Critical Sour Underbalanced Drilling

Industry Recommended Practice (IRP)

Volume 6 - 2004

Retired

2004 - 01

ENFORM

DACC
Drilling and Completion Committee

NOTE: As of October 2023, IRP 6 has been 'Retired'. This IRP no longer reflects current best practices and will not be updated or maintained. The information remains posted and available for historical reference.

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6.0 Scope and Contents

6.0.1 Introduction

The Industry Recommended Practices (IRPs) document has been developed by the Critical Sour Underbalanced Drilling (CSUBD) committee, consisting of representatives from the CAODC, CAPP, PSAC and AEUB, under the auspices of the Drilling and Completions Committee (DACC). The main committee members are listed below, however many more individuals significantly contributed to the technical task groups:

Subcommittee Member	Company	Industry
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Bill Gavin	Nowsco	PSAC
Mark Hornet	Poco	CAPP
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The CSUBD mandate was to develop minimum recommended practices regarding equipment, procedures and personnel for the enhancement of safe underbalanced drilling of critical sour wells throughout Western Canada.

This IRP is a continuation of a series of Alberta Recommended Practices (ARPs) that have been developed over the years for the drilling and servicing of sour wells in Alberta.

Underbalanced drilling is a drilling technology that is increasingly being used throughout Western Canada to complete new wells and to deepen or drill from existing wellbores. With the development of technology and equipment, operators began to apply the underbalanced drilling technology to sour wells, and the need for safe operating guidelines became necessary.

The IRPs were developed using existing documentation and regulations in Alberta. The use of the IRPs within other regulatory jurisdictions must be in conjunction with the applicable regulations.

The recommendations set out in the IRP were derived with the safety of on-site personnel, public and environment as the priority consideration and it is the operator's responsibility to ensure these issues are addressed adequately.

While every effort has been made to ensure the accuracy and reliability of the data contained in the IRP, and to avoid errors or omissions, DACC, its sub-committees, and individual members make no representation, warranty, or guarantee in connection with the publication or the contents of any IRP recommendation, and hereby disclaim liability or responsibility for loss or damage resulting from the use of the IRPs, or for any violation of any statutory or regulatory requirement with which an IRP recommendation may conflict.

6.0.2 Scope

This Industry Recommended Practice (IRP) applies to the underbalanced drilling of critical sour wells (see 6.0.4 Glossary for the definition of “Critical Sour Well”)

In Alberta, a critical sour well is defined in Interim Directive ID 97-6 Appendix 1 Section (2). Also included in ID 97-6 Section (4.4.3) Underbalanced Drilling, is a note stating “the EUB will not approve sour underbalanced drilling operations which place residents inside the calculated EPZ” (moratorium General Bulletin GB 96-17).

Critical sour underbalanced drilling should only be considered if the operator is confident in their understanding of the reservoir characteristics and bottom hole information.

The recommendations set out in the IRP are meant to allow flexibility, however; the need for exercising competent technical judgment is a necessary requirement to be employed concurrently with its use. The recommendations should also be considered in conjunction with other industry recommended practices, individual operator’s drilling practices and regulatory requirements.

The well control equipment IRPs were developed with the consideration that the hydrostatic head of the drilling fluid column no longer is the primary method of well control. The well control equipment is the primary well control mechanism prevent escape of sour well effluent and ensure the safety of on-site personnel during the critical underbalanced drilling operations. The guidelines were developed with two lines of defense for all operations.

The drill string recommendations were developed with regard for the issues and implications of maintaining the integrity of jointed tubulars or coiled tubulars when exposed to sour effluent flow during a critical sour underbalanced drilling operation, and includes consideration of pressure integrity of all surface related components.

The surface circulating equipment includes all equipment downstream of the BOP stack that is necessary for the safe circulation, separation and handling of sour effluent flow from wellbore. The recommendations were developed with consideration for pressure, material specifications, erosion, corrosion, fluid and solids handling.

Wellbore integrity recommendations were based on the issues and implications of sour effluent flow in the wellbore such as: casing metallurgy, wear and corrosion and cement, open hole and wellhead integrity.

The circulating media IRPs were developed recognizing the importance of the circulating media in sour underbalanced drilling and considered media properties, kill fluids, corrosion, monitoring, handling, storage, trucking and waste disposal.

Safety recommendations for on-site personnel were intended to enhance existing regulations and industry standards recognizing the added safety concerns involved in sour underbalanced drilling.

Wellsite supervision recommendations are intended to complement existing ARPs, industry standards and regulatory requirements, particularly regarding the qualifications of personnel, level of supervision, and training.

6.0.3 IRP Revisions

The current editions of reference specifications, standards and recommended practices were used when the Critical Sour Underbalanced Drilling IRPs were published. Revisions in these documents may result in a need to periodically revise the IRPs. In addition, periodic updating of the IRPs will be necessary as new equipment and procedures are developed.

Revisions can be recommended to the Drilling and Completions Committee (DACC). DACC is a standing industry/government committee having representation by CAODC, CAPP, ICOTA, SEPAC, PSAC, BC O&G Commission, BC WCB, Manitoba MEM, Saskatchewan Energy & Mines, Saskatchewan Labour, Alberta EUB, Alberta OH&S and Enform.

6.0.4 Glossary

API Gravity is a special function of relative density (specific gravity) used in the accurate determination of the gravity of petroleum and its products for the conversion of measured volumes at the standard temperatures of $60^{o}F$ ($15.56^{o}C$) represented by:

API gravity (degrees) = (141.5 / specific gravity $60^{o}F/60^{o}F$) - 131.5

Bleed-off line is part of the pressure containing equipment on a snubbing stack that provides a means of bleeding off trapped wellbore pressure.

Certified infers that components of the Pressure Containing System have been manufactured and maintained under a quality program to ensure conformance with their design specification. Certification during shop servicing must be performed by an API or ISO-licensed manufacturer or company or Technical Expert that meets the requirements of ARP 2.10.2.2 (Non-API Well Pressure Containing Equipment Manufacturing).

Coiled tubing string separation is defined as a separation above the highest disconnect in the coiled tubing drill string.

Circulating Media for purposes of this IRP includes both injected and produced fluids as well as their mixtures.

Closed Cup Flash Point (ASTM D 93 Pensky-Martens Closed Cup Tester) is similar to the open cup, but this method allows for better thermal equilibrium between the vapor and liquid.

Coiled Tubing Annular BOP (also known as the "stripper") is defined as the uppermost packing element on the Coiled Tubing BOP stack that enables the coiled tubing to be deployed into the well under pressure.

Coiled Tubing Drill String includes all equipment from the drill bit up to and including the rotating joint on the coiled tubing unit. The drill string refers to all bottom hole assemblies, continuous tubing and pressure control devices in the continuous tubing. The drill string also refers to any fishing bottom hole assembly required to be run into the hole to recover portions of coiled tubing drill string inadvertently left in the well.

Critical Sour Well for the purposes of Underbalanced drilling and this IRP refers to:

Alberta: as defined in Interim Directive ID 97-6 Appendix (1) Section (2)

Other: any well with residents within the Emergency Planning Zone or any well with a potential H_2S release rate greater than 0.3 m3/sec.

Diverter/Annular Preventer refers to an annular-type preventer that is designed to be closed around the drill string to contain wellbore pressure, and may be rotating or non-rotating type, and designed for various working pressure ratings depending on manufacturer specifications.

Drill String includes all equipment from the drill bit to and including the stabbing valve at surface. The Drill String refers to all bottom hole assemblies, jointed drill pipe and pressure control devices run into the hole. The Drill String also refers to any fishing bottom hole assembly required to be run into the hole to recover portions of drill string inadvertently left in the well.

Elastomer Seals refer to all elastomeric seals that contain any wellbore pressure within the Pressure Containing System. These seals are not limited to the ram type preventers but include all seals (O-ring, ram shaft, etc.) exposed to the wellbore environment that prevents the wellbore pressure from escaping outside the Pressure Containing System. Further definition of Elastomers, are referenced in ARP 2.11.2.

Emergency Shutdown Valve (ESD) refers to a remotely-controlled, full-opening valve that is installed on the flowline usually as near the BOP stack as possible.

Equalizing line or loop refers to the pressure containing line on the snubbing stack that provides the means to equalize pressure between the snubbing stack and the wellhead during snubbing operations.

Flash Point is the lowest temperature at which a combustible liquid will give off flammable vapor which can be ignited and will burn momentarily.

Inert gas for purposes of this IRP refers to gases that exhibit stability and extremely low or no reaction rates, such as helium and nitrogen.

Integrity of the drill string means that there is pressure integrity between circulated fluids inside the drill string and wellbore fluids or the atmosphere outside the drill string, except where otherwise designed. Integrity of the drill string requires pressure integrity of all components from the swivel to the drill bit during rotary drive applications, from the top drive unit to the drill bit during top drive applications, and from the rotary joint on the coiled tubing reel to the drill bit during coiled tubing drilling applications. Loss of containment may be caused by a failure of any tubular component.

Open Cup Flash Point (ASTM D 92 Cleveland Open Cup) is the lowest temperature flash point corrected to a barometric pressure of 101.3 kPa, at which application of a test flame causes the vapor of a specimen to ignite under specified conditions of test, and is used primarily for viscous materials having a flash point of 79^{o}C and above.

Pressure Containing System is defined as the blowout prevention system and includes all equipment from the top wellhead flange to the uppermost piece of pressure control equipment (e.g. BOP, snubbing, pressure deployment), and specifically the BOP stack, snubbing stack, coiled tubing stack and pressure deployment system including all bleed lines.

Pressure Deployment is defined as the process by which drill string components or coiled tubing drill string components are deployed into or recovered from the well while the well is live.

Reid Vapor Pressure (ASTM D 323) is the test method used to determine vapor pressure of volatile petroleum liquids at 37.8 ^{o}C (100 ^{o}F) with an initial boiling point above 0 ^{o}C (32 ^{o}F). Vapor pressure is critically important for both automotive and aviation fuel affecting starting, warm-up and vapor lock tendency with high operating temperatures or altitudes. Maximum vapor pressure limits for gasoline are legally mandated in some areas as a measurement of air pollution control.

Shut-in Tubing Head Pressure (SITHP) for the purpose of this IRP is equal to the original reservoir pressure minus the gas gradient, or 85% of the original reservoir pressure. The pressure can be reduced to 85% of the current reservoir pressure if a qualified reservoir specialist endorses a reduction based on factual data.

Snubbing is defined as conducting underbalanced tripping operations when the weight of the drill string or coiled tubing drill string is not sufficient to overcome the upward force exerted on the drill string or coiled tubing drill string by pressure from the well.

Sour refers to an H_2S concentration equal or greater than 10 ppm, and is consistent with 8-hour Occupational Exposure Limit (OEL) for workers exposed to H_2S.

Stripping is defined as the tripping of the drill string or coiled tubing drill string when the string is of sufficient weight to overcome the upward forces exerted on the string by pressure from the well.

Wellsite Supervisor refers to the operator’s representative at the wellsite and includes both the operator’s employee Foreman and Consultant Foreman.

6.0.5 References

NOTE: References are also tabulated on the last page of each chapter.

6.0.5.1 Alberta Energy And Utilities Board

AEUB, Drilling Rig Inspection Manual, June 1995, Calgary, Alberta.

AEUB, Information Letter, 1988, IL 88-11, Calgary, Alberta.

AEUB, Interim Directive ID 87-2, Section 7.3.11, Calgary, Alberta.

AEUB, Interim Directive ID 90-1, Completion and Servicing of Sour Wells, Calgary, Alberta.

AEUB, Interim Directive ID 94-3, Recommended Practices for Underbalanced Drilling, Calgary, Alberta.

AEUB, Interim Directive ID 97-6, Sour Well Licensing and Drilling Requirements, Calgary, Alberta.

AEUB, Oil and Gas Conservation Regulations, October 1996, Calgary, Alberta.

6.0.5.2 American Petroleum Institute

API, Formulas and Calculations for Casing, Tubing, Drill Pipe and Line Pipe Properties, Bulletin 5C3, July 1989, pages 8 and 9, Section 1.1.5, Dallas, Texas.

API, Recommended Practices 750, Management of Process Hazards, First Edition, January 1990, Dallas, Texas.

API, Recommended Practice for Field Inspection of New Casing, Tubing and Plain-End Drill Pipe, First Edition, April 1983, RP 5A5, Dallas, Texas.

API, Recommended Practice for Field Inspection of New Casing, Tubing and Plain-End Drill Pipe, Sixth Edition, December 1997, RP 5A5, Washington D.C.

API, Recommended Practice for Drill Stem Design and Operating Limits, Eleventh Edition, May 1984, RP 7G, Dallas, Texas.

API, Recommended Practice for Drill Stem Design and Operating Limits, Fifteenth Edition, January 1995, RP 7G, Washington D.C.

API, Specification for Wellhead and Christmas Tree Equipment, Fifteenth Edition, Specification 6A, April 1986, Dallas, Texas.

6.0.5.3 American Society Of Mechanical Engineers

ASME, B31G, Manual for Determining the Remaining Strength of Corroded Pipelines, June 1991, New York, N.Y.

6.0.5.4 **American Society Of Testing And Materials**

ASTM, Corrosion Tests in High Temperature or High Pressure Environments, or Both, G111, Philadelphia, PA

ASTM, Evaluating Tensile Properties, D412, Philadelphia, PA

ASTM, Hardness Testing and Explosive Decompression Testing, D2240, Philadelphia, PA

ASTM, Notched Bar Impact Testing of Metallic Materials, 1982, E-23-82, Philadelphia, Pennsylvania.

ASTM, Rubber Property-Effect of Liquids, D471, Philadelphia, PA

ASTM, Standard Test Methods for Determining Average Grain Size, 1984, E112-84, Philadelphia, Pennsylvania

ASTM, Standard Test Methods for Notched Bar Impact Testing of Metallic Materials, May 1996, E 23-96, West Conshohocken, PA.

ASTM, Standard Test Methods for Determining Average Grain Size, May 1996, E 112-96, West Conshohocken, PA.

6.0.5.5 **Drilling And Completions Committee**

DACC, ARP Volume 1, Alberta Recommended Practices for Drilling Critical Sour Wells, July 1987, Calgary, Alberta

DACC, ARP Volume 2, Alberta Recommended Practices for Completing and Servicing Critical Sour Wells, April 1989, Calgary, Alberta

DACC, ARP Volume 4, Alberta Recommended Practices for Well Testing And Fluids Handling, June 1993, Calgary, Alberta.

6.0.5.6 **Government Of Alberta, Occupational Health And Safety**

AOH&S, Alberta Occupational Health and Safety Act and Regulations, Edmonton, Alberta.

6.0.5.7 **National Association Of Corrosion Engineers**

NACE, Standard Test Method for Evaluating Elastomeric Materials in Sour Gas Environments, TM0187-87, Houston, Texas

NACE, Testing of Metals for Resistance to Sulfide Stress Cracking

at Ambient Temperatures, 1977, TM-01-77, Houston, Texas.

NACE, Laboratory Testing of Metals for Resistance to Specific

of Environmental Cracking in H_2S Environments,

December 1996, TM0177-96, Houston, Texas.

6.0.5.8 **National Fire Protection Association**

NFPA, National Fire Protection Association Standards, 1987, Quincy, Mass.

6.0.5.9 **Petroleum Services Association Of Canada**

PSAC, Industry Recommended Practice for Pumping of High Flash Hazard Hydrocarbons, 1998 Draft Edition, Calgary, Alberta.

6.0.5.10 **Society Of Petroleum Engineers**

SPE, Paper 37067, High Pressure Flammability of Drilling Mud/Condensate/Sour Gas Mixtures in De-Oxygenated Air for Use in Underbalanced Drilling, November 1996, Calgary, Alberta.

6.1 Planning

6.1.1 Scope

6.1.1.1 The Planning IRPs have been developed by the Drilling and Completions Sub Committee for Critical Sour Underbalanced Drilling, and addresses the technical and safety planning issues of a critical sour underbalanced drilling operation.

6.1.1.2 An underbalanced drilling project is a complex combination of a drilling operation and a production operation. The presence of sour wellbore fluids increases the complexity and potential risk. The purpose of this section is to outline the planning and review practices that should be conducted to ensure technical and safety integrity of the project.

6.1.1.3 The recommendations in the IRP are meant to be accurate and reliable based on current knowledge, data and practices, but must also be used concurrently with competent technical judgement. DACC, its sub-committees, and individual members make no representation, warranty, or guarantee in the contents of any IRP recommendation and disclaim liability or responsibility for loss or damage resulting from the use of the IRP, or for any violation of any statutory or regulatory requirements.

6.1.1.4 The Planning IRPs have been developed by the Drilling and Completions Sub Committee for Critical Sour Underbalanced Drilling, and addresses the technical and safety planning issues of a critical sour underbalanced drilling operation.

6.1.2 Project Approval

IRP

The overall project plan and application to the AEUB to undertake the underbalanced drilling of a critical sour well will be signed by a qualified and corporately authorized technical representative. That representative, by his/her signature will be confirming that all the requirements of this IRP have been addressed in the plan and that the terms of the plan will be applied during the execution of the plan. The signature will also confirm that appropriate input from qualified technical experts has been obtained where required and that the qualifications of the technical experts are valid.

Due to the complexity of an underbalanced project, and to allow for continuous improvement regarding safety and operational efficiency, IRP 6 recommendations are meant to allow flexibility. However, the need for exercising competent technical judgement is a necessary requirement to be employed concurrently with its use.

It is the operator's responsibility to ensure the required technical judgement has been used to develop the project plan and will be used during the execution of the project.

6.1.2.1 **Qualified Technical Expert**

IRP 6 allows flexibility in practices in several instances **provided the options have been approved by an owner/operator endorsed qualified technical expert** relative to the practice/technology in question. It is the owner/operator's responsibility to ensure that the expert is qualified by normal industry standards (eg: years of technical/operational experience, review of applicable completed projects, references, etc), and meets all regulatory certification requirements. The operator should be able to demonstrate this upon audit.

6.1.2.2 **New Material, Equipment And Practices**

IRP 6 is based on currently available technology and practices and is not intended to discount future technological advances in materials, equipment and practices.

IRP **Different materials, equipment and practices may replace those outlined in IRP 6 provided**:

- They provide at least the same level of safety and public protection as those they are replacing.
- The design has been reviewed by the appropriate technical experts and that this review is included in the project plan.
- There is some actual field performance history in similar use, eg: non-critical sour or sour underbalanced wells. The performance data must be reviewed by the appropriate qualified technical experts and this review is included in the project plan.
- The Safety and Operability review IRP 6.1.6.2 specifically addresses in detail all potential impact of the replacements.

6.1.3 Project Plan

IRP

An underbalanced drilling project plan will be developed which will address the regulatory requirements such as:

- **AEUB ID 90-1 "Completion and Servicing Of Sour Wells"**
- **AEUB ID 94-3 "Underbalanced Drilling"**
- **AEUB ID 97-6 "Sour Well Licensing and Drilling Requirements"**
- **In Alberta, prior to commencing a critical sour underbalanced drilling operation, the licensee must have an EUB approved sour gas flaring permit.**

6.1.4 Well Control

IRP

It is the operators responsibility to have a plan in place to kill the well without hesitation should there be an unplanned release of formation fluids. The operator's on-site representative must have the authority to execute this plan immediately.

During an underbalanced drilling operation, the normal drilling primary well control tool of a hydrostatically overbalanced fluid in the wellbore is not present. The following recommended practices will ensure that the well can immediately be shut-in and that an appropriate fluid (kill fluid) is on hand and is able to be pumped into the wellbore. In this respect the operation more closely resembles a critical sour well servicing operation than a drilling operation, and hence a critical sour well servicing procedure should be used.

Should any equipment malfunction reduce the system integrity, the well will immediately be shut-in. If the well cannot be shut-in, the kill fluid will immediately be pumped into the wellbore.

Should any event occur causing a unplanned release of formation fluid, the well will immediately be shut in. If the well cannot be shut-in, the kill fluid will immediately be pumped into the wellbore preventing any further release. Hence any release should be of very short duration.

The kill fluid holding and pumping system are critical components of the well control system and should be included in well control inspection and testing programs.

6.1.5 Emergency Response Plan

IRP

A site specific Emergency Response Plan for the underbalanced drilling operation must be developed which will address regulatory requirements.

In Alberta, prior to commencing a critical sour underbalanced drilling operation, the licensee must have a EUB approved, site specific emergency response plan.

Since an underbalanced drilling operation is a combination of drilling and production test, a site specific Emergency Response Plan must be developed which addresses both drilling and production conditions.

6.1.6 Reviews and Safety Meetings

6.1.6.1 Reliability Assessment Summary

The DACC sub-committee developing IRP 6 commissioned (and funded through CAPP) C-FER Technologies Inc. to do a Reliability Assessment of critical sour underbalanced drilling.

In summary, the probability of a release (leak) from underbalanced drilling BOP stack leak is significantly higher for critical sour underbalanced well than for a critical sour overbalanced well. However the probability that the release will be controlled is increased due to the added redundancy provided by the practices outlined in IRP 6. The probability of a release is governed by the reliability of the BOP stack. Drill string reliability accounts for a small percentage of the total release probability. There is no significant difference between jointed pipe and coil. The assessment does identify critical components and potential system weaknesses. These must be addressed in the site specific plans that will be conducted for each critical sour underbalanced well (see Safety and Operability Review 6.1.6.2). It is essential therefore, that the recommended practices in IRP 6 are followed.

6.1.6.1.1 Background

The purpose was to:

- Estimate the probability of an undesirable event (a release or uncontrolled release) during a critical sour underbalanced drilling operation relative to current acceptable critical sour overbalanced drilling.
- Identify critical components, potential system weaknesses, and methods of mitigation.

The analysis "Reliability Assessment for Underbalanced Drilling of Critical Sour Wells" has provided valuable insight into critical sour underbalanced drilling and the sub-committee wish to acknowledge the work of C-FER in preparing the report.

6.1.6.1.2 Scope and Methodology

The assessment looked at and compared three drilling procedures:

- overbalanced drilling with jointed pipe using ARP 1
- underbalanced drilling with jointed pipe using IRP 6
- underbalanced drilling with coiled tubing using IRP 6

The assessment only addressed that part of the underbalanced drilling system comprised of drillstring and BOP equipment. It was assumed that:

- The surface circulating system is similar to current critical sour production test systems and would pose similar risks and hazards (IRP 6.4 Circulating System).
- Wellbore integrity is provided by adequate casing and wellhead (IRP 6.5 Wellbore Integrity).
- The drilling fluid could be slightly sour and pose a safety hazard if released, but much less of a hazard than a release of sour formation fluid (IRP 6.6 Circulating Media).

The methodology used was Fault Tree Analysis, which is a structured deductive technique which identified the basic events leading to a release or uncontrolled release. It then used historical statistical failure information for the basic events to estimate the probability of a release. These probabilities were then validated against Alberta Energy and Utilities Board (AEUB) statistics on blow and blowouts.

No attempt was made to address the consequences of these events. Intuitively it would be expected that a release (equivalent to the AEUB definition of a blow which is an event that allows gas to escape from the well but can be contained by the well control equipment) would be “smaller” and pose less of a hazard to the public than an uncontrolled release (equivalent to the AEUB definition of a blowout which is a blow that cannot be contained by the well control equipment) and requiring repair of the existing equipment or installation of additional equipment. Both, obviously, have significant impact on wellsite workers.

6.1.6.1.3 Quantitative Results

The component failure data came from North Sea and European operations databases and is based, in general, on non-sour service. The AEUB database used is for all wells in Alberta and does not differentiate sour wells, nor; critical sour wells drilled using current ARPs. While the absolute probabilities would likely be influenced by the incorporation of sour service failure rates, the relative magnitude of probabilities with different equipment configurations can be compared reliably. It is the DACC sub-committee's interpretation that:

- The lack of sour service drilling data does not address possible higher failure probabilities for drilling systems exposed to sour fluids.
- The lack of data on critical sour wells drilled and tested using existing recommended practices, does not address the possible lower failure probabilities for systems operated using higher than industry-norm practices.
- The probability of an uncontrolled release (blowout) should be about the same for a critical sour underbalanced well as for a critical sour overbalanced well.

The probability of a release (blow) from an underbalanced drilling BOP stack leak is significantly higher for a critical sour underbalanced well than for a critical sour overbalanced well. However, the probability that the release will be controlled is increased due to the added redundancy provided by the practices outlined in IRP 6.

6.1.6.1.4 Qualitative Results

The following are some general comments and observations based on the analysis.

Overbalanced Drilling

- Assuming a kick has been taken, by far the most significant event leading to a release is the combination of a BOP leak and failure to operate the BOP stack. For critical sour wells, ARPs 1 and 2 address these issues.

Underbalanced Drilling

- Since sour wellbore fluids are already present at surface during critical sour underbalanced operations, external events have a higher probability of causing a release. These external events could be:
  - Fire and explosion
  - Earthquake
  - Severe storm (severe weather conditions-hot or cold)
  - Damage by heavy equipment
  - The Safety and Operability Review required for all critical sour underbalanced wells (IRP 6.1.6.2) should address these possible external events and ensure there is a plan in place to mitigate them.
  - Assuming these external events are addressed, the most significant event leading to a release is the same as for overbalanced drilling - the combination of a BOP leak and failure to operate the BOP stack.
  - Based on the failure data reviewed drill string leaks have a much lower probability of causing a release. Catastrophic failure of the drill string could, however, play a significant role in a failure to operate the BOP stack. In addition, as mentioned before, the failure data does not address drilling sour service, nor wells drilled using ARPs. The drill string integrity is a key component of system performance and is addressed in IRP 6.3 Drill String.
  - Based on the data reviewed, there is little difference in the probabilities of release for underbalanced drilling with either jointed pipe or coiled tubing.
  - The increased redundancy of the IRP 6 underbalanced BOP stack should improve the ability to control a release relative to an overbalanced stack.
  - Based on the data reviewed, the probability of a circulating media release is about the same as for wellbore fluids. Since the circulating media could be slightly sour, the Safety and Operability Review required for all critical sour underbalanced wells (IRP 6.1.6.2) should address this possibility and ensure there is a plan in place to mitigate it.

6.1.6.2 Safety and Operability Review

IRP

Prior to commencement of operations a detailed Safety and Operability Review must be conducted.

6.1.6.2.1 Purpose

The purpose is to critically review the proposed plan to identify and correct, or develop contingency plans for, possible problems.

Although this IRP (and previous ARPs and IRPs) have provided practices to address general situations, each project is unique and must be reviewed in detail.

The review also provides a training tool for field personnel.

6.1.6.2.2 General Outline

In general, the review process should include:

- a review of the final project plan including well plan, equipment specifications and layout, procedures, practices as outlined in 6.1.3.
- a review team consisting of:
  - technical staff who wrote the program
  - ALL site supervisors--operator and contractor
  - an experienced facilitator who has had prior sour well experience
  - senior operations person responsible for the operation

The team would conduct an orderly, systematic review of the project plan to identify possible failure scenarios. Some possible methodologies are referred to in:

- API RECOMMENDED PRACTICE 750 "Management of Process Hazards".

An assessment of possible failure scenarios together with appropriate mitigation measures. If not already included in the project plan, the plan should be modified.

A detailed documented review of the operation, which would be approved/signed by the Senior Operations person (i.e. Superintendent, Operations Manager) responsible and accountable for its execution.

Note: **If an operator has previously conducted a similar critical sour underbalanced project, the safety and operability review conducted for the previous project may be used as the basis for the new project, but may not replace the requirement for a new review of the new project.**

6.1.6.3 Pre-Job Safety Meeting	
IRP	**Immediately prior to starting critical sour underbalanced drilling operations, a pre-job safety meeting must be conducted with ALL personnel on location. It should include a review of the Safety and Operability Review.**
6.1.6.4 Emergency Response Plan Meeting	
IRP	**Immediately prior to starting critical sour underbalanced drilling operations, an Emergency Response Plan (ERP) meeting must be conducted with ALL personnel involved with the ERP to review the ERP.**
6.1.6.5 Tailgate Safety Meetings	
IRP	**A short tailgate meeting must be conducted with all personnel on location to review upcoming operations:** • **prior to each shift or crew change, or** • **prior to a significant change in operations (eg: prior to a stripping / snubbing trip.**

6.1.7 List of References

1. AEUB, Interim Directive ID 90-1, Completion and Servicing of Sour Wells, Calgary, Alberta

2. AEUB, Interim Directive ID 94-3, Underbalanced Drilling, Calgary, Alberta

3. AEUB, Interim Directive ID 97-6, Sour Well Licensing and Drilling Requirements, Calgary, Alberta

4. API, Recommended Practices 750, Management of Process Hazards, First Edition, January 1990, Dallas, Texas

6.2 Well Control Equipment

6.2.1 Scope

6.2.1.1 The Well Control Equipment IRP has been developed by the Drilling and Completions Sub Committee for Critical Sour Underbalanced Drilling, and addresses the concerns and issues regarding well control equipment and procedures while being exposed to effluent flow from a critical sour well during underbalanced drilling operations.

6.2.1.2 This IRP is to be used in conjunction with existing ARPs and AEUB Regulations, and have been referenced throughout this document. Special attention should be given to the AEUB Oil and Gas Conservation Regulations sections 8.129 - 8.149 inclusive entitled "Blowout Prevention Requirements".

6.2.1.3 The recommendations set out in this IRP are based on the premise that the BOP equipment is the first line of defense in an underbalanced operation versus the second line of defense in an overbalanced operation.

6.2.1.4 The recommendations in the IRP are meant to be accurate and reliable based on current knowledge, data and practices but must always be used concurrently with competent technical judgment. DACC, its subcommittees, and individual members make no representation, warranty, or guarantee in the contents of any IRP recommendation, and disclaim liability or responsibility for loss or damage resulting from the use of the IRP, or for any violation of any statutory or regulatory requirement.

6.2.2 Design Considerations

6.2.2.1 Safety Considerations

The safety of the public and on-site personnel is the most important factor in any design.

In selections of preferred BOP stack arrangements and equipment, it is necessary to accept the fact that equipment can fail during drilling, stripping, snubbing or pressure deployment operations. A redundant system is necessary to reduce the effect of a failure.

One main difference between overbalanced drilling and underbalanced drilling is that the primary stack will be exposed to wellbore effluent during the underbalanced operation.

The blowout prevention system in a sour underbalanced drilling operation is the first line of defense between the sour well effluent and the on-site personnel (versus the second line of defense in an overbalanced operation).

6.2.2.2 General Requirements

The amount and type of equipment needed is affected by the magnitude of the surface pressures expected, the method of pipe rotation (top drive or rotary table), the nature of the reservoir fluids to be encountered (critical sour gas and/or oil), and the type of drilling fluid system. Taking these factors into consideration, underbalanced drilling requires a BOP system which:

- permits drilling to proceed while controlling annular pressure;
- allows connections to be made either with the well flowing or shut-in;
- allows tripping of the drill string under pressure to change bits or bottom-hole assemblies;
- provides for backup annular control in case of a primary diverter/annular preventer failure;
- provides a means to quickly and safely shut-in the well;
- includes a system for bleeding off and equalizing pressure between the rams.

The casing, wellhead and BOP stack must be able to accommodate all forces it could be subjected to during the course of underbalanced operations, including axial and lateral loads imparted by the drill string, and weight of the stack.

6.2.2.3 Stack Configurations

IRP

All BOP stack configurations must include shear or shear/blind rams. The shear blades must be capable of shearing the tube in the sour environment. Jointed pipe operations must conform to standards outlined in ARP 1.1.5. Empirical data supporting the reliability of the blades for service in the sour environment is required for coiled tubing operations.

IRP

The stack configuration must include two lines of defense, and a monitoring system to indicate when the primary line of defense has failed.

Consideration should be given to using a tubing spool to allow the landing of the tubing hanger. Consideration should also be given to a full opening master valve. This would provide additional flexibility in pressure testing and will allow the well to be shut-in independently of the BOPs.

Acceptable stack configurations are illustrated in:

- Appendix I, II and III for jointed pipe operations
- Appendix IV for coiled tubing operations

6.2.2.3.1 Jointed Pipe Operations

IRP

Two diverter/annular preventers must be installed above the critical sour stack and during any underbalanced operation both diverter/annular preventers must be closed. The top diverter /annular preventer, is in place to provide a second line of defense to the personnel working on the floor. A monitoring system is to be installed between the two diverter /annular preventers, to monitor for failure of the primary diverter /annular preventer. The operation must be stopped if a failure occurs, and the diverter/annular preventer must be repaired before operations proceed.

IRP

The capability must be in place to allow the replacement of the primary diverter /annular preventer elements with the drill string in the well.

This is a precautionary measure since personnel are working on the floor above the stack (versus a coiled tubing operation where personnel are not required to work around the wellhead during the underbalanced operation).

6.2.2.3.2 Coiled Tubing Operations

Refer to Appendix IV for an acceptable stack configuration.

6.2.3 Equipment Specifications

6.2.3.1 Working Pressure

IRP	**All pressure containing equipment, including equalizing loops and bleed-off lines will have a minimum working pressure equal to the SITHP.**

6.2.3.2 Connections

IRP	**All pressure containing connections must either be flanged or, if threaded connections are used, the threads must be isolated from the wellbore environment by seals. EUE-type connections will only be acceptable to 21 MPa working pressure. National Pipe Thread (NPT) is acceptable to a maximum pipe OD of 25.4 mm in accordance with API Specifications 6A (Section 3, Part B-1B).**

6.2.3.3 Internal Pressure Control

6.2.3.3.1 The Drill String

IRP

The drill string must be equipped with a minimum of one primary and one redundant pressure control device before it can be deployed into or out of the well.

Provisions must be made in the drill string so additional pressure control devices can be added while the drill string is in the well. If the pressure control devices in the drill string are known to have failed during operations in the well, an additional pressure control device must be installed in the drill string before it is pulled from the well.

6.2.3.3.2 Stabbing Valve

IRP

The internal diameter of the stabbing valve must match the drift diameter of the drill string to enable pressure control devices to be lubricated into the hole on wireline under pressure through the stabbing valve.

The stabbing valve must conform to ARP 2.2.5 (Tubing Safety Valves).

6.2.3.3.3 Coiled Tubing Drill String

IRP	**The coiled tubing drill string must be equipped with a double check valve in the bottom hole assembly.**

6.2.3.3.4 Wireline Equipment

IRP

Wireline pressure deployment systems must conform with the following guidelines:

ARP 2.7.5.1	Equipment Specifications
ARP 2.7.5.2	Equipment Configuration
ARP 2.7.5.4	Bolting, (except cold service)

6.2.3.4 Materials

IRP

All metallic materials utilized in the pressure containing system including equalizing loops and bleed-lines must conform with materials of construction ARPs as listed below:

- **ARP 1.1.5.1 Metallic Materials for Sour Service**
- **ARP 1.1.5.2 Bolting (except cold service)**
- **ARP 1.1.5.3 Non-Metallic Materials for Sour Service**
- **ARP 1.1.5.4 Transportation, Rigging Up and Maintenance**
- **ARP 1.1.5.5 Welding for Sour Service**
- **ARP 1.1.5.6 Sour Service Identification**

6.2.3.5 BOP Control System

IRP

Prior to and during underbalanced drilling operations all BOP control systems must conform to regulatory requirements for whichever rig operation is applicable, such as:

<u>Drilling Rig</u>

- **AEUB Oil and Gas Conservation Regulations, sections 8.133 - 8.134**
- **ARP 1.1.6**

<u>Service Rig</u>

- **AEUB Oil and Gas Conservation Regulations, sections 8.145 -8.146**
- **ARP 2.2.4**

IRP

Auxiliary BOP equipment must be installed to operate independently of the primary control system and to the manufacturer's specifications.

6.2.4 Elastomers

IRP

Manufacturer-supplied performance properties and recommend-ations must be used for seal design, packaging, storage and shelf life.

This IRP applies to all elastomers in the Pressure Containing System, as well as any elastomers in pressure control devices which are run as part of the drill string.

Compatibility of any elastomeric seal with the intended service should be determined when selecting materials and equipment for the underbalanced drilling of any sour well. This includes consideration of the effect of any fluid or substance that elastomer seals may be exposed to, as well as ambient temperatures at which seals are required to perform.

<u>Refer to:</u>

ARP 2.11 (Guidelines for Selecting Elastomeric Seals)

ARP 2.11.2 (Service Conditions)

ARP 2.11.3 (Seal Design)

6.2.4.1 Testing And Evaluation

IRP

If manufacturer-supplied performance properties and recommendations for seals are not available for anticipated underbalanced drilling conditions, specific testing of seals must be performed based on the underbalanced drilling conditions.

To evaluate the suitability of elastomers for a particular well, the well operator should first refer to the equipment manufacturer's recommendations. These recommendations should be based on materials testing and experience. In addition, the well operator must be satisfied that the information or data on seal materials meets the intended service requirements. If no data is available, a field-specific testing program must be performed to determine an elastomers suitability.

6.2.4.2 Testing Methodology

No industry standards (such as API) exist for the manufacturer of elastomers for oilfield equipment. An example of available field-specific testing methodology for elastomers could include but not be limited to the following:

Example

Placing elastomer samples in an autoclave and introducing the samples to a representative underbalanced drilling environment taking into consideration the pressure, temperature, reservoir fluid composition, drilling fluid composition and exposure times. The elastomer samples could then be evaluated to determine their suitability for the field-specific application by utilizing some or all of the test methods listed below:

NACE TM 0187-87 Standard Test Method for Evaluating Elastomeric Materials in Sour Gas Environments

ASTM D471	Rubber Property-Effect of Liquids
ASTM G111	Corrosion Tests in High Temperature or High Pressure Environments, or both
ASTM D412	Evaluating Tensile Properties
ASTM D2240	Hardness Testing Explosive Decompression Testing

Since most BOP manufacturers utilize proprietary formulas for their elastomers it is recommended that any testing be performed in conjunction with the BOP manufacturer and a qualified elastomer chemist.

Refer to ARP 2.11.4 (Testing and Evaluation).

6.2.4.3 Records

IRP

The well operator must ensure that records identifying the elastomer materials in use for all pressure control seals are available, and during underbalanced drilling operations, this information is to be available at the wellsite.

Refer to ARP 2.11.5 (Records).

6.2.5 Inspection And Testing

6.2.5.1 Certification

IRP

All pressure control equipment shall be inspected, certified and pressure tested to the manufacturer's standards immediately prior to its use on the well which critical sour underbalanced drilling operations will be conducted.

All pressure control equipment shall be pressure tested immediately prior to its use on critical sour underbalanced drilling operations.

Documentation of the inspection is to be kept on location during the critical sour drilling operation.

Procedures for inspection, pressure testing and certification are outlined in the following documents:

AEUB IL 88-11	(Shop Servicing and Testing of Blowout Preventers and Flexible Bleed-Off and Kill-Line Hoses).
ARP 2.10	(Quality Programs for Well Pressure Containing Equipment).

6.2.5.2 Shear Cutoff Test

IRP

A shear cutoff test must be conducted on the coiled tubing BOP stack immediately prior to being put into service on a critical sour underbalanced drilling operation. The test must be conducted with the coiled tubing BOP stack pressured up to its maximum operating pressure and a representative sample of coiled tubing, including telemetry cable if applicable, must be sheared. The shear rams should be visually inspected after the test and prior to being put into service.

Wireline Pressure Deployment Systems must conform with the following guidelines:

ARP 2.7.5.5 (Certification).

6.2.5.3 Wellsite Testing

Pressure testing of the pressure containing system conducted at the wellsite must conform to regulatory requirements such as AEUB Regulation 8.141. The intent of the pressure test requirements is that the bottom hole assembly can be pressure deployed at the highest possible anticipated pressure.

This IRP requires that a gas pressure test with an inert gas be conducted in addition to a hydrostatic pressure test of all pressure containing equipment if the circulating medium is a gaseous fluid and/or if drilling a critical sour gas well.

6.2.5.3.1 Pressure Containing System

IRP

The pressure containing system will be hydrostatically pressure tested for a minimum of 10 minutes to:

- **a low pressure of 1400 kPa,** and
- **a pressure equal to the SITHP**

IRP

The pressure containing system will then be pressure tested with an inert gas if the circulating medium is a gaseous fluid and/or if the wellbore effluent is expected to contain free gas, for a minimum of 10 minutes to:

- **a low pressure of 1400 kPa,** and
- **a pressure equal to 90% of the SITHP**

IRP

Documentation of the hydrostatic and gas pressure tests must be kept at the wellsite throughout the duration of the sour underbalanced drilling operation.

Refer to Section 6.5 for Casing Pressure Testing requirements.

IRP

If any connections in the pressure containing system are broken during operations, those connections must be re-pressure tested before operations can continue.

All tests conducted on the snubbing stack annular type preventers shall be conducted with pipe in the hole.

Test plugs can be utilized to isolate the BOP system from the production casing during pressure tests.

6.2.5.3.2 Jointed Pipe Drill String

IRP

Prior to tripping the drill string into the hole the pressure control devices within the drill string must be pressure tested from the bottom up to 1400 kPa for a minimum of 10 minutes and to 1.1 times the SITHP for a minimum of 10 minutes utilizing a low viscosity fluid.

Prior to tripping the drill string out of the well, the pressure control devices within the drill string must be pressure tested from the bottom up utilizing the pressure in the well at the bottom of the drill string, and reducing the pressure at the top of the drill string to atmospheric pressure. The top of the drill string must then be monitored for a minimum of 10 minutes to determine if any leaks exist in the drill string pressure control devices.

If the drill string does not pass this pressure test at least one pressure control barrier must be added to the drill string and the pressure test repeated.

After pulling the drill string out of the hole and prior to re-running the drill string back into the well, the drill string pressure control devices must be inspected and redressed as required.

6.2.5.3.3 Coiled Tubing Drill String

IRP

Prior to tripping the coiled tubing drill string into the hole, the double check valve in the bottom hole assembly must be bench-tested just prior to being run in the hole, to 1400 kPa for a minimum of 10 minutes and to 1.1 times the SITHP for a minimum of 10 minutes with an inert gas.

The coiled tubing drill string between the double check valve and the rotating joint on the coiled tubing reeled unit should be pressure tested to 1400 kPa for a minimum of 10 minutes and 1.1 times the SITHP for a minimum of 10 minutes utilizing a low viscosity fluid.

The pressure control devices in the bottom hole assembly during pressure deployment operations into the hole must be pressure tested from the bottom up utilizing wellbore pressure at surface.

If the pressure control devices in the bottom hole assembly do not hold pressure from below during pressure deployment operations into the hole, the coiled tubing is to be pulled from the hole and the existing barriers replaced and re-pressure tested before pressure deployment operations into the hole continue.

If any connections in the coiled tubing drill string between the double check valve and the rotating joint on the coiled tubing reeled unit are broken during operations, those connections must be re-pressure tested as outlined in this section before the coiled tubing drill string can be run back into the well.

6.2.6 Operation Guidelines

6.2.6.1

Snubbing, stripping and pressure deployment is allowed after dark provided the lighting at the wellsite is sufficient to enable work to be conducted safely, and to allow personnel to:

- leave the wellsite safely, and
- initiate emergency shutdown procedures, and
- perform a rescue.

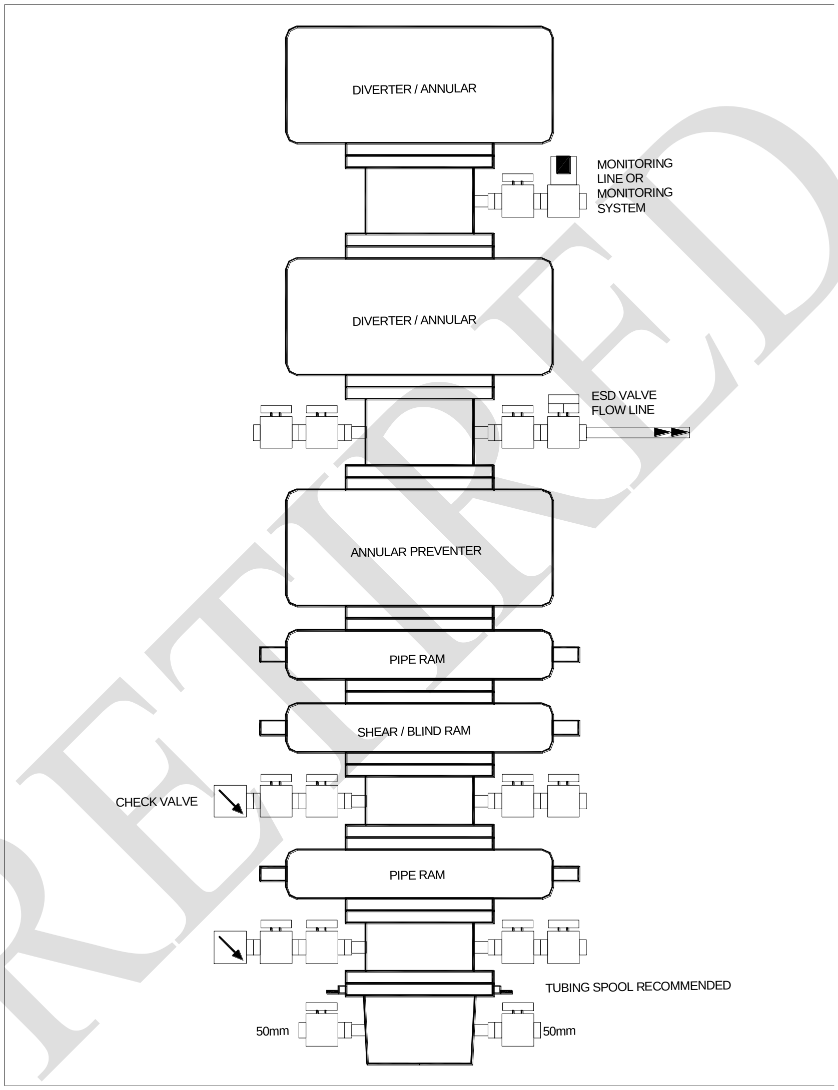
6.2.6.2

Prior to tripping out of the well with jointed pipe drill string, all sour fluids must be displaced from the drill string.

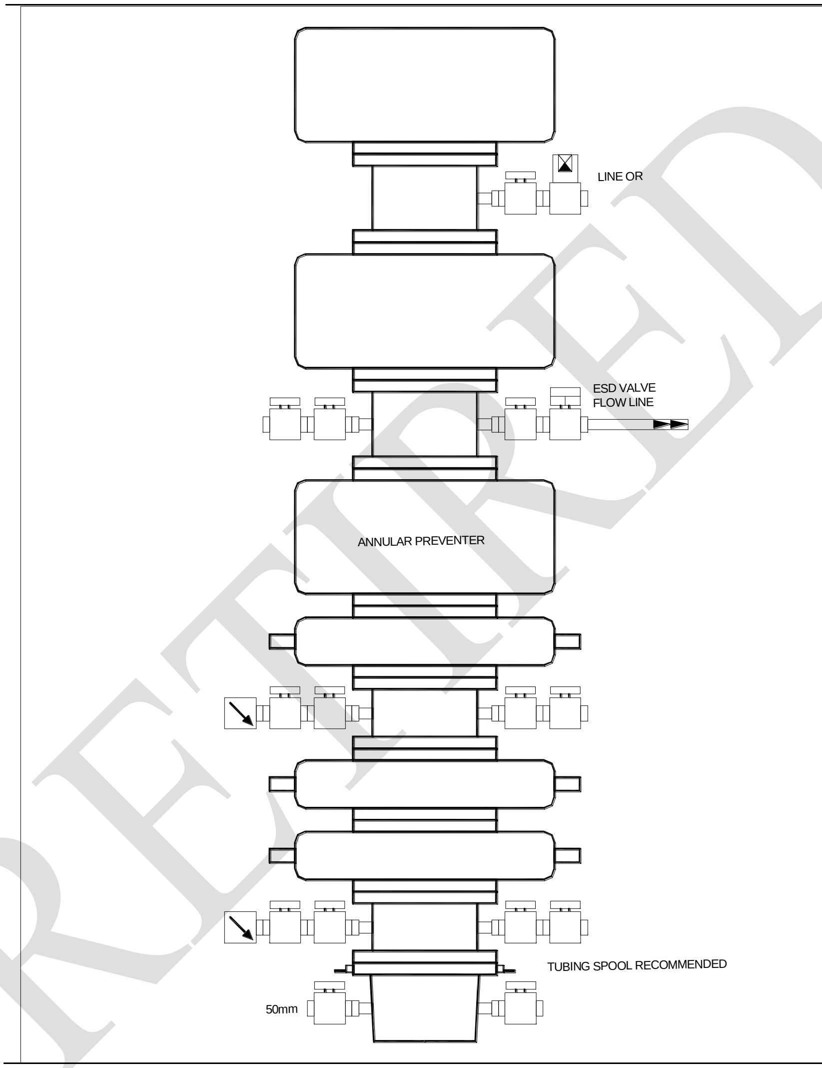
6.2.6.3

If the well is not flowing during tripping operations consideration should be given to bullheading a nitrogen blanket into the annulus prior to tripping to provide an additional level of safety for the workers by allowing the detection of a nitrogen leak before any H_2S leak.

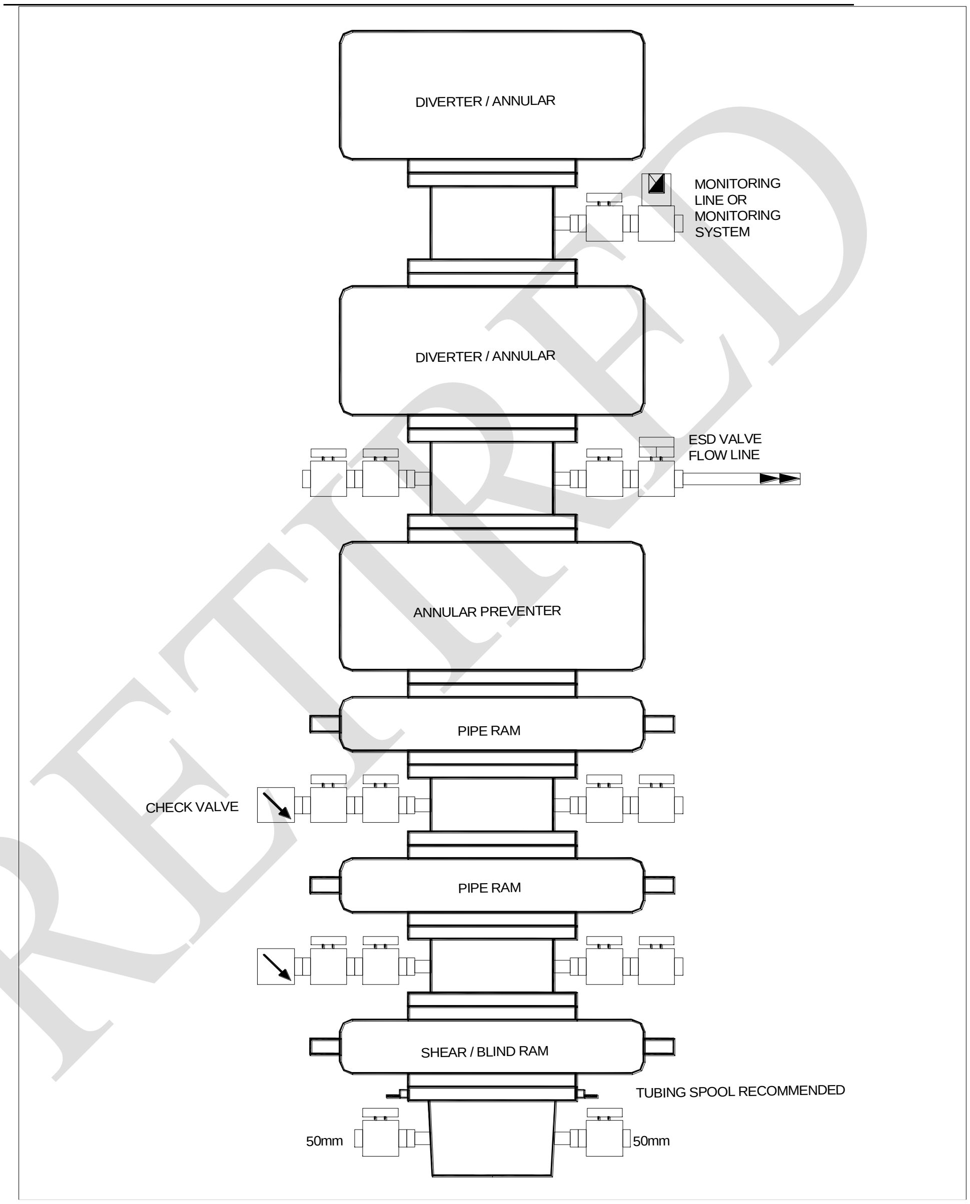
Appendix I - BOP Stack Configuration 1



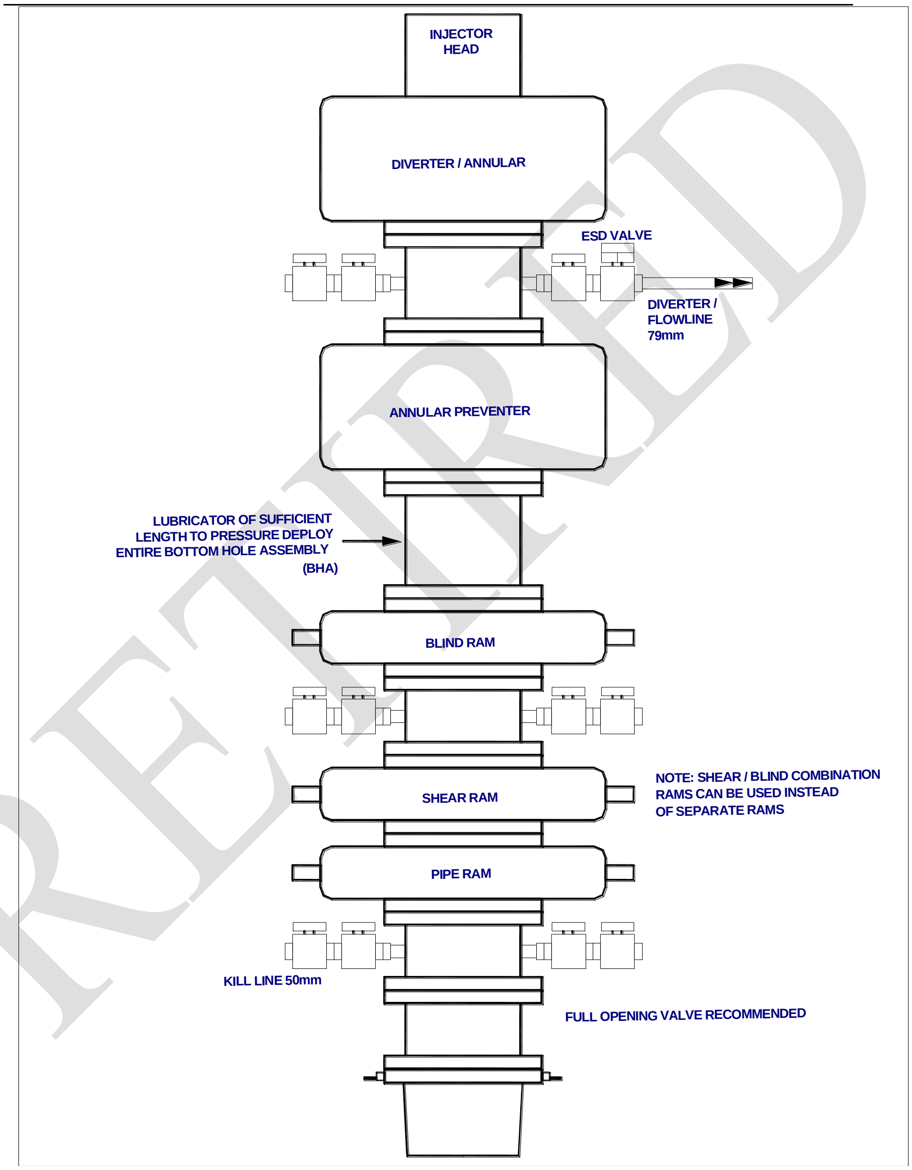
Appendix II - BOP Stack Configuration 2



Appendix III - BOP Stack Configuration 3



Appendix IV - Coiled Tubing BOP Stack Configuration



6.2.7 List of References

1. AEUB, Information Letter IL 88-11, Calgary, Alberta

2. AEUB, Oil and Gas Conservation Regulations, Sections 8.129-8.149, October 1996, Calgary, Alberta

3. AEUB, Interim Directive ID 94-3, Recommended Practices For Underbalanced Drilling, Calgary, Alberta

4. API, Specification for Wellhead and Christmas Tree Equipment, Fifteenth Edition, Specification 6A, April 1986, Dallas, Texas

5. ARP Volume 1, Alberta Recommended Practices For Drilling Critical Sour Wells, July 1987, Calgary, Alberta

6. ARP Volume 2, Alberta Recommended Practices For Completing and Servicing Critical Sour Wells, April 1989, Calgary, Alberta

7. ASTM, Rubber Property-Effect of Liquids, D471, Philadelphia, PA

8. ASTM, Evaluating Tensile Properties, D412, Philadelphia, PA

9. ASTM, Hardness Testing and Explosive Decompression Testing, D2240, Philadelphia, PA

10. ASTM, Corrosion Tests in High Temperature or High Pressure Environments, or Both, G111, Philadelphia, PA

11. NACE, Standard Test Method for Evaluating Elastomeric Materials in Sour Gas Environments, TM0187-87, Houston, Texas

6.3 Drill String

6.3.1 Scope

6.3.1.1

The Drill String IRPs have been developed by the Drilling and Completions Sub Committee for Critical Sour Underbalanced Drilling (UBD), recognizing the need for drill string integrity during critical sour UBD operations. This section addresses issues related to drill string components when exposed to effluent from a critical sour well. The designation "drill string" refers to both jointed and coiled tubulars. The designation "drill pipe" refers to traditional drill pipe with tool joints and tubing with connections suitable for drilling service.

6.3.1.2

Integrity of the drill string means that there is pressure isolation between circulated fluids inside the drill string and wellbore fluids or the atmosphere outside the drill string, except where otherwise designed. This requires pressure integrity of all components from the swivel to the drill bit during rotary drive applications, from the top drive unit to the drill bit during top drive applications, and from the rotary joint on the coiled tubing reel to the drill bit during coiled tubing drilling applications.

6.3.1.3 This IRP was formulated following completion of a screening level testing program to approximate limits on drill pipe material properties for critical sour UBD conditions. IRP recommendations relating to coiled tubulars were based upon a combination of sour well servicing operational experiences, laboratory and field-measured fatigue life information under sweet conditions, and laboratory testing under sour conditions for non-fatigued tubulars. Coiled tubing fatigue performance under sour conditions is the subject of on going research and testing.

6.3.1.4 The recommendations contained in this IRP include drill string inspection, documentation and operational guidelines to be considered when UBD a critical sour well. Minimum purchasing specifications have been provided for various grades of drill pipe (conventional and tubing), tool joint, and coiled tubing materials (minimum yield strength for each grade listed in brackets) as follows:

- Grade SU-65 (448 MPa / 65 ksi) coiled tubing
- Grade SU-75 (517 MPa / 75 ksi) drill pipe tubes
- Grade SU-80 (551 MPa / 80 ksi) tubing
- Grade SU-95 (655 MPa / 95 ksi) drill pipe tubes
- Grade SU-105TJ (724 MPa / 105 ksi) drill pipe tool joints
- Grade SU-110TJ (758 MPa / 110 ksi) drill pipe tool joints

The "SU" designation material grades reflects material and performance specifications used in the manufacture of these grades, designating them as more suitable for "sour underbalanced" drilling than commonly available grades having similar minimum yield strengths.

6.3.1.5 The recommendations set out in this IRP are meant to allow flexibility, however; the need for exercising competent technical judgment is a necessary requirement to be employed concurrently with its use. It remains the responsibility of the user of the IRP to judge whether or not a drill string is suitable for a specific critical sour UBD operation. While every effort has been made to ensure the accuracy, reliability and completeness of the data contained in this IRP, DACC, it's subcommittees, and individual members make no representation, warranty, or guarantee in connection with the publication or the contents of any IRP recommendation, and hereby disclaim liability or responsibility for loss or damage resulting from the use of the IRP, or for any violation of any statutory or regulatory requirement with which an IRP may conflict.

6.3.1.6 This IRP is part of a series. For the overall intent of, and as a general reference to, the whole series; refer to IRP 6.0. The recommendations contained in this IRP provide operators with industry-endorsed advice, and are intended to be applied in association with all existing regulations as well as the other IRPs. While strict prescription of good practices is not desired, the subcommittee believes that such practices place considerable onus on the legally responsible party to comply or otherwise provide a technically equivalent or better solution.

6.3.1.7 In cases of inconsistency or conflict between any of the recommended practices contained in this IRP and the applicable regulatory requirements, the regulatory requirements shall prevail.

6.3.2 General Requirements For Drill Pipe

IRP	**Drill pipe grades SU-75 or SU-95 and tubing grade SU-80 are to be used for critical sour UBD.**
IRP	**Existing drill strings (ie: not originally manufactured to meet SU-75, SU-80 or SU-95 material and performance specifications) must meet all of the requirements stipulated for the appropriate SU grade in order to qualify for critical sour UBD.**
IRP	**Drill string floats must be placed at various intervals in the drill string to allow for the drill string to be bled off to make connections during drilling and prior to/during tripping the drill string out of the hole. A minimum of two additional floats, placed in tandem, are to be inserted as close to the bit (or downhole motor) as possible.**
IRP	**All drill string equipment not covered in this IRP and introduced to the critical sour UBD environment must satisfy material and performance requirements for the anticipated sour conditions.**
IRP	**The well must be killed in the event of any parted pipe during critical sour UBD operations.**

6.3.2.1 Grades 75 and 95 drill pipe meeting the specifications in sections 6.3.4 and 6.3.6 are herein referred to as grades SU-75 and SU-95, respectively. Tool joint grades 105 and 110 meeting specifications in section 6.3.7 are herein referred to as grades SU-105TJ and SU-110TJ respectively. Grade 80 tubing meeting the specifications in section 6.3.5 is herein referred to as grade SU-80. These new drill pipe and tubing specifications provide substantially increased SSC resistance as compared to grade E-75 and grade X-95 drill pipe, and grade L80 tubing as currently specified through API.

A material testing program has confirmed the viability of materials performance of the SU-95 material as specified. This committee has used extensive industry experience and testing to confirm that grades SU-75 and SU-80 will meet the specified performance criteria.

6.3.2.2 Higher strength tube materials (greater than 758 MPa / 110 ksi maximum yield strength) should not be used at this time as their sour service performance is currently considered unacceptable for critical sour UBD applications.

6.3.2.3 (Maximum yield strength) should not be used at this time as their sour service performance is currently considered unacceptable for critical sour UBD applications.

6.3.2.4

Mixed strings of grade SU-75 and SU-95 or heavy wall SU-75 are acceptable. Heavy wall grade SU-75 or SU-95 are desirable for the uppermost section in critical sour UBD wells to increase the tensile margin as compared to that achieved by the use of regular weight SU-95. Heavy wall grades SU-75 or SU-95 refer to 37.4 daN/m (25.6 lb/ft), 29.2 daN/m (20.0 lb/ft), and 23.1 kg/m (15.5 lb/ft) for the 127.0 mm (5.0"), 114.3 mm (4.5"), and 88.9 mm (3.5") sizes, respectively.

6.3.2.5

Desirable minimum overpull margins are in the order of 35000 - 60000 daN. The final margin of overpull at surface should be higher than the margin at the crossover between two grades or two weights.

6.3.2.6

Drill pipe exposure control, although limited during critical sour UBD, may be enhanced through several means such as batch or continuous injection of H_2S inhibitors and/or increased pH of water phase in water based systems. Under severe operating conditions (deep, increased probability of failure, increased consequence of failure) oil based fluids are preferred over water based fluids for exposure control. Additional safety measures such as regularly purging the drill string and casing annulus with inert gas, and minimizing drill string exposure time to H_2S should also be considered.

6.3.2.7	For drill string tensile calculations it is desirable to utilize the force-balance (i.e. pressure-area) method of drill string design. This recognizes a decreasing tension with increasing depth in the string at a rate equal to the air weight of the drill pipe tube and the buoyed weight of the tool joints. This method will permit utilization of more pipe of lower linear density and/or grade as the well depth increases. This technique will also simultaneously increase the remaining tensile margin at surface when using heavy wall drill pipe for the upper section of the drill string, and increases as the well continues to greater depths.
6.3.2.8	Drill string floats are to be incorporated into the drill string to prevent flow up the drill string. In the case of rotary assemblies, a minimum of two floats are to be placed in the bit sub, the float sub directly above the bit, or in the bottom-hole drill collar. In the case of directional drilling where a downhole motor is being used, a minimum of two floats are to be placed as close to the motor as possible. These two floats placed in the BHA are to be inserted in tandem. The actual number of drill string floats and the interval of placement within the upper portion of the drill string is a function of how much underbalanced hole is to be drilled. Conventional wisdom has seen a drill string float (in addition to the two floats at the bit or motor) inserted into the drill string at the point where underbalanced drilling is to commence, and approximately every 200 meters after that point until the underbalanced portion of the well is completed.
6.3.2.9	Drill string floats with a design incorporating an outer sealing mechanism with a positive seal between the float body and the carrying assembly are recommended over conventional designs.

6.3.3 Qualification Of Used Su Drill Pipe

IRP

Premium class drill pipe (as defined by API) or Class 1 drill pipe (as defined below) is acceptable for critical sour UBD.

Class 1 drill pipe is defined as drill pipe with less than 10% tube wall thickness wear, and therefore possesses tensile ratings approximately midway between those for new drill pipe and those for premium drill pipe. Class 1 drill pipe may be used as per tensile rating specifications contained in Appendix I.

IRP

Drill pipe used to drill the critical sour underbalanced zone must be inspected for corrosion, wear, pitting and cracking prior to the penetration of the critical zone, unless a recent inspection has been conducted on each joint within 30 sour-exposure operating days. Follow API Level 1 inspection criteria.

The SU-75, SU-80 and SU-95 pipe owner shall maintain documentation of all inspections as listed above. This information is to be provided to the operator or the appropriate regulatory agency upon request.

IRP

Each joint of drill pipe to be used for critical sour UBD must be periodically evaluated for hardness level prior to continued use. Hardness levels must meet the appropriate tube and tool joint specifications listed in this IRP. Hardness testing will conform to API RP 5A51 Subsection 4.5 with the following additional requirements:

- **Retest frequency shall be once every 120 sour UBD operating days.**
- **Direct reading Rockwell "C" (HRC) scale is required for the drill pipe.**
- **Rockwell "C", Brinell, or velocity rebound devices are satisfactory for the tool joints.**
- **A total of 9 impressions per joint required - 3 each at the box, pin and mid-tube. Hardbanding, heat-affected zones and areas of cold working such as slip tong marks should be avoided.**
- **Abnormally high or low readings should be confirmed with one re-test on the prepared surface.**

IRP

A drill string service history shall be initiated and maintained current by the SU-75, SU-80 and SU-95 pipe owner for the sour service life of the string. Total drilling days will be monitored along with date of each exposure to free H_2S. All washouts and drill string failures shall be recorded, including date, location, depth, and general operating conditions during the event. In addition, all drill string failures will require analyses as specified in section 6.3.11. Inspection results and string refurbishing shall be documented and included with the drill string service history.

6.3.3.1	Follow API RP 5A51, Sections 1 through 4. Drill pipe should meet or exceed specifications from API RP 7G2, Section 10 (Identification, Inspection and Classification of Drill Stem Components) for Premium Class Drill Pipe. Applicable sections are all subsections of 10.1 through 10.11. Refer to Appendix II for API inspection and hardness testing reporting requirements.
6.3.3.2	Timing of drill pipe inspection is to be at operator/contractor discretion. On deep wells or wells of extended duration, the drill pipe used to drill the critical zone need only be inspected once, ideally less than 30 days prior to completion of underbalanced operations. Drill pipe used in critical wells of less than 30 sour-exposure operating days duration need be inspected only every 30 days (eg: once every third well for wells of 10 day duration).
6.3.3.3	Drill string service history information such as cumulative rotating hours, H_2S concentration, duration of exposure, jarring, fishing, directional drilling, etc may or may not be monitored according to the discretion of the contractor.

6.3.4 Su-75 Drill Pipe Specifications

6.3.4.1 General Requirements

IRP

Mill certifications are required for all grade SU-75 material criteria stipulated herein. Mill certification shall be retained for the premium class life of the drill string.

IRP

Documentation necessary to demonstrate that an SU-75 drill string meets all the applicable requirements specified in IRP 6.3 shall be provided to the operator by the drill string owner prior to beginning critical sour UBD operations.

IRP

No more than one re-test per set of tests may be conducted for any sample to confirm grade SU-75 material and performance requirements as stipulated herein.

6.3.4.2 Tube Specifications

6.3.4.2.1 Tensile Properties

IRP

Tensile properties for SU-75 drill pipe tubes shall meet the following limits:

Minimum yield strength: 517 MPa (75 ksi)

Maximum yield strength: 621 MPa (90 ksi)

Minimum ultimate tensile strength: 621 MPa (90 ksi)

Maximum ultimate tensile strength: 758 MPa (110 ksi)

Specified reduction in area and elongation should be 55% minimum and 23% minimum, respectively.

IRP

Maximum operating stress for SU-75 drill pipe tubes is 85% of specified minimum yield strength.

6.3.4.2.2 Hardness

IRP

Hardness specifications for SU-75 drill pipe tubes shall be HRC 20 maximum average, with a maximum single point reading of HRC 22. Hardness level is to be verified on a ring sample with a set of 9 impressions in each of four quadrants. Testing frequency shall be one per heat treat lot or every 100 tubes, whichever is the more frequent.

In addition, a minimum of one set of 3 impressions on each tube (C-Clamp Rockwell) is required.

6.3.4.2.3 Toughness

IRP

Toughness specifications for SU-75 drill pipe tubes require a minimum longitudinal Charpy "V" notch impact value of 100 Joules (74 ft-lb) at room temperature for a 3/4 size sample per ASTM E23-823. Testing frequency should be one set per heat treat lot or every 100 tubes, whichever is the more frequent. One set is comprised of 3 samples.

6.3.4.2.4 H_2S Resistance

IRP

H_2S resistance specification for grade SU-75 drill pipe tubes shall include a demonstrated minimum threshold of 95% of specified minimum yield strength for 720 hours per NACE TM-01-77, Method A, latest revision.

Testing frequency should be one set per heat treat lot or every 100 tubes, whichever is the more frequent. One set is comprised of 3 samples. One re-test allowed per set of samples.

For the same frequency of tests, the minimum single-point DCB toughness shall be 32.0 MPa m0.5 and the average DCB toughness shall be 35.0 MPa m0.5 based on a full size sample equivalent for 14 days as per NACE TM-01-77, Method D, latest revision.

6.3.4.2.5 Heat Treatment

6.3.4.2.5.1 Transformation

IRP

Minimum transformation to martensite after quenching must be an average 95% across the full wall of the SU-75 drill pipe tube. This microstructure must be examined from material directly adjacent to any of the material taken for mechanical testing.

6.3.4.2.5.2 Tempering Temperature

IRP **Minimum tempering temperature for SU-75 drill pipe tubes shall be 621°C. Actual tempering parameters shall be included on the mill certification.**

6.3.4.2.5.3 Grain Size

IRP **Grain size specification for SU-75 drill pipe tubes shall be 8 or finer per ASTM E112-845.**

6.3.4.2.6 Chemistry

Chemistry specifications for SU-75 drill pipe tubes are recommended to meet the following weight percent limits:

	Minimum	Maximum
Carbon	-	0.35
Manganese	-	1.20
Sulfur	-	0.007
Phosphorus	-	0.015

6.3.4.2.7 Tube / Tool Joint Transition

IRP

Toughness specifications for SU-75 tube upsets require a minimum longitudinal Charpy "V" notch impact value of 80 Joules (59 ft-lb) at room temperature for a full size sample per ASTM E23-823. Toughness specifications for SU-75 weld area tube / tool joint transitions require a minimum longitudinal Charpy "V" notch impact value of 60 Joules (44 ft-lb) at room temperature for a full size sample per ASTM E23-823. Testing frequency should be one set per heat treat lot or every 100 tubes, whichever is the more frequent. One set is comprised of 3 samples.

IRP

H_2S resistance specification for the full wall SU-75 tube upset shall include a demonstrated minimum threshold of 80% of specified minimum yield strength for 720 hours per NACE TM-01-77, Method A, latest revision.

H_2S resistance specification for the tube / tool joint weld line shall include a demonstrated minimum threshold of 80% of specified minimum yield strength for 720 hours per NACE TM-01-77, Method A, latest revision.

Testing frequency should be one set per heat treat lot or every 100 tubes, whichever is the more frequent. One set is comprised of 3 samples. One re-test allowed per set of samples.

IRP

The transition from the SU-75 drill pipe ID to the standard upset ID (Miu) shall occur over a sufficient length as to minimize drill pipe tube fatigue failures adjacent to the upset area. Transition tapers (Inside Diameter and Outside Diameter) are to be similar to specifications stated in the following two sections.

6.3.4.2.7.1 Inside Diameter Taper

This minimum transition should be approximately 101.6 mm (4") for standard wall thickness IEU drill pipe and commensurately longer for any pipe having large differences between the upset ID and the drill pipe ID such that the internal taper angle remains below 6.0 degrees. The length of the internal upset (Liu) should be in the range of 114.3 mm (4.5") to 127.0 mm (5") for IEU drill pipe.

6.3.4.2.7.2 Outside Diameter Taper

The transition from the drill pipe OD to the standard upset OD should similarly be gradual with a minimum taper length (Meu) of 88.9 mm (3.5") for EU drill pipe and a taper length of 50.8 mm (2") to 63.5 mm (2.5") for IEU drill pipe. The length of the external upset (Leu) should be in the range of 88.9 mm (3.5") to 114.3 mm (4.5") for EU drill pipe and in the range of 88.9 mm (3.5") to 101.2 mm (4") for IEU drill pipe.

6.3.5 Su-80 Tubing Specifications

6.3.5.1 General Requirements

IRP	**Mill certifications are required for all grade SU-80 material criteria stipulated herein. Mill certification shall be retained for the premium class life of the drill string.**
IRP	**Documentation necessary to demonstrate that an SU-80 drill string meets all the applicable requirements specified in IRP 6.3 shall be provided to the operator by the drill string owner prior to beginning critical sour UBD operations.**
IRP	**No more than one re-test per set of tests may be conducted for any sample to confirm grade SU-80 material and performance requirements as stipulated herein.**
IRP	**High torque connections, rated to 75% or greater of tube torsional rating must be used for SU-80 drill pipe.**

6.3.5.2 Tube Specifications

6.3.5.2.1 Tensile Properties

IRP

Tensile properties for SU-80 tubes shall meet the following limits:

Minimum yield strength: 551 MPa (80 ksi)

Maximum yield strength: 655 MPa (95 ksi)

Minimum ultimate tensile strength: 655 MPa (95 ksi)

Maximum ultimate tensile strength: 827 MPa (120 ksi)

Specified reduction in area and elongation should be 50% minimum and 22% minimum, respectively.

IRP

Maximum operating stress for SU-80 tubes is 85% of specified minimum yield strength.

6.3.5.2.2 Hardness

IRP	**Hardness specifications for SU-80 tubes shall be HRC 21 maximum average, with a maximum single point reading of HRC 22. Hardness level is to be verified on a ring sample with 9 impressions in each of four quadrants. Testing frequency shall be one per heat treat lot or every 100 tubes, whichever is the more frequent.** **In addition, a minimum of one set of 3 impressions on each tube (C-Clamp Rockwell) is required.**

6.3.5.2.3 Toughness

IRP	**Toughness specifications for SU-80 tubes require a minimum longitudinal Charpy "V" notch impact value of 100 Joules (74 ft-lb) at room temperature for a 3/4 size sample per ASTM E23-823. Testing frequency should be one set per heat treat lot or every 100 tubes, whichever is the more frequent. One set is comprised of 3 samples.**

IRP

H_2S resistance specification for SU-80 tubes shall include a demonstrated minimum threshold of 95% of specified minimum yield strength for 720 hours per NACE TM-01-77, Method A, latest revision.

Testing frequency should be one set per heat treat lot or every 100 tubes, whichever is the more frequent. One set is comprised of 3 samples.

For the same frequency of tests, the minimum single-point DCB toughness shall be 32.0 MPa m0.5 and the average DCB toughness shall be 35.0 MPa m0.5 based on a full size sample equivalent for 14 days as per NACE TM-01-77, Method D, latest revision.

6.3.5.2.5 Heat Treatment

6.3.5.2.5.1 Transformation

IRP

Minimum transformation to martensite after quenching must be 95% across the full wall of the SU-80 tube. This microstructure must be examined from material directly adjacent to any of the material taken for mechanical testing.

6.3.5.2.5.2 Tempering Temperature

IRP

Minimum tempering temperature for SU-80 tubes shall be 621oC. Actual tempering parameters shall be included on the mill certification.

6.3.5.2.5.3 Grain Size

IRP

Grain size specification for SU-80 tubes shall be 8 or finer per ASTM E112-845.

6.3.5.2.6 Chemistry

Chemistry specifications for SU-80 tubes are recommended to meet the following weight percent limits:

	Minimum	Maximum
Carbon	-	0.35
Manganese	-	1.20
Sulfur	-	0.007
Phosphorus	-	0.015

6.3.5.3 Integral Joint Upset Specifications

6.3.5.3.1 Heat Treatment

IRP

Full heat treatment processes must be conducted after upsetting of SU-80 tube ends.

6.3.5.3.2 Toughness

IRP

Toughness specifications for SU-80 tube upsets require a minimum longitudinal Charpy "V" notch impact value of 90 Joules (66 ft-lb) at room temperature for a 3/4 size sample per ASTM E23-823. Testing frequency should be one set per heat treat lot or every 100 tubes, whichever is the more frequent. One set for integral joint tubing is comprised of 6 samples, 3 from each the pin and box. One re-test allowed per set of samples.

6.3.5.3.3 H_2S Resistance

IRP

H_2S resistance specification for the full wall SU-80 tube upset shall include a demonstrated minimum threshold of 85% of specified minimum yield strength for 720 hours per NACE TM-01-77, Method A, latest revision.

Testing frequency should be one set per heat treat lot or every 100 tubes, whichever is the more frequent. One set for integral joint tubing is comprised of 6 samples, 3 from each the pin and box. One re-test allowed per set of samples.

6.3.5.3.4 Integral Joint Bending And Tensile Requirements	
IRP	**Tensile connection efficiency of at least 95% of SU-80 tube wall is required. Bending strength capacity of at least 80% of tube wall bending moment capacity required. Yield and toughness specifications are as per SU-80 tube.**
6.3.5.3.5 Upset Transition	
IRP	**The transition from the SU-80 tube ID to the standard upset ID shall occur over a sufficient length as to minimize tube fatigue failures adjacent to the upset area.**

6.3.5.4 Coupling Specifications

6.3.5.4.1 Tensile Properties

IRP

Tensile properties for SU-80 couplings shall meet the following limits:

Minimum yield strength:	**551 MPa (80 ksi)**
Minimum yield strength:	**655 MPa (95 ksi)**
Minimum ultimate tensile strength:	**655 MPa (95 ksi)**
Minimum ultimate tensile strength:	**827 MPa (120 ksi)**

Specified reduction in area and elongation should be 45% minimum and 20% minimum, respectively.

IRP

Maximum operating stress for SU-80 couplings is 75% of specified minimum yield strength.

6.3.5.4.2 Hardness

IRP

Hardness specifications for SU-80 couplings shall be HRC 21 maximum average, with a maximum single point reading of HRC 22. Hardness level is to be verified on a ring sample with 9 impressions in each of four quadrants. Testing frequency shall be one per heat treat lot or every 100 connections, whichever is the more frequent.

In addition, a minimum of one set of 3 impressions on each coupling (C-Clamp Rockwell) is required.

6.3.5.4.3 Toughness

IRP

Toughness specifications for SU-80 couplings require a minimum longitudinal Charpy "V" notch impact value of 90 Joules (66 ft-lb) at room temperature for a 3/4 size sample per ASTM E23-823. Testing frequency shall be one set per heat treat lot or every 100 connections, whichever is the more frequent. One set is comprised of 3 samples.

6.3.5.4.4 H_2S Resistance

IRP

H_2S resistance specification for SU-80 couplings shall include a demonstrated minimum threshold of 95% of specified minimum yield strength for 720 hours per NACE TM-01-77, Method A, latest revision.

Testing frequency should be one set per heat treat lot and must include every heat. One set for coupled connections consists of 3 coupling samples. One re-test allowed per set of samples.

For the same frequency of tests, the minimum single-point DCB toughness shall be 32.0 MPa m0.5 and the average DCB toughness shall be 35.0 MPa m0.5 based on a full size sample equivalent for 14 days as per NACE TM-01-77, Method D, latest revision.

6.3.5.4.5 Heat Treatment

6.3.5.4.5.1 Transformation

IRP

Minimum transformation to martensite after quenching must be 95% across the full wall of the SU-80 coupling. This microstructure must be examined from material directly adjacent to any of the material taken for mechanical testing.

6.3.5.4.5.2 Transformation	
IRP	**Minimum tempering temperature for SU-80 coupling shall be 621 °C. Actual tempering parameters shall be included on the mill certification.**
6.3.5.4.5.3 Grain Size	
IRP	**Grain size specification for SU-80 couplings shall be 8 or finer per ASTM E112-845.**
6.3.5.4.6 Chemistry	Chemistry specifications for SU-80 couplings are recommended to meet the following weight percent limits:

	Minimum	Maximum
Carbon	-	0.35
Manganese	-	1.20
Sulfur	-	0.007
Phosphorus	-	0.015

6.3.5.4.7 Coupled Connection Bending And Tensile Requirements

IRP

Tensile efficiency of at least 85% of tube wall is required for SU-80 couplings. Bending strength capacity of at least 70% of tube wall bending moment capacity required.

6.3.5.5 Connection Performance Specifications

6.3.5.5.1 Make, Break and Torque Capacity

IRP

Thread design for SU-80 connections must be such that a minimum of 20 make/break cycles can be demonstrated without leakage. At least one torque shoulder or alternative high torque capacity feature (such as wedge threads) is required to minimize wear, fatigue and over-torque failure.

6.3.5.5.2 Sealing Integrity

IRP

At least one tapered metal to metal seal is required in the SU-80 connection.

A metal to metal flank seal is desirable to prevent annular H_2S access to thread root areas.

6.3.5.5.3 Compression Capacity

IRP

SU-80 connections must be capable of a minimum of 80% of the rated tensile yield strength of the tube without permanent deformation.

6.3.5.5.4 Maximum Stress Concentrations

Maximum stress concentrations should be determined on a connection basis to reflect the reduced sour service performance resulting from stress risers caused by sharpness and depth of thread profile. Finite element analysis should be performed to calculate coupling stress concentrations.

6.3.5.6 Identification

IRP

All coupled and integral joint tubing conforming to SU-80 specifications shall be marked with a unique identifier. Two milled flats shall be applied on the outside of each coupling for coupled tubing and within 25 mm of the threads on each pinned connection for integral joint tubing. These flats shall be die stamped with the pipe owner's unique joint number and the letters "SU-80".

6.3.6 Su-95 Drill Pipe Specifications

6.3.6.1 General Requirements

IRP	**Mill certifications are required for all grade SU-95 material criteria stipulated herein. Mill certification shall be retained for the premium class life of the drill string.**
IRP	**Documentation necessary to demonstrate that an SU-95 drill string meets all the applicable requirements specified in IRP 6.3 shall be provided to the operator by the drill string owner prior to beginning critical sour UBD operations.**
IRP	**No more than one re-test per set of tests may be conducted for any sample to confirm grade SU-95 material and performance requirements as stipulated herein.**

6.3.6.2 Tube Specifications

6.3.6.2.1 Tensile Properties

IRP

Tensile properties for SU-95 drill pipe tubes shall meet the

Minimum yield strength:	**655 MPa (95 ksi)**
Minimum yield strength:	**758 MPa (110 ksi)**
Minimum ultimate tensile strength:	**724 MPa (105 ksi)**
Minimum ultimate tensile strength:	**896 MPa (130 ksi)**

following limits:

Specified reduction in area and elongation should be 45% minimum and 20% minimum, respectively.

IRP

Maximum operating stress for SU-95 drill pipe tubes is 85% of specified minimum yield strength.

6.3.6.2.2 Hardness

IRP

Hardness specifications for SU-95 drill pipe tubes shall be HRC 24.0 maximum average, with a maximum single point reading of HRC 25.0. Hardness level is to be verified on a ring sample with 9 impressions in each of four quadrants. Testing frequency shall be one per heat treat lot or every 100 tubes, whichever is the more frequent.

In addition, a minimum of one reading (3 impressions) on each tube (C-Clamp Rockwell) is required.

6.3.6.2.3 Toughness

IRP

Toughness specifications for SU-95 drill pipe tubes require a minimum longitudinal Charpy "V" notch impact value of 110 Joules (81 ft-lb) at room temperature for a 3/4 size sample per ASTM E23-823. Testing frequency should be one set per heat treat lot or every 100 tubes, whichever is the more frequent. One set is comprised of 3 samples.

6.3.6.2.4 H_2S Resistance

IRP

H_2S resistance specification for SU-95 tubes shall include a demonstrated minimum threshold of 95% of specified minimum yield strength for 720 hours per NACE TM-01-77, Method A.

Testing frequency should be one set per heat treat lot or every 100 tubes, whichever is the more frequent. One set is comprised of 3 samples. One re-test is allowed per set of samples.

For the same frequency of tests, the minimum single-point DCB toughness shall be 32.0 MPa m0.5 and the average DCB toughness shall be 34.0 MPa m0.5 based on a full size sample equivalent for 14 days as per NACE TM-01-77, Method D, latest revision.

6.3.6.2.5 Heat Treatment

6.3.6.2.5.1 Transformation

IRP

Minimum transformation to martensite after quenching must be 95% across the full wall of the SU-95 drill pipe tube. This microstructure must be examined from material directly adjacent to any of the material taken for mechanical testing.

6.3.6.2.5.2 Tempering Temperature	
IRP	**Minimum tempering temperature for SU-95 drill pipe tubes shall be 680°C. Actual tempering parameters shall be included on the mill certification.**
6.3.6.2.5.3 Grain Size	
IRP	**Grain size specification for SU-95 drill pipe tubes shall be 8 or finer per ASTM E112-845.**

6.3.6.2.6 Chemistry

Chemistry specifications for SU-95 drill pipe tubes are recommended to meet the following weight percent limits:

	Minimum	Maximum
Carbon	-	0.35
Manganese	-	1.10
Sulfur	-	0.008
Phosphorus	-	0.015
Chromium	0.90	-
Molybdenum	0.40	-

6.3.6.2.7 Tube / Tool Joint Transition

IRP

Toughness specifications for SU-95 drill pipe tube upsets require a minimum longitudinal Charpy "V" notch impact value of 90 Joules (66 ft-lb) at room temperature for a full size sample per ASTM E23-823. Toughness specifications for Grade SU-95 weld area tube / tool joint transition require a minimum longitudinal Charpy "V" notch impact value of 60 Joules (44 ft-lb) at room temperature for a full size sample per ASTM E23-823. Testing frequency should be one set per heat treat lot or every 100 tubes, whichever is the more frequent. One set is comprised of 3 samples.

IRP

H_2S resistance specification for the full wall SU-95 tube upset shall include a demonstrated minimum threshold of 80% of specified minimum yield strength for 720 hours per NACE TM-01-77, Method A, latest revision.

H_2S resistance specification for the tube / tool joint weld line shall include a demonstrated minimum threshold of 80% of specified minimum yield strength for 720 hours per NACE TM-01-77, Method A, latest revision.

Testing frequency should be one set per heat treat lot or every 100 tubes, whichever is the more frequent. One set is comprised of 3 samples. One re-test allowed per set of samples.

IRP	**The transition from the SU-95 drill pipe ID to the standard upset ID (Miu) shall occur over a sufficient length as to minimize drill pipe tube fatigue failures adjacent to the upset area. Transition tapers (Inside Diameter and Outside Diameter) are to be similar to specifications stated in the following two sections.**
6.3.6.2.7.1 Inside Diameter Taper	This minimum transition should be approximately 101.6 mm (4") for standard wall thickness IEU drill pipe and commensurately longer for any pipe having large differences between the upset ID and the drill pipe ID such that the internal taper angle remains below 6.0 degrees. The length of the internal upset (Liu) should be in the range of 114.3 mm (4.5") to 127.0 mm (5") for IEU drill pipe.
6.3.6.2.7.2 Outside Diameter Taper	The transition from the drill pipe OD to the standard upset OD should similarly be gradual with a minimum taper length (Meu) of 88.9 mm (3.5") for EU drill pipe and a taper length of 50.8 mm (2") to 63.5 mm (2.5") for IEU drill pipe. The length of the external upset (Leu) should be in the range of 88.9 mm (3.5") to 114.3 mm (4.5") for EU drill pipe and in the range of 88.9 mm (3.5") to 101.2 mm (4") for IEU drill pipe.

6.3.7 Tool Joint Specifications

6.3.7.1 General Requirements

IRP	**Drill pipe tool joints SU-105TJ or SU-110TJ, with material and performance requirements specified herein are to be used for grades SU-75 and SU-95 tool joints.**
IRP	**To compensate for reduced strength materials being used for SU-75 and SU-95 drill pipe tool joints, pin ID's and/or box OD's shall be modified to maintain tensile and torsional strengths typically associated with each specific drill pipe size. Tool joint geometry shall be adjusted according to Appendix III, Tables 1 and 2.** **Refer to Appendix IV for a comparison of tool joint dimensions, tensile ratings and torsional ratings for the reduced strength materials used for SU-105TJ and SU-110TJ tool joints and those recommended by API for various drill pipe sizes.**
IRP	**Mill certifications are required for Grade SU-75 and SU-95 drill pipe tool joint material criteria stipulated herein. Mill certification shall be retained for the premium class life of the drill string.**
IRP	**Documentation necessary to demonstrate that SU-75 and SU-95 drill pipe tool joints meet all the applicable requirements specified in IRP 6.3 shall be provided to the operator by the drill string owner prior to beginning critical sour UBD operations.**

IRP **No more than one re-test per set of tests may be conducted for any grade SU-75 or SU-95 drill pipe tool joint sample to confirm material and performance requirements as stipulated herein.**

6.3.7.2 Tensile Properties

IRP **Tensile properties for SU-75 and SU-95 drill pipe tool joints used for critical sour UBD operations shall conform to either of the SU-105TJ or SU-110TJ specifications as follows:**

	SU-105TJ	SU-110TJ
Minimum yield strength:	724 MPa (105 ksi)	758 MPa (110 ksi)
Maximum yield strength:	827 MPa (120 ksi)	862 MPa (125 ksi)
Minimum ultimate tensile strength:	793 MPa (115 ksi)	827 MPa (120 ksi)
Maximum ultimate tensile strength:	965 MPa (140 ksi)	1000 MPa (145 ksi)

Specified reduction in area and elongation shall be 40% minimum and 18% minimum, respectively.

6.3.7.3 Hardness

IRP

Hardness specifications for grades SU-75 and SU-95 drill pipe tool joints shall be HRC 28.0 maximum average, with a maximum single point reading of HRC 30.0. Hardness level is to be verified by two types of samples:

i) on a ring sample with 9 impressions in each of four quadrants, and

ii) on longitudinal strip type cross-section samples with full-length hardness traverses conducted near mid-wall and near inner and outer surface.

Testing frequency shall be one sample of each type per heat treat lot or every 100 tool joints, whichever is the more frequent. Both pin and box ends shall be tested. In addition, C-clamp Rockwell impressions are to be taken on every tool joint element tested (pin and box) prior to threading.

6.3.7.4 Toughness

IRP

Toughness specifications for grades SU-75 and SU-95 drill pipe tool joints require a minimum longitudinal Charpy "V" notch impact value of 120 Joules (88 ft-lb) at room temperature for a full size sample per ASTM E23-823. Testing frequency should be one set per heat treat lot or every 100 tool joints, whichever is the more frequent. One set is comprised of 3 samples.

Toughness specification for grades SU-75 and SU-95 drill pipe weldments between tube and tool joint shall require a minimum longitudinal Charpy "V" notch impact value of 60 joules (44 ft.-lb.) at room temperature for a full size sample as per ASTM E23-823.

6.3.7.5 Tool Joint Connection

IRP

Tool joint connections for grades SU-75 and SU-95 drill pipe will utilize friction weld or inertia weld techniques. Alternative superior methods, if developed and proven, will also be acceptable.

6.3.7.6 H_2S Resistance

IRP

H_2S resistance specification for grades SU-75 and SU-95 drill pipe tool joints shall include a demonstrated minimum threshold of 80% of specified minimum yield strength for 720 hours per NACE TM-01-77, Method A, latest revision. One retest per heat-treat lot allowed.

Testing frequency should be one set per heat treat lot and must include every heat. One set is comprised of a minimum of 4 samples, with a minimum of 2 samples each from the pin and box.

For the same frequency of tests, the minimum single-point DCB toughness shall be 26.0 MPa m0.5 and the average DCB toughness shall be 28.0 MPa m0.5 based on a full size sample equivalent for 14 days as per NACE TM-01-77, Method D, latest revision.

6.3.7.7 Heat Treatment

6.3.7.7.1 Transformation

IRP

Minimum transformation to martensite after quenching must be 95% across the full wall of SU-75 and SU-95 drill pipe tool joints. This microstructure must be examined from material directly adjacent to any of the material taken for mechanical testing.

6.3.7.7.2 Tempering Temperature	
IRP	**Minimum tempering temperature for SU-75 and SU-95 drill pipe tool joints shall be 649 ˚C. Actual tempering parameters shall be included on the mill certification.**
6.3.7.7.3 Grain Size	
IRP	**Grain size specification for SU-75 and SU-95 drill pipe tool joints shall be 8 or finer per ASTM E112-845.**

6.3.7.8 Chemistry

Chemistry specifications for SU-75 and SU-95 drill pipe tool joints are recommended to meet the following weight percent limits:

	Minimum	Maximum
Carbon	-	0.40
Manganese	-	1.20
Sulfur	-	0.007
Phosphorus	-	0.015
Chromium	0.90	-
Molybdenum	0.45	-

6.3.7.9 Hardbanding

IRP

Grade SU-75 and SU-95 drill pipe tool joint hardbanding materials, if required, must either be applied prior to quenching and tempering or must incorporate a low-temperature application method after tempering. Thin-walled heat shrink wear bands or pressed in tungsten carbide wear buttons (away from the threaded area) are examples of low-temperature application methods.

6.3.7.10 Identification

IRP

All SU-75 and SU-95 drill pipe conforming to the above tool joint specifications must be marked with a unique identifier. Two milled flats shall be applied immediately adjacent to the chamfer on the outside of each pin end tool joint. These flats shall be die stamped to identify the pipe body material with the pipe owner's unique joint number and the letters "SU-75" or "SU-95". They shall similarly be die stamped to identify the tool joint material with the letters "SU-105TJ" or "SU-110TJ".

6.3.8 General Requirements For Coiled Tubing

IRP

Coiled tubing manufactured to meet requirements as specified in section 6.3.9 is to be used for coiled tubing critical sour UBD.

IRP

A coiled tubing drill string service history shall be initiated and maintained current for the entire service life of the drill string for critical sour UBD. Total exposure time to free H_2S, cyclic fatigue data and ongoing operations are to be monitored. Results of pipe inspections shall be documented and included in the coiled tubing drill string history.

IRP

Drill string floats are to be placed in coiled tubing drill strings to allow for the tubing to be bled off during critical sour UBD operations. A minimum of two drill string floats, placed in tandem, are to be inserted as close to the downhole motor as possible.

IRP	**All drill string equipment not covered in this IRP and introduced to the critical sour UBD environment must satisfy material and performance requirements for the anticipated sour conditions.**
IRP	**The well must be killed in the event of any coiled tubing separation within the wellbore while drilling a critical sour UBD well. String separation is defined as a separation above the highest disconnect in the coiled tubing string. This separation may be intentional or as a result of material failure.**
6.3.8.1	**Material and performance specifications for grade coiled tubing are contained in section 6.3.9.**

6.3.8.2

Coiled tubing is used on a daily basis in sour wells for well servicing operations and a long history of safe operations exists under these conditions. However, drilling with coiled tubing is not directly comparable to well servicing operations. Issues that differentiate coiled tubing drilling and well servicing operations include the following:

- Well servicing operations have historically used smaller diameter coiled tubing than that typically required for drilling operations.
- Stresses on coiled tubing are likely to be more severe under drilling conditions than those typically experienced in well servicing operations.
- Drilling conditions may result in fluids containing H_2S being re-circulated down the drill string. Limited well servicing data exists regarding prolonged coiled tubing internal exposure to H_2S.
- The adsorption of H_2S inhibitors circulated to protect the external wall of coiled tubing may be less effective under drilling conditions than under well servicing conditions due to the effect of scouring by drilled solids.
- Exposure times to sour conditions are likely to be greater for drilling operations.

6.3.8.3 Many of the coiled tubing guidelines included in this IRP are based upon a combination of sweet service performance, a long history of well servicing in sour environments, and an application of increased safety margins and increased redundancy in well control equipment.

Unfortunately, no comprehensive testing program of coiled tubing fatigue life under exposure to H_2S has been completed. Although some testing has been performed and is ongoing to establish coiled tubing sour service fatigue performance, the level of materials testing required, due to the statistical nature of coiled tubing fatigue, makes this objective a multi-year project. Industry work on coiled tubing fatigue under sour conditions is proceeding and will likely result in modifications to these guidelines.

CAUTION:

The operator must undertake due diligence reflecting the current lack of definitive data regarding coiled tubing sour service fatigue performance. A lower coiled tubing fatigue life limit has been recommended in this IRP because of this lack of information.

6.3.8.4 Monitoring of the coiled tubing, levels of redundancy in pressure control equipment and operating safety margins should all be increased above standard levels to reflect the need to ensure that stringent standards of public and worker safety are met.

6.3.8.5

Coiled tubing exposure control, although limited during critical sour UBD, may be enhanced through several means such as batch or continuous injection of H_2S inhibitors and/or increased pH of water phase in water based systems. Under severe operating conditions (deep, increased probability of failure, increased consequence of failure) oil based fluids are preferred over water based fluids for exposure control. Additional safety measures such as regularly purging the coiled tubing and casing annulus with inert gas, and minimizing coiled tubing exposure time to H_2S should also be considered.

6.3.8.6 Coiled Tubing Drilling Database

It is recommended that a database be set up by each coiled tubing operator to track work done on critical sour UBD wells. Information on each well drilled should be archived for future reference, and should include the following:

- circulated and produced fluid properties
- tube diameter, wall thickness, and grade
- hours drilling and hours exposure to free H_2S
- comments section, such as problems and key learnings

Fluid properties are to include gas type, source (liquid N2, membrane, etc), oxygen content, salinity, additives, H_2S concentration, and CO_2 concentration and flow rates.

6.3.9 Coiled Tubing Material Specifications

As of January, 2004, there are currently no agreed coiled tubing material specifications for critical sour underbalanced drilling.

A Joint Industry Project group is reviewing the specifications. For further information contact DACC (through Enform).

6.3.10 Coiled Tubing Design And Operating Guidelines

6.3.10.1 Fatigue Life

IRP

It is recommended that coiled tubing be retired from use in critical sour UBD when 15% of the mean fatigue life has been reached. Coiled tubing shall be retired from use in critical sour UBD when 25% of the mean fatigue life has been reached.

Mean fatigue life is to be specified as per Appendix V, "Maximum Trips & Related Dilation versus Operating Pressure for Common Sizes of Grade SU-65 Coiled Tubing."

Mean fatigue life is defined as the statistical average number of trips (including short trips such as wiper trips, reaming tight hole, etc.) to be expected under non-sour conditions and actual circulating pressures.

6.3.10.2 Torsional Yield

IRP	**The torsional rating of the coiled tubing must be greater than 2.0 times the downhole motor stall torque.**
IRP	**The torsional rating of the coiled tubing bottom-hole assembly, including any connectors, shall be their original specification less 20% for all critical sour UBD. This rating must be greater than 1.5 times the downhole motor stall torque.**
IRP	**The coiled tubing owner shall carry out such tests as are deemed appropriate by the coiled tubing owner to prove the fitness for purpose for sour service of the coiled tubing connector system. The connector system comprises all of the items carrying loads from the BHA to the coiled tubing and the condition of the coiled tubing at the interface with the connector.** **These precautions are required to ensure that neither the pipe nor the BHA/connector twists off under stall conditions. Unless information exists to the contrary it should be assumed that the motor stall torque is twice the maximum operating torque.**

6.3.10.3 Maximum Applied Loading

IRP

For critical sour UBD operations the downhole combined applied stresses in the coiled tubing shall be planned to be less than 65% of the pipe minimum yield.

Combined applied stresses consider triaxial stresses caused by internal and external pressure, torque, and axial loads. They do not include residual stresses.

6.3.10.4 Injector Head Tensile Rating

IRP

The injector head shall be capable of pulling 80% of calculated tube minimum yield load during critical sour UBD, as per normal coiled tubing operating standards.

6.3.10.5 Stress Analysis

IRP **Coiled tubing stress analysis (including drag predictions) must be completed prior to beginning critical sour UBD operations. Drill string design must take into account appropriate factors such as desired overpull, drag and wellbore profile.**

IRP **Operating limits are to be established for maximum coiled tubing pull weights, set down loads and circulating pressures for critical sour UBD operations. These limits are to be clearly posted in the coiled tubing operating unit.**

IRP **Technical personnel competent in tubing force and circulation analysis shall be on location during all coiled tubing critical sour UBD operations.**

6.3.10.6 Pressure Limits

IRP **Coiled tubing differential pressure limits must be established for each critical sour UBD operation. These limits are to take into account tube diameter, ovality, wall thickness, applied loads and the anticipated operating conditions.**

6.3.10.7 Pipe Inspection	
IRP	**Pipe inspection of the coiled tubing drill string is to be carried out prior to use in critical sour UBD. Inspection results are to be utilized in conducting tubing force analysis and in calculating circulation limits. As a minimum, coiled tubing OD, minimum wall thickness and ovality are to be measured.**
IRP	**During drilling operations a device will be used to measure continuously the dilation and ovality of the coiled tubing. The coiled tubing will be retired from critical sour UBD operations if the dilation exceeds 2% of original tube circumference.**
6.3.10.8 Fatigue Cycles	
IRP	**Fatigue cycles remaining in the coiled tubing drill string at the anticipated circulating pressures, and at 25% above the anticipated circulating pressures or the maximum operating pressure (whichever is less) are to be posted in the coiled tubing operating unit during critical sour UBD.** **Specifying fatigue cycles remaining at 25% above the anticipated circulating pressure accounts for situations where the circulating pressure is higher than predicted (due to higher than anticipated reservoir pressures or flow rates).**

6.3.10.9 Plastic Strain Limit

IRP

Refer to Appendix V, "Maximum Trips & Related Dilation versus Operating Pressure for Common Sizes of Grade SU-65 Coiled Tubing" to estimate the appropriate combination of tubing size, wall thickness and operating pressure to remain below recommended maximum strain levels.

Coiled tubing selections are listed in Appendix V for cases that do not significantly exceed 3% dilation. However, particular care should be taken when the estimated tubing dilation exceeds approximately 2% to ensure that actual circumferential strain does not exceed 2% during operations.

6.3.10.10 Inhibitors

IRP

Inhibitors must be present in sufficient quantities to protect the exposed materials (coiled tubing, downhole equipment, etc) during critical sour UBD. Consideration is to be given to the total circulation system (eg: the presence of water, salinity, oxygen content, H_2S, CO_2, temperature).

6.3.10.11 On-Site Documentation

IRP

Records must be kept by the coiled tubing operator with regard to coiled tubing cycle life, pipe management and well conditions during critical sour UBD operations.

6.3.11 Post Failure Reporting And Testing Requirements

IRP

The Operator is responsible to investigate the physical causes of any drill string failure during critical sour UBD operations and to report the findings of the investigation to the appropriate regulatory officials. This failure analysis shall address material, metallurgical and performance requirements as specified within IRP 6.3. These analyses shall include strength, ductility, impact toughness, hardness, chemistry, sulfide stress cracking resistance, dimensional control and metallographic analysis.

Failed components shall be archived by the Operator for two years after the failure and available for possible further testing, as determined necessary by regulatory officials.

IRP

The operator is responsible to report any loss of drill string pressure integrity, such as a washout, to the appropriate regulatory agency.

6.3.11.1

Failure is defined as any separation of the drill string during operation or any situation causing a sour gas release from the drill string into the atmosphere.

Appendix 1

Drill Pipe Tensile Ratings

Table 1A - Class 1 Drill Pipe (Maximum 10% Wear)

Pipe Size (mm)	Nominal Weight (daN/m)	Min. OD (mm)	Min. Wall (mm)	Min. Area (cm^2)	Tensile SU-75 (daN)	Rating SU-95 (daN)
88.9	19.4	87.03	8.41	20.78	107,400	136,100
88.9	22.6	86.62	10.26	24.62	127,300	161,300
114.3	24.2	112.59	7.70	25.38	131,300	166,300
114.3	29.2	112.12	9.83	31.59	163,300	206,900
127.0	28.5	125.16	8.28	30.39	157,100	199,000
127.0	37.4	124.46	11.43	40.59	209,900	265,800

Table 1B - Class 1 Drill Pipe (Maximum 10% Wear)

Pipe Size (in)	**Nominal Weight (lb/ft)**	**Min. OD (in)**	**Min. Wall (in)**	**Min. Area (in^2)**	**Tensile SU-75 (lb)**	**Ratings SU-95 (lb)**
3 ½	13.3	3.4264	0.3312	3.2205	241,500	306,000
3 ½	15.5	3.4102	0.4041	3.8163	286,200	362,500
4 ½	16.6	4.4326	0.3033	3.9346	295,100	373,800
4 ½	20.0	4.4140	0.3870	4.8960	367,200	465,100
5	19.5	4.9276	0.3258	4.7101	353,300	447,500
5	25.6	4.9000	0.4500	6.2911	471,800	597,700

Ratings are based on 10% uniform wear on outside diameter:

Tensile Rating = 0.7854[OD - 2 x (wall thickness x % wear)^2 - ID^2]x Minimum Yield Strength

Appendix II

API Inspection And Hardness Testing

Inspection and hardness testing should conform to API Recommended Practice 5A5. The Inspection Report shall include:

i) Inspection Report

- location, rig, and pipe owner
- inspection company, date(s), and inspector
- diameter, weight, grade, and connection type
- total number of joints inspected
- rejection rate
- classification

ii) Hardness Testing Report

- location, rig and pipe owner
- inspection company, date(s), and inspector
- diameter, weight, grade, connection type, and pipe classification
- test equipment - make and model
- calibration details - each occurrence
- surface preparation technique (light filing or sanding)
- individual and average readings for pin, tube and box for each joint
- summary indicating total number of joints inspected, total rejected, and rejection criteria

Appendix III

Recommended Tool Joint Dimensions And Resulting Strengths For Typical Connections

Table 1A - Grade SU-75 Drill Pipe

Material: 758 MPa minimum yield; 896 MPa maximum yield
896 MPa minimum UTS; 1034 MPa maximum UTS

Pipe Size (mm)	Recommended Connection	Nominal Weight			Tensile Rating		Torsional Rating	
		(daN/m)	OD (mm)	ID (mm)	Pipe (daN)	TJ (daN)	Pipe (N·m)	TJ (N·m)
88.9	NC38IF Modified	19.4	127	65.1	120,700	264,700	25,140	25,230
88.9	NC38IF Modified	22.6	127	61.9	143,500	288,710	28,580	27,590
114.3	NC 46XH Modified	24.2	158.8	76.2	146,900	427,500	41,750	49,220
114.3	NC 46XH Modified	29.2	158.8	69.9	183,300	482,750	50,000	55,800
127.0	NC 50XH Modified	28.5	165.1	88.9	175,800	452,700	55,790	55,550
127.0	NC 50XH Modified	37.4	168.3	82.6	235,700	517,540	70,810	63,880

Table 1B - Grade SU-75 Drill Pipe

Material: 110,000 PSI minimum yield; 130,000 PSI maximum yield

130,000 PSI minimum UTS; 150,000 PSI maximum UTS

Pipe Size (in)	Recommended Connection	Nominal Weight			Tensile Rating		Torsional Rating	
		(lb/ft)	OD (in)	ID (in)	Pipe (in)	TJ (lb)	Pipe (ft·lb)	TJ (ft·lb)
$3\frac{1}{2}$	NC38IF Modified	13.3	**5**	$2\frac{9}{16}$	271,570	595,060	18,550	18,610
$3\frac{1}{2}$	NC38IF Modified	15.5	5	$2\frac{7}{16}$	322,780	649,060	21,090	20,350
$4\frac{1}{2}$	NC 46XH Modified	16.6	$6\frac{1}{4}$	3	330,560	961,060	30,810	36,300
$4\frac{1}{2}$	NC 46XH Modified	20.0	$6\frac{1}{4}$	$2\frac{3}{4}$	412,360	1,085,260	36,900	41,160
5	NC 50XH Modified	19.5	$6\frac{3}{8}$	$3\frac{1}{2}$	395,600	1,017,720	41,170	40,970
5	NC 50XH Modified	25.6	$6\frac{1}{2}$	$3\frac{1}{4}$	530,150	1,163,470	52,260	47,120

Table 2A - Grade SU-95 Drill Pipe

Material: 758 MPa minimum yield; 862 MPa maximum yield

862 MPa minimum UTS; 1000 MPa maximum UTS

Pipe Size (mm)	Recommended Connection	Nominal Weight			Tensile Rating		Torsional Rating	
		(daN/m)	OD (mm)	ID (mm)	Pipe (daN)	TJ (daN)	Pipe (N·m)	TJ (N·m)
88.9	NC38IF Modified	19.4	127	61.9	152,900	288,710	31,840	27,590
88.9	NC38IF Modified	22.6	127	54.0	181,700	341,050	36,190	32,810
114.3	NC 46XH Modified	24.2	158.8	69.9	186,100	482,750	52,870	55,800
114.3	NC 46XH Modified	29.2	158.8	63.5	232,200	533,190	63,330	61,640
127.0	NC 50XH Modified	28.5	161.9	82.6	222,700	517,540	70,650	63,880
127.0	NC 50XH Modified	37.4	165.1	69.9	298,500	632,820	89,690	78,800

Table 2B - Grade SU-95 Drill Pipe

Material: 110,000 PSI minimum yield; 125,000 PSI maximum yield

125,000 PSI minimum UTS; 145,000 PSI maximum UTS

Pipe Size (in)	Recommended Connection	Nominal Weight			Tensile Rating		Torsional Rating	
		(lb/ft)	OD (in)	ID (in)	Pipe (in)	TJ (lb)	Pipe (ft·lb)	TJ (ft·lb)
$3\frac{1}{2}$	NC38IF Modified	13.3	5	$2\frac{7}{16}$	343,990	649,060	23,500	20,350
$3\frac{1}{2}$	NC38IF Modified	15.5	5	$2\frac{1}{8}$	408,850	766,700	26,710	24,200
$4\frac{1}{2}$	NC 46XH Modified	16.6	$6\frac{1}{4}$	$2\frac{3}{4}$	418,700	1,085,260	39,020	41,160
$4\frac{1}{2}$	NC 46XH Modified	20.0	$6\frac{1}{4}$	$2\frac{1}{2}$	522,320	1,198,670	46,740	45,470
5	NC 50XH Modified	19.5	$6\frac{1}{2}$	$3\frac{1}{4}$	501,090	1,163,470	52,140	47,120
5	NC 50XH Modified	25.6	$6\frac{5}{8}$	$2\frac{3}{4}$	671,520	1,422,630	66,190	58,120

Appendix IV

Comparison Of 110 Ksi Restricted Yield Oversized Connections To Standard API Connections

Pipe Size (in.)	Nominal Weight		Recommended (& Standard)	Recommended	Recommended vs. Standard TJ Ratings	
	(lb./ft.)	Grade	TJ Size (in.)	TJ Equivalent to API	Tensile	Torsional
$3\,^{1}/_{2}$	13.3	SU-75	$5 \times 2\,^{9}/_{16}$ ($4\,^{3}/_{4} \times 2\,^{11}/_{16}$)	$3\,^{1}/_{2}$" x 13.3 lb./ft. Grade X	+ 1.3%	+ 2.8%
$3\,^{1}/_{2}$	15.5	SU-75	$5 \times 2\,^{7}/_{16}$ ($5 \times 2\,^{9}/_{16}$)	$3\,^{1}/_{2}$" x 15.5 lb./ft. Grade X	- 0.02%	+ 0.2%
$4\,^{1}/_{2}$	16.6	SU-75	$6\,^{1}/_{4} \times 3$ ($6\,^{1}/_{4} \times 3\,^{1}/_{4}$)	$4\,^{1}/_{2}$" x 16.6 lb./ft. Grade X	+ 6.6%	+ 7.1%
$4\,^{1}/_{2}$	20.0	SU-75	$6\,^{1}/_{4} \times 2\,^{3}/_{4}$ ($6\,^{1}/_{4} \times 3$)	$4\,^{1}/_{2}$" x 20.0 lb./ft. Grade X	+ 3.5%	+ 3.9%
5	19.5	SU-75	$6\,^{3}/_{8} \times 3\,^{1}/_{2}$ ($6\,^{3}/_{8} \times 3\,^{3}/_{4}$)	5" x 19.5 lb./ft. Grade X	+ 7.8%	+ 8.7%
5	25.6	($6\,^{3}/_{8} \times 3\,^{1}/_{2}$)	$6\,^{1}/_{2} \times 3\,^{1}/_{4}$ Grade G	5 " x 19.5 lb./ft.	+ 4.8%	+ 5.4%
$3\,^{1}/_{2}$	13.3	SU-95	$5 \times 2\,^{7}/_{16}$ ($5 \times 2\,^{9}/_{16}$)	$3\,^{1}/_{2}$" x 13.3 lb./ft. Grade G	- 0.02%	+ 0.2%
$3\,^{1}/_{2}$	15.5	SU-95 ($5 \times 2\,^{7}/_{16}$)	$5 \times 2\,^{1}/_{8}$ Grade G	$3\,^{1}/_{2}$" x 15.5 lb./ft.	+ 8.3%	+ 9.0%
$4\,^{1}/_{2}$	16.6	SU-95	$6\,^{1}/_{4} \times 2\,^{3}/_{4}$ ($6\,^{1}/_{4} \times 3$)	$4\,^{1}/_{2}$" x 20.0 lb./ft. Grade X	+ 3.5%	+ 3.9%
$4\,^{1}/_{2}$	20.0	SU-95	$6\,^{1}/_{4} \times 2\,^{1}/_{2}$ ($6\,^{1}/_{4} \times 2\,^{3}/_{4}$)	$4\,^{1}/_{2}$" x 20.0 lb./ft. Grade G	+ 1.2%	+ 1.3%
5	19.5	SU-95	$6\,^{1}/_{2} \times 3\,^{1}/_{4}$ ($6\,^{3}/_{8} \times 3\,^{1}/_{2}$)	5" x 19.5 lb./ft. Grade G	+ 4.8%	+ 5.4%
5	25.6	SU-95 ($6\,^{1}/_{2} \times 3$)	$6\,^{5}/_{8} \times 2\,^{3}/_{4}$ Grade G	5 " x 25.6 lb./ft.	+ 0.4%	+ 2.0%

Appendix V

Maximum Trips & Related Dilation Versus Operating Pressure For Common Sizes Of Grade SU-65 Coiled Tubing.

As of January, 2004, there are currently no agreed coiled tubing specifications for critical sour underbalanced drilling.

A Joint Industry Project group is reviewing the specifications. For further information contact DACC (through Enform).

Appendix VI – Results Of Materials Testing Program

Summary

Two drill pipe tube bodies, one tool joint blank and three coiled tubings were evaluated by mechanical and chemical testing to determine whether the proposed IRP 6.3 for these materials was technically feasible. The results of testing on the selected drill pipe tube body materials show that drill pipe tube body can be manufactured to meet the proposed IRP 6.3 using current state-of-the-art manufacturing processes. The results of testing on the one tool joint do not meet the proposed IRPs. Experience by several end users indicates that more sulfide stress cracking (SSC) resistant materials are available and have already been used as tool joints. However, more work has to be done by manufacturers to consistently provide such tool joint materials. The results of testing on coiled tubing materials are mixed. Some longitudinal cracking in the coiled tubing may have formed during the plastic fatigue deformation of the tubing. These imperfections skewed the SSC behavior of the tubing. For tensile samples, these imperfections initiated SSC failures while these same imperfections pinned crack propagation in the double cantilever beam samples, giving no results. Coiled tubing materials can be susceptible to SSC, especially after plastic deformation, under high loads and if prior fatigue damage exists as indicated in this report. These results give no indication of the fatigue behavior of the coiled tubing materials. More work needs to be done to define accurate fatigue limits in sour service.

Introduction

CAPP/DACC Taskforce on Drill Strings for Critical Sour Underbalanced Drilling conducted a series of mechanical, environmental and chemical tests on drill pipe tube body, tool joint and coiled tubing materials during the preparation of IRP 6.3. The objective of the tests performed was to verify the material specifications as set out in this IRP were achievable using current manufacturing best practices. It was not the intent to verify a particular material's suitability for sour underbalanced drilling. This brief report summarizes the materials examined, the tests performed indicates results achieved and gives comments with respect to IRP 6.3 requirements.

Materials Tested

The following materials were obtained and tested. These materials were from available commercial or prototype production and were requested as among the best materials available at the time of testing. Materials are designated by type and grade in ksi:

- Two drill pipe (DP) tube bodies, DP90 and DP95.
- One tool joint blank (TJ), TJ105.
- Three coiled tubing (CT) bodies, CT70, CT80A and CT80B.

Testing

Testing conducted was as per IRP 6.3 requirements. This included determination of chemistry and mechanical testing for strength, impact toughness, hardness and resistance to sulfide stress cracking (SSC). Not all tests were conducted on all materials. Because coiled tubing are generally manufactured with smaller outer diameters and thinner walls than drill pipe, some custom tests were conducted on coiled tubing materials. SSC tests on coiled tubing should be considered exploratory as little data is available in the literature [1]. All Tests are summarized in Table 1.

Table 1: Testing Overview

Material	Test Description	No. of Tests
DP90	ASTM A370 (E8) Round Tensile Test	6
	ASTM A370 (E23) Impact Test at Room Temperature	6
	NACE TM01-77(96)Method A (85% SMYS)	6
	NACE TM01-77(96)Method A (90 and 95 % SMYS)	6
	NACE TM01-77(96)Method D	3
	Chemical Analysis	2
DP95	NACE TM01-77(96)Method D	3
TJ105	ASTM A370 Round Tensile Test	3
	ASTM A370 (E23) Impact Test at Room Temperature	3
	NACE TM01-77(96) Method A (75,80,85% SMYS)	6
	Chemical Analysis	1
CT-80A	Custom Flat Tensile Test	6
	ASTM A370 (E23) Impact Test at Room Temperature	6
	ASTM A370 (E23) Impact Test at -40 C	6
	Chemical Analysis	1
	Custom Flat SSC Tensile Test in NACE Solution A	9
CT-70	Custom Full Body Tensile Test	1
	ASTM A370 (E23) Impact Test at Room Temperature	6
	ASTM A370 (E23) Impact Test at -40 C	6
	Chemical Analysis	1
	Custom Flat SSC Tensile Test in NACE Solution A	9
CT-80B	ASTM A370 (E23) Impact Test at Room Temperature	6
	Custom Full Body Tensile Test	1
	ASTM A370 (E23) Impact Test at -40 C	6
	Chemical Analysis	1
	Custom Flat SSC Tensile Test in NACE Solution A	9

TEST RESULTS FOR DP90

Strength

Table 2 gives the measured tensile properties for DP90. Although this material was manufactured as a lower grade material, it meets the tensile requirements for SU-95.

Table 2: Tensile Properties of DP90 Material

Sample I.D.	Yield Strength		Tensile Strength		Elongation %	Reduction of Area %
	MPa	psi	MPa	psi		
1	663	96156	783	113560	25	70
2	668	96881	790	114575	25	69
3	656	95141	784	113705	27	70
4	664	96301	782	113415	24	68
5	669	97026	787	114140	26	71
6	661	95866	783	113560	27	69
Average	***664***	***96229***	***785***	***113826***	***26***	***70***

Hardness

The Rockwell hardness of the DP90 was measured to be a Rockwell hardness of 18.0 +/- 0.5 HRC, which is equal to a Brinell hardness of 219 +/- 3 HB. This value conforms to the maximum allowed hardness of 22 HRC or 241 HB.

Impact Toughness

Table 3 gives the impact properties of DP90. DP90 exceeds the IRP impact requirements for SU-95.

Table 3: Impact (CVN) Properties of DP90

Heat No./ Material	Specimen I.D.	Dimensions mm	Test Temperature °C	°F	Absorbed Energy Joules	Ft-lbs.	Shear %
1 / DP90	1	55x10x10	22	72	168	124	100
	2	55x10x10	22	72	178	131	100
	3	55x10x10	22	72	175	129	100
			Average:		***174***	***128***	***100***
2 / DP90	4	55x10x10	22	72	176	130	100
	5	55x10x10	22	72	182	134	100
	6	55x10x10	22	72	172	127	100
			Average:		***177***	***131***	***100***

Chemistry

Table 4 gives the chemical analysis for DP90, which meets the suggested chemistry.

Table 4: Chemical Composition of DP90

Element	% Composition		
	Sample 1	**Sample 2**	**Suggested**
Carbon, C	0.18	0.17	0.35 max
Manganese, Mn	0.71	0.70	1.10 max
Phosphorous, P	<0.01	<0.01	0.015 max
Sulphur, P	0.007	0.006	0.008 max
Silicon, Si	0.25	0.24	Not Specified
Nickel, Ni	0.10	0.10	Not Specified
Chromium, Cr	1.5	1.4	0.9 min
Molybdenum, Mo	0.80	0.80	0.4 min

<u>SSC Resistance</u>

Sulfide Stress Cracking (SSC) susceptibility was evaluated by two types of NACE tests, tensile and DCB. The tensile tests were performed in two stages. First, all the samples were loaded to 85% of specified minimum yield stress (SMYS). Table 5 summarizes these results. After these tests were completed, any samples that had not failed were reloaded to 90% greater of SMYS. As per NACE TM0177, all samples were exposed for 720 hours in NACE test solution A. Table 6 shows the results of the second set of NACE tensile tests.

Table 5: NACE Tensile Test Results for DP90 at 85% of SMYS

Sample No.	Time, Hours	Result	Comments
1	720	Pass	No cracks
2	720	Pass	No cracks
3	720	Pass	No cracks
4	720	Pass	No cracks
5	720	Pass	No cracks
6	720	Pass	No cracks

Table 6: NACE Tensile Test Results for DP90 at 90% or greater of SMYS

Sample No.	Load, %SMYS	Time, Hours	Result
1	90	720	Pass
2	95	720	Pass
3	95	720	Pass
4	90	720	Pass
5	95	720	Pass
6	101	240	Failed due to overload

Sample No. 6 failed after 240 hours under a calculated load of 95% of SMYS. Closer scrutiny of the crack showed some plastic deformation at SSC. The effective applied load for sample 6 was at least 101% of SMYS, an overload of the sample. The other samples experienced numerous pits and one sample had some cracks. These observations are summarized in Table 7.

Table 7: Visual Examination of DP90 NACE Tensile Samples

Sample			Pitting			Corrosion Deposit	Cracks	
#	% SMYS	Results	Pits	Depth mm	Width mm	mm	Presence	Depth mm
1	90	Pass	Random	0.05	0.05	No	No	--
2	95	Pass	Numerous	0.2-0.3	0.2-0.3	No	Yes	<0.05 mm
3	95	Pass	Numerous	0.2	0.2	0.4	No	--
4	90	Pass	Couple	0.15	0.15	No	No	--
5	95	Pass	Numerous	0.2	0.2	0.4	No	--
6	101	Failed due to tensile overload					Numerous	0.8 mm

Table 8 gives the NACE double cantilever beam (DCB) results for DP90 and DP95. All results meet the proposed IRPs for SU-95.

Table 8: DCB Drill Pipe Body Results

SPECIMEN I.D.	CRITICAL STRESS INTENSITY FACTOR MPa $m^{0.5}$	ARM DISPLACEMENT mm	VALID TEST RESULT?
DP90-D	35.5	0.77	Yes
DP90-E	35.2	0.78	Yes
DP90-F	34.4	0.77	Yes
Average	35.0		
DP95-5	35.1	0.71	Yes
DP95-6	34.1	0.71	Yes
DP95-7	34.1	0.69	Yes
Average	34.4		

Test Results For Tj105

Strength

Table 9 gives the measured tensile properties for TJ105. These meet the proposed IRPs for SU-105TJ and are just below the strength requirements for SU-110TJ.

Table 9: Tensile Properties of TJ105

Sample I.D.	Yield Strength		Tensile Strength		Elongation %	Reduction of Area %
	MPa	psi	MPa	psi		
1	780	113125	867	125743	21	67
2	767	111240	862	125018	19	67
3	753	109209	851	123422	20	67
Average	***767***	***111,191***	***860***	***124,728***	***20***	***67***

<u>Impact Toughness</u>

Table 10 gives the measure impact properties for TJ105. These meet the proposed IRP for both grades of tool joints.

Table 10: Impact (CVN) Properties of TJ105

Heat No./ Material	Specimen I.D.	Dimensions mm	Temperatures		Absorbed Energy		
			°C	°F	Joules	Ft-lbs.	
SSC 105	1	55x10x10	22	72	170	125	100
	2	55x10x10	22	72	160	118	100
	3	55x10x10	22	72	164	121	100
Average:					*165*	*122*	*100*

<u>Hardness</u>

The Rockwell hardness of the TJ105 was measured to be 24.0 +/- 0.5 HRC, which is equal to a Brinell hardness of 247 +/-3 HB. These values conform to the required Rockwell hardness of less than 28.0 HRC.

Table 11: Chemical Composition of TJ105

Element	% Composition	
	Measured	**IRP**
Carbon, C	0.26	0.40 Max
Manganese, Mn	0.62	1.20 Max
Phosphorus, P	0.01	0.015 Max.
Sulphur, S	0.01	0.007 Max.
Silicon, Si	0.29	-
Nickel, Ni	0.15	-
Chromium, Cr	1.4	0.90 Min
Molybdenum, Mo	0.64	0.45 Min

<u>SSC Resistance</u>

Sulfide Stress Cracking (SSC) resistance for TJ105 was evaluated by two types of NACE tests, tensile and DCB. The tensile tests were performed at loads of 75%, 80% and 85% of SMYS. Table 12 summarizes these results. As per NACE TM0177, all samples were exposed for 720 hours in NACE test solution A. TJ105 passed at 75% SMYS but not at 80%. TJ105 does meet the applicable IRP for SSC resistance.

Table 12: Results of NACE Tensile Tests for TJ105

Sample	% SMYS	Exposure Hours	Results	Pits	Cracks
7	75	720	Pass	No	No
8	75	720	Pass	No	No
9	80	720	Pass	No	No
10	80	240	Fail	--	--
11	85	456	Fail	--	--
12	85	720	Pass	No	No

Table 13 gives the DCB results for TJ105. No DCB test result achieved the IRP requirement. This and the NACE tensile test result indicate that improvements are necessary. However, manufacturers and experienced end users have indicated that substantial improvements in SSC resistance have been seen for these grades of steels. As such, it is not recommended to lower the IRP 6.3 in this area.

Table 13: TJ105 DCB Tests

SPECIMEN ID	SPECIMEN THICKNESS M	CRITICAL STRESS INTENSITY FACTOR MPa $m^{0.5}$	ARM DISPLACEMENT	VALID TEST
TJ-1	0.00952	23.9	0.59	yes
TJ-2	0.00953	17.9	0.60	yes
TJ-3	0.00953	21.0	0.59	yes
Average		20.9		
TJ-7	0.00635	19.4	0.60	yes
TJ-8	0.00634	16.8	0.60	yes
TJ-9	0.00634	21.8	0.61	yes
Average		19.3		

Discussion of Drill Pipe Tube Body and Tool Joints

The test results indicate that the IRP 6.3 material requirements as proposed for drill pipe tube body and tool joints are in large part already achievable through current manufacturing processes. The one weakness in the testing was for the SSC resistance of the tool joint. This material, although submitted as sour service material, is not considered state-of-the-art technology and is not considered suitable for critical sour underbalanced drilling. Manufacturers' and end users' experience is that materials are available that will approach the proposed IRP 6.3 materials requirements. Because of this, it is not recommended at this time to lower the requirements for the tool joint. This committee encourages other groups to qualify materials to the proposed IRPs.

Testing of Coiled Tubular Materials

Three sets of coiled tubular materials were tested namely: CT80A, CT70, and CT80B. These tubes were pre-fatigued by 709 cycles of bending, each time exceeding the yield point to simulate field operation. The SSC testing was performed in accordance with NACE TM0177 (96), Method A, on custom flat samples, loaded up to 3% total elongation. Test samples were taken from 3 locations on the tubing, points of maximum tensile bending (extrados), neutral bending (neutrados) and compressive bending (Intrados).

Testing Results of Coil Tubing CT80A

Strength

Table 14 gives the measured tensile behavior of CT80A. This material is not currently allowed in IRP 6.3 but was included as a comparison since this grade of material is commonly used in the industry. It does not meet the current requirements. Note that the extrados locations showed softening, likely due to the pre-fatigue.

Table 14: Tensile Properties of Coiled Tubing Grade CT80A

Specimen I.D.	0.2 Yield Strength		Tensile Strength		Elongation %	Reduction of Area %
	MPa	**psi**	**MPa**	**Psi**		
Extrados 1	504	73, 096	694	100, 652	22	62
Extrados 2	396	57, 433	637	92, 385	21	60
Extrados 3	392	56, 853	629	91,225	20	54
Average:	***431***	***62, 461***	***653***	***94, 754***	***21***	***59***
Neutrados 1	573	83, 103	676	98, 042	19	46
Neutrados 2	587	85, 134	675	97, 897	19	53
Neutrados 3	545	79, 042	664	96, 301	18	52
Average:	***568***	***82, 462***	***672***	***97, 413***	***19***	***50***
Intrados 1	592	85, 871	664	96, 338	22	59
Intrados 2	589	85, 391	662	96, 082	21	55
Average:	***591***	***85, 631***	***663***	***96, 210***	***22***	***57***

Impact Toughness

Table 15 shows the impact toughness for CT80A. Although there are currently no impact toughness requirements in the IRP, the results show low values for fatigue-damaged material. The results also show that this is not a concern for low temperature service (without H_2S).

Table 15: Impact (CVN) Properties of Coiled Tubing Grade CT80A at Room Temperature

Heat No./ Material	Specimen I.D.	Dimensions mm	Test Temperature		Absorbed Energy		Shear %
			°C	°F	Joules	Ft-lbs.	
Neutrados	1	55 x 10 x 2.5	Room	Room	25	18	100
	2	55 x 10 x 2.5	Room	Room	26	19	100
	3	55 x 10 x 2.5	Room	Room	25	18	100
			Average:		***25***	***18***	***100***
Extrados	4	55 x 10 x 2.5	Room	Room	26	19	100
	5	55 x 10 x 2.5	Room	Room	24	18	100
	6	55 x 10 x 2.5	Room	Room	24	18	100
			Average:		***25***	***18***	***100***
Extrados	1	55 x 10 2.5	-40	-40	25	18	100
	2	55 x 10 2.5	-40	-40	26	19	100
	3	55 x 10 2.5	-40	-40	24	18	100
			Average:		***25***	***18***	***100***
Neutrados	1	55 x 10 2.5	-40	-40	28	21	100
	2	55 x 10 2.5	-40	-40	29	21	100
	2	55 x 10 2.5	-40	-40	26	19	100
			Average:		***28***	***21***	***100***

Chemistry

As seen in Table 16, this material meets the suggested chemistry in the IRP.

Table 16: Chemical Composition of Coiled Tubing CT80A

Element	% Composition		
	Sample #1	**Sample #2**	**Mill Certification**
Carbon, C	0.13	0.13	0.14
Manganese, Mn	0.77	0.78	0.76
Phosphorous, P	0.014	0.012	0.009
Sulphur, S	0.007	0.007	0.007
Silicon, Si	0.36	0.36	0.37
Nickel, Ni	0.18	0.19	0.09
Chromium, Cr	0.59	0.60	0.61
Molybdenum, Mo	0.21	0.21	0.20
Aluminum, Al	0.04	0.04	--
Copper, Cu	0.29	0.28	0.25
Vanadium, V	0.006	0.005	--
Niobium, Nb	--	--	--
Boron, B	--	--	--

<u>SSC Resistance</u>

Sulfide Stress Cracking (SSC) resistance for CT80A was evaluated by two types of NACE-related tests, tensile and DCB. The custom tensile tests were performed at a total gauge length strain of 3% to simulate loading up to previous plastic deformation. As per NACE TM0177, all samples were exposed for 720 hours in NACE test solution A. Table 17 represents these SSC results, along with subsequent microscopic examination. CT80A experienced failures on the extrados and intrados and showed SSC initiation at all locations. IRP 6.3 currently does not have any SSC test requirements. The data shows that overload coiled tubing can be susceptible to SSC.

Table 17: Results of SSC Testing under a Load Producing 3% Elongation

Location	#	Hours	Result	Results of Visual Examination
Extrados	1	80	Fail	No additional SSC cracks. Possible overload.
	2	720	Pass	One 0.5 mm SSC crack initiation.
	3	552	Fail	Numerous SSC cracks.
Neutrados	1	720	Pass	Several SSC cracks up to 0.5 mm long
	2	720	Pass	Several cracks up to 1.5 mm long
	3	720	Pass	Four 1 mm cracks
Intrados	1	720	Pass	No defects
	2	720	Pass	Several SSC cracks initiations up to 0.2 mm long
	3	264	Fail	

Table 18 shows the curved DCB test results. The size of the DCB specimens was determined by the thin wall of the coiled tubing. The curved DCBs do meet the NACE TM0177 curvature criteria. These specimens were first exposed with insufficient arm displacement to cause cracking. They were re-exposed with an arm displacement of approximately 0.88mm and these results are given in Table 18. These results show that fatigued CT80A has low resistance to SSC. Results in high 20's and low 30's are usually required for a fully SSC-resistant material. A longitudinal crack or lamination was found in some of the DCBs. This likely formed during the fatigue. This defect skews the results because it is perpendicular to the plane of cracking for the test and therefore "pins" the SSC crack. It is unknown whether this would happen under actual operating conditions.

Table 18: Curved DCB Results for CT80A

SPECIMEN I.D.	WEDGE LOAD Final MN	A Final m	ARM HEIGHT m	SPECIMEN THICKNESS m	D diameter mm	KISSC (curved) MPa m0.5	Valid Y/N	LAM. Y/N	REASON FOR INVALID TEST RESULT
N1	0.00043	0.055700	0.01268	0.004510	51	21.9	Y	N	
N2	0.00051	0.052720	0.01268	0.004490	51	23.9	Y	Y	
N3	0.00048	0.053020	0.01267	0.004490	51	23.4	Y	N	
E1	0.00042	0.053870	0.01269	0.004550	51	19.9	Y	N	
E2	0.00044	0.052390	0.01269	0.004600	51	20.4	Y	N	
E3	0.00044	0.053780	0.01273	0.004600	51	20.5	Y	N	
I1	0.00102	0.041050	0.01265	0.004660	51	39.5	N	N	pinned and out of plane
I2	0.00082	0.046020	0.01267	0.004660	51	35.5	N	N	pinned and out of plane
I3	0.00026	0.066060	0.01265	0.004670	51	15.1	Y	N	

Results of Testing of Coiled Tubing CT70

Strength and Impact Toughness

Tables 18 and 19 represent the full body tensile and impact properties for CT70. This material just does not meet the requirements of IRP 6.3 before fatigue. After fatigue it shows significant softening. Again, impact properties are not specified and although the material failures in 100% shear (ductile) at all temperatures, it has relatively low impact toughness.

Table 18: Full-Body tensile Properties of Coiled Tubing CT70

Sample I.D.	Yield Strength		Tensile Strength		Elongation in 50 mm %	Reduction of area %
	MPa	Psi	MPa	Psi		
CT70, Fatigued	443	64, 285	592	85, 900	29	59
CT70*	--	81, 800	--	90, 700	--	--
***** Tested at Anderson & Associates***						

Table 19: Impact (CVN) Properties of CT70

Heat No./ Material	Specimen I.D.	Dimensions mm	Test Temperature		Absorbed Energy		Shear %
			°C	**°F**	**Joules**	**Ft-lbs.**	
Extrados	1	55 x 10 x 2.5	Room	Room	26	19	100
	2	55 x 10 x 2.5	Room	Room	26	19	100
	3	55 x 10 x 2.5	Room	Room	26	19	
	Average:				***26***	***19***	***100***
Neutrados	1	55 x 10 x 2.5	Room	Room	26	19	100
	2	55 x 10 x 2.5	Room	Room	27	20	100
	3	55 x 10 x 2.5	Room	Room	27	20	100
	Average:				***27***	***20***	***100***
Extrados	1	55 x 10 x 2.5	-40	-40	27	20	100
	2	55 x 10 x 2.5	-40	-40	26	19	100
	3	55 x 10 x 2.5	-40	-40	26	19	100
	Average:				***26***	***19***	***100***
Neutrados	4	55 x 10 x 2.5	-40	-40	29	21	100
	5	55 x 10 x 2.5	-40	-40	24	18	100
	6	55 x 10 x 2.5	-40	-40	27	20	100
	Average:				***27***	***20***	***100***

Chemistry

Table 20 indicates that CT70 meets the suggested chemistry in IRP 6.3.

Table 20: Chemical Composition of Coiled Tubing CT70

Element	% Composition
	*
Carbon, C	0.13
Manganese, Mn	0.86
Phosphorous, P	0.019
Sulphur, S	0.002
Silicon, Si	0.31
Nickel, Ni	0.17
Chromium, Cr	0.62
Molybdenum, Mo	0.01
Aluminum, Al	0.029
Copper, Cu	0.26
Vanadium, V	0.003
Niobium, Nn	0.002
Boron, B	0.0005
**** Tested at Anderson & Associates***	

SSC Resistance

Sulfide Stress Cracking (SSC) resistance for CT70 was evaluated by two types of NACE-related tests, tensile and DCB. The custom tensile tests were performed at a total gauge length strain of 3% to simulate loading up to previous plastic deformation. As per NACE TM0177, all samples were exposed for 720 hours in NACE test solution A. Table 21 gives the tensile SSC testing results along with the microscopic examination of the surfaces of the samples. Note that all the failures are due to the presence of longitudinal cracking which is thought to have initiated during the fatigue of the material. This indicates that prior fatigue damage can be very detrimental for SSC resistance. CT70 also suffered from blistering and X-cracks. This indicates some susceptibility to hydrogen-induced cracking (HIC). HIC susceptibility testing has not been considered in the IRPs.

Table 21: CT70 Results of SSC Testing under a Load Producing 3% Elongation

Location	#	Hours	Result	Results of Visual Examination
Extrados	1	720	Pass	**Several SSC crack initiations up to 0.1 mm long. A corner crack, 2.5 mm long.**
	2	720	Pass	Several X-shaped cracks 0.8mm long.
	3	720	Pass	Blistering. Attack on elongated stringers.
Neutrados	1	624	Fail	Contained a long crack in longitudinal direction.
	2	720	Pass	Numerous crack initiation. A corner crack 0.5 mm long.
	3	288	Fail	Sample contained longitudinal crack.
Intrados	1	720	Pass	Several SSC crack initiations up to 0.4 mm long.
	2	480	Fail	Sample contained longitudinal crack.
	3	720	Pass	Several SSC cracks initiations up to 0.2 mm long.

Table 22 shows the curved DCB test results. The subsize curved DCB specimens were chosen because of the thin wall of the coiled tubing. The curved DCBs do meet the NACE TM0177 curvature criteria. These specimens were exposed with an arm displacement of approximately 1.02 mm. These results show that fatigued CT70 has a higher SSC resistance than CT80A. A longitudinal crack or lamination was found in some of the DCBs. This likely formed during the fatigue. This defect skews the results because it is perpendicular to the plane of cracking for the test and therefore can "pin" the SSC crack. It is unknown whether this would happen under actual operating conditions. Even when pinned the SSC resistance was low.

Table 22: Curved DCB results for CT70

SPECIMEN I.D.	WEDGE LOAD FINAL MN	CRACK LENGTH FINAL m	ARM HEIGHT m	SPECIMEN THICKNESS m	D diameter mm	K (curved) MPa $m^{0.5}$	VALID Y/N	LAM. Y/N	REASON FOR INVALID TEST RESULT
N1	0.00102	0.03829	0.012615	0.00432	50.2	38.64266	N	Y	Pinned and out of plane
N2	0.00113	0.03533	0.012635	0.00431	50.2	39.62942	N		Not cracked
N3	0.00107	0.03533	0.01261	0.00433	50.2	38.22268			Not cracked
E1	0.00078	0.04156	0.01264	0.00434	50.2	31.05499	N	Y	Pinned and out of plane
E2	0.00061	0.0473	0.012625	0.00433	50.2	27.18603	Y	Y	
E3	0.00046	0.05154	0.01269	0.00437	50.2	22.3304	Y	Y	
I1	0.00094	0.03648	0.012615	0.00435	50.2	34.0655	N	Y	pinned and insufficient growth
I2	0.00113	0.03533	0.01261	0.00437	50.2	39.32426	N		Not cracked
I3	0.00108	0.03533	0.01262	0.00437	50.2	38.22476	N		Not cracked

Results Of Testing Of Ct80b

Strength And Impact Toughness

Tables 23 and 24 represent the full body tensile and impact properties for CT80B. This material just does not meet the requirements of IRP 6.3. Impact properties are not specified and although the material failures in 100% shear (ductile) at all temperatures, it has relatively low impact toughness.

Table 23: Full-body Tensile Properties of CT80B

Sample I.D.	Yield Strength		Tensile Strength		Elongation %	Reduction of Area %
	MPa	psi	MPa	psi		
	618		664			
CT80B ***(Tested at Henderson & Associates)***		89, 700		96, 300		

Table 24: Impact (CVN) Properties of CT80B

Heat No./ Material	Specimen I.D.	Dimensions mm	Test Temperature		Absorbed Energy		Shear %
			°C	°F	Joules	Ft-lbs.	
Extrados	1	55 x 10 x 2.5	Room	Room	29	21	100
	2	55 x 10 x 2.5	Room	Room	25	18	100
	3	55 x 10 x 2.5	Room	Room	27	20	100
	Average:				***27***	***20***	***100***
Neutrados	4	55 x 10 x 2.5	Room	Room	28	21	100
	5	55 x 10 x 2.5	Room	Room	29	21	100
	6	55 x 10 x 2.5	Room	Room	27	20	100
	Average:				***28***	***21***	***100***
Extrados	1	55 x 10 2.5	-40	-40	25	18	100
	2	55 x 10 2.5	-40	-40	30	22	100
	3	55 x 10 2.5	-40	-40	26	10	100
	Average:				***27***	***20***	***100***
Neutrados HS-80	4	55 x 10 2.5	-40	-40	25	18	100
	5	55 x 10 2.5	-40	-40	27	20	100
	6	55 x 10 2.5	-40	-40	28	21	100
	Average:				***27***	***20***	***100***

Chemistry

Table 25 gives the chemical analysis of CT80B. This material meets the suggested chemistry of IRP 6.3.

Table 25: Chemical Composition of CT80B

Element	% Composition CT80B*
Carbon, C	0.14
Manganese, Mn	0.79
Phosphorous, P	0.018
Sulphur, S	0.002
Silicon, Si	0.32
Nickel, Ni	0.16
Chromium, Cr	0.58
Molybdenum, Mo	0.0005
Aluminum, Al	0.035
Copper, Cu	0.26
Vanadium, V	0.003
Niobium, Nn	0.002
Boron, B	0.0005
Tested at Anderson & Associates	

SSC Resistance

Sulfide Stress Cracking (SSC) resistance for CT80B was evaluated by two types of NACE-related tests, tensile and DCB. The custom tensile tests were performed at a total gauge length strain of 3% to simulate loading up to previous plastic deformation. As per NACE TM0177, all samples were exposed for 720 hours in NACE test solution A. Table 26 represents these SSC results, along with subsequent microscopic examination. CT80B experienced one failure on the neutrados and showed SSC initiation at all locations. The failed specimen contained a longitudinal crack that could have formed during fatigue. IRP 6.3 currently does not have any SSC test requirements. The data shows that overload and fatigued coiled tubing can be susceptible to SSC. CT80B also showed evidence of surface blistering and therefore some susceptibility to HIC. This 80 grade material performed almost as well as the 70 grade material.

Table 26: Results of SSC testing under a load producing 3% Elongation for CT80B

Location	#	Hours	Result	Results of Visual Examination
Extrados	1	720	Pass	**No defects**
	2	720	Pass	Several SSC cracks up to 0.4 mm long. A corner crack, 1 mm long.
	3	720	Pass	Several SSC cracks initiations up to 0.5 mm long
Neutrados	1	720	Pass	No SSC crack. Surface affected by corrosion.
	2	720	Pass	Multiple SSC cracks initiations up to 0.5 mm long.
	3	96	Fail	Sample contained longitudinal cracks
Intrados	1	720	Pass	Multiple SSC cracks initiations up to 0.5 mm long. Blistering.
	2	720	Pass	No SS. Corrosion along inclusions.
	3	720	Pass	Several SSC cracks initiations up to 0.2 mm long.

No curved DCB tests for CT80B resulted in valid test results. The subsize curved DCB specimens were chosen because of the thin wall of the coiled tubing. The curved DCBs do meet the NACE TM0177 curvature criteria. These specimens were exposed with an arm displacement of between 0.8 mm and 0.95 mm. The results are caused either by no crack initiation or by crack “pinning” caused by the presence of a longitudinal crack. This longitudinal crack was likely formed during the fatigue of the tubing. This defect skews the results because it is perpendicular to the plane of cracking for the test and therefore can “pin” the SSC crack. The CT80B material behaved in similar way to the CT70.

Discussion of Coiled Tubing

The test results indicate that the IRP 6.3 material requirements as proposed for coiled tubing are incomplete and do not provide a way of extending the service life of coiled tubing in critical sour service. The test results do not give any indication of sour fatigue performance. The results do strongly indicate that prior fatigue can significantly influence the sulfide stress cracking susceptibility of the coiled tubing. It also suggests that new coiled tubing may be relatively resistant to SSC. Some coiled tubing is susceptible to HIC. IRP 6.3 does not address HIC and little is known about the effect of HIC on fatigue performance. It is recommended that more work be done in this area.

The test results do not clearly indicate that a lower strength coiled tubing must be used. One of the higher strength, 80 grade materials performed almost identically to the 70 grade. This committee encourages other groups to further study the sour fatigue and loading behavior of coiled tubing in an effort to properly understand performance. Only then can more accurate guidelines be recommended.

6.3.12 Reference List

1. API, Recommended Practice for Field Inspection of New Casing, Tubing and Plain-End Drill Pipe, Sixth Edition, December 1997, RP 5A5, Washington, D.C.

2. API, Recommended Practice for Drill Stem Design and Operating Limits, Fifteenth Edition, January 1995, RP 7G, Washington D.C.

3. ASTM, Standard Test Methods for Notched Bar Impact Testing of Metallic Materials, May 1996, E 23-96, West Conshohocken, PA.

4. NACE, Laboratory Testing of Metals for Resistance to Specific Forms of Environmental Cracking in H_2S Environments, December 1996, TM0177-96, Houston, Texas.

5. ASTM, Standard Test Methods for Determining Average Grain Size, May 1996, E 112-96, West Conshohocken, PA.

6.4 Surface Circulating System

6.4.1 Scope

6.4.1.1 The Surface Circulating System IRPs have been developed by the Drilling and Completions Sub-committee for Critical Sour Underbalanced Drilling to address the equipment requirements for a critical sour underbalanced drilling operation.

6.4.1.2 The recommendations in this IRP supplement existing ARP Volume 4 and AEUB Interim Directive ID 94-3, and are based on industry standards and existing regulatory requirements. In cases of inconsistencies between any of the recommended practices contained in this IRP and applicable legislation, the legislative requirements shall prevail.

6.4.1.3 The recommendations in the IRP are meant to be accurate and reliable based on current knowledge, data and practices, but must also be used concurrently with competent technical judgement. DACC, its sub-committees, and individual members make no representation, warranty, or guarantee in the contents of any IRP recommendation and disclaim liability or responsibility for loss or damage resulting from the use of the IRP, or for any violation of any statutory or regulatory requirements.

6.4.2 Equipment

6.4.2.1 General Requirements

Equipment requirements and configurations are based on the characteristics of each well, such as depth, hole size, anticipated volume of produced fluid, amount of solids to handle, H_2S concentration, and maximum pressures.

During underbalanced drilling operations the fluid environment is altered, and drilling components normally exposed to drilling fluids will in all probability be exposed to H_2S, therefore all surface separation equipment (with the exception of storage tanks) must conform to NACE MR-01-75 specifications. Material selection and quality control are required to ensure satisfactory performance in the service to which the material is exposed. As a minimum, the original manufacturer of the components shall provide quality assurances with test certification, that the equipment supplied meets the requirements of NACE MR-01-75. The scope of the NACE MR-01-75 standards is limited to acceptable metallurgy for sour service. A number of sub-components constructed of non-metallic material such as elastomers, must also be considered.

Elastomer technology continues to evolve, and consultation with the original supplier as to the most suitable elastomers is recommended. Elastomers tend to be less tolerant than metallic materials due to the wide range of drilling environments encountered, therefore, detailed fluid properties and the range of operating conditions expected should be addressed in the selection process.

The failure potential is not the same for all components of the underbalanced drilling operation. The BOP stack on the upstream side of the choke manifold is highly stressed and highly prone to Sulfide Stress Corrosion Cracking (SSCC).

Conversely, the equipment downstream of the choke manifold operates at lower pressure and therefore a lower risk of SSCC, but a potentially much greater risk of failure due to erosion. The consequences of an equipment failure, also varies depending upon the particular service. The failure of the BOP stack components, for example, is considered more serious than the failure of a manifold or degasser component since the ability to contain sour fluids and gas within the wellbore would be lost in the former situation. The resulting combination of high risk and consequence of failure of components, such as the BOP stack, warrants the highest degree of material control relative to other drilling equipment.

6.4.2.2 Emergency Shutdown Valve (ESD)

IRP

The working pressure of the ESD components must be equal to or greater than the anticipated SITHP.

The recommended installation of the ESD is that it be as close to the BOP stack as possible to minimize the potential of failure between the stack and the ESD. A valve position indicator is recommended, equipped with a visual and audible alarm system to be actuated when the ESD is in the closed position.

6.4.2.3 Main Flowline

The main flowline installed between the ESD and the choke manifold is to be as straight as possible to minimize friction and erosion. It is also recommended that a uniform piping inside diameter be maintained to minimize turbulence within the flowline. Butt weld unions and flanges also help to minimize turbulence. Installation of appropriate ports for chemical injection is also recommended. Consideration should be given to the installation of a redundant flowline, connected to the manifold and separator.

6.4.2.3.1 Pressure Rating

IRP

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

6.4.2.3.2 Internal Diameters

IRP

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

Preferably, the inside diameter of the downstream piping from the choke manifold be larger than the upstream piping.

6.4.2.3.3Erosion Calculations

IRP **Erosion calculations are required to determine proper flowline sizing, taking in to account abrasion, corrosion (cushion tees) and slug flow (line jacking).**

6.4.2.3.4 Inspection And Certification

IRP **Third party pre-job inspection shall include a thickness inspection and a hydrostatic pressure test. The pressure test must be equal to 1.5 times the working pressure rating of the piping. Mill documentation of the piping metallurgy must be available at the wellsite.**

6.4.2.3.5 Wellsite Testing And Certification

IRP

The flowline downstream of the BOP stack to the first control valve must be:

- **Hydrostatically pressure tested for a minimum of 10 minutes to a low pressure of 1400 KPa, and to the anticipated SITHP.**
- **Tested with an inert gas medium for a minimum of 10 minutes if the circulating medium is a gaseous fluid and/or the wellbore effluent is expected to contain free gas, to a low pressure of 1400 KPa and to a pressure equal to 90% of the anticipated SITHP.**

Refer to IRP 6.2 for Well Control Equipment pressure test requirements.

Pressure testing of the flowline piping must conform to regulatory requirements such as the AEUB Oil and Gas Regulation 8.141, and the pressure testing criteria set out in ARP Volume 4.

6.4.2.3.6 Wellsite Inspection

IRP

Piping must be thickness tested (ie. ultrasonically) at predetermined erosion spots to determine loss of piping thickness, and records of the inspection must be retained at the wellsite. The inspection frequency must be increased if wear becomes noticeable. High rate gas wells must be monitored on a continuous basis.

The intent of this inspection is to ensure that wear spots are identified prior to pipe failure.

Refer to Planning, Section 6.1 for operability recommendations, which includes erosion calculations.

6.4.2.4 Choke Manifold

IRP

The choke manifold must have a pressure rating equal to or greater than the anticipated SITHP, and must include the following components:

- **two chokes**
- **isolation valves for each choke and flow path**

All components within the choke manifold must conform to NACE MR-01-75 specifications.

6.4.2.5 Downstream Inlet Piping

IRP **All piping downstream of the choke manifold, up to and including the separator inlet must conform to NACE MR-01-75 specifications and have a working pressure equal to or greater than the design operating pressure of the separator.**

6.4.2.6 Sample Catcher

IRP **Prior to geological sample recovery, the sample catcher must be purged with either an inert gas or a sweet gas. The sample recovery procedure must still be considered sour and personnel must take precautions accordingly. The purged sour gas is to be vented into the vapor recovery system.**

6.4.2.7 Standpipe Bleedoff Line

IRP **The standpipe bleedoff line components must comply with NACE MR-01-75 specifications and have a working pressure equal to or greater than the anticipated SITHP.**

The standpipe bleedoff line is required to be tied into the standpipe injection header to provide a safe means of bleeding down the standpipe to the separation equipment (ie. drill pipe connections when injecting gaseous fluid). This line should also be installed with a check valve.

6.4.2.8 Separator

IRP

Separator equipment components that will come into contact with sour gas must comply with NACE MR-01-75 specifications.

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

Current documentation must be available at the wellsite that verifies the function testing of the pressure relief valves. Assurance of correct sizing of the pressure relief valves must be supported with gas flow calculations available at the wellsite.

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

6.4.2.9 Fluids Handling

IRP

All fluids handling equipment, except storage tanks, must conform to NACE MR-01-75 specifications.

The fluids handling system and the separator capacity should be based upon maximum potential production at maximum drawdown (in a prolific gas reservoir this may not be possible, therefore; an adequate manifold system for holding back-pressure would be mandatory). Note: short term near wellbore flush production can result in flow rates which can significantly exceed expected rates. If the well to be drilled is in an area with little production experience, or is a significant step location, the fluids handling system and the separator size should be selected to provide for excess capacity.

For the drilling of a sour gas reservoir where the potential exists for production rates larger than the sizing of the separator vessel and/or at a relatively high flowing well head pressure, it is recommended that a high pressure separator be used, and/or as a minimum a double manifold be considered to step down any potential large surface circulating pressures (instead of using one manifold and taking the entire pressure drop across a single system) and chokes which are highly erosion resistant be used. Rationale for these recommendations is to minimize the degree of pressure drop across one restriction, thereby minimizing erosion. In an oil well these steps may not be warranted if the anticipated bottom hole pressures would not cause high flowing well head pressures. In this event an industry accepted manifold and separation vessel would be sufficient.

NACE MR-01-75 specifications do not apply to storage tanks since fluids are stored below 350 KPa.

Refer to AEUB Interim Directive ID 94-3 for additional sour fluids requirements.

6.4.2.10 Pump Lines

Pump lines and related components used for pumping fluid down the drill pipe must have a working pressure equal to or greater than the anticipated SITHP. Elastomers must be compatible with the fluid circulating medium and the service conditions.

Pump line equipment must also include two check valves installed between the pump and standpipe, and have a working pressure equal to or greater than the anticipated SITHP.

6.4.3 List Of References

1. AEUB, ID 94-3, Recommended Practices For Underbalanced Drilling, July 18, 1994, Calgary, Alberta.

2. AEUB, Oil and Gas Conservation Regulations, October 1996, Calgary, Alberta.

3. ARP Volume 2, Alberta Recommended Practices For Completions and Servicing Critical Sour Wells, April 1989, Calgary, Alberta.

4. ARP Volume 4, Alberta Recommended Practices For Well Testing And Fluids Handling, June 1993, Calgary, Alberta.

6.5 Wellbore Integrity

6.5.1 Scope

6.5.1.1 The Wellbore Integrity IRPs have been developed by the Drilling and Completions Sub Committee for Critical Sour Underbalanced Drilling, recognizing the need for wellbore integrity during critical sour underbalanced drilling operations. This section addresses the issues and implications regarding wellbore integrity when exposed to effluent flow from a critical sour well during underbalanced drilling operations.

6.5.1.2 Integrity of the wellbore means the wellbore fluids are contained by the casing, cement, open hole and the wellhead. Loss of containment can be caused by a failure of the casing, the cement or the wellhead.

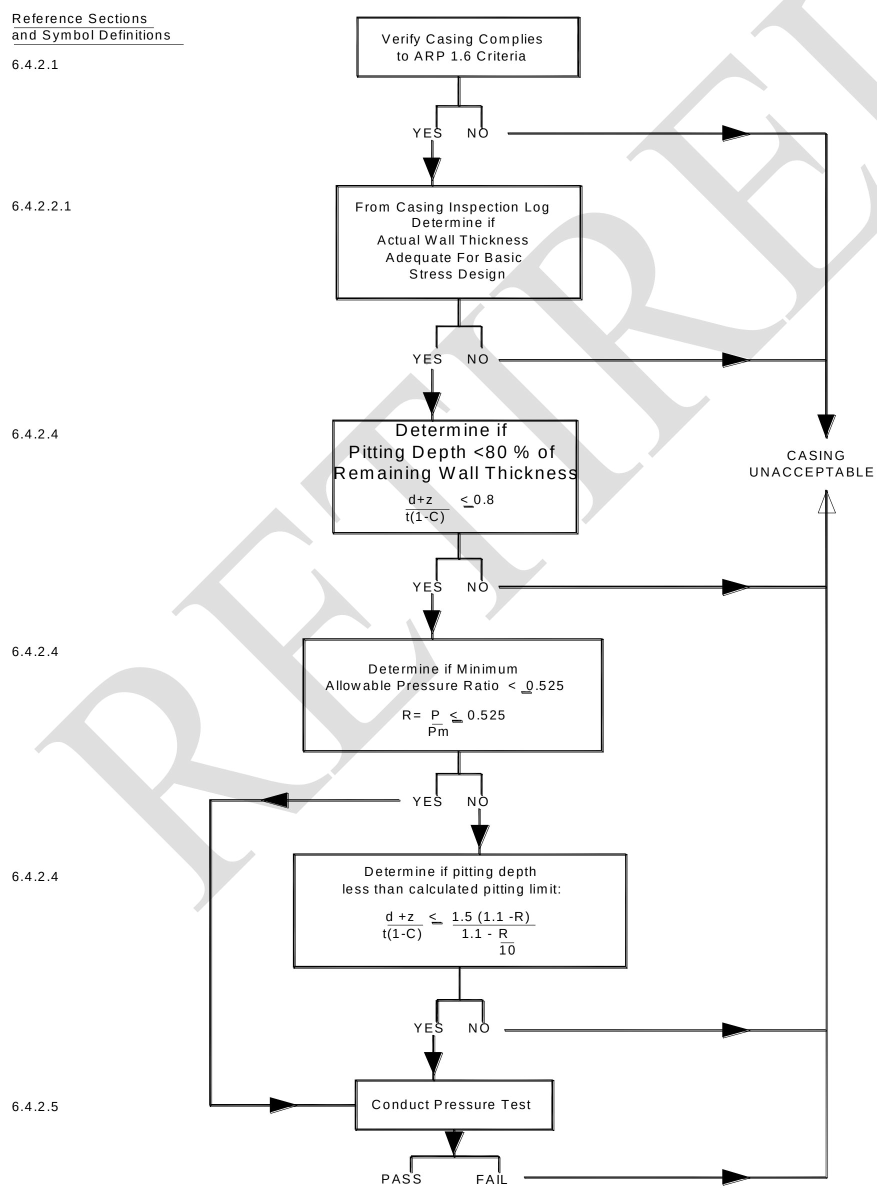
6.5.1.3 The recommendations define the design and verification requirements to be considered when assessing the condition of the casing, the wellhead, and the cement in an existing or new wellbore before undertaking an underbalanced drilling operation on a critical sour well.

6.5.1.4 Typical underbalanced drilling conditions that are not seen during overbalanced operations are:

- exposure of the wellbore to reservoir fluids
- reduced bottom hole pressure and temperature
- high surface pressures
- high flow rates
- reservoir pressure, should the well be shut in

6.5.1.5	This IRP examines the possible ways the wellbore could lose integrity and containment. The risks of failure, once the causes are identified, can be mitigated by appropriate wellbore design and adequate assessment of current integrity of the candidate wellbores.
6.5.1.6	The Casing Integrity Assessment Flowchart is intended to provide a systematic approach to evaluating current casing integrity.
6.5.1.7	The recommendations set out in this IRP are meant to allow flexibility. However, the need for exercising competent technical judgment is a necessary requirement to be employed concurrently with its use. It remains the responsibility of the user of the IRP to judge a well's suitability for a particular application. While every effort has been made to ensure the accuracy and reliability of the data contained in the IRP and to avoid errors and omissions, DACC, its subcommittees, and individual members make no representation, warranty, or guarantee in connection with the publication or the contents of any IRP recommendation, and hereby disclaim liability or responsibility for loss or damage resulting from the use of the IRP, or for any violation of any statutory or regulatory requirement with which an IRP may conflict.

Casing Integrity Assessment Flowchart



6.5.2 Casing

6.5.2.1 Casing Metallurgy

IRP

Each well must be assessed to determine if its current condition meets regulatory design requirements. The design for a new or an existing well must meet requirements as covered in ARP 1.6.

Specific documentation of suitable metallurgy or evidence of sulfide stress cracking resistance is required in order to qualify a casing which would not currently be considered sour service.

Many of the concerns regarding the casing integrity are addressed if the wellbore has an appropriate casing design.

Note:

For a well to meet the recommendations in ARP 1.6 its age is likely to be less than 15 years old.

Metallurgy can be verified with mill certification or sample and testing of the top joint of a verified homogeneous string of casing.

6.5.2.1.1 Sulfide Stress Cracking

IRP

A wellbore temperature profile simulation must be conducted if any sections of the casing string are non-sour service, to determine the dynamic conditions during underbalanced drilling operations, and to ensure design requirements are still valid with respect to sulfide stress cracking as per ARP 1.6.

Sulfide stress cracking may cause parting or splitting of the casing. Typically, a temperature drop in the bottom of the hole will occur during underbalanced drilling operations. Simulations have shown that wellbore temperature during underbalanced drilling operations could drop down to 50°C. This would result in a non-sour casing set deep in a well becoming unacceptable even though it was acceptable based on the requirements in ARP 1.6.4.

6.5.2.2 Casing Wear

IRP

A wall thickness inspection log is required to assure collapse and/or burst will not occur due to wall loss.

The intent of the assessment is to verify that sufficient wall thickness exists to allow for expected wear during the drilling operation. Reductions in wall thickness, or changes in axial load, may result in collapse, burst or tensile failure.

A statement on the vulnerability of the casing to casing wear is required, and if casing wear is of concern, mitigation measures should also be prescribed.

An assessment of casing wear is required if doglegs exist above values listed in Table 6.5.1 below:

- from surface to 1000 m of cemented casing, or
- from surface to 150 m below the cement top, whichever is the greater depth (minimum of 1000 m)

Table 6.5.1 - Maximum Allowable Dogleg Severity

True Vertical Depth (metres)	Maximum Dogleg Severity - Degrees/30 m*	
	170 Rotating Hrs.	340 Rotating Hrs.
2000	7.5	2.0
3000	3.5	1.5
4000	2.0	1.0

*Simulation run in 178 mm casing using 89 mm drill pipe with 170 and 340 rotating hrs at 40 rpm

The wear factor varies significantly between fluid mediums. Gaseous medium and water have high wear factors. The presence of solids or a lubricant significantly reduces wear factors.

The casing must be pressure tested to verify it still meets the burst criteria following the underbalanced operations and as required by regulatory casing design requirements.

6.5.2.2.1 Casing Wear Assessment

IRP

A casing wear simulation must utilize wall thicknesses from the wall thickness inspection log.

Wear assessment is important for the up-hole casing. Assessment of doglegs and contact force will highlight severe situations. Generally, wear concern is small since drilling time is presumed to be short and with the use of directional tools, pipe rotation will also be minimal. If these two presumptions are not valid, then assessment of casing wear is of a greater concern. Commercial casing wear software (such as the Maurer DEA casing wear program or equivalent) can be used to evaluate casing wear.

6.5.2.2.2 Design Requirements

When evaluating an existing casing design, the following design factors and assumptions should be useful. Refer to the example in Appendix I.

Design Factor	Safety Factor	Design Requirements
Collapse	1.1	1. No internal pressure 2. Assessment is required from: - surface to 150 m below the confirmed cement top, <u>or</u> - surface to 1000 m of an cemented casing, whichever is the greater 3. Collapse resistance is reduced by tensile load in accordance with the latest edition of API Bulletin 5C3, “Formulas and Calculations for Casing, Tubing, Drill Pipe and Line Pipe Properties”. The AEUB publication G-15 “Effect of Tensile Loading on Casing Collapse” may be used to determine the collapse resistance and equations in API Bulletin 5C3. 4. The design check should be based on an external fluid gradient of the original mud density prior to running the casing. Approval may be granted for less (minimum 10 kPa/m) provided the actual fluid gradient does not exceed design gradient. Collapse strength is based on remaining wall thickness.

Tension	1.2	1. The safety factor has been reduced from 1.6 to 1.2 since an existing casing will not experience running or cementing loads anticipated in the original design. 2. Buoyant effect is neglected. 3. Assessment is required only from: - surface to 150 m below the confirmed cement top, <u>or</u> - surface to 1000 m if the casing is cemented, - <u>whichever is the greater.</u> 4. Yield strength of the casing wall is used if this is less than joint strength. 5. Tensile strength is adjusted to remaining wall thickness.
Burst	1.3	1. Burst = (1 - accuracy of wall thickness log) x 2(Specified Minimum Yield Strength) x (<u>current wall thickness</u>) (casing OD) 2. Maximum required pressure is free to act over the full length of casing string. 3. No allowance is made for external pressure. 4. Design check should be based on an applied surface pressure of 85% of original formation pressure or if documented, 85% of current formation pressure.

6.5.2.3 General Corrosion

Degradation of the casing by general corrosion because of H_2S during the underbalanced drilling operation is typically not a concern. Degradation of the casing by corrosion generally takes a significant amount of time compared to the time to drill an interval of hole.

Nitrogen supplied from membrane generation units may introduce oxygen contamination into the wellbore, which can cause general corrosion problems. The use of an appropriate inhibitor for the casing and drilling components is necessary.

Refer to the Circulating Media section 6.6 for inhibitor requirements.

6.5.2.4 Isolated Corrosion

IRP

The casing from surface to 150 metres below the confirmed cement integrity log top cannot have pitting in excess of the maximum allowable pitting depth.

Localized corrosion and pitting can happen rapidly. Pre-existing corrosion will enhance greater deterioration by pitting during drilling operations if the environment is conducive. A sour, CO_2 - contained environment can accelerate pitting up to approximately 3.0 mm/month. Generally the underbalanced drilling operation would not be longer than 15 days in duration; therefore, the maximum loss allowance during drilling is 1.5 mm.

Injection of a corrosion inhibitor may mitigate sour gas corrosion. Selection of an effective inhibitor is a technical issue based on the environment in the well, and an appropriate inhibitor may protect the casing from additional pitting damage. The effectiveness of an inhibitor under sour underbalanced conditions must be validated (such as through laboratory testing).

Supporting data to confirm the severity of the downhole corrosive environment is required to substantiate a reduction of the corrosion rate (of 1.5 mm over a 15 day period). Corrosion during a drilling period longer than 15 days must be prorated.

Isolated external or internal corrosion, such as pitting or abrasion may result in a leak. Pitting may also result in burst if the pitting is linked (that is, the edges of various pits are touching and thereby have a contiguous length). Casing wall thickness logs may not discern isolated pitting versus contiguous pitting. This document assumes indicated pitting is contiguous and structural burst of the casing must be downgraded. If an inspection can discern the longitudinal length of pitting, then individual integrity calculations using accepted techniques such as ASME B31G are acceptable.

The following equation modified from ASME B31G can be used to estimate the maximum allowable pitting depth before drilling operations commence.

The pitting allowance must meet the following conditions:

1. The pitting depth must be equal to or less than 80% of the remaining wall thickness (maximum limit).

$$\frac{d + z}{t\,(1 - C)} \le 0.8$$

2. The internal pressure that will not burst a pit is established by the internal pressure ratio which must be equal to or less than 52.5%.

$$R = \frac{P}{Pm} \le 0.525$$

3. The actual limit is compared (if Step 2 > 0.525) and must be equal to or greater than the maximum limit.

$$\frac{d + z}{t\,(1 - C)} \le \frac{1.5\,(1.1 - R)}{1.1 - \frac{R}{10}}$$

Where:	d	depth of pitting from the inspection log (mm)
	t	actual casing wall thickness around the pitting (mm) (reduced from nominal by any general wall reduction i.e. casing wear)
	C	accuracy of inspection, as a fraction
	z	pitting growth allowance during drilling
	R	internal pressure ratio P/Pm
	P	expected maximum internal pressure in casing (MPa) 85% of original reservoir pressure
	Pm	internal pressure giving casing hoop strength at SMYS $\frac{2\,(\text{SMYS})\,t}{D}$ (MPa)
	SMYS	specified minimum yield strength (MPa)
	D	outer diameter of casing (mm)

Note: A modified ASME B31G philosophy is used to prevent failure. A contiguous pitting defect is assumed. External pressure on the casing is not considered. Unless proven otherwise, maximum pit propagation is assumed to occur during drilling operations.

6.5.2.5 Casing Pressure Test and Monitoring

IRP

The casing must be hydrostatically pressure tested to the SITHP.

If the circulating medium is a gaseous fluid and /or if the wellbore effluent is expected to contain free gas, a second pressure test shall be conducted to some lesser pressure (i.e. 7000 kPa) on the top 100 metres of casing to indicate any obvious visible or audible leaks using an inert gaseous medium.

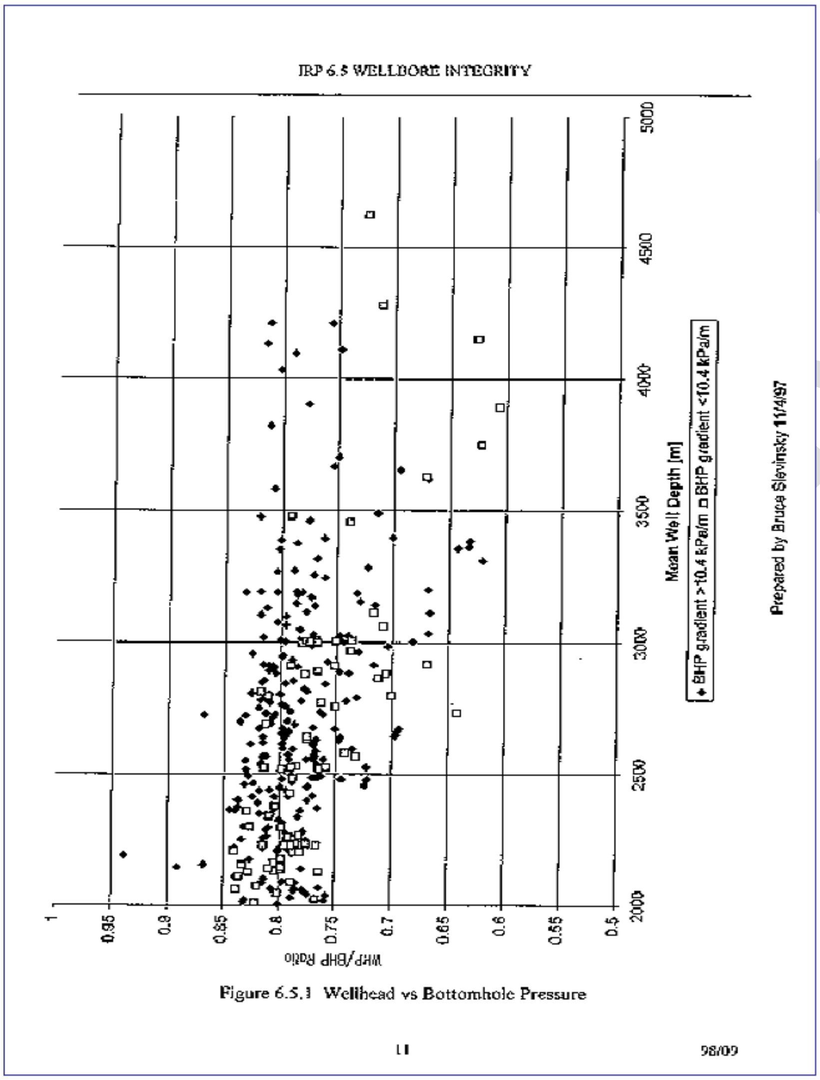
The design and current condition is to be validated by a qualified corporately authorized technical specialist and the validation is indicated by an appropriate signature on the application.

This recommended practice is applicable to over-pressured as well as normally pressured reservoirs as indicated by Figure 6.5.1, representing a cross section of equally proportioned normally and abnormally pressured reservoirs. The four wells above the 85% line represent highly overpressured reservoirs.

The casing vent should be monitored for reaction to the test and the observations recorded. A visible indication of flow from the vent side of the casing will require repairs to the casing before the underbalance drilling plan may proceed. A retrievable test packer could be used to limit the amount of gaseous medium required to carry out the pressure test.

This test is addressed in the sections of IRP 6.2 on surface equipment and BOP stacks which will include the top section of the casing and wellhead.

Figure 6.5.1 Wellhead Vs Bottom-Hole Pressure



6.5.3 Cement Integrity

IRP

A cement integrity test is to be conducted on the last casing shoe or window above the critical zone, if the casing shoe or window will be exposed to underbalanced drilling conditions. A cement integrity test is not required if the shoe is set in the critical zone.

The cement integrity test (10 minute stabilized, static) is to be conducted to demonstrate the window of re-entry or the setting depth of the last casing will hold a pressure equivalent to the maximum reservoir pressure plus 1400 kPa.

Example:

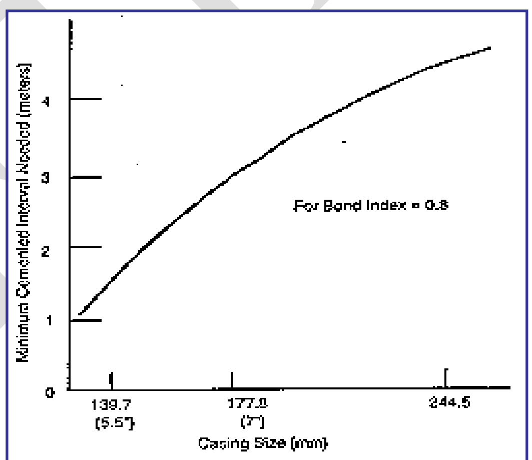
Reservoir Pressure + 1400 kPa head = 22 600 kPa

Hydrostatic Pressure = 20 000 kPa

Therefore, surface pressure required = 2600 kPa

A segmented cement bond log is required to confirm hydraulic segregation through adequate cement bond on either side of the casing window. This is required to prevent potential crossflow to the wellbore from adjacent zones behind the casing. A bond index of 80 percent is generally accepted cut-off for hydraulic isolation. The minimum cemented interval with 80% bond index necessary for hydraulic isolation varies with casing size as shown in Figure 6.5.2 below.

Courtesy Schlumberger of Canada



Courtesy Schlumberger of Canada

Figure 6.5.2 - Minimum Cemented Interval at 80% bond index.

6.5.4 Wellhead Integrity

IRP

The wellhead must be inspected to verify it conforms to ARP 2.1 Appendix 5 and is consistent with regulatory requirements such as AEUB Interim Directive ID 90-1 Section 7.3.5.

Production Specification Level of the wellhead and the secondary spool must meet regulatory requirements such as AEUB Interim Directive ID 90-1.

Pressure integrity must be confirmed with a pressure test conforming to ARP 4.

If casing is uncemented to surface, the surface casing vent should be connected with a piping system to the surface circulating system and equipped with a continuous monitoring system. Should communication to the annulus be indicated, bleed the pressure and fluids to the surface circulating system, terminate the drilling operation and secure the well.

6.5.5 Open Hole Section Above The Target Zone

IRP

Any open hole interval between the last casing seat or the casing window of a re-entry must meet the intent of regulatory requirements such as AEUB Interim Directive ID 87-2, Section 7.3.11 with the understanding that the open hole section will have the stability to withstand an underbalance condition.

All potable water zones must be isolated from the open hole section that is being drilled underbalanced.

Note:

AEUB Interim Directive ID 87-2, Section 7.3.11 states:

"(1) Intermediate casing shall be set to an appropriate point above the zone from which the sour gas or oil is expected

(2) Notwithstanding (1), upon application the Board may waive the requirements for intermediate casing providing

a. the geological prognosis of the proposed well is well established and it offsets existing development,

b. no significant lost circulation is expected,

c. normal formation pressures are expected, and

d. the wellbore (surface casing and open hole section) integrity will be evaluated prior to penetrating the critical zone and found satisfactory."

Appendix I - Casing Design Check Of Existing Casing String

Refer to Guideline outlined in 6.5.2.2.1, Casing Wear Assessment

The following example is for 177.8 mm, L-80, LT&C casing.

Existing Casing	Nominal		Section		Cumulative	
	Safety Factors				Load In Air Burst (daN)	Load In Air (daN)
	Wall Depth (m)	Thickness (mm)	Collapse	Tension		
43.2 kg/m	0	2.0	1.46			131056.1
43.2 kg/m	300	10.36	2.22		12697.65	
34.2 kg/m	300	1.63	1.13			118358.4
34.2 kg/m	1600	8.05	1.03	2.60	43638.61	
38.7 kg/m	1600	1.47	3.20	1.29		74719.8
38.7 kg/m	2900	9.19	1.01	8.90	49324.51	
43.2 kg/m	2900	1.31	10.27	1.46		25395.3
43.2 kg/m	3500	10.36			25395.3	

- The casing weight changes at 1600 and 2900 m are driven by collapse and the change at 300 m is driven by tension.
- The working stress design requirements are as per AEUB Guide 10.

Assumptions for Sample Calculations:

1. For this example, uniform casing wall thickness loss of 15% (typical wear would be removal of material from one side, i.e. crescent-shaped wear).

2. Confirmed top of cement 1350 m, therefore the casing integrity must be checked from 1500 m to surface.

3. The producing formation pressure is 37,100 kPa.

4. The required design pressure is 85% of the formation pressure
= (0.85 x 37,100 kPa) = 31,535 kPa

Burst Calculation

Burst calculation for casing for 177.8 mm, 34.2 kg/m, L-80, LT&C

$$Pm = (1 - C) \times 2(SMYS) \times \frac{t}{D} \quad \text{(in kPa)}$$

Where:

Pm = maximum burst design capacity for the casing.

C = accuracy of inspection as a fraction

T = actual casing wall thickness (mm), (reduced from nominal by any general wall reduction. i.e. casing wear).

SYMS = specified minimum yield strength (kPa).

D = outer diameter of casing (mm).

Pc = expected maximum collapse pressure of the casing (kPa).

<u>Data:</u>

D = 177.8 mm

t = 6.84 mm (measured from inspection log), therefore casing wear of 1.2 mm

SYMS = 55l,581 kPa

C = 2% inaccuracy of inspection for wall thickness

$$Pm = (1 - 0.02) \times 2\,(551{,}581) \times \frac{6.84}{177.8}$$

$$= 41{,}590 \text{ kPa}$$

Required Burst = 0.85 x formation pressure

$$= 0.85 \times 37{,}100 \text{ kPa}$$

$$= 31{,}535 \text{ kPa}$$

$$\text{Safety Factor in Burst} = \frac{41{,}590}{31{,}535}$$

$$= 1.32$$

Collapse Calculation

There are four API Collapse equations outlined in API Bulletin 5C3. The equation to be used depends on grade and D/t ratio.

$$\frac{D}{t} = \frac{177.8}{6.84} = 25.99$$

Data:

From API 5C3,

F = 1.998

G = 0.0434

SYMS = 80,000 psi

$$Pc = SYMS\left[\frac{(F)}{D/t} - G\right] \text{ psi}$$

$$= 80{,}000\left[\frac{1.998}{25.99} - 0.0434\right] \text{ psi}$$

= 2677 psi

= 18,457 kPa

The highest stress in the top section of 177.8 mm, 34.2 kg/m, L-80, LT&C is at 300 m and 1500 m. The tension load is 118,358 daN and 74,800 daN respectively. The axial stress is 203,695 kPa. The equations to decrease the collapse capacity due to tension can be found in API Bulletin 5C3, July 1989, Pages 8 and 9, Section 1.1.5.

Derated Collapse at 300 m = 13,375 kPa
Derated Collapse at 1500 m = 15,306 kPa

Data:
Drilling Mud Density: 1100 kg/m^3
Collapse Load at 300 m = Depth x Density x 0.00981
= 300 m x 1100 kg/m^3 x 0.00981
= 3237 kPa

Collapse Load at 1500 m = 16,186 kPa

SF in Collapse at 300 m = $\frac{13375}{3237}$ kPa = 4.13

SF in Collapse at 1500 m = $\frac{15306}{16186}$ kPa = 0.94

The casing design fails in collapse at 1500 m. In order to qualify, the casing must be reset in the slips to lower tension load to approximately 45,000 daN at 1500 m or 101,000 daN surface load. Since the stresses are based on the casing weight in air, the actual load with buoyancy may actually be approximately 100,000 daN.

Tension Calculation for Worn Casing

Tension design was constrained by strength of connection.

Data:

Tension capacity of the connection (new casing 177.8 mm, 34.2 kg/m, L-80, LT&C) = 193,000 daN, equivalent t = 6.5 mm.

The wear on the casing was 1.2 mm; therefore, if the wear was at the connection,

t = 5.3 mm

where: SMYS = 551,581 kPa

D = 177.8 mm

T = 5.3 mm

$$\text{API Tension} = \text{SMYS} \times \frac{\pi}{4} \left[D^2 - (D - 2t)^2\right] / 10^6$$

= 551,581 kPa x 0.0002782 m^2

= 1584.25 kN

= 158,425 daN

The weakest point in the existing casing design is at 300 m in 177.8 mm, 34.2 kg/m, L-80, LT&C, where the Tensile Load = 118,358 daN, based on the tensile load from point of assessment to total depth.

$$\text{Therefore: S.F.} = \frac{158{,}425 \text{ daN}}{118{,}358} = 1.34$$

Appendix II - Pitting Evaluation Examples

The following examples use the pit depth evaluation decision tree at the beginning of this document, for an in-service L-80 casing.

<u>Assumptions</u>

Casing is standard API L-80, 34.2 kg/m, with a nominal wall thickness of 8.05 mm and an OD of 177.8 mm.

Casing wear may be present.

Pitting may be found within casing wear region.

Various pitting depths were identified but length cannot be distinguished.

Proven inhibitors may or may not be used.

Casing has already passed structural evaluation.

Case One

Data:

- no general wall thinning was found. Wall thickness, t = 8.05 mm
- maximum pit depth found, d = 4.0 mm
- no inhibition will be used, therefore z = 1.5 mm
- expected internal pressure ratio, R = 0.7

Step One - compare maximum limit:

$$\frac{d + z}{t(1-C)} = \frac{(4.0 + 1.5)}{8.05} = 0.68 < 0.8$$

Passes. Determine minimum limit.

Step Two - compare minimum limit:

$$R = \frac{P}{Pm} = 0.7 > 0.525$$

Does not pass. Determine actual limit

Step Three - compare actual limit:

$$\frac{1.5\ (1.1 - R)}{(1.1 - \frac{R}{10})} = 0.58$$

which is less than limit established in Step One and therefore **casing** is **rejected** as a candidate for this operation.

Case Two

Data:

- same as for Case 1, except that a proven effective inhibitor is used
  so that z = 0.2 mm

Step One - compare maximum limit:

(d + z) / t(1 - C) = (4.0 + 0.2) / 8.05 = 0.52 < 0.8

Passes, go to Step Two.

Step Two - compare minimum limit:

R = 0.7 > 0.525

Does not pass, compare actual limit

Step Three - compare actual limit:

1.5 (1.1 - R) / (1.1 - R / 10) = 0.58 > 0.52

therefore, **casing passes** and can proceed with pressure test.

Case Three

Data:

- casing wear at 900 m, t = 6.04 mm (including inspection accuracy).
- maximum pit depth found is 2.4 mm; d = 2.4 mm
- no inhibitor will be used; z = 1.5 mm
- expected internal pressure ratio, R = 0.8

Step One - maximum limit compared:

$(d + z) / t(1 - C) = (2.4 + 1.5) / 6.04 = 0.65 < 0.8$

Pass, determine minimum limit.

Step Two - minimum limit compared:

$R = 0.80 > 0.525$

Does not pass, determine actual limit

Step Three - actual limit compared:

$1.5 (1.1 - R) / (1.1 - R / 10) = 0.44 <$ max limit = 0.65

therefore, casing fails as a candidate

Case Four

<u>Data</u>:

- casing wear at 900 m, $t = 6.04$ mm (including inspection accuracy)
- -maximum pit depth found is 1.2 mm; $d = 1.2$ mm
- no inhibition will be used; $z = 1.5$ mm
- expected internal pressure ratio, $R = 0.75$

Step One - maximum limit compared:

$(d + z) / t (1 - C) = (1.2 + 1.5) / 6.04 = 0.45 < 0.8$

Pass, determine minimum limit

Step Two - minimum limit compared:

$R = 0.75 > 0.525$

Does not pass, determine actual limit

Step Three - actual limit compared:

$1.5 (1.1 - R) / (1.1 - R / 10) = 0.51 >$ max limit $= 0.45$

therefore, **casing passes**; proceed with pressure test

Case Five

<u>Data</u>:

- nominal wall intact; $t = 8.05$ mm (including inspection accuracy)
- maximum pit depth found is 2.5 mm; $d = 2.5$ mm
- no inhibition will be used therefore $z = 1.5$ mm
- expected internal pressure ration, $R = 0.5$

Step One - compare maximum limit:

$(d + z) / t (1 - C) = (2.5 + 1.5) / 8.04 = 0.50 < 0.8$

passes, determine minimum limit

Step Two - compare minimum limit:

$R = 0.5 < 0.525$

therefore **casing passes**; proceed with pressure test

6.5.6 List Of References

1. AEUB, Interim Directive 87-2, Section 7.3.11, Calgary, Alberta.

2. AEUB, Drilling Rig Inspection Manual, June 1995, Calgary, Alberta.

3. API, Formulas And Calculations For Casing, Tubing, Drill Pipe and Line Pipe Properties, Bulletin 5C3, July 1989, pages 8 and 9, Section 1.1.5, Dallas, Texas.

4. ARP Volume l, Alberta Recommended Practices for Drilling Critical Sour Wells, July 1987, Calgary, Alberta.

5. ARP Volume 2, Alberta Recommended Practices for Completing and Servicing Critical Sour Wells, April 1989, Calgary, Alberta.

6. ARP Volume 4, Alberta Recommended Practices for Well Testing and Fluids Handling, June 1993, Calgary, Alberta.

7. ASME, B31G, Manual for Determining the Remaining Strength of Corroded Pipelines, June 1991, New York, N.Y.

6.6 Circulation Media

6.6.1 Scope

6.6.1.1 The Circulating Media IRPs have been developed by the Drilling and Completions Sub-Committee for Critical Sour Underbalanced Drilling with consideration for critical sour underbalanced drilling activities and the environment, recognizing the importance of the circulating media system as it relates to these operations. Circulating media system design forms an integral part of the preplanning and programming for a critical sour underbalanced well. The following recommended practices have been developed to provide guidelines for media properties, kill fluids, corrosion/erosion, scavengers/inhibitors, monitoring, fluids handling, storage, and trucking, and waste treatment/disposal.

6.6.1.2 This IRP is part of a series. For the overall intent of, and as a general reference to, the whole series, please refer to IRP 6.0. The recommendations contained in this IRP provide operators with industry-endorsed advice, and are intended to be applied in association with all existing government regulations as well as other corresponding IRPs. While strict legal enforcement of recommended practices is not desired or possible, the DACC believes that such practices place considerable onus on the legally responsible party to comply or otherwise provide a technical equivalent or better solution.

6.6.1.3	While the recommendations set out in the IRPs are meant to allow flexibility, the need for exercising competent technical judgment is a necessary requirement to be employed concurrently with their use. It remains the responsibility of the user of the IRP to judge its suitability for a particular application. While every effort has been made to ensure the accuracy and reliability of the data contained in the IRP, and to avoid errors and omissions, DACC, its subcommittees, and individual members make no representation, warranty, or guarantee in connection with the publication or the contents of any IRP recommendation, and hereby disclaim liability of responsibility for loss or damage resulting from the use of the IRP, or for any violation of any statutory or regulatory requirement with which an IRP recommendation may conflict.
6.6.1.4	In cases of inconsistency or conflict between any of the recommended practices contained in this IRP and the applicable legislative requirements, the legislative requirement shall prevail.

6.6.2 Media Properties

6.6.2.1 Flammability & Explosive Limits

IRP	**Explosive limits must be established for all circulating media systems which have the potential to introduce oxygen into the circulating stream. If explosive limits are not clearly defined, systems which have the potential to introduce oxygen to the circulating stream must not be used.**
IRP	**Explosive limits must be documented and posted next to the oxygen monitoring system for all circulating streams which contain oxygen. Steps must be taken to ensure that these limits are never reached throughout underbalanced drilling (UBD) operations.**
Note:	The circulating media for purposes of this IRP includes both injected and produced fluids as well as their mixtures.

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

6.6.2.2 Hydrates

IRP	**Measures must be taken to prevent hydrate formation unless it can be proven that hydrates cannot be formed in the gas stream expected to flow from the well while drilling underbalanced. These measures will include, but are not limited to, the use of surface line heaters and the injection of fluids to appropriately control the freezing point of the circulated/produced fluid stream.**

6.6.2.2.1	Hydrate plugs are an ice-like crystalline structure made up of water and hydrocarbon gases. Due to the chemical composition of this structure, its freezing point is well above the normal freezing point of fresh water. These plugs can form when a gas/water mixture flows through a pressure drop which causes a localized cooling effect. A solid structure may start building up, and if not controlled can completely bridge off the flowing area. Pressure drops may occur at various locations within a circulating path such as inside tubulars, across choke manifolds, across flow path diameter changes, etc.
6.6.2.2.2	When exposed to the appropriate pressure and temperature conditions, hydrates can form in a gas well, or a high gas content oil well, as it is being drilled underbalanced. Hydrates limit the ability to produce fluids, inject fluids and ultimately control the well safely.
6.6.2.2.3	If methanol is introduced into the system, consideration must be given to changes in flammability limits.

6.6.2.3 Carrying Capacity

6.6.2.3.1

A multiphase flow simulation of the returning flow stream must be performed to ensure adequate hole cleaning through proper design and implementation of the underbalanced circulation system.

6.6.2.3.2

The flow regime of multiphase circulating streams is typically more complex than for single-phase circulating streams. To ensure adequate hole cleaning while drilling with a multiphase system, a proper understanding of cuttings transport in this environment is necessary. Inadequate hole cleaning could result in the circulation returns path becoming packed-off, limiting the ability to circulate and thereby resulting in a potential reduction of well control. Loss of the ability to circulate due to cuttings pack-off will also likely result in a "stuck" drill string.

6.6.2.4 Separation Qualities

IRP

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

6.6.2.4.1

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

6.6.2.4.2

Formation of emulsions may be a concern with specific circulating media/produced fluids combinations. This may result in pumping difficulties, which in extreme cases could result in plugged suction lines. Fluid density control may also be compromised when emulsions form. Operational practices such as the use of demulsifiers, line heaters, constant removal of emulsified fluids, etc, should be considered where emulsion formation is anticipated to be a problem. If demulsifiers or other chemicals are introduced into the system, consideration must be given to changes in flammability limits.

6.6.2.4.3

The use of viscosified or hydrocarbon based fluids in underbalanced drilling operations may result in gas entrainment. Gas entrainment may result in vapour locking of fluid pumps, lack of fluid density control as well as re-circulation of produced gases. Where the system is open to the atmosphere (eg: open mud tanks, drill pipe on connections), entrained gas may break out causing hazards to workers. These areas must be monitored and operations stopped if worker exposure limits are exceeded. Refer to IRP 6.7 Site Safety.

6.6.2.5 Computability with Other Systems

IRP

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

IRP

The chemical composition of any additives to be used in the circulating media must be examined to ensure they do not contain constituents which could result in premature failure of elastomers, seals, etc, either alone or in combination with produced fluids. Refer to IRP 6.2 for detailed requirements.

IRP

If H_2S re-circulation is anticipated, operational issues regarding H_2S computability with metallic components, elastomers and fluids handling/storage equipment must be addressed.

6.6.2.5.1

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

6.6.2.5.2	Sour fluids may be stripped of H_2S by employing a properly designed scrubber system. Such a system is recommended for drilling fluids containing H_2S which are to be reinjected into the wellbore.

6.6.3 Kill Fluids

IRP	**Operational and/or safety considerations may require the killing of a well which is being drilled underbalanced. A minimum of 1.5 hole volumes of kill fluid must be available at all times for immediate circulation to the wellbore. The kill fluid must provide for a minimum 1500 kPa overbalance when spotted.**
IRP	**Degradation of the kill fluid (gel strength if weighting material is required), lost circulation issues, and the effects of winter operations must be taken into account when managing the kill fluid system.**
IRP	**Two pump units must be installed on-site so as to ensure continuous deliverability of the kill fluid if required. Pump units must be sized assuming worst case conditions for the zone(s) to be drilled through so that required rates and pressures can be provided to kill the well.**
6.6.3.1	If weighting or lost circulation material (LCM) material is required to kill the well, consideration should be given to the ability to successfully circulate these materials through the bottom hole assembly (BHA). Circulating subs above flow restrictions may be necessary.

6.6.4 Corrosion And Erosion

IRP

Steps must be taken to minimize the corrosive potential of the circulating media and produced fluids when corrosive conditions exist. These can include minimizing/eliminating oxygen, carbon dioxide, hydrogen sulfide, and chlorides in the injection stream; adding scavengers and/or inhibitors into the injection stream; or the use of corrosive resistant materials. The effectiveness of corrosion control steps must be established prior to initiating underbalanced drilling operations.

6.6.4.1

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

6.6.4.2

Erosion is the wear of material by mechanical means. Solids contained in the produced fluids stream typically result in erosion of surface flow control equipment. Factors that affect erosion rates include concentration, type and size of solids, and transport velocity. Refer to IRP 6.4 Surface Circulating System for recommendations regarding erosion monitoring and control.

6.6.5 Monitoring

6.6.5.1 H_2S Monitoring

IRP

Recommendations for H_2S monitoring have been discussed in ARP 1.10, 2.12. These references deal with general requirements, equipment, communications etc, and together with regulatory requirements, such as outlined in OH&S Regulations, are to be followed.

6.6.5.2 Oxygen Monitoring

IRP

The oxygen content of any injection stream which has the potential to introduce oxygen into the circulating stream must be monitored to ensure that explosive limits are never reached during UBD operations. Continuous read out monitors are required and calibration reports must be available on-site.

6.6.5.3 Flow Rate Monitoring

IRP

Circulation parameters must be monitored to ensure that the system capabilities are not exceeded. Parameters that require monitoring include, but are not limited to: gas and liquid production rates, injection pressures, wellhead annular pressure, bottom-hole annular pressure, and surface volumes.

6.6.5.4 Corrosion Monitoring

IRP	**A corrosion monitoring program must be in place and designed appropriate for the corrosion risks of the fluid being used.**
6.6.5.4.1	When drilling under corrosive conditions the circulating media must be monitored to provide for an indication of corrosion and to determine the effectiveness of corrosion control measures being utilized.
6.6.5.4.2	Corrosion indicators (rings, coupons, or suitable alternatives) are to be installed at appropriate/practical circulating stream locations (surface piping, drillpipe, BHA, etc) to measure corrosion rates if operating under potentially corrosive conditions. Corrosion indicators are to be regularly inspected to establish corrosion rates.
6.6.5.4.3	Consideration should be given to taking precautionary steps such as regularly tripping to inspect the drill string / BHA to establish the severity of downhole corrosive conditions when drilling in an area where the corrosive environment is not thoroughly understood.

6.6.5.5 Erosion Monitoring

IRP	**Surface equipment exposed to high pressures and/or high flow velocities must be inspected on a regular basis using industry accepted practices to monitor for materials erosion. Refer to IRP 6.4 Surface Circulation System for detailed recommendations.**

6.6.6 Fluids Handling, Storage And Trucking

IRP

Operators must have site specific plans in place for collection, transportation and disposal of hazardous fluids and/or gases.

6.6.6.1 Fluids Handling System

IRP

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

6.6.6.2 On-Site Storage Capacity

IRP

Sufficient storage capacity must be available to temporarily store produced fluids during drilling operations. Flush production is to be considered in determining storage requirements. Alternatively, provisions for fluid injection or offsite fluids transport are to be in place if on-site facilities do not have the capacity to handle the necessary volumes.

6.6.6.2.1

Consideration should be given to providing excess storage capacity in the event of unforeseen circumstances, such as inclement weather conditions, which may compromise proper fluid handling abilities.

6.6.6.2.2	It is recommended that sour fluid volumes stored on location be minimized for added safety of on-site personnel.
6.6.6.3 Fluids Transport	
IRP	**Spill contingency plans for storage, loading, unloading and transporting fluids must be included in the operators site specific Emergency Response Plan. Refer to IRP 6.1 Planning for detailed Emergency Response Plan requirements.**
6.6.6.3.1	Refer to existing industry documents (i.e. ARP Volume 4) and regulatory requirements regarding the transportation of hazardous fluids.
6.6.7 Waste Treatment/Disposal	
IRP	**A waste management plan for produced liquids and drilled solids must be developed prior to commencement of UBD operations. This plan should consider the volume of solids that will be generated and their residual oil, chloride and H_2S content.**
6.6.7.1	If a third party waste handler will be used for disposal they should be contacted in advance to determine their sour fluids and sour solids handling capabilities.

6.6.8 List Of References

1. ARP Volume l, Alberta Recommended Practices For Drilling Critical Sour Wells, July 1987, Calgary, Alberta.
2. ARP Volume 2, Alberta Recommended Practices For Completing and Servicing Critical Sour Wells, April 1989, Calgary, Alberta.
3. ARP Volume 4, Alberta Recommended Practices For Well Testing And Fluids Handling, June 1993, Calgary, Alberta.
4. OH&S, Alberta Occupational Health and Safety Statues and Regulations, Edmonton, Alberta.
5. SPE, Paper 37067, High Pressure Flammability of Drilling Mud/Condensate/Sour Gas Mixtures in De-Oxygenated Air for Use in Underbalanced Drilling, November 1996, Calgary, Alberta

6.7 Site Safety

6.7.1 Scope

6.7.1.1 The Site Safety IRPs have been developed by the Drilling and Completions Sub-Committee on Critical Sour Underbalanced Drilling to address the safety issues and provide minimum standards for site safety during the critical sour underbalanced drilling operation.

6.7.1.2 The recommendations in this IRP supplement existing ARPs, and are based on industry standards and regulatory requirements. In cases of inconsistency between any of the recommended practices contained in this IRP and applicable legislation, the legislative requirements shall prevail.

6.7.1.3 Every effort has been made to ensure the accuracy and reliability of the data contained in the IRP and to avoid errors and omissions, DACC, its sub-committees and individual members make no representation, warranty, or guarantee in connection with the publication or the contents of any IRP, or for any violation of any statutory or regulatory requirement with which an IRP recommendation may conflict.

6.7.2 General Requirements

6.7.2.1 Pre-Job Orientation

IRP

Prior to any work commencing on a critical sour well, a site-specific orientation must be reviewed with all on-site personnel involved in the operation. Documentation supporting this orientation must be kept at the wellsite.

Topics for review and discussion shall include, but not be limited to:

- Hazards involved, such as pressures, H_2S percentage, etc.
- Emergency preparedness
- Site specific equipment
- Communications
- Security
- Worker status (as to critical/non-critical) and subsequent responsibilities

6.7.2.2 Lease Lighting

IRP

The lighting at the wellsite must be sufficient to enable work to be conducted safely, and to allow personnel to:

- leave the wellsite safely,
- initiate emergency shutdown procedure, and
- perform a rescue

The intent of this IRP is that in addition to the standard rig lighting, extra lighting be provided to illuminate all areas where work is being conducted on the lease area.

6.7.2.3 Communications

IRP

Prior to drilling into the critical sour zone, open channel radio communication is required on-site. All radios require the same frequencies for concurrent operations.

The intent of this IRP is to maintain operational efficiency for concurrent on-site operations.

6.7.2.4 Safety Supervision

IRP

Prior to drilling into the critical sour zone, a minimum of two H_2S Safety Supervisors are required on a 24-hour basis, each working no more than 12-hour shift while on location.

6.7.2.5 Site Access Control

IRP

Prior to drilling into the critical sour zone, two dedicated security personnel are required on a 24-hour basis, each working no more than a 12-hour shift while on location, to control access to the lease area and to maintain a record of the personnel on the lease.

The number of personnel on the lease area during the critical sour underbalanced drilling operation should be kept to a minimum, and restricted to those directly involved in the operation. Visitors must be briefed on emergency procedures before entering the lease area, and their visitation kept as short as possible.

6.7.2.6 Hydrogen Sulphide Equipment

IRP

Prior to drilling into the critical sour zone, adequate air monitoring, breathing air and rescue equipment must be on-site, installed, tested, and ready for service. The equipment requirements shall include, but not be limited to, the equipment list in Appendix I.

6.7.2.7 Medical Services

Special Considerations

Prior to drilling into the critical sour zone, an Industrial First Aid Attendant and emergency conveyance vehicle should be on-site when Emergency Medical Service (EMS) is greater than 20 minutes surface travel time from the lease location.

The intent of this guideline is to provide adequate on-site medical attention in the event of a knockdown. Although this requirement is not mandatory, operators need to assess the risk of personal injury and determine services required.

6.7.2.8 Equipment Placement

IRP

On-site equipment must be placed in a manner allowing for two routes of egress with consideration for prevailing wind direction.

The intent of this IRP is to allow safe egress in the event of a gas release.

6.7.3 Fire Protection

6.7.3.1 Flammable Fluids

IRP

The following minimum fire protection equipment, based on the level of flammability risk (Table 6.7.1) is required for critical sour underbalanced drilling:

Flammability Risk	Fire Protection Equipment
Low	**four (4) 40-BC type extinguishers**
Moderate	**four (4) 40-BC type extinguishers** **50 kg ABC Wheel Unit extinguisher** **Burn Kit**
High	**four (4) 40-BC type extinguishers** **Fire truck and personnel (refer to Appendix II)** **Burn Kit**

Table 6.7.1 Risk Categories of Flammable Fluids

Risk level	flammability			
	rvp	**api**	**ocp**	**ccfp**
Low	< 7 kpa	< 50	> 12ºC	> 12ºC
Moderate	7 - 14 kpa	> 50	> 0ºC	> 0ºC
High	14 kpa	****	< 0ºC	< 0ºC

The intent of this IRP is to provide fire protection services in the event of a flash fire. The risk level of the pumping fluid may be different from that of the produced fluid. If either produced or pumping fluid is a high risk fluid then the identified fire protection equipment is required.

6.7.3.2 Fire Retardant Clothing

IRP

Fire retardant clothing must be worn by all personnel involved in the critical sour underbalanced drilling operation on the wellsite.

Appendix I Breathing Air / Gas Detection Equipment

The minimum basic equipment for a compressed breathing air and gas detection shall include:

- 2400 cu ft breathing air supply
- 2 - two-stage high pressure regulators
- 2 - six-outlet air header assemblies
- 8 - supplied air breathing apparatus c/w egress cylinders
- 8 - self-contained breathing apparatus
- 8 - spare 45 cu ft compressed breathing air cylinders
- 2 - 30 m x 10 mm I.D. special hose c/w quick couplers
- 6 - 30 m x 6 mm I.D. special hose c/w quick couplers
- 1 - 610 mm x 760 mm H_2S warning sign on tripod
- 2 - wind direction indicators
- 1 - multi-gas detector c/w H_2S detector tubes
- 2 - continuous H_2S/LEL/O portable monitors
- 1 - continuous H_2S/LEL gas detection system complete with alarms and 4 detection sensors

Appendix II Minimum Fire Truck Requirements

The minimum fire truck requirements shall include the following:

Continuous Foam Unit

- 0.475 m^3 (125 gallons) ATC foam concentrate
- 680 kg (1500 lbs) Purple “K” Dry Chemical System c/w 30 m discharge hose
- 1.89 m3/min (500 gpm) centrifugal Certified Fire Pump c/w
- one 65 mm discharge port,
- two 38 mm discharge ports,
- one 100 mm suction port

Water Truck

- 16 m3 (100 barrels) fresh water or legal seasonal load
- two 75 mm drafting ports

Foam Application Rating

- Based on the NFPA Standard 11 Application Rate of 6.5 l/min/m2 for non-polar hydrocarbons

Personal Protective Clothing

- Fire Fighters will don personal protective equipment that conforms to NFPA Standards 1971, 1972, 1973, 1974.

6.7.4 List Of References

1. AOH&S, Alberta Occupational Health and Safety Act and Regulations, Edmonton, Alberta.
2. ARP Volume I, Alberta Recommended Practices for Drilling Critical Sour Wells, July 1987, Calgary, Alberta.
3. NFPA, National Fire Protection Association Standards, 1987, Quincy, Mass.
4. PSAC, Industry Recommended Practice for Pumping Of High Flash Hazard Hydrocarbons, 1998 Draft Edition, Calgary, Alberta

6.8 Wellsite Supervision

6.8.1 Scope

6.8.1.1

The Wellsite Supervision IRPs have been developed by the Drilling and Completions Sub Committee on Critical Sour Underbalanced Drilling to address the issues regarding the supervisory qualifications and requirements for conducting a sour underbalanced drilling operation.

6.8.1.2

The recommendations in this IRP are based on existing ARPs, industry standards and regulatory requirements. In cases of inconsistency between any of the recommended practices contained in this IRP and applicable legislation, the legislative requirements shall prevail.

6.8.1.3

The recommendations set out in this IRP are meant to allow flexibility, however, the need for exercising competent technical judgment is a necessary requirement to be employed concurrently with its use. While every effort has been made to ensure the accuracy and reliability of the data contained in the IRP and to avoid errors and omissions, DACC, its sub committees, and individual members make no representation, warranty, or guarantee in connection with the publication or the contents of any IRP recommendation, and hereby disclaim liability of responsibility for loss or damage resulting from the use of this IRP, or for any violation of any statutory or regulatory requirement with which an IRP recommendation may conflict.

6.8.2 Responsibilities

6.8.2.1 Operator's Representative

IRP

The Operator will delegate a primary wellsite supervisor as having overall control in the chain of command. The Primary Wellsite Supervisor has the overall responsibility to his company for the well and for compliance with all regulations relating to the operation of the well. He must establish a chain of command and a line of communication at the wellsite. The primary wellsite supervisor must be onsite (or readily available) at all times.

6.8.2.2 Rig Contractor's Representative

IRP

The Rig Contractor's representative has the responsibility to the Operator's representative for the operation of the rig during the drilling of the well which provides for a single chain of command for the well operation. He is responsible to his company for the rig equipment and crew, and for compliance with all regulations relating to the operation of the rig.

6.8.2.3 Shared Responsibility

IRP **The day-to-day operations on a lease are a shared responsibility between the contractor's and operator's representatives, but the ultimate responsibility for supervision of the well operation is assigned by the Operator to the Operator's representative.**

6.8.3 Level Of Supervision

6.8.3.1 Wellsite Supervisors

IRP **A 24 hour operation will require two supervisors, each working 12-hour shifts. The Primary Wellsite Supervisor must be delegated by the Operator as having overall control in the chain of command.**

6.8.3.2 Rig Manager

IRP **The Rig Manager must be available to the operation on a 24-hour call basis.**

IRP **The rig crews must consist of a minimum of 5 crew members for each shift.**

6.8.3.3 Safety Supervisors

IRP

A minimum of two Safety Supervisors will be required on a 24-hour basis, each working no more than a 12-hour shift.

Prior to drilling into the critical zone, safety supervisors and safety equipment must be on location. The equipment must be installed and ready for service, and crew members must be trained in the use of the equipment.

6.8.3.4 Coiled Tubing Crews

IRP

On-site Coiled Tubing personnel available to the operation on a 24-hour call basis shall include:

- one project supervisor
- one drilling engineer (if required)
- one directional tools supervisor (if required)
- The Coiled Tubing crews must consist of a minimum number of the following members for each shift:
- one shift supervisor
- three operators
- one directional tools operator (if required)

Each member must be competent to fully handle his/her individual responsibilities and to fully understand his/her responsibilities in the well control operation.

6.8.3.5 Snubbing Crews

IRP

One Snubbing Supervisor must be available to the operation on a 24-hour call basis.

The snubbing crews must consist of a minimum of 2 crew members for each shift. Each member must be competent to fully handle his/her individual responsibilities and to fully understand his/her responsibilities in the well control operation.

6.8.3.6 Testing Crews

IRP

Testing crews must consist of 3 crew members with at least 2 on-shift crew members competent in sour well testing. Each member must be competent to handle his/her individual responsibilities for the critical sour well control operation.

6.8.4 Minimum Qualifications

6.8.4.1 Operating Company Supervisors

The demands placed on office supervisors (i.e. Superintendents) of a critical sour underbalanced drilling operation are very high due to the inherent complex nature of the operation, the increased risk factor, and the larger numbers of personnel involved. Supervisors must therefore, have the technical, organizational and operational competence to meet these demands accordingly.

6.8.4.2 Primary Wellsite Supervisor

IRP

The Primary Wellsite Supervisor must have a minimum of 5 years wellsite supervisory experience, and must have supervised a minimum of 5 critical sour and/or sensitive overbalanced drilling and/or servicing operations while operations were being conducted in the sour zone. This will ensure the primary wellsite supervisor is competent in the application of existing ARPs/IRPs and Emergency Response Planning.

Since the complexity of a well generally increases with depth, the primary wellsite supervisor's previous critical sour/sensitive well experience must have been on wells of equal or greater depth when compared to the critical sour underbalanced drilling operation he/she will be supervising.

The supervisor must be prepared to substantiate his/her work history. Time forward work is to be logged by the supervisor and supported by his/her direct supervisor of the operating company.

6.8.4.3 Second Wellsite Supervisor

IRP

The Second Wellsite Supervisor must have a minimum of 5 years wellsite supervisory experience and must have supervised a minimum of 2 critical sour and/or sensitive overbalanced drilling and/or servicing operations while operations where being conducted in the critical zone. This will ensure that the second wellsite supervisor is competent in the application of existing ARPs/IRPs and Emergency Response Planning.

Since the complexity of a well generally increases with depth, the second wellsite supervisor's previous critical sour/sensitive well experience must have been on wells of equal or greater depth when compared to the critical sour underbalanced drilling operation he/she will be supervising.

The supervisor must be prepared to substantiate his/her work history. Time forward work is to be logged by the operating supervisor and supported by his/her direct supervisor of the operating company.

IRP

One supervisor must have critical sour and/or sensitive drilling experience and certification, and one supervisor must have flowing sour gas (sour well testing) experience and certification.

6.8.4.4 Rig Manager	
IRP	**The Rig Manager must have a minimum of 5 years experience as a Rig Manager, and must have been involved in 5 critical sour and/or sensitive operations (drilling or well servicing) while these wells were in the sour zone.**
6.8.4.5 Rig Crews	Each member must be competent to fully handle his/her individual responsibilities and to fully understand his/her responsibilities for the critical well control operation.
6.8.4.5.1 Drillers	
IRP	**Drillers must have a minimum of 3 years as a driller, with experience in sour well operations.**
6.8.4.5.2 Derrickmen/Motormen	
IRP	**Derrickmen/Motormen must have a minimum of 3 years rig experience, with experience in sour well operations.**
6.8.4.5.3 Floorhands	
IRP	**Floorhands must have a minimum of six months rig experience, with experience in sour well operations.**

6.8.4.6 Coiled Tubing Personnel

6.8.4.6.1 Project Supervisor

IRP

The project supervisor must have a minimum of 5 years supervisory experience and must have supervised on a minimum of 5 critical sour and/or sensitive wells while operations were being conducted in the critical zone.

6.8.4.6.2 Shift Supervisor

IRP

The shift supervisor must have a minimum of 3 years of coiled tubing operations experience, including sour well experience.

6.8.4.6.3 Operators

IRP

Coiled tubing operators must have a minimum of one year experience as an operator, and must have sour well experience.

6.8.4.7 Snubbing Personnel

6.8.4.7.1 Supervisors

IRP **Snubbing supervisors must have a minimum of 5 years experience as a supervisor and must have supervised on a minimum of 5 critical sour and/or sensitive wells.**

6.8.4.7.2 Operators

IRP **Operators must have a minimum of 3 years operating experience and must have sour well experience.**

6.8.4.8 Testing Personnel

6.8.4.8.1 Supervisors

IRP

Testing supervisors must have a minimum of 5 years experience as a supervisor and must have supervised on a minimum of 5 critical sour and/or sensitive wells.

The primary supervisor must have underbalanced drilling experience.

6.8.4.8.2 Operators

IRP

Operators must have a minimum of 3 years testing experience including a minimum of 30 days of sour well testing experience.

6.8.4.8.3 Assistants

IRP

Assistants must have a minimum of one year testing experience and must have sour testing experience.

6.8.5 Certification And Training

IRP

The minimum training requirements for on-site personnel involved in the critical sour underbalanced drilling operation are shown in Table 6.8.1.

Certification and Training Courses in this IRP refer to courses offered, or equivalent courses sanctioned by, Enform.

Abbreviated Name	**Enform Course Name**
Coiled Tubing	Coiled Tubing Course (under preparation at the time of writing, *course name assumed*)
Confined Space Entry	Confined Space Entry
Fall Protection	Fall Protection for Rig Workers
First Aid	St. John Ambulance Standard First Aid
First Line BOP	First Line Supervisor's Blowout Prevention
H_2S	H_2S Alive
Second Line BOP	Second Line Supervisor's Well Control
TDG	Transportation of Dangerous Goods
WHIMS	Workplace Hazardous Material Information System
Well Service BOP	Well Service Blowout Prevention
Well Testing	Well Testing Supervisor's Safety Course

	Operator Supervisors		Drilling Rig		Service Rig		Coiled Tubing			Snubbing		Testing		Safety Supervisor	Mud Engineer	Truck Drivers	Other** Personnel
	Drilling	Well Servicing	Crews	Manager	Crews	Manager	Crews	Shift Supervisor	Project Supervisor	Operator	Supervisor	Crews	Supervisor				
WHMIS	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
H_2S	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
First Aid	x	x	1	x	1	x	1	x	x	1	x		x	x			
TDG	x	x		x		x		x	x		x		x	x	x	x	
Confined Space	7	7	2	x	2	x	1					x	x	x		6	
Fall Projection			x	x	x	x	x	x	x	x	x			x			
Coiled Tubing*							x	x	x								
First Line BOP			3						5								
Well Services BOP		x			3	x	x	x	x	x	x						
Second Line BOP	x			x													
High Angle Rescue***			4	x	4	x		x	x	x	x			x			