet or exceed federal, state, and/or local standards.

First-Aid Kits

Each unit shall have a first-aid kit. The first-aid kit should be attached to a mounting bracket in the operator enclosure, truck cab, or weatherproof box. The kit should be adequately stocked to deal with minor injuries, such as abrasions and burns, and contain eye wash to remove particles from the eyes and PPE to protect first-aid responders from exposure to blood and other body fluids. A list of items shall be kept in the kit and periodic inspections made. Add or replace supplies as necessary. As a minimum, first-aid boxes shall be inspected monthly.

When working in remote areas, additional first-aid equipment may be required. When working with unusually hazardous materials such as flammable liquids, HF acid, or calcium bromide, additional emergency medical supplies may be required. This will be determined by the local HSE manager.

Power Unit Safety Devices

Each Halliburton coiled tubing unit shall incorporate certain safety devices at the power source.

CT power packs are equipped with:

- Overspeed shutdown devices
- Fiberglass fan (supplied with the engine)
- Antistatic belts
- Spark arrestor/muffler
- Manual emergency kill
- Low-oil shutdown
- High-temperature shutdown

In addition, Zone 2 equipment requires:

- Exhaust coolers
- Inlet flame arrester
- Exhaust-gas conditioner box/flame trap
- ATEX-certified electrical equipment

Safety Equipment Inspection Procedure

NV*	1. The supervisor in charge inspects the unit or delegates inspection of the unit to check that safety equipment is provided before loading out equipment. A pre-job inspection report is to be filled out and included in the job pack.

**No variance. Rule/process must be strictly followed.*

NV*	2. Fire extinguishers must have an inspection tag indicating that Halliburton-supplied extinguishers have been inspected within the past 12 months. An up-to-date register of firefighting equipment is to be maintained by designated authority (normally, the HSE manager).

**No variance. Rule/process must be strictly followed.*

NV*	3. Check that Halliburton-supplied fire extinguishers are properly charged (daily when the unit is working).

**No variance. Rule/process must be strictly followed.*

NV*	4. Check that Halliburton-supplied first-aid kits are adequately stocked. Add or replace supplies as necessary during the post-job inspection.

**No variance. Rule/process must be strictly followed.*

5. Inspect the power unit for safety devices (pre-/post-job inspections).
6. Function-test the emergency kill before load out and before each job or daily operation.

Note — The emergency kill test shall not be performed with the engine speed above an idle because of potential mechanical damage.

Safety Equipment References

- HSE Category 2 Standard 4: Hydrocarbon Pumping
- HSE Category 4 Standard 14: Fire Extinguishers
- HSE Category 9 Standard 7: Vehicle Equipment
- PM/EM pre-job inspection
- PM/EM daily hand-over inspection

Personal Protective Equipment (PPE)

Safety equipment is essential when working in hostile environments, such as with acids, bromides, and H_2S. Failure to use personal protective equipment (PPE) could cause serious injury or death.

Breathing Apparatus

Two common types of breathing apparatus are the self-contained apparatus and the supplied-air apparatus.

- With the **self-contained breathing apparatus (SCBA)**, the standard cylinder supplies air for approximately 30 minutes (other cylinders are available for longer use). All SCBA must have a positive-pressure regulator to help ensure that H_2S does not leech in around the face seal.
- With the **supplied-air breathing apparatus**, the tank is replaced by a large cylinder connected by a hose to the regulator valve on the wearer's body. An escape bottle is worn with this type of apparatus.

H_2S Gas

H_2S gas is one of the most vicious and deadly hazards in the oilfield. Several types of portable detectors are available to determine the amount of H_2S present. The supervisor should determine what equipment is necessary and ensure its availability on location.

- The **electronic detector** is belt-mounted and gives an audible alarm upon exposure to a predetermined level of H_2S.
- **Coated-strip detectors** change color in the presence of H_2S. These detectors are a passive system and should be used only as an indicator for the presence of H_2S.
- **Detector tubes** are also used for detecting the concentration of H_2S.

Hostile Liquids

Precautions should be taken when working with hostile fluids, such as acids, calcium chloride, calcium bromide, and zinc bromide. Wear approved slicker suits, goggles, rubber gloves, steel-toed rubber boots, and other protective equipment. The coiled tubing string should be displaced with water to prevent pulling the string containing these fluids or gas.

Precautions should be taken when working with extremely cold liquids, such as liquid nitrogen and liquid petroleum. Wear approved PPE to include proper gloves, goggles, approved safety boots, and hard hat. Extremely cold liquids cause damage to most ferrous metals. It is important that extremely cold liquids not come in contact with pumping iron, valves, structural components, or hand tools.

PPE Level Definitions

Level A – protects against atmospheres containing poisonous chemicals that can penetrate the skin; it is also used during emergencies involving unknown substances. Level A protection consists of:

1. Air-tight, totally encapsulated suit
2. Self-contained breathing apparatus in positive mode
3. Hard hat
4. Protective footwear
5. Hearing protection
6. Proper communication devices

Level B – protects against chemical concentrations presenting an immediate danger to life and health; it is also used in situations of low oxygen concentrations. Level B protection does not protect the entire body against skin absorption of chemicals. Level B protection consists of:

1. Self-contained breathing apparatus in positive mode, or an air line respirator with escape pack
2. Chemical-resistant clothing
3. Hard hat
4. Protective footwear
5. Impervious gloves
6. Gauntlets or protective sleeves
7. Hearing protection
8. Proper communication devices
9. Personal gas-detection device

Level C – protects against airborne chemical concentrations that exceed the occupational exposure limits. Level C protection consists of:

1. Air-purifying respirators with appropriate filters
2. Full-facepiece respirator or chemical goggles
3. Chemical-resistant clothing
4. Hard hat
5. Protective footwear
6. Impervious rubber gloves
7. Hearing protection
8. Proper communication devices

Level D – protects against physical hazards and **may** include:

1. Safety glasses
2. Goggles
3. Face shields
4. A combination of: hard hat, hand and arm protection, protective footwear, hearing protection, and escape breathing devices

PPE References

- HSE Standards Category 7 Sections 1–8: Personal Protective Equipment
- HSE Guidelines Category 7 Sections 1–8: Personal Protective Equipment
- HMS PMGLHESCT200 Step 5.3
- HMS PMGLHESCT300 Step 2.0
- HMS PMGLHESCT400 Step 1.1
- HMS PMGLHESCT500 Step 3.3

Safety Meetings

Pre-Trip, or Journey-Management Safety Meetings

1. Select a meeting place away from areas where loud noise would interfere with communication.

NV*	*2. All Halliburton personnel involved with the job shall attend. Others involved, such as the third-party transport, are urged to attend.*

**No variance. Rule/process must be strictly followed.*

3. Ensure that directions and route are clear to all drivers.
4. Inspect equipment prior to departure.
5. Ensure that loads are secured.
6. Ensure that lights are on.
7. Ensure that drivers carrying hazardous materials have MSDS.
8. Ensure that all DOT drivers are carrying DOT log books.
9. Ensure that all vehicles are in compliance with HSE Category 9, Standard 7, *Vehicle Equipment*.
10. Discuss weather conditions.
11. Discuss road conditions.
12. Plan rest stops.
13. Plan brake checks, when required (steep grades).
14. In addition to the Halliburton corporate driving policy, ensure that all known road hazards ahead are covered (school zones, construction sites, and detours, etc.).

Wellsite, or Pre-Spot Safety Meetings

1. Select a meeting place away from the immediate wellsite, avoiding areas where loud noise would interfere with communication.

NV*	*2. All Halliburton personnel involved with the job shall attend. Others involved, such as the third-party transport, are urged to attend.*

**No variance. Rule/process must be strictly followed.*

3. Review unsafe practices (e.g., backing up without spotters).

4. Review hazards on location (guy wires, unmarked holes, mud pits, wellhead, flow lines, power-line rig equipment, tripping hazards, H_2S, etc.).
5. Promote “back safety” awareness (know your limits, plan lift, team work).
6. Wear provided personal protective equipment. Minimum requirements on location are to include, but are not limited to: approved safety boots, approved Halliburton long-sleeved coveralls, hard hat, safety glasses, ear protection, and work gloves.
7. Cover communication (headsets and hand signals).
8. Smoking allowed only in designated smoking areas.

Pre-Job, or Pre-Rig Up Safety Meetings

1. Select a meeting place away from the immediate wellsite, avoiding areas where loud noise would interfere with communication.

NV*	*2. All Halliburton personnel involved with the job shall attend. Others involved, such as the third-party transport, are urged to attend.*

**No variance. Rule/process must be strictly followed.*

3. Discuss dangerous situations (working cranes, MSDS, pinch points, energized vessel, and lines, etc.).
4. Stress the use of tag lines.
5. Discuss emergency job assignments, emergency shutdowns, and fire-extinguishing equipment.
6. Ensure personnel are aware of their roles and responsibilities during rig up and job execution.
7. Discuss the location of first-aid kits and a designated meeting area in case of an emergency.
8. Inform the company representative and other personnel of unexpected or unusual noise or operating procedures.
9. Cover communication (headsets and hand signals).
10. Review the emergency contingency plan.
11. Review safe area locations and escape routes.
12. Discuss the daily log report when two crews are involved, placing special emphasis on equipment operating status and other operational aspects of the job.

Pre-Rig Down Safety Meetings

1. Select a meeting place away from the immediate wellsite, avoiding areas where loud noise would interfere with communication.

NV*	2. All Halliburton personnel involved with the job shall attend. Others involved, such as the third-party transport, are urged to attend.

*No variance. Rule/process must be strictly followed.

3. Identify and communicate site-specific hazards on location dealing with rig-down operations.
4. Identify and communicate hazardous materials on location.
5. Review equipment-handling procedures and identify equipment-handling devices.
6. Designate an individual to supervise the rig down of the wellhead operation.
7. Confirm that the well is secured and locked out and that all lines to be rigged down are bled off.
8. Ensure that there is an eyewash station on location or mounted on the equipment.

Demobilization, or Journey-Management Safety Meetings

1. Select a meeting place away from areas where loud noise would interfere with communication.

NV*	2. All Halliburton personnel involved with the job shall attend. Others involved, such as the third-party transport, are urged to attend.

*No variance. Rule/process must be strictly followed.

3. Ensure that directions and route are clear to all drivers.
4. Inspect equipment prior to departure.
5. Ensure that loads are secured.
6. Ensure that lights are on.
7. Ensure that drivers carrying hazardous materials carry MSDS.
8. Ensure that all DOT drivers are carrying DOT log books.
9. Ensure that all vehicles are in compliance with HSE Category 9, Standard 7, *Vehicle Equipment.*
10. Discuss weather conditions.
11. Discuss road conditions.

12. Plan rest stops.
13. Plan brake checks, when required (steep grades).
14. In addition to the Halliburton corporate driving policy, ensure that all known road hazards ahead are covered (school zones, construction sites, and detours).

Supervisor Duties (Safety Related)

The following procedure cannot be varied.

**No variance. Rule/process must be strictly followed.*

1. The supervisor in charge is to stop the job if necessary and correct any unsafe practice or equipment malfunction that could lead to the injury of personnel or damage to equipment.
2. Stop the job immediately upon the discovery of an unsafe situation.
3. Inform the company representative of the situation and advise him/her of the course of action to be taken, if time allows (non-emergency situations).
4. Make necessary changes to correct the unsafe practice or condition if the condition is under Halliburton control.
5. Notify local Halliburton management immediately if problems arise with a customer or personal injury or equipment damage. Refer to the Halliburton incident-reporting document, BP GL BU HSE ADM0108.
6. Note the situation on the field ticket/job log and record the course of action taken to correct problems.

Personal Protective Equipment (PPE)

The following procedure cannot be varied.

**No variance. Rule/process must be strictly followed.*

1. Provide personal protective equipment to Halliburton personnel at the wellsite. Minimum requirements are to include, but are not limited to: approved safety boots, approved Halliburton long sleeved coveralls, hard hats, safety glasses, ear protection, and work gloves.

2. Personal protective equipment and service equipment requirements are addressed in job planning. The supervisor in charge checks to see that the equipment is provided and used.
3. Confirm that all personnel know how to use equipment (i.e., safety meeting).
4. Confirm that personnel know when and where to use equipment (i.e., safety meeting).
5. Stop any operation where personnel are not properly equipped.

Personnel Safety References

- HSE Category 1 Standards 3 and 7: Risk Assessment and Safety Meetings
- HSE Category 7 Standards 1–8: Personnel Protective Equipment
- HSE Category 9 Standard 7: Vehicle Equipment
- HMS GL HES CT 300 Activity 4.0: Pre-Mobilization Safety/Job Meeting
- HMS GL HES CT 400 Activity 1.0: Pre-Job Meeting and Activity 3.1, Pre-Rig Up
- HMS GL HES CT 500 Activity 2.0: Post-Job/Pre-Rig Down

Hydrogen Sulfide (H_2S Safety Procedures)

Before rigging up on a well with potential H_2S content, exercise safety precautions to help prevent the escape of H_2S gas to the atmosphere and to avoid personal injury. H_2S gas is highly hazardous to unprotected personnel and equipment. Careful attention to equipment selection and planning of the job helps lead to job success.

General Information

A well with a high concentration of H_2S is potentially hazardous to the crew and the environment if control is lost for any reason. Whenever a coiled tubing unit is rigged up on an H_2S well, use the following safety precautions and operating techniques.

- Personal protective equipment should include a SCBA and H_2S detector tape or monitor for each person on location.
- A flanged spool is required for the connection between the tree and the BOP.
- A four-man crew is recommended on an H_2S job.
- Every member of the crew must be trained and be H_2S certified.

Procedures for H_2S Locations

NV*	The following procedure cannot be varied.

*No variance. Rule/process must be strictly followed.

1. All personnel on location must be clean-shaven for the air mask to form a proper seal against the face.
2. Before arriving at the wellsite, the supervisor in charge shall:
   a. Check the wind direction. While staying upwind of the well, the supervisor in charge shall stop the crew at a safe distance from the well.
   b. Unless the customer is furnishing an outside safety company that has already checked the location for the presence of H_2S gas, the supervisor in charge shall designate a trained crew member to approach the well.
   c. The designated person shall cautiously approach the well on foot with an H_2S metering device, while wearing a self-contained breathing apparatus.
   d. Only after allowable levels of H_2S gas have been detected will the rest of the crew and units be allowed to enter the location unprotected. If the H_2S concentration exceeds allowable limits, the crew must be protected before proceeding to the wellsite.
3. The supervisor in charge should hold a safety meeting. Each member of the crew should be assigned tasks and given the locations of two safe briefing areas. Two people should be appointed to handle the well if problems should develop.
4. The location must have two wind socks or another means of monitoring the wind direction. These should be installed at the briefing areas and other conspicuous locations.
5. Verify the breathing apparatus is on location and in proper working condition. Ensure that all personnel have received instruction on the proper use of equipment.
6. Rig up the equipment in the normal manner (refer to Section 5, “Coiled Tubing Unit Rig Up”).

   Note — All pressure-containing equipment shall be rated for H_2S service. Before rigging up the BOP, bleed any trapped pressure to the atmosphere while checking wind direction and gas concentration.

7. Carefully unflange the tree top and connect the BOP stack with an approved flanged connection. Consideration should be given to rigging up an additional BOP below the main BOPs.
8. Run the job using standard procedures while monitoring wind conditions and H_2S warning devices.

HSE Standards for Hydrogen Sulfide

Category: 5 Hazardous Chemicals

Standard: 7 Hydrogen Sulfide

Conduct pre-job planning to determine the suitability of all equipment and PPE for use in H_2S conditions. All personnel on the job shall have current H_2S training.

Objective: To minimize the risk of exposure to hydrogen sulfide.

Performance Criteria

Hydrogen Sulfide Assessment

Identify areas where H_2S may potentially be present at concentrations above 10 ppm.

Sources for information about H_2S concentrations at a wellsite include, but are not limited to:

– Customer/operator
– Worksite knowledge
– Results of H_2S monitoring

Note	Hydrogen sulfide may be created when acidizing wells with high iron-sulfide concentrations.

Phase One of H_2S Planning

Include the following items in phase one of the H_2S plan:

- All employees who will perform the job are trained in H_2S and the use of the PPE.
- Inspect all personal protective equipment before and after use.
- Inspect all equipment to be used on the job to ensure that it is compatible with H_2S and is working properly.
- Inspect and calibrate H_2S detectors.
- Ensure that wind-direction indicators and a sufficient number of H_2S alarms are available for the job.
- Draft a site-specific emergency/contingency plan (see guidelines for a sample site-specific emergency response plan).

Phase Two of H_2S Planning

When on location, conduct the following in phase two of the H_2S plan:

- Ensure that the location has the following equipment available:

- H_2S alarms in sufficient quantity (at least one monitor per person on location or area monitors in locations of potential release)
- Inspected and working personal protective equipment for each employee
- Wind-direction indicators, such as windsocks to detect wind direction

• Complete site-specific emergency/contingency plan and communicate plan to all affected personnel.

• Conduct a pre-job safety meeting.

Pre-Task Health and Safety Meeting

• Conduct a pre-task health and safety meeting before starting the job. The pre-task safety meeting must cover the following topics at a minimum:

- Emergency procedures
- Safe zone upwind from H_2S source for assembly and accounting of personnel (a secondary safe zone is designated in case of a change in wind direction).
- Wind direction
- Emergency phone number or method of contact
- Never attempt rescue without proper protective equipment and rescue training

Note — See Health, Safety and Environmental Standards, C1S7, *Job Site Health and Safety Meetings. 2.0 Hydrogen Sulfide Protection*

Equipment

• In H_2S areas, use the following equipment. This list of equipment is not exhaustive; other equipment may be necessary or required in certain situations.

- Gas-detection alarm systems
- Check valves on discharge lines
- Compatible material such as pipe, manifolds, etc. for use with H_2S
- Wind-direction indicators, such as windsocks to determine the wind direction for safe zones
- Warning signs

• Test equipment before each use.

Personal Protective Equipment

• In areas where potential H_2S concentrations above 10 ppm are expected, the following personal protective equipment are required to be available at the worksite:

- Self-contained breathing apparatus (SCBA) for rescues and designated “rescue personnel”
- Five-minute escape packs on the person of each worker (see HSE Standards, C7S5, Respiratory Protection for Respirator Requirements)

Training

- Inform all employees who will be working in areas with potential H_2S concentrations of the following:
  - First-aid response
  - Hazards of H_2S, including the hazards of flaring, which may produce sulfur dioxide
  - Symptoms of H_2S exposure
  - Health effects of exposure to H_2S
  - How to recognize the presence of H_2S
  - How to care for, maintain, and wear personal protective equipment
- Refresh training frequently.

Inhibitors for Coiled Tubing in H_2S Environments

A CT job circulating fluid should include one of the following inhibitors:

- 0.2% CoilGard®
- 1.3% Baker Cronox® 669
- 0.6% Tretolite® KP158

Note	The inhibitors listed above are not compatible with acid. For acid, use SCA 130 sulfide cracking agent at 0.4 to 6%, depending on BHT.

To run a job involving pumping of N_2, a corrosion-inhibitor pump should be connected to the coiled tubing unit. Pump the manufacturer's suggested rate per 1,000 scf of nitrogen. This should provide added protection against hydrogen embrittlement of the coiled pipe. In dry gas wells or when RIH without circulating, an injection sub in the well control stack can be used to add inhibitors directly to the OD of the coiled tubing.

Whenever possible, an oil-soluble chemical with water dispersant should be used. This will help eliminate emulsion problems.

For more information concerning H_2S qualifications for equipment, visit

http://halworld.corp.halliburton.com/internal/PS/pe/contents/Papers_and_Articles/web/A_through_P/considerations_QT900_QT1000.pdf

Purging Hazardous Materials

Hazardous materials remaining in the coiled tubing may be harmful to personnel, equipment, and the environment. Customers are responsible for properly disposing of hazardous materials pumped through the coiled tubing. This includes any material left inside the tubing.

Pre-Planning

Halliburton supervisors in charge should confirm that the customer has the proper fluid or gas on location to purge the coiled tubing before moving off site. If hazardous materials are to be disposed of off site, the proper paperwork must be completed and the proper signs must be displayed.

If acid or corrosive fluids have been pumped, a base material such as soda ash can be used to displace the acid in the coiled tubing. Soda ash may help neutralize the effects of the acid on the tubing and should be on location before starting a job.

Special care should be taken when explosive gases or fluids have been used. Purge tubing before leaving location. If possible, the tubing should be purged while still in the well or through the flow line. If not possible, flow line should be laid and secured for disposal of fluids to a pit or tank.

Special precautions should be taken in cold weather to reduce the chances of freezing the purging fluid. It is recommended that the tubing be blown dry with N_2 to help avoid problems.

HazMat Disposal Procedure

NV*	1. Conduct a JSA and hold a tailgate/toolbox safety meeting before displacing hazardous materials in accordance with HMS processes. All personnel are to be supplied with and required to wear correct PPE as per HMS and HSE.

**No variance. Rule/process must be strictly followed.*

NV*	2. Identify hazards and inform all personnel on location when purging hazardous materials from the tubing. Supply all pertinent personnel with MSDS as per HMS processes.

**No variance. Rule/process must be strictly followed.*

3. Ensure that required emergency, first-aid, and medical supplies are on location and that all key personnel know how to administer them (for example: eyewash station, chemical shower, and chemical neutralizers).

4. Displace the hazardous material with a proper fluid or gas for adequate protection of the tubing (for example: Annib II™ inhibitor, soda ash, or N_2).

NV*	5. Hazardous materials must be properly displaced before transporting the unit. Do not leave corrosive fluids and/or gases in coiled tubing during transport.

**No variance. Rule/process must be strictly followed.*

NV*	6. Disposal of hazardous waste materials must be in compliance with all local, state, and federal regulations.

**No variance. Rule/process must be strictly followed.*

Information about Disposal of Hazardous Waste Materials

For information concerning the proper disposal of hazardous waste materials, consult the following groups:

Terry Byerly
Duncan TSDF
(580) 251 4151

or

RTTS Requirements Management
Houston, TX
(281)575 4018

HazMat Disposal References

- HSE Category 5 Standards 1, 2, 5, 6, and 7: Hazardous Chemicals
- HSE Category 5 Guideline 1: Hazardous Chemicals
- HSE Category 6 Standards 1 and 3: General Health and Safety
- HSE Category 6 Guideline 1: General Health and Safety
- HSE Category 7 Standard 1: Personal Protective Equipment
- HSE Category 10 Standards 1, 2, 6 and 11: Environmental
- HMSPM GL HES CT 400 Notes 1.6, 3.1 and 4.14: Perform Services
- Best Practice Series *Purging Fluids from Coil Tubing*
- Best Practice Series *Pumping CO_2 through Coil Tubing*
- MSDS link: http://msds.corp.halliburton.com
- *Coiled Tubing Handbook*, “Displacing Fluid from Coiled Tubing with Nitrogen”

PPE for Above-Ground Work

Table 2.1 lists some PPE needed for above-ground work. These items as well as others are discussed in the sections that follow.

Table 2.1—Personal Protective Equipment for Above-Ground Work

Equipment		Part No.
Full-body harnesses		Small 100027938
		Medium 100002139
		Large 100002140
		X-Large 100002141
Lanyard, shock-absorbing, 6-ft		100012998
Lanyard, dual-leg		101209644
Fall anchorage, 30/38K injector		100082347
Fall anchorage, V45/60K/V95/V135 injectors		100082346
Life line (50-ft cable)		101209643
Life line (85-ft cable)		101483245
Safety block supports for the injector		10029206
OSHA-type 4-man personnel baskets w/test weights	36 × 108 in.	101553901
	58 × 58 in.	101553900

Full Body Harnesses

A full-body harness is used rather than a belt for fall protection because the harness is more likely to prevent injury when stopping a fall (belts are not approved as a fall-prevention device). Full-body harnesses distribute the arresting forces over the seat as opposed to the soft, vulnerable midsection of the body.

Note — Color coding the top and bottom straps of the harness can help employees put the harness on correctly with greater ease and speed. Do NOT paint the harness; solvents from the paint or other materials may damage fibers or deteriorate material.

The employee's full-body harness may be attached by a lanyard or directly to the life line with a sliding "D" ring. The "D" ring will absorb the force and position the body in an upright position should a fall occur.

Lanyards

Lanyards are short, flexible ropes, cables, or strap webbing with locking snaps used to secure the employee's safety harness to an anchor point capable of withstanding the impact of a fall. Lanyards are made of synthetic materials constructed in a manner that reduces the shock to the user by absorbing the energy through the length of the lanyard.

Note — A shock-absorbing system is required by U.S. law and company minimum standards. This is a device that gradually "slows" the employee's fall to lessen the impact forces exerted on the employee's body. This device may be a mechanical unit connected to an anchorage point with the lanyard connected to the device, or some lanyards have a shock-absorbing feature built into them. Such lanyards will contain "rip stitched" material that will unfold to slow descent before stopping the fall. In any case, 900 ft-lb is the maximum force that can be exerted on the person.

Ladder-Fall Devices

The rope-fall device for a ladder consists of a rope and several rope-grab devices. The rope is attached to a secure object on the top end that must withstand a 5,000-lb static load and tied off to the bottom of the ladder or a weight at the bottom of the ladder. The harness is secured to a single rope-grab device on the rope designed to "catch" if a person falls but move freely up and down under normal use of the ladder.

Caution — **Do not attach more than one person to a single rope-grab device.**

Safety Blocks

The safety block is a slightly spring-loaded payout device that automatically "catches" if the payout rate exceeds 4.9 ft/sec. They are normally mounted on a support attached to the injector frame or another component frame with the attached points designed for a 5,000-lb static load (refer to the OSHA requirement). Many of these devices include a shock-absorbing system in their design.

Pre-Job Planning for Fall Prevention/Protection

Identify areas where fall protection is required.

1. Use railings, floors, and scaffold (when possible) to help prevent falls.
2. Use only full-body harnesses with shock absorbing lanyards or equivalent life-line systems, when working at 6 ft or more above the surface (e.g., rig floor, ground, platform).
3. Follow the most stringent standard required by regulation.
4. Use safety harnesses free from:
    a. Cuts and tears.
    b. Undue stretching.
    c. Alterations or additions.
    d. Deterioration from acid, fire, or corrosives.
    e. Distorted hooks or parts.
    f. Faulty hook springs.
5. Anchor the life line or lanyard to structural members or other supports that will withstand the impact of the fall. Refer to the following guidelines regarding anchorage points.
    a. Keep the distance between the anchor point and the worker as short as possible to prevent dangerous swinging from side to side should the worker fall.
    b. The free-fall distance cannot exceed 6 ft.
    c. Attach the life line and/or lanyard directly overhead of the user to prevent swinging into the structure in the event of a fall.
    d. Snaphooks must be equipped with self-locking devices.
6. Lanyards must be equipped with shock absorbers and only allow a maximum free fall of 6 ft.
7. Inspect body harnesses, life lines, and lanyards before and after each use.

Working Above Ground: General Procedures

The following procedures are applicable when working at least 6 ft above the floor or ground.

Harness and Lanyards

1. Visually inspect the devices before use. Replace damaged or excessively worn equipment. Refer to applicable Inspection Maintenance (IM) documents.
2. Use the harness in conjunction with either the lanyards, shock-absorbing device, a safety block, or a rope-fall device. Use the harness when (1) ascending or descending a ladder, (2) working on various components during rig up and rig down, and (3) when the employee is working 6 ft or more above ground level and not protected by a platform with handrails, etc.
3. Remain attached at all times when not protected by a platform with handrails, etc. When using a ladder, attach the harness to the rope-fall device for the ladder. When working 6 ft or more above ground level, always attach the harness either directly to a safety block or to a structural member by means of a lanyard.
4. The safety block provides a wide range of movement without attaching and detaching; however, when moving out of the range of one safety block (or when using just lanyards), it is necessary to change attachment points. Always attach to the second point before detaching from the first. The “attach before detach” rule will necessitate the use of two lanyards when not using the safety block.
5. A 6-ft lanyard shall not be attached below the person using it. This would expose the employee to a fall of greater than 6 ft.
6. Replace harness and lanyards that have been subjected to the shock of catching someone (refer to the manufacturer’s instructions).

Rope-Fall Devices

1. Make a visual inspection of the rope-grab device and the rope before use. Replace damaged or excessively worn equipment. Refer to applicable Inspection Maintenance (IM) documents.
2. When using the ladder to reach a work position, attach the harness to the next rope-grab device on the ladder. Climb to the work position and attach yourself directly to a safety block or a structural member with a lanyard. Detach from the rope-grab device and position it to use on the way down. If two people are at this work position, two rope-grab devices should be positioned for use on the way down. If three people are at this work position, three devices should be positioned for use on the way down, etc.
3. To descend, attach the harness to the next rope-grab device, detach the safety block or lanyard, and climb down the ladder. When on the ground, detach the rope-grab device from the harness. Only one person should be on the ladder at any given time.

4. Inspect and replace rope-grab devices and ropes that have been subjected to the shock of catching someone as specified in the manufacturer's instructions.

Safety Blocks

1. Visually inspect the block before use. If the block is damaged, send it to the manufacturer for inspection. Refer to applicable Inspection Maintenance (IM) documents.
2. Two safety blocks are connected to supports on the injector for use during the job. The attached points are designed to hold a 5,000-lb static load. Safety blocks can also be mounted elsewhere, such as to the upper portion of a lift or to the crane to facilitate rig-up and rig-down procedures.
    a. Safety block-attachment points must withstand a 5,000-lb static load.
    b. Safety blocks are always mounted above the worker.
    c. A tag line is attached to the clip to pull the clip down when necessary.
    d. The safety-block line is attached to the safety harness.
3. Do not attach more than one person to a single safety block. To attach yourself to a safety block, pull down the tag line and attach the clip to the harness. You can then climb without being attached by lanyards to other structural members.
4. Do not allow the safety block cable to have any slack or to rub across a sharp abrasive edge.
5. If it becomes necessary to detach from the safety block, you must first attach to a structural member with a lanyard. When detaching from the safety block, do not release the cable to spring back in a quick and uncontrolled manner.

The safety block must be sent in annually for inspection and repair by the manufacturer. If a block has been subjected to the shock of catching someone, send it to the manufacturer for inspection immediately.

Personnel Hoisting

An OSHA-type personnel basket used with a crane is a means of transporting personnel when no other method is possible. OSHA has certain minimum requirements for these personnel baskets. If it is necessary to move personnel by crane, use a personnel basket and crane that meet all OSHA requirements (Refer to CFR 29 1926.550).

Restrictions on Hoisting Personnel

- Use of the cathead to lift personnel is strictly prohibited.
- Personnel hoisting may not be performed while the drillstring is rotating or while other work activities are occurring in the immediate vicinity.
- Personnel hoisting may only be performed after a pre-lift meeting has been conducted.

- Personnel hoisting may only be performed using a full-body harness with integral suspension workseat that meets or exceeds ANSI, BS, or other internationally recognized standards for man-lifting/fall-arrest equipment.
- Use of open hooks or non-locking spring-loaded hooks is strictly prohibited.
- Detaching the lifting line from the lifting harness to enable work at elevations of 6 ft or more is prohibited unless the employee immediately attaches the harness to a fall-arrest system as defined in the fall-protection standard (Category 6 Standard 4).

Hoisting Operation Procedures

Personnel hoisting may only be performed when there are no alternative methods for safely performing the task, or when the alternative methods present a greater risk of injury. A full-body harness with integral workseat must be used. Personnel must use independent fall protection when working at elevations of 6 ft or more.

Pre-Lift Meeting

A pre-lift meeting to review the OSHA requirements is required. The following topics should be included:

- The outcome of the hazard assessment (see HSE Category 1 Standard 3, *Hazard Identification and Risk Assessment*, for further information)
- Objectives of the task, and methods for completion
- Method of communication between the winch operator and the employee being hoisted. Communication must be maintained at all times
- The employee being hoisted controls the lift. The winch operator may only raise or lower the rider as directed by the rider
- Review of the competency of the winch operator
- Verification that the winch operator has examined the winch and determined that the wire rope and brakes are in good condition, the control lever returns to neutral automatically, the winch is fully operational, and that the winch has been load tested within the past 12 months
- Review of operator and/or drilling contractor policies and procedures on man-riding. Policies or procedures where a secondary fallarrest system independent of the winch line is required are to be followed

Lifting Procedure

1. Inspect all equipment before beginning hoisting operations.
   a. A full-body harness with integral workseat must be used.
   b. Hooks must be of a type that can be closed and locked, eliminating the hook-throat opening. Alternatively, the hook may be replaced by an alloy anchor-type shackle with a bolt, nut, and retaining pin.

c. Winches certified for man-riding are required by local and/or international regulation.
d. Personnel must wear the harnesses and the harnesses must be attached to the basket.
e. The basket must have a grab rail and be stamped with the load rating and statement that it meets OSHA requirements.
f. The weight of the loaded platform must be less than one half the rated capacity for the crane at the angle being used.
g. The load lines must exceed 7 times the capacity of the platform for ordinary wire rope and 10 times the capacity for rotation-resistant wire rope.
h. The crane line must not have a "free fall" feature and must have an anti-two block device.

2. Before hoisting employees, perform a trial lift of the platform from the ground to the work position with a load of 125% of the work load.
3. Visually inspect the equipment after the trial lift.

Vehicle-Mounted Platforms

Vehicle-mounted platforms will be operated by competent personnel only. The function of all controls will be plainly marked. All modifications will be certified by the manufacturer and will meet industry standards. Personnel in lifts will wear approved fall protection.

Equipment Types

Aerial devices include the following types of vehicle-mounted equipment used to elevate personnel to jobsites above ground:

- Extendable-boom platforms
- Aerial ladders
- Articulating-boom platforms
- Vertical towers
- A combination of any of the above

Controls

- All articulating-boom and extendable-boom platforms, primarily designed as personnel carriers, will have both platform (upper) and lower controls.
- Upper controls will be in or beside the platform within easy reach of the operator.
- Lower controls will enable overriding the upper controls.
- The function of controls will be plainly marked.
- Lower controls will not be operated unless permission has been obtained from the employee in the lift, except in case of emergency.

Operating Aerial Lifts

Only trained, competent persons may operate an aerial lift. If lifts are rented, training should be provided before employees are allowed to operate the equipment. Leasing companies should provide training or a demonstration of the proper use of equipment.

- Never operate any aerial-lifting apparatus near power lines unless the lines have been de-energized.
- Position outriggers, if present, on pads or a solid surface.
- Stand firmly on the floor of the basket, and do not sit or climb on the edge of the basket or use planks, ladders, or other devices for work position. Use a full-body harness and a lanyard attached to the boom or basket when working from an aerial lift (see HSE Standard C6S4, “Fall Protection,” for further discussion of lanyards).
- Never tie off to an adjacent pole, structure, or equipment while working from an aerial lift.
- Test lift controls each day before use to ensure they are in safe working condition.
- Never exceed the boom and basket load limits specified by the manufacturer.
- Set the brakes.
- Install wheel chocks before using an aerial lift on an incline.
- Never move an aerial lift truck when the boom is elevated in a working position with men in the basket, unless the equipment is specifically designed for such operation.
- Never wear pole climbers while performing work from an aerial lift.
- Before moving an aerial lift for travel, inspect the boom(s) to ensure they are properly cradled and outriggers are in stowed position.

Scaffolds

Scaffolding must meet OSHA 29 CFR 1910.28 requirements. It must be designed for the configuration and load being used. It must have an OSHA-approved guardrail system that is enclosed from toeboard to midrail. Scaffolds must be capable of supporting at least four times the maximum intended load. The OSHA document lists the maximum heights allowed, the member spacing, the nominal member sizes, and the allowable load. Scaffolds will be erected or modified under the supervision of a qualified person. Scaffold assemblies will be inspected before use and after modifications or adjustments have been made. Scaffold assemblies will be equipped with proper railing and decking.

Inspecting Scaffolds

Inspect all scaffold components before erecting and during dismantling.

1. Replace defective parts.

2. Inspect the following:
    - Handrails, midrails, cross bracing, and steel tubing for nicks (especially near center span) and indications that a welding has struck
    - Components for straightness and freedom from bends, kinks, dents and severe rusting
    - Weld zones for cracks, and ends of tubing for splitting or cracking
    - Manufactured decking for loose bolt or rivet connections and bent, kinked, or dented frame
    - Plywood surfaces for softening due to rot, wear, peeling, or laminated layers at edges
    - Check safety plank for rot cracks and other damage
    - Quick-connecting devices for proper operation
    - Casters for smooth rolling surfaces, free turning, free-acting swivel, and to ensure that the locking mechanism is in good working order.

This list is not exhaustive; it may be necessary to inspect other equipment in certain situations.

Erecting Scaffolds

A designated competent person should supervise all erecting, altering, or dismantling of scaffolding. A registered professional engineer must design all scaffolds over 125 ft (38 m).

1. Erect scaffolding plumb and only on a sound foundation capable of supporting the scaffold and its intended load without tipping or settling.
2. Provide a safe means of access to all scaffold platforms.
3. Completely deck work platforms with scaffold-grade planking.
4. Secure planking in place.
5. Equip scaffold platforms erected 6 ft (2 m) or more above ground (or adjacent surface) with a standard guardrail system. The guardrail system consists of the following:
    a. Top rail
    b. Mid rail
    c. Toe boards that will support at least 200 lb (90 kg) of lateral force

Building Welded-Frame Scaffolds

1. Provide adjustable or plain base plates with adequate mudsills on soft ground.
2. Never extend adjustable bases more than 18 in. (7 cm).
3. Crossbrace each scaffold section.
4. Where uplift may occur, couple sections together with pins that can be locked.
5. Secure scaffolds taller than four full sections, or 20 ft, with guy wires (or other means) at least every 26 ft.

6. Provide positive locking devices for rolling scaffolds with casters.
    a. NEVER use casters with adjusting screws.
    b. NEVER exceed four times the minimum base dimension on freestanding scaffolds.
    c. NEVER ride on rolling scaffolds.

Building Tube and Coupler Scaffolds (Pole Scaffolds)

1. Provide diagonal and crossbracing on each vertical section on at least two sides.
2. Never exceed 6 × 10 ft with upright pole spacing.
3. For bearers and runners, horizontal members must be at least 4 in. longer than the post spacing, but not more than 12 in. longer than the post spacing.

Building Suspended Scaffolds

Suspended scaffolds must be erected by qualified personnel.

1. Inspect scaffolds before and during use.
2. Equip all scaffolds with separate vertical safety lines, anchored independently of the scaffold system.
3. Secure workers to the vertical safety lines.

Terms Used in this Section

Aerial device. Any vehicle-mounted device, telescoping or articulating, or both, used to position personnel.

Aerial ladder. An aerial device consisting of a single- or multiple-section extendable ladder.

Anchorage. A secure point of attachment for life lines, lanyards, or deceleration devices.

Articulating-boom platform. An aerial device with two or more hinged boom sections.

Body harness. Straps that may be secured around the employee in a manner that will distribute the fall-arrest forces over at least the thighs, pelvis, waist, chest, and shoulders with means of attaching it to other components of a personal fall-arrest system.

Buckle. A device for holding the body harness around the employee's body.

Competent person. A person capable of identifying hazardous or dangerous conditions in the personal fall-arrest system or any component thereof, as well as in their application and use with related equipment.

Connector. A device used to connect parts of the personal fall-arrest system and positioning device system together. It may be an independent component of the system, such as a carabiner, or it may be an integral component or part of the system (such as a buckle or D ring sewn into a body harness, or a snap hook spliced or sewn to a lanyard or self-retracting lanyard).

Controlled-access zone (CAZ). An area in which certain work may be taking place without the use of guardrail systems, personal fall-arrest systems, or safety nets, and where access to the zone is controlled.

Deceleration device. A mechanism, such as a rope grab, rip-stitch lanyard, specially woven lanyard, tearing or deforming lanyard, or automatic self-retracting lifeline/lanyard, etc. that serves to dissipate a substantial amount of energy during a fall arrest, or otherwise limit the energy imposed on an employee during a fall arrest.

Deceleration distance. The additional vertical distance a falling employee travels, excluding lifeline elongation and free-fall distance, before stopping, from the point at which the deceleration device begins to operate. It is measured as the distance between the location of an employee's body-harness attachment point at the moment of activation of the deceleration device during a fall, and the location of that attachment point after the employee comes to a complete stop.

Extendable-boom platform. An aerial device (except ladders) with a telescopic or extendable boom. Telescopic derricks with personnel platform attachments will be considered extendable-boom platforms when used with a personnel platform.

Free fall. The act of falling before a personal fall-arrest system begins to apply force to the fall.

Free-fall distance. The vertical displacement of the fall-arrest attachment point on the employee's body harness between the onset of the fall and just before the system begins to apply force to arrest the fall. This distance excludes deceleration distance and lifeline/lanyard elongation, but includes any deceleration device-slide distance or self-retracting lifeline/lanyard extension before they operate and fall-arrest forces occur.

Hole. A gap or void 2 in. (5.1 cm) or more in its least dimension in a floor, roof, or other walking/working surface.

Insulated aerial device. An aerial device designed for work on energized lines and apparatus.

Lanyard. A flexible line of rope, wire rope, or strap that generally has a connector at each end for connecting the body harness to a deceleration device, life line, or anchorage.

Life line. A component consisting of a flexible line for connection to an anchorage at one end to hang vertically, or for connection to anchor at both ends to stretch horizontally, and which serves as a means of connecting other components of a personal fall-arrest system to the anchorage.

Mobile unit. A combination of an aerial device, its vehicle, and related equipment.

Opening. A gap or void 30 in. (76 cm) or more high and 18 in. (48 cm) wide in a wall or partition, through which an employee can fall to a lower level.

Personal fall-arrest system. A system used to arrest an employee in a fall from a working level. It consists of an anchorage, connectors, a body harness, and may include a lanyard, deceleration device, life line, or a suitable combination of these.

Note	As of January 1, 1998, the use of a body belt for fall arrest is prohibited.

Platform. Any personnel carrying device (basket or bucket) that is a component of an aerial device.

Positioning-device system. A body-harness system rigged to allow an employee to be supported on an elevated vertical surface, such as a wall, and work with both hands free while leaning.

Qualified person. One with a recognized degree or professional certificate and extensive knowledge and experience in the subject field who is capable of design, analysis, evaluation, and specifications in the subject work, project, or product.

Rope grab. A deceleration device that travels on a life line and automatically, by friction, engages the life line and locks so as to arrest the fall of an employee. A rope grab usually uses the principle of inertial locking, cam/level locking, or both.

Self-retracting life line/lanyard. A deceleration device containing a drum-wound line that can be slowly extracted from, or retracted into, the drum under slight tension during normal employee movement, and which, after onset of a fall, automatically locks the drum and arrests the fall.

Snap hook. A connector comprised of a hook shaped member with a normally closed keeper, or similar arrangement, that may be opened to permit the hook to receive an object and, when released, automatically closes to retain the object. Snaphooks are generally of two types:

- **A locking-type** snap hook with a self-closing, self-locking keeper that remains closed and locked until unlocked and pressed open for connection or disconnection.
- **A non-locking-type** snap hook with a self-closing keeper which remains closed until pressed open for connection or disconnection.

Tie off. The act of an employee, wearing personal fall-protection equipment, being connected directly or indirectly to an anchorage. It also means the condition of an employee being connected to an anchorage.

Vehicle. Any carrier that is not manually propelled.

Vertical tower. An aerial device designed to elevate a platform in a substantially vertical axis.

Walking/working surface. Any surface, whether horizontal or vertical, on which an employee walks or works, including, but not limited to, floors, roofs, ramps, bridges, runways, formwork, and concrete-reinforced steel, but not including ladders, vehicles, or trailers, on which employees must be located to perform their job duties.

Warning-line system. A barrier erected on a roof to warn employees that they are approaching an unprotected roof side or edge, and which designates an area in which roofing work may take place without use of guard rails, or safety nets to protect employees in the area.

Section

3

Maintenance and Repair

Pre-Trip Inspection

A pre-trip inspection shall be made before departing for a job or after a maximum of two weeks has elapsed without operation of the coiled tubing unit. The purpose of this inspection is to ensure that the unit is complete and ready to depart to location.

Important **This inspection is not to be confused with the post-job inspection.**

1. The pre-trip inspection check sheet can be found at: http://halworld.corp.halliburton.com/support_services/maint/Default.aspx?navid=3756&pageid=4522
2. Ensure that the post-job inspection was conducted and passed (see procedure in this section).
3. A pre-trip inspection should be made before departing for location or every two weeks that the unit is not in operation.
4. The pre-trip inspection does not replace the DOT-required inspection for tractors and trailers.
5. Any problem that requires repair or replacement also requires a complete function test of that component before departing for location.
6. This inspection does not replace any Halliburton HSE-required meeting or inspection.
7. All BOP, coiled tubing, stripper, and tree connections should be inspected for visible damage.
8. The coiled tubing equipment should not be returned to operation if any failure of components or function is considered a safety hazard.
9. It is the responsibility of the service supervisor to ensure that the pre-trip inspection is performed in the time stated.

10. After completing the pre-trip inspection, the results should be documented and filed in the unit report or the unit SAP file.

Daily/Shift-Change Inspection

1. The daily/shift-change check sheet can be found at: http://halworld.corp.halliburton.com/support_services/maint/Default.aspx?navid=3756&pageid=4522
2. This is the minimum required check for daily or shift-change operations. All operations will meet these minimum requirements.
3. After completing documentation of the daily or shift-change inspection, this form should be signed and added to the job packet for that day.
4. It is the responsibility of the service supervisor that this inspection be completed each day before operations or before each shift of the unit begins.
5. This inspection does not replace any Halliburton HSE meeting or inspection that may be required.
6. All BOP, coiled tubing, stripper, and tree connections should be inspected for visible damage.
7. Any unusual item or problem area should be documented when found.
8. If there are any safety hazards to personnel or customer property found during inspection, the unit should not be operated until the component is repaired or replaced.

Post-Job Inspection

Requirements

A post-job inspection should be made after completing a job or after a maximum of two weeks has elapsed while on location. The purpose of this inspection is to replace, lubricate, calibrate, and perform general maintenance of the coiled tubing unit.

Important **This inspection is not to be confused with the pre-trip inspection.**

It is the responsibility of the service supervisor that the post-trip inspection be performed on schedule.

- If equipment is in continuous use, substitute the post-trip inspection check sheet for the daily/shift-change inspection check sheet on 2 week intervals or as soon as job parameters permit while the equipment is in use.
- A level "A" maintenance may be used in place of a post-trip inspection.
- This inspection does not replace any Halliburton HSE required meeting or inspection.

Inspection Procedure

1. Print a copy of the Post-Trip Inspection check sheet and inspect the items in the order given.The post-trip inspection check sheet can be found at: http://halworld.corp.halliburton.com/support_services/maint/Default.aspx?navid=3756&pageid=4522
2. Inspect all BOP, coiled tubing, stripper, and tree connections for visible damage.
3. If repair or replacement of any component is necessary, perform a complete function test of the component after repair/replacement.
4. Do not return the coiled tubing unit back into operation if any failure of components or function is considered a safety hazard.
5. After completing the post-trip inspection, document the results and file them in the unit report or the unit SAP file.

Field Welding and Repair of Coiled Tubing

This section presents the requirements for field welding coiled tubing. It is critical that proper weld preparation and butt-welding procedures be followed to obtain a satisfactory joint. Tubing that has been butt-welded by a qualified service center can be certified to meet all the mechanical properties of the parent material.

Properties of Butt-Welded Coiled Tubing

When coiled tubing is butt-welded, both the mechanical properties, such as tensile strength, yield, elongation, hardness, and fatigue life can be affected. The principles of derating fatigue life for butt-welds in coiled tubing have been studied by several researchers and the results have been incorporated into the available coiled tubing management software programs. Mechanical properties are determined by the procedure used for welding and the conditions at the time the weld is made.

Welds can be made at the factory or in service centers under nearly ideal conditions. Welds made at service company district yards, field camps, outside operations, and onsite operations can present the least ideal welding environments.

Welding procedure specifications (WPS) for coiled tubing are designed to meet the minimum requirements of accepted national standards organizations, such as ASME and API. In addition, the produced weldment must exceed the minimum requirements of the parent tube. In mechanical testing, the failure must not occur in the weld or in the heat-affected zone. To become qualified to perform these procedures, welders must meet the same minimum mechanical property requirements. The procedure assures the heat-affected zone is not overheated (and softened) by the weld process. Extending the mechanical test requirement to the welder qualification ensures the welder is capable of following the procedure and producing the same quality weld. Welds made by experienced welders qualified in this manner are capable of carrying all mechanical loads for which the parent tube is designed.

Weld Integrity

The proficiency of the welder making the weld is also a factor in weld integrity. Welders may have passed coiled tubing qualification tests as described above, but their proficiency can decline from not welding coiled tubing regularly or for some other reason. Practice and mechanical property verification before making a weld may restore proficiency. In cases where this is not practical, or where inexperienced welders are employed, the resulting weld should be considered as having been made under non-ideal conditions. Welds made under non-ideal conditions may need to have a safety factor or mechanical property derating applied to the tubing. This derating should be considered independently from the fatigue derating and only to the tubing segment containing the butt-weld (as defined by INSITE® for Well Intervention software). The amount of any derating is the responsibility of the coiled tubing user. Derating guidelines for welds can be found in Table 3.1. These less than ideal butt-welds should be removed at the earliest opportunity and replaced by a butt-weld made under ideal conditions. The replacement weld should be capable of carrying all intended loads of the parent tubing.

Welding dissimilar grades of coiled tubing is not recommended. The different strengths on each side of the weld concentrate bending stresses in the weaker member during coiling tubing operations. This can significantly increase the tendency for coiled tubing to kink.

Halliburton-Recommended Butt-Weld Proficiency Ratings

Level 1

Butt-welds may be made by approved service centers or by an approved welder in an approved habitat. These welds meet all the mechanical properties of the parent material.

Level 2

Butt-welds made in the field by highly qualified coiled tubing welders without approved habitats using qualified WPSs are listed in Table 3.2. Welds made under these conditions should be considered capable of carrying loads for material with strengths of 70,000 psi minimum yield strength and 80,000 psi minimum ultimate tensile strength. See QT 700 coiled tubing technical data for any production limitations on these welds. If a certified welding habitat is used on a remote location or in a Halliburton service center, it is possible to obtain a Level 1 weld in these conditions. A habitat is defined as any structure that creates an environment similar to that of an approved service center. These welds must be performed by a certified welder and inspected as outlined in Halliburton Procedure 70.99983. The certified welder will make the determination whether conditions exist to produce a Level 1 weld.

Table 3.1—Recommended Butt-Weld Derating for Non-Ideal Conditions (Level 2 Weld)

Parent Metal	Welded Service Rating Guidelines
QT 700	QT 700
QT 800	QT 700
QT 900	QT 700
QT 1000	QT 700

Table 3.2—Qualified Welding Procedures for Coiled Tubing

Coiled Tubing	Procedure
QT 700 and QT 800	Halliburton Procedure 70.99983
	Quality Tubing Procedure WPS 209
QT 900	Halliburton Procedure 70.99983
	Quality Tubing Procedure WPS 214
QT 1000	Halliburton Procedure 70.99983
	Quality Tubing Procedure WPS 218

Section

4

Pre-Job Planning and Preparation

Introduction

All coiled tubing well-intervention work should be based on sound knowledge of current well conditions. The key to this requirement is up-to-date information on the wellbore diagram, reservoir history, well location, coiled tubing performance capability, surface equipment, well control equipment, and proposed layout. The following information should be considered in preparation for coiled tubing-service applications.

Job Design

A planning meeting should be held, and all parties involved should have a clear understanding of the objectives of the operation. The intended work, services, and methods for the particular well operation should be outlined by the operator. Responsibility for provision of all equipment, materials, and services should be delegated.

The following items outline the desired detail to be discussed during the job design and pre-job meetings.

Wellbore—Physical Characteristics

Wellbore physical characteristics include the following:

- Casing sizes, weights, grades, depths, and threaded connections
- Tubing sizes, weights, grades, depths, and threaded connections
- Dimensions, depths, and descriptions of downhole completion equipment
- Directional survey
- Type and density of fluids in the wellbore
- Description of current completion including wellbore diagram

- Well zero depth
- Location and dimensions of obstructions or restrictions
- Specifications of wellhead and related surface equipment
- Locations and types of wellbore safety devices
- Known problems with the wellbore
- Derating of casing or tubing pressure capacities

Reservoir—History and Current Parameters

Reservoir history and current parameters include the following:

- General well history (workovers, wireline work, problems)
- Reservoir characteristics
- Description and location of all zones communicating with the wellbore
- Initial and current shut-in and flowing tubing pressures.
- Initial and current shut-in and flowing bottomhole pressures
- Maximum potential shut-in pressure
- Flowing bottomhole pressures
- Type(s) of produced fluids and maximum potential-production rates
- Conditions that could promote erosion, corrosion, scale, or other problems
- Known field problems

Location—Physical, Environmental, and Regulatory Factors

Onshore or marine location factors include the following:

- Type of facility (floating, fixed-platform, satellite, or caisson)
- Water depth, if applicable
- Supply requirements for any connections such as fuel, air, and electricity
- Capacity of any hoists or winches that may be used on location
- Any specific training or rig-specific considerations required
- Location plan and constraints
- Emergency shutdown and evacuation contingency plans
- Crane capacity and reach
- Pollution prevention and containment
- Other operations in close proximity

- Handling and disposal of fluids and materials
- Logistical support
- Governmental and regulatory agency regulations
- Landowner concerns
- H_2S, CO_2, and NORM levels

Location—Equipment Layout

Location equipment-layout considerations include the following:

- Location constraints (load limit, overhead obstructions, and site dimensions)
- Dimensions of vee-door and A-frame, if applicable, to ensure CT equipment can be rigged up and run.
- Identification and classification of hazardous areas
- Dimensions and weights of service equipment
- Placement and orientation of equipment
- Location and description of remote-control operator panels and emergency shutdown devices (ESD)
- Escape routes and accessibility
- Tiedown locations
- Lodging and subsistence

Well Control Equipment

Well control equipment considerations include the following:

- Type, size, configuration, and pressure rating of well control equipment required
- Personnel assignments and responsibilities
- Pump, choke, and kill-line requirements, pressure ratings, and configurations
- Fluid to be pumped or circulated (energized and/or corrosive)
- Hydrate prevention considerations (i.e., glycol or methanol-water mix)
- Choke manifold requirements, pressure rating, and configuration
- Coiled tubing requirements, pressure rating, and configuration
- Pumping unit requirements, pressure rating, and configuration

- Bottomhole and flow-check assemblies (dimensional information)
- Review of onsite pressure-testing procedure
- Tree connection, riser, and crossover spool requirements

Documentation and Safety Guidelines

Documentation and safety guidelines include the following:

- Operator-supplied procedures and guidelines
- Contractor-supplied procedures and guidelines
- Health, safety, and environmental contingency plans
- Pre-job and safety meeting

Coiled Tubing Equipment

The minimum equipment generally needed to safely and efficiently complete operations includes the following components:

- Coiled tubing string
- Coiled tubing reel
- Coiled tubing injector
- Injector support and stabilizing equipment
- Well control equipment and riser components
- Control cabin
- Power supply/prime mover
- Maintenance and support equipment
- Emergency contingency equipment

In addition to these items, ancillary equipment needed for performing the desired service will be required. This equipment may include high-pressure positive-displacement pumps, nitrogen pumps and tanks, high-pressure treating lines, rig-up equipment, and downhole tools.

Pre-Job Review Meeting

A pre-job meeting shall be held with all service personnel and operator employees involved either directly or indirectly in the operation.

The pre-job meeting should include the topics in Section 2, "Safety Meetings" as well as the following:

1. Identify the onsite representative in charge.
2. Ensure that the detailed, written job procedure and areas of responsibility are discussed.
3. Review the expected hazards (particularly chemicals, flammable fluids, and energized fluids), contingencies, and emergency procedures at the wellsite (see also Section 9, "Contingency or Emergency Operations").
4. Discuss the pressure and operating limits of equipment and service.
5. Review the procedure for pressure and function testing of surface equipment.
6. Review the wellhead schematics, downhole tubular schematics, and downhole assembly schematics, noting all potential obstructions. A copy of the downhole schematic and bottomhole assembly diagrams should be in the control cabin at all times.
7. Review the type and location of required PPE.
8. Review the type and location of fire extinguishers and other firefighting equipment.
9. Review emergency well control equipment operating procedures.
10. Identify a smoking area for any service job (signs to be posted on land locations).

Equipment Rig-Up Considerations

Onshore and Offshore Operations

The following is a partial list of items that should be considered when rigging up for coiled tubing operations:

1. Check the space available for optimum equipment rig up.
2. If possible, spot equipment upwind or crosswind of the wellhead. The coiled tubing unit should be aligned with the wellhead so the crane is not on the reel wellhead line.
3. Check the wind speed. Consideration should be given to gusting, sudden wind direction shifts, debris, sand, or heavy rain.
4. Verify that proper support equipment is in use for stabilizing the injector and well control stack.
5. Make provisions for securing the injector to minimize movement and bending moments.

6. The supervisor in charge should be aware of and have authorized all wellhead operations. The number of turns required to open the master valve shall be recorded.
7. Verify the compatibility of the adapter from the wellhead to the well control stack.
8. Zero the counters with the bottomhole assembly at a suitable reference point and record the reference point.
9. Function test all equipment.
10. Zero the weight indicator.
11. Secure the choke, kill, and pump lines to prevent excessive whip or vibration.

Semisubmersible Rig-Up

For semisubmersible service, a lift-frame structure is generally used and requires special rig up and operating procedures. These procedures should be reviewed and agreed upon by the operator and the vendor.

Equipment Testing

The function and pressure-testing procedures detailed in this document should be used as a guide to enable thorough testing of the well control equipment. The following is a list of the minimum equipment-test recommendations:

- All pressure-isolating well control stack equipment installed should be function and pressure tested in compliance with API 16 ST or with superceded local regulatory requirements.
- All choke and kill lines and valves should be pressure tested in compliance with API 16 ST or with superceded local regulatory requirements.
- The coiled tubing BHA flow-check assembly should be pressure tested in compliance with Section 7, “CT Well Control Equipment and Test Procedures”.

General Testing Considerations

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

1. Only personnel authorized by the supervisor in charge should go into the test area when the equipment involved is under pressure.
2. Tightening, repair, or any other work is to be done only after pressure has been released and all parties have agreed that there is no possibility of pressure being trapped.
3. Pressure should be released only through pressure release lines.

4. All fittings, connections, and piping used shall have pressure ratings equal to or greater than the maximum anticipated working pressure.

Coiled Tubing Service Considerations

- Good engineering judgment should be used to help ensure safe coiled tubing service.

NV*	The intentional pumping or production of hydrocarbon gas through coiled tubing is prohibited.

**No variance. Rule/process must be strictly followed.*

- Pumping or production/reversing of flammable liquids should follow strict procedures and guidelines set by HSE standard Category 2, Standard 4, "Hydrocarbon Pumping," as well as governmental and regulatory agencies.
- Pumping of energized fluids and/or corrosive fluids should follow strict procedures and guidelines set by current guidelines found in the *HSE Standards Manual.*
- Recommended pumping velocities should not be exceeded.
- BHA flow-check assemblies should be used unless reverse circulating is anticipated.
- When reverse circulating, consider frictional pressure losses, combined loading, and ovality on the collapse resistance of the coiled tubing. Review BOP barriers and include additional shear/blinds if required.
- The well control stack kill line or BOP inlet shall not be used as the return line for circulating well fluids during normal operations.
- Choke-line installations should be configured to minimize erosion. Methods typically used to minimize erosion include, but are not limited to, using large-diameter components, using heavy wall-thickness pipe, minimizing the number of turns in the line, increasing the radius of piping turns, and using targeted tees.
- In cold-weather operations and/or on gas-filled wells, glycol or a methanol-water mixture should be used to help prevent freezing or the formation of hydrates. Equipment used shall be rated for the temperature in which it will be operated.

Communication Systems

Communication between personnel is important, especially when separated by distances or noise.

General Information

A good communication system is required to complete jobs efficiently, successfully, and safely. It is important to coordinate operations performed by Halliburton and other service company personnel and to maintain an effective information link with the customer.

Many forms of communication have been used with success. Considerations in selecting equipment include: (1) whether hands-free operations are necessary, (2) equipment environmental compatibility and requirements (moisture resistant, explosion proof, etc.), (3) mobility requirements, and (4) equipment weight, if worn by the operator.

Types of communication systems include:

- Hand signals.
- Bullhorns.
- 2-Way radios.
- Rig phones.
- FM headsets.
- Communication helmets.

Communication Planning Procedure

- In job planning, communication system requirements are determined based on the customer's requirements as well as the nature of the job.
- If hand signals are to be used, these signals should be discussed and understood by everyone involved. A good time to discuss these signals is in the daily tailgate/toolbox safety meeting. Be aware that hand signals are an indirect means of communication and often leave room for interpretation.
- If rig phones, headsets, or communication helmets are used, these systems should be tested frequently for proper operation. It is important to have extra batteries on hand during critical jobs.

Note — When using radio frequency-types of communication systems, it is advised that some of these may interrupt the signals or cause spikes on the analog weight indicators used on the data-acquisition systems (DAS). The electronic technicians can be consulted about how to remedy this situation, should it be a problem.

Caution — **Turn off communication when electronic triggering devices are on location.**

Caution — **Cellular phones should be turned off in a 75-ft (25-m) radius of the wellhead, flowback tanks, or any process equipment. Some regulations or customer policies may require a wider radius or may not permit cellular phones in restricted areas.**

Contingency Plans

Before executing a job, the service supervisor should consider possible failure modes or risks and discuss recovery options with the crew and the company representative. For example, if it is determined that getting stuck is a potential failure mode for the operation, stuck pipe procedures should be reviewed before tripping into the hole. Methods should be employed to minimize the risk of getting stuck; indicators of stuck pipe should be reviewed and immediate actions highlighted with the crew.

Well Control Mechanisms

Coiled tubing operations are commonly performed with pressure at the surface using special pressure containment equipment. The surface pressure containment system is comprised of many separate components. The various components may include but are not limited to a split elastomer stripping assembly, quad-ram BOP stack, flanged flow tee, flanged riser spools, secondary BOP stack, and flanged tree connection.

The sizes of equipment components and pressure ratings reflect coiled tubing services performed within wellbores and are stated in Section 7, "CT Well Control Equipment and Test Procedures". Larger component sizes will be needed as the coiled tubing OD size and bottomhole assembly OD size increases. However, the minimum pressure rating for the coiled tubing riser assembly will remain as per Section 7, "CT Well Control Equipment and Test Procedures". These individual components are described in greater detail below.

Stripper Assemblies

The function of the stripper assembly is to provide the *primary* pressure seal between the wellbore and the atmosphere while allowing pipe to move into or out of the well. The stripping assembly is a hydraulically actuated, remote-operated stuffing box located beneath the injector head. The stripper assembly employs two elastomer elements molded as halves of a vertically split cylinder approximately 4 in. tall, with the ID bore equal to the OD of the coiled tubing in service. From this design, the molded elastomers of the stripper can be changed out even while coiled tubing is in the hole. In some well control equipment (WCE) categories, a secondary stripper/packer may be required.

Primary Blowout Preventers (BOPs)

The wellhead blowout prevention system for coiled tubing operations will be API rated and consist of at least four hydraulically operated, dual-opposed rams in the following configuration (from top down):

- Blind rams
- Shear rams
- Slip rams
- Pipe rams

Additional rams may be needed for tapered-OD coiled tubing or for different OD tool strings as well as for work on high-H_2S, high-pressure, and offshore wells. In hazardous environment services, the quad-BOP stack shall be NACE MR 01 75 certified. Before performing any coiled tubing service in a hostile environment well (CO_2, H_2S, acid, etc.), ensure that all the sealing element elastomers are designed for the prescribed service.

All quad-BOP stacks must have a flanged outlet located between the shear ram and the slip ram bonnets for use as a kill line in case of a well control situation.

NV*	*Returns shall not be taken through the side outlet on the quad BOP.*

**No variance. Rule/process must be strictly followed.*

Important **Taking returns through the kill spool will expose the pipe ram and slip ram assemblies to fluids that generally contain solids and debris; contact with these fluids can adversely affect the performance of the rams.**

It is recommended to use a flow tee or flow cross mounted directly below the BOP stack to take returns from the wellbore.

Flow Tees/Crosses

A flow tee/cross will be installed in the riser directly below the quad-BOP stack to provide an outlet for surface fluid returns. The run of the flow tee/cross will be equipped with the appropriate-size API flanges needed to directly connect to the quad-BOP stack above and the riser spool (or additional BOP) below. The branch(s) of the flow tee/cross will be equipped with a 2-in. or larger flange where two fullbore, integral flanged plug valves will be connected. In hazardous environment services, the flow tee shall be NACE MR 01 75 certified.

Secondary Blowout Preventers

Secondary blowout prevention systems for coiled tubing operations will be API rated and can consist of the following configurations.

- Four hydraulically operated, dual-opposed rams in the following configuration (from top down):
  a. Blind rams
  b. Shear rams
  c. Slip rams
  d. Pipe rams
- Two hydraulically operated, dual-opposed rams in the following configuration (from top down):
  a. Combination shear/blind rams
  b. Combination pipe/slip/tubing rams
- One hydraulically operated, dual-opposed ram in the following configuration:
  a. Combination shear/blind rams or combination pipe/slip/tubing rams

Section 7, "CT Well Control Equipment and Test Procedures" lists the type of secondary BOP that may be required. Additional rams may be needed for tapered-OD coiled tubing or for different OD tool strings and work on high-H_2S high-pressure offshore wells, and specific customer requirements. In hazardous environment services, the secondary BOP stack shall be NACE MR 01 75 certified. Before performing any coiled tubing service in a corrosive environment well (CO_2, H_2S, acid, etc.), ensure that all the sealing element elastomers are designed for the prescribed service.

NV*	*All secondary BOP stacks with multiple rams must have a flanged spool located between the shear/blind ram and the pipe ram bonnets for use as a kill line in case of a well control situation.*

**No variance. Rule/process must be strictly followed.*

Important — **Taking returns through the kill spool will expose the pipe and slip ram assemblies to fluids that generally contain solids and debris; contact with these fluids can adversely affect the performance of the rams.**

Lubricator

A lubricator is a section of pipe made up ABOVE the coiled tubing BOPs normally used for making up long tool strings. Connections can be flanged or hand unions, depending on the conditions.

A lubricator can only be positioned between the standard BOP and the stripper. Some jobs may require very long tool strings. If the rig up is to be freestanding using a crane an additional full-opening radial stripper or annular BOP located at the bottom of the lubricator is recommended. This allows the tubing to be safely pulled from the well in the event that a leak develops in the lubricator.

Riser/Spacer Spool

A riser/spacer spool is a section of pipe made up BELOW the coiled tubing BOPs or in BETWEEN separate sets of coiled tubing BOPs. A riser is normally used for spacing out of CT pressure control equipment. Connections are always flanged.

A riser/spacer spool can be positioned anywhere in the pressure control stack below the standard BOP.

If the riser/spacer spool is positioned below the additional BOPs, then the minimum of an extra shear/seal BOP is required just above the wellhead.

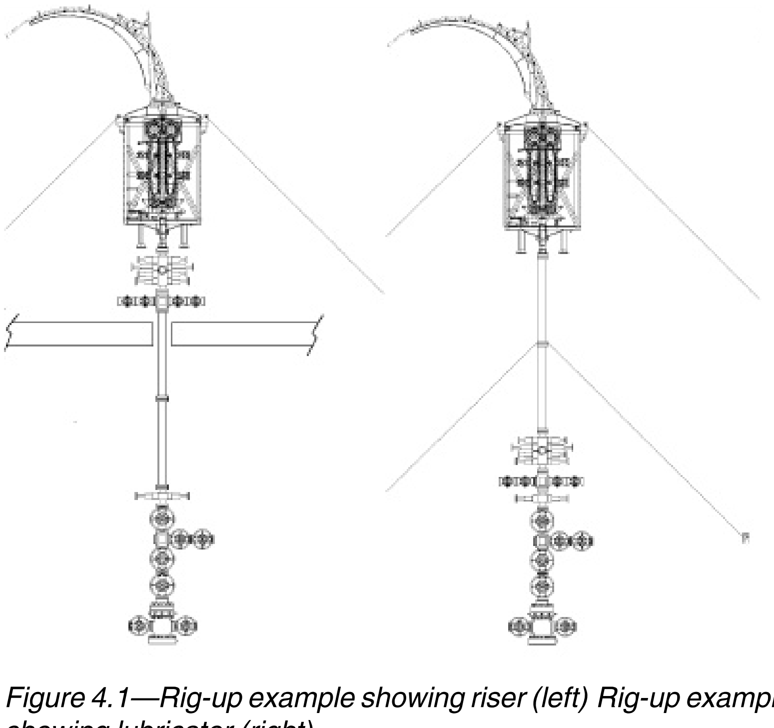


Figure 4.1—Rig-up example showing riser (left) Rig-up example showing lubricator (right)

Tree Connections

If the well control stack cannot mount directly onto the well, an API-rated crossover flange will be used to complete the WCE assembly. In hazardous environment services, the tree connection shall be NACE MR 01 75 certified.

Flow-Check Device (Backpressure Valves)

A flow-check device is a valve that permits fluid to flow freely in one direction and contains a mechanism to automatically prevent flow in the reverse direction. Bottomhole assembly dual flow-check devices are designed to prevent flow back up the coiled tubing. Flow-check devices should be run on every CT job except in certain special circumstances where the specific application does not allow it. Appropriate safeguards and approval are required for these operations.

BOP Actuation Systems

The hydraulic actuation system used to operate the quad-BOP stack is comprised of a direct-drive hydraulic charge pump, accumulator bottles for storage of fluid and pressure, and independent control valves needed to open and close the rams. The charge pump is used to supply hydraulic pressure and liquid volumes needed to operate all the designated hydraulic devices within the circuit. Although all of the aforementioned components must operate properly in the BOP system, the accumulator is the one component that has a wide range of performance capability and must be sized properly to ensure that the needs of the system are met.

Well Control Methods

The two common types of well control technique are described as the "drillers method" and the "wait and weight method."

- The **drillers method** uses two annulus volume circulations to kill the well. The first circulation is used to remove the hydrocarbons or undesired fluids from the wellbore while blending kill-weight fluid in the mud tanks. The second circulation uses the blended fluid to kill the well.
- The **wait and weight method** is a one circulation process that requires the operator to wait until the kill-weight fluid is mixed before pumping. Because coiled tubing operations are generally not prepared for mixing weighted materials above light-brine concentrations, the methods most applicable to coiled tubing kill operations are the circulation, bullhead, and dynamic kill methods.

Circulation Method

The circulation method is a process that involves pumping kill-weight fluid down the coiled tubing and up the host annulus (the host may be the production tubing, casing, or open hole). To be most effective, the end of the coiled tubing should be placed at or below the source of pressure. At that location, undesired fluids can be circulated out of the wellbore and displaced with a uniform-density fluid. Halliburton recommends that at least two times the annular volume be circulated out of the well or the volume needed to help ensure that returns are absent any undesired fluids.

In certain situations, it may be feasible to reverse circulate by pumping down the annulus and up the coiled tubing. It is important to realize that the ECD (equivalent circulating density) can be significant due to the high friction pressures generated when circulating fluids in the coiled tubing by host annulus or up the coiled tubing. While this effect could help the situation by adding resistance to flow up the annulus, the ECD could prevent the well from being totally displaced if returns are lost. Should this occur, the fluid circulation rate should be decreased to reduce the ECD. The fluid pump-in and returns rate should be closely monitored to ensure that the volumes pumped into the well are equal to the volumes recovered in the surface returns. Close attention should also be paid regarding the potential of collapsing the coiled tubing at surface.

If kill-weight fluid is not available, it may be necessary to circulate the workover fluid available on location to reduce the surface wellhead pressure or follow the Dynamic Kill Method (see Page 4-16).

Bullhead Method

The bullhead method implies that fluid is pumped from surface down into the formation. Depending on the situation, the fluid can be pumped down the coiled tubing, the coiled tubing by host annulus, or both. Bullheading the fluid through the kill line or flow tee may become necessary if circulation cannot be established down the coiled tubing (i.e., buckled, collapsed, or parted tubing). The objective of this method is to pump the undesired fluids back into the formation while leaving a column of uniform-density kill fluid in the wellbore.

Dynamic Kill Method

Note	The dynamic kill method may be used as a temporary well control method to buy time needed to obtain kill-weight fluid, weight-up additives, or repair any broken surface well control equipment.

The dynamic kill method is a circulation procedure that can be used when the available workover fluid is less than kill weight. This method uses the ECD principle of annular friction pressure and hydrostatic pressure to balance the formation and prevent any further influx. Because many coiled tubing operations are performed (a) through the production tubing or (b) where the coiled tubing by host annulus is small, high fluid-flow rates will result in significant frictional pressure losses within the system. This frictional pressure can be combined with the hydrostatic weight of the workover fluid to yield an ECD that will overbalance the formation pressure and kill the well. It is important to realize that this is a temporary solution because the well will be underbalanced once the pumps are stopped again.

Coiled Tubing Unit Rig Up

Introduction

The components required to make up a coiled tubing service unit can be trailer mounted, truck mounted, or skid mounted for offshore operations. Locations for wellsites include land, inland waters, and offshore. Some locations may have a workover or drilling rig on location; available space on location and proximity to other service equipment often affect rig-up procedures. The following procedures provide general rig-up guidelines.

Note — Government regulations may vary by location. The recommendations found in this manual should always be applied in compliance with local regulations.

Rig-Up Safety Precautions

The following procedures cannot be varied.

Before beginning any rig-up procedure, read and observe the following safety precautions.

1. Hold a safety meeting before every rig up and note on the daily ticket.
2. On H_2S locations, provide detectors and escape respirators for all Halliburton employees. Give instructions on the proper use of the equipment. Refer to "Hydrogen Sulfide (H2S Safety Procedures)" on page 2-13.
3. Wear the appropriate PPE, such as proper clothing, safety glasses and/or goggles, gloves, approved safety boots, and hard hats.
4. Use the proper PPE for fall protection while climbing or when exposed to a fall over 6 ft.
5. Wear the correct type of PPE for hearing protection while in posted high-noise zones or any other areas where the noise level exceeds standards.
6. Use certified slings and shackles only.
7. Correct and/or report all pressure leaks.

Rig-Up Procedures

Rig Up On Land

1. Position the unit as close as feasible to the well, aligning the reel with respect to the well.

   Note: API recommends that all non-essential vehicles be parked at least 100 ft from the wellhead when the location allows.

2. Lower the catwalks and stairs and install safety railings.
3. Connect all hydraulic hose between components; follow the numbering code, matching the hoses to the bulkhead connections.
4. Ensure that the controls in the house are in Neutral and start the power-pack engine or engage the auxiliary drive on tractor-driven hydraulic systems. After warm up, increase the throttle to 1,500 RPM and load the injector pumps and console circuit if required.
5. Scope the outriggers (see "Foundations (Well Location) for Support Structures and Crane Outriggers" on page 5-22) using adequate pads under each outrigger foot to stabilize the unit. Close the road/bypass valves. Raise the crane enough to allow movement of the reel and levelwind.
6. Raise the operator house and lock it in place.
7. Using hydraulic cylinders, raise the levelwind assembly and align the reel with the well.
8. Activate the data acquisition system (DAS).
9. Perform hydraulic functional tests and visually inspect all components. Correct any defects.
10. Perform an inspection and function tests of the coiled tubing BOP as stated in "Rig-Up Procedure" on page 7-28.
11. Install the coiled tubing BOP on the wellhead. Ensure the connection seal is not damaged. BOP configuration will depend on the type of well conditions present and/or job requirements. See the "BOP Ram Sets" on page 7-9 for suggested BOP ram numbers and configuration.
12. Test the blind rams and connections as discussed in "Test Procedure" on page 7-29.
13. Open the gripper chains hydraulically.

    Note: Steps 14 through Step 16 will be skipped if the tubing is already stabbed in the tubing guide.

14. Spool off enough tubing to get past the tubing guide by approximately 6 ft (2 m) and install a tubing clamp close to the levelwind.
15. Stab the tubing into the tubing guide.

Note Use of a crane on the upper section of pipe may be beneficial during this operation.

16. Lift the tubing guide with the crane about 6 ft (2 m) and pull about 3 ft (1 m) of tubing under the tubing guide. Place a tubing clamp on the tubing directly below the tubing guide.
17. Remove the tubing clamp at the levelwind.
18. Place the tubing guide on top of the injector while guiding the tubing into the gripper blocks on the injector drive chains.
19. Install all four pins to lock the tubing guide to the injector. Change the position of the lift linkage (30/38K) on the tubing guide or move the crane hook to the injector lift sling.
20. Center the tubing in the gripper blocks. Close the injector drive chains on the tubing and apply sufficient linear-beam pressure for the grade and wall thickness of the tubing

Note If the tubing does not extend past the lower hydraulic ram, insert a spacer bar in the lower chain section before closing the beams. This will prevent damage to the tubing and linear chain rollers.

Note See Appendix C for alternate stabbing methods.

21. Loosen the bolts that hold the injector drive off the load-sensing device during transport.
22. Remove the tubing clamp installed below the tubing guide before rotating the drive chains.
23. Lift the injector off the deck and install the stripper/packer (some units transport with the stripper/packer installed on the injector).
24. Check the stuffing box seal for damage. Repair or replace if needed.
25. Operate the injector in the “in” position to slowly run the tubing into the stuffing box about 1 ft (30 cm). Back out on the injector maximum pressure adjust valve and shift the injector to neutral.
26. Install a clamp below the stuffing box. Dump the linear-beam pressure and rotate the injector head to align the linear beams with the reel. Raise the linear-beam pressure to 500 psi.
27. Lift the injector about 6 ft (2 m). Install the coiled tubing connector and remove the clamp installed in Step 26.
28. Perform a connection pull test by pulling the connector from the injector to the highest possible connector tension level that will be encountered downhole during the job.

Note Do not exceed the adjusted yield strength of the tubing.

Note	Steps 29 through 31 will vary depending on job requirements and how Step 11 on Page 5-2 is performed.

29. Make up the required length of lubricator to the stripper packer.

Note	The lubricator should be sufficient to accommodate the entire toolstring length above the uppermost blind ram.

30. Install any additional tools specified by the job requirements.
31. Connect the injector and lubricator assembly to the BOP. Orient the injector and tubing guide in relation to the reel.
32. The crane block should remain connected to the injector lift bail/sling unless the injector is supported by a structure. Secure the injector from the frame corners to anchors for additional stability.

Note	See the guy-line recommendations in "Guy Line Placement Charts" on Page 5-26.

33. Activate the coiled tubing DAS. Zero the service-weight indicator system and check that the analog gauge is on zero. Check that speed, tubing pressure, wellhead pressure, and rate/total readouts are set on zero. Set the depth to the calculated depth in reference to the well zero point.
34. Test the coiled tubing and BOP assemblies, and all connections as discussed in "Pressure Testing" on page 7-29.
35. If the well is pressurized, the stuffing box hydraulic pressure should be set at 1,000 psi initially and adjusted accordingly to the lowest pressure required to hold well pressure as the tubing moves through the stuffing box.
36. Equalize the pressure above the master valve. Slowly open the master valve, or valve in the wellhead used to close the well. Count the revolutions of the handle required to fully open the valve and record in the job data pack.

Caution	**Slowly start the tubing into the well, watching the weight indicator for obstructions. Speed is at the discretion of the supervisor.**

Note	Recommended speed for the first trip in the hole is 40 to 100 ft/min.

37. During RIH, reverse the tubing direction to check the tubing weight at predetermined intervals (maximum 1,500 ft, or 500 m).

Rig Up Offshore

1. Spot the coiled tubing components on the service deck using the platform or rig crane. If possible, place the reel 25 ft (8 m) or more from the well with the operator enclosure directly behind the reel. Consideration should be given to placement of the power pack.
2. Place the injector, tubing guide, and coiled tubing BOP in front of the reel.
3. Connect the hydraulic hoses from the power pack to the operator enclosure, injector, and BOP. Make connections by identification number and function.
4. Rig the injector, tubing guide, tubing, and BOP as discussed in Steps 6 through 29 in the land rig-up section (beginning on Page 5-2).
5. The crane block should remain connected to the injector lift bail/sling unless the injector is supported by a structure. Secure the injector from the frame corners to anchors for additional stability.

   Note — See the guy-line recommendations in "Guy Line Placement Charts" on Page 5-26.

6. Follow Steps 33 through 37 in the land rig-up section (beginning on Page 5-4).

Semisubmersible Rig-Up

When lifting the injector and/or BOP stack off the rig floor or catwalk with the rig block, an air winch cable or snub line can be used to control the injector. If possible, set the injector on the rig floor before lifting with the rig blocks.

When performing coiled tubing work from a semisubmersible rig, it is essential that a lift frame be used. The injector head assembly and BOPs are mounted in the lift frame. Lifting bails or hydraulic latches will be used to connect the lift frame to the tree. The following procedure is intended to provide general rig-up guidelines.

Lifting the Frame Using a Base Plate with Bails

Bails will be used to connect the lift frame to the tree. The following steps are intended to provide general rig-up guidelines for dual access. A toolbox talk should be conducted before rigging up equipment.

1. Make up the top handling device to the top plate of the lift frame.
2. Fit the eye bolts to the sides of the top and base plate and attach the handling slings.
3. Make up the hoses to the hoist and tie back to the inside of the frame tie rod.
4. Attach the pipe deck tugger or similar to the base plate. Gently pick up the frame with the crane to turn it into its side. Pick up the frame and move the top plate up onto the drill floor.

5. Lower the rig blocks and attach the elevators to the top handling device. Pick up with the blocks, transferring the weight held by the crane to the base plate only. Once the frame is in the derrick, release the crane.
6. Attach rig floor tuggers to the base of the lift frame and tie back to the front of the vee-door. Then pick up the lift frame into the derrick. Once the lift frame is clear of the drill floor, slack off the tuggers.
7. Lower the lift frame down to the rig floor and attach the two bails to the base plate eye bolts in preparation for lifting the test tree.
8. Pick up the test tree and landing joint and move them up onto the drill floor with the crane.
9. Attach the two bails on the lift frame to the elevator on the test tree while the test tree and landing joint are suspended from the crane horizontally.
10. Attach rig floor tuggers to the test tree and tie back to the front of the vee-door. Then pick up the lift frame and tree into the derrick.

Note — In some situations, it may be more convenient to position the test tree and landing joint in the mouse hole prior to picking up the lift frame.

11. Lower and land off the test tree onto the landing string, then slack off the tuggers.

Note — The riser/spacer spool should protrude above the base plate sufficiently to allow make up of the connection to the BOPs.

12. Install the BOP inside the lift frame.
13. Rig up, function test, and spot the coiled tubing on the catwalk and rig floor.
14. Make up the coiled tubing BHA.

Note — Depending on the length of the BHA, it may be required to make up in sections and hang off the CT using a lift clamp.

15. Place the injector onto the rig floor, pick up the injector, and position it in the lift frame above the BOP. Connect the BHA on the pipe and function test as required.

Note — With long tool assemblies, it may be necessary to set the tools in the riser using a tugger before connecting to the coiled tubing.

16. Using a lift frame winch, lower the injector and make up the connection to the BOP.
17. Energize the stuffing box and pressure test the BOP, etc. through coiled tubing.

Note It is important that the toolpusher/driller be made aware that when coiled tubing is run in hole, the actual coiled tubing weight will register on the driller's weight indicator.

Rig-Up Procedure Using Quick Latch

A hydraulic latch will be used to connect the lift frame to the riser. The following steps are intended to provide general rig-up guidelines for primary or secondary string. A toolbox talk should be held prior to rigging up the equipment.

1. Make up the top handling device to the top plate of the lift frame.
2. Make up the lower handling device to the base plate and tighten the collar with the C spanner.
3. Transfer the skid handling slings to the top and base plates of the lift frame and lift the frame from the skid.
4. Fit the eye bolts to the sides of the top and base plates and attach the handling slings.
5. Assemble the latch top sub to the lift frame. Tighten using chain tongs or strap wrenches.
6. Make up the latch body to the primary/secondary string riser section. Tighten with chain tongs.
7. Make up the two hoses to the hoist and tie back to the frame tie rod.
8. Attach the pipe deck tugger or similar to the base plate. Gently pick up the frame with the crane to turn it onto its side. Pick up the frame and move the top plate up onto the drill floor.
9. Lower the rig blocks and attach the elevators to the top handling device. Pick up with the blocks, transferring the weight held by the crane to the base plate only. After the frame is in the derrick, release the crane.
10. Attach rig floor tuggers to the base of the lift frame and tie back to the front of the vee-door. Next, pick up the lift frame into the derrick, ensuring that it clears the flowhead. After the lift frame is clear of the flowhead, slack off the tuggers.
11. Attach the control hoses to the latch. Pump the latch fully open.

    Note Visually verify that the latch is fully retracted.

12. Grease the sealing surfaces of the latch top sub, then lower the lift frame and lower the latch top sub into the guide cone on the flowhead, taking care not to slack off any weight onto the riser.

    Note At this stage, it is essential that the two parts of the latch are aligned. Otherwise, the top sub will not fit into the latch body. It may be necessary to use an iron roughneck or similar to maneuver the latch body.

13. Check that the two sections are fully engaged before pumping the latch closed. Set the indicator gauge in the locating hole in the guide cone and check that the shoulder on the gauge falls below the guide cone OD. Remove the gauge from the locating hole. If the two sections are not fully engaged, pick up the lift frame and repeat the make up procedure from this section, "Lifting the Frame Using a Base Plate with Bails" (Page 5-5).
14. When correct engagement is confirmed, pump the latch closed.

Note	Visually confirm that the latch is fully closed.

15. With the latch closed, pick up the full assembly with an overpull to confirm engagement. Do not exceed manufacturer's suggested limits.
16. Spot the coiled tubing components on the catwalk and drill floor, connect all coiled tubing hydraulic hoses, and function test all hydraulic circuits.
17. Stab the tubing into the gooseneck and injector.
18. Lift the injector assembly and run tubing through the stuffing box (remove any damaged pipe; redo the connector, if necessary).
19. Install the coiled tubing BOP inside the lift frame. Pressure test the coiled tubing blind rams using a rig pump.
20. Make up the coiled BHA.

Note	The length of the BHA may necessitate that it be made up in sections and hung off in the rig using a lift clamp.

21. Place the injector onto the drill floor with the crane and using lift frame hoist drill floor tuggers, pick up the injector and position it in the lift frame above the BOP.
22. Run tubing through the injector/stuffing box and connect to the BHA at the drill floor. Pick up the BHA and function test as required, then run into the riser assembly.

Note	With long tool assemblies, it may be necessary to set the tools in the riser using a tugger before connecting to the coiled tubing.

23. Using a lift frame hoist, lower the injector and make up the quick union to the BOP (ensure that the quick union O ring is not damaged).
24. Energize the stuffing box and pressure test the stuffing box and BOP through coiled tubing reel.

Important	**Tool pushers/drillers should be aware that when coiled tubing is run in hole, the actual coiled tubing weight will register on the driller's weight indicator.**

Rig Up on a Tender

Risk Assessment Guidelines

When performing coiled tubing work from a tender rig (CT reel located on a tender and the injector on a platform), it is essential to hold a safety meeting before rigging up. The following procedure is intended to provide general guidelines. Radio headsets are necessary for all personnel involved in the rig up for good communication. A risk assessment must be conducted prior to mobilization. To minimize risk, the following requirements must be fulfilled:

1. At least two service supervisors assisted by two service operators.
2. Good communications, i.e., radio contact.
3. Good visibility from and to the platform.
4. Maximum of 6 feet of swell.
5. Allow enough time to perform rig up and rig down.

CT Rig-Up Procedure

1. Position and line up the control house, coiled tubing reel, and power pack on the tender to face the platform.
2. Connect all hydraulic hoses to the control house, power pack, and coiled tubing reel.
3. Prepare the BOP and lift with transfer line winch to the platform.
4. Prepare and make up the injector and lift it to the platform.
5. Chain down the tubing guide and injector onto the platform.
6. Move the BOP and injector hydraulic hoses to the platform.
7. Make up the hoses from the control cabin and power pack to the BOP and injector head on the platform.
8. Start the power unit and perform a function test.
9. Lower the platform tugger’s line next to the CT reel onto the tender’s deck; attach the tugger's safety hook to a secured clamp previously installed onto the pipe.
10. Pull the tugger slowly while releasing enough pipe from the reel to reach the platform plus an additional 20 ft.
11. Secure the pipe onto the levelwind with a safety clamp and move the other clamp back (±15 ft) to get enough tubing to stab inside the chains.

Note — Sometimes the weather will make this operation difficult. Steps 9–11 may have to be repeated if necessary to adjust the length of pipe to counteract the motion of the tender. Consider stabbing the pipe while the injector is still on the tender or winching the coiled tubing into the injector. See Appendix A, “Alternate Stabbing Methods.”

12. Pick up the pipe with the rig's tugger and stab into the injector. Close the chains.
13. Use the tugger to rig up the BOP onto the riser.
14. Lower the rig block down to the rig floor; attach to the injector lift device; and attach the rig floor tugger to the injector tie back to the front of the vee-door.
15. Release the holding chains. Pick up with the blocks, transferring the weight held by the rig floor tugger.
16. Remove both clamps from the pipe end and levelwind.
17. Pick up the injector; run the tubing in; and connect the BHA.

Note	With long tool assemblies, it may be necessary to set the tools in the riser using a tugger before connecting to the CTU.

18. Lower the injector and make up to the BOP.
19. Energize the stuffing box and pressure test the BOP, etc. through the CTU.
20. Follow the same procedure to rig down the equipment.
21. A safety meeting must be conducted prior to rigging down. Re-evaluate the weather conditions.

Injector Support Systems

Support Structures

Injector support structures serve two main purposes: (1) they act as a manipulator to move safely and efficiently from well to well on offshore platforms, and (2) they serve as an elevated support tower when numerous sections of lubricator are required.

Most injector support structures are made of sections stacked on one wide, heavy base section placed on solid, level ground. The top section (normally hydraulic) enables final adjustments and the attachment of long tool assemblies. They make for a safe working platform. Because several models have been manufactured in recent years, it is important to refer to the manufacturer’s manual for exact rig-up requirements.

Support Structure Rig Up

1. Ensure that Section 2, “Working Above Ground (Fall Prevention/Protection),” has been read and understood.
2. Prepare the area around the wellhead. Be sure the area is free of debris and that trip hazards have been identified.

3. A flat concrete surface is preferred; however, wooden pads can be used safely to increase stability while minimizing settling. Laminated wooden pads, 24×24×6 inches thick, are sufficient to support a 50 ft × 130,000 lb load support structure. Be sure the ground is solid and free of voids.
4. Prior to rigging up the support structure, place four anchors or weight blocks off the four corners at a distance from the wellhead equal to the height of the support structure (see Section 5, “Placing Guy Lines and Base Supports for CT Operations,” for guy line recommendations and anchor positioning).
5. Close in the wellhead in accordance with the operating company’s procedures and ensure that the flow line is bled off between the wellhead and the flow line safety valve. This may not always be possible.

Caution **Use extreme caution when lifting heavy objects over wellheads and flow lines.**

6. Whenever possible, install a flow line protection device.
7. Ensure that the crane is adequate to handle the load and that it is positioned correctly. Operating on the margins of the crane’s capacity could result in serious injury.
8. Line up sections in the order they will be lifted, starting with the base section. Additionally, have them facing the correct direction prior to erecting the support structure.
9. Pick up the base section with the approved, certified, four part sling and place it over the wellhead until the legs begin to touch the ground. Stop the crane. At this point, screw down any remaining leg adjustments not touching the ground—take care to not place fingers under the legs.

   Note: The type of base section you are using will determine which way to place the base in respect to the reel. When using the “C” style base, set the base such that the open “C” section accommodates the flow line and pump lines. Bigfoot bases can be placed as required and give more access to the wellhead.

10. Make sure that the base section is set so that the ladders will line up with the ladders in the spacer sections.
11. Set the weight on the legs and check the cross sections with a level. Adjust as required.
12. With tag lines in place, lift the spacer sections into place and pin.

   Note: The inside walkways are adjustable and can be pinned to specific work heights; however, it is recommended that those heights be planned prior to lifting onto the well. Adjusting them over the wellhead can create a hazard and is not recommended.

13. Install the BOP stack and lubricator as required. If necessary, install stabilizers between the well control stack and the pad eyes provided on the front of the open “C” sections.

14. Attach the four guy wires to the top spacer section and secure them to anchors.

Warning **Never attach guy wires to the top of a movable section.**

15. Prior to lifting the top section, fold down the extended work platforms and attach the fall protection ropes alongside the ladders.
16. Carefully set the top section in place and secure it with four pins.
17. Although the support structures are normally equipped with operator consoles designed to set on the ground, they can be mounted on the inside walkway of the top section. This enables running two hoses to the ground rather than six. It also gives control of the support structure to those working in it, resulting in better communication. This can be determined by the local application as to which is safest and most efficient.
18. Connect the hydraulic section control console to an 1,800 psi, 10 gal/min hydraulic power supply.

Note The pump that supplies the console should be a variable displacement pressure compensated pump. Do not use positive displacement pumps.

19. Disconnect the tie down bars used to secure the movable section to the frame.

Important **Failure to disconnect will result in severe damage of the tie down bars.**

20. Function test the hydraulics before rigging up the injector.
21. Adjust the top section so that the injector can be placed on top without attaching to the lubricator (normally, the top section is moved to one side and lowered).
22. Personnel may now move up to the top of the work platform.

Warning **The hydraulic platform must not be moved when personnel are climbing ladders.**

23. Using two way radios to ensure good communication with the tower and operator, lift the injector with pipe stabbed to the top of the support structure. With higher rig ups and larger pipe, consider winching the tubing into the injector after it is installed on the tower (see Appendix A for alternate stabbing methods).
24. Set the injector on the mounting bracket and pin.
25. Move the injector over the wellhead and connect it to the well control equipment riser.

26. Attach two additional guy wires on the top rear frame of the injector: attach to rear anchors. Tension all guy wires to ±1,000 lb.

Caution **It is extremely important to leave the injector guy lines slack when moving the top section of tower.**

27. Disconnect the crane and move it from the work area. The crane can be released if long term work is planned.
28. Conduct the coiled tubing job in accordance with standard operating procedures.
29. Rig down in reverse order.
30. It is recommended that personnel be cleared from the support structure when moving pipe. Do not move pipe when personnel are climbing on the support structure. If pipe must be moved while personnel are in the support structure, ensure that they are clear of injector moving parts and are standing in a secure position. Standing on the injector while pipe is moving is unacceptable.

Warning **If an injector connector is used, ensure that the locking indicator is in the locked position. The connectors may be replaced with 8 1/4 × 4 Acme unions.**

Placing Guy Lines and Base Supports for CT Operations

Free Standing Injector Supported by Telescopic Legs/Crane

1. When possible, 4 guy lines should be placed using 90° spacing.
2. The angle formed between the guy line and the ground (horizontal) should be at a 45° angle and should not be greater than 65°.

   Rule of thumb: For every 2 ft of height, get at least 2 ft away. See rig-up guy line position tables starting on Page 5-26.

3. Attach the 4 primary guy lines to the top of the injector. Only shackles or hooks with safety latches are to be used on the top end of each guy line for the connection. Additional guy lines to the well control equipment may be required if conditions or height warrant.
4. The top end of each guy line should have a formed eye with thimble and either a swaged connection or minimum of three cable clamps.
5. A minimum of 1/2 in. galvanized cable, with independent wire rope core, must be used for the guy lines with 38K, 60K and 95K units. Larger units must use a minimum of 9/16 in. galvanized cable, with independent wire rope core.

6. Anchors should be screwed into the ground as far as possible, using a minimum of 4 anchors, and pull tested. Anchor blocks must have sufficient weight to hold the tension. On high rig ups and critical jobs, it may be necessary to bury anchor blocks in the ground.
7. For rig ups with long riser sections, a minimum of two sets of guy lines should be used, one set (of four) to the top of the injector and the second set to the top BOP or midpoint of the riser or lubricator, depending on the job. Rig-ups that require more than 40 feet of lubricator should be modeled with FEA software such as CTES Zeta.
8. A crane must remain attached to the stack at all times.
9. Guy lines placed 180° from each other (directly opposite) must be tensioned and slacked off evenly.
10. Using an approved cable tensioning device, attach each guy line to an anchor. Hamper type land stakes should not be used.

    Note Shackles, turn buckles, and cable clamps can damage the cable and are not recommended for anchoring the guy lines; using grip pullers allows the cables to be tensioned without damage.

11. Temporary screw type marsh anchors can be used. A 1 in. OD anchor rod, 5 ft long, with a 10 in. blade, is recommended as a minimum. If temporary anchors are being used, it may be necessary to use 8 anchors on land locations for greater stability on higher rig ups.
12. Do not attach guy lines to the wellhead or process equipment of any kind. On onshore locations, guy lines should not be attached to anything mobile, such as a tank, pump, etc. Guy lines must not be attached to jack up boats.
13. The guy lines should be uniformly tensioned to ±1,000 lb.

Support Structure (Track Stack or Injector Stand)

1. When possible, guy lines should be placed using 90° spacing.
2. The angle formed between the guy line and the ground (horizontal) should be at a 45 degree angle and should not be greater than 65°.

> **Rule of thumb:** For every 2 ft of height, get at least 2 ft away. See rig-up guy line position tables starting on Page 5-26.

3. The four primary guy lines should be attached to the bottom, or stationary portion, of the hydraulic section. Only shackles or hooks with safety latches are to be used on the top end of each guy line for the connection. Additional guy lines to the structure may be used if conditions or height warrant.
4. The top end of each guy line should have a formed eye with thimble and either a swaged connection or minimum of three cable clamps.

5. A minimum of 1/2 in. galvanized cable, with independent wire rope core, must be used for the guy lines with 38K and 60K units. Larger units must use a minimum of 9/16 in. galvanized cable with independent wire rope core.

6. Anchors should be screwed into the ground as far as possible, using a minimum of 4 anchors, and pull tested. Anchor blocks must have sufficient weight to hold the tension. On high rig ups and critical jobs, it may be necessary to bury anchor blocks in the ground.

7. A minimum of two sets of guy lines should be used, one set (of four) to the bottom or stationary portion of the hydraulic section and the second set (of two) to the top of the injector extending opposite to the reel side of the track stack. Rig-up heights over 25 feet require additional sets of guy lines, one set (of four) every 20 to 30 feet, or for every 2 to 3 sections of additional spacer section added.

8. A crane must remain attached to the structure until all guy lines rigged up to that point are secured and uniformly tensioned. A crane must be attached to the top of the stack whenever it becomes necessary to release any of the guy lines to the structure (such as when rigging down). Guy lines placed 180° from each other (directly opposite) must be slacked off evenly. Releasing guy lines to the injector to facilitate repositioning of the injector with the travel carriage is permissible without having a crane attached. The injector must be correctly pinned to the travel carriage.

9. Using an approved cable tensioning device, attach each guy line to an anchor.

   Note: Shackles, turn buckles, and cable clamps can damage the cable and are not recommended for anchoring the guy lines; using grip pullers allows the cables to be tensioned without damage.

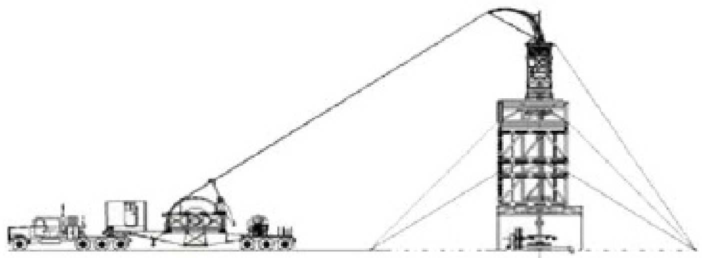
10. Hamper type land stakes should not be used.

11. Temporary screw type marsh anchors can be used. A 1 in. OD anchor rod, 5 ft long, with a 10 in. blade, is recommended as a minimum. If temporary anchors are being used, it may be necessary to use 8 anchors on land locations for greater stability on higher rig ups.

12. Do not attach guy lines to wellhead or process equipment of any kind. On onshore locations, guy lines should not be attached to anything mobile, such as a tank, pump, etc. Guy lines must not be attached to jack up boats.

13. The guy lines should be uniformly tensioned to ±1,000 lb. Tension lines to the support structure to +/ 1,000 lb maximum. Tension lines to the injector to ±1,000 lb maximum. Bring the tension up evenly on all lines at 100 lb increments. Use load cells and tension pulleys on multiline rigups to ensure even tensioning.

Guy Lines



Guy lines should be constructed of a minimum ½ inch, 6 × 25 strand regular lay wire rope made of improved plow steel (IPS) or better with independent wire rope core (IWRC), not previously used in any other application. They should be visually inspected at least monthly and removed from service if the following damage, corrosion, or wear exists:

- Three (3) broken wires are found within one (1) lay length.
- Two (2) broken wires are found at the end connection in the strand valley.
- Marked corrosion appears.
- Corroded wires at end connections.
- End connections are corroded, cracked, bent, worn, or improperly applied.
- Evidence of kinking, crushing, cutting, cold working, or bird caging is found.

1. Guy line end terminations should be made in accordance with good guy line practice and the current copy of API RP 9B.
2. Never turn guy lines back over small radius eyes when making an end termination.
3. Wire rope thimbles or appropriately sized sheaves should be used to turn back guy line ends.
4. When wire rope clips are used, double saddle type clips are recommended and should be installed in accordance with the manufacturer's recommendations using proper torque.

Note — When a sheave is used in place of a thimble for turning back the wire rope, add one additional clip.

5. Guy line hardware, such as shackles, turn buckles, walking boomers, chain come-alongs, load binders, etc., that remain in the live guy line system should have a safe working load capacity that meets or exceeds 40% of the breaking strength of the guy line. The handles on walking boomers, come-alongs, etc., should be positively secured to prevent accidental release.

6. Cable pullers with a 3 ton rating are preferred over rope clips in applications where the length of the guy line is not fixed.
7. Upper guy line terminators should be swaged ends with thimbles installed.
8. Guy lines should be pretensioned to ±1,000 lb.
9. The catenary or sag in the guy line may be used to estimate proper pre-tension.

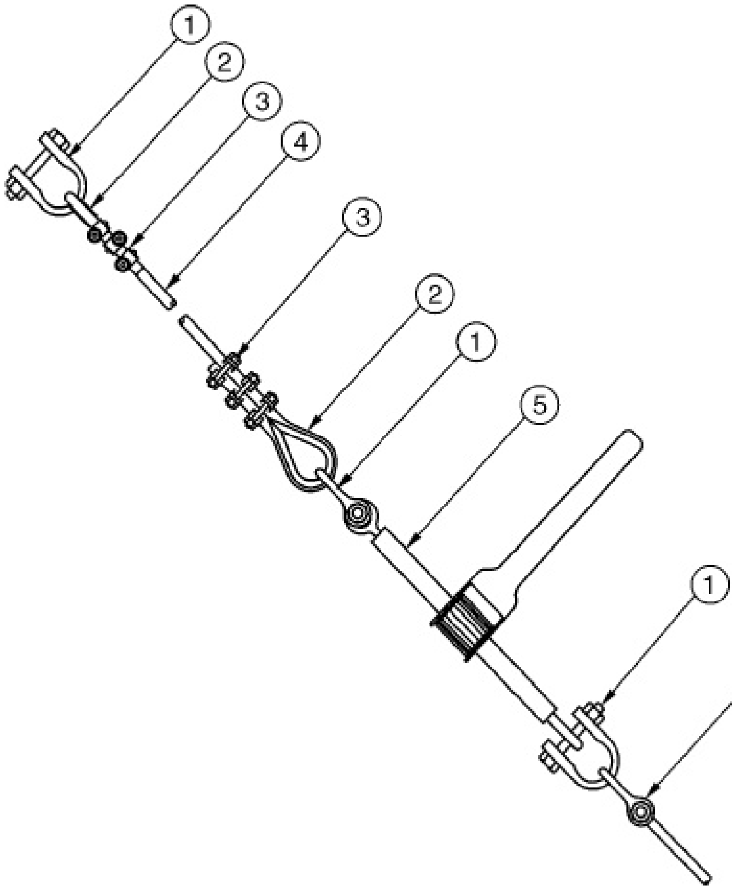


Figure 5.1—Example of suitable guy line hardware.

Table 5.1—Examples of Suitable Guy Line Hardware

Location	Qty	Part Number	Description
1	4	Crosby 1019533	Shackle
2	2	Crosby 1037719	Heavy wire rope thimble, galv., ½ in.
3	6	Crosby 1010532	Clamp, fist grip
4	100 ft	—	Wire, 6×25 strand IPS, IWRC ½ in. OD, galv.
5	1	Crosby 1048422 (SAP 101344875)	Turn buckle, ratchet type

Anchors

Anchors should meet the following criteria for installation, use, and verification.

- Only qualified persons using accepted engineering practices should design anchors.
- Steel components should be protected from corrosion.
- Anchors should meet the requirements of federal or state laws.
- Anchors should be designed to meet the structure manufacturer's recommendations or use API recommended anchor values.
- Anchors should have a minimum capacity of at least twice the guy line load.
- Install the anchor so that liquids drain away from the anchor shaft.
- The capacity should be verified every 24 months or immediately prior to use and rechecked if changes occur that would decrease the capacity of the anchor.
- Verify anchor capacity by pull testing or other appropriate method that uses accepted engineering practices.
- Inground anchors can be substituted with weighted anchor blocks that are equivalent to the required rating.

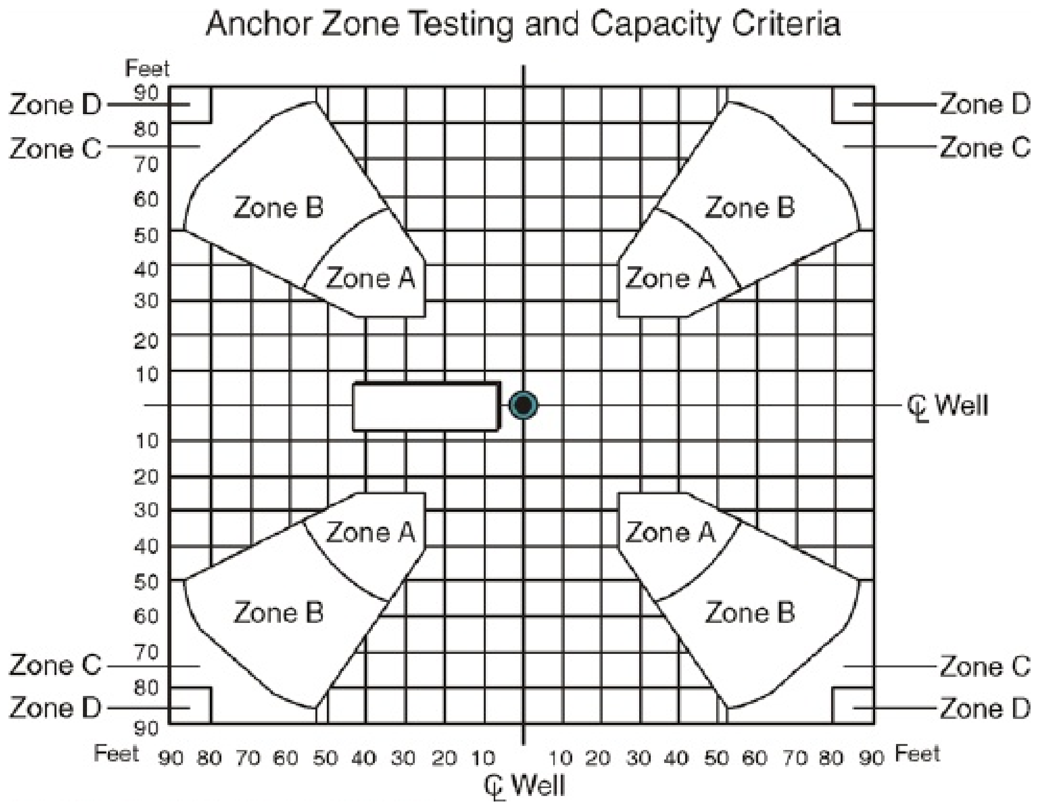


Figure 5.2—Anchor zone testing and capacity criteria

Table 5.2—Anchor Capacity, Tons*

Zone	0–50 ft Height	50–100 ft Height
A	7.0	15.6
B	4.0	11.5
C	4.0	9.0
D	4.0	7.4

*Anchor capacities shown assume:

1. Adequate foundation support for structure base or crane out-riggers.
2. Anchors in the two quadrants on the reel side of the well are located in the same zone and with equal spacing (± 10 feet) either side of the horizontal centerline and with equal spacing (± 10 feet) either side of the Vertical centerline.
3. Maximum wind velocity of 70 MPH.

Foundations (Well Location) for Support Structures and Crane Outriggers

Foundation design should consider (1) the safe bearing capacity of local ground conditions, (2) concentrated loads at the track stack base or crane outrigger support points, (3) supplemental footing required to safely distribute concentrated loads to the ground, and (4) location preparation.

- Grade the location so that oil, water, and other fluids will drain away from the working area. Wet conditions and drainage ditches around the wellhead significantly reduce the soil bearing capacity.
- The safe bearing capacity of local soils can be determined from Table 5.3 or from appropriate soil core tests, penetrometer tests, or other suitable test/analysis methods. Where surface soil conditions are used to determine soil bearing capacity, ensure that the soil is homogeneous (uniform) to a depth of at least twice the width of the supplemental footing used to support the concentrated load. Underlying soft soils should be used to determine the safe bearing capacity rather than the firmer surface soil.
- Supplemental footing must be provided to distribute the load from the structure or outrigger support points to the ground. Follow the manufacturer's load distribution diagram, or design supplemental footings to the maximum load that will be present during operation and rig up/rig down. Total loading will include the weight of the injector/BOP stack, weight of the support structure or crane chassis, hanging weight of the coiled tubing at maximum depth, and any additional load that may be applied by the injector over the string weight of the coiled tubing. The area and stiffness of the footing must meet the demands of the load. Wood timbers should be free of knots and splits.
- Earthen cellars reduce the soil bearing capacity and have the potential for cave in. Cellars with wood lined walls allow fluids to seep into the soil. Large concrete cellars may require steel beams for support. A qualified person should determine whether adequate cellar support is provided.

Table 5.3—Safe Bearing Capacity of Soils

Soil Description	Tonne/m²	Ton/ft²
Solid ledge of hard rock, such as granite or trap	264	25
Sound shale and other medium rock requiring blasting for removal	105.6	10
Hard pan, cemented sand, and gravel difficult to remove by picking	84.5	8
Soft rock, disintegrated ledge; in natural ledge, difficult to remove by picking	52.8	5
Hard clay	70	6.5
Stiff clay	35	3.3
Soft clay	8	0.7
Gravel, coarse sand, in natural thick beds	42	4
Medium dense to dense coarse sand	80	7.5
Loose medium and coarse sand/dense finely compacted sand	50	4.7
Loose fine sand	10.5	1
Loose fill	Not rated	Not rated

Most crane load charts are based on the outriggers being supported by 100% stable ground, such as listed for hard rock. The area of the manufacturer supplied outrigger pad will most likely require supplementary blocking timbers or larger pads to increase the contact area for softer soils.

Timber blocks must be hardwood and free of decay, gum veins, or termite galleries. Knots, knot holes, and borer holes must not exceed half an inch (12 millimeters) in diameter for the blocks to be considered suitable for supporting heavy equipment. The blocks must be at least 8 inches (200 millimeters) wide and at least 4 inches (100 millimeters) high, with square edges so that they form a smooth, even, flat surface when placed on top of one another to form a support for the outrigger jack. Timber that has become warped must not be used for jacking.

The timber blocks forming a base must be bolted together through the face (the widest dimension) so they stand on edge (on the side with the narrowest dimension) to obtain the maximum strength from the blocks. The reason the blocks should be bolted together is to avoid the possibility of soil being forced between the blocks during jacking, thereby separating them and rendering them unstable. The bolts used to join the timber blocks together should be a minimum of 5/8 inch (16 millimeters) in diameter.

Care should be taken when selecting the sleeper to ensure that it provides sufficient stability across the width of the sleeper and that there is no likelihood of the sleeper splitting under load. Handles of rope or steel rod (preferably steel rod) should be fitted to make it easier to move and carry the blocks to reduce the risk of manual handling injuries.

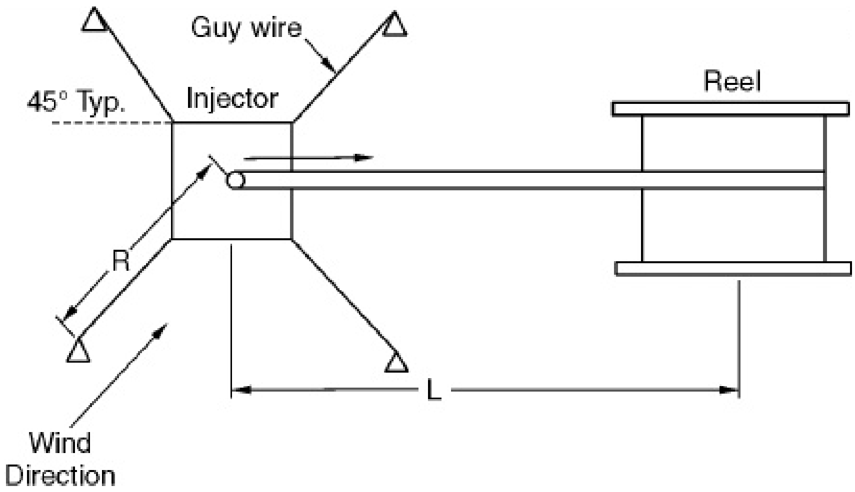
A stock of jacking timber is as much a tool as any other piece of equipment used for maintenance. This jacking timber should therefore be: stored undercover, well supported, and off the ground to protect against termite attack. The blocks should also be oiled to resist rot, weathering, and premature warping, which will render them unfit for use.

Working Near Power Lines

- When working within 10 feet of any power line, lines must be de-energized with proper lockout/tag out procedures, grounded, and certified by the appropriate electrical authority verifying that they are de-energized.
- Where spacing does not provide 10 feet of clearance in the fall radius area for the height of the equipment plus appendages, de-energize or ensure that work crews are trained in recognizing the extraordinary electrical hazards prior to starting work.
- Post a permanent sign stating “CAUTION—ENERGIZED OVERHEAD POWER LINE” to warn against potential overhead power line hazards or unsafe practices.
- Conduct a tailgate/toolbox safety meeting about electrical and rig safety. Identify hazardous energy sources and proper lockout/tag out procedures.
- Establish the rig-up position as far as possible from power lines with the fall line/lane parallel to the power line. Vehicles used for communication or transport should be kept out of the fall line and radius.
- Visually inspect the crane position, guy wires, emergency structure escape line (Geronimo line), and coiled tubing for unsafe conditions (clearance to power lines) prior to and during rig up/rig down.
- Ensure that the emergency response plan includes working near overhead power lines.
- The 10-foot (depending on kV) radius around the guy lines and escape path should be considered “danger zones” when working or rigging up/down.

Guy Line Placement Charts

Tables 5.4 through 5.12 give minimum anchor radiuses from the wellhead based on rig-up height and distance of the reel from the wellhead. Maximum loading is considered for worst case conditions of 70 MPH winds and maximum reel pressure applied to the reel motor(s).



When using tables, use the total rig-up height and not the height of the connecting point of the guy line.

Table 5.4—Rig Up Chart for Halliburton 104 in. Flange 72 in. Core Reel with One (1) Motor

Length (L), ft (Distance from the Wellhead to the Center of the Reel)	Height, ft (Top of Gooseneck)										
	20	**25**	**30**	**35**	**40**	**45**	**50**	**55**	**60**	**65**	**70**
10	15	17	18	20	22	24	25	27	29	31	33
15	18	20	22	24	25	27	29	31	32	34	36
20	21	23	25	27	29	30	32	34	36	37	39
25	22	25	28	30	32	33	35	37	39	41	42
30	24	27	30	32	34	36	38	40	42	44	46
35	25	29	32	35	37	39	41	43	45	47	49
40	25	30	33	37	39	42	44	46	48	50	52
45	26	31	35	38	41	44	46	49	51	53	55
50	26	31	36	40	43	46	49	51	53	55	58
55	27	32	37	41	44	48	51	53	56	58	60
60	27	33	37	42	46	49	52	55	58	60	63
65	27	33	38	43	47	51	54	57	60	63	65
70	27	33	39	44	48	52	55	59	62	65	67
75	27	34	39	44	49	53	57	60	63	66	69
80	28	34	39	45	50	54	58	62	65	68	71

Locate the height and length that correspond to your specific rig up. The radial distance (R) from the wellhead must be at least equal to the value at their intersection.

Table 5.5—Rig Up Chart for Halliburton 104 in. Flange 72 in. Core Reel with Two (2) Motors

Length (L), ft (Distance from the Wellhead to the Center of the Reel)	Height, ft (Top of Gooseneck)										
	20	**25**	**30**	**35**	**40**	**45**	**50**	**55**	**60**	**65**	**70**
10	18	19	21	22	24	25	27	29	31	33	34
15	23	24	25	27	28	30	32	33	35	37	39
20	28	29	30	32	33	35	36	38	40	41	43
25	32	33	35	36	38	39	41	42	44	46	47
30	35	37	39	41	42	44	45	47	49	50	52
35	38	41	43	45	47	48	50	52	53	55	56
40	40	44	47	49	51	53	54	56	58	59	61
45	42	47	50	53	55	57	59	60	62	64	65
50	43	49	53	56	59	61	63	65	66	68	70
55	45	51	56	59	62	65	67	69	71	72	74
60	46	52	58	62	65	68	71	73	75	76	78
65	46	54	60	64	68	71	74	76	79	81	82
70	47	55	62	67	71	74	77	80	82	84	86
75	48	56	63	69	73	77	81	83	86	88	90
80	48	57	64	71	76	80	84	87	89	92	94

Locate the height and length that correspond to your specific rig up. The radial distance (R) from the wellhead must be at least equal to the value at their intersection.

Table 5.6—Rig Up Chart for Halliburton 128 in. Flange 72 in. Core Reel with Two (2) Motors

Length (L), ft (Distance from the Wellhead to the Center of the Reel)	Height, ft (Top of Gooseneck)										
	20	**25**	**30**	**35**	**40**	**45**	**50**	**55**	**60**	**65**	**70**
10	19	20	21	22	24	26	27	29	31	33	35
15	24	25	26	27	29	30	32	34	35	37	39
20	29	30	31	32	34	35	37	38	40	42	43
25	33	35	36	37	38	40	41	43	44	46	48
30	36	39	40	42	43	45	46	48	49	51	52
35	39	42	44	46	48	49	51	52	54	55	57
40	41	45	48	50	52	54	55	57	58	60	61
45	43	48	51	54	56	58	60	61	63	64	66
50	44	50	54	57	60	62	64	65	67	69	70
55	45	52	57	60	63	66	68	70	71	73	75
60	46	53	59	63	66	69	71	74	76	77	79
65	47	55	61	66	69	72	75	77	79	81	83
70	48	56	62	68	72	75	78	81	83	85	87
75	48	57	64	70	74	78	82	84	87	89	91
80	49	58	65	72	77	81	85	88	90	93	95

Locate the height and length that correspond to your specific rig up. The radial distance (R) from the wellhead must be at least equal to the value at their intersection.

Table 5.7—Rig Up Chart for Halliburton 128 in. Flange 80 in. Core Reel with Two (2) Motors

Length (L), ft (Distance from the Wellhead to the Center of the Reel)	Height, ft (Top of Gooseneck)										
	20	**25**	**30**	**35**	**40**	**45**	**50**	**55**	**60**	**65**	**70**
10	17	18	20	21	23	25	26	28	30	32	34
15	21	23	24	26	27	29	30	32	34	36	37
20	25	26	28	30	31	33	34	36	38	40	41
25	27	30	32	33	35	37	38	40	42	43	45
30	29	32	35	37	39	40	42	44	46	47	49
35	30	34	38	40	42	44	46	48	49	51	53
40	32	36	40	43	45	47	49	51	53	55	57
45	32	38	42	45	48	50	53	55	57	58	60
50	33	39	43	47	50	53	56	58	60	62	64
55	34	40	45	49	53	56	58	61	63	65	67
60	34	40	46	51	55	58	61	64	66	68	70
65	34	41	47	52	56	60	63	66	69	71	74
70	35	42	48	53	58	62	65	69	71	74	76
75	35	42	48	54	59	63	67	71	74	77	79
80	35	42	49	55	60	65	69	73	76	79	82

Locate the height and length that correspond to your specific rig up. The radial distance (R) from the wellhead must be at least equal to the value at their intersection.

Table 5.8—Rig Up Chart for Halliburton 142 in. Flange 84 in. Core Reel with Two (2) Motors

Length (L), ft (Distance from the Wellhead to the Center of the Reel)	Height, ft (Top of Gooseneck)										
	20	**25**	**30**	**35**	**40**	**45**	**50**	**55**	**60**	**65**	**70**
10	17	18	19	21	23	24	26	28	30	32	33
15	21	22	24	25	27	28	30	32	33	35	37
20	23	25	27	29	30	32	34	35	37	39	41
25	26	28	30	32	34	36	37	39	41	43	44
30	27	31	33	35	37	39	41	43	44	46	48
35	28	32	35	38	40	42	44	46	48	50	51
40	29	34	37	40	43	45	47	49	51	53	55
45	30	35	39	42	45	48	50	52	54	56	58
50	30	36	40	44	48	50	53	55	57	59	61
55	30	36	41	46	49	53	55	58	60	62	65
60	31	37	42	47	51	54	58	60	63	65	67
65	31	37	43	48	52	56	60	63	65	68	70
70	31	38	44	49	54	58	61	65	68	70	73
75	31	38	44	50	55	59	63	66	70	73	75
80	31	38	45	50	56	60	64	68	72	75	78

Locate the height and length that correspond to your specific rig up. The radial distance (R) from the wellhead must be at least equal to the value at their intersection.

Table 5.9—Rig Up Chart for Halliburton 148 in. Flange 84 in. Core Reel with Two (2) Motors

Length (L), ft (Distance from the Wellhead to the Center of the Reel)	**Height, ft (Top of Gooseneck)**										
	20	**25**	**30**	**35**	**40**	**45**	**50**	**55**	**60**	**65**	**70**
10	17	18	20	21	23	24	26	28	30	32	33
15	21	22	24	25	27	28	30	32	33	35	37
20	24	26	27	29	31	32	34	35	37	39	41
25	26	28	31	32	34	36	38	39	41	43	44
30	27	31	33	36	37	39	41	43	45	46	48
35	28	32	36	38	41	43	44	46	48	50	52
40	29	34	38	41	43	45	48	50	51	53	55
45	30	35	39	43	46	48	50	53	55	57	58
50	30	36	40	44	48	51	53	55	58	60	62
55	31	36	41	46	49	53	55	58	60	63	65
60	31	37	42	47	51	55	58	60	63	65	68
65	31	37	43	48	52	56	60	63	65	68	70
70	31	38	44	49	54	58	61	65	68	70	73
75	31	38	44	50	55	59	63	67	70	73	75
80	31	38	45	51	56	60	64	68	72	75	78

Locate the height and length that correspond to your specific rig up. The radial distance (R) from the wellhead must be at least equal to the value at their intersection.

Table 5.10—Rig Up Chart for Halliburton 996.15954 with 128 in. Flange 80 in. Core Reel with One (1) Motor

Length (L), ft (Distance from the Wellhead to the Center of the Reel)	Height, ft (Top of Gooseneck)										
	20	**25**	**30**	**35**	**40**	**45**	**50**	**55**	**60**	**65**	**70**
10	13	15	16	18	20	22	24	25	27	29	31
15	15	17	19	20	22	24	26	28	30	31	33
20	16	18	21	22	24	26	28	30	32	34	36
25	17	20	22	24	26	28	30	32	34	36	38
30	17	20	23	26	28	30	32	34	36	38	40
35	18	21	24	27	29	32	34	36	38	40	42
40	18	22	25	28	31	33	35	38	40	42	44
45	18	22	25	29	31	34	37	39	41	43	45
50	18	22	26	29	32	35	38	40	43	45	47
55	18	22	26	30	33	36	39	41	44	46	49
60	18	23	27	30	34	37	40	42	45	48	50
65	19	23	27	31	34	37	40	43	46	49	51
70	19	23	27	31	35	38	41	44	47	50	52
75	19	23	27	31	35	38	42	45	48	51	53
80	19	23	27	31	35	39	42	46	49	52	54

Locate the height and length that correspond to your specific rig up. The radial distance (R) from the wellhead must be at least equal to the value at their intersection.

References

API RP 54—*Recommended Practice for Occupational Safety for Oil and Gas Well Drilling and Servicing Operations*

API RP 4G—*Recommended Practice for Maintenance and Use of Drilling and Well Servicing Structures*

API RP 9B—*Recommended Practice on Application, Care and Use of Wire Rope in Oilfield Service*

AESC (American Energy Service Contractors, formerly AOSC)—*Recommended Safe Procedures and Guidelines for Oil and Gas Well Servicing*

OSHA—*Oil Well Derrick Stability: Guywire Anchor Systems*

Crane Usage Requirements

Regulatory Requirements

All cranes are subject to certain regulatory requirements concerning operation, inspection, repair, and maintenance. Refer to the following documents that outline inspection and maintenance criteria for all hydraulic cranes:

- Halliburton Management System, Category 4, Standard 6 Health, Safety, and Environmental Standard: “Lifting & Hoisting Equipment Inspections”
- Halliburton Management System, Category 4, Standard 7 Health, Safety and Environmental Standard: “Lifting & Hoisting Equipment Operations”

General Crane Usage Requirements

1. **Inspection and maintenance**—All cranes shall be maintained, repaired, and periodically inspected in accordance with *Halliburton Scheduled Maintenance Documents C14 and C15*. Weld repairs on major structural components are prohibited unless performed by a qualified crane repair facility. The original crane manufacturer or manufacturer approved dealers are qualified repair facilities. The following procedures shall be performed:

   a. Inspect the crane. Before operating the crane, visually inspect the entire crane for obvious defects. The inspection criteria is defined in *Halliburton Scheduled Maintenance Documents C14 and C15*. The condition of the wire rope at the terminations, hooks, and shackles is especially critical.

   b. Inspect the chain, hoist, wire rope, hooks, etc.

   c. Document inspections and training.

   Personnel training—The crane operator shall be properly trained and licensed as per the Production Enhancement crane operator qualification program in addition to fulfilling any local requirements. Crew members acting as signalmen must know universal hand signals, crane operation, rigging procedures, crane maintenance, and other safety procedures. Training shall be documented.

   As a minimum requirement, in accordance with ASME/ANSI B30.5 3 regulations, all coiled tubing crane operators will be required to:

   a. Pass a current physical.

   b. Complete the seven *Qualified Rigger I-Learn modules.*

   c. Pass a set of secure written examinations.

   d. Be assessed competent on the PE 400 STIM 26 Licensed to Operate Mobile Cranes competency exam.

   e. Successfully complete an objective practical operating examination.

2. **Load rating**—The crane shall be equipped with an operable boom angle indicator and a load chart showing the maximum load rating as a function of distance from the crane centerline. Do not operate the crane with load and distance combinations that exceed the load chart.

   Note — The reach is the horizontal distance from the centerline of rotation of the bearing to the suspended wire rope hook (not the near edge of the pedestal or suspended weight).

   No crane should be loaded beyond its rated load capacity. This includes the weight of all auxiliary handling devices. Hoist blocks, hooks, and slings must be considered part of the load. Legible rating charts should be fixed to the crane cab where the operator can refer to them easily.

3. **Relief valve**—The hydraulic supply relief valve installed on the crane control console should not be readjusted to a higher setting.

4. **Control console**—The control console should have each control function identified, and the direction of actuation indicated.

5. **Outriggers**—Before moving the crane boom from the stowed position, deploy the outriggers. Visually inspect the outriggers for cracks and visible damage. The outrigger jacks should be set on a mat or pad (timbers) to provide enhanced ground support. The outriggers should be adjusted to level the crane base.

   Note — If the crane is not level, the accuracy of the load chart is affected.

6. **Test for leakdown**—After deploying the outriggers, test the crane for leakdown by suspending a load (less than the load chart rating) with the boom at an angle of 30°. With all valves in the neutral position, verify that the suspended weight does not creep more than 1 inch over a period of 15 minutes.

   Note — Ambient temperature changes may affect performance of the crane during the test.

7. **Trial lift**—When moving loads near the load chart limits, first make a trial lift at the desired distance before hoisting the load over 2 ft high. This is to verify stability and avoid tipping over.

8. **Verify equipment**—Before hoisting any load, verify that the proper hooks, lift bars, and slings are used.

9. **Appoint a signalman**—Before using a crane to lift or move any object, the crane operator should appoint one person as the signalman.

10. **Communication**—The signalman will communicate with the operator by hand signals unless another means of communication is available, such as two way radio headsets or equivalent. Standard signals should be thoroughly understood by both operator and signalman.

    Lost contact—Should the crane operator lose contact with the signalman, he will immediately stop any function in progress until contact is regained.

11. **Emergencies**—Other personnel should not signal the crane operator except in an emergency. An emergency situation can be described as any time a movement of the load can result in foreseen personal injury or equipment damage.
12. **Securing the boom**—Before leaving the job site, the crane boom shall be stored and secured in the transport cradle. If the crane is equipped with road/bypass valve(s), open the valve(s) so that the boom cannot rise while being transported.

    Note Limit work under the crane boom or the suspended load. Some operations during rig up require working under or near a suspended load. Proper crane procedures, inspection, and maintenance are required to limit exposure.

13. **Lift capacity**—Cranes are rated at the completely retracted and fully boomed up position. When scoping out and/or booming down, the useable lift capacity decreases (refer to angle/reach charts for lift capacity).
14. **Remain alert**—People working with or near a crane should not be under the load or boom, should be alert at all times, and should watch warning signals closely.
15. **Securing loads**—Hoist chain or rope must be free of kinks or twists. It must not be wrapped around the load. Loads must be attached to the load block hook by means of a sling or other approved device.
    - Load must be secured and properly balanced in the sling or lifting device.
    - Before starting to hoist, make sure multiple part lines are not twisted around each other.
16. **Reduce swinging**—Hooks should be brought over the load slowly to reduce swinging. During the hoisting operation, there should be no sudden acceleration or deceleration of the moving load.
17. **Side pulls**—Cranes must not be used for side pulls. Avoid excessive side load due to reel tension.
18. **Connecting/disconnecting or carrying the load**—Never hoist, lower, or travel a crane while an employee is connecting or disconnecting the load. Never carry loads over people.
19. **Test brakes**—Test brakes each time a load approaching the rated load capacity is handled.
20. **Suspended loads**—The operator must not leave his or her position at the controls while a load is suspended.

Crane Training and Qualification

Table 6.1—Crane Related Training/Qualification Activities*

Training/ Qualification Activity	Training Type	Personnel
Crane Awareness Orientation	Online/ I-Learn	• Account representatives, mid management.
Rigging 1 & Task List	Online/ I-Learn	• Must be completed by all CT employees who manually assist with lifting and handling operations.
Rigging 2 & Task List	Online/ I-Learn	• Intended for offshore personnel required to perform rigging operations as a condition of their work.
Crane Fundamentals Course	Online/ I-Learn	• Provides essential knowledge for personnel directed to serve as crane operators. • (Rigging 1 is a prerequisite.)
Basic Crane Written Exam	Online/ I-Learn	• An online, password protected, proctored examination that serves as a threshold for all crane operators.
Specific Crane Category Written Exams	Online test	• An online, password protected, proctored examination to qualify the employee to commence skills development before taking the practical skills examination. • Each specific crane an individual operates requires both written and practical exams. • The Basic Crane Written Exam is a prerequisite for any specific exam
Mobile Crane Task List	Online/ I-Learn CDS	• A skills task list placed in I-Learn where a competent (qualified crane operator with a license) assesses a new candidate (one who has met the prequalifications).
Practical Crane Exam	Facility administered	• A specific practical exam “timed course” for each crane category. • For crane operators to maintain multiple licenses, they must successfully complete a written and practical exam for each crane type they operate.
*Production Enhancement crane operator qualification program		

Standard Hand Signals

Standard hand signals for controlling operation of overhead and gantry cranes can be found at http://halworld.corp.halliburton.com/internal/hsesd/pubsdata/standards/standards_cat_eng.htm in the guideline for Category 4, Standard 7.

Tripping Pipe

Introduction

Pipe speed and control should be maintained for personnel safety and to help prevent equipment damage. A coiled tubing injector and reel are capable of running at speeds up to 220 ft/min. Pipe tripping speeds will vary depending on the job, equipment, tools, well situations, and operator experience. Proper power pack hydraulic settings and weight indicator settings are required to maintain the tubing loads within an acceptable range, usually less than 80% of material yield and below buckling loads.

Tripping Procedure

1. Obtain the following information:
   a. Well schematic and last wireline run reports, if available.
   b. Obtain from the operating company representative: the location of gas lift mandrels, nipples, any obstruction or tight spots, end of tubing, total depth, casing size, and present well conditions.
   c. Obtain the current shut in pressure and record it.
2. Note the approximate coiled tubing wrap position on the reel. This may become useful in the event of a depth counter malfunction.
3. Zero the depth counter at a known point in relation to the well zero point. Calculate the offset and enter it into the DAS, or reset the depth counter to the well depth.
4. With the pressure in the BOP at 0 psi, zero the weight indicator analog gauge and zero weight channel on the Unipro II™, PLC, or FLECS™ controller. Make sure the toolstring is not pulled up against the stuffing box and that the stripper pressure is reduced to zero before zeroing the weight indicator.
5. Verify that the flow line, production wing valves, and kill line are closed.
6. Pressure up the coiled tubing and well control equipment to a value equal to the shut in pressure recorded in Step 1c.
7. Slowly open the wellhead master valves starting at the lower most valve. Count the number of turns required to fully open each valve and record the number on the job log.
8. Set the choke on the flow line and slowly open the flow line valves starting with the inner most valve (closest to the wellhead) and working outward.
9. First trip in the hole:
   a. Run tubing slowly through the well control equipment and wellhead. Ensure that the injector max. pressure is set at the minimum pressure required to move the tubing.

b. When clear of surface equipment, the injector speed may be increased to 50 to 100 ft/min (15 to 30 m/min). When snubbing into pressure, remain below 50 ft/min (15 m/min) until a positive response is seen on the weight indicator.

c. Conduct pickup and slack off weights at every 1,000 to 1,500 ft (300 to 500 m) on the first trip in the hole. Pick up at least 25 to 50 ft (10 to 20 m) to establish good readings. When approaching the end of the production tubing, additional pickups may be required at every 50 to 100 ft (15 to 30 m) to check for drag caused by buckled or corkscrewed production tubing. Record pickup and slack off weights vs. depth for future reference. Vary the starting depth of periodic weight checks from job to job to avoid creating high cycle fatigue areas on the string.

d. At 1,000 ft (500 m), make a pickup and slack off weight check. The average of these two will be the actual pipe weight if there is no pressure on the well. The average is required to eliminate the drag effects of the stuffing box element and the production tubing, especially in deviated wellbores. If the well is pressurized, the average weight will be pipe weight less the force exerted on the pipe because of pressure applied to the cross sectional area of the tube. Buoyancy affects the pipe weight indicator reading and should be considered.

Example 1: If the pickup weight = 1,200 lb and the slack off weight = 800 lb, the calculated pipe weight = 1,000 lb. If the actual pipe weight is different from that shown by the weight indicator, it should be adjusted.

Example 2 (with well pressure): A pickup is made at 1,000 ft with 1 1/4 × 0.087 in. tubing with 2,000 psi on the well. The pickup shows a snub or negative weight of 1,200 lb, and the slack off shows 1,600 lb snub force. The average snub force is 1,400 lb. Use the following calculations to check pipe weight and weight indicator.

Well pressure force on the tubing is determined from well pressure times the cross sectional area of the tubing.

$F = A \times P = 1.25\ \text{in.}^2 \times 0.7854 \times 2{,}000\ \text{psi}$
$F = 2{,}454$ lb upward or snub force
Pipe weight = weight per foot × total footage
$Wt = Wt/ft \times L$
$= 1.081\ \text{lb/ft} \times 1{,}000\ \text{ft}$
$= 1{,}081$ lb downward force
Net forces are a summation of the above calculated component forces.
Net forces = pressure forces + weight forces
= 2,454 lb upward and 1,081 lb downward
= 1,373 lb upward force

10. It is recommended that the weight indicator not be adjusted after the weight check has been made and the indicator is set at 1,000 ft (500 m).

11. When approaching any known obstacles, such as plugs, bridges, or tight spots, make a pickup and slack off weight check, reset the INJECTOR MAXIMUM PRESSURE ADJUST to the minimum

required to move the coiled tubing, proceed with caution, and move the pipe slowly (± 20 ft/min) to allow indication of when contact is made with an obstruction.

12. Proceed slowly through restrictions, such as landing nipples, gas lift mandrels, and sliding side doors.
13. Set the INJECTOR MAXIMUM PRESSURE ADJUST to allow tubing movement to stall out before 10% of the total weight is set down on the obstruction.
14. Pulling out of the hole (POOH).
    a. When the tubing starts out of the hole, the hydraulic motor pressure requirement increases.
    b. As more tubing is lifted from the well, the hydraulic motor pressure requirement drops.
    c. Continually reduce the supply pressure by backing out on the INJECTOR MAXIMUM PRESSURE ADJUST valve. Every 1,000 ft, back out the Injector Maximum Pressure adjust valve until the injector pressure drops 50 psi.
    d. When pulling out of the hole, proceed with caution when entering the end of the production tubing with any kind of tools on the coiled tubing.
    e. At about 500 ft from surface, slow the injector speed and adjust the injector maximum hydraulic pressure to stall when the tool string bumps up on the stuffing box.

Note — Venting the “B” and “C” pumps on 30/38K units allows better control of the injector speed.

    f. Ensure that the counter is functioning properly. Compare with the manual counter and wrap position on the reel.
    g. Slowly shut in the tree while counting the turns on the master valve to confirm a complete closure. If the coiled tubing string is pressurized, bleed off the pressure before loosening any wellhead pressure containing components.
    h. Log the tubing run in the tubing records noting any severe service or issues.

Snubbing

When running coiled tubing into a well with pressure, it is considered closed ended, and the well pressure acts across the whole outer area of the tubing, creating an upward force trying to push the coiled tubing out of the well. With larger OD coiled tubing, this effect is greater when running into a well with the same wellhead pressure. An additional upward force is generated from the stripper when running into a well under pressure. This is due to friction between the tubing and the stripper's sealing elements. Typical values can be seen in Table 6.2, excluding and including the additional force generated by the stripper. For this table, the stripper force equates to approximately 0.5 lbf/psi of wellhead pressure.

$$Fwp = OD^2 \times 0.7854 \times \text{well pressure}$$

$$Fst = \text{Well pressure} \times 0.5$$

$$Fsn = Fwp + Fst$$

Fwp = Force due to well pressure

Fst = Force due to stripper drag

Fsn = Total snub force

Table 6.2—Typical Snubbing Loads for 7,500 and 10,000 psi Surface Pressures

Outer Diameter (in.)	Snub Force at 7.5K psi (lbf)		Snub Force at 10K psi (lbf)	
	Excluding Stripper	Including Stripper	Excluding Stripper	Including Stripper
1.000	5,888	9,638	7,850	12,850
1.250	9,202	12,952	12,270	17,270
1.500	13,253	17,003	17,670	22,670
1.750	18,038	21,788	24,050	29,050
2.000	23,565	27,315	31,420	36,420
2.375	33,225	36,975	44,300	49,300

The tubing and injector must be capable of running against the total of these two forces. The effect of these two forces acting simultaneously can cause the tubing to buckle between the stripper and the bottom of the injector chains. It is at this point where the tubing has the least amount of support before entering the well. The chance of buckling the tubing at this point can be reduced by either increasing the tubing wall thickness and/or reducing the unsupported length between the two points or by using tubing with a greater yield strength.

Tables 6.3 and Table 6.4 (Pages 6-13 through 6-15) detail the maximum unsupported length for an eccentricity ratio of 0.25 for current tubing grades/sizes. These tables are used to calculate the amount of axial compressive load that can safely be applied to the CT in this unsupported length.

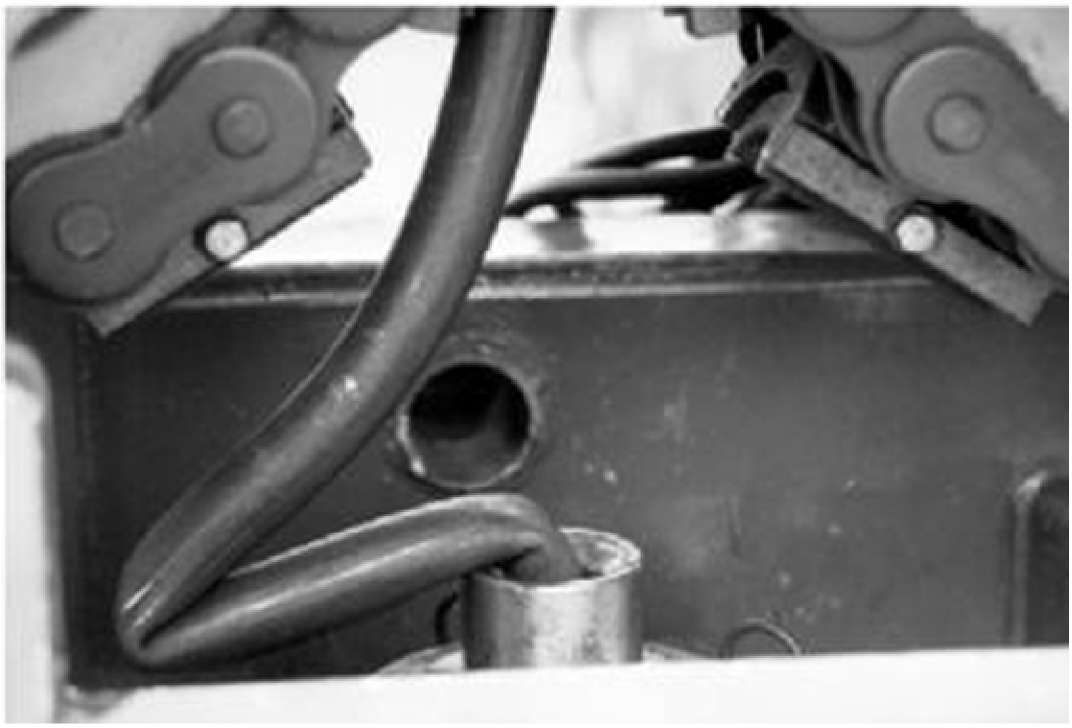


Figure 6.1—Catastrophic buckling.

Unsupported Length Calculation

Refer to Tables 6.3 and Table 6.4 (Pages 6-13 through 6-15). To use these tables:

1. Find the longest unsupported length above the stripper/packer.
   a. Measure the vertical length from the top of the inner frame guide to the centerline of the lower linear beam chain sprockets (HES injectors).
   b. Measure the vertical length from the top of the stripper guide to the bottom of the inner frame guide (HES injectors).
   c. Measure the vertical length from the top of the stripper guide to the centerline of the lower gripper chain sprockets (Hydra Rig injectors).
2.. Look up the largest measured value from Table 6.3 or Table 6.4 (Page 6-13 or 6-15) in the appropriate unsupported length column for the CT size of interest.
3. Multiply the value from Table 6.3 or Table 6.4 (Page 6-13 or 6-15) by the yield strength of the CT material.
   a. For English units, the yield strength must be in psi.

b. For metric units, the yield strength must be in MPa.
The result is the maximum safe axial compressive load (including a 50% safety factor) in the unsupported section in pounds for the English units and Newtons for the metric units.

Unsupported length calculators are also available in the CT Toolbox Spreadsheet, INSITE™ for Well Intervention and Cerberus software.

Example—The unsupported length is 14 inches for 1.5 in. diameter, 0.109 in. wall CT with a yield strength of 80,000 psi. The value from Table 6.3 (Page 6-13) is 0.1381.

80,000 × 0.1381 = 11,048 lb

In metric units, the unsupported length is 350 mm for 38.10 mm diameter, 2.77 mm wall CT with a yield strength of 552 MPa. The value from the metric units Table 6.4 (Page 6-15) is 90.3.

552 × 90.3 = 49,845 Newtons

These calculations are based on the ASCE Test Recommendation and assuming pin to pin mode and 0.25 eccentricity ratio.

Equations

The equation for the radius of gyration is:

$$r_g = \frac{1}{2}\sqrt{r_o^2 + r_i^2}$$

The equation for the slenderness ratio is:

$$\xi = L/r_g$$

The equation for the buckling load is:

$$\frac{P_b}{\sigma_y} = \frac{A}{1+(0.03\xi 0^2)}$$

This value is multiplied by 0.5 to provide a factor of safety of 2.

Table 6.3—Catastrophic Buckling English Units

OD (in.)	Wall Thick ness (in.)	Unsupported Length (in.)										
		4	6	8	10	12	14	16	18	20	22	24
		in.2*	in.2*	in.2*	in.2*	in.2*	in.2*	in.2*	in.2*	in.2*	in.2*	in.2*
1.000	0.087	0.1097	0.0954	0.0806	0.0672	0.0559	0.0466	0.0391	0.0331	0.0282	0.0243	0.0210
1.000	0.095	0.1186	0.1029	0.0868	0.0722	0.0600	0.0499	0.0419	0.0354	0.0302	0.0259	0.0225
1.000	0.102	0.1261	0.1092	0.0920	0.0765	0.0634	0.0527	0.0442	0.0373	0.0318	0.0273	0.0237
1.000	0.109	0.1335	0.1154	0.0971	0.0806	0.0667	0.0554	0.0464	0.0392	0.0334	0.0286	0.0248
1.250	0.087	0.1465	0.1335	0.1187	0.1039	0.0902	0.0780	0.0675	0.0585	0.0510	0.0446	0.0393
1.250	0.095	0.1587	0.1445	0.1283	0.1122	0.0973	0.0840	0.0727	0.0630	0.0548	0.0479	0.0422
1.250	0.102	0.1693	0.1539	0.1366	0.1193	0.1033	0.0892	0.0770	0.0667	0.0581	0.0508	0.0446
1.250	0.109	0.1796	0.1632	0.1446	0.1262	0.1092	0.0942	0.0813	0.0704	0.0612	0.0535	0.0470
1.250	0.118	0.1927	0.1748	0.1548	0.1349	0.1165	0.1004	0.0866	0.0749	0.0651	0.0569	0.0499
1.250	0.125	0.2027	0.1837	0.1625	0.1414	0.1221	0.1051	0.0906	0.0783	0.0680	0.0594	0.0521
1.250	0.134	0.2153	0.1949	0.1721	0.1496	0.1290	0.1110	0.0955	0.0825	0.0716	0.0625	0.0549
1.250	0.145	0.2303	0.2082	0.1836	0.1593	0.1372	0.1178	0.1013	0.0874	0.0758	0.0661	0.0580
1.250	0.156	0.2450	0.2211	0.1946	0.1686	0.1450	0.1244	0.1068	0.0921	0.0798	0.0696	0.0610
1.250	0.175	0.2693	0.2425	0.2128	0.1839	0.1577	0.1350	0.1157	0.0996	0.0862	0.0750	0.0657
1.500	0.095	0.1982	0.1854	0.1701	0.1538	0.1377	0.1225	0.1087	0.0963	0.0855	0.0760	0.0678
1.500	0.102	0.2116	0.1979	0.1814	0.1639	0.1466	0.1304	0.1156	0.1024	0.0908	0.0808	0.0720
1.500	0.109	0.2249	0.2102	0.1926	0.1739	0.1554	0.1381	0.1223	0.1083	0.0961	0.0854	0.0761
1.500	0.118	0.2417	0.2257	0.2067	0.1864	0.1665	0.1478	0.1308	0.1158	0.1026	0.0911	0.0812
1.500	0.125	0.2546	0.2377	0.2174	0.1960	0.1749	0.1551	0.1373	0.1214	0.1075	0.0955	0.0850
1.500	0.134	0.2710	0.2527	0.2310	0.2080	0.1855	0.1644	0.1453	0.1285	0.1137	0.1009	0.0898
1.500	0.145	0.2906	0.2708	0.2473	0.2224	0.1980	0.1754	0.1549	0.1368	0.1210	0.1073	0.0955
1.500	0.156	0.3098	0.2885	0.2631	0.2364	0.2103	0.1860	0.1641	0.1448	0.1280	0.1134	0.1009
1.500	0.175	0.3422	0.3181	0.2895	0.2596	0.2305	0.2035	0.1793	0.1579	0.1394	0.1234	0.1097
1.750	0.102	0.2533	0.2411	0.2259	0.2089	0.1913	0.1740	0.1575	0.1423	0.1284	0.1159	0.1047
1.750	0.109	0.2695	0.2564	0.2401	0.2219	0.2031	0.1846	0.1671	0.1509	0.1361	0.1228	0.1109
1.750	0.118	0.2900	0.2758	0.2581	0.2384	0.2181	0.1981	0.1792	0.1617	0.1457	0.1314	0.1187
1.750	0.125	0.3058	0.2907	0.2719	0.2510	0.2295	0.2084	0.1884	0.1699	0.1531	0.1380	0.1246
1.750	0.134	0.3259	0.3096	0.2894	0.2670	0.2440	0.2213	0.2000	0.1802	0.1623	0.1463	0.1320
1.750	0.145	0.3500	0.3324	0.3105	0.2862	0.2613	0.2369	0.2138	0.1926	0.1733	0.1561	0.1408
1.750	0.156	0.3738	0.3548	0.3311	0.3050	0.2782	0.2520	0.2273	0.2046	0.1840	0.1656	0.1493
1.750	0.175	0.4140	0.3924	0.3658	0.3365	0.3064	0.2772	0.2497	0.2245	0.2017	0.1813	0.1633
1.750	0.188	0.4408	0.4175	0.3889	0.3573	0.3251	0.2938	0.2644	0.2375	0.2132	0.1916	0.1724
2.000	0.109	0.3137	0.3020	0.2869	0.2697	0.2512	0.2324	0.2139	0.1962	0.1796	0.1642	0.1502
2.000	0.118	0.3379	0.3251	0.3088	0.2901	0.2701	0.2497	0.2297	0.2106	0.1927	0.1762	0.1610
2.000	0.125	0.3565	0.3430	0.3257	0.3058	0.2846	0.2630	0.2419	0.2217	0.2028	0.1853	0.1693

*Multiply by the yield stress in lb per square inch (psi) to obtain the compressive force in lb
**Includes 50% safety factor

Working with Nitrogen and CO2

Introduction

Coiled tubing operations often use nitrogen. Nitrogen is stored as a cryogenic liquid and used by converting it to a gas. Proper personal protective equipment (PPE) and unit safety equipment procedures are required to handle nitrogen safely. This section provides important information regarding proper rig ups, safety equipment, and safety procedures for nitrogen operations.

Liquid nitrogen is hazardous. In the cryogenic state, the nitrogen is in a liquid form at a temperature of minus 320°F. Contact of human tissue with severe cold will destroy tissue in a manner similar to high temperature burns. Freeze burns will result from contact with the actual liquid or cold surfaces of piping and equipment containing the liquid. Liquid nitrogen will cause immediate, often irreparable eye damage. The danger increases when the liquid is under pressure; therefore, it is important to wear protective clothing.

Ambient air will condense on the cold surface of the liquid nitrogen piping. This can create a liquid air hazard. The boiling point of nitrogen is lower than the boiling point of oxygen; therefore, liquid air can result in puddles containing approximately 52% oxygen. This oxygen enriched air may cause normally noncombustible material to become flammable and normally flammable material to burn at an increased rate.

Effects of Oxygen Deficiency

Nitrogen and CO_2 will displace oxygen without warning. Proper ventilation must be maintained to help prevent asphyxiation.

Table 6.5—Effects of Oxygen Deficiency*

Oxygen, %	Effect
12 to 16	Deep breathing, accelerated heart beat, impaired attention, impaired thinking, impaired coordination.
10 to 14	Very faulty judgment, very poor coordination, rapid fatigue from exertion that may cause permanent heart damage, intermittent breathing.
10 or Less	Nausea, vomiting, inability to perform vigorous movement or loss of all movement, unconsciousness followed by death.
6 or Less	Spasmodic breathing, convulsive movements, death in minutes.

*NIOSH Technical Report: *A Guide to Industrial Respiratory Protection*, p. 17, June 1976

Oxygen is necessary for humans to function correctly. A slight oxygen deficiency will result in deeper respiration, faster pulse, and poor coordination. As the oxygen deficiency increases, one's judgement becomes so poor that the employee may not be able to move to a well ventilated area.

Awareness of oxygen displacement by nitrogen is difficult without monitoring equipment because nitrogen is colorless, odorless, nontoxic, and nonirritating.

Note	One full breath of pure nitrogen can strip blood of necessary oxygen, resulting in a loss of consciousness.

Nitrogen is an excellent gas to use in oilfield operations because it is inert (does not react with other substances), nonflammable, and has a large expansion ratio from liquid to gas (696:1). Because of the large expansion ratio, care is required to help prevent trapping liquid nitrogen. If a 1 ft^3 container is filled with liquid nitrogen at minus 320°F and 0 psi and raised in temperature to 70°F, the nitrogen would be in a gas phase at 42,500 psi pressure.

Note	Non-cryogenic materials include carbon steels, low alloy steels, most rubbers, and plastics. Contact with liquid nitrogen can cause the materials to become very brittle; any shock could cause them to break like glass.

Nitrogen Training

All nitrogen and coiled tubing personnel involved in nitrogen services shall be trained in both cryogenic and high pressure states of nitrogen as specified in Halliburton guidelines. Training should include videos and classroom training.

Mandatory Videos

- *Basic Nitrogen Safety* (5 min) – The purpose of this film is to provide new employees with basic nitrogen safety principles and practices. The short film discusses cryogenic safety, asphyxiation, and basic oilfield procedures for safe handling of the cold liquid and high pressure gas. This film may also be used in conjunction with other oilfield safety training, and as a refresher course.
- *Nitrogen Demands Your Respect* (30 min) – The purpose of this film is to provide extensive training on all aspects of safety on nitrogen use in oilfield work. Topics include: general nitrogen physical properties, nitrogen equipment, first aid, and potential hazards associated with cryogenic temperatures and high pressure equipment. Special efforts are made to demonstrate specific nitrogen properties, cryogenic materials, and liquid air hazards. Also potential hazards from stored energy, iron restraints, and high pressure leak detections are demonstrated. This film may also be used in conjunction with other oilfield safety training, and as a refresher course.

Available Training

A safety training course entitled *Nitrogen Safety* is available on I LEARN. The following are also recommended classes on I LEARN.

- Wellsite nitrogen basic safety training.
- Nitrogen operator training.
- Nitrogen applications and calculations training.
- Halliburton nitrogen awareness course for international operators.

Required PPE for N_2 and CO_2 Use

When handling liquid nitrogen or carbon dioxide, priming up, or operating the nitrogen pump, wear personal protective equipment. Required personal protective equipment includes:

- Safety goggles or face shield.
- Clean, insulated, loose fitting gloves.
- Hard hat.
- Cuffless trousers worn outside of boots.
- Long sleeved shirt or coveralls.

Basic Safety Rules for N^2 and CO^2 Use

The following general rules should be reviewed before an operation involving usage of N_2 and CO_2.

- Wear approved clothing, trouser legs outside boots, and heavy easily removed gloves.
- Always wear safety goggles.
- Keep liquid N_2 and CO_2 away from non-cryogenic materials.
- Keep drip pans and areas under liquid N_2 piping free of oil and other hydrocarbons.
- Do not discard cigarettes or matches around N_2 and CO_2 equipment.
- Leave vent paths from all lines open until flow stops.
- Vent high pressure lines as quickly as possible following pumping operations.
- Stay away from high pressure if not involved in the operation.
- Keep all body parts away from suspected leaks.
- Do not vent N_2 or CO_2 into an enclosed area.

- Do not enter a thick ground fog which has been caused by N2 or CO2.
- Discharge of the vent line must be at least 5 ft (2 m) away from personnel contact and directed away from the work area.
- Ensure adequate ventilation is available when working with N_2 or CO_2 in an enclosed area. Test the atmosphere for oxygen content prior to entry into an area suspected to be oxygen deficient.
- When conducting a rescue from an oxygen deficient area, wear a positive pressure SCBA.
- Escape packs having a minimum duration of five minutes must be worn by each employee involved in the operation.
- Do not put pieces of solid CO_2 (dry ice) into the mouth.
- Position N2 and CO2 pumping equipment so that the cylinder heads are facing away from personnel.
- Blow down liquid CO_2 flow lines before rigging down, because liquid CO_2 left in the lines can flash to dry ice when flow lines are disconnected after a job. As the temperature rises, the plugs of dry ice lodged in the lines will vaporize and the resulting pressure release can be hazardous.

Note	Specific rig up procedures are required to ensure correct venting of liquid CO_2.

Make sure all unions are liquid tight before introducing CO_2 liquid into the discharge manifold equipment and lines. This equipment becomes extremely brittle at minus 109ºF or lower and can shatter when struck. Do not attempt to tighten a union at these temperatures or under pressure.

Rig-Up Procedure for an N_2 Operation

Figure 6.2 and Figure 6.3 show example rig-ups.

1. All discharge lines must be of proper working pressure. Equipment with a minimum of 15,000 psi is recommended.
2. All discharge lines must be swivel type, rated for nitrogen gas service. Piping should have a flow capacity compatible with the maximum rate of the pumping unit.
3. Secure all discharge lines at the termination points with approved restraints.
4. Ensure that two check valves are used: at the tie in to the wellhead, on displacement jobs, or at the reel, when nitrogen is used with the coiled tubing. This will help prevent flowback in case of loss of integrity of surface treating iron.
5. A bleed-off valve should be used downstream of check valves to allow trapped pressures to be bled off before rigging down. A pressure recording device should also be connected downstream of the check valves. A low torque valve should be used downstream of the pressure recording connection.

6. Commingling operations require 4 check valves: 2 at the nitrogen pump tee, 1 at the fluid pump tee, and 1 at the tie in to the reel or wellhead. The check valves are used to help prevent fluid from entering the nitrogen pump or nitrogen from entering the fluid pump and to help prevent flowback from the well if line failure occurs.
7. Equip all double insulated liquid nitrogen transfer hoses with relief valves that can vent the layers.
8. Do not put nitrogen returns into an improperly vented tank.
9. Use appropriate waterflood techniques when on platforms, work boats, or other steel decks.

Post-Rig Up Testing Procedure

1. After proper rig up, test all lines using a low/high test procedure to the working pressure of the wellhead equipment or the surface equipment as per API 16ST.
2. Bleed off all lines before repairs.

Operating Procedures for an N_2 Operation

1. The nitrogen pump must be manned and monitored at all times while in operation.
2. Keep nitrogen discharge temperatures between 70 and 160°F. Elastomers used in the treating iron, valves, and swivel joints are normally nitrile polymer with a maximum temperature range of 20 to 250°F.
3. Bleed off all lines before rigging down. Check for trapped pressure before loosening any connections.

N_2 and CO_2 Operations References

- HSE Category 5 Standard 5: Cryogenic Materials

Nitrogen Rig-Up

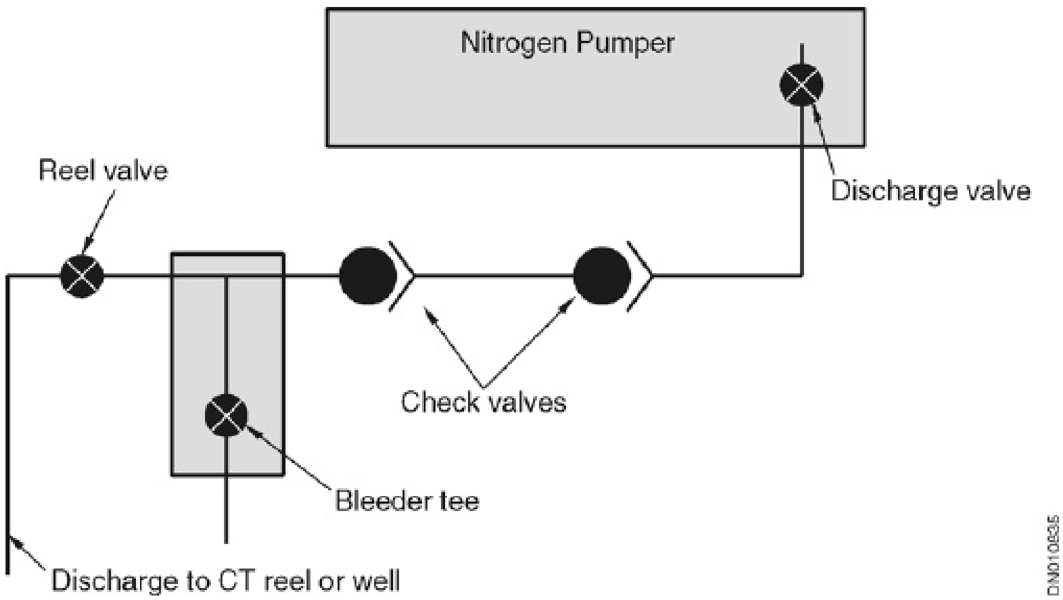


Figure 6.2—Nitrogen rig-up

Note — Jointed pipe and swivels should be used in place of flexible hose when pumping gas or commingling any fluid with gas. Test lines using low/high test procedure as per step 2 on page 6-37 before pumping.

8. When taking returns into a closed top tank, sufficient vents should be present to release gas that has entered the tank.
9. Take special precautions to avoid asphyxiation when gauging a closed top tank.
10. A choke should be installed in the flow line with two full opening valves in the line upstream of the choke. The initial choke size should be 1/6 of the flow line ID. Do not use ball, plug, or gate valves for chokes. All equipment shall have a minimum working pressure equal to or greater than the maximum anticipated wellhead pressure.
11. Secure discharge lines and pumps only when required. Contact the Global FSQC for details on restraint systems.
12. Use suitably rated discharge manifold equipment to pump acids. Before pumping acid, pressure test all lines using a low/high procedure to working pressure with a test fluid. H_2S rated iron is preferred to help prevent the hydrogen ions in the acid from reacting with the piping and causing hydrogen embrittlement.

Flowback Control Equipment

Flowback equipment is used to transfer well fluid from the wellbore to production tanks, production facilities, or return pits. The equipment must be able to control the rate and pressure of the flow as well as any solids that may be present in the wellbore fluid.

Flow Tee/Flow Cross

Both flow tees and flow crosses are designed as the primary outlet for production of the well. This equipment is generally incorporated into the wellhead, but at times will be an integral part of the coiled tubing blowout preventer (BOP) equipment. If at all possible, flow should be taken off the wellhead flow tee or cross. If this is not possible because of production line hookups, a flow cross will need to be included in the CT rig up.

This will require additional BOP equipment; see Table 7.4.

All flow tees/crosses must be designed for the purpose and rated for the pressure and well conditions present. Two plug valves must be used on any flow outlet between the flow tee/cross and the flow line. High pressure and H_2S applications require that these valves be flanged. The inner valve is used as a shut in device and can be equipped with either a hydraulic actuator or a manual valve to shut in the flow line. The outer valve is used to open and close the flow line for normal operations. The outer valve can be manually or hydraulically controlled, but when a minimum of one remote operated valve is specified, this should be the inner valve.

Flow Line

Flow line is designated as any piping used to carry wellbore fluid from the well to the final receptacle (i.e., tank, pit, or pipeline). All flow line assemblies and data headers have a direct impact on the safety of personnel. Therefore, the piping should be subject to certain testing and inspection procedures before being placed into service. All flowback piping must comply with ANSI B31.3 and API 6A. It must comply with NACE MR 01 75 if necessary, and if required, Det Norske Veritas (DNV) or American Bureau of Shipping (ABS) standards.

Ensure that sufficient piping of the correct size and pressure rating is available for the surface rig up. Piping may consist of straight lengths, elbows, and crossovers. Additional assemblies may be needed to reduce flow cutting and erosion in the flow system: target elbows, block tees, and lead targets. The pipe should be pressure tested to working pressure before being sent on a job.

Flow line should be made up of piping with integral union connections for up to 10,000 psi and flanged or hub connections for 10,000 to 15,000 psi. All piping shall have a rated working pressure equal to or greater than the minimum well control stack pressure rating designated by the operational pressure category.

Because flow lines can be subjected to high velocity erosive fluids, they are not to be used on the pumping side of the rig up. All flow line assemblies should be marked with distinctive color coding that designates it as flow piping. Flow line used on reverse manifolds that may see service as both pump and flow lines should be specifically marked as such and should have a more frequent inspection interval.

Each HES assembly will include painted identification bands to identify pressure rating and service. An assembly should have a 12 in. band of the proper color for the working pressure of that particular piece. H_2S service is identified by a 4 in. wide green band with 4 in. wide bands of the pressure rating bordered on each side. The pressure rating color code presently in use is:

- 10,000 psi – Yellow
- 15,000 psi – Orange
- 20,000 psi – White

Choke Manifold

The choke manifold is the primary means of controlling the flow of the well and shall be monitored and operated by competent personnel. The assemblies normally contain two chokes: (1) an adjustable

Recommended Procedure for the 4 Valve (Non Bypass) Configuration

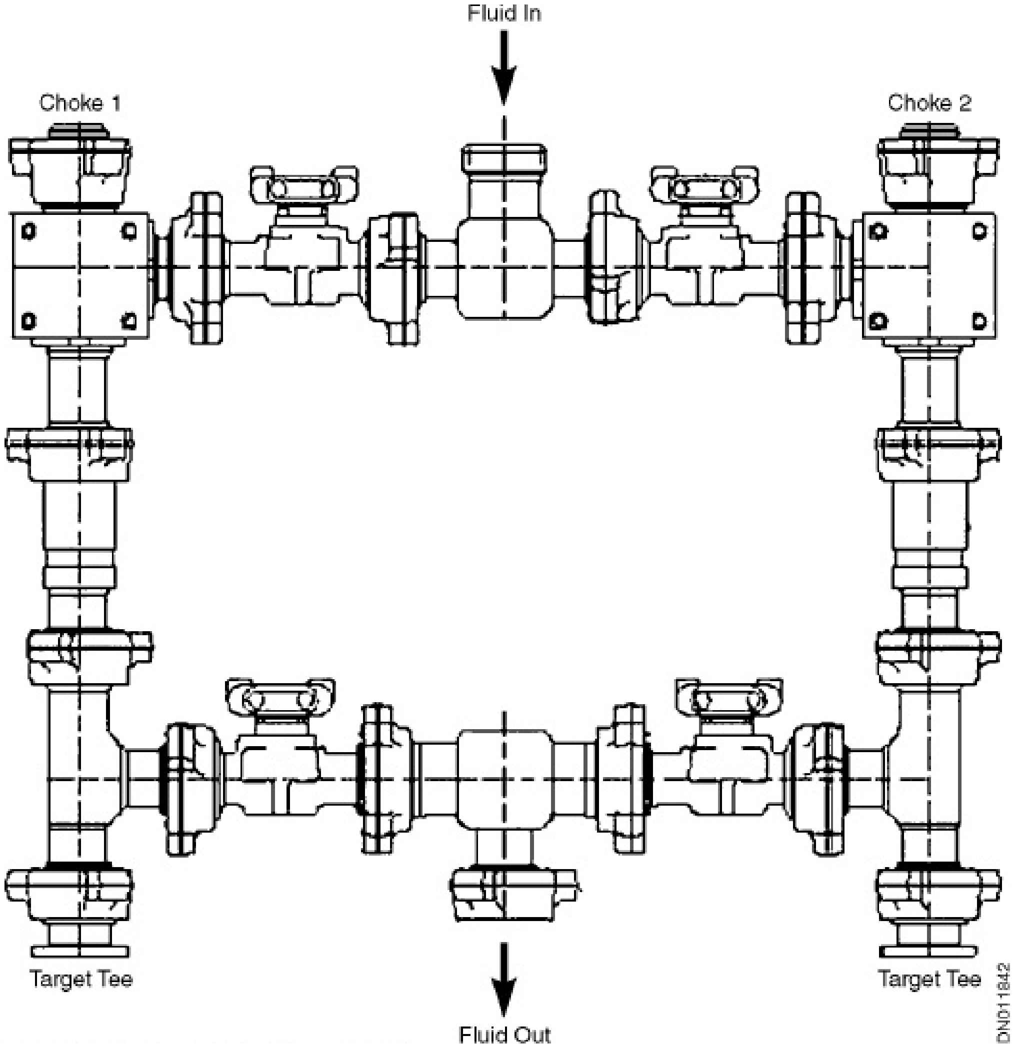


Figure 6.4—Four-valve choke manifold configuration.

1. Before all pressure testing:
   - Erect warning barriers around the test area and conduct safety meeting.
   - Announce that pressure testing is about to commence.
   - Ensure all non-essential personnel are clear of the test area.
2. Ensure all needle valves with the exception of those to the recorder and pressure gauge are closed.
3. Open all four valves on the manifold.
4. Fully open the adjustable choke.
5. Commence pumping slowly to flush lines and choke manifold.

6. Stop pumping.
7. Close both downstream valves on the manifold.
8. Commence pumping slowly to test pressure. Visually inspect all connections for signs of leaks.

Note	Report leaks immediately. Do NOT attempt any remedial action while pressure is applied.

9. Once at test pressure, isolate the pump (if possible) and monitor for the test period.
10. Bleed pressure via the pump vent to zero.
11. Close both upstream valves on the manifold.
12. Open both downstream valves on the manifold.
13. Commence pumping slowly to test the pressure. Visually inspect all connections for signs of leaks.
14. Once at test pressure, isolate the pump (if possible) and monitor for the test period.
15. Bleed pressure via the pump vent to zero.
16. Open both upstream valves on the manifold.

Recommended Procedure for the 5 Valve (Bypass) Configuration

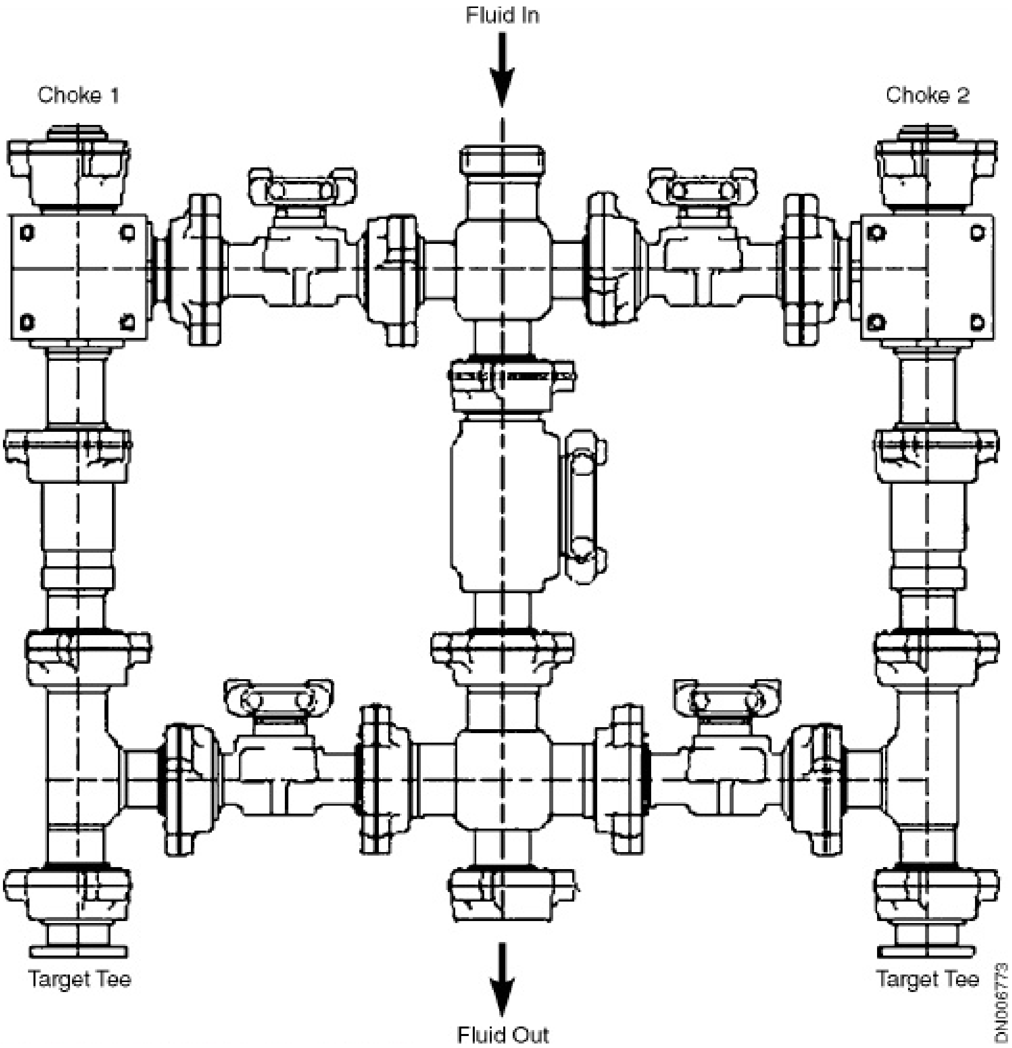


Figure 6.5—Single valves not used for high-pressure rig-ups.

1. Before all pressure testing:
   a. Erect warning barriers around the test area and conduct safety meeting.
   b. Announce that pressure testing is about to commence.
   c. Ensure that all non-essential personnel are clear of the test area.
2. Ensure that all needle valves (with the exception of those to the recorder and pressure gauge) are closed.
3. Open all five valves on the manifold.

4. Fully open the adjustable choke.
5. Commence pumping slowly to flush the lines and choke manifold.
6. Stop pumping.
7. Close both the downstream valves and the bypass valve on the manifold.
8. Commence pumping slowly to test the pressure. Visually inspect all connections for signs of leaks.

   Note — Report leaks immediately. Do NOT attempt any remedial action while pressure is applied.

9. Once at test pressure, isolate the pump (if possible) and monitor for the test period.
10. Bleed pressure via the pump vent to zero.
11. Close both upstream valves on the manifold.
12. Open both downstream valves on the manifold.
13. Commence pumping slowly to test the pressure. Visually inspect all connections for signs of leaks.
14. Once at the test pressure, isolate the pump (if possible) and monitor for the test period.
15. Bleed pressure via the pump vent to zero.
16. Open both the upstream valves and the bypass valve on the manifold.

Valve repairs and maintenance undertaken at this point should follow recommended maintenance procedures.

General Operating Guidelines for Chokes

Manipulations of the chokes should be done in conjunction with the company representative. It is essential that perfect understanding and communication exist between the choke operator, customer, and CT supervisor in charge.

NV*	*Never flow through the manifold without either the adjustable choke seat or fixed choke bean in place to protect the body threads.*

**No variance. Rule/process must be strictly followed.*

- Both upstream valves are closed.
- Both downstream valves are open.
- Close bypass valve, if installed.
- Sample point needle valves are closed.
- Needle valve to downstream gauge is open.
- Adjustable choke is set off zero.
- Positive choke installed (choice dependent on well performance).

On initial opening, a low adjustable choke size may be selected. The upstream valve is then opened and the well flowed through the adjustable side. The downstream pressure, if applicable, is carefully monitored to ensure the working pressure of the downstream configuration is not exceeded. The adjustable choke size is then manipulated up or down depending on well response. Well effluent samples can be taken during this period. It is good practice to take these samples at a point directly in the flow path (in this case, from the adjustable side sampling point). Samples should be taken throughout the flowing periods and results recorded.

Installing a Positive Choke

For accuracy of results, it is a good practice to flow the well once cleanup is achieved on a positive choke. The choice of positive choke bean will be predetermined by the adjustable choke size.

The procedure for installation of a positive choke bean is as follows:

1. Ensure that the upstream and downstream valves on the positive choke side are closed.
2. Bleed pressure to zero via the bleed valve at the downstream side of the manifold. Avoid discharge of well effluent onto floor or work area because this may present a safety hazard.
3. Leaving the bleed line open, break out and remove the wingnut.
4. Install the choke bean as per the manufacturer’s recommended procedure.
5. Replace and make up wingnut.
6. Close the bleed needle valve.

The choke bean is now installed on the positive side. The flow path must now be switched from the adjustable to the positive side.

Note	Two operators may be required.

The procedure is as follows:

1. Open the downstream valve on the positive side.
2. Begin to slowly close upstream valve on the adjustable side while simultaneously and slowly opening the upstream positive side valve. Observe the downstream pressure gauge.

Note	It is essential that the working pressure of the downstream configuration not be exceeded.

3. Generally, a pressure "kick" is observed on the downstream gauge, indicating flow through both sides of the choke. At that point, smoothly close the upstream adjustable valve while opening the upstream positive valve.

The adjustable side may be isolated at this point, pressure bled off, and the adjustable choke removed, cleaned, and inspected.

- Never flow through the manifold without either the adjustable choke seat or fixed choke bean in place to protect the body threads.
- Rented equipment or third party service providers should meet the minimum standards and should be involved in the planning process of the job so that the correct equipment is delivered to location.

Pressure Test Requirements for All Pressure Control Equipment

NV*	*The test pressure shall not exceed the manufacturer's rated working pressure for the specified assembly. Rated test pressure is a factory test of the product and shall not be used as the working pressure.*

**No variance. Rule/process must be strictly followed.*

Note: Pressure tests conducted with nitrogen require special procedures for testing and bleed off of test pressure. If a suitable fluid is available, it should be used for pressure tests rather than nitrogen.

1. These test requirements cover all pressure control stack, pumping lines, flowback lines, and manifolds. Function tests are required on all pressure containing equipment every time the hydraulic lines are connected and every time the equipment is rigged up on location.
2. All well control equipment components shall be pressure tested. The pressure test sequence consists of a low pressure test, followed by a high pressure test. The pressure test fluid should be water or some other nonflammable solids free liquid.
   - *Low Pressure Test*—Well control components should be subjected to a low pressure test (200 to 300 psi). The pressure should be maintained at stabilized pressure with no departure or visible leakage for at least five (5) minutes.

Note: All low pressure tests should be between 200 and 300 psi. Any initial pressure above 300 psi must be bled back to a pressure between 200 and 300 psi before starting the test. If the initial pressure exceeds 500 psi, the pressure should be bled back to zero and the test re-initiated. Note that a pressure of 500 psi or greater could energize a seal that may continue to hold pressure after bleeding down and, therefore, not be representative of an acceptable low pressure test.

   - *High Pressure Test*—Well control components should be subjected to a pressure equal to the maximum anticipated operating pressure (MAOP) or 1.1 times MASP, whichever is greater, but not to exceed the MAWP (maximum allowable working pressure). The pressure should be maintained at stabilized pressure with no departure or visible leakage for at least ten (10) minutes.

Use proper tools with care when recharging the accumulator with nitrogen and when measuring the precharge pressure. Use the proper accumulator charging kit, available from all accumulator suppliers, to safely recharge the accumulators (charge kit, SAP 100047954, is an acceptable charging device). Use a regulator capable of reducing the gas pressure from 3,000 psi to the approximate precharge pressure in conjunction with the charge kit.

The accumulator package to be used for the BOP operation must be properly sized. The accumulators must have sufficient volume, and the system pressure must be properly set to store sufficient hydraulic power.

The usable volume must be sufficient to close all rams. The minimum hydraulic pressure should not be less than 2,000 psi and should be high enough to shear the largest diameter, thickest walled coiled tubing currently on the unit at the maximum anticipated shut in pressure.

For all applications, accumulators should be sized to provide the volume needed to close–open–close all actuators at the rated working pressure of the BOP.

Precharging/Prejob Testing

1. All accumulators should be marked with the maximum hydraulic pressure rating.
2. Inspect all accumulators for the proper nitrogen charge. Accumulators shall be in good working order before operation and during prejob testing.

   The check valve(s) in the accumulator system help prevent backflow to the power pack.

   - The **check valve(s) for the BOP accumulator** are located under the control console panel in the operator enclosure.
   - The **check valve for the gripper system** is attached to the accumulator on the injector frame (this valve is a pilot operated check valve).
3. Vent the fluid end of the accumulator to the tank BEFORE precharging the accumulator (described in Step 4) with nitrogen as follows:

   a. Vent the BOP accumulator by opening the isolation valve located under the accumulator.

   b. Verify that the pressure gauge adjacent to the valve indicates zero pressure.

   c. Vent the gripper accumulator by opening the isolation valve attached to the pilot operated check valve.

   d. Consult the applicable equipment manuals for information on venting accumulators on variable OD gripper circuits.
4. Precharge all accumulators with nitrogen only. Use only approved gas bottles clearly and permanently marked “Nitrogen.” Use a charging kit, such as SAP 100047954, consisting of a high pressure hose, a regulator, a gauge, and a bleed-off valve.

5. Use the following guide to perform nitrogen precharge.
   a. Injector accumulators:
      - *30/38K and V45HP CTUs*—Precharge the accumulator(s) on the injector to 350 psi. Refer to the equipment manual.
      - *60K and V95HP CTUs*—Precharge the accumulator(s) on the injector to 500 psi. Refer to the equipment manual.
      - *Hydra Rig 400 Series*—Charge to 400 psi on the main skates and 80 psi on the tension skates.
      - *Hydra Rig 500 Series*—Charge to 500 psi on the main skates.
      - *Hydra Rig 600 Series*—Charge to 500 psi on the main skates.
      - *All DeepReach™ CT injectors*—Precharge the accumulator(s) on the injector to 500 psi. Refer to the equipment manual.
      - *DeepReach™ CT stripper systems*—Precharge the accumulator(s) on the stripper to 500 psi. Refer to the equipment manual.
   b. BOP accumulators:
      - Precharge the house or console accumulator package to 200 psi less than the minimum pressure needed to close the preventer. Many BOPs require a minimum of 1,200 psi to close against the working pressure. To store energy in the accumulators, the system hydraulic operating pressure must be greater than the pre-charge pressure.

        Example: If the minimum hydraulic pressure is 1,200 psi for the BOP, the nitrogen precharge pressure should be 1,000 psi. The operating system pressure must be increased above 1,000 psi to store energy in the accumulator.
6. For testing bladder type accumulators, be sure to have the proper nitrogen regulator, charging hose kit, test hose kit, and all the necessary tools required to perform these procedures safely and correctly.
7. Bleed off all accumulator pressure and nitrogen pre-charge pressure before replacing any gauges and fittings to prevent danger from trapped pressures.
8. Before transporting the unit, vent the pressure on the hydraulic side of the accumulator.
9. The minimum accumulator size for all BOP control accumulator systems must provide the volume needed to close–open–close all actuators on the circuit with a final hydraulic closing pressure sufficient to hold the preventer sealed at the maximum rated working pressure, or a minimum of 1,200 psi hydraulic pressure. Verify the requirement before each job with a functional test.
10. Determine the proper accumulator size for each job.

usable volume (UV) ≡ $(N_{RAMS} \times V_{close}) + (N_{RAMS} \times V_{open}) + (N_{RAMS} \times V_{close})$

$= (4 \times 0.136) + (4 \times 0.120) + (4 \times 0.136)$

$= 1.268$ gal

- Min. hyd. operating pressure = 10,000 psi W.P./9
  HP = 1,111 psi (use 1,200 psi because it is larger)
- Nitrogen precharge = HP   200 psi
  NP = 1,200   200 psi
  NP = 1,000 psi
- Select system pressure = 2,000 psi
  SP = 2,000 psi

Calculate the required accumulator volume.

$$AV = \frac{UV}{\frac{NP}{HP} - \frac{NP}{SP}} = \frac{1.268}{\frac{1000}{1200} - \frac{1000}{2000}}$$

AV = 3.807 gal

API BOP Accumulator Volume Calculation

Volumetric Capacity Calculations

The following is an example of how volumetric capacity of the well control accumulator system may be calculated.

Accumulator Volume

The volume of usable hydraulic fluid (V_{use}) per accumulator is the difference between the calculated volume of compressed nitrogen at 200 psig above the precharge pressure ($V_{@p}$) and its maximum compressed volume after hydraulic fluid has been pumped into the accumulator ($V_{@max}$). $V_{@p}$ is equivalent to the volume of a single accumulator. The total usable hydraulic fluid volume (V_{totuse}) is equal to the usable hydraulic fluid capacity (V_{use}) per accumulator multiplied by the number of accumulators (N_A) in the hydraulic system.

$V_{use} = V_{@p+200} - V_{@max}$

$V_{totuse} = V_{use} \times N_A$

The total usable hydraulic fluid capacity (V_{totuse}) shall be greater than or equal to the minimum volume of hydraulic fluid needed to perform the well control stack close-open-close operating cycles desired and have 200 psig above precharge remaining in the accumulator system.

The volume of fluid needed to operate each individual set of rams (close and open) is a function of the ram piston area, the piston rod area and the stroke length of the ram. Once these volumes are determined, the total volume of hydraulic fluid needed for a close-open-close operating sequence (V_{COC}) on a multi-ram stack can be determined using the following equation.

$$V_{COC} = 2(V_{close\ Slips} + V_{close\ pipe} + V_{close\ shears} + V_{close\ blind}, \ldots) +$$

$$(V_{open\ slips} + V_{open\ pipes} + V_{open\ shears} + V_{open\ blind}, \ldots)$$

Once the minimum volume needed for actuating the multi-ram stack through the close-open-close sequence has been determined, the minimum required accumulator bank volume (V_{acc}) may be found using the following equation.

$$V_{acc} = \frac{V_{COC}}{\rho_{@P_p}\left(\frac{1}{(\rho_{@P_{p+200}})} - \frac{1}{\rho_{@P_{max}}}\right)}$$

Where:

$\rho_{@P_p}$ = nitrogen density at pre-charge pressure and temperature

$\rho_{@P_{p+200}}$ = nitrogen density at the precharge pressure plus 200 psi and minimum operating temperature or the pre-charge temperature, whichever is the least

$\rho_{@P_{max}}$ = nitrogen density at the minimum charged accumulator system pressure and maximum operating temperature

The density of nitrogen for the various pressures at the temperature of interest can be found in the NIST gas table data (http://webbook.nist.gov/chemistry/fluid).

Once the minimum accumulator volume has been determined, the number of accumulators in the accumulator bank, N_A should be selected such that

$$N_A \times V_{@p} = V_{acc}$$

Accumulator Pressures

The variable (P_p) is the pre-charge pressure of the nitrogen in the accumulator prior to filling with hydraulic fluid. $P_{charged}$ is the minimum accumulator bank pressure needed to perform the specified ram functions and effectively shear the coiled tubing. P_{crit} is the hydraulic system pressure needed to shear the coiled tubing and is dependent upon the size of the coiled tubing, wall thickness, material grade, type of rams and the wellbore pressure within the well control stack.

For onsite operations, the stabilized accumulator system pressure reading of record (P_{max}) shall be obtained 30 minutes after initial pressurization (to allow the accumulator bank to reach thermal equilibrium).

Minimum Accumulator Volume Example Calculations

A well control stack system needs a volume of 10.715 gallons to perform the requisite close-open-close functions of all ram components. A nitrogen pre-charge of 1,200 psig will be applied to the accumulators and the minimum planned charge pressure is 2,950 psig. The pre-charge will be performed at a temperature of 70°F, which is also the minimum anticipated operating temperature. The maximum anticipated operating temperature is 100°F.

From the NIST gas table data (http://webbook.nist.gov/chemistry/fluid):

Density of Nitrogen at 1,200 psig and 70°F: 5.9996 lbm/ft^3 = $\rho_{@P_p}$

Density of Nitrogen at 1,400 psig and 70°F: 6.9659 lbm/ft^3 = $\rho_{@P_{p+200}}$

Density of Nitrogen at 2,950 psig and 100°F: 12.959 lbm/ft^3 = $\rho_{@P_{max}}$

And V_{coc} is given as 10.715 gallons

Substituting into the previous equation gives

$$V_{acc} = \frac{10.715}{5.9996\left(\frac{1}{6.9659} - \frac{1}{12.959}\right)} = 26.90 \text{ gallons}$$

which is the minimum accumulator bank volume required to ensure a close-open-close sequence can be effected at the anticipated conditions and have 200 psi remaining in the accumulator bank. For an accumulator bank using 10 gallon accumulators, then N_A will be 3 or greater to meet or exceed the calculated value of V_{acc}.

Minimum Operating Pressure Example Calculation

The volume required to close the slip, pipe and shear rams is 1.45 gallons.
The hydraulic pressure required to shear the coiled tubing size and grade for the prescribed service at atmospheric pressure was observed to be 1,800 psig. The maximum anticipated surface pressure (MASP) for the given well was determined to be 6,125 psig and the closing ratio of the shear ram was found to be 12.25. Using the equation given previously, the value for P_{crit} was found to be 2,300 psig.

P_{crit} = 1,800 psig + (6,125 psig / 12.25) = 2,300 psig

With a minimum required pressure of 2,300 psig to shear the coiled tube (P_{crit}) at MASP and a volume of 1.45 gallons to close the slip, pipe, and shear rams, the minimum operating pressure in the accumulator system may be found.

From the NIST gas table data (http://webbook.nist.gov/chemistry/fluid):

Density of Nitrogen at 2,300 psig and 70°F: 11.104 lbm/ft^3 = $\rho_{@P_{crit}}$

$$\rho_{@P_{max}} = \frac{1}{\left(\frac{1}{11.104} - \frac{1}{5.9996}\left(\frac{1.45}{10 \times 3}\right)\right)} = 12.186 \text{ lb/ft}^3$$

From the data reference, the pressure required for the nitrogen to have a density of 12.186 lbm/ft^3 at 70°F is 2,764.7 psia, which is the minimum recommended hydraulic pressure the accumulator bank should be operated at to ensure that there is sufficient pressure available to shear the coiled tube at MASP.

Section

7

CT Well Control Equipment and Test Procedures

Introduction

The blowout preventer (BOP), stripper/packer, riser, and lubricator used on coiled tubing units are critical pressure containing, hydraulically operated, wellhead control equipment. Use proper rig up procedures for safe and reliable operation of the coiled tubing unit.

General Information

The primary function of the coiled tubing BOP and stripper are to maintain control of the well at all times. The coiled tubing BOP and stripper shall be properly maintained and kept in a state of operational readiness. This is verified by functional testing and pressure testing before the start of the job.

Coiled tubing BOPs and stuffing boxes are designed and manufactured by a number of suppliers but are mainly supplied by Texas Oil Tools (TOT). Although they differ in details, all BOPs and strippers basically operate on the same design principle.

Standard coiled tubing BOPs are monoblock, quad type with four sets of ram operators. Each set of rams functions independently of the others by manual selection of hydraulic controls at the operator's console. The BOPs are available in 5,000-, 10,000-, and 15,000-psi working pressure ratings. The working pressure of the BOP is determined by body design and the lower connection rating.

BOPs can also have a secondary function of connecting and deploying long tool strings in situations where the lubricator is too short to accommodate the entire toolstring. BOPs used for tool deployments are not considered pressure control components and must be used in addition to the necessary BOPs.

All pressure control equipment shall be suitable for the environment (H_2S, temperature, etc.) being worked in (i.e., elastomers, stripper packers, ring gaskets, etc.).

Well Control Equipment

Coiled tubing well control equipment is designed to allow performance of safe well intervention services under pressure. However, well pressure should be kept at a minimum to avoid unnecessary wear and tear on well control equipment. All well control equipment shall be manufactured in accordance with API Specs. 6A and 16A. The selection of well control equipment for a given application should be consistent with the manufacturer's recommendations.

Selection of the correct pressure control equipment based on the environment and well conditions is important and should be based on the specifications in Table 7.1 (Page 7-15).

NV*	H_2S certified equipment must be used when working on any well that contains H_2S. Make sure all valves and BOP parts are H_2S certified.

**No variance. Rule/process must be strictly followed.*

Note — The high hardness required for any BOP shear ram blades makes them very susceptible to sulfide stress cracking (SSC) in an H_2S environment. For this reason, the condition of the blades should be checked after working in an H_2S environment.

Well Control Components

Stripper/Annular Type Devices

The stripper, or annular component, is a pressure containing device designed to isolate well pressure and effluents from the atmosphere during coiled tubing operations. Its purpose is to seal around the coiled tubing in both static and dynamic applications.

Pressure Sealing Rams (Blind and Pipe)

Blind rams (Figure 7.1) are designed to isolate pressure and shut the well in when the bore of the ram is unobstructed.

Blind rams are normally the top ram well control component in the standard well control stack configuration.

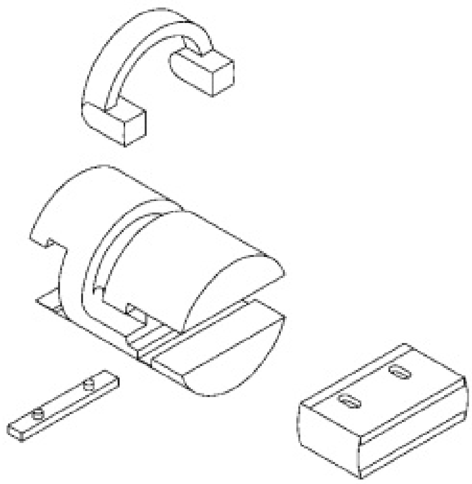


Figure 7.1—Blind ram

Pipe rams (Figure 7.2) are designed to isolate annulus pressure around the coiled tubing OD and should have coiled tubing guides to center the tubing in the well control stack bore. Pipe rams are normally the bottom ram well control component in the standard well control stack configuration.

Pipe rams should be designed to hold at least the kill pressure margin differential pressure from above the ram.

Note	For the differential pressure seal from above the ram, a bubble tight seal is not required and some percentage of leakage may be acceptable.

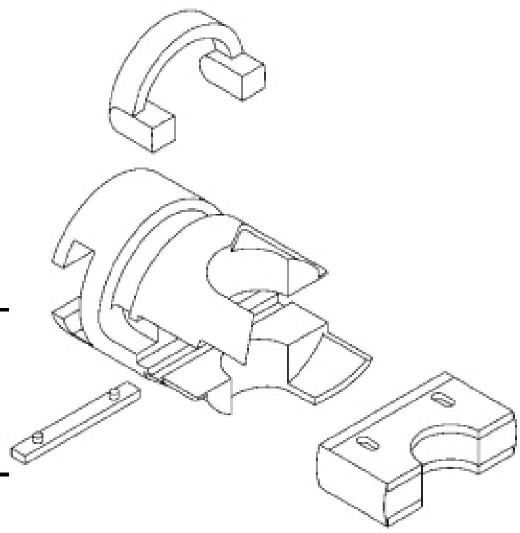


Figure 7.2—Pipe ram

Shear/Blind Combination Rams

Shear/blind combination rams (Figure 7.5) incorporate two ram functions into a single well control ram component. The shear/blind rams shall be capable of shearing the coiled tubing body (and any spoolable components inside the tubing) at the MASP of the well without tensile loads applied to the tubing. The shear/blind rams should be capable of isolating the wellbore without requiring movement of the coiled tubing. The shear/blind rams should be sized for the coiled tubing being used.

The shear/blind rams should be capable of two or more shear and seal operations. The cut should facilitate subsequent through tubing pumping and well killing operations. The geometry of the shear cut should also enable fishing operations.

Shear/blind rams should be capable of shearing the coiled tubing when the tubing is secured within a slip or pipe/slip ram.The closing pressure required to shear the coiled tubing and seal the wellbore at the MASP of the well shall be less than the stabilized pressure of the well control accumulator operating system.

The shear/blind ram blade and required components should be replaced after each coiled tubing shearing operation as soon as practically possible.

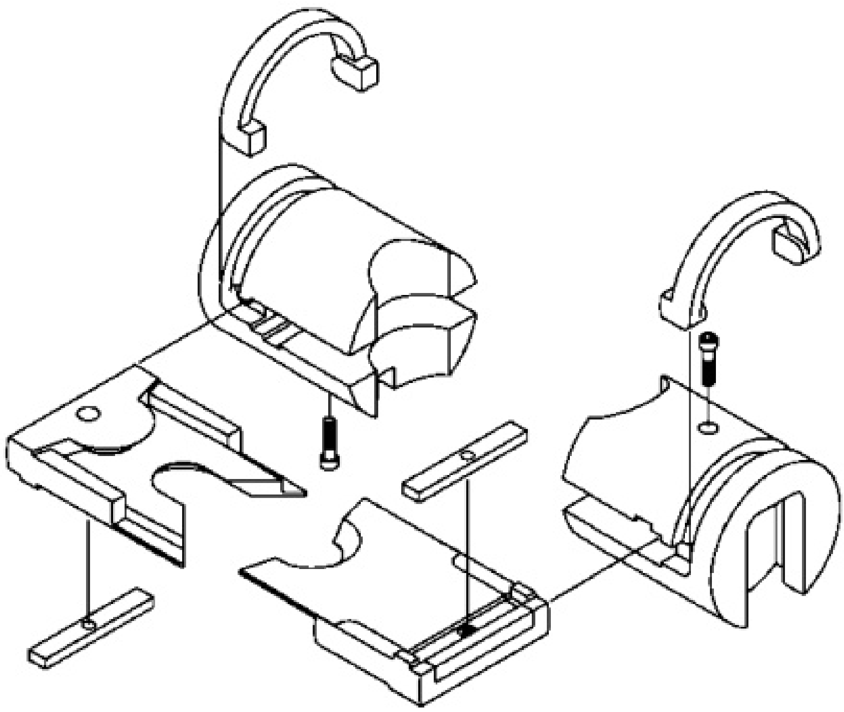


Figure 7.5—Shear/blind ram

Pipe/Slip Combination Rams

Pipe/slip combination rams (Figure 7.6) incorporate two ram functions into a single well control ram component, holding the coiled tubing and isolating pressure in the coiled tubing by wellbore annulus.

The pipe/slip rams shall be sized for the coiled tubing being used and shall be configured with coiled tubing guides to center the tubing in the well control stack bore. The pipe/slip rams shall be capable of sealing the annulus while holding the maximum anticipated hanging weight of the coiled tubing. In addition, the pipe/slip rams shall be capable of sealing the annulus while holding the coiled tubing in the pipe light condition to the force equal to the MASP multiplied by the cross sectional area of the tube.

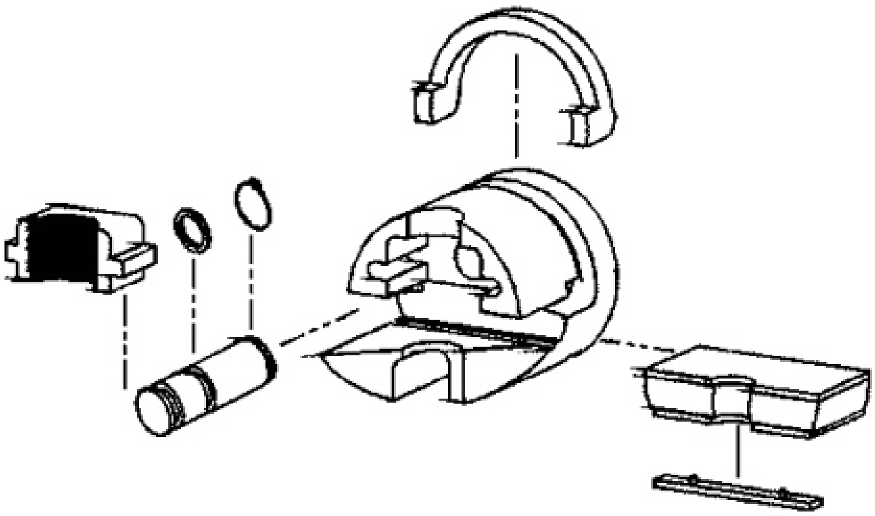


Figure 7.6—Pipe/slip ram

Pipe/slip rams should be designed to hold at least the kill pressure margin differential pressure from above the ram.

Note	For the differential pressure seal above the ram, a bubble tight seal is not required and some percentage of leakage may be acceptable.

The closing pressure required to hold the coiled tubing and seal the annulus at the MASP of the well shall be less than the stabilized pressure of the well control accumulator operating system.

Ram type well control equipment shall provide a visual means to determine the ram position for each ram component (as open or closed).

Kill Line Inlet

The kill line inlet shall be a flanged connection sized for at least a 2 in. nominal flange and a working pressure rating at least equivalent to the well control ram body. The location of the kill line inlet is normally between the shear ram and slip rams in the standard well control stack configuration.

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

Flow Cross or Flow Tee

The flow cross or flow tee is typically located below the standard well control stack configuration (Figure 7.7). If a flow cross or flow tee is installed, the flanged cross or tee shall be in compliance with API Spec. 6A and/or API Spec. 16A.

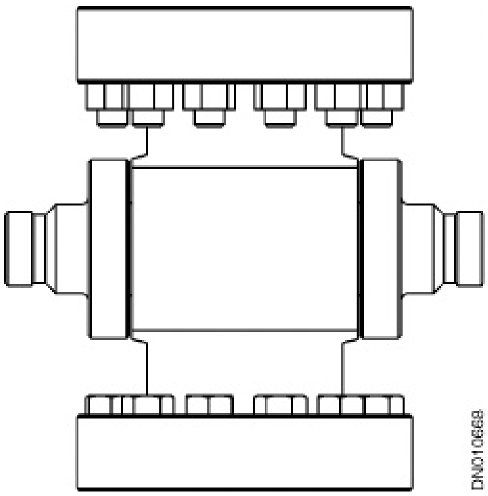


Figure 7.7—Flow cross

Strippers

Positioned at the top of the pressure control stack is the stripper (either single or multiple elements), which allows movement of the coiled tubing while keeping the well pressure contained. The five types of strippers are convetional top loader, side door, two-door side door, sidewinder, and over/under. Three of these are illustrated in Figure 7.12.

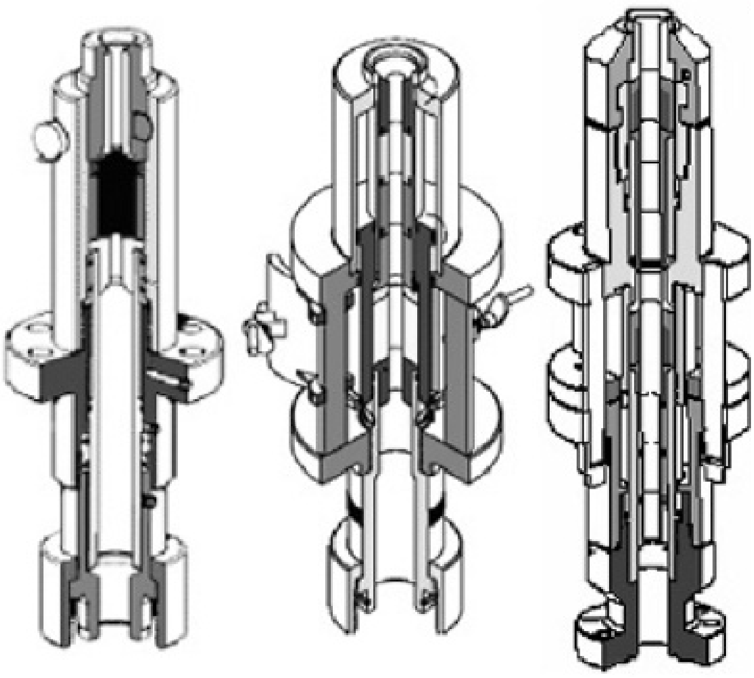


Figure 7.12—Three types of stripper: (from left) conventional top loader, the side door, and the over/under

Hydraulic Quick Latches/Connectors

Type JU Hydraconn Connector Unions

- Design facilitates a secure connection between the coiled tubing BOP and stripper packer, providing an elevated level of personal safety by minimizing the need for operator assistance during rig up of the pressure control stack
- Constructed to provide a safe and reliable connection in a compact, rugged design
- Incorporates a tapered seal bore that facilitates stabbing the connection
- Safety latch with a manual override and an indicator included to prevent an unintentional release while operating with well pressure in the stack
- Available in 3.06-, 4.06-, 5.12-, 6 3/8-, and 7.06-in. sizes in pressure ranges 5,000, 10,000 and 15,000 psi

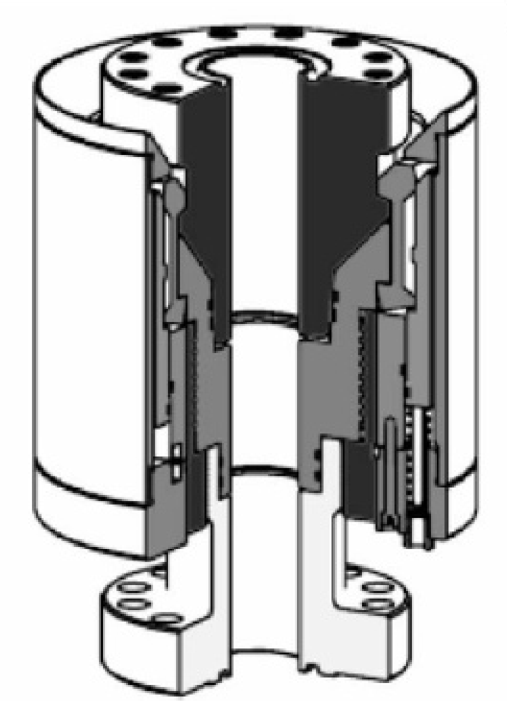


Figure 7.13—Type JU Hydraconn connector union

Spacer Spools, Adapter Spools, and Lubricators

Spacer spools, adapter spools, and lubricators may be used when bottomhole assemblies are too long to be contained within the well control stack or when the work environment necessitates spacing out the well control equipment. The spacer spools, adapter spools, and lubricators shall meet or exceed all requirements stipulated in API RP 16ST.

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

- Compression loads generated by the weight of the injector and well control equipment on top of the assembly plus axial tensile loads resulting from the coiled tubing suspended in the well.
- Bending loads generated by the reel back tension, dynamic motion, and wind loads.
- Loads due to internal pressure.

External support (e.g., guy wires, crane, support structure) shall be used to reduce the bending and transmitted loads from the equipment onto the connections.

When bottomhole assemblies are too long to be contained within the well control stack, alternative deployment methods or processes meeting the barrier requirements of API RP 16ST may be used. Alternative methods may include use of deployment bars, remotely actuated connectors, etc.

Maximum Anticipated Surface Pressure (MASP)

The maximum anticipated surface pressure (MASP) is the highest pressure predicted to be encountered at the surface of a well. This pressure prediction should be based on:

- Formation pressure minus a wellbore filled with native formation fluid at current conditions

If formation fluid information is unknown, this pressure prediction should be based on:

- Formation pressure minus a wellbore filled with dry gas from the surface to the completion interval

Maximum Anticipated Operating Pressure (MAOP)

The maximum anticipated operating pressure (MAOP) for a given piece of equipment is the highest calculated pressure that a given piece of equipment will be subjected to during the execution of the prescribed service and/or during a contingency operation.

Well Control Barriers

A coiled tubing well control barrier is defined as a tested mechanical device, or combination of tested mechanical devices, capable of preventing uncontrolled flow of wellbore effluents to the surface. Tested barrier(s) should be incorporated in the well control stack and bottomhole assembly (BHA) for the prescribed service, except when it is planned to take returns through the coiled tubing, in which case, the tested barrier(s) should be located within the well control stack.

The following mechanical devices, or combination of mechanical devices, are coiled tubing well control barriers:

- The combination of an annular sealing component, or pipe ram sealing component, and a flow-check assembly installed within the coiled tubing BHA.
- A single blind ram and single shear ram.
- The shear/blind combination ram.

The difference between the MASP and minimum stack pressure rating is a recommended pressure margin for pumping kill weight fluid through a string of coiled tubing cut and suspended in the well control stack. The kill pressure margin accounts for frictional pressure losses when conducting a circulation kill program. The user may apply a different kill margin, provided calculations are performed for the pumped fluid kill program. These calculations should include the coiled tubing string design, wellbore geometry, kill and resident fluid rheological properties, kill pump rate, and other variables that affect frictional pressure losses within the system.

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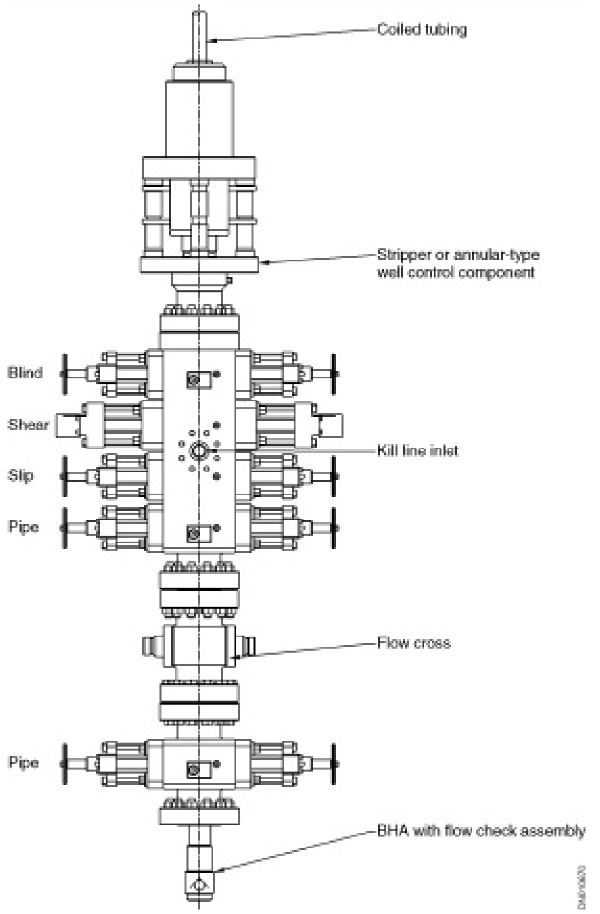

Figure 7.15—Well control stack components for PC 0 conditions. Returns taken through outlet in the well control stack.

Pressure Category 1 (1–1,500 psi MASP)

For PC 1, the well control components should be installed (from top down) as described below:

Returns not taken through an outlet in the well control stack:

- Standard quad BOP configuration with a dual flow-check device installed within the coiled tubing BHA.

Returns taken through an outlet in the well control stack:

- Standard quad BOP configuration with a dual flow-check device installed within the coiled tubing BHA.

- One flow tee or flow cross.
- One pipe ram or annular well control component.

Where a flow-check assembly cannot be used due to job design considerations, one shear/blind combination ram well control component can be installed to provide the necessary additional barrier component.

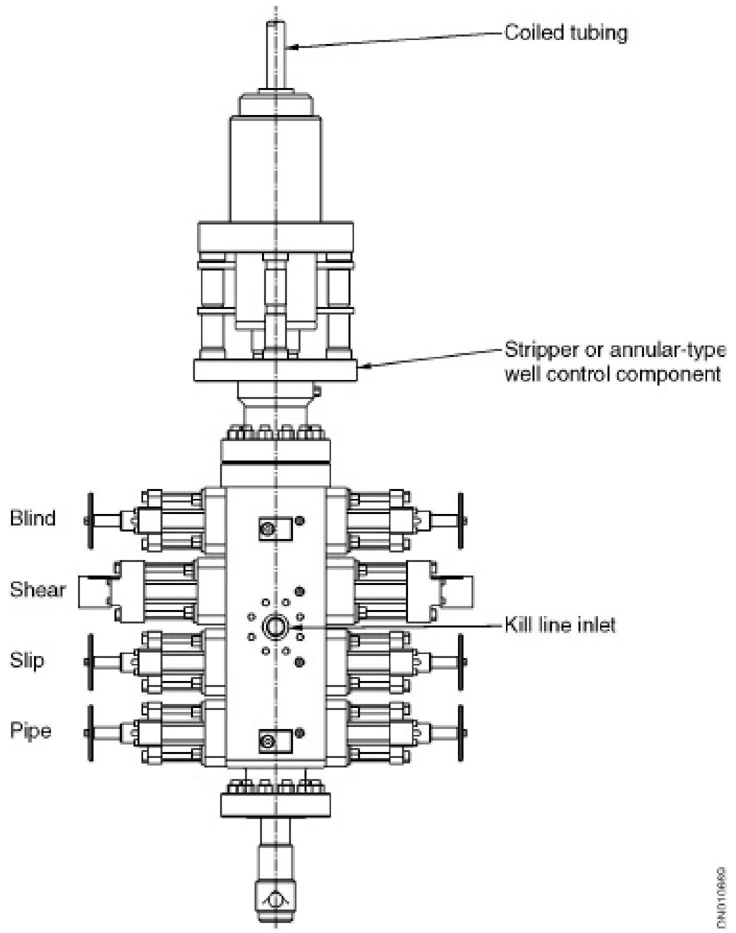

Figure 7.16—Well control stack components for PC 1 conditions. Returns not taken through the outlet in the well control stack.

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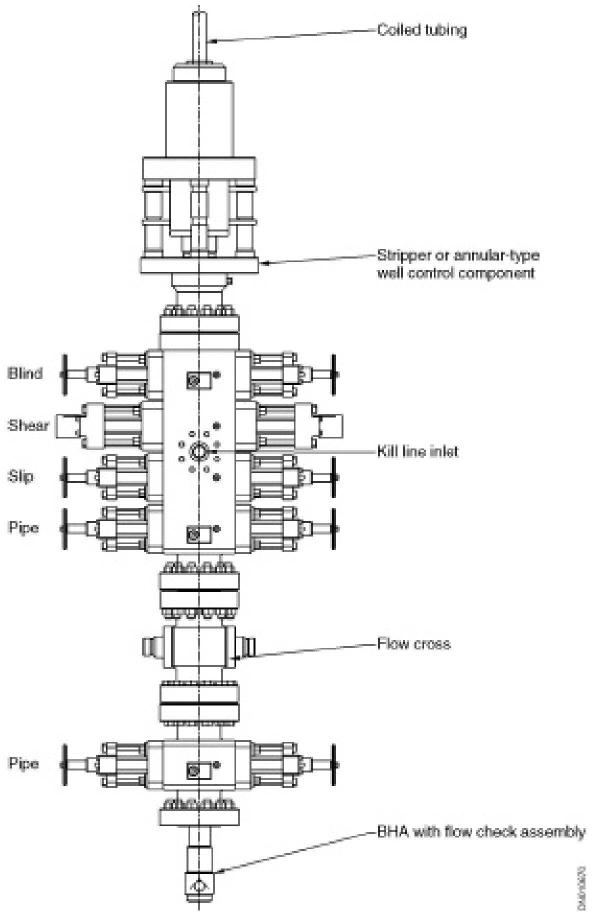


Figure 7.17—Well control stack components for PC 1 conditions. Returns taken through outlet in the well control stack.

Pressure Category 2 (1,501–3,500 psi MASP)

For PC 2, the well control components should be installed (from top down) as described below:

Returns not taken through an outlet in the well control stack:

- Standard quad BOP configuration with a dual flow-check device installed within the coiled tubing BHA.

Returns taken through an outlet in the well control stack:

- Standard quad BOP configuration with a dual flow-check device installed within the coiled tubing BHA.
- One flow tee or flow cross.
- One pipe ram or annular well control component.

Where a flow-check assembly cannot be used due to job design considerations, one shear/blind combination ram well control component can be installed to provide the necessary additional barrier component.

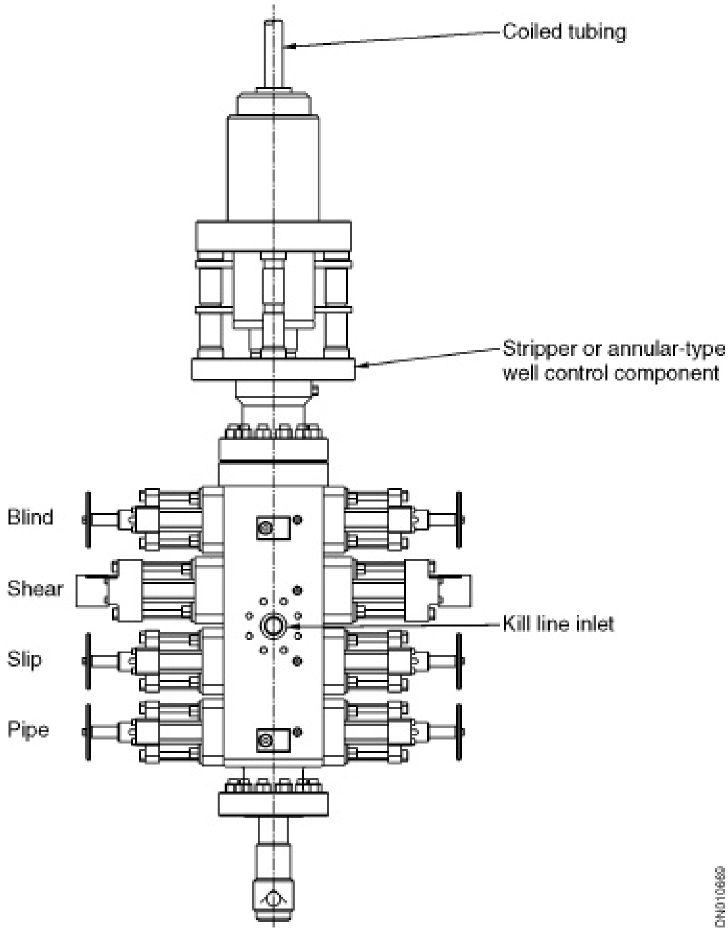


Figure 7.18—Well control stack components for PC 2 conditions. Returns not taken through the outlet in the well control stack.

- Standard quad BOP configuration with a dual flow-check device installed within the coiled tubing BHA.
- One flow tee or flow cross.
- One pipe ram well control component.
- A shear/blind ram.

Where a flow-check assembly cannot be used due to job design considerations, the shear/blind ram may serve as the second barrier.

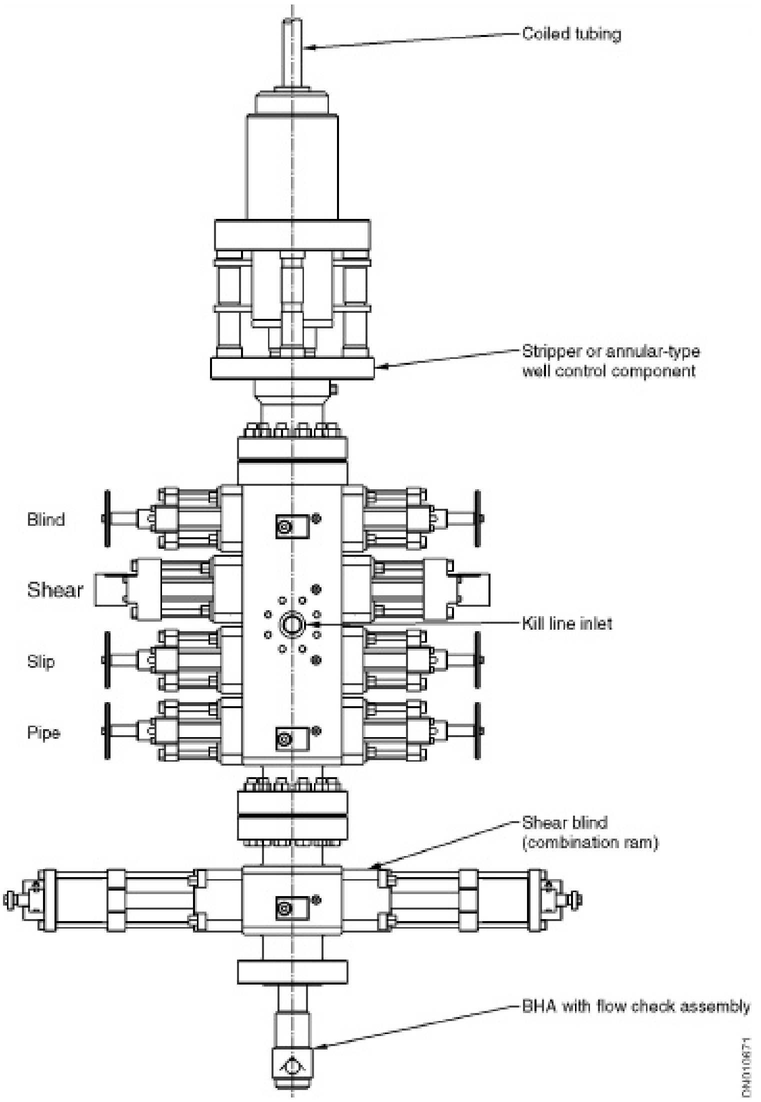


Figure 7.20—Well control stack components for PC 3 conditions. Returns not taken through the outlet in the well control stack.

Bore Size, Working Pressure Rating, and Connections of Well Control Equipment

The bore of well control stack components (with the exception of the stripper assembly) should be greater than the maximum predicted width of collapsed coiled tubing.

A method used to predict the width of a plastically collapsed tube is as follows:

$$WCOL = 0.95\ [D + 0.5708D\ (1 - 2t/D)]$$

where:

WCOL = predicted collapse width of coiled tubing body (inches)

D = outside diameter of coiled tubing body (inches)

t = wall thickness of coiled tubing body (inches)

Table 7.2—Example Collapse Width Predictions and Minimum Stack Bore Sizes for CT

CT Size (OD × Wall)	D/t Ratio	Predicted Collapse Width (in.)	Minimum Bore Size (in.)
1.250 in. × 0.087 in.	14.4	1.771	2 9/16
1.500 in. × 0.095 in.	15.8	2.135	2 9/16
1.750 in. × 0.109 in.	16.1	2.493	2 9/16
2.000 in. × 0.125 in.	16.0	2.849	3 1/16
2.375 in. × 0.145 in.	16.4	3.399	4 1/16
2.875 in. × 0.156 in.	16.4	4.100	5 1/8
3.500 in. × 0.203 in.	17.2	5.013	5 1/8

For a given coiled tubing string OD size, the predicted collapse width increases when the wall thickness decreases.

In cases where the bore of well tubulars could deter the removal of collapsed coiled tubing, contingency plans should be in place.

Connections

Connections in the well control stack shall conform to API Spec. 6A and/or API Spec. 16A. Flanges, hub connections, or other non-threaded end connectors may be used.

External support (e.g., guy wires, crane, support structure) should be used to reduce the bending and transmitted loads from the equipment onto the connections.

- **PC 0—**All connections should have a minimum pressure rating of 3,000 psi.
- **PC 1**—All connections from the tree to the uppermost required ram component in the well control stack configuration should be flanged and should have a minimum pressure rating of 3,000 psi. Flanged or other connection types used above the uppermost ram component should have a minimum pressure rating of 3,000 psi. Where surface wellhead and tree construction prevents use of a flange connection, an installation plan for use of other end connectors should be available and reviewed by the user and service vendor personnel involved in the well intervention operation. For tree construction with a threaded connection only, the threaded connection should meet the minimum pressure rating of 3,000 psi and should be restricted to the connection between the tree and well control stack.
- **PC 2**—All connections from the tree to the uppermost required ram component in the well control stack configuration should be flanged with a minimum pressure rating of 5,000 psi. Flanged or other connection types used above the uppermost ram component should have a minimum pressure rating of 5,000 psi. Where surface wellhead and tree construction prevents use of a flange connection, an installation plan for use of other end connectors should be available and reviewed by the user and service vendor personnel involved in the well intervention operation. For tree construction with a threaded connection only, the threaded connection should meet the minimum pressure rating of 5,000 psi and should be restricted to the connection between the tree and well control stack.
- **PC 3**—All connections from the tree to the uppermost required ram component in the well control stack configuration shall be flanged with a minimum pressure rating of 10,000 psi. Flanged or other connection types used above the uppermost ram component shall have a minimum pressure rating of 10,000 psi.

Note	Other types of connections may be used above the uppermost ram component, provided they conform to requirements stipulated in API Spec. 6A and/or API Spec. 16A.

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

All **studs**, **bolts** and **nuts** used in connection with flanges, clamps, and hubs shall be selected in accordance with the provisions of API Spec. 6A.

Ring gaskets shall meet the requirements of API Spec. 6A. Ring gaskets shall not be reused.

Well Control Equipment for Hydrogen Sulfide Service

All well control equipment inclusive of surface piping, manifolds, valves and fittings exposed to hydrogen sulfide shall comply with the latest version of NACE MR 01 75.

H_2S and Equipment Selection

Table 7.3 defines the limits for what can be defined as sweet service. Above these limits qualifies as sour service and therefore all equipment being used needs to be suitable. Table 7.3 has been calculated using data taken from NACE MR-01-75.

Table 7.3—Sweet Service Criteria

Pressure	Maximum H_2S Concentration
< 1,000 psi (6.89 MPa)	50 ppm
< 3,000 psi (20.68 MPa)	15 ppm
< 5,000 psi (34.47 MPa)	10 ppm
< 10,000 psi (68.95 MPa)	5 ppm
< 15,000 psi (103.42 MPa)	3 ppm

Rig-Up Procedure

1. Before rigging up on the well, perform a visual inspection of the critical components, including the lift harness, the quick union sealing surface, O-ring and groove, and the ring grooves on flanged connections.
2. Before attaching the injector to the BOP, perform a mechanical function test of the BOP to check for damage that may have occurred during transportation to location, such as crushed hydraulic hoses, cracked or damaged bonnets, or broken quick connects. With the hoses hooked up and the power pack running, make a visual inspection for hydraulic leaks.
3. Place all the rams in the open position and check that the indicator pins are in the fully extended outward, or open, position. Visually inspect inside the BOP bore for obstructions that can damage the rams.

   a. The supervisor in charge should have an assistant watch the rams and indicator pins as he closes the No. 1 ram (blinds). The assistant will signal when the rams and indicators are completely in the closed position.

   b. The supervisor in charge will then open the No. 1 rams (blind) and the assistant will signal when the rams and indicator pins have reached the fully extended position.

   c. This sequence should be repeated for the No. 2 rams (cutters), No. 3 rams (slips), No. 4 rams (tubing rams), and any additional rams used in a particular rig up.

   d. Visually inspect inside the BOP bore for any obstructions that can damage the coiled tubing.

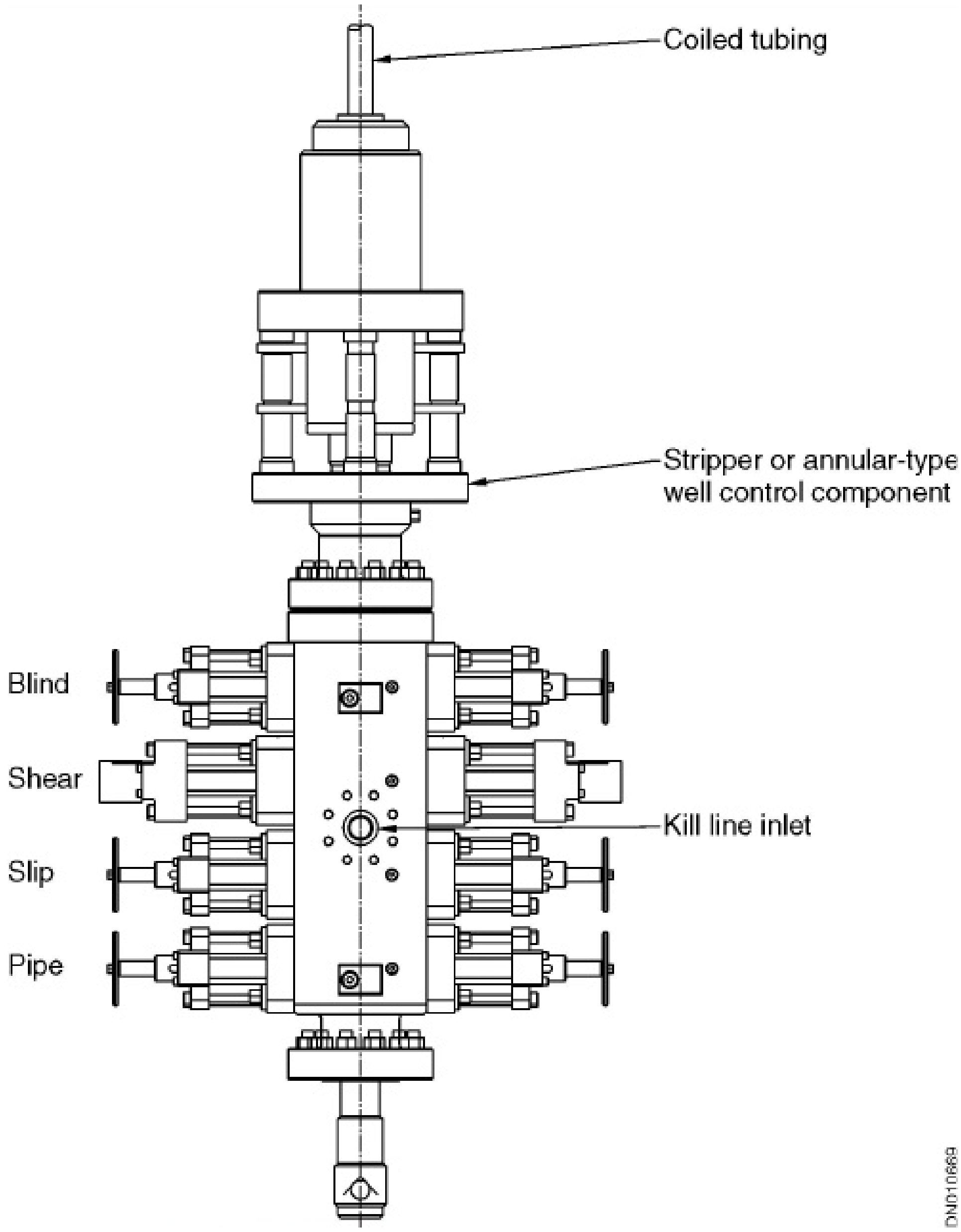


Figure 7.24—For this rig-up, the test pressure may be applied through the side inlet in the BOP

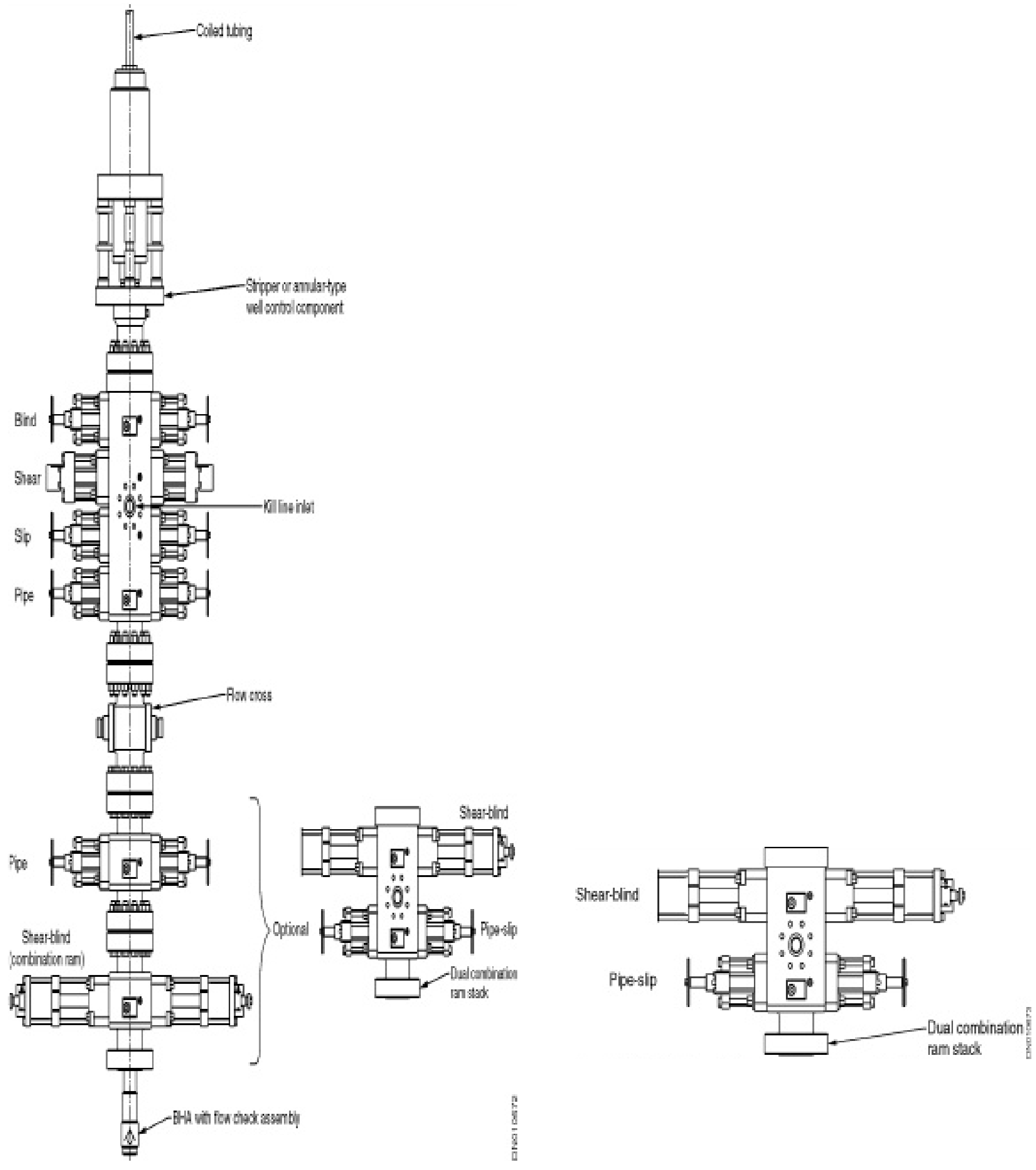


Figure 7.25—Blind/shear ram test. Test pressure is applied through the wing valve on the tree

General Night Operation Procedures

1. The supervisor in charge should review the requirements for the job and determine whether night operations are necessary. This should be considered during job planning, but it may not be predictable before arriving on the jobsite.
2. Prepare for the safety of personnel and equipment.
3. Notify area management, if necessary.
4. Commence the night operations.
5. Suspend the night operations if conditions or job situations become unsafe. Take corrective actions within Halliburton's control.

Lighting

The primary requirement for industrial lighting is: high quality illumination of sufficient quantity to perform the task. Proper lighting conditions will allow employees to perform tasks more effectively, control operations, and operate equipment in a safe manner. The objective is to provide sufficient lighting at all worksites.

Lighting Definitions

- **Candle power** is a measurement of luminous intensity from the light source. It is measured in candelas. A candela is equal to 1 candle power and is the same as 12.57 lumens.
- **Footcandle** (FC) is a standard unit, established as a reference, that is used when measuring quantity of light. It is equal to 1 lumen per square foot or 10.764 lux. A footcandle equals the total intensity of light that falls upon a 1 ft^2 surface placed 1 foot away from a point source of light that equals 1 candle power.
- **Illumination** is the amount of light striking a unit surface.
- **Lumen** is the unit of measurement used to show the rate at which light energy is emitted from a source (luminous flux). Similar to other flow rates such as gallons per minute. A 1 candela source is equal to 12.57 lumens.
- **Lux** is the metric reference for light level. One lux equals the total intensity of light that falls on a 1 m^2 surface placed 1 meter away from a point source of light that equals 1 candle power.
- **Workstation**, within this standard, means any work surface where job tasks are conducted.

These values represent absolute minimum illuminance at any time in locations where safety is related to visibility. However, in some cases, higher levels may be required, such as when security is a factor. A lighting assessment may be required depending on the degree of hazard and level of work activity.

In general, levels of illuminance are determined on the basis of the task to be performed. The IESNA adapted the following guidelines.

- For orientation and simple visual tasks, where visual performance is largely unimportant (e.g., in public spaces or where reading and visual inspection are only done occasionally).
  - Public spaces: 3 FC.
  - Simple orientation for short visits: 5 FC.
  - Working spaces, simple visual tasks performed: 10 FC.
- For common visual tasks, where visual performance is important (e.g., tasks in commercial, industrial, and residential settings where higher lighting levels are needed for tasks with critical elements of low contrast or small size).
  - Visual tasks, high contrast, large size: 30 FC.
  - Visual tasks, high contrast, small size, low contrast, large size: 50 FC.
  - Visual tasks, low contrast, small size: 100 FC.
- For special visual tasks (e.g. where visual performance is of critical importance or may involve very special tasks, including those with very small or very low contrast critical elements, supplementary task lighting is necessary, often requiring moving the light source closer to the task).
  - Performance of visual task near threshold: 300–1,000 FC.

Recommended task related lighting levels for various workplaces within Halliburton operations are listed in Tables 1 and 2 for facilities and field operations (non office environment), respectively, in the guidelines to this standard, which can be accessed at the following site:

http://halworld.corp.halliburton.com/internal/hsesd/pubsdata/standards/standards_cat_eng.htm

Glare

Glare, either direct or reflected, concerns the quality of light. It reduces the efficiency of the eye and may cause discomfort or fatigue. Glare may reduce the detail of the visual task to such an extent as to seriously impair vision, creating a hazard.

In general, glare can be reduced and controlled by different means. Fluorescent tubes and light bulbs can be shielded to reduce brightness. Where possible, indirect lighting can be used. A task, or the person performing the task, can be positioned in such a way as to eliminate glare. For example, a computer screen should always be positioned perpendicular to a window. Paint can also be used to reduce general glare from ceilings and walls in a work area.

Direct Glare Reduction
Direct glare results from a high level of brightness or from unshielded light sources. It can be reduced as follows:

- Decrease the brightness of the light source (reduce wattage).
- Position the light source at a greater distance from the workstation.
- Increase the brightness of the surrounding area.

Reflective Glare Reduction

Reflective glare results from bright sources or from light being reflected from shiny surfaces. It can be controlled as follows:

- Decrease the brightness of the light source.
- Position the light source or the visual task so that the reflection is directed away from the employee.
- Increase the number of light sources to reduce the relative brightness of the glare.
- Use surfaces with matte finishes, when possible.

Classified Areas

Classified areas would include areas where flammable gases, vapors, or combustible dust are or can be expected to be present. Explosion proof lighting must be used in those areas. Explosion proof lighting provides an airtight atmosphere, which does not allow gases, vapors, or dust to come into contact with the heated surface of the light. Lighting levels in classified areas are as follows:

- Class 1, Division 1—Hazardous gas normally present
- Class 1, Division 2—Hazardous gas not normally present
- Class 2, Division 1—Hazardous dust normally present
- Class 2, Division 2—Hazardous dust not normally present
- Class 3, Divisions 1 and 2—Fibers and flyings

Lighting levels in classified areas should be consistent with the required lighting levels specified in

Tables 1 and 2 located in the guidelines to this standard, which can be accessed at the following site:
http://halworld.corp.halliburton.com/internal/hsesd/pubsdata/standards/standards_cat_eng.htm

Means of Egress

In all areas, in the event of a loss of electrical power, a minimum of 5 FC of illumination should be provided for safe emergency evacuation purposes.

Night Operation References

- Illuminating Engineering Society of North America, "Recommended Practice for Lighting Industrial Facilities," ANSI/IESNA RP 7 01, ISBN #0 87995 176 1, 2001.
- National Safety Council, "Fundamentals of Industrial Hygiene," p.311, Lighting.
- April 9, 2004 Revision 1. This is the minimum Halliburton Company Standard. If local, country, or contractual requirements exceed this standard, those requirements must be followed.

http://halworld.corp.halliburton.com/internal/hsesd/pubsdata/standards/standards_cat_eng.htm

Severe Weather Operations

Personnel safety during severe weather conditions is important. To help avoid injury, the following suggestions should be considered.

Coiled tubing units are possible grounding points for lightning during electrical storms. High winds in excess of 35 MPH may become hazardous to personnel during coiled tubing rig up and rig down operations.

Severe Weather Procedures

1. During lightning storms, crews should suspend operations and stay away from the coiled tubing unit. Take covered protection, preferably in a car or truck.

Warning **Trees are not considered safe shelter.**

2. During high winds in excess of 35 MPH, rig up or rig down operations should be suspended until wind speeds subside.
3. Coiled tubing operations should be suspended during severe rain, snow, or sand storms that may obstruct the supervisor's vision of the wellhead, injector, and tubing.
4. Care should be taken in rain or snow conditions that could affect footing on slick surfaces found on well equipment, walkways, trailer decks, and all other surfaces. Climbing should be avoided and ladders used whenever possible to avoid the chance of slipping.
5. When working in extreme heat, i.e., in temperatures greater than 35°C (95°F), or in high humidity, ensure that the crew consumes adequate fluids and takes sufficient rest breaks to avoid heat exhaustion. Surfaces of equipment and tools can become extremely hot.

10. Purge all fluids from the pump and wellhead pressure connections at completion of daily work.
11. Use Martin Decker load cell fluid for hydraulic weight indicator systems. This fluid performs better than automatic transmission fluid or antifreeze.
12. Equipment operated in temperatures below -20°C (-4°F) should have certified cold weather frames. Rig up or rig down operations should be suspended at temperatures below -35°C (-31°F). Job operations below -40°C (-40°F) should be suspended unless auxiliary heating is provided for critical load carrying and pressure containing equipment.

Hot Weather Operations

1. Ensure that the power pack heat exchanger and radiator are in good working condition.
2. Ensure that the engine coolant is at the proper level.
3. Use manufacturer recommended engine oil.
4. Ensure that the hydraulic fluid is at the proper level.
5. Eliminate unnecessary exhaust restrictions.
6. If the engine or hydraulic fluid temperature begins to rise above the maximum level, reduce the injector speed or shift to low range on the injector motor to reduce the heat load in the system. On 30/38 power packs, it may be necessary to vent the B and C pumps.
7. Set the power pack pressure control valves properly. Careless adjustment of these settings may lead to inefficient operation and excessive heat generation.
8. Drain compressed air tanks regularly to avoid excessive condensation fluid buildup; this is a particular problem in hot, humid offshore environments.
9. Power pack and hydraulic cooling is designed for 50°C (120°F) ambient temperature; equipment run in conditions above this temperature will have overheating issues and will require reduced loading.

Personnel Issues in Extreme Weather

Heat Stress Assessment at Fixed Work Locations

A review of all work activities at a fixed location should be performed to determine the potential for elevated heat stress. Factors to consider are expected apparent temperature (from Table 1 in the standard, accessible from the following site:

http://halworld.corp.halliburton.com/internal/hsesd/pubsdata/standards/standards_cat_eng.htm

Other factors to consider include heating and cooling systems in place, how much natural or forced air ventilation is available, exhaust ventilation to remove heat or humidity at the source, radiant heat load from the sun or from work processes, heat producing sources in the work environment, intensity of physical labor, and permeability of clothing (i.e., Tyvek® suits vs. cotton coveralls). The results of this heat stress assessment and any control measures implemented should be documented.

Thermal Stress Assessment at Mobile Work Locations

Mobile work locations typically involve outdoor work in conditions that can change dramatically from day to day, or even from morning to afternoon. For this reason, thermal stress risk should be considered on a daily basis when temperature extremes are possible. Heat and cold stress can be assessed by considering the work to be performed along with the local weather forecast. When thermal stress risk is high, thermal stress and steps to take control of thermal stress should be discussed at a tailgate/toolbox meeting.

Cold Weather Clothing

The insulating capacity of the clothing worn is mainly determined by the amount of air trapped inside and between the surfaces of the textiles. Sweat accumulated in garments may result in cold stress due to either reduced insulation or evaporation of the sweat during rest periods.

Cold weather clothing should consist of an inner, middle, and outer layer. The inner layer (underwear) is important for absorbing and transporting sweat. Modern woolen underwear, with a knit construction that facilitates moisture transport, is very effective. Cotton is not recommended because it absorbs moisture, which reduces the insulating value. Fabrics made of continuous polypropylene filaments are non-absorbent and have high wicking properties, but they tend to develop unpleasant odors when wet.

The middle layer of clothing provides insulation and moisture transport. Clothing made of moisture absorbing materials, such as wool, will enhance movement of sweat to the outer layer.

The outer layer of clothing protects against the external environment and should therefore be waterproof and windproof. If the temperature of the inner side of the outer garment is above the freezing point, garments coated with breathable membranes, such as those made with Gore-Tex® and Helly Tech® fabrics, will facilitate water vapor transport. Below the freezing point, water will freeze inside the pores and moisture will not move through the garment.

Heat Stress

Heat stress is the net heat load to which a worker may be exposed from both external heat sources (warm air/radiant heat from the sun) and the heat generated by the body during work activities. Heat strain is the overall physiological response from heat stress. The body attempts to maintain a steady core temperature by increasing blood circulation to the skin and producing sweat. If the body core temperature rises and/or dehydration occurs because of sweating, various heat induced illnesses may occur.

Employees can acclimate to hot environments by gradually increasing exposure over a 4 day period. Acclimatization is reduced when an employee is away from the hot environment for three consecutive days.

Heat Related Illnesses

- **Heat rash**—small red bumps in the skin caused by continuous exposure to heat and humid air and aggravated by chafing clothes. Wearing loose fitting clothing and reducing exposure to heat and humidity can reduce it.
- **Heat cramps**—caused by profuse perspiration followed by copious water intake without salt replacement. Signs include muscle spasms and pain in the extremities and abdomen.
- **Heat exhaustion**—low arterial blood pressure caused by increased stress on the cardiovascular system to meet increased demands to cool the body. Signs include shallow breathing; pale, cool, moist skin; profuse sweating; nausea; weakness; and dizziness.
- **Heatstroke**—the most severe form of heat stress. Occurs when the core body temperature exceeds 105.8°F. The body must be cooled immediately to prevent severe injury or death. Signs include red, hot, dry skin, no perspiration, nausea, dizziness and confusion, convulsions, strong, rapid pulse, or coma. Seek medical attention. Hypothermia can occur if cooling is too rapid.

Other possible effects of heat stress include long term damage to the kidneys, heart, and other internal organs.

Cooling Methods

When overheated, remove employee to a cool area and allow employee to rest. If signs of heatstroke are present, immediately immerse employee in chilled water or wrap in wet clothing and fan with dry air. Avoid overcooling. Do not use ice water to cool employee.

Activities or Conditions that can Contribute to Heat Related Illness

- Alcohol consumption.
- Drug use (and drug abuse).
- Illness (flu, colds, etc.).
- Kidney problems.
- General physical fitness.
- Dehydration.
- Obesity.
- Degree of acclimation.
- Individuals who have experienced a heat related illness are more susceptible to developing heat related illness again.

Heat Stress Assessment

Evaluate work environments and work tasks to identify conditions that may lead to heat stress. Assessments should be ongoing during warm summer weather. Determine the level of heat stress by considering:

- The amount of air movement. Restricted air movement will limit the amount of cooling that will occur through sweat evaporation.
- The type of clothing worn. Heavy clothing will insulate the skin, and non-breathable materials will limit sweat evaporation.
- Physical condition and state of acclimation.
- Amount of radiant heat (sunlight, equipment).
- The intensity of physical labor.
- The apparent temperature.

Apparent Temperature—The Potentially Deadly Combination of Heat and Humidity

Hot, humid weather is more uncomfortable than hot, dry weather because high humidity slows the evaporation of perspiration (sweat). Evaporation is nature's way of cooling. Hot, humid weather is not only uncomfortable, it is dangerous to those exercising in it. Figure 8.1 shows how to find the "apparent temperature," that is, how hot various temperature humidity combinations feel. For example, if the temperature is 100°F and the relative humidity is 50%, find 100 in the temperature column on the left side; follow that row to the right to the 50% humidity column. The apparent temperature is 120°F. This falls into the "danger" area where outdoor physical activity may become dangerous and could require additional administrative controls and monitoring. The different shades on the chart show the levels of danger for various combinations.

Note	The apparent temperature may be higher or lower than the air temperature in certain cases. For example, when the air temperature is 140°F and the humidity is 0%, the apparent temperature in only 125°F. This is because perspiration significantly cools the skin, even though the perspiration may be unnoticed in such low humidity. Similarly, an air temperature of 80°F and 100% humidity would feel like 91°F because perspiration evaporates so slowly in high humidity.

When working in extreme apparent temperatures classified as "danger" or "extreme danger" in Figure 8.1, an evaluation of workload and administrative controls should be ongoing. In addition, the monitoring of employees should be ongoing

How temperature and humidity combine to make it feel hotter

Extreme Danger — Danger — Extreme Caution — Caution

Air Temperature F (C)	Relative Humidity (Percent) 0	10	20	30	40	50	60	70	80	90	100
140 (60)	125 (52)										
130 (54)	117 (47)	131 (55)									
120 (49)	107 (42)	116 (47)	130 (54)	148 (64)							
110 (43)	99 (37)	105 (41)	112 (44)	123 (51)	137 (58)	150 (66)					
100 (38)	91 (33)	95 (35)	99 (37)	104 (40)	110 (43)	120 (49)	132 (56)	144 62)			
90 (32)	83 (28)	85 (29)	87 (31)	90 (32)	93 (34)	96 (36)	100 (38)	108 (42)	113 (45)	122 (50)	
80 (27)	73 (23)	75 (24)	77 (25)	78 (26)	79 (26)	81 (27)	82 (28)	85 (29)	86 (30)	88 (31)	91 (33)
70 (21)	64 (18)	65 (18)	66 (19)	67 (19)	68 (20)	69 (21)	70 (21)	70 (21)	71 (22)	71 (22)	72 (22)

Apparent temperature
is how hot the heat-humidity combination makes it feel.

Figure 8.1—Chart showing apparent temperatures

Reduce the potential for developing a heat related illness with engineering controls where feasible. Engineering controls include:

- Ventilation.
- Shading.
- Shielding.
- Air conditioning.

Administrative Controls

Implement administrative controls where engineering controls are not sufficient or not feasible. Administrative controls include:

- Rotating employees from hot areas to cooler areas.
- Rest breaks in a cool area.
- Performing jobs in the coolest part of the day.

Table 8.1—Wind Chill Index

Wind Speed MPH (km/h)	Actual Thermometer Reading, °F (°C)									
	50 (10)	**40 (4.4)**	**30 (-1)**	**20 (-7)**	**10 (-12)**	**0 (-18)**	**10 (-23)**	**20 (-29)**	**30 (-34)**	**40 (-40)**
calm	50 (10)	40 (4.4)	30 (-1)	20 (-7)	10 (-12)	0 (-18)	10 (-23)	20 (-29)	30 (-34)	40 (-40)
5 (8)	48 (9)	37 (-3)	27 (-3)	16 (-9)	6 (-14)	5 (-21)	15 (-26)	26 (-32)	36 (-38)	47 (-44)
10 (16)	40 (4)	28 (-2)	16 (-9)	4 (-16)	9 (-23)	21 (-29)	33 (-36)	46 (-43)	58 (-50)	70 (-57)
15 (24)	36 (2)	22 (-6)	9 (-13)	5 (-21)	18 (-28)	36 (-38)	45 (-43)	58 (-50)	72 (-58)	85 (-65)
20 (32)	32 (0)	18 (-8)	4 (-16)	10 (-23)	25 (-32)	39 (-40)	53 (-47)	67 (-55)	82 (-63)	96 (-71)
25 (40)	30 (-1)	16 (-9)	0 (-18)	15 (-26)	29 (-34)	44 (-42)	59 (-51)	74 (-59)	88 (-67)	104 (-76)
30 (48)	28 (-2)	13 (-11)	2 (-19)	18 (-28)	33 (-36)	48 (-44)	63 (-53)	79 (-62)	94 (-70)	109 (-78)
35 (56)	27 (-3)	11 (-12)	4 (-20)	20 (-29)	35 (-37)	49 (-45)	67 (-55)	82 (-63)	98 (-72)	113 (-81)
40 (64)	26 (-3)	10 (-12)	6 (-21)	21 (-29)	37 (-38)	53 (-47)	69 (-56)	85 (-65)	100 (-73)	116 (-82)
Over 40 (64) *(Little Added Effect)*	**Little Danger** *(For Properly Clothed Person)*				**Increasing Danger**			**Great Danger**		
					(Danger from Freezing of Exposed Skin)					

Work Practices

- Never work alone in extreme cold environments.
- The work rate should not be high enough to cause sweating that results in wet clothing. If heavy work must be done, allow employees to take all rest periods in heated shelters and give them an opportunity to change into dry clothing.
- Minimize periods of sitting still or standing still in cold environments.
- Do not allow direct skin contact with metal objects.
- Protect employees from wind.

Cold Stress Training

Train employees who work in cold environments on:

- Proper re-warming procedures and appropriate first aid treatment.
- Proper clothing practices.
- Proper eating and drinking habits.
- Recognition of impending frostbite.
- Recognition of signs and symptoms of impending hypothermia or excessive cooling of the body, even when shivering does not occur.
- Safe work practices.

For the latest updates see the *HSE Standards Manual*, which can be accessed at:

http://halworld.corp.halliburton.com/internal/hsesd/pubsdata/standards/standards_cat_eng.htm

Section

9

Contingency or Emergency Operations

Introduction

For all coiled tubing operations, contingency plans are required to provide guidelines for recovery from critical situations. The following procedures are provided as guidelines only—the actual procedure employed should be tailored to suit actual rig up arrangements and well conditions.

Killing a Well Using CT or Bullheading from Surface

The following scenarios describe general procedures for killing a well using coiled tubing or bullheading from surface, depending on whether the well is filled with gas or liquid.

General Gas Well Kill Procedures

Bullhead Kill Fluids from Surface

1. Mix and pump a non-damaging viscous pill or bridging agent. The size of the pill is dependent on the size of the tubular(s) and the length of the interval.
2. Follow the pill with kill weight fluid. Do not over displace.

Circulation, Kill Assisted with Coiled Tubing

Since this scenario involves circulating gas out of the well, be sure the gas can be vented properly or placed in the production system. The vent should not be near any flames, sparks or engine air intakes.

1. Place the end of the coiled tubing below the source of pressure. The rat hole below the pressure source must be filled with kill weight fluid before the kill program begins.
2. Spot a bridging agent across the interval of the pressure source. The bridging agent should be non-damaging and fairly easy to clean up, such as sheared and filtered HEC. If the zone or

source of pressure will not be considered for future commercial production, it may not be necessary to use clean fluids.

3. Circulate kill weight fluid to surface (at least 2 annular volumes). A kill sheet should be used to adjust the choke on the returns line as the gas is circulated out of the well.
4. Stop pumping and shut in the well for +30 minutes to see if any pressure buildup is evident. Break circulation while pulling out of the hole to ensure that the hole remains full and to prevent swabbing.
5. If there is still pressure at surface after circulating the fluid, either the kill weight was not correct or the zone may be swapping fluid (taking the liquid while percolating out gas).

General Liquid Well Kill Procedures

Bullhead Kill Fluids from Surface

1. Mix and pump clean kill weight fluid. A gelled pad may be used in front of the kill weight fluid to minimize mixing with the wellbore fluid.
2. Pump at least one tubing and open casing volume or total tubular volume, depending on the wellbore configuration.

Circulation Kill Assisted with Coiled Tubing

1. Place the end of the coiled tubing below the source of pressure.
2. Circulate kill weight fluid to surface (at least 2 annular volumes).
3. Stop pumping and shut in the well for +30 minutes to see if there is any pressure buildup.
4. Be sure to pump fluid while POOH to prevent swabbing and to keep the hole full.

Runaway CT

Runaway CT can quickly become very dangerous. Immediate response is required to attempt to slow down the speed of the pipe by applying whatever braking loads are available.

Important — **The area around the well, drill floor, and reel must be evacuated. If the situation continues out of control, the reel can be pulled from its mountings toward the injector.**

Although coiled tubing is often "light" when starting in a live well, it soon becomes heavy and tries to fall in the hole. The coiled tubing injector uses gripper blocks in continuous chains with a chain tensioning system to control the movement of the coiled tubing. The injector is equipped with an accumulator to supply hydraulic power to the gripping system should system power fail. Fail set brakes are installed in the drive system to lock the drives if a power failure occurs. A counter balance valve in the hydraulic motor circuit closes to trap hydraulic oil in the motors if hydraulic pressure is lost. The slip rams and tubing rams in the blowout preventers can also be used to control tubing movement. The stuffing box can also apply braking force to the tubing.

Caution — **Rapidly falling tubing can create a very hazardous situation. Friction and heat caused by the falling tubing can cause the stuffing box to leak well fluids and gases. Sparks could be created by the falling tubing, increasing the fire hazard. All non-essential personnel should be cleared from the wellsite as the supervisor in charge attempts to stop the tubing.**

If tubing starts to fall uncontrolled into the well:

1. Back out the maximum injector pressure adjust and place the directional control valve in the neutral position (the lower hydraulic pressure allows the brakes to set and the counterbalance valve to close).
2. Increase the pressure to the gripper or linear beam system to increase the gripper block grip on the tubing.
3. If tubing continues to run away, increase the hydraulic pressure to the stuffing box (the friction between the stuffing box element and the tubing will cause a braking action to slow the tubing).
4. Stop gas injection and fluid pumps. Close the ESD on the return line.
5. As soon as possible, clear all nonessential personnel from the area.
6. If tubing continues to fall in the hole, hydraulically close the slip rams in the BOP. If the tubing stops, manually lock the rams.

3. Check for fluid returns, and attempt to maintain circulation if possible.
4. Check the pump pressure recorder to identify any pressure fluctuations.
5. Compare the current tubing weight with the previous pick up weight.
6. Apply a tensile load to the coiled tubing up to 80% of the pipe yield rating (corrected for fatigue) and hold. Monitor the weight indicator for changes in weight.

Note — Halliburton reduces this value for used CT (see Section 2 of the *Coiled Tubing Handbook* for details regarding the “Allowable Stress Factor.”)

Assessing a Stuck Tubing Situation

1. Develop a plan of action with input from the district technical personnel and company representative.
2. If circulation was lost at the time the coiled tubing became stuck, try to re establish it. Circulation through the coiled tubing is preferred. Circulate a friction reduction fluid if available.
3. Analyze the loading condition to determine the maximum allowable pull that can be applied to the tubing at various internal pressures. Use the plugged end calculations as a more conservative figure.
4. Consult the coiled tubing records to determine the condition of the tubing and whether the maximum allowable load should be downrated.
5. Check the weight indicator, BOP stack, and the complete unit before attempting to pull loose. Compare the weight indicator readings and hydraulic pressure to the injector motors for accuracy.
6. Consider the following options for freeing stuck tubing.

Options for Freeing Stuck Tubing

If Able to Circulate...

1. Work the coiled tubing while maintaining circulation down the coiled tubing. **Do not exceed 80% of the allowable stress**.
2. Displace the well with heavier fluid and/or friction reducer to increase buoyancy and decrease friction.
3. Displace the coiled tubing with nitrogen to increase buoyancy.
4. If the coiled tubing remains stuck, attempt to pump down the production tubing. Determine the ovality of the coiled tubing and calculate its collapse rating. **Do not exceed 80% of the calculated collapse pressure rating or 25% of the published rating**.

5. If attempts to pump down the production tubing are not successful, discuss options with the customer representative and the district office to determine additional actions.

If Unable to Circulate...

Inability to circulate is usually caused by one or more of the following three conditions:

- Plugged work string
- Low bottomhole pressure
- Plugged annulus

Consider the following guidelines if unable to circulate:

- If the CT becomes plugged, back surging to clear the coiled tubing or pumping down the annulus are available options.
- If circulation is lost yet the ability to pump through the CT remains, the formation may be taking the fluid. Nitrogen may be added to the circulation fluid and circulation may be re established.
- Should the annulus be plugged with debris, pressurize and back surge the annulus to break up the debris. It may be possible to hold pressure on the work string to lessen the chance of collapse. You might consider leaving the pipe in tension overnight.
- Cycling the CT back and forth in one place with high internal pressure fatigues the tubing and can lead to failure of the tubing at the surface.
- If the well is dead, calculate the stuck tubing free point, cut the tubing on the top of the injector, and rig up the electric wireline with a jet or chemical cutter. Shoot the coiled tubing off above the stuck point.
- Properly manipulating certain physical properties such as fluid density, buoyancy, temperature, and pressure may help free friction stuck tubing.
- In a dry gas well, friction factors of coiled tubing sliding on tubing or casing can be very high. Adding a fluid to the system can greatly reduce the friction factor, allowing the tubing to be pulled free.
- The use of slick polymers and glass or plastic beads in the circulation fluid spotted at the stuck point will aid in reducing friction.
- If the production tubing sets a lot of weight on the packer, it could corkscrew or helically buckle right above the packer. This may be caused by large increases in pickup weights near the end of the production tubing. This condition can cause the CT work string to become stuck. To help free the tubing, circulate a cold fluid down to decrease the production string temperature, causing it to contract in length and straighten.
- Fluid density and its buoyancy effect on the coiled tubing can greatly help free the stuck pipe. The buoyed forces acting on the tubing are distributed along the entire length of the tubing. The heavier the fluid the tubing displaces, the greater the buoyed forces on the tubing. The maximum effect can be achieved by plugging the tubing and running dry or displacing the inside of the tubing with gas.

Tubing collapse on bottom is a concern in this situation. Use a lighter fluid on the inside of the coiled tubing to help increase the buoyed force when the pipe is in heavy fluid.

- Use annular pressure to help free stuck tubing by causing the bridges holding it in place to be broken free or by the ballooning and elongation effects created on the production tubing. Imposing an annular pressure can cause some problems such as collapsed or parting pipe.

Friction Stuck—With Circulation

If the weight indicator reading decreases, it is likely that the pipe is friction stuck. Consider the following options.

- Increase pipe buoyancy by circulating heavier fluids into the wellbore.
- Pump friction reducing fluids or additives, such as HEC, XCD, or TORQ TRIM®.
- Displace the coiled tubing with a lighter fluid such as nitrogen or diesel.
- Work the tubing free of the stuck area by applying tensile loads on the CT up to 80% of the pipe tensile yield rating (corrected for fatigue) and watching for the load decrease on the weight indicator. Keep pumping fluids to maintain circulation.
- As a last resort, kill the well and cut the coiled tubing. Follow normal fishing procedures.

Mechanically Stuck—With Circulation

If the weight indicator does not decrease after applying a tensile load up to 80% of pipe tensile yield rating, it is likely that the coiled tubing is mechanically stuck. Attempt to lower the CT into the well to determine whether it is actually stuck at that point or is unable to pass through a restriction or upset in the host pipe.

If the coiled tubing can be moved downward, determine the following.

- Whether the pipe (or tools) could have been bent or buckled by setting down excessive weight or running into an obstruction.
- The type of connection used to connect the tool string to the coiled tubing.
- The pipe (and tools) position in the well compared to the well sketch to identify any obstructions or restrictions.

Consider the following options.

1. If it is determined that the BHA is getting hung up, pump a ball to release the hydraulic disconnect.
2. Ensure that the injector pulling limit is set at 80% of the coiled tubing tensile yield rating (corrected for fatigue). Lower the CT 10 to 15 ft and attempt to pull the pipe past the previous "stuck point" again.
3. Kill the well, cut the coiled tubing at the surface, and run a free point tool to determine the depth to the stuck point. Follow normal fishing procedures.

Mechanically Stuck—Cannot Circulate

1. Pump kill weight fluid down the coiled tubing. If it is not possible to pump down the CT, attempt to pump kill weight fluid down the annulus (at pressures below the collapse pressure of the CT).
2. Once the well is dead, cut the coiled tubing at surface and run a free point tool. Follow normal fishing procedures.

Recovering Stuck Coiled Tubing

Initial Response Procedure

1. Attempt to establish where the CT is stuck by conducting free point checks. If the pipe is stuck in a horizontal section, wireline access to the stuck point will not be possible and the pipe will have to be cut as deep as possible in the vertical section.
2. Mobilize the chemical cutters and operator from the wireline company.
3. Check all tools required for holding, cutting, and re-connecting to the CT, including:
   - TEC
   - Box by box crossover
   - Dual ball valve assembly
   - Flexible dual roll on connector
   - Pipe cutters
   - CT plugs
   - Cable clamp
   - Pipe clamps
   - Slip bowl and slips

Recovery Procedure

The overall objective is to cut and recover the stuck pipe with minimum exposure to risk. Where possible, maintain two barriers to well pressure. The objective of the recovery procedure is to spool the pipe onto an empty shipping spool. This is the most effective way to handle long lengths of CT.

At some stages in this procedure, the BHA check valves will be relied on as a pressure barrier. If the check valves are suspect or cannot be relied on, the CT should be filled with a kill weight fluid. This may involve pumping a heavy gel ahead of the weighted fluid, or adding gel to the fluid.

1. Pull the CT in tension and set the slip and pipe rams in the BOP. Close the secondary pipe rams.
2. Conduct a leak off test on the riser above the BOP. Conduct a leak off test on the CT to check that the downhole check valves are holding.

16. Pick up to the estimated hanging weight of the CT in the well. Equalize the pressure across the top pipe rams. Open the upper pipe rams. Equalize the pressure across the secondary pipe rams, and open the secondary pipe rams. Open the slip rams.
17. Pull the CT out of the well. Slowly pull the flexible connector over the guide arch and onto the reel.
18. Pull out of the well until the estimated end of coil is 50 ft below the wellhead. Stop and prepare for pulling back into the riser.
19. Slowly pick up 10 ft from the holding depth (never pick up more than the distance between the stripper and swab valve), closely monitoring the stripper. Prepare to close the CT BOP blind ram if the CT is pulled out of the stripper. Test close the swab valve, counting the turns. If the CT is across the valve, pick up a further 10 ft and repeat the test.
20. If the swab valve closes, close the master valve and bleed down the riser.
21. Rig down the recovered pipe. Rig up the replacement work string.

Other Problem Situations

Problem: The CT Parted between the Reel and the Injector

1. Stop the injector and set the direction control to Neutral.
2. Stop the pumps.
3. Close the slip rams.
4. Close the pipe rams.
5. If the downhole check valve(s) are holding pressure (no flow through the coiled tubing at surface), attempt to mechanically connect the broken pieces of the pipe and continue to pull out of the hole.
6. If the check valve(s) are leaking, cut the coiled tubing using the shear rams.
7. Pull up the coiled tubing one foot with the injector head to remove the sheared end of the coiled tubing from across the blind rams.
8. Close the blind rams.
9. Check and compare the pressures above the blind rams, at the kill spool, and at the choke or flow tee.
10. Attempt to bleed pressure above the blind ram prior to pulling the coiled tubing out of the stripper assembly.

11. Initiate kill procedures using the bullhead method by pumping kill weight fluid through the BOP kill flange outlet and down the coiled tubing. If this is not possible, pump fluid through the flow tee.
12. Once the well is dead, discuss options for retrieving the coiled tubing left in the well.

Problem: The CT Parted Downhole

1. Close the choke and determine whether the wellhead pressure is below the MAWP of the coiled tubing. If the wellhead pressure exceeds the MAWP of the coiled tubing, go directly to Step 7.
2. Record tubing weight at the load cell to estimate the amount of pipe above the part.
3. Record the depth counter reading for future reference.
4. Measure the distance from the upper swab or upper master valve on the wellhead to the bottom of the stripper/packer and record the distance.
5. Attempt to establish injection down the coiled tubing. Circulate kill weight fluid if available and/or if necessary.
6. If fluid injection down the coiled tubing is not possible, pump the kill fluid through the BOP kill line inlet or the flow tee until the well is dead. If possible, bleed pressure as needed to minimize buildup of surface pressure.
7. Pull the coiled tubing out of the well slowly (the location of the end of tubing is unknown). Be prepared to close the blind rams and master valve in case the coiled tubing is accidentally pulled out of the stripper assembly.
8. Stop at 300 ft from the theoretical end of the tubing and confirm that the well is dead.
9. Continue to POOH slowly, stopping at intervals equal to the distance recorded in Step 4. At each interval, attempt to close the master valve gently. If resistance is felt before the required number of turns have been made, open the valve. Slowly POOH the distance recorded in Step 4; stop, and repeat.

   Note: Depending on the type of failure, the end of the CT may jam in the stripper. If the injector stalls, do not apply additional force; stop the injector and attempt to close the master valve before increasing the injector force.

10. When the master valve closes fully without interference, secure the well.
11. Discuss options for retrieving the lost coiled tubing and for killing the well, if necessary.
12. If the wellhead surface pressure approaches or exceeds the MAWP of the coiled tubing, begin pumping kill weight fluid through the coiled tubing.

13. If fluid cannot be pumped through the coiled tubing, pump fluids through the kill or return spool while slowly pulling the coiled tubing out of the well. Bleeding pressure at the choke may reduce the wellhead pressure. Do not exceed the rated collapse pressure of the coiled tubing. Be prepared to close the master valve if the coiled tubing is accidentally pulled out of the stripper assembly. Initiate or continue the kill procedure using the bullhead method.
14. If the wellhead pressure becomes critical (final alternative), halt the extraction of the coiled tubing, close the slip rams and pipe rams, and activate the shear rams. Pick up the end of the coiled tubing 1 to 2 feet and close the blind rams.

Problem: The CT Parted between the Injector and the Stripper Assembly

1. Close the slips.
2. Close the pipe rams.
3. Close the shear rams and note the amount of instantaneous hydraulic pressure needed to determine whether the coiled tubing remained across the shear rams when closed or whether the parted coiled tubing dropped below the quad BOP stack.
4. If the instantaneous hydraulic pressure needed to activate the shear rams was below that required to operate the rams, close the blind rams, close the master valve, and discuss options for fishing the coiled tubing out of the well.
5. If it is suspected that there is coiled tubing across the blind rams and the well is flowing through the coiled tubing: close the blind/shear ram assembly located above the wellhead, or if not equipped with blind shear rams, open the slip, pipe, and shear rams allowing the coiled tubing to drop. Close the blind rams, then close the master valve.
6. Bleed down the pressure in the riser assembly and remove the injector head. Discuss options for retrieving the coiled tubing.

Note: If the coiled tubing string was equipped with a check valve at the end of the pipe, no fluid or pressure should be escaping from the ID of the coiled tubing. If the CT did not drop downhole, it may not be necessary to close the shear or blind rams. Continue with the appropriate kill procedure and discuss options for retrieving the CT.

Problem: While RIH, A Hole Formed in the CT above the Stripper

1. Stop the injector and the reel.
2. Reduce the fluid pump in pressure as much as possible. DO NOT shut down the pumps because hydrocarbons could flow back up the coiled tubing.
3. Pull out of the hole and repair/replace the coiled tubing string.
4. If the hole is large and leaks significantly, continue to RIH with the coiled tubing and position the hole between the stripper and tubing rams.
5. Close the slips and tubing rams.

3. Depending on the severity of the damage to the CT, run the damaged section of pipe back into the stripper. This action will contain the leak and allow time to assess the situation.
4. Close the pipe/slip rams.
5. Displace the reel to water or other non-hazardous fluid.
6. If conditions permit (i.e., small pinhole), retrieve the tubing from the well.
   - If it is thought that the CT has collapsed or that the downhole check valves are not holding, kill the well.
   - If it is considered unsafe to recover the pipe normally, either the CT can be (a) cut and joined with a dual roll on connector or spliced with two tubing clamps and binders, or (b) cut in the BOP for later recovery.
7. If the remaining CT on the reel is long enough to complete the job/well:
   a. Fit clamps on either side of the pinhole and choke with a wire sling/canvas strop.
   b. POOH slowly until the CT pinhole is at the levelwind/tensioner head. Be aware that the CT may part during this operation.
   c. Secure and cut the pipe.
   d. Connect the in hole end to a spooling drum and POOH, spooling the CT onto the drum.
8. With the pipe out of the well, report the failure, noting the string number, position of the failure, the recorded life used at the failure, and max life used on the string.
9. Cut 3 ft samples of pipe for analysis (3 ft either side of the failure plus two off 3-ft samples from another part of the same string).

Problem: The CT Buckled between the Stripper and the Injector

1. Close the slip rams.
2. Close the pipe rams.
3. Close the shear rams and cut the coiled tubing.
4. Attempt to pick up the coiled tubing 1 to 2 feet and close the blind rams.
5. If the buckled tubing does not allow the blind rams to be clear of the coiled tubing or it is suspected that there is coiled tubing across the blind rams and the well is flowing through the coiled tubing: close the blind/shear ram assembly located above the wellhead. If not equipped with blind shear rams, open the slip, pipe, and shear rams allowing the coiled tubing to drop. Close the master valve.
6. Discuss options for killing the well, if required, and for fishing the CT out of the well.

Problem: Leak(s) in the Riser or Connections Below the BOPs

Stop the pump to determine whether there is flow or pressure at the surface.

1. If there is no surface pressure, POOH with coiled tubing while pumping a minimal amount to keep the hole full and to prevent swabbing. When the end of the coiled tubing reaches the BOPs, close the master valve and replace or repair the leaking riser section.
2. If there is surface pressure, begin pumping kill weight or the heaviest weight fluid available through the coiled tubing while POOH. This will create a dynamic kill effect by increasing the ECD. When the end of the CT is above the tree, close the master valve and replace or repair the leaking riser section.
3. If the situation becomes critical or is deemed unsafe, perform the following steps:
    a. Close the slip rams.
    b. Close the shear rams.
    c. Pick up the coiled tubing 1 to 2 feet and close the blind rams.
    d. Open the slip rams to allow the coiled tubing to fall into the wellbore.
    e. Close the master valve while counting the turns to be assured no coiled tubing is across the valve and that it is closed properly.
    f. If equipped, close the secondary shear/blind closest to the wellhead.

Problem: While Descending into the Well, Pipe Hits the Bottom or an Obstruction

1. Close the pipe rams and slip rams.
2. Observe pump pressures and circulation rate to determine whether there is any damage to the bottom of the coiled tubing, such as a crimp, kinks, or buckling.
3. If the well is under control and there are no mechanical (surface) problems, open the tubing rams and slip rams.
4. Begin POOH slowly to determine whether the end of the coiled tubing can be pulled inside the production tubing string.

Note — If the coiled tubing entered the casing at the bottom of the well, it is probable that there are some kinks or buckling.

5. Check the pick up weight and drag compared to previous data.
    - If there are no suspected problems, continue with the project.
    - If there are indications of a problem, POOH and inspect the coiled tubing.

Problem: Uncontrolled Ascent Out of the Well

This problem usually occurs when the coiled tubing is shallow in a well with high surface pressure. As the coiled tubing gets closer to the wellhead, the pressure in the well can overcome the weight of the coiled tubing in the wellbore and the static frictional force exerted by the injector chains. In essence, the coiled tubing is being “blown” out of the well.

Important **If the coiled tubing is blown out of the stripper assembly, close the blind rams and master valve as quickly as possible.**

1. Attempt to increase the injector gripper chain pressure.

   Note The gripper chains should be moving in the same direction as the coiled tubing.

2. Apply additional pressure to the stripper assembly. Prepare to close the master valve in case the coiled tubing is blown out of the well.
3. If these attempts are unsuccessful, put the injector motor in Neutral and close the slip rams.
4. Once pipe motion is halted, close the pipe rams and slips if not closed already.
5. Pump the hydraulic cylinders open on the injector head linear beams.
6. Inspect the chain blocks and remove any debris (paraffin, scale, etc.).
7. Reset the beam pressures to the appropriate amounts.
8. If the well is under control and there are no mechanical problems, open the tubing rams and slip rams. Change the stripping element if necessary.
9. Reduce the hydraulic pressure on the stripper element and pick up the coiled tubing enough to inspect the area of pipe held by the slips.
10. Determine whether it will be necessary to repair or replace that section of coiled tubing prior to resuming the pipe extraction.

Caution **Be extremely cautious while checking the area of pipe held by the slips; the pipe may be weakened and fail with the high surface pressure present.**

11. Continue to POOH, and close the master valve. Determine the cause for the uncontrolled movement of pipe prior to entering the well again. Replace or repair the coiled tubing string as required.

Section

A

Coiled Tubing Management

Introduction

Coiled tubing is both the most important and the least durable part of a coiled tubing unit. Coiled tubing has a finite life and is considered an expendable, although costly, component. The life of a string can be limited by bending fatigue, OD growth, tubing corrosion, or some combination. Accurate records of the events endured by a string and consistent calculation methods are required to help determine when the usable limit of the tubing has been reached. This section addresses record keeping requirements, electronic recording tools, life calculation tools, and general life maintenance procedures. Corrosion mitigation procedures are covered in "Corrosion" on page A-19. Information regarding the fatigue impact of welds will be covered here, but the topic of CT welding is covered completely in Section 3, "Field Welding and Repair of Coiled Tubing."

General Information

Many variables affect the life of coiled tubing, including:

- Coiled tubing OD.
- Coiled tubing wall thickness.
- Coiled tubing alloy.
- Bend radius at the outer reel wrap.
- Minimum tubing guide arch radius.
- Internal pressure when cycling.
- Rig up configuration.
- Corrosive exposure (e.g., acid, oxidation, H_2S, CO_2).
- Surface defect and condition.
- Coiled tubing movement (cycling).
- Coiled tubing orientation.
- Bias welds and butt welds.

Historically, many field locations used the "foot of run" convention of measurement to determine the life utilization of a tubing string. This form of measurement counted the number of feet the tubing is run into the well one way. While fair results could be obtained with the limited number of tubing sizes and grades then available, this method is now considered obsolete. Counting jobs or counting bend cycles are also considered obsolete.

This section addresses the use of computer gathered and manually gathered bend records combined with life prediction models to determine CT life. This method can improve both economics and safety if properly understood and implemented. It should be pointed out that the purpose of this record keeping is not to burden field operations. Rather, the effort entailed will be offset by the benefits of extended pipe life, improved customer perception, and fewer problem jobs.

String Records

For string life optimization, string records must be complete. Events endured by a string are recorded and used in the determination of life, including:

- All tubing movements.
- All tubing cuts.
- All weld positions.
- All string reversals.
- Corrosive well conditions.
- Corrosive fluid exposure.

Expanding this concept, a complete string record should consist of the following items:

- String manufacturer.
- Original string dimensions and condition.
- Length.
- OD(s).
- Wall thicknesses (all tapers).
- Manufacturer’s weld positions.
- Material grade(s).
- Original yield and tensile material values.
- Date of manufacture.
- Shipping and preservation method.
- Unique string identification number.

5. Check the String History Log for correct information. This log contains details of all the jobs previously run on the string and also information on any cuts that have been made.

Note — Cuts can only be made in multiples of the string segment length (usually 10 ft/3 m). If cuts are shorter than the segment length, they should be manually recorded and then cut from the string records once the length of cuts reaches or exceeds the segment length.

6. Check the chart of the Strings Fatigue Life to ensure that the string has enough life left to handle any planned operation.
7. To lock the string, use the padlock icon.

Data Recording—Non DAS Units

The preferred method of data collection is through a data acquisition system (DAS). If no DAS is available or if the installed DAS fails, manual pipe records must be maintained. Simulations have shown that good manual records can report fatigue to within ± 5% of electronically recorded data.

Accurate pipe records are essential for this system to work effectively. A well written *CT Pipe Log* includes records of significant changes in pressure and depth as well as changes in direction. Greater detail in the *CT Pipe Log* means a more accurate record of work done by the pipe and therefore a better record of the life used. Every change of direction (P/U, RIH, S/O, etc.) MUST be recorded on the *Pipe Log* along with the pump and wellhead pressures. Also note any pipe cuts made (always cut in multiples of 5 ft) and the type of job (e.g., acid job).

Table A.2—Recording Data for Non-DAS Units

Step	Details	Responsible Personnel
1	Check that blank *Pipe Log* sheets are available in the CT cabin.	CT Supervisor
2	Enter the customer, lease number, well number, and date on the log. Check the string number. Check the wellsite geometry and enter the reel to gooseneck and zero depth distances.	CT Supervisor
3	Note the job type and record the length of any pipe cut off at the start of the job. Note that pipe cuts should be made in 5 ft lengths only; the recording database cannot handle lengths less than 5 ft or anything other than multiples of 5 ft.	CT Supervisor
4	Throughout the job, record pump and well pressures for every change of direction; each time the pipe is picked up, enter the pump pressure, well pressure, start depth, and end depth.	CT Supervisor
5	At the end of the job, record any additional pipe cut off.	CT Supervisor
6	Return the pipe log to the CT office. Turn in a copy with the job ticket and job log.	CT Supervisor

Life Management Guidelines

Various options exist in the CT software for life management variables. The following notes outline the preferred settings and limits.

1. For CT units equipped with DAS, use Fatigue Calculator with an application factor of 2.0, or as determined by local history (see "Application Factors" on Page A-20.). For CT units without DAS, use Fatigue Calculator with an application factor of 2.5, or as determined by local history (see "Application Factors" on Page A-20.). With this set up, the useable life limit is 100%.
2. Cut off 20 ft every time the tubing end connector is re-made. Note the peak life used before an operation and consider where additional frequent cycles may be made. If necessary, cut off further pipe (e.g., 100 ft, 200 ft).
3. Update the string file with the length cut off.
4. Report the length cut off on the job log and *CT Pipe Log*.
5. Note any areas of pipe damage and add a derate zone to the string database. Recommended derate factors are given in Table A.3.

Table A.3—De rating Factor for Various Weld Types

Weld Type	De-rating Factor
Factory bias weld – no wall change	0.80
Factory bias weld – step wall change	0.50
Orbital butt weld – no wall change	0.45
Orbital butt weld – step wall change	0.20
Manual butt weld – no wall change	0.35
Manual butt weld – step wall change	0.15

6. For frequent trips into the same well, change the depth of weight checks to move the fatigue cycle point. Analysis of string failures has shown that corrosion is a major contributing factor in pipe failures. Refer to the Tubing Maintenance Guideline Best Practices to Minimize CT Corrosion (T. McCoy, HES, Duncan, OK, August 1997) for recommended procedures.
7. Pay particular attention to flushing strings after acid jobs and preparing strings for longer term storage.
8. Mark IWI string files as "Retired" and upload them to the CT vault.

End of Life Procedures

At the end of the life of the string, the data files should be downloaded and stored on disc. The final fatigue chart and string history should be printed and filed in the *String Record Book*.

The file details in the CTU laptop computer hard drive should be deleted.

1. As the string nears the end of its life, specify and order a new string.
2. Assess string as "unusable" when appropriate due to damage, length, or fatigue life used.
3. Arrange a date for the unit to travel to the pipe manufacturer or spooling center to collect new string.
4. Spool the string off the working reel. Spool the new string on.
5. Check the string details in String Manager and download the data file. Delete the data file from the CTU computer.
6. Review the end of life data. Print and file the last report for the *String Record Book*. Archive the string file in Used Strings on the network.
7. Upload the latest data file and create new records as described in "Receiving New Strings," (Page A-5).

Coiled Tubing Fatigue Management

Fatigue

When a material is bent to such a degree that the level of stress goes beyond its elastic limit and reaches the yield point, permanent deformation occurs. When coiled tubing is repeatedly cycled between the reel and tubing guide, it exceeds its elastic limit and is forced to plastically deform. With repeated plastic yielding, fatigue failure eventually occurs. Therefore it is critical to know what the expected fatigue life of the tubing will be when cycled under different conditions. The expected fatigue life will depend on the coiled tubing material grade, diameter, wall, and internal pressure.

Fatigue is a critical factor in the life of coiled tubing because it is unavoidable, cannot be measured non-destructive, and yet can have a major impact on the working life. Understanding and predicting the fatigue condition of the string and derating it accordingly is critical to a successful and safe operation.

Fatigue is often classified into the following categories:

- **High cycle fatigue**—Loading is primarily elastic and failure occurs after excess of 10,000 stress cycles. Examples include triplex pumps, shafts and bearings, and any items subject to vibration.
- **Low cycle fatigue**—Loading is mostly elastic, and failure occurs in 1,000–10,000 stress cycles. Examples are those where loading is normally low but where occasional peaks can be seen, such as a car suspension absorbing shock load due to rough road surfaces.

The simplest approach to predict the service life of CT is based on the concept of running feet. This is where the cumulative footage for a string of coiled tubing run into a well is recorded. The CT is retired when the footage totals a specified amount. Typically, this ranges from 250,000 to 750,000 feet. Although an easy to implement system, it is based on previous experience with the same type of tubing performance operating under the same wellsite conditions. No consideration is given to coiled tubing dimensions, bending radius of the equipment, internal pressure, or where the cycles are applied. The system is site specific and cannot be reliably transferred to another area where operating conditions may be significantly different.

CT Cutting

An improvement on the running foot method is to track sections of the string as it is cycled in and out of the well. The service string is divided into discrete sections of typically 500 feet long or less. The number of trips into and out of the well can then be tracked to account for the fact that some parts of the CT are subjected to more bending than other parts during a given job. The smaller the section length, the more accurate the over all record of bending history, which better identifies the most used section of tubing.

As the string is divided into sections, the effect of internal pressure can be applied. Empirical data can be gathered as to the amount of bending events that the tubing could withstand before failure at a given internal pressure. The number of trips to failure can be interpolated over a range of pressures and each pressure range is assigned a value. The lower pressure ranges have lower values, and as the pressure increases, the value of the range increases as well. This enables values to be subtracted from the base failure value, allowing sections cycled under higher pressure to show more life used. The CT string can now be managed by removing (cutting) high fatigue areas from the string.

Although a vast improvement over the running foot method, massive amounts of cycle testing have to be performed for each combination of coiled tubing OD, wall thickness, bending radius, and tubing material. The empirical coefficients are based on constant pressure while the CT experiences a continuously varying pressure that could over or under estimate the remaining life, depending on which end of a range the tubing was actually cycled at. Applying fatigue estimates linearly when job conditions are varying may not produce reliable results.

Advances in computer technology and data acquisition methods enabled the development of a theoretical model based on fundamental principles of fatigue and the appropriate consideration of geometry and material properties. Accurate pressures, depths, and positional tracking of tubing sections enable precise predictions of fatigue life used. The ability to incorporate full scale testing and laboratory results into the model enables increased reliability of predictions. The ability to process data in real time or near real time has reduced the risks associated with operating coiled tubing, especially during high pressure operations.

Fatigue Model

It is globally recognized that fatigue life is a random variable. That is, fatigue life can be predicted with desired probability of failure, or desired reliability (probability of non-failure). The coiled tubing stress strain condition is three dimensional and complex. It can be described as the superposition of the following two distinct stress states.

- Uniaxial alternating plastic stress/strain state caused by bending over the tubing guide and over the reel.
- Plane (2D) stress state imposed by internal pressure; its principle strains are elastic and steady, as compared with bending strain.

Alternating axial strains are very high, and can exceed yield strain multiple times. Unfortunately, there is no universal failure theory in low cycle fatigue under combined loading and no universal formula for converting a 3D stress/strain state into an equivalent uniaxial alternating state. The Halliburton fatigue model was developed from a local equivalent stress theory based on full scale fatigue tests of various brands and dimensions of coiled tubing.

As coiled tubing is not completely homogenous, differences in material properties, dimensions, surface conditions, and molecular structure can be expected across the length of the coiled tubing string. Bend machine fatigue testing is a localized test and can be expected to over estimate the fatigue life because the sample length is fairly short. Full scale fatigue testing utilizes the equipment that will be used to handle the CT at the wellsite and includes equipment induced effects to the coiled tubing samples. Full scale testing allows longer samples to be cycled across the actual bending radius as well as better approximation of material differences inherent across the length of a coiled tubing string.

Bending cycles are defined as two plastic strain events from either a bent configuration to a straight configuration or a straight configuration to a bent configuration. Three plastic cycles (6 strain events) constitute a stroke or trip. The coiled tubing also undergoes one elastic strain cycle due to axial load during a stroke or trip.

As stated above, typical failure criteria such as the von Mises (distortion energy) criterion are useful in static, non-plastic loading cases, but do not correlate well with low cycle (plastic loading) fatigue data. A local equivalent stress theory was developed by Dr. Vladimir Avakov based upon full scale fatigue tests of differing tubing material, OD, wall thickness, and pressure. This model is composed of two interrelated parts, the “stress vs. cycles to failure” calculations and the “reliability calculations.” When the accumulated damage has reached 100% on a specific section of tubing, the section must be removed or the string retired.

Equipment rig up configuration plays a part in how many cycles a specific point in the tubing string may encounter on a reversal of direction. Distances between the reel and tubing guide are far enough to consider a partial stroke of a section of tubing that may leave the reel but does not reach the tubing guide.

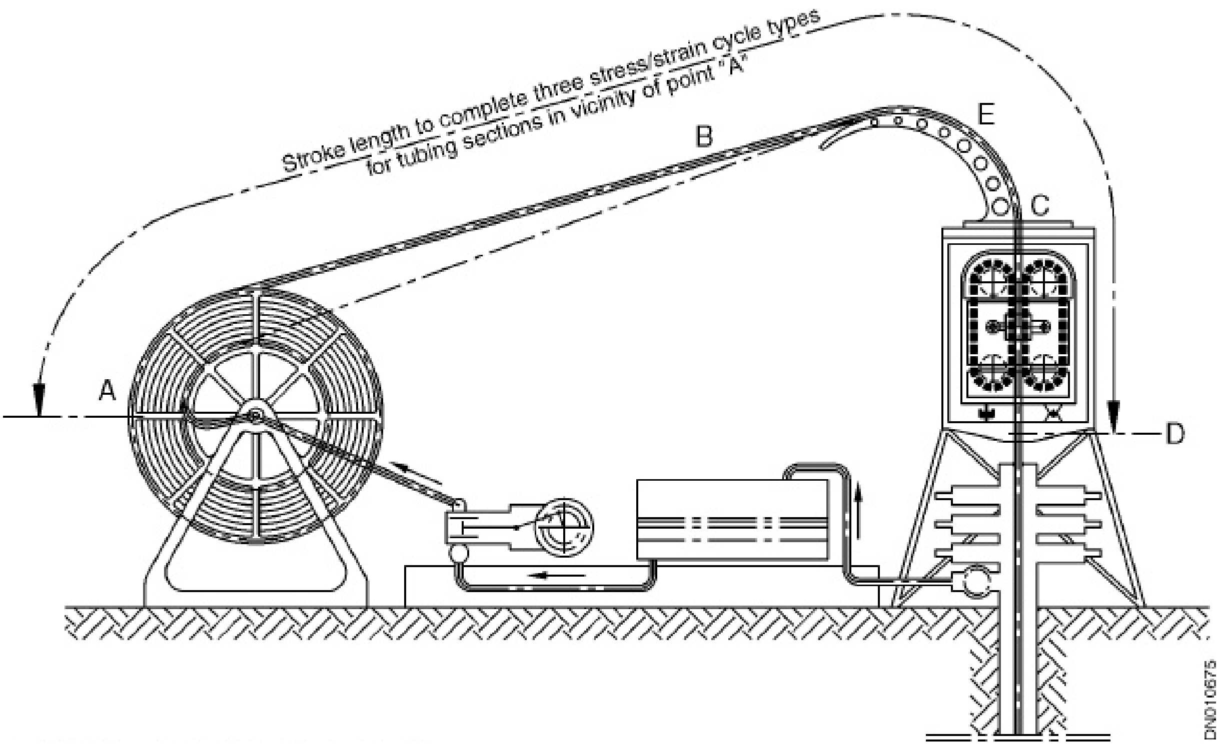


Figure A.1—Fatigue cycle areas

Referring to Figure A.1, when a CT section at point A (or below) travels up to point D (or deeper, into the well) and back to the reel:

A. Section at point A experiences alternating axial strains/stresses as follows:
   - One cycle due to bending over the reel.
   - Two cycles due to bending over the gooseneck.
   - One cycle in tension due to hoisting load.

B. Section at point B experiences alternating axial strains/stresses as follows:
   - Two cycles due to bending over the gooseneck.
   - One cycle in tension due to hoisting load.

C. Section at point C experiences:
   - One alternating axial strain/stress cycle in tension due to hoisting load.

D. Section at point D does not experience alternating deformations, and tensile stress is steady.

E. Section at point E experiences alternating axial strains/stresses as follows:
   - One cycle due to bending over the gooseneck.
   - One cycle in tension due to hoisting load.

Factors that Affect Fatigue

Although pressure is the most active component in fatigue life, material difference, dimensional properties, and equipment setup affect fatigue in different ways. The compound effect of all the factors should be considered when designing a coiled tubing string for applications in a particular area.

- Larger ODs decrease fatigue life.
- Higher material yield strength increases fatigue life.
- Increased wall thickness increases fatigue life.
- Larger bend radius increases fatigue life.

The amount of pressure at which the coiled tubing is cycled has a significant effect on the above factors. The graphs in Figures A.2 through A.6 show the effect of pressure over ranges of variables.

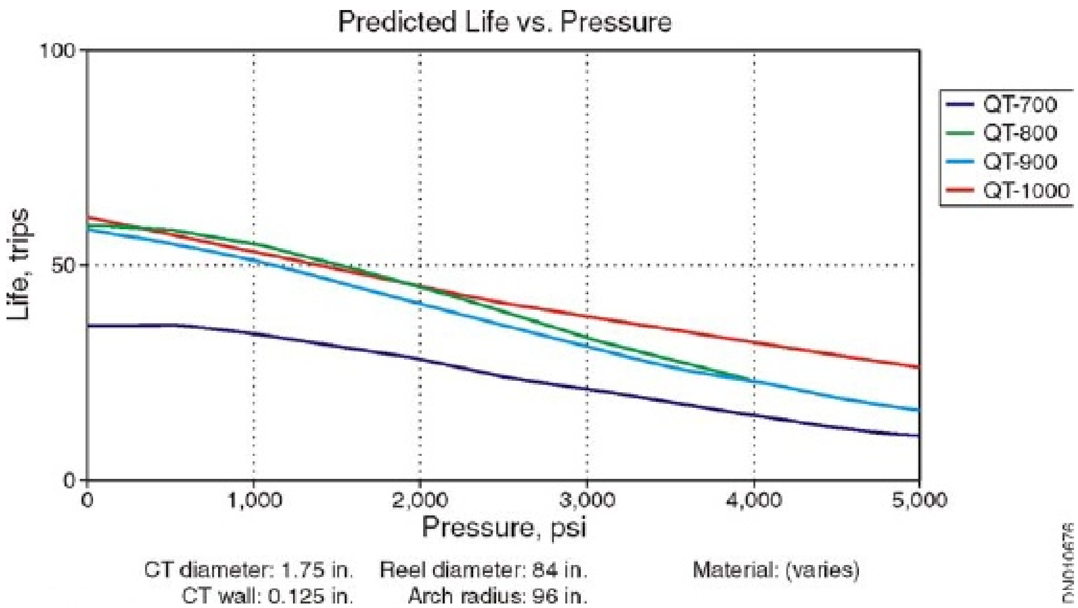


Figure A.2

7. Risk or consequence of failure.
8. Expected exposure time of string life.
9. Length of string.

The ideal application factor is one that results in 100% fatigue when experience indicates the tubing is at the point of failure and further string use would be too risky. The previous nine factors can be weighted by importance and a compliance level applied. The compliance level is rated on a scale of 0 to 10 with 0 being "no compliance with relevant guidelines" and 10 being "completely compliant with the guidelines." Requirements and guidelines on string and job record keeping will be discussed throughout this section. All relevant sections must be read to determine the level of compliance at a particular field location. Good and fair judgment must be used to estimate the level of compliance.

Table A.4 estimates an application factor based on the quality of a field location's fatigue management practices. Unit configuration and data acquisition equipment can dictate specific application factors on a per unit basis for the strings used by the particular coiled tubing unit. Shared strings should be weighted on the average conditions apparent in the equipment used to run the string.

Table A.4—Fatigue Application Factor Calculator

	AF	**BASELINE**
	4.00	Default; poor tubing management practices; 6 month string life
Enter 0 to 10 for Compliance Level		
		ADJUSTMENTS
10	0.50	Cerberus software fatigue calculations performed on every job using *accurate* manual or electronic records
10	0.20	All tubing cuts recorded; rig up was accurately measured and entered in Cerberus software
10	0.50	Full Data Acquisition System capability used on every job for fatigue records
10	0.50	Consistently followed corrosion prevention practices
10	0.40	No reverse bends at levelwind
10	0.10	String reversals modeled or avoided (spooling jobs more than the initial)
10	0.50	Risk/Cost of Failure 0 = High Risk/Cost 10 = Minimal Risk/Cost
10	0.30	String Length in 1000's of feet
6	0.00	Enter String Life (Months)
Estimated Application Factor	**1.60**	

String Files

Fatigue records for individual strings are stored in the Cerberus software string database. Each string has its corresponding string file. The string files are accessed and edited with the Cerberus String Manager software.

Sections

The string file database contains all the mechanical data, job history, and fatigue records. The string is either created in the Cerberus String Manager software or is imported from the file supplied by the manufacturer. Each material strip (section) that makes up the coiled tubing string is entered into the database with the physical properties of the material for that particular strip. Sections are configurable as straight wall or tapered wall. The connection between each section is designated as a weld type that is derated for fatigue depending on the type of weld used to connect the sections. The string is divided into 5- or 10-ft segments for tracking and recording fatigue. Each segment has a positional reference in the database that contains all relevant information about the segment such as wall size, OD, material strength, position from each end of the string, current life used, and any user defined derating. The string's makeup and properties can be viewed and edited from the Sections tab in String Manager (Figure A.7).

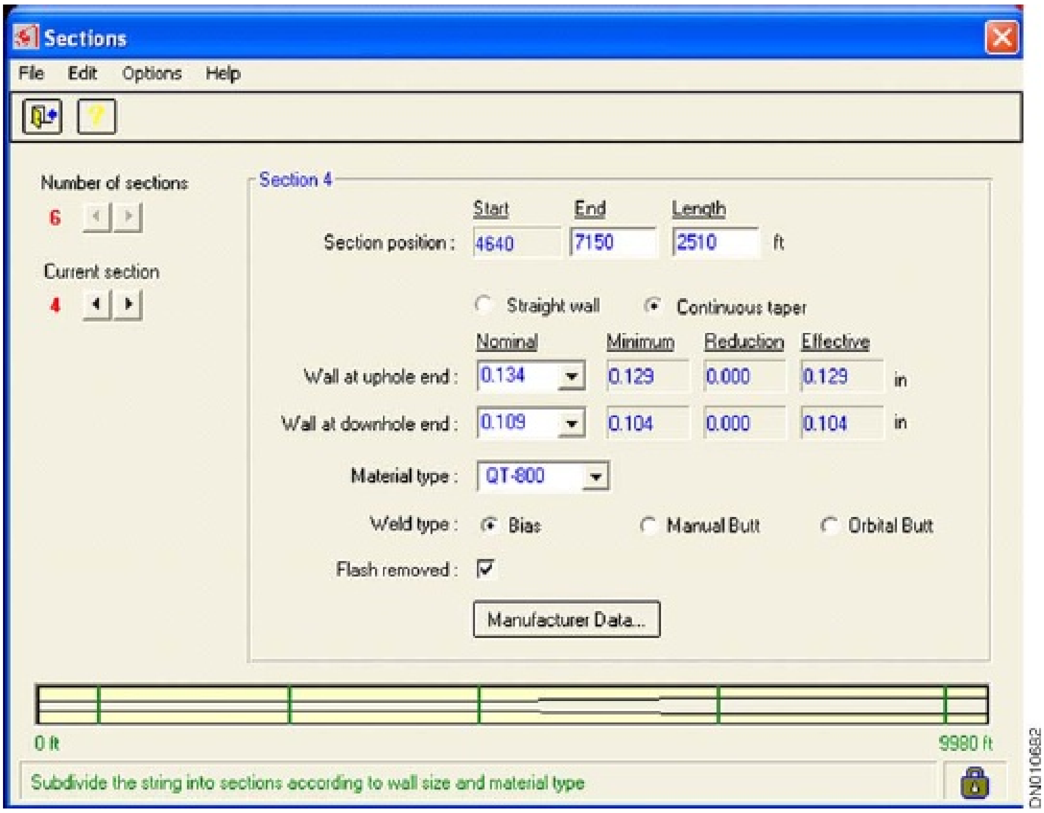


Figure A.7—Effective wall sizes used in fatigue calculations

Welds

The weld joining each strip is configured on the Welds tab of the Cerberus String Manager software (Figure A.8). Each weld is derated to account for the changes in the material due to the welding process. Every type of weld holds a different derating factor depending on the quality of the process used to make the weld. Derating factors are the point when the weld will reach 100% life utilization as compared to the parent material. A manual weld with a 35% derating will reach 100% life when the parent material of the same dimensions is at 35%.

The default deratings for welds are as follows:

- 0.80 for factory bias welds, no wall change
- 0.50 for factory bias welds, step wall change
- 0.45 for orbital butt welds, no wall change
- 0.20 for orbital butt welds, step wall change
- 0.35 for manual butt weld, no wall change
- 0.15 for manual butt weld, step wall change

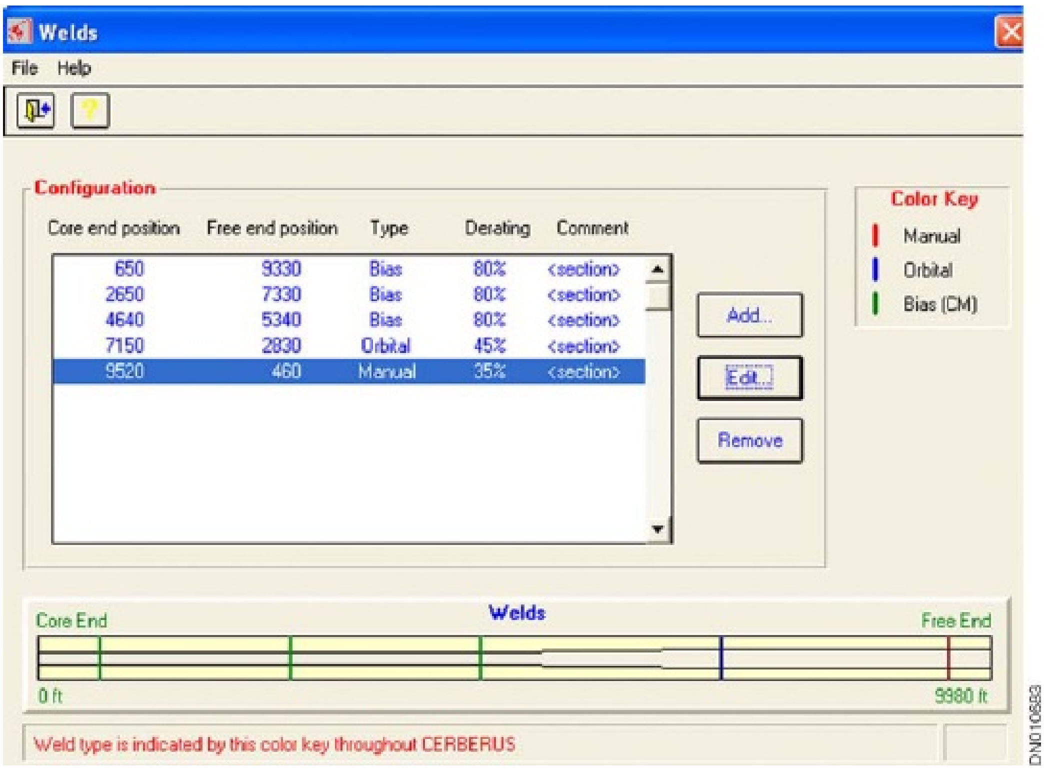


Figure A.8—Weld joining each strip is configured on the Welds tab

Zones

Specific zones of the string can be modified for fatigue accumulation rates without having to change the application factor using the Derate Zones tab of the Cerberus String Manager software (Figure A.9). Mainly this would be done for localized damage or material abnormalities. Derated zones accumulate fatigue faster the lower the derating factor is. The derating factor will multiply the application factor for the length of the tubing it is applied to except at welds where the worst derating is used. For example, a derating of 90% will result in an accumulation rate increase of 1.11 times (1 / 0.9 = 1.11). The number of derated zones that can be applied is unlimited.

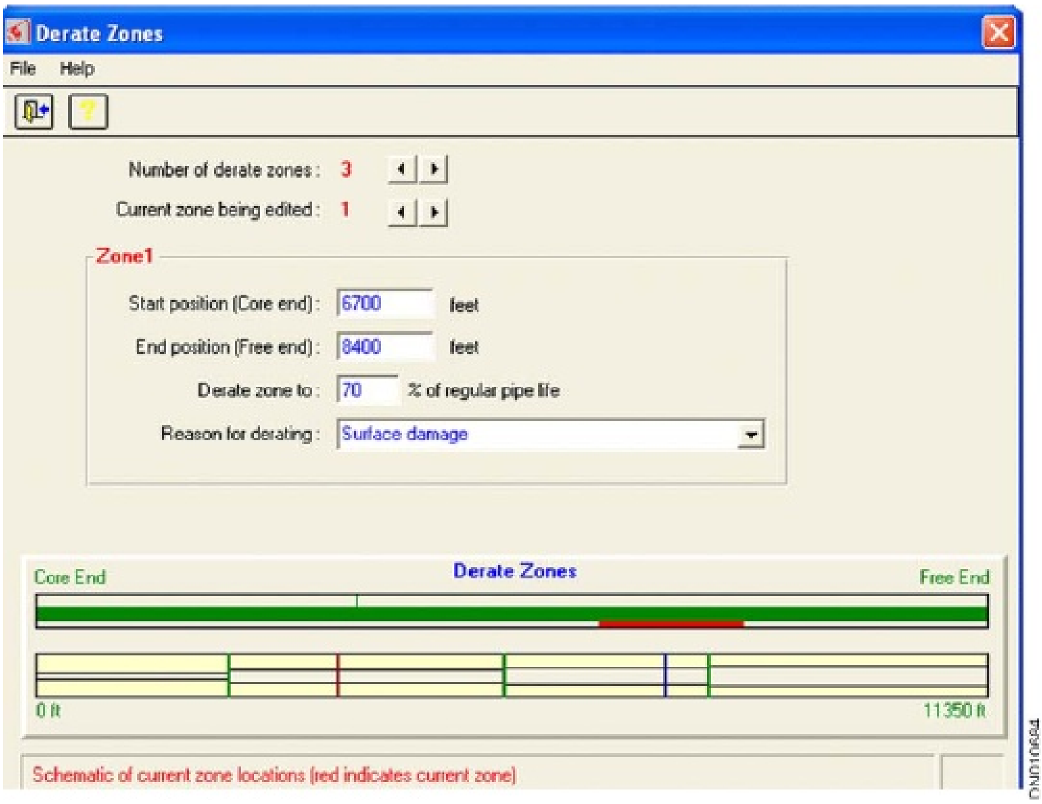


Figure A.9—Specific zones of the string can be modified for fatigue accumulation rates without having to change the application factor

Fatigue Model Settings

Each string has an independent fatigue model setting that is set using the Fatigue Model tab under the Configuration menu when the string is created (Figure A.10). Here the segment length for fatigue tracking and application factor are set. The reliability of the model is accessed here but it is inadvisable to change the reliability from the default value of 0.95. String files from Quality Tubing are generally supplied with an application factor other than that required for the area of operation. Segment lengths must be changed prior to saving any fatigue to the file. Application factors can be changed at any time but will result in a recalculation of accrued fatigue using the new value for the entire history of usage.

Wall thinning values collected from measurements made during the life of the string can be imported to update the effective wall thickness in the database. To import wall thinning values, enable (check) the *Import wall thinning values* box. When the box is checked, a dialog box will pop up every time the string is opened in Reel Trak™ fatigue simulator and the user will be asked if it is desired to update the values before applying additional fatigue.

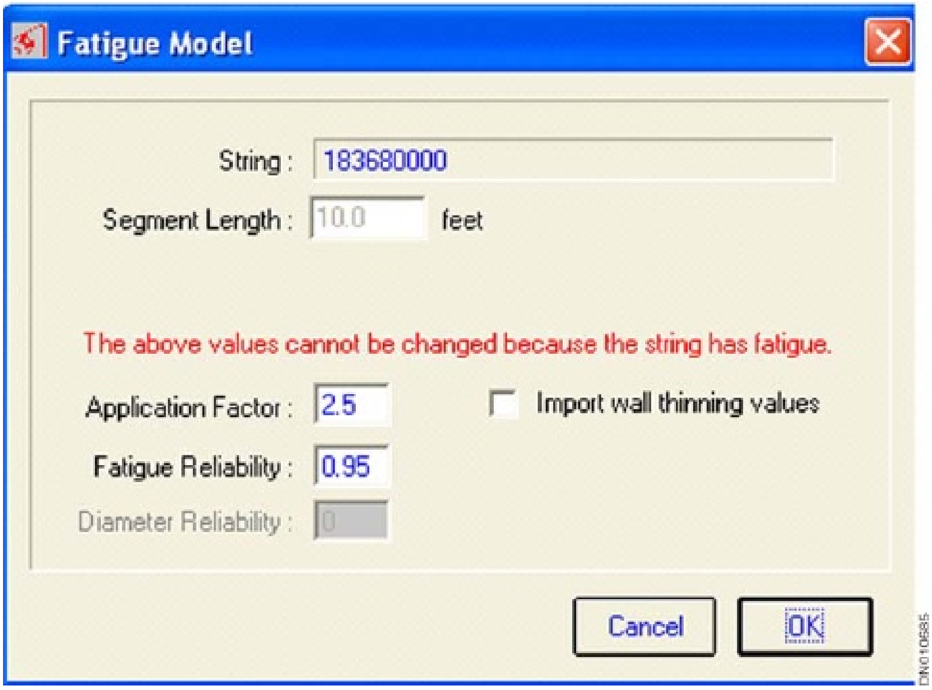


Figure A.10—The independent fatigue model is set using the Fatigue Model tab under the Configuration menu

Corrosion

Minor storage corrosion that could affect fatigue can be dealt with by selecting the Corrosion tab under the Configuration menu. A warning regarding the HES corrosion methods will appear; clicking OK will open the Corrosion screen. Storage corrosion reflected in reduced life can be added to the string file using two methods: the wall reduction method or the string life reduction method (Figure A.11).

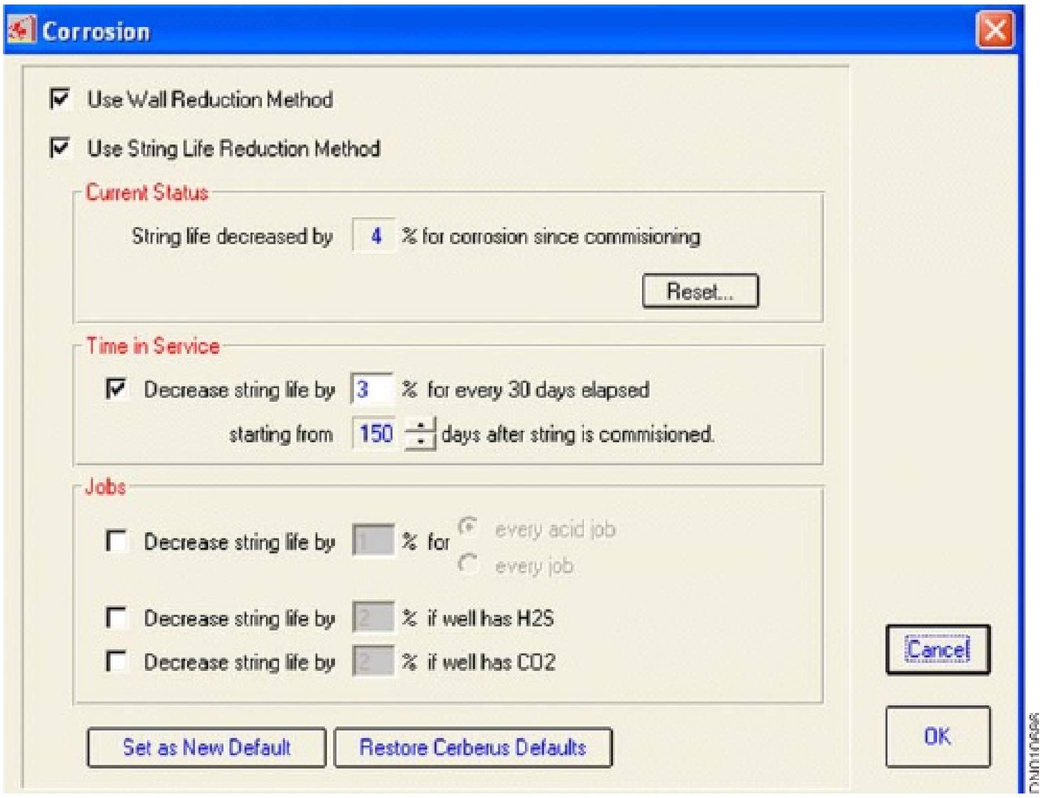


Figure A.11—Minor storage corrosion that could affect fatigue can be accounted for using the Corrosion tab under the Configuration menu

1. **Current Status**—Adds a one time value for a string that has been in storage and will be moved out to field operations. The value entered will be added directly to the cycle fatigue present for the entire length of the string.
2. **Time in Service**—Can be set for a string being removed from field operations and put into storage where the storage period may be unknown. Life usage values can be applied for every 30 day period the string remains in storage. The start date is set by inputting the number of days that have passed since the string was commissioned. The value used here will be added directly to the cycle fatigue present for the entire length of the string.

Note Using the string life reduction properties is not a substitute for proper corrosion control practices and is only intended for long term storage to account for evenly distributed filiform type corrosion that does not create a significant loss of wall thickness. Any string that experiences corrosion in storage that could significantly reduce wall thickness should be inspected and the new wall thickness values should be entered into the string database using the wall thinning function on the Fatigue Model screen.

3. **Jobs**—This section should not be used for adding fatigue values for job related corrosion events. Fatigue derating for job induced corrosion due to acid, H_2S, or CO_2 in the Halliburton fatigue model is automatically triggered by parameters selected in the setup of Job Manager files and are job specific. Fatigue derating for job induced fatigue is also triggered by selecting Matrix Stimulation from the Job Type screen, advancing an acid stage in TWI, or checking the H_2S or CO_2 boxes on the Well Data screen. Selection of any of these parameters will turn on the corrosion algorithm internal to the fatigue model.

Note **For Cerberus software string files only**: user applied corrosion will appear on the fatigue plot as a separate line or shading from the cycle fatigue on the string. Corrosion applied life utilization is stored separate from cycle life utilization in the string database. CTWin software does not recognize life utilized due to user applied corrosion when it calculates the combined loading limits plot; it only uses cycle life fatigue induced by bending cycles.

Cuts

The three options available for cutting string all affect fatigue. Cut string data is entered on the Cut String window (Figure A.12)

1. **Cut and discard from the downhole end**. This method is used for any tubing cut off during rig up procedures to redress for makeup of a connector or tubing cut for life management reasons. Any cut made from the downhole end should be in increments that match the segment length set on the Fatigue model screen. This action will delete the cut segments along with the fatigue data from the string database.
2. **Cut and discard a section of tubing from the middle of the string and rejoin the remaining sections**. This method is used when a damaged section of tubing is removed from the string. This action will delete the segments along with the fatigue data in the section removed and re number the remaining segments in relation to the reel core position and corresponding new downhole zero point.
3. **Cut and save both sections as separate strings**. This method enables sections of the string to be cut off while saving all the fatigue data of both sections so that the pieces can be rejoined at a later date or cycled out as two separate strings.

All string positions for cuts are measured from the core end of the string.

Figure A.12—Three options are available for cutting string

Splices

Strings can have sections added at either end or any place in the middle of the string. Splice information is entered into the database using the Splice String window (Figure A.13). New or used pipe can be added and the related fatigue life of the added section will be incorporated into the updated string file. The software will only allow splicing of strings that have matching segment lengths of either 5 or 10 ft. If splices are common in the area, all strings should be configured with the same segment length.

Important	**Once fatigue is saved to a string, the segment length cannot be changed.**

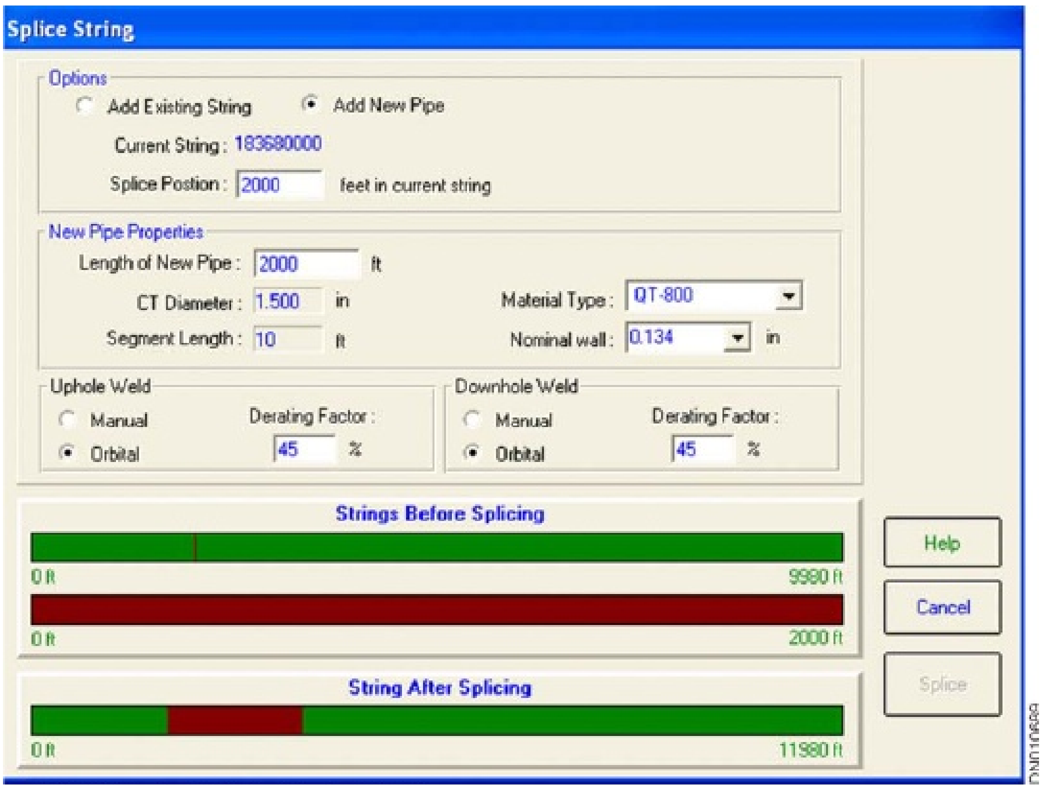


Figure A.13—Splice information is entered into the database using the Splice String window

Job History

All relevant changes in the string file are recorded in the String History log (Figure A.14). This includes any cuts, splices, spooling operations, executed jobs, and changes in the fatigue model made to the string. In the history log, any entries displayed in red text indicate a point in time that the fatigue or editing history can be undone.

Important **Once the string file is downloaded to another computer or saved under another name, the history is locked and cannot be changed. For this reason a copy of the original string file should be saved as a backup if it will be required to correct records at a future date.**

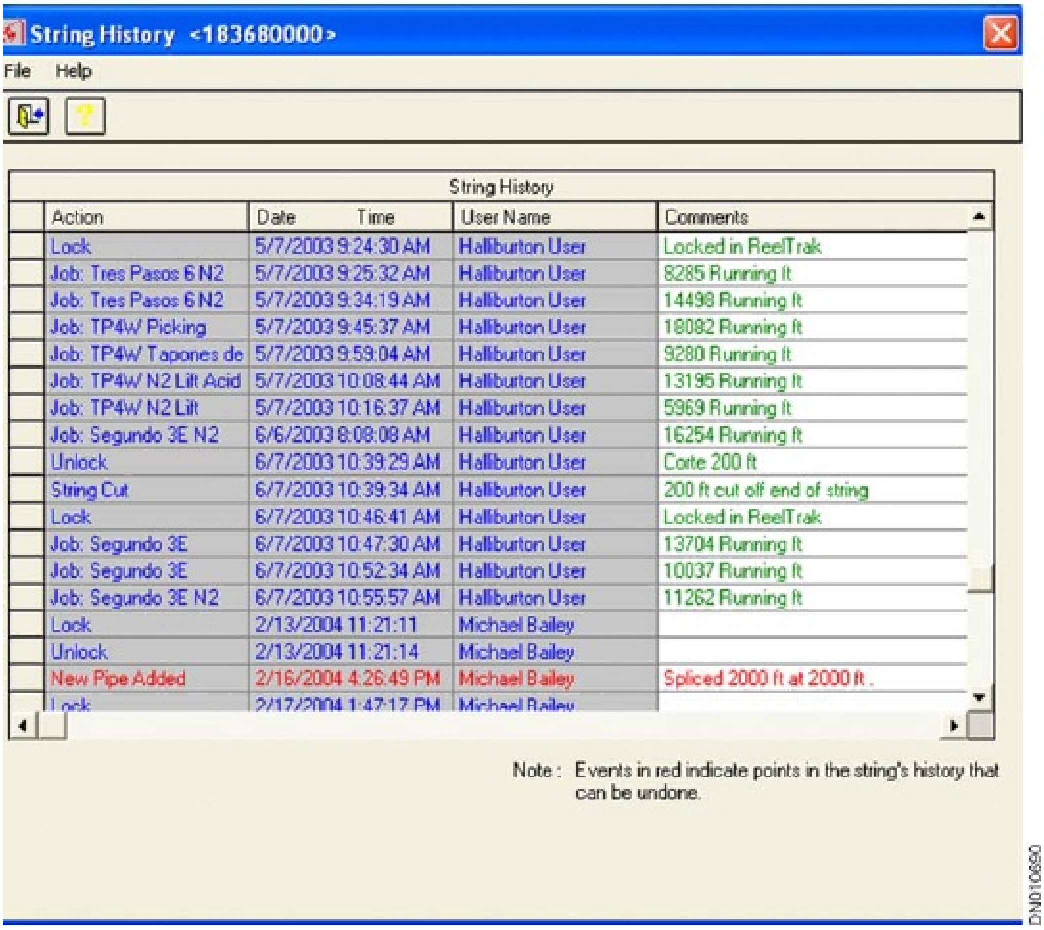


Figure A.14—All relevant changes in the string file are recorded in the String History log

Reel Files

The effective diameter of the coiled tubing as it is spooled on and off the reel plays a major part in fatigue because this is typically the smallest bend radius the tubing encounters. This radius increases as the wraps are stacked onto the reel. The position and corresponding bend radius are required for accurate calculation of fatigue accumulation. The physical dimensions of the reel are set up in Reel Manager (Figure A.15) and saved for retrieval in other modules where tubing position on the reel plays a factor in calculations. The core diameter, flange diameter, and width of the reel are required so that the string can be virtually spooled onto the reel to determine positions of segments and the affective wrap radius for bending events or friction calculations.

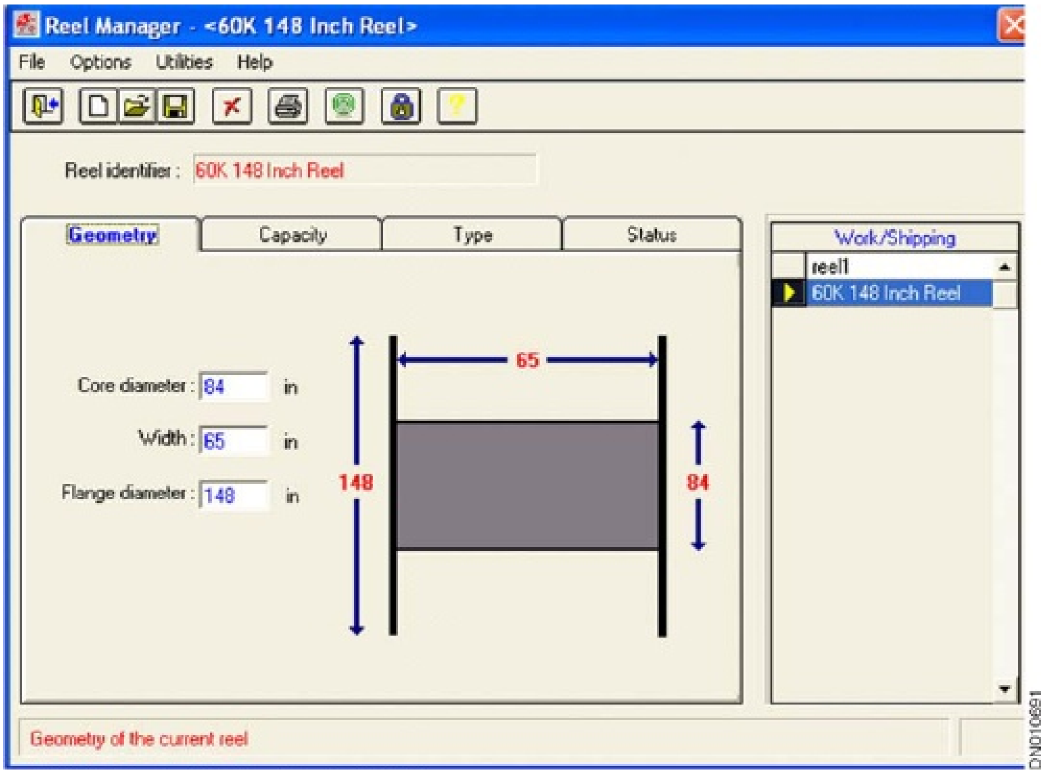


Figure A.15—The physical dimensions of the reel are set up in Reel Manager

Job Manager Files

All the parameters necessary to execute and calculate fatigue are stored in the Job Manager file. Here all of the variables are configured to match the equipment and conditions present during a job. Typically the job file is set up prior to the job so that the string and well data can be pulled into CTWin software for real time combined limits, forces, and fatigue calculations. Once the job has been completed, the fatigue data can be saved directly to the string file or executed later. Job setup data in IWI is entered in the Job Setup section of the navigation tree and is stored with the real time data. Although significant information is stored in the job file, only the required data for fatigue calculations will be discussed.

Configuration

A file is created and named with the well name or job ticket number. The naming convention should be uniform for all jobs completed in the area. The string and reel that will be used for the job are loaded on the main screen. Well files can be loaded from Well Manager or configured in the Job Manager Figure A.16). If the well contains H_2S or CO_2, a well must be configured for fatigue calculations. A tool is not required for fatigue calculations

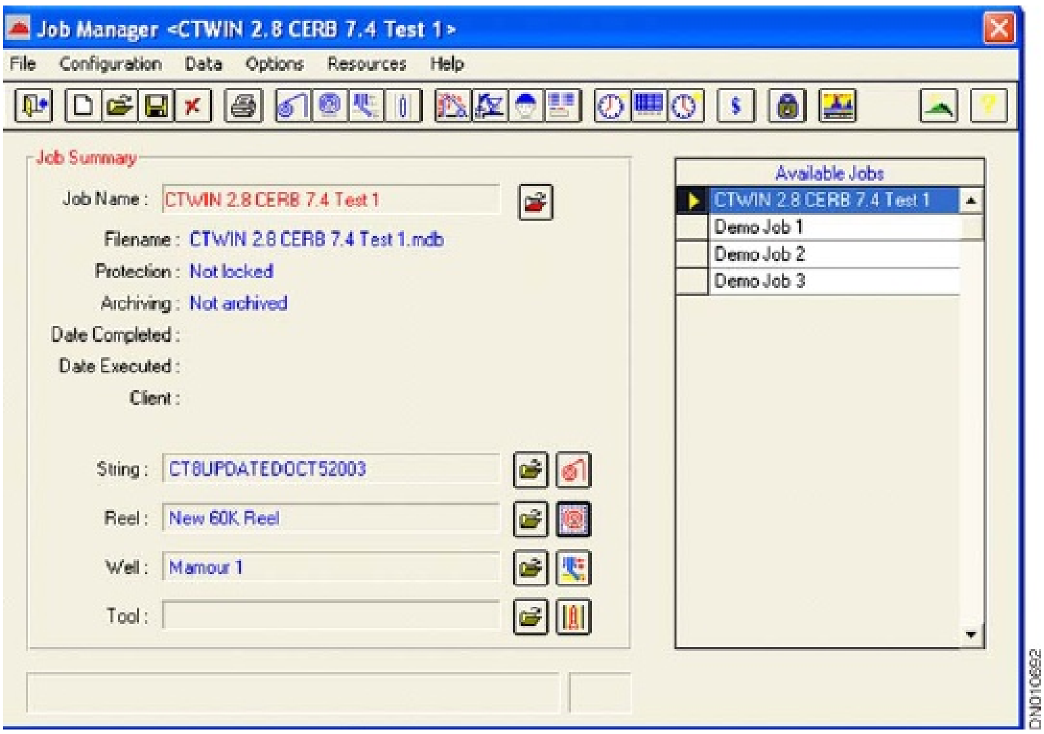


Figure A.16—All parameters necessary to execute and calculate fatigue are stored in Job Manager

Wellsite Geometry

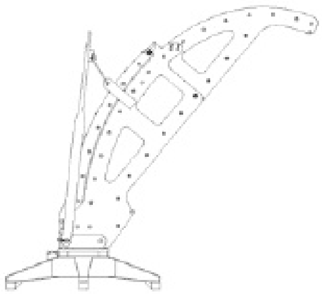
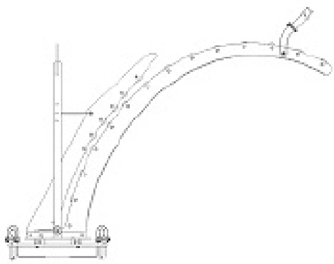
The wellsite geometry is required to track each segment as it comes off the reel, bends over the tubing guide radius, and is run in the well. During execution of the job, each segment is tracked as it moves through the rig up geometry.

- **Reel to gooseneck distance** is the length of pipe suspended from the end of the tubing guide to where the tubing contacts the reel. This distance determines the segments not cycled at the tubing guide for a bending event during a reversal of direction. Segments that do not reach the tubing guide will only count one cycle off and onto the reel.
- **Gooseneck radius** is the effective radius the tubing is bent over at the tubing guide. Each standard tubing guide has a corresponding length of the bend, which is entered automatically as the radius size is selected. Any radius or length can be hard entered into the fields. The effective radius of progressive radius tubing guides will depend on the rig up height and tubing diameter. The smallest radius on which the tubing bends should be used for the gooseneck radius. Sometimes this cannot be determined until the rig up is complete.

Table A.5 on the following page shows the default values for the progressive radius tubing guides.

Reel tension should be kept at the minimum required to prevent larger tubing sizes from being pulled down onto the smaller radius.

Table A.5—Progressive Radius Guide Arch Data

<table>
<tr><td rowspan="4"></td><td colspan="2">52–96 in. Progressive
Radius Guide Arch
(standard on the
30/38K injector)</td></tr>
<tr><td>CT Size, in.</td><td>Radius, in.</td></tr>
<tr><td>1.0–1.25</td><td>52</td></tr>
<tr><td>1.5–1.75</td><td>72</td></tr>
<tr><td rowspan="5"></td><td colspan="2">72–120 in. Progressive
Radius Guide Arch
(standard on the 60K injector,
also same radius profile used on
95K segmented guide arch)</td></tr>
<tr><td>CT Size, in.</td><td>Radius, in.</td></tr>
<tr><td>1.0–1.5</td><td>72</td></tr>
<tr><td>1.75–2.0</td><td>96</td></tr>
<tr><td>Larger than
2.0</td><td>120</td></tr>
</table>

The distance across the guide arch is also required for the wellsite geometry. Table A.6 shows the typical contact length for each guide arch, but again, this length will vary depending on tubing stiffness due to tubing OD and wall thickness
.

Table A.6—Typical Contact Length for Guide Arches

Guide Arch Style	Typical Contacted Length, ft (m)
72- to 120-in. Progressive	13 (4.0)
52- to 94-in. Progressive	13 (4.0)
54-in. Fixed	9 (2.9)
60-in. Fixed	11 (3.2)
72-in. Fixed	13 (3.8)
94-in. Fixed	16 (5.0)
96-in. Fixed	17 (5.1)
100-in. Fixed	18 (5.3)

The **top of injector to zero depth datum** is the distance from the point at the top of the injector to the end of the coiled tubing relative to the counter zero point. This measurement is to correct the counter depth reading to the string position so that fatigue is calculated on the correct segments. Different applications, long tool strings and well zero points change the starting depth of the counter. The fatigue model needs to know which segment was at the top of the injector at the start of the job.

> *Example*: Assume a zero depth distance at the end of tubing with no toolstring, even with the end of the lower brass of the stripper packer; the counter is set to zero. The zero depth datum in this case would be the distance from the lower brass to the top of the injector, or approximately 10 ft. If the counter reads 100 ft, the string position at the top of the injector will be 110 ft. Take the same situation but assume that the counter is set to the well zero point, which is at the same point as the top of the injector. The counter is set to 10 ft to match the well depth at start. In this case, the zero depth datum is set at 0.

In the real world, the zero reference for each well is not conveniently placed at the top of the injector. This is usually a point in space where the original rig floor was when the well was drilled. Although the original well zero point may not be inaccessible to measure from, the well depths and surface equipment position are marked in relation to the original zero depth. In most cases, there will be a reference to the distance from the original zero to a point in the existing wellhead equipment.

For most operations, it is desirable to have CTWin software reporting the depth at the bottom of the tool; however, for fatigue calculations, Reel Trak™ fatigue simulator is only interested in the location of the end of the CT. Reel Trak™ fatigue simulator needs to know where the end of the CT is in relation to the depth being written to the fatigue file by the CTWin software.

To further complicate matters, it is usually desirable for the depth indicator in CTWin software to match the depth on the wellbore schematic. Zero depth on the wellbore schematic will often be based on the rig floor level of the rig that drilled the well, which may not be in position any more. The well zero depth can be anywhere above or below the CT equipment rig up.

The deployment of long tool strings can increase the error of applied fatigue by hundreds of feet. Not correcting for the length of the tool string could create a false perception that the cycling on tubing has sufficient life remaining, when in actuality, a situation for potential failure may exist. The method of calculating the zero depth datum to correct for the tool string length and well zero points is outlined in Table A.7, which shows five scenarios covering the majority of situations likely to be encountered.

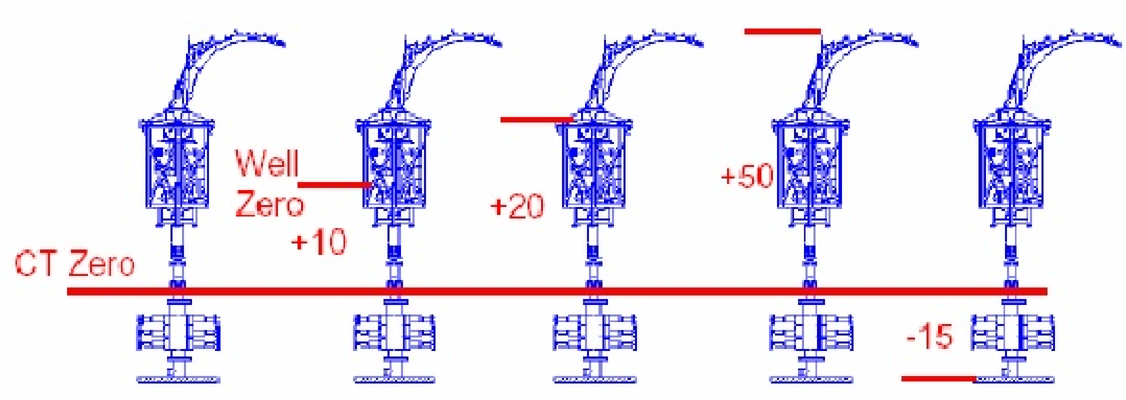


Table A.7—Calculating Zero Depth Datum

Distance from CT Zero to Well Zero (Z)	0 (same)	+10	+20	+50	15
Toolstring Length (T/S)	200	200	200	200	200
Counter Depth CD = Z + T/S	200	210	220	250	185
Top of Injector to Well Zero (TI)	20	10	0 (same)	30	35
Cerberus Zero* CZ = TI – T/S	180	190	200	230	165

* Number required in Cerberus Job Manager software, Wellsite Geometry box labeled "Top of Injector to Zero Depth Datum" (with short tool strings, this will be a positive number; with longer toolstrings, a negative number).

The calculations in Table A.7 require selection of a measuring point in the rig up to which well zero and the top of the injector can be referenced. This is the point where the physical end of the tubing or the top of the tool string is in relation to the CT equipment between the injector and the wellhead. This should be a point from which it is easy to make measurements. The simplest reference is to pull the connector to the lower brass of the stripper/packer. This is referred to as the “CT zero depth.” In the cases that follow, the CT zero point is at the connection just above the BOP where the tools are deployed into the well.

For the five scenarios, the following factors have been assumed for all cases:

- Toolstring length is 200 ft and the top of the tool string is located at the connection above the BOP, setting the CT zero point at the top of the BOP.
- Distance from CT zero (BOP connection) to the top of the injector is 20 ft.
- The well zero distance height varies and is shown on each picture.
- The depth counter will be set to the bottom of the tool string in reference to well depth.
- The relevant position of the various reference points will determine whether the distance will be recorded as a positive or a negative number.
  - If the well zero point is above the CT zero point, the distance will be positive.
  - If the well zero point is below the CT zero point, the distance will be negative.
  - If the well zero point is above the top of injector, the distance will be negative.
  - If the well zero point is below the top of injector, the distance will be positive.
- When the relation of the end of the tool string and the well depth is ignored, the counter is set to 00000 and not corrected for well depth. The zero depth datum is calculated as in Scenario 1 where the CT zero point and the well zero point are the same point.

Figures A.17 and A.18 show the wellsite geometry input as in Scenario 5 and how Reel Trak™ software uses the configuration to set the position of the segments.

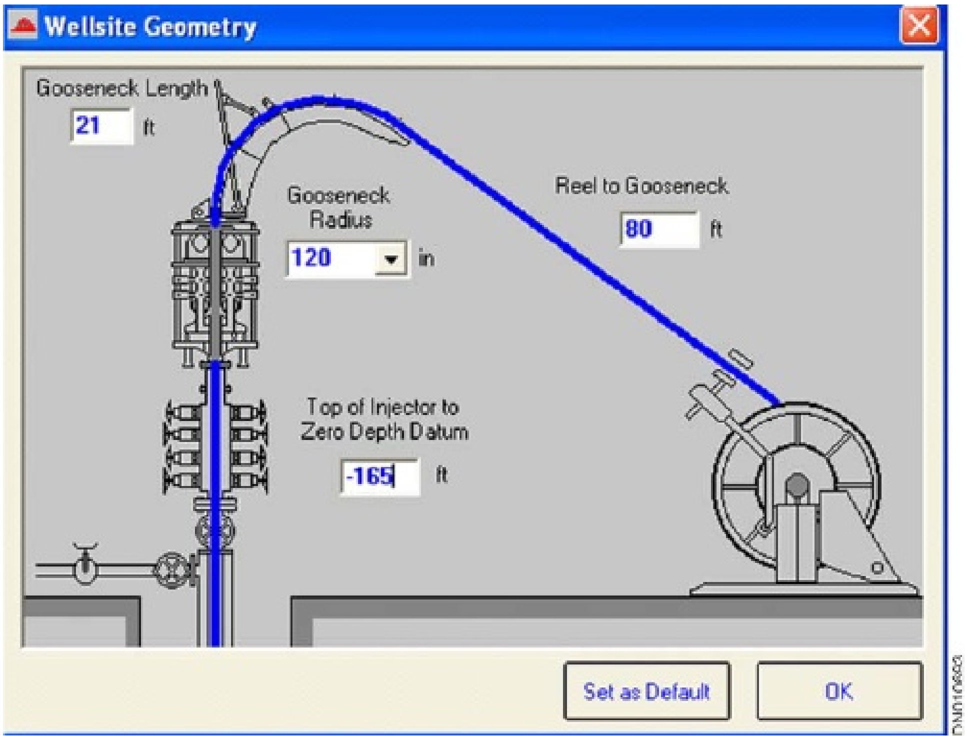


Figure A.17—The string position shows the 20 ft of tubing past the top of the injector with the depth reading at 185 ft

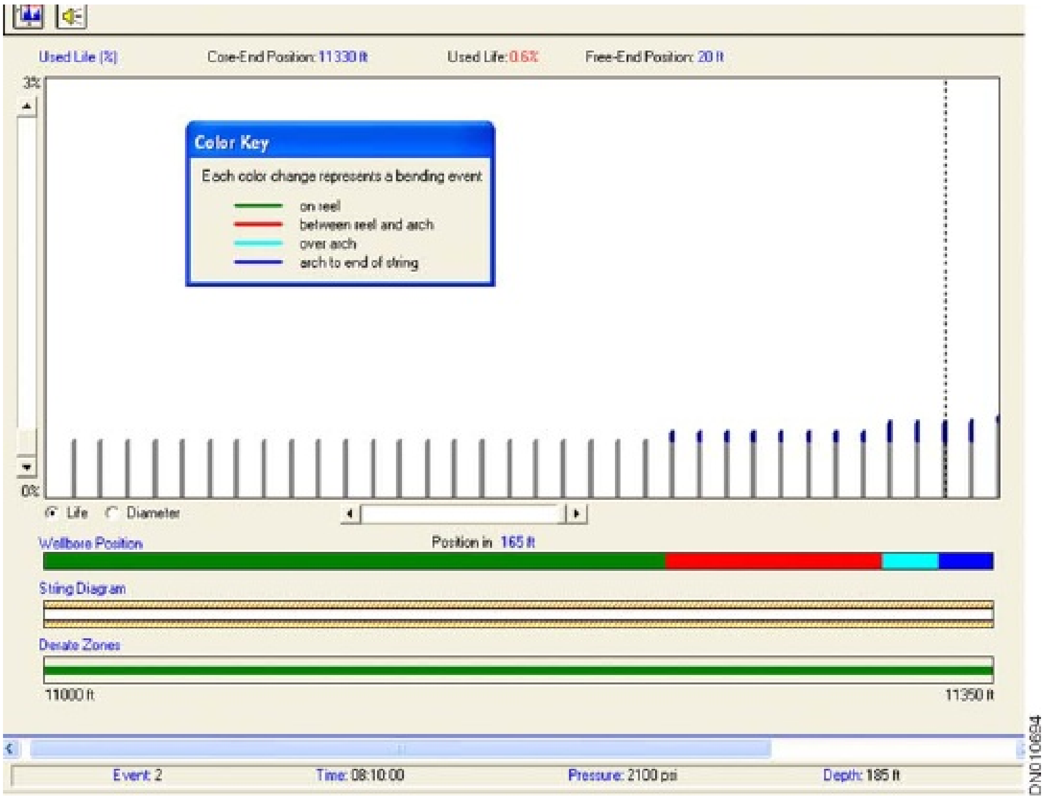


Figure A.18—Reel Trak™ software uses the configuration to set the position of the segments

Well Physical Data

If imported from Well Manager, most of the information fields will be populated (Figure A.19). If the well was not created in Well Manager, the fields can be filled in with the minimal data required for fatigue calculations. At a minimum, the well name and wellhead pressure must be entered. If there is H_2S or CO_2 present in the well, checking the related box will include the corrosion calculation for H_2S or CO_2.

Calculations affect the whole string not just the exposed parts. The concentration of H_2S or CO_2 has no effect on the calculations. The derating for H2S or CO2 is calculated for the one job only. For H2S or CO_2, the derating is: 0.90 or 1.11 times more fatigue added.

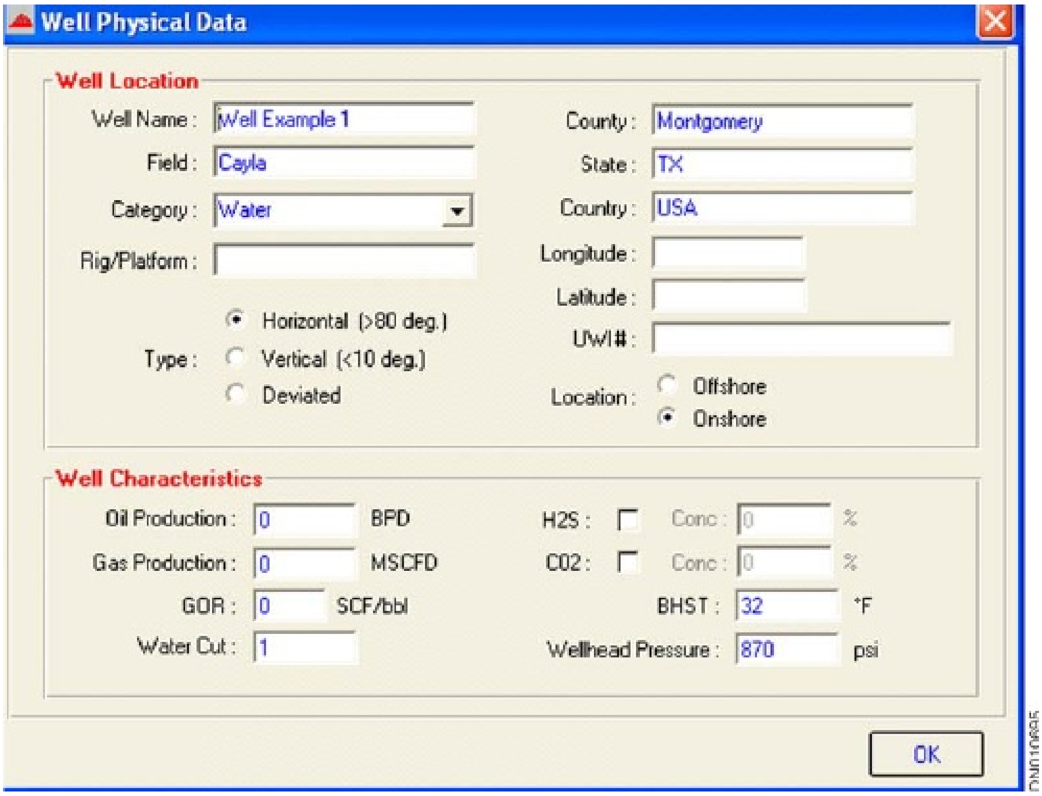


Figure A.19—If imported from Well Manager, most of the information fields will be populated

Job Type

Fatigue cannot be executed unless a job type is selected.

Selecting matrix stimulation as a job type will trigger the acid corrosion calculation and is the only job type that has additional effect on the fatigue calculation. Any time acid is pumped, matrix stimulation should be selected as the Master Job Type (see Figure A.20). As with H_2S or CO_2, the whole string is affected, not just the exposed parts, and the concentration of acid has no effect on the calculations.

The assumption is that all acid is properly inhibited during pumping and that there will be no adverse wall loss during the job. The derating is applied after the acid is pumped at the start of the next job. Acid derating is permanent and cumulative and ignores any external corrosion.

For acid derating, the equation is:

$$Cn = 0.5 + .5\,(.8)n$$

where n = the number of jobs

Examples: If Job 1 has used acid, then for Job 2, C1 = 0.90, or 1.11 times fatigue added.

If 5 jobs have used acid, then for Job 6, C5 = 0.66, or 1.51 times fatigue added.

If 10 jobs have used acid, then for Job 11, C10 = 0.55, or 1.81 times fatigue added.

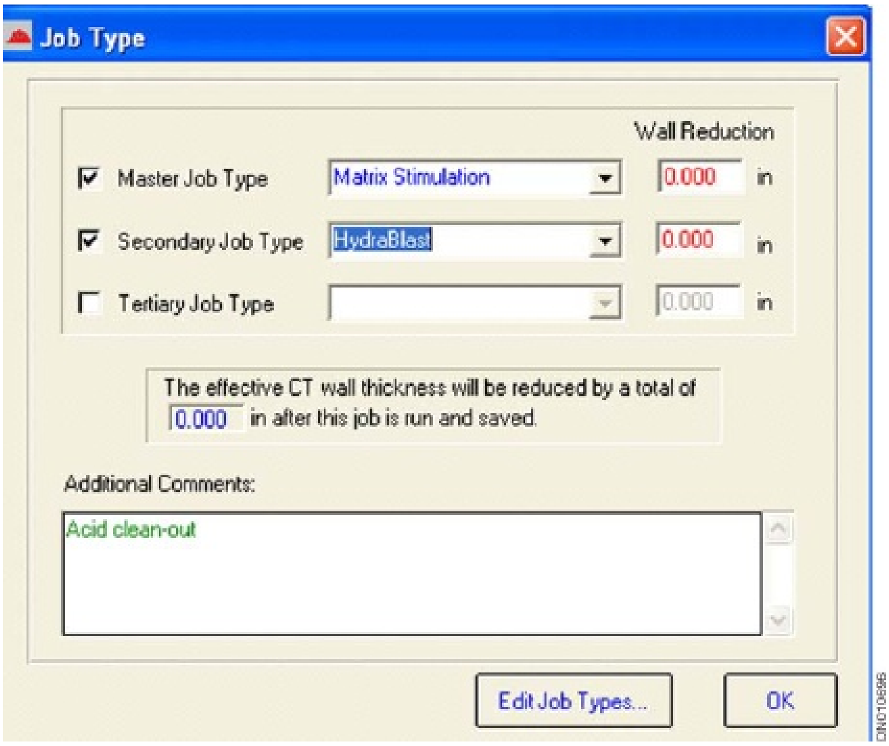


Figure A.20—Any time acid is pumped, Matrix Stimulation should be selected as the Master Job Type.

Job Log

Job data for fatigue calculations can be entered into the Job Log (Figure A.21) three ways:

1. Manual entry.
2. Imported from *CTWin Fatigue.mdb* file or other electronic formats.
3. Real time entry by linking data files when the job is open in Reel Trak™ software.

The fatigue model calculates fatigue using the entered pressure for the length of tubing between the start and end depths. The more frequent and accurate the data, the better the fatigue calculations will be. The average wellhead pressure for the job is required to calculate the pressure inside the tubing at the tubing guide if the value in the pressure column is pump pressure. If the value in the pressure column is the calculated pressure at the tubing guide, the wellhead treating pressure should be set to zero.

Figure A.21—Job log

Start and Final Depth Options (Figure A.22) sets the depths at which the fatigue calculations will begin. In most cases, there is no need to change the defaults. One instance in which defaults would be changed is if electronic data recording was interrupted and the job was recorded in two files. The final depth on the first file can be set at the depth when the recording stopped and the start depth of the second file can be set to the same depth to avoid additional fatigue being recorded if the default start or final depths are not changed.

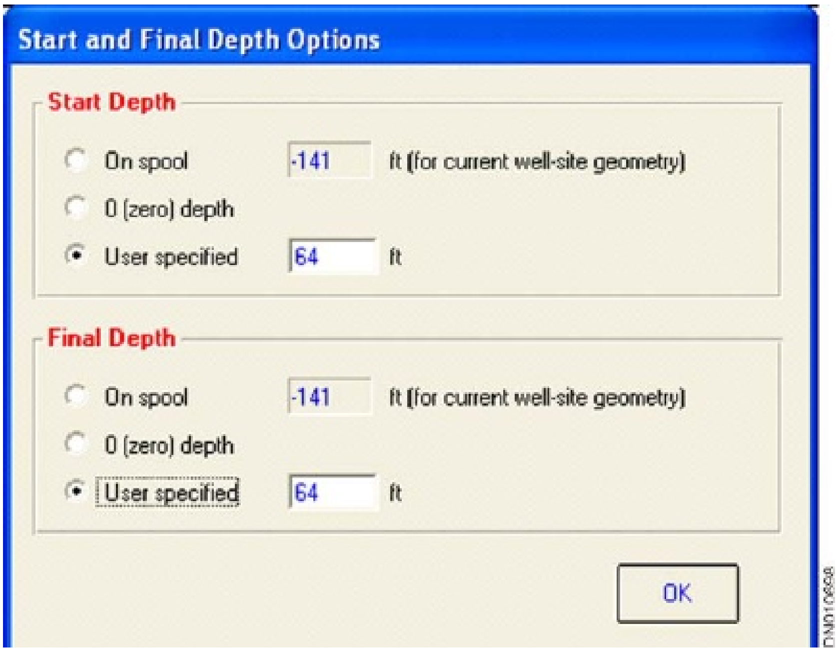


Figure A.22—Start and Final Depth Options window sets the depths at which the fatigue calculations will begin

Three options are available to set the start and final depths. None of these options affect the zero depth datum and only set the depths at which fatigue calculations are activated and stopped.

- **On spool** will include rig up bending events and calculates the fatigue for every segment that leaves the reel. This is the default setting and should be used in most cases. It will be a negative number.
- **0 (zero) depth** will not include any bending events for tubing off the reel before the job starts. This option would be selected for subsequent runs in the well on the same job recorded on separate job logs and avoids stacking false fatigue at the downhole end of the string.
- **User specified** is used to set a specific depth from which to start the job. This option is used for any reason that would require the job log to be saved or for opening a new job log while the tubing is in the well. No fatigue will be recorded for any tubing off the reel from the downhole end to get to the set depth. This is the default setting for imported electronic job logs.

Heave

For on shore jobs, fatigue only accumulates when the CT is moving. However, for offshore jobs having a wave compensation system, additional fatigue can accumulate when the CT is essentially stationary. The additional fatigue occurs because, even though the CT is stationary at the injector, the reel moves relative to the injector to compensate for the movement of the waves. The movement of the reel causes tubing to spool on and off the reel, and possibly move at the guide arch. This additional movement is called heave.

The actual fatigue calculations for the bending events due to heave are the same as fatigue calculations for regular movement of the CT. However, fatigue due to heave can be far more serious because all the fatigue accumulates at the same position along the string.

Heave is not a problem when the CT is in motion. Once the CT reaches a critical velocity, the movement of the pipe is not influenced by the wave compensation system. Due to this situation, the program will only calculate heave when the coiled tubing is stationary. Entries must be made in the job log for the time when the tubing was stopped and for when it started moving again. Jobs that will be executed from DAS records require that an event be entered to ensure a line is written to the *Fatigue.mdb* file when the tubing is stopped and started. Any two consecutive entries in the job log with the same depth will cause the fatigue for the heave to be calculated for the time elapsed between the two entries.

The counter for the DAS system must be at the injector to use **Heave Calculating**. If the counter is at the reel, the amount of movement will be recorded as a depth change and the heave calculation is not required. Heave calculations must be enabled at the main Cerberus software screen under the Cerberus Setup tab of the Options menu

To configure heave:

1. Open the job log.
2. Click the Heave tab to display the Heave screen.
3. Select the Enable Heave Calculations check box.
4. Enter the heave period.
5. Click the Position tab to configure where along the wellsite geometry the extra fatigue will occur.
   - Select if you want to perform heave calculations for only CT segments at the reel, or for segments at both the reel and the guide arch.
   - Select if you want to perform heave calculations only for CT segments at the bending points, or for all affected segments based on amplitude.
6. Click the CT Speed tab to configure speed requirements. Currently you can only perform heave calculations when the depth does not change.

If the tubing will be stationary for long periods of time, measures should be taken to eliminate heave effects. This can be done by creating enough slack in the tubing between the reel and tubing guide to accommodate the wave motion.

Executing Fatigue

Reel Trak™ fatigue simulator is where the jobs configured in Job Manager are run and the new CT life is calculated. All the information needed to calculate fatigue is contained in the job database. Reel Trak™ fatigue simulator loads that information, performs the calculations, and saves the new life in the string database. To protect important string data, a number of safeguards are built into this system to ensure that only valid data is input and saved.

Using IWI or Cerberus software to track fatigue helps maximize the working life of CT strings. The fatigue model accurately monitors which part of the CT string is fatigued for each movement of the tubing into and out of the well, and applies the appropriate inputs (diameter, wall thickness, material type, bending radius, and pressure) to the fatigue model. The fatigue model calculates the change in fatigue life, which is then recorded in the string database.

When the job has been completed, you can save the new string used life to the string file. When you save the string, a record is written to the String History table showing that this job has been executed. This record is checked to ensure you don't run the same job twice for the same string.

There are two mode types in Reel Trak™ fatigue simulator:

- **The mode the job was opened with** principally determines whether or not you can save the new used life of a string after running the job. This mode can be Test mode, or Execute mode.
- **Data entry mode** determines what types of data entry Reel Trak™ fatigue simulator accepts. The three data entry modes are: Playback, Manual Data Entry, and Auto Data Entry.

Different mode combinations should be chosen for different situations.

- If you are at the wellsite and want to enter the Job Log as you run the job:
    a. Open the job in Test mode, and select Manual Data Entry.
    b. Save the Job Log periodically.
    c. To actually save the new used life, run the job later in Execute mode.
- If you are at the wellsite and want to acquire the Job Log data from a CTWin software database:
    a. Open the job in Execute mode and select Auto Data Entry. This function can be called from the CT Calculations Screen of CTWin software, which will configure the data set link automatically.
- If you are planning the job and want to experiment with the wellsite geometry and Job Log:
    a. Open the job in Test mode and select Manual Data Entry.
- If the actual job has already been performed, and you only want to calculate and save the new used life of the string:
    a. Open the job in Execute mode, and use the default Playback mode.

Table A.8 shows the relationship between the Data Entry, Test, and Execute modes.

Table A.8—Data Entry, Test, and Execute Modes

Data Entry Mode	Test Mode	Execute Mode
Playback (default)	• Data cannot be changed. • Used life cannot be saved.	• Data cannot be changed. • Used life can be saved
Manual Data Entry	• Job Log, reel geometry, and wellsite geometry can be changed, but the changes can only be saved to the Job Log. • Used life cannot be saved.	• The Job Log can be edited and changes saved. • Used life can be saved.
Auto Data Entry	N/A	• The Job Log is acquired from the data acquisition system (DAS). • Used life can be saved.

This section will concentrate on fatigue that will be executed and saved to the String File.

Manual records are required if no data acquisition system (DAS) is being used or the electronic data has been lost. It is recommended that any manual records be entered into the Job Log of the Job Manager file and not at the Fatigue Simulator Job Log screen.

The main criteria for manual records is that information be recorded as often as possible. The primary purpose of the manual Job Log is to document all significant tubing movements and pressure changes to track the fatigue life of the CT string. The secondary purpose is to document job activities and fluid stages.

The sample job logs attached at the end of this section allow the accurate reporting of the job details. The more accurate the records, the more accurate the fatigue calculation will be. A Job Log entry should be made whenever any of the following occur:

- Tubing direction changes, even slightly.
- Depth changes by approximately 100 to 500 feet.
- Tubing or wellhead pressure changes by 100 to 500 psi.
- Fluid changes.
- Pump rate changes.
- Job actions are performed.
- Unusual events occur.

Importing Electronic Job Logs

1. Enter Event Data into the Job Log

The following file types can be imported into the Job Log of Job Manager.

- ASCII files
- Comma delimited .TXT files
- MS Excel files
- .CSV files
- MS Access files
- .MDB files
- Cerberus .LOG files
- CT Acquire data set files

Data will be entered into the Job Log columns in the same order as the data is set out in the original file. The first row of data (or the column headers of an imported file) is then searched for the keywords: Pressure, Depth, and Comments. The first column (as read from left to right) having a keyword in the heading will be imported into the corresponding Job Log column. If the data set has "Wellhead Pressure" listed before the pump pressure, the wellhead pressure will be the value imported into the Pressure column of the Job Log.

Files without labeled columns should have the data configured in the following order from left to right:

Event, Date, Time, Pressure, Depth, Comment

ASCII, .TXT, .CSV and .LOG files are imported using the Import icon or by selecting the Import ASCII file selection from the File menu of the Job Log screen.

CTWin and Orion data acquisition programs both write data to a MS Access .MDB file for transfer to the job log. The columns are set in the correct order to fill in the correct time and date in the job log for each entry. CTWin and Orion software files are imported by selecting "Import Orion File" from the File menu of the Job Log screen.

When the CT Calcs Module of CTWin software is activated, a file named *FATIGUE.mdb* is created and placed in the corresponding CTWin software data directory for the job. When the Import Orion File option is selected from the menu, the directory that comes up will be the last CTWin software data directory accessed. Because there is a *FATIGUE.mdb* file in every saved CTWin software data directory, care must be taken to ensure that the correct file is being imported. Highlighting the *FATIGUE.mdb* file and clicking on Open will import the data into the job log.

CT ACQUIRE data sets are imported through a setup screen accessed from the File menu of the main Job Manager screen or by holding down the CTRL + I keys. Follow the on screen instructions to import the Acquire data sets.

2. Calculate the Average Well Pressure

Once the event data is entered into the job log of the Job Manager file, an average well pressure must be calculated over the entire job. The wellhead pressure is used for every event to calculate the pressure in the tubing at the injector when the bending events take place. A decision has to be made about the impact of the well pressure on the fatigue. The pressures during tubing movement should be used to determine the average well pressure. Using the highest pressure encountered will overestimate the fatigue, which will shorten the usable life of the tubing; whereas, using the lowest pressure or the default of zero will underestimate the fatigue and could allow the tubing to be used longer than is safe.

Note — If values in the Pressure column are the calculated pressure at the tubing guide, the well pressure entered should be zero.

3. Review, Save, and Lock the File

Once the well pressure is entered save the job log and exit to the main screen of Job Manager. Review the input screens to make sure that any other fatigue related information is correctly entered. Save the job and lock the file.

4. Access the Job File in Fatigue Simulator

1. Click on the Fatigue Simulator icon or select Fatigue Simulator from the Resources dropdown menu. This will open the job file in Fatigue Simulator.
2. You will be asked if you want to open the file in Execute mode. Clicking No will open the file in test mode. Clicking Yes will open in Execute mode to save fatigue data to the string file.
3. Fatigue Simulator will open all related string and reel files selected in Job Manager. If the files are not locked, you will be asked to lock the files.
4. Once the files are locked, the program will open to the Job Log screen. This is a copy of the job log from the Job Manager file. The data entry fields will be grayed out and no changes can be made at this screen.
5. Select Options > Model Preferences from the menu bar to access the Preferences window to enter model settings for the fatigue calculations (Figure A.23).

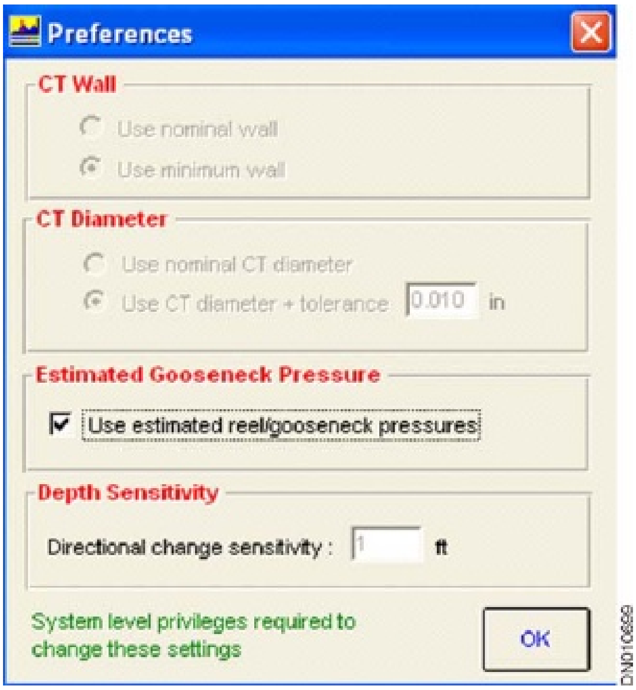


Figure A.23—Model settings for fatigue calculations

5. Set Fatigue Calculations

The Preferences window (Figure A.23) is where parameters for fatigue calculations are set. The default settings use the minimum wall and CT diameter + tolerance, which represents the manufacturing tolerances Halliburton accepts from Quality Tubing. These settings should not be changed unless the string database has been updated with physical wall thickness and diameter measurements.

The **Estimated Gooseneck Pressure** is another area where fatigue life can be over- or under-estimated if the correct parameters are not set.

- If the data in the Pressure column of the Job Log is the pressure recorded at the inlet of the reel, you will need to have the program calculate the pressure at the reel and gooseneck. A checkmark in the box will calculate the reel/gooseneck pressure from the reel inlet pressure and the current wellhead pressure entered on the Job Log screen.
- If the box is unchecked, the value in the Pressure column will be used as the pressure at the reel/gooseneck.

Depth sensitivity is not required for manually entered records, and the default value of 1 will suffice for the calculations. If the counter used for DAS is mounted on the reel levelwind, pump oscillation can make the reel rock slightly, which can cause excess fatigue to stack up in one spot if the counter is switching between two full foot increments. Setting **Directional change sensitivity** to 2 should resolve this issue.

Running Fatigue Calculations

Fatigue calculations can be run from five windows in Fatigue Simulator. The choice of window during calculations only affects the display shown during the calculations.

- The **String Viewer** screen (Figure A.24) shows a graphic representation of the fatigue as it is accumulated along the string. This screen contains the most information on the string and applied fatigue.
- The **Reel Viewer** screen shows the dimensions of the reel loaded from Job Manager.
- The **Wellsite Geometry** screen shows the measurements of the rig up and zero depth datum set in the Job Manager file.
- The **Data Monitor** screen shows numeric data for the string as the calculations progress through the Job Log event entries. The Maximum Life Used tab will pinpoint the segment that has accumulated the most fatigue.

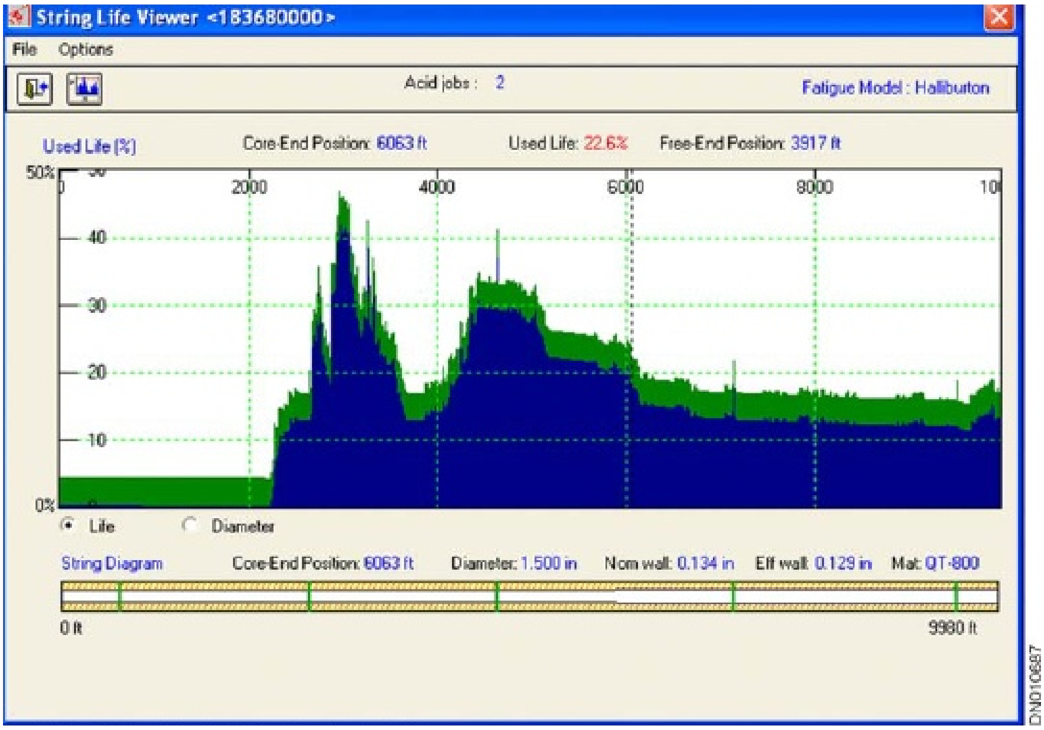


Figure A.24—String Life Viewer

The point shown is at 4,469 ft in the well. Below the well position bar is a diagram of the string that shows the sections and welds in the string. The data posted above the diagram are the properties of the string at the point that the cursor is positioned. Here the core position, OD, nominal wall thickness, effective wall thickness, and material type are listed. The effective wall thickness is the wall thickness from which the fatigue calculations are made.

On the main graph, fatigue is displayed as bars representing each segment of the string.

- The **gray** area of the graph is fatigue accumulated prior to this job.
- The **blue** area is fatigue added for the current job.

Once the calculations have run to the end of the job log, the Save icon will be activated and the fatigue can be saved to the string file. Once the fatigue is saved, the string file will be tagged to indicate that the current job has been executed with this string. You will not be able to run it again in Execute mode. You can also exit the Fatigue Simulator without saving the fatigue.

Calculating Fatigue in Real Time

CTWin software is the module in the HalWin software suite that records data from coiled tubing jobs. When the Coiled Tubing Calculations Module is open and a Cerberus Job Manager file is attached to the Calculation Module, fatigue can be calculated in real time as the job is progressing. If the CT calculations are started without a Job Manager file (file attached to give the program the required parameters), the data collected may not reflect the actual conditions of the job. This could adversely affect the execution of the fatigue on the string.

Important **Even if the fatigue file will be updated at a later time, the correct string and reel must be loaded to ensure that calculations are correct and that the data captured in the *FATIGUE.mdb* file reflects the actual job.**

HalWin 2.8.3 and Cerberus 8.5 Software Revisions

The following describes the interface and functions for HalWin 2.8.3 and Cerberus 8.5 versions and later. These versions have incorporated a feedback loop to update the calculations as fatigue is added to the string. Two problems encountered with earlier versions have been eliminated: averaging of the wellhead pressure and confusion as to when to use the gooseneck calculation. The program now calculates the cycling pressure inside the tubing at the reel and tubing guide using the real time tubing and wellhead pressure and writes this value to the Pressure column of the *FATIGUE.mdb* file.

In previous versions, although the fatigue plot was updated during the job using an average wellhead pressure entered before the job, limits calculations were based on the fatigue profile saved at the end of the previous job and did not reflect the increase in life utilized during the current job. This produced a displayed operating envelope of the coiled tubing larger than the actual envelope as the fatigue accumulated during the job.

These changes eliminate averaging pressures in fatigue calculations and give the supervisor in charge a realistic view of the operating limits of the CT string at the time the information is needed. Together, these changes should provide more cost effective string usage and help avoid failures caused by incorrect information.

CT Calculations Module and Cerberus Software Data

The CT Calculations module organizes and connects the Cerberus software data and the real time data collected by CTWin software. It effectively provides the bridge between the two programs so that fatigue and limit calculations can be carried out.

- In the **CTWin software side of the interface**, material limits are calculated as a function of the maximum combined load that can be applied and the actual current loading conditions. In addition, the cycling pressure and reel friction pressure are calculated for subsequent fatigue calculations. These are displayed graphically and numerically. Periodically, the fatigue database for the string is accessed by CTWin software, which then updates the maximum allowable limit in relation to the accumulated fatigue. The maximum allowable limit is updated for increased fatigue every 30 minutes with a function for the supervisor in charge to manually update the maximum allowable limits anytime during the job if required.
- The **Cerberus software side of the interface** uses the calculated pressure values and tubing movement records from CTWin software to update the life utilized during the job. The additional fatigue for the job is stored in the string database in a separate column specifically for real time calculations. At the end of the job, the fatigue can be permanently saved to the string database, or if required, the original fatigue at the start of the job can be preserved by exiting the fatigue simulator without saving.

FATIGUE.mdb File Functionality

Functionality of the *FATIGUE.mdb* file has been expanded to record all the data required to complete post-job analysis in the Force Calculator (Orpheus) module of Cerberus software.

A backup function also writes the live Pump Pressure to the *FATIGUE.mdb* file. This would be required to run fatigue calculations after the job in the case where a Job Manager file was not available or the file was unusable. The job log in Job Manager will recognize .CSV files created from HalWin .RTD files.

Effect of Fatigue on Limits Plots

The Coiled Tubing Calculation module calculates pressure inside the tubing at the bending points, the combined forces of the tubing at four points, and the maximum allowable limits in relation to fatigue life used. All the calculations require that a string file and reel be loaded into the module. The output of the calculations is recorded in the *ctcalcs.rtd* file and can be displayed on a strip chart or the numerical display screen.

Circulating Pressure

Circulating pressure is calculated at the tubing guide and reel used in the calculation of fatigue usage of the string. Current pump pressure, wellhead pressure, and string length and depth are used to calculate this value. The method is a simple calculation that runs on the basis that all fluid rate changes, fluid rheology changes, hydrostatic differences, and choke setting changes will be directly reflected in the recorded live pressures. When compared to empirical data collected in tests at the University of Oklahoma, the calculation was found to have an average error margin of ± 3% across a wide range of fluids.

Reel Friction

Reel friction is the calculated friction loss for the section of tubing currently on the reel. This pressure is not used in any calculations but is used to cross check the calculated circulating pressure in instances where the pump pressure falls below the wellhead pressure or when the pumps are off and there is still pressure in the tubing. If the differences in the calculations become negative, the program assumes that there is no friction pressure and that the pump pressure and circulating pressure are the same.

SF at Inlet

Pump pressure, reel core diameter, and the material specifications of the first segment of tubing at the core end of the string are used to calculate this value. The SF at Inlet value represents the combined stresses at the first layer of tubing at the core of the reel. Pump pressure is the controlling factor in this calculation and the displayed value is a percentage of yield for the material. This value can be used to determine the maximum allowable pump pressure.

SF above Injector

Circulating pressure, tubing guide radius, and the depth and material specifications of the segment of tubing currently at the tubing guide are used to calculate this value. The SF above Injector value represents the combined stress loading of the tubing currently bent over the tubing guide arch in relation to the pressure in the tubing at the guide arch and the tubing guide radius. Circulating pressure is the controlling factor in this calculation and the displayed value is a percentage of yield for the material.

SF above Stripper

Circulating pressure, depth, weight indicator reading, and material specifications of the segment currently in position between the injector chains and the stripper/packer are used to calculate this value. The SF above Stripper value represents the combined stresses caused by (1) radial stress from internal pressure plus axial load from weight of the tubing, (2) internal pressure effects acting on the end of the tubing, and (3) force applied by the injector or drag from the packer element. Both axial load and pressure are the controlling factors in this calculation and the displayed value is effective force as a percentage of yield for the material.

SF below Stripper

Circulating pressure, wellhead pressure, depth, weight indicator reading, and material specifications of the segment currently in position in the well below the stripper/packer are used to calculate this value. The SF below Stripper value represents the combined stresses caused by (1) collapse instability due to external/internal pressure differential, (2) radial stress from internal pressure plus axial load from weight of the tubing, (3) pressure effects acting on the end of the tubing, and (4) force applied by the injector. Axial load and internal/external pressure are the controlling factors in this calculation and the displayed value is effective force as a percentage of yield for the material.

SF Allowable

Accumulated fatigue and material specifications of the segments of the coiled tubing string are used to calculate this value. As fatigue accumulates, the minimum yield strength of the material drops due to cold working of the material as it is bent. The SF Allowable value represents the 80% yield limit corrected for accumulated fatigue and displays the maximum allowable safety factor for load limits. **This value should not be exceeded.** On the Coiled Tubing Calculations Graph screen, this value is displayed across the entire length of the coiled tubing string. On the Numeric Display screen or if charted on a strip chart, the value is for the segment of coiled tubing currently moving through the surface equipment.

Allowable Limits Line

This is the lowest value for the correct minimum yield of the string. This line is projected across the entire length of the string as the maximum allowable working limit for the job. Although the fatigue and resultant derating is not even for the entire length of the string, staying below the Allowable Limits line (see Figure A.26) will help ensure that all loads applied are within the capabilities of the weakest section of tubing. This is particularly important when tapered sections are in the top part of the well.

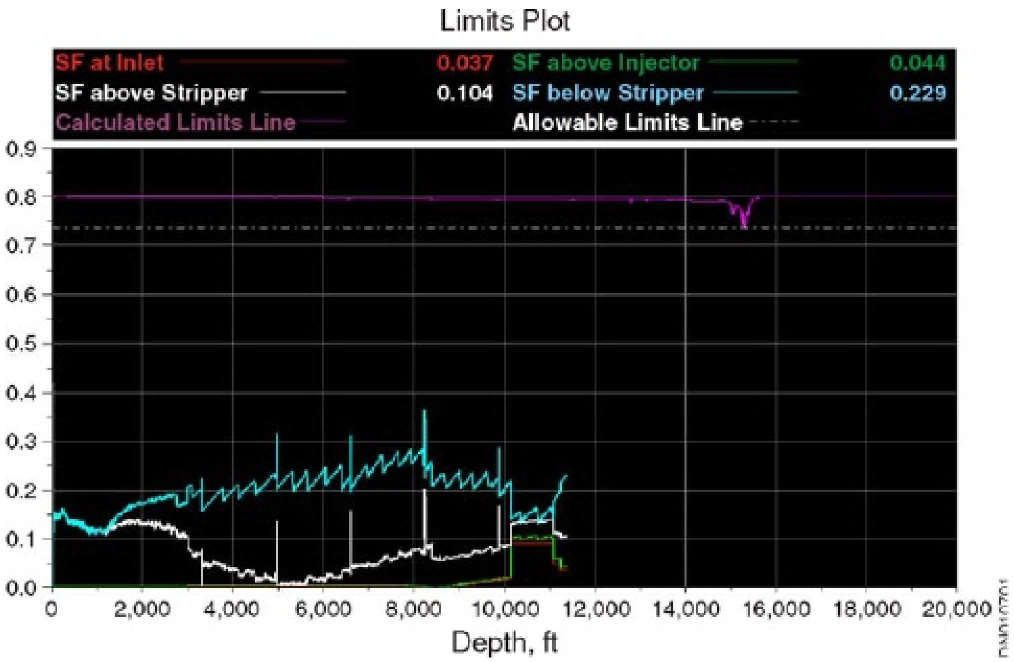


Figure A.26—Staying below the Allowable Limits line will help ensure that all loads applied are within the capabilities of the weakest section of tubing

Storage

Because corrosion is the number one cause of premature fatigue failures and corrosion typically occurs between jobs, the practices used to protect the coiled tubing between jobs must be adequate to help prevent failures. Local conditions must be taken into account when determining the amount of maintenance required to help prevent CT corrosion while tubing is being stored.

- In warm climates with high humidity, damaging corrosion can occur within a short time and can be especially severe near coastal areas. In dry climates, storage protection requirements may be minimal.
- Changing conditions during day and night hasten corrosion when the temperature of coiled tubing falls below the dew point.
- Moisture may be trapped for extended periods between the tubing wraps, and if chlorides are present, pitting corrosion will be accelerated.
- For long term storage, it may be necessary to store the coiled tubing inside, out of the weather. Application of a corrosion inhibitor is recommended if environmental conditions (temperature and relative humidity) are not controlled and can be damaging.
- Infrequently, used coiled tubing is also subject to internal corrosion usually attributed to aqueous solutions remaining in the tubing for extended periods of time. Coiled tubing units going in for major maintenance or having long wait times between jobs are the most susceptible to storage corrosion. In most cases, working units are not idle for long periods of time and inhibitors are not regularly applied to the inside or outside of the tubing.

The nature of the industry does not always allow for accurate forward planning as to how long a unit may wait between jobs. Generally, the following guidelines should be observed:

- Incorporating corrosion control as outlined in the Best Practices for CT Corrosion Prevention after every job will help minimize the effects of corrosion.
- Any unit that will be idle longer than 14 days should be protected with internal and external inhibitors.

Covers

Use of weather resistant covers may be helpful in minimizing the amount of water and contaminants (such as chlorides from salt spray at sea or in some coastal areas) the coiled tubing is exposed to and in preventing the washing away of inhibitors. Unfortunately, covers can also be detrimental to the tubing because they act to trap moisture (condensation) and may not let the tubing "breathe," even if the bottom of the cover is open. Covers are not the answer to external coiled tubing corrosion problems but may be useful in some limited situations.

Freeze Protection

Although the tubing should be free of water during storage, there is always a possibility that unintended residual moisture can be present in the tubing string. If the tubing is to be stored at a location where the temperature is expected to drop below the freezing point, it may be advisable to pump an antifreeze (ethylene glycol) mixture through the string. Commercially available antifreeze fluid has the added advantage of containing corrosion inhibitors.

Other Factors that Affect Fatigue

Several conditions can occur during the life of a coiled tubing string that are not accounted for in the fatigue model or the application factor. These usually involve localized damage to short sections of the tubing that can affect the total cycling that the tubing can undergo in the area in question. These conditions can be managed and typically do not require any changes to the string database except in certain cases to add a derated section.

Abrasion

The residual bend in the tubing at the downhole end of the string causes the coiled tubing to rub the wall of the well tubulars with more force than a straight piece of pipe. This is typically seen in the first 100–150 ft of tubing and is more pronounced closer to the toolstring. As axial load is applied, the curve of the residual bend is straightened by the hanging weight. This can cause wall thinning near the downhole end of the tubing that will affect the fatigue life and load properties of the tubing. In most jobs, this is not an issue because the downhole end of the tubing typically has the lowest accumulated fatigue and the lowest loads. Normal tubing management techniques will control this problem with regular cutting of tubing from the downhole end of the string.

Quick rig up units are the most susceptible to failures related to this problem because the connector is not usually cut off after every job.

The transportation of reel with loose wraps can cause abrasion if the wraps rub against the drip pan, frame members, or crash bars. Any reel that arrives on location with loose wraps should be closely inspected and any damaged tubing removed before the job.

Gripper Block Marks

V type gripper blocks have a tendency to leave faint marks on the coiled tubing. No failures have been directly linked to these marks, but full scale fatigue cycling has been conducted with V-type blocks and any effect from normal marking is incorporated into the model. These marks become less apparent as the gripper blocks wear. Marking of CT by gripper blocks can occur in the following ways:

- Applying excessive pressure to the linear beam can cause deformation and deep marking of the tubing. Good maintenance of the traction system and adherence to recommended linear beam pressures for size and grade of coiled tubing can help in avoiding this problem.

- Not applying sufficient linear beam pressure can cause the gripper blocks to slip, resulting in longitudinal scarring on the coiled tubing. Minimum and maximum linear beam pressures for specific injectors can be found in Section 8 of the *Coiled Tubing Handbook.*
- A common cause of deep marking of the tubing by the gripper blocks is caused by snubbing against pressure with low gripper chain tension. The chain becomes slack between the drive sprockets and the top of the linear beam causing the grippers to contact the tubing at the wrong angle, which damages the pipe or the gripper block.

Any excessive marking of the coiled tubing should be closely inspected. Transverse marking is more detrimental than longitudinal marking. The marking should be accounted for by derating the section of tubing by editing the derated zones in the string database. Consideration should be given to removing the section of pipe if the marking is excessive or the tubing is deformed.

Roller/Wear Pad Damage

Tubing guide rollers and wear pads are designed to minimize fatigue damage as the tubing moves across the tubing guide. If these components are not maintained properly, resulting damage to the coiled tubing can be severe.

Seized bearings are the main cause of roller damage, scraping the tubing as it moves across the stationary roller. Wear blocks allowed to wear to the mounting bolts will cause the same effect. Evidence of seized rollers or worn-out pads is apparent by the appearance of metal shavings collecting at the top of the stripper/packer or anti-buckling guide. Regular post-job inspection of the tubing guide can help avoid this type of damage.

BOP Slip Damage

Closing the slip rams on the tubing will leave damaging marks on the tubing. This is a function of the design of the well control equipment and cannot be avoided. BOP slips leave transverse grooves 360° around the tubing. If possible, slip marks should be dressed off with emery cloth as soon as the section of pipe is recovered from the well or during the next post-job maintenance. The depth of the slip marks should be recorded and the segment of tubing at that depth derated to 70% if the marks were dressed or 50% if the marks were not dressed.

Kinks

The fatigue model is based on smooth, even wraps as each layer of tubing is added to the reel. Occasionally some event leads to gaps in the wraps that increase as the layers are added. This intensifies and eventually leads to an uneven spooling job. The supervisor in charge is forced to “fill in” the gaps to get all the tubing onto the reel. This causes the tubing to be bent over a sharp radius and causes kinks in the pipe. If this is a one time occurrence and the spool is straightened out soon after the problem occurs, the effect will be negligible. If the condition is allowed to continue, the fatigue calculated for the string will be incorrect because the bending radius for the tubing on the reel will be unknown and could cause the fatigue to be calculated lower than what is experienced. This is more critical for strings running lower application factors.

Erosion

Because a greater percentage of work done with coiled tubing involves circulating some material from the wellbore, erosion has become a factor in fatigue and load limits.

High external erosion occurs at areas of high turbulence typically near the tool string and at the point where the fluid exits the wellbore at the return tee/cross. Erosion that occurs near the tool string can be handled by regularly cutting tubing from the end of the string. Erosion at the flow tee/cross can be minimized by not allowing the tubing to remain stationary while sand or scale is being circulated from the well. The tubing should be in continuous movement while erosive material is being circulated from the well.

Internal erosion from pumping cement or sand slurries can be minimized by keeping the velocity of the fluid below 32 ft/sec.

Units that consistently perform cleanout work or pump erosive fluid on a regular basis should have a regular wall thickness inspection and have the wall thinning value in the string database updated.

Reverse Bends

Reverse bending occurs when tubing is bent in the opposite direction of the bending on the reel or tubing guide. This causes extremely high stress reversals and compounds the fatigue damage by a factor of 1.5 to 2.0, depending on the severity of the bend.

Reverse bending most commonly occurs at the levelwind or at tubing straighteners. Rigging up with the reel too close to the wellhead for the height of the injector is the most common cause of reverse bending. In this case, the levelwind cannot physically raise high enough to allow the tubing to exit the reel in a straight line. Halliburton equipment is designed for a maximum reel exit angle of 30 or 70° from horizontal. Placing the center of the reel the same distance from the wellhead as the total height of the injector stackup will provide sufficient movement in the levelwind assembly to avoid reverse bends.

When using one piece trailer units with mounted cranes, it is not always possible to have the reel far enough away from the wellhead and still have enough reach on the crane to rig up. In such cases, an extension should be mounted between the levelwind traveler and the counter to increase the angle. When the exit angle of the tubing changes as wraps are removed, reverse bending may only affect the first few outside wraps on the reel. If reverse bending is unavoidable, the section of tubing can be derated on the Zones screen.

Units that employ a tubing straightener on a regular basis should increase the application factor for the string.

String Life Management

Coiled tubing life management is sometimes thought of as a system in which junior engineers process jobs after they are completed and send the results back out to the supervisors. Mainly the emphasis is on the next job and whether the string can last. True life management of a coiled tubing string is a proactive activity that requires foresight and communication between the process engineer and the service supervisor.

In most cases, pipe management is not implemented until significant life has been consumed on a section of the string and the amount of remaining life is insufficient to complete the next job. This type of management requires cutting major lengths from the string, which can lead to limited usage of the string due to length restrictions. Pipe life management should be implemented the day the string is delivered to the location and continue to the end of the string's useful life, with maximum safe utilization as the primary goal.

The coiled tubing crew has the best knowledge of the condition of the string and how it is going to be used. They will play the biggest part in controlling what is done to the string and when. The role of the engineering staff and coordinators is to support the process with fatigue friendly job programming, accurate recording, and string designing that reflects the conditions of the area where the string will be used.

String Design

In most string designs, usable life is the last constraint considered—if included at all. The driving forces behind most string designs are to achieve the most pulling power, at the highest pump rate, at the best pressure range, with the lightest weight, at the lowest cost. Most of the time, a generic string design is used over several areas and is not reviewed as the scope of work in an area changes. As material strength has increased over the years, the tendency has been to upgrade the material and leave section lengths and wall thicknesses the same.

Examples

Table A.9, on the following page, shows four strings and their specifications. Strings 1 and 2 are actual design iterations made over the last seven years in an operating field camp. String 3 is a string designed from specific requirements of the operations in the area. String 4 is an optimization of String 3 with increased life and performance in mind while capitalizing on the gains of the String 3 design changes while trading off slightly on pump rate and cost.

- String 1: 1.75-in. QT 800, 0.175- to 0.156-in. True Taper
- String 2: 1.75-in. QT 900, 0.175- to 0.156-in. True Taper
- String 3: 1.75-in. QT 900, 0.188- to 0.125-in. True Taper
- String 4: 1.75-in. QT 900, 0.188- to 0.125-in. True Taper

Table A.9—String Design Examples

String	Dry Weight, lb	Max. Pump Rate at 6,500 psi, gal/min	Max Pull at 15,000 ft, lb	Max Force at 15,000 ft, lb	Life Used After 15 Cycles at 6,500 psi	Cost	Length, ft
1	44,527	107	52,698	4,882	78.7%	$65,200	16,000
2	44,527	107	58,917	6,943	62.7%	$66,205	16,000
3	42,457	109	63,581	9,832	55.8%	$65,560	16,000
4	47,000	102	61,369	11,651	46.9%	$71,792	17,900

When QT 900 became available, String 1 was upgraded to String 2 material, but the increased strength was not taken advantage of. The design of Strings 1 and 2 was simply two wall thicknesses with a true tapered section in the middle of the string. String 3 is a four wall thickness design with three true tapered sections placed to minimize high stress areas across the wall thickness changes. Thicker wall sections were placed at high cycle areas to reduce the fatigue usage per cycle, and thinner wall sections were placed at the downhole end to offset fluid friction to maintain the pump rate and reduce the hanging weight in the well. This produced better performance characteristics, increased the usable life of the string by a factor of 1.15, and reduced costs.

String 4 is a refined version of the String 3 design. Here we took advantage of the reduced weight and increased the length of the string to the legal limits of the reel trailer. Most of the additional length was added to the thinner wall sections, further reducing the hanging weight while maximizing the total length of the string. This provides an additional 1,900 ft of tubing that can be cut for pipe management, which can increase the utilization of the tubing up to 2.0 times that of the existing string design at a minimal cost increase of 8%.

From a purely financial standpoint, without considering any cuts for management, the increase in “chargeable feet run” is 34%.

Active management of the cycle areas as the string is used is the primary method of life management. Reviewing the upcoming job procedure and relating expected fatigue to the area that will be cycled can assist in making decisions as to how much pipe to cut before the job.

Table A.10, on the following page, is a summary of actual examples of two 1.75 strings that shows the extremes of active pipe management. Both strings engaged in high pressure cleanouts and plug milling after fracturing treatments. Neither string had pumped acid.

String 1 is an aggressively managed string while String 2 has had no management activity at all.

String 1 was removed from service when fatigue life reached 100% on the bias welds; String 2 was removed from service after a tubing failure.

Table A.10—Guide Arch Contact Length

	String 1	String 2
Maximum Life Used	100% at AF 1.8	130% at AF 1.5
Number of Jobs	64	28
Number of Management Cuts	52	0
Total Length Cut for Management, ft	3,845	0
Average Working Pressure, psi	6,500	6,500
Chargeable Feet Run	701,129	340,406
Revenue at $0.60/ft	$420,677.40	$204,243.60
Cost of Tubing	$102,543.00	$98,654.00
Payout for Pipe Related Problems	$0.00	$48,000.00
Profit	75%	28%

The key to the success of String 1 was a concerted effort by the wellsite crew to plan the next job and make the decision about when to cut and how much to cut. Running real time fatigue during the job allowed the tubing to be managed as the work continued.

String 2 is an example of management done in the office where job files are sent in and processed. The results are sent back to the crew in the form of a fatigue plot of the string. In this case, the crew arrived on location with a fatigue plot of their string that was four jobs old and did not reflect the actual condition of the tubing. The result is that the crew over cycled the tubing, believing they were still within the usable life of the string.

Job Design

The ability of coiled tubing to move up and down a live wellbore while pumping fluids is one of the primary reasons it is chosen for a well intervention application. Here the sales pitch is in direct conflict with the best life management practices. What follows is a look at some of the common applications that typically involve high cycling.

Acid Stimulation

There are several reasons for stimulating with acid and most require some amount of pipe movement. In the following section, we will look at cases that can be designed to minimize life utilization.

An application will be defined as pumping acid into a formation at matrix rates while moving a jetting tool across the perforated interval as many times as possible. The main thought behind this process is that you will always have fresh acid along the entire interval and the best chance to open all the perforations. Once the perforations are opened, the acid will take the easiest path, which in most cases is the area with the highest permeability. Once this occurs, unless there is some diversion technique being employed, movement of the tubing will do little in placing acid in low perm areas. This relates to contact time of the acid on the cement or scale plugging the perforation tunnel.

> *Example*: Lets look at a "Best Practice" used in every newly perforated well in a specific area for a specific customer. The procedure was to inject 60 barrels of 15% HCl into 30 ft of perforated interval. The previous practice was to circulate two barrels of wash acid across the interval and allow it to soak for 15 minutes. After the soak time, the annulus was closed in and the treatment acid was injected at a rate of 1 bbl/min while making 10 passes across the interval with the CT at 5 ft/min. This resulted in a life usage of 26.5% per job in the cycled area. Weight restrictions did not allow enough additional pipe on the reel to effectively manage life using cuts and still remain profitable at current discount pricing.
>
> The customer was approached and the issues were discussed. An agreement was reached where the amount of passes would be reduced as long as well performance did not suffer. Using contact time and acid spend time as constraints, the number of passes was reduced to four. As the beginning point would experience the longest delay between fresh acid contact, the high perm area at the top of the formation was chosen as the starting point. The only change to the procedure was the travel rate of the CT and the number of passes. The result was life usage of 10.5% per job, which resulted in an increase of revenue for the string of 250% and a decrease in cost to the customer of 2% per well due to savings on cycling charges. Well performance was maintained, and in a good percentage of the cases was improved.

Extending this concept to acid treatments for near wellbore damage with treatment enhancing tools such as the Pulsonix® TF jet can give the customer a better job at lower costs while increasing profitability of the operation.

Wellbore Cleanout

The most common usage of coiled tubing is to remove material from the wellbore. Cleaning proppant is at the top of the list in this category. It is also the number one application where coiled tubing becomes stuck in the well. Because of the sticking possibility, these jobs are approached in a cautious manner with rule of thumb procedures that include excessive cycling. In this method, a section of fill is cleaned out and the coiled tubing is pulled out of the well for approximately twice the distance cleaned; the procedure is repeated until TD is reached. The most common procedure using this method is to clean 50 ft and pull back 100 ft. The basis of this method is: if you don't go in to the fill too far, you can always pull out if the tubing starts to stick. In reality, it is a crude method to control the hydrostatic loading of the cleaning fluid.

Cleaning material from a wellbore is a balance of annular velocity and the hydrostatic pressure of the cleaning fluid with the pressure of the formation. The choice of cleaning fluid is the key factor in successful cleanout operations. The fluid has to be able to move the particle uphole and be light enough to allow the additional weight of the material to be added without severely overbalancing the formation.

The benefits that make coiled tubing a preferred method for cleaning wells can also set up a situation where a large annular space can occur and annular velocities will be low. Fluid choices can assist with reducing the fallback velocity of the material, but in most cases, the annular velocity is less than ideal. As the coiled tubing is pulled from the well, the annular velocity can be reduced as much as 75% depending on the pump rate and speed of the tubing movement. This can cause fallback of the material and increase the annular density to a point where the formation cannot support the weight and fluid is lost to the formation, decreasing the annular velocity further. This can quickly degrade into an unrecoverable situation.

A properly designed wellbore cleanout using available predictive software can minimize cycling and decrease the possibility of sticking the coiled tubing.

Milling/Drilling

This is similar to wellbore cleanouts with the addition of having to cycle the pipe to recover from motor stalls. As with wellbore cleanouts, the material transport must be considered as well as the motor requirements and limitations. Choosing the correct motor and bit for the application will minimize the need to make pickups due to stalling. Because CT specific motors are high RPM and low torque, the milling process can be slow. Over application of weight in a desire for higher penetration rates and the improper selection of motors are the major causes of motor stalls.

Fishing

The mechanical function of most fishing jars requires up and down movement of the pipe to operate the equipment. The inherent cycling in fishing operations can be managed successfully by good prejob planning and proper equipment selection. The number of jar actuations before pulling out to cut tubing should be determined before the job starts and discussed with the customer. Reluctance to "come off" a hard to catch fish is probably the biggest reason for over cycling during fishing operations. Using a baited overshot allows the release of the BHA while leaving an easy to latch profile on the fish.

Logging

Production logging is one application in which it is difficult to reduce the cycling of the tubing. Logging programs usually have set running procedures that obtain information. Combining tools can reduce some of the cycling.

Any job that requires more than three cycles in one area as a function of design should be reviewed as to the effect on the future life utilization of the string.

Pipe Management Cuts

Cutting lengths of tubing from the downhole end of the string is the most effective method for managing the fatigue life of the string and extending the service life. In extreme cases, cutting high cycled sections from the middle of the string and re-welding is an option, but the field applied butt weld will reduce the fatigue life at the joint and may not be economical in high usage strings.

The following section discusses field methods for making life management cuts.

Job Review Method

This method is most effective with coiled tubing strings that do not have an abundance of extra length to remove for life management. In this case, the upcoming job procedure is reviewed to determine the areas that will be cycled and the expected life utilization that will be consumed. The current life used at the section is compared to determine whether a cut is required to move the job cycling to a lower utilized area of the string. Software such as the Cerberus Hydraulics Simulator enable job stage information to be simulated; the resulting job log can be executed in the Fatigue Calculator to estimate the life that will be used during the job.

If the life utilized will be acceptable, no cut is made. If the life usage will be high, enough tubing is cut from the end of the string to move the job cycle area to a lower utilized section of the string.

Half Life Method

This method is effective for coiled tubing strings consistently run to the same depth and cycled across the same section area for most jobs. This method requires a moderate amount of spare length in the string.

From the time the string is new, no cuts are made until a section reaches 50% life used. At that time, a section is cut from the downhole end equal to the normal working length experienced in same depth wells. This positions un cycled tubing at the normal working depth. The process is repeated until all the extra tubing length is used and the string is fully utilized. Some adjustment may be required to the percentage of life used before the cuts are made to ensure the tubing does not reach 100% in the tripping section before the extra length is used.

Continuous Cut Method

This method is most effective for coiled tubing strings that work at various depths and/or can accommodate 3,000+ additional feet of tubing for pipe management. As the unit will most likely be running at several common depths, the tubing is continuously cut with every job. The amount of each cut is determined by the length on the extra pipe vs. the amount of jobs that can be expected. The method allows for adjustment during the life of the string if the usage is different from that projected.

Once one is familiar with the methods of cutting tubing for pipe management, and the trend of cycle fatigue for the area of usage is determined, a combination of all the methods can further extend the life of the tubing.

Figures A.28 through A.30 are examples of the fatigue life of an actual string managed with the above methods. All examples have the exact same jobs executed in the fatigue calculator. As this string was used in wells varying from 4,500 to 15,500 ft, the continuous cut method provided the best life. One high

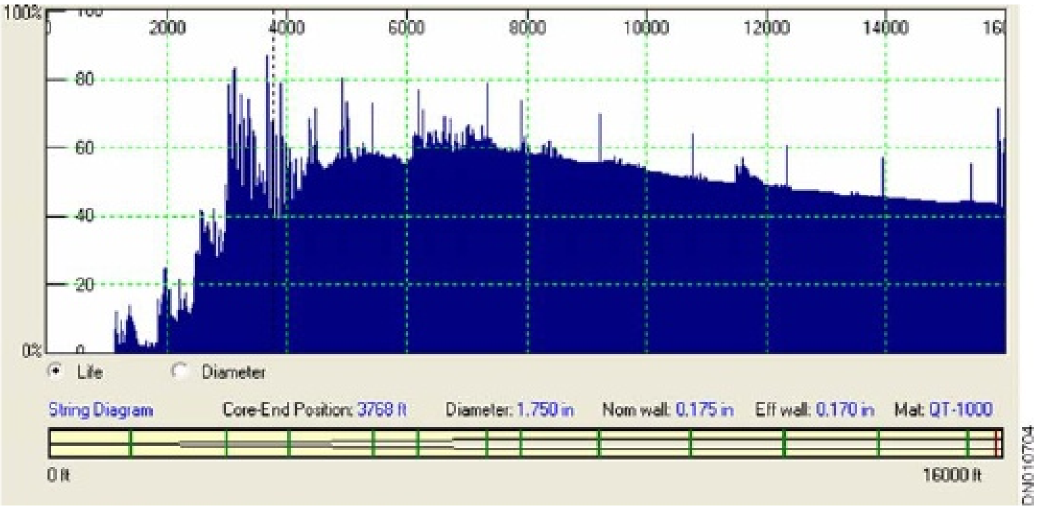


Figure A.29—Half life method

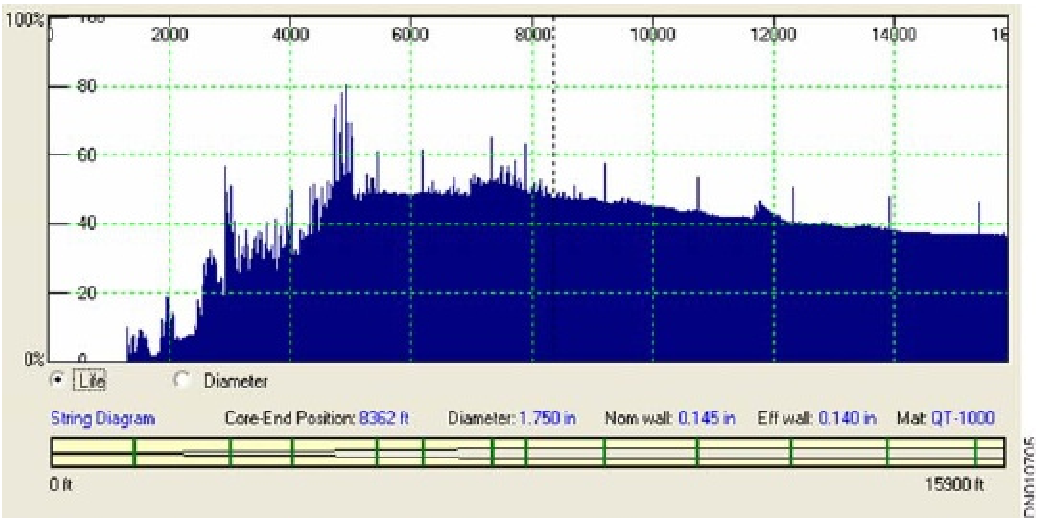
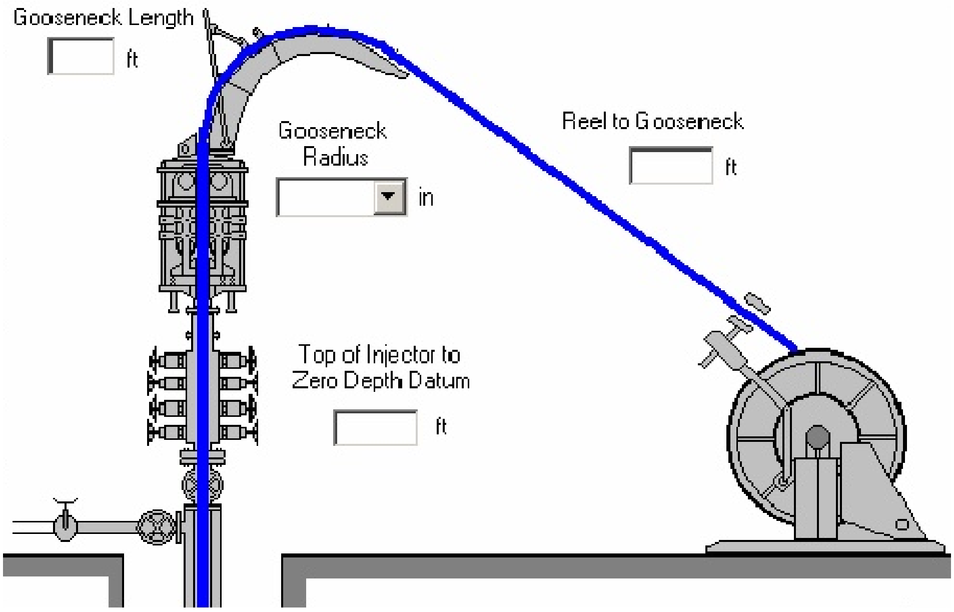


Figure A.30—Continuous cut method

HALLIBURTON	COILED TUBING WORKSHEET	
	WELLSITE GEOMETRY	CT Supervisor:

DATE		RIG/LOCATION		TICKET/RU
CLIENT		WELL		DATA SET I



	Description	
Choose a CT Zero Depth (eg. QU above BOP)		
Well Zero Depth (eg. previous rig floor elevation)		
Reel Dimensions	**Length**	**ft / m**
Reel Core Diameter		
Reel Core Width		
Reel Flange Diameter		

Item
Reel to Gooseneck
Length Across Gooseneck
Gooseneck Radius

Zero Depth Calculation
Distance from CT Zero to Well Ze
Toolstring Length (T/S)
Counter Depth, CD when top of T at CT Zero, CD = Z + T/S
Top of Injector to Well Zero, (TI)
Top of Injector to Zero Depth Dat (required by Cerberus), CZ CZ = TI – T/S

Tubing C	
Before Run #	L

HALLIBURTON	COILED TUBING WORKSHEET	
	JOB SUMMARY	CT Supervisor:

DATE		RIG/LOCATION		TICKET/RU
CLIENT		WELL		DATA SET

FIELD		UWI NUMBER	
COUNTY		WELL CATEGORY	
STATE /PROVINCE		MAX DEVIATION	
COUNTRY			

START DATE & TIME		PRESSURE CATEGORY	
END DATE & TIME		ACID CONCENTRATION	
JOB TYPE		ACID VOLUME	
STRING NUMBER		H_2S / CO_2 CONC.	
REEL NUMBER		AVE. W.H. PRESSURE.	

COMMENTS

Section

B

Hydraulic Pump Pressure Settings

Introduction

The following operating procedures pertain to those coiled tubing power packs manufactured or converted to include the 3 stage pump (presently Hydreco) and unloading circuits.

The significance of this pump configuration is to allow higher operating pressures to the injector circuit when using power packs with the existing 471 Detroit engine. It also allows standardization of pumps between the coiled tubing power packs and snubbing power packs. The maximum recommended operating pressure on the injector circuit is now 2,500 psi.

Pressure Adjustment Procedures

Pressure Adjustments for Vickers Piston Pump and Reel Circuit Manifold

Refer to Spec. Drawing 996.10742 for complete power pack RPM and pump settings information.

1. Turn the valves on the pump control panel to the Vent position.
2. Turn the dump valve on the reel manifold (Figure B.1, Page B-2) and injector manifold (Figure B.2, Page B-2) in line with the tubing (Dump position).
3. Select the injector position on the Crane/Injector Selector valve.
4. Position the Injector Directional Control valve (In House) to the Center (Neutral) position.
5. Check that the Barksdale Directional Control valve on the control console for the reel circuit is in the Center position.
6. Disconnect the reel drive motor hoses from the power pack bulkhead.
7. Disconnect the remote pressure control hose No. 120 from the bulkhead.

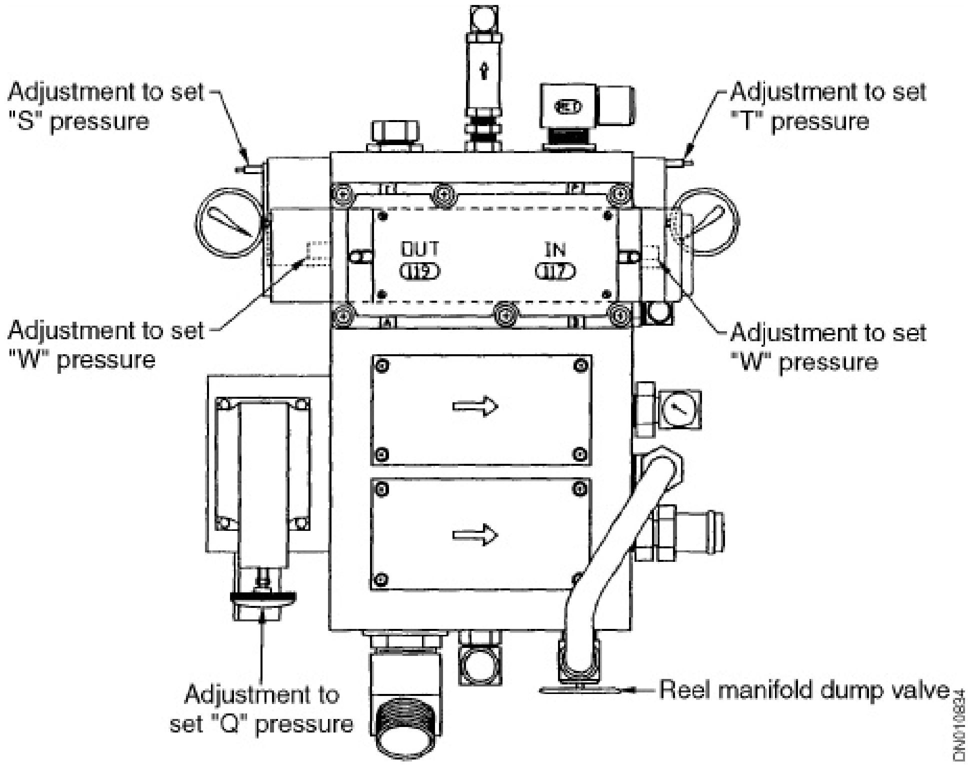


Figure B.1—Top view of the reel manifold.

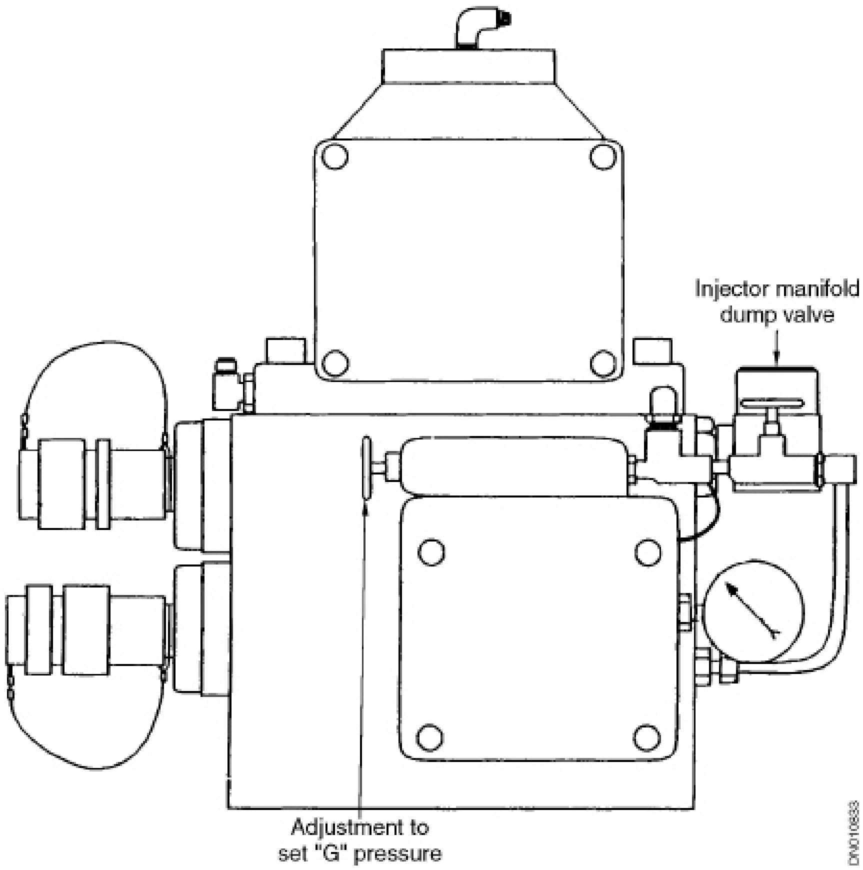


Figure B.2—Front view of the injector manifold.

8. Reduce to a minimum the setting of the Pressure Relief valve located on the reel manifold block by turning the adjustment counter clockwise (see location “Q” in Figure B.1, Page B-2).

9. Start the engine, allow for warmup, then run at 1,200 to 1,800 RPM.

10. Close the Reel Circuit Dump valve. Little or no pressure should be indicated by the gauge located on the Reel Circuit Relief valve (see location “Q” in Figure B.1, Page B-2).

11. Adjust the Reel Manifold Block Relief valve closed by turning clockwise (see location “Q” in Figure B.1, Page B-2). At this time, reel manifold pressure will increase until the piston pump compensator setting is reached. Continue to close the relief valve setting adjustment completely.

12. Temporarily adjust the piston pump compensator to 2,800 psi by turning the compensator clockwise (see location “J” in Figure B.3).

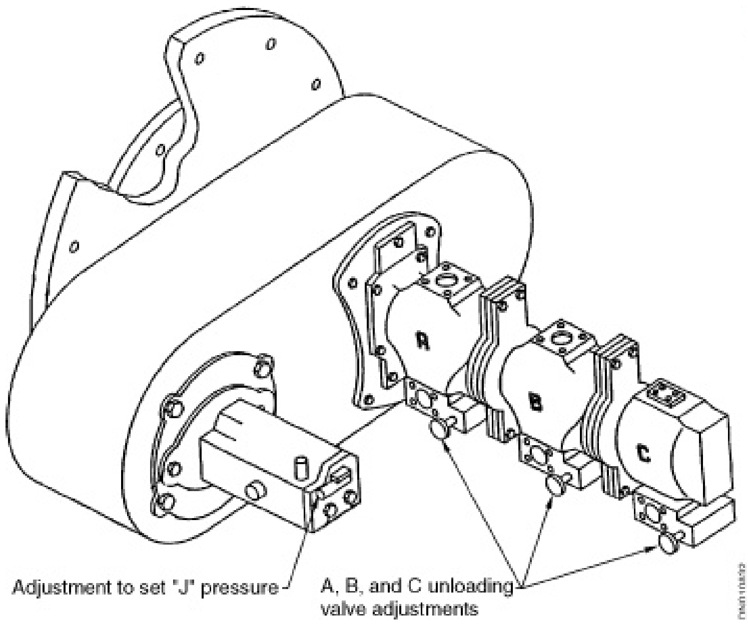


Figure B.3—Hydraulic pressure setting for CT power packs (front view).

13. Adjust the Reel Manifold Relief valve down to setting “Q” (see Table B.1, Page B-7) by turning counter clockwise; then set the jam nut.

Note	At this time, the engine will sound loaded.

14. Adjust the piston pump compensator counter clockwise to set the system pressure to setting “J” (see Table B.1, Page B-7).

15. Adjust the Pressure Relief valve located on the side of the valve block facing the Funk gear box, to 250 psi. Tighten the jam nut (see location "S" in Figure B.1, Page B-2).
16. Temporarily adjust the other pressure reducing relief valve (facing the outside) to the same pressure used in the previous step (Refer to location "J" in Figure B.1, Page B-2 to set the pressure). Observe the pressure on the gauge located on the valve.
17. Shift the Reel Circuit Barksdale valve on the console from Neutral to the reel "In" position.
18. Adjust the Crossover Relief valve located between the Vickers 4 way directional valve and the valve block to setting "W" (see Table B.1, Page B-7). Lock the jam nut. Observe the pressure gauge located on the (outside) Pressure Relief valve.
    a. The crossover relief valve has two adjustment stems (one on each side); however, currently, only one can be adjusted.
    b. At this time, the engine should sound loaded.
    c. Shift the Reel Circuit Barskdale valve to the reel "Out" position.
    d. Adjust the second crossover relief stem to setting "W" (see Table B.1, Page B-7). Lock the jam nut. Observe the pressure gauge located on the (outside) Pressure Relief valve.

Note — At this time, the engine should sound loaded.

    e. Adjust the (outside) Pressure Relief valve down to setting "T" (see Table B.1, Page B-7).

Note — At this time, the engine should sound unloaded.

    f. Shift the Reel Circuit Barksdale valve to the Center position.
    g. Turn the dump valve on the reel manifold to the Dump position (in line with the tubing).
    h. Stop the power pack.
    i. Reconnect all hoses removed from the power pack bulkhead.

Pressure Adjustment for House Control Console Circuit

(6V 53 and 3116TA Power Packs Only)

1. Run the engine at 1,200 to 1,800 RPM.

Note	This circuit has no dump valve to manually unload the pump while the engine is running. Once the engine is started, the pump will produce the pressure to which the pump compensator is set.

2. Adjust the compensation on the pump fully counter clockwise.
3. Adjust the Console Circuit Relief valve (located under the hydraulic tank) to its maximum setting by turning the adjustment stem clockwise completely.
4. Temporarily adjust the compensator on the Vickers PVB 10 pump to 2,100 psi.
5. Adjust the Circuit Relief valve pressure down to 2,000 psi. Set the jam nut.

Note	At this time, the engine should sound loaded.

6. Adjust the PVB 10 pump compensator to 1,500 psi (setting "M").

Pressure Adjustment for Hydreco Pumps

1. Check that the injector Barksdale valve is in the Center position and that the Crane/Injector selector is in the Injector position.
2. Turn all pump Vent/Load valves to the Vent position.
3. Run the engine at 1,200 to 1,800 RPM.
4. Close the dump valve on the reel/console manifold.
5. Close the Injector Dump valve.
6. Turn the Injector Double A Pilot Control valve clockwise to completely close it.

   Pressure in the injector circuit will not increase when turning (clockwise) on the Injector Double A Pilot Control valve at this time because Vent/Load valves "A," "B," and "C" on the pump control panel are still in the Vent position (Refer to Step 2).
7. Load pump "C" by turning the Vent/Load valve to the Load position. Observe the 0 to 5,000 psi pressure gauge located on the side of the Injector Relief valve mounted on the large aluminum valve block. Adjust the unloading valve located under pump "C" so that the pressure gauge reads C setting (see Table B.1, Page B-7). Set the jam nut on the adjustment stem.
8. Pump "C" is the end pump (farthest from the gear box).

9. It is normal for an unloading valve to cycle on and off to maintain its set pressure. This will cause the gauge reading to fluctuate between the set pressure and approximately 10% below the set pressure.
10. Vent pump "C" by turning the Vent/Load valve to the Vent position. Also turn the dump valve located on the Injector Relief valve to a position in line with the tubing to dump the pressure remaining on the pressure gauge. Close the dump valve.
11. Load pump "B" and observe the pressure gauge. Adjust the unloading valve located under pump "B" so that the pressure gauge reads B setting (see Table B.1, Page B-7). Set the jam nut. Pump "B" is the middle pump on the stack.
12. Vent pump "B." Turn the injector dump valve to the in line (Open) position to dump the remaining pressure on the gauge, then close dump valve.
13. Load pump "A" only and observe the pressure gauge. Adjust the unloading valve located under pump "A" so that the pressure reads 2,500 psi and set jam nut ("A" setting).

    If the maximum pressure obtainable by adjusting the pump "A" unloading valve is less than 2,500 psi and the engine starts to load, it will be necessary to increase the maximum pressure setting on the injector manifold relief valve "G." This relief valve should be set at 2,800 psi by performing the following procedure.

    a. Adjust both the Injector Manifold Relief valve and pump "A" Pressure Unloading valve to increase the system pressure to 2,900 psi.
    b. Adjust the relief valve to reduce the system pressure to 2,800 psi (setting "G") and set the jam nut.

    Note — At this time, the engine should sound loaded.

    c. Adjust the pump "A" Unloading valve down so that the system pressure now reads 2,500 psi, and set the jam nut.

    Note — At this time, the engine should load only intermittently as the Unloading valve kicks in and out to maintain 2,500 psi.)

14. Vent pump "A" and dump the remaining pressure on the gauge and close the dump valve.
15. Check the set pressures by loading pumps "C," "B," and "A." Pump pressures should correspond to the pressures listed in Table B.1, Page B-7.
16. Vent all pumps and dump the remaining pressure.
17. Back off the injector Double A Pilot Control valve completely.

The system is now ready for operation.

Normal Operation

1. For normal operations, load the pumps in sequence “C,” “B,” “A,” and reverse this sequence prior to shutdown to unload the pumps.

   During operation, the pumps will unload (kick out of the circuit) automatically as the system pressure rises past each unloading valve setting. This allows the power pack to generate more pressure for the injector than it was capable of generating with a single pump.

2. When using the power pack to power a coiled tubing crane, it is recommended that pumps “C” and “B” be unloaded, and only Pump “A” loaded. Limit the engine speed to 1,500 RPM. This will provide the maximum recommended flow of hydraulic fluid to the crane.

Table B.1—Standard Coiled Tubing Power Pack and Engine Size

Chart Values, lb/in.^{2}		Apr 71	6V 53	Jun 71	3116TA
Hydreco end pump	C	1,300	1,900	1,300	1,900
Hydreco middle pump	B	1,800	2,200	1,800	2,200
Hydreco front pump	A	2,500	2,500	2,500	2,500
Injector manifold block relief valve	G	2,800	2,800	2,800	2,800
Vickers PVB 29 piston pump compensator	J	1,500	1,700	1,700	1,700
Vickers PVB 10 piston pump compensator (6V 53 only)	M		1,500		1,500
Reel manifold block relief valve	Q	1,800	2,000	2,000	2,000
Pressure reducing/relief valve (low pressure side)	S	250	250	250	250
Pressure reducing/relief valve (high pressure side)	T	1,500	1,500	1,500	1,500
Reel crossover relief valve (both sides)	W	2,000	2,200	2,200	2,200

Pressure Settings

House and Auxiliary Pump Pressure Setting

Three people are required to safely set the house pump and auxiliary/BOP hydraulic pumps: an operator, a hydraulic mechanic, and a person to monitor gauges and equipment and relay information between the mechanic and the operator.

Important **The same steps are required for adjusting either pump.**

Important **Read the procedure completely before beginning an adjustment.**

Important **Use all recommended safety equipment required to work in the environment as stated by Halliburton HSE.**

To set the maximum pressure on the house pump and auxiliary/BOP pumps perform the following:

1. Locate the gauge that shows the pressure supplied to the pump you are adjusting.
2. Locate the pump that requires adjusting.
3. Locate the pressure compensator adjustment screw (Figure B.4) on the Rexroth A10VO45 pump.

Caution **Never adjust the torque control adjustment. Serious damage to the pump and the system may result.**

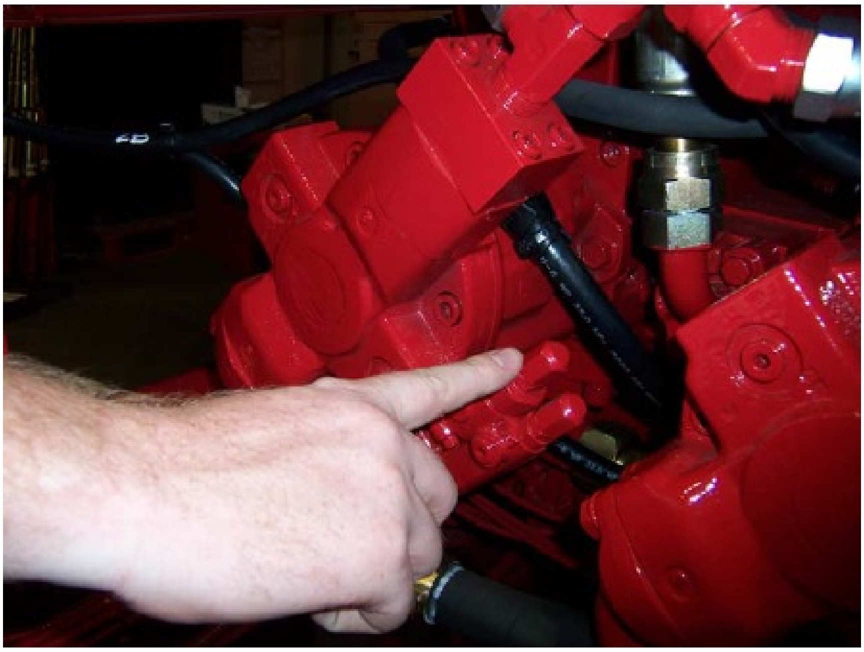


Figure B.4—Pressure compensator adjustment screw (Step 3).

4. Assemble the tools required for adjusting the pump.
5. Loosen the locking nut on the pump.
6. Turn the adjustment screw counterclockwise until the screw becomes loose. Turn the adjustment screw clockwise one turn and lightly retighten the locking nut. This step reduces the pressure on the pump to a minimum to prevent over pressuring the system.
7. Ensure that the power package has all the fluids needed for operation; then, start the power package and allow the engine to warm up.
8. Engage the hydraulic pumps and allow the hydraulic system to warm up.

Note	The charge pressure gauge should display a minimum of 20 to 25 psi as the engine is idling. If the gauge displays a pressure below 20 psi, shut down the engine and check the charge system.

9. Bring the engine to full speed (2,100 RPM maximum).
10. Ensure that the accumulator valve in the house is closed.
11. Turn the pressure compensator adjustment screw on the A10VO45 pump clockwise until the gauge shows 2,000 psi.

Note	Units produced after 2002 have house pressure at 3000 psi.

12. Tighten the locking nut and replace the protective cover.
13. Bring the unit to idle speed.
14. Disengage the hydraulic pumps.
15. Allow the engine to cool down at the correct speed.
16. Repeat the process for the other pump if necessary.

Injector Motor Pre-Charge Pressure Setting

1. Locate the injector motor pre-charge valve (Figure B.5).

Figure B.5—Injector motor pre-charge valve (Step 1).

2. Loosen the locking nut on the pre-charge valve and gently turn the adjusting screw counter-clockwise until it stops.
3. Ensure that the power package has all the fluids needed for operation; then, start the power package and allow the engine to warm up.
4. Engage the hydraulic pumps and allow the hydraulic system to warm up. Check all gauges.
5. Verify that the accumulator valve in the operator house is closed.
6. While one person is monitoring the 0- to 600-psi gauge, turn the adjusting screw clockwise until the pressure reads 150 psi. Do not exceed 150 psi.
7. Retighten the locking nut.

Injector Pump Pressure Setting for Rexroth A11V0 Injector Pump Linde HPR100

Three people are required to set the injector hydraulic pumps safely: an operator, a hydraulic mechanic, and a third person to monitor gauges and equipment and relay information between the mechanic and the operator.

Important	**Read the following procedure completely before beginning an adjustment.**
Important	**Use all recommended safety equipment required to work in the environment as stated by Halliburton HSE.**

To set the maximum pressure on a 5,000 psi injector pump, perform the following steps:

1. Locate the injector motor pre-charge valve.
2. Remove both lines from port No. 1 on the pre-charge valve. Separate the plug and cap the port and hoses.
3. Locate both injector pumps.
4. Locate the pressure compensator adjust screw (Figure B.6) on the injector pumps.

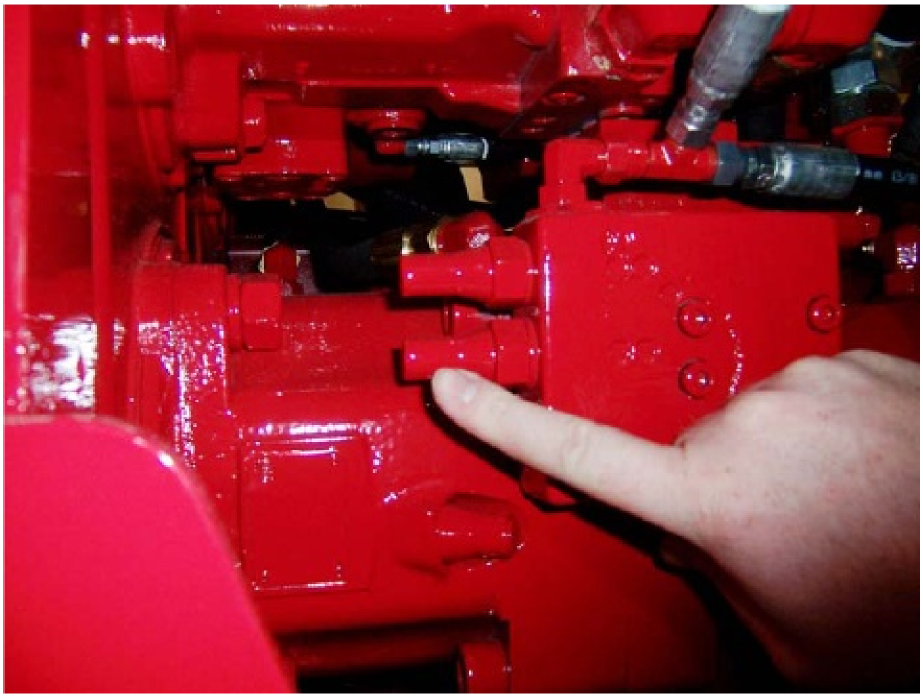


Figure B.6—Pressure compensator adjust screw on the injector pump.

5. Assemble the tools required to loosen the locking nut and turn the adjustment screw.
6. Disconnect the 1 1/2 in. hydraulic drive hoses from the power pack.
7. Ensure that the power package has all the fluids needed for operation; then, start the power package and allow the engine to warm up.
8. Engage the hydraulic pumps and allow the hydraulic system to warm up.

Note — The charge pressure gauge should have a minimum of 20 psi when the engine is idling. If the charge system pressure is below 20 psi, shut down the engine and check the charge system.

9. Bring the engine to full speed (2,100 RPM maximum).
10. Ensure that the accumulator valve is closed in the house.
11. Set the injector brake.
12. Set the direction of the injector to Out Hole.
13. Bring the injector speed to 500 psi.
14. Turn the injector Maximum Pressure Adjust clockwise to full pressure.
15. The injector Max Pressure gauge should read 5,000 psi ± 200 psi.

Caution — Do not exceed 5,000 psi.

Note — At the power package, both injector gauges should read 5,000 psi ± 200 psi.

16. Adjust the pumps as required, with the third man available to monitor the pump gauge at the power package and help communicate information to the operator.

Note — Always use the power package gauges to set hydraulic pump pressure settings.

17. After setting both pumps to the correct pressure, bring the injector pressure down to minimum.
18. Bring the injector speed control down to minimum.
19. Set the injector to neutral.
20. Allow the unit to cool down properly.
21. Stop the engine.
22. Ensure that no pressure is on the system.
23. Reconnect the lines from the injector pump to port No. 1 on the injector pre-charge valve assembly (the lines disconnected from Port No. 1 in Step 2 of this procedure).
24. Restart the unit and function test the injector system.

Pressure Settings for all Rexroth AA4VG Reel Pumps

Three people are required to safely set the reel hydraulic pump: an operator, a hydraulic mechanic, and a person to monitor gauges and equipment and relay information between the mechanic and the operator.

Important	**Read the procedure completely before beginning adjustment.**

Important	**Use all recommended safety equipment required to work in the environment as stated by Halliburton HSE.**

To set the maximum pressure on the AA4VG Rexroth reel pump, perform the following steps:

1. Disconnect lines No. 401 and 402 at the power package bulkhead or reel.
2. Locate the reel pump.
3. Locate the POR (pressure override, see Figure B.7) adjustment valve on the reel pump.
4. Assemble the tools required for adjusting the valve.
5. Loosen the locking nut on the POR valve and turn the adjusting screw counter clockwise until the adjustment screw is almost out of the valve.

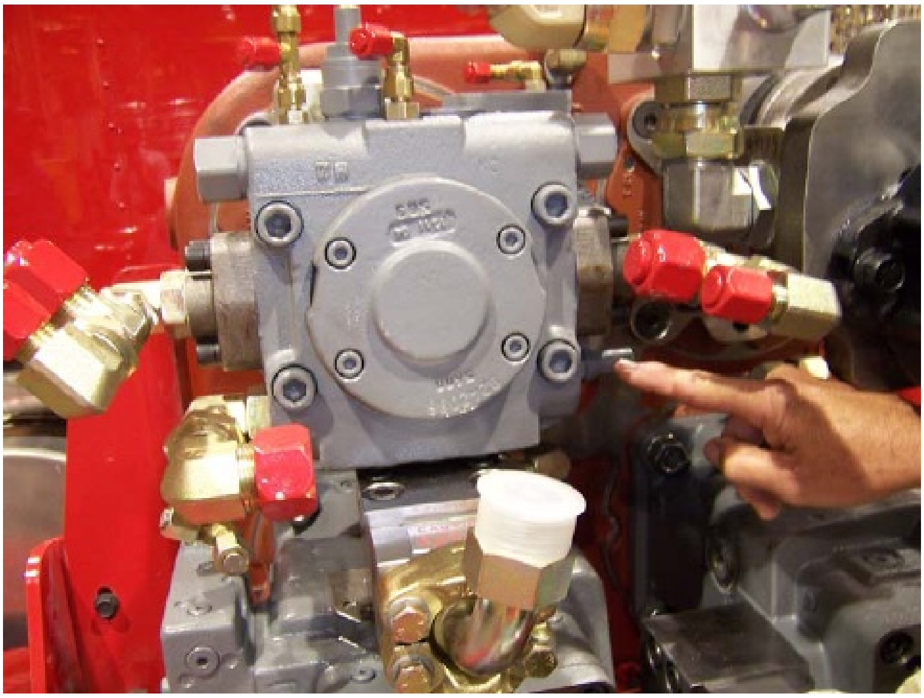


Figure B.7—Pressure override adjustment valve on the reel pump.

6. Turn the screw two turns clockwise and lightly retighten the locking nut.

Note	This is not a precise adjustment. This takes the pump to a minimum pressure to ensure that the system does not overpressure.

7. Locate the remote pilot operated relief valve. Assemble the tools required to adjust the valve.
8. Loosen the locking nut on the remote pilot operated relief valve. Gently turn the adjusting screw clockwise until the screw bottoms out. This step takes the valve out of the circuit.
9. Ensure that the power package has all the fluids needed for operation; then, start the power package and allow the unit to warm up.
10. Engage the hydraulic pumps and allow the hydraulic system to warm up. Check all gauges.

Note	The charge pressure gauge should read 20 to 25 psi when the engine is idling.

11. While one person is monitoring gauges at the power package, bring the engine to full speed (2,100 RPM maximum). The charge pressure should be 30 psi.
12. Bring the reel control to Full Tension.
13. Turn the reel Maximum Pressure Adjust valve clockwise to full pressure.

Caution	**Do not allow the pressure to exceed 3,000 psi. If the pressure does exceed 3,000 psi, be certain that you have performed Step 4 correctly. If Step 4 has been properly completed and the pressure exceeds 3,000 psi, the pump is malfunctioning. Shut down the system and consult the manufacturer's troubleshooting information.**

14. Loosen the locking nut on the POR adjustment and turn the adjusting screw clockwise until the reel pressure gauge reads 3,000 psi. Securely retighten the locking nut.

Note	Monitor the power package gauges whenever making a pump adjustment.

15. Adjust the pilot operated relief valve (plumbed into ports X4 and MA on the reel pump) counterclockwise until the reel pump gauge on the power package reads 2,750 psi. Lock the adjustment in place.

Note	Make all pump adjustments using the power package gauges.

16. Allow the power package to cool down.
17. Bring the reel controls in the control house to minimum pressure.
18. Disengage the pumps.

Pressure Adjustment of the Reel Circuit Hot Oil Shuttle

To adjust the hot oil shuttle valve, perform the following steps:

1. Locate the hot oil shuttle valve (Figure B.8). Follow the supply and return lines from the reel pump to the hot oil shuttle valve.

Figure B.8—Hot oil shuttle valve.

2. Locate the hydraulic relief valve on the hot oil shuttle valve.
3. Locate the hydraulic pressure gauge plumbed on the valve block.
4. Start the power pack and let the engine warm up.
5. Engage the hydraulic pumps and allow the hydraulic fluid to warm to operating temperature.
6. Set all other controls in the control house to minimum pressures and safe positions.
7. Bring the engine speed to 2,100 RPM.
8. Position the reel brake knob to the brake set position.
9. Bring the reel tension adjust to full tension.
10. Adjust the reel maximum pressure to 700 psi.

11. Loosen the locking nut on the hot oil shuttle relief valve.
12. While monitoring the gauge plumbed into the valve block gauge port, gently turn the adjusting screw clockwise until it stops.

Note	Review the highest pressure displayed on the gauge. This reading should be between 390 and 450 psi. If this pressure cannot be seen, see the reel pump vendor information on the charge pump.

13. Adjust the relief valve counter clockwise until the pressure is 50 psi below the highest pressure displayed in Step 12.
14. Set all the reel controls in the control house to minimum settings.
15. Reduce the engine speed and allow the hydraulic system and the engine to cool down.

Setting Pressure on Power Packs with 3 Pump Crane System

Three people are required to safely set the crane hydraulic pumps: an operator, a hydraulic mechanic, and a person to monitor gauges and equipment and relay information between the mechanic and the operator.

Note	The same steps are required for adjusting all three pumps.

Important	**Read the procedure completely before beginning an adjustment.**

Important	**Use all recommended safety equipment required to work in the environment as stated by Halliburton HSE.**

To set the maximum pressure of the crane system winch, boom, and swing perform the following steps:

1. Locate the crane On/Off block.
2. Disconnect the quick disconnects from P1 (crane winch), P2 (crane boom), and P3 (crane swing) on the crane On/Off block.
3. Ensure that all systems are in a safe position to start the unit.
4. Ensure that the crane system On/Off blocks are in the Off position.
5. Start power pack and allow sufficient time to warm up.
6. Engage the hydraulics.
7. Turn the crane winch On/Off selector to On.

8. Bring the power pack to full RPM.
9. Loosen the locknut on the Winch, Boom, or Swing Relief valve; turn clockwise until the gauge reads the correct psi, and retighten the locknut.

Pressure Setting for Crane Stack

- Winch pump: 3,500 psi
- Boom pump: 3,500 psi
- Swing pump: 1,500 psi

Zone 2 Power Pack Crane and Auxiliary Pressure Setting

Note This procedure is for Zone 2 units built before 2004.

1. Locate the crane valve block on the power pack.
2. Disconnect lines #544 and #545.
3. Ensure that the crane On/Off valve is in the Off position.
4. Start the power pack.
5. Turn the crane On/Off valve to the On position.

Caution **Do not allow the system to go over 2,900 psi.**

6. Bring the power pack up to full RPM.
7. Loosen the locking nut on the Crane Valve Block Relief valve.
8. Turn the adjusting screw clockwise until the pressure reads 2,900 psi.
9. Retighten the locking nut.
10. Turn the crane On/Off valve to the Off position.
11. Bring the power pack to 1,000 RPM and let it cool down.
12. Bring the power pack to idle, and kill.

Pump Pressures for all Standard/DDEC, Tractor, and Zone 2 Universal Power Packs

Injector pump circuit: 5,000 psi

Reel pump circuit: 2,750 psi

House/BOP pump circuit (pre-2002): 2,000 psi

House/BOP pump circuit (post-2002): 3,000 psi

Winch pump circuit: 3,500 psi

Boom pump circuit: 3,500 psi
Swing pump circuit: 1,500 psi

Appendix

C

Alternate Stabbing Methods

Introduction

When stabbing tubing into Halliburton's 30/38K, 45K, 60K, 95K, and 135K coiled tubing (CT) injectors, it is important to understand the hydraulic and mechanical systems. Prior to stabbing, many locations install a solid tool, or solid stabbing bullet, into the end of the tubing. The stabbing bullet helps prevent the tubing from hanging up on items in the injector and can also help prevent deforming of the tubing. However, the use of a stabbing bullet may not prevent the occurrence of serious problems if improper stabbing techniques and tools are used. For example, the linear chain roller bearings can be damaged, causing linear chain failure.

The following section outlines the events that can take place during a typical linear chain failure using a solid stabbing bullet. This description is followed by a set of solutions that can be applied according to the particular application and circumstances involved.

In an effort to alleviate linear chain failures, some general preliminary steps and then several solution options are presented. Depending on your equipment, rig-up methods, or local practices, you may prefer one method over another. Please review these solutions to determine the one that best fits your particular needs.

Preliminary Steps

No matter which solution you choose, you must first open the gripper beams on the injector. To open the gripper beams, follow these steps:

1. On the console, use the Gripper Position valve to select Retract.
2. Allow the gripper beams to travel in the open direction until they contact the outermost point of the frame. The pressure at the injector gripper will match the gripper pressure gauge reading on the console.
   - For 30/38K, 60K, and 95K CT injectors, use no more than 500 psi gripper pressure while stabbing tubing.
   - For the 135K CT injector, use no more than 250 psi gripper pressure while stabbing tubing.
3. With the Gripper Position valve still in the Retract position, adjust the Gripper Pressure Adjust valve to 500 or 250 psi. This will be the pressure at the injector when the chains contact the pipe.
4. After stabbing the tubing, move the Gripper Position valve to the Grip position. Do not readjust the Gripper Pressure Adjust valve.

Manual Stabbing

Note Never use more than 500 psi pressure on gripper beams when stabbing tubing on the 30/38K, 60K, and 95K CT injectors. Use only 250 psi gripper beam pressure on the 135K injector.

When stabbing tubing into the injector, do not close the beams unless the tubing is past the center line of the bottom cylinder (Figure C.1, Page C-3). This helps prevent the bottom cylinders from closing further than the top cylinders. Often, this method is not possible because the curve of the tubing will hit the tubing guide, not allowing it to insert half way through the injector.

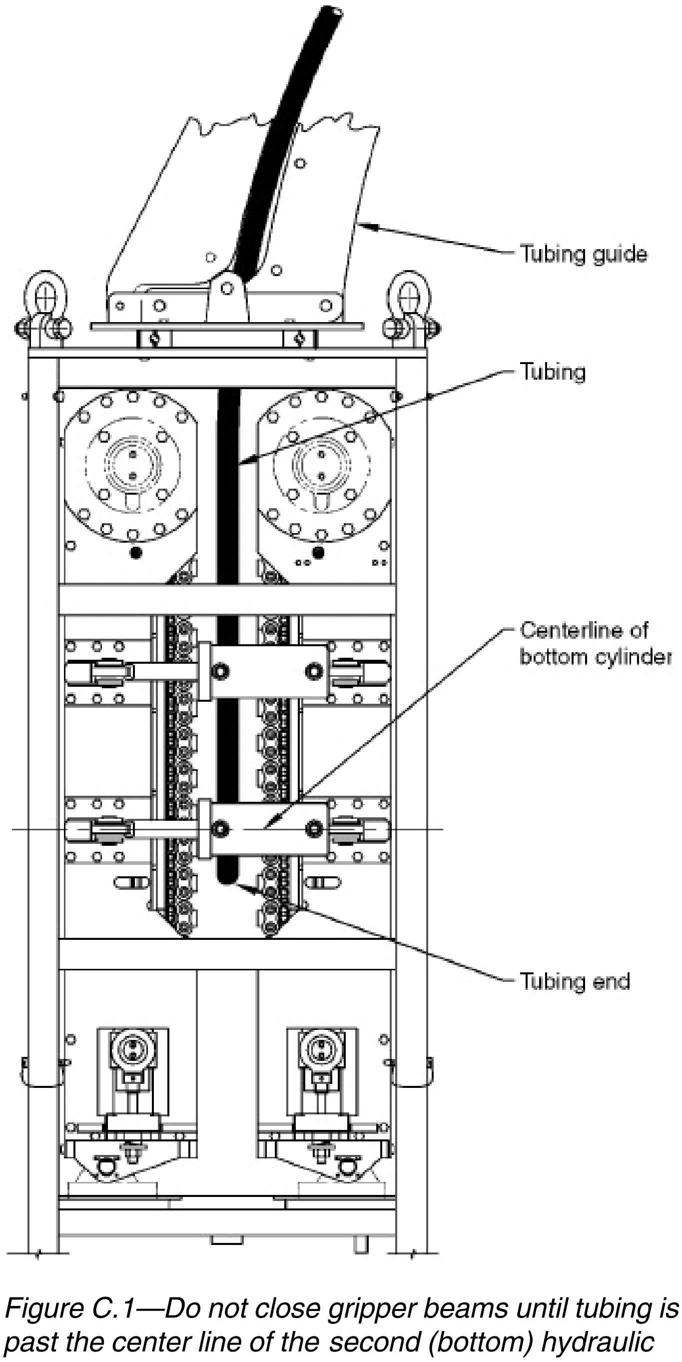


Figure C.1—Do not close gripper beams until tubing is past the center line of the second (bottom) hydraulic cylinder.

On quick rig-up units, the quickest solution may be as follows:

1. Before closing the beams on the tubing at the top of the injector, place a piece of tubing the same diameter as the tubing on the reel across the lower section of the beams (Figure C.2).

   When the injector beams close, the beams will not create the V shape, and the cylinders will not spread as the tubing is rolled into the injector.

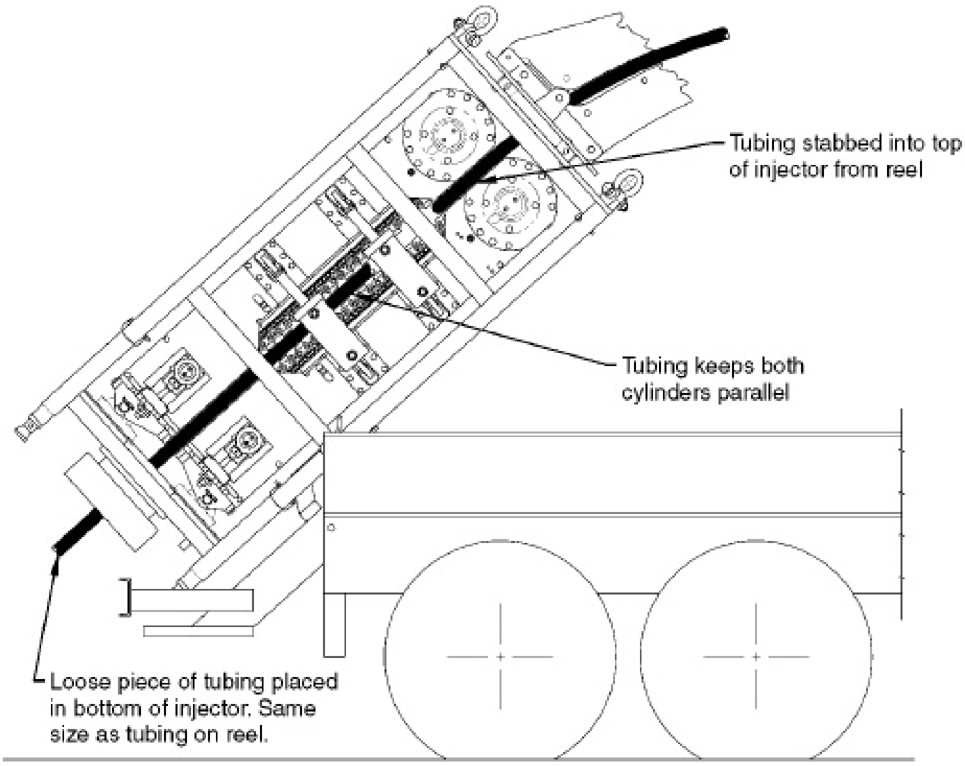


Figure C.2—Sub tubing in the bottom of the injector keeps the beams aligned.

Caution **Ensure that you use a length of pipe sufficiently long to accommodate handling of the pipe below the quick latch. DO NOT place hands in the gripper chain area to center the pipe.**

2. To further help ensure that the system does not overpressure, a "bleed and feed" action can be used. This is accomplished by opening the Circle Seal valve or Gripper Beam Dump valve on the injector. Set the gripper grip pressure to 500/250 psi (as described above). If any problems occur during this process, the excess pressure will be bled through the dump valve.

Stabbing Snakes

The use of stabbing snakes, or threading cables, is another possible solution (Figure C.3). A stabbing snake is commonly made of cable or a cable and lead assembly the same diameter as the CT on the reel. The following tubing snakes can be ordered using the Part Number that matches the CT diameter being used.

- 1 1/4 in. CT—Use stabbing snake Part No. 101406660.
- 1 1/2 in. CT—Use stabbing snake Part No. 101437897.
- 1 3/4 in. CT—Use stabbing snake Part No. 101437898. Because they are difficult to handle, stabbing snakes larger than 1 3/4 in. diameter are not recommended.
- 2 in. CT or larger—Use a winch and cable assist system (see “Winch/Cable Assist” below).

All stabbing snakes have a way of attaching to an internal grapple system threaded into the tubing. The stabbing snake is placed into the injector and the beams are closed. Beam pressure is applied to the injector and it is rolled in hole. The snake pulls the tubing into the injector while keeping the beams and cylinders properly spread apart.

Figure C.3—Cable stabbing snake or threading cable.

Winch/Cable Assist

In winch and cable assisted stabbing, a cable is attached to the CT (similar to attaching a stabbing snake) and a winch is used to pull the CT through the injector, facilitating the stabbing process (Figure C.4).

At this time, a standard system for winch and cable assisted stabbing is not available because of differences in applications. The following is a general procedure, but you may need to contact the Technical Services Group for assistance with your particular application.

1. With the gripper beams open, the internal grapple is attached to the tubing. The cable is threaded through the bottom of the injector and over the tubing guide, then attached to the grapple.
2. The winch is engaged to pull the cable and CT back through the tubing guide and into the injector.

3. Once the tubing is pulled into the injector, the beams are closed to securely hold the tubing.

Figure C.4—Example of a removable winch assist for stabbing tubing, mounted on the back of a trailer.

Stabbing Guide

A stabbing guide is similar to a stabbing bullet except that the length is 48 in. The additional straight length enables insertion into the injector with sufficient depth to keep the gripper beams parallel along the length of the injector (Figure C.5).

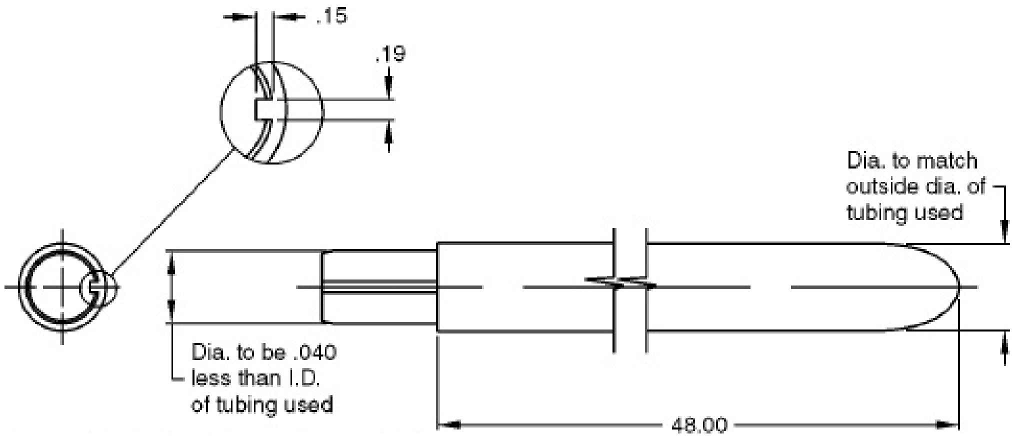


Figure C.5—Example of a stabbing guide.