Intervention & Coiled Tubing Association

ICoTA Technical Review

IRP21 R2016

Coiled Tubing Operations

September 7th , 2016

Introductions

Speakers: Eric Plante, Sam Robb

Mediator: John Misslebrook

Panel:

- Sam Robb – Coiled Tubing Operations – Trican Well Service
- Eric Plante – DACC IRP21 Review Committee – Calfrac Well Services
- Ryan Smith – Coiled Tubing BOP Manufacturer – Nexus Energy Technologies
- Ron Lasecke – Coiled Tubing Equipment Manufacturer - NOV

IRP 21 UPDATE:
COILED TUBING WELL CONTROL FUNCTIONALITIES
(A risk based approach and its implications)

Presented by: Eric Plante - IRP 21 Committee, Sam Robb – Trican Well Service

INDUSTRY RECOMMENDED PRACTICES:
WHAT

- A set of best practices and guidelines prepared by knowledgeable industry and government experts
- Technical topics related to design, construction, and operations in the oil and gas industry, based on safety management principles
- An IRP is not…
  - A practice manual
  - A regulation, act, or code

INDUSTRY RECOMMENDED PRACTICES:
IRP STATEMENT DEFINITIONS

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

These recommendations are considered to be the minimum recommended procedures and best practices necessary to carry out operations in a manner that protects people (the public and workers) and the environment.

INDUSTRY RECOMMENDED PRACTICES:
WHO

Professional associations that comprise the Drilling and Completions Committee

CAODC · CAPP · PSAC · EPAC

Logistics administrated by Enform

DACC – Drilling and Completion Committee

INDUSTRY RECOMMENDED PRACTICES:
WHERE

- An Alberta publication
- Subject Matter Experts from Western Canada appropriate to the topic
- Referenced across Canada & globally
- Increasingly regarded as the Canadian "best practices" guide
- Draw from global oil & gas industry experiences

INDUSTRY RECOMMENDED PRACTICES:
WHY

- Why Now?
  - Reservoir pressures, pumping pressures and rates today are significantly higher than when IRP21 was first drafted
    - Increased number of well interventions at higher pressures and potential rates significantly increases operational risk
    - Increased public scrutiny of our industry – can’t afford any well control incidents
- Why Be Involved?
  - To create a strong and progressive industry
    - An opportunity for industry to collaborate and share wisdom
- Why Comply?
  - Support industry accepted practices
    - IRP 21 is a common standard referenced by regulators, oil & gas companies and service companies
    - Goal of self-regulation

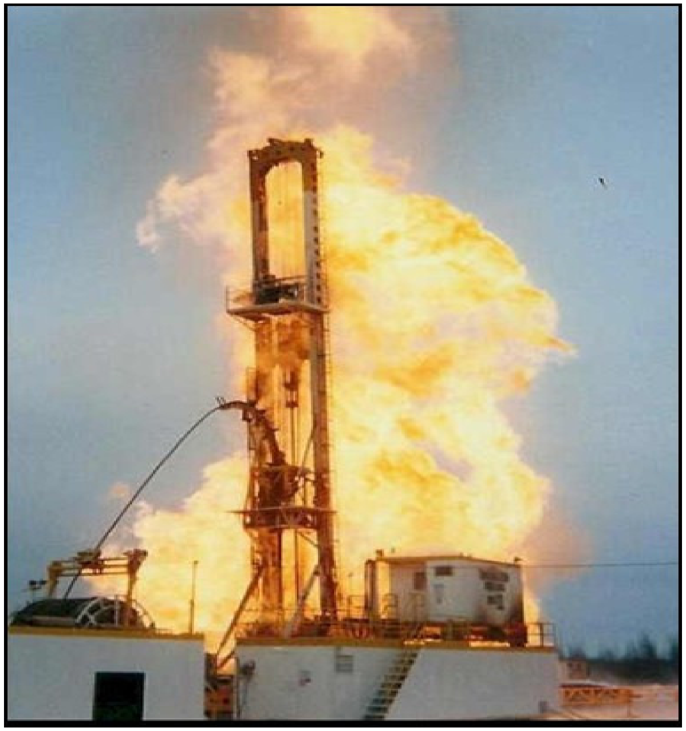
IRP 21: COILED TUBING OPERATIONS
LIMITED SCOPE REVIEW

"As there seems to be some potential concern with the increased recommendations offered within the Proposed IRP21, I think it is also worthwhile to mention that the evolution of the industry and achievable reservoirs has resulted in a need for more guidance and risk mitigation measures to be incorporated. With tight gas and Shale formations of 10,000 (+) psi being plausible to complete due to the advancements in technology and becoming more common, not having a structure in place will eventually lead to a catastrophic incident. Being diligent requires us to evaluate the risks and implement a minimum level of controls."

IRP 21 Committee Member

IRP 21-coiled tubing operations: Background

- Initiated 2009, released September 2010
- Deficiency in guidelines for high pressure wells reported to Enform March, 2015
  - DACC agreed and committee formed May 2015
  - All service companies, oil & gas companies and regulators invited to participate
  - Scope limited to well control for well servicing only – drilling not addressed
- Risk-Based Approach
  - Frequency is low but consequences are high



IRP 21 UPDATE – COILED TUBING OPERATIONS:
WHO'S INVOLVED

Government:

Lonestar Energy Services

Other Subject Matter Experts:

IRP 21 UPDATE – COILED TUBING OPERATIONS:
DEVELOPMENT AND STATUS

Dates	Activities
07-Apr-2015	IRP initiated
May-2015	Call for volunteers open
June-2015	Call for volunteers closed
23-Jun-2015	First meeting
26-Aug-2015	New IRP formatting reviewed by committee
26-Oct-2015	Version 2 of proposed changes for committee debate
16-Dec-2015	Version 3 of proposed changes for committee debate
4-Feb-2016	**1st complete draft sent to committee review**
16-Mar-2016	2nd draft complete and sent to industry for review
8-Jun-2016	3rd and final draft with industry comments sent out for additional review
15-Aug-2016	Feedback period closed
19-Sept-2016	DACC 30 day review
19-Oct-2016	**DACC Sanction vote**

IRP 21 – COILED TUBING OPERATIONS
WELL CONTROL RISK MANAGEMENT PROCESS

AS RISK (consequences) INCREASE,
NUMBER OF BARRIERS (backups) INCREASE

Original IRP 21
- **For sour service, this was increased annular barriers**
- **For Class 2 wells, a shear and blind were added**
- **For Class 3 only an annular was added**

Revised IRP 21
- **For sour service, this is increased annular barriers**
- **As wellhead pressure increases, number of backup wellbore barriers increase**

IRP 21 – COILED TUBING OPERATIONS:
WHAT IS A BARRIER?

IRP Samples of recommended BOP configurations are shown in this section. Best efforts have been made to represent configurations that are typical in the operating industry but these configurations should not be considered exclusive of alternate configurations that provide equivalent or additional levels of well control (e.g. through combination ram functions or alternate pipe sealing methods).

- One complete barrier is either a BLIND RAM or an ANNULAR SEAL <u>with</u> a CHECK VALVE <u>and</u> TUBING INTEGRITY
- A stripper, pipe ram and single check valve is only 1 complete barrier.
- A stripper, 2 pipe rams and double check valve is only 2 complete barriers

IRP 21 – COILED TUBING OPERATIONS
VARIATIONS TO FULFILL A BARRIER

Alternative configurations are acceptable as long as they manage the potential risks through sound engineering and procedural considerations, and meet or surpass the intent of the recommendations

Barrier Type
- **BOP**
- **Stripper**
- **Annular Bag**

BOP Type
- **Single**
- **Tandem**
- **Quad**

Ram Type
- **Single Function**
  - **Blind, Shear, Slip, Pipe**
- **Combination Function**
  - **Blind/Shear, Slip/Pipe**

IRP 21 – COILED TUBING OPERATIONS
WELL CONTROL RISK MANAGEMENT PROCESS

Well Servicing Pressure Categories are more fit-for-purpose than depth or casing flange categories.

Original IRP 21

- **Followed Alberta well classifications (mostly)**
- **Did not match BC, Saskatchewan or Manitoba**
- **Mixture of pressure, H_2S, density and flow rate**
- **Everything over 21 MPa treated the same**

Revised IRP 21

- **Servicing category defined by Maximum Anticipated Surface Pressure that the well can deliver during the planned operation.**
- **As wellhead pressure increases, number of backup wellbore barriers increase.**
- **H_2S requirements separate from pressure category.**
- **Applicable in ALL jurisdictions**

IRP 21 – COILED TUBING OPERATIONS
ORIGINAL WELL SERVICING CATEGORIES

Classification for IRP 21		Provincial Classifications			
CLASS	DESCRIPTION	Alberta	B.C.	Saskatchewan	Manitoba
CLASS I	Reservoir pressure no less than 5.5 MPa, no H_2S and: (i) Is a gas well, or (ii) Produces heavy oil density >920 kg/m^3, GOR< 70 sm^3/m^3 and produces by primary recovery or is included in a waterflood scheme	CLASS I		N/A	N/A
CLASS II	Pressure rating of casing flange $\leq$ 21,000 kPa and H_2S < 10 moles/kilomole	CLASS II CLASS IIA	CLASS A	N/A	N/A
CLASS III	Pressure rating of casing flange is (i) > 21,000 kPa, or (ii) $\leq$ 21,000 kPa and $H_2S \geq$ 10 moles/kilomole	CLASS III	CLASS B	N/A	N/A
CLASS IV	Based on potential H_2S discharge rate and proximity of public as per ERCB and BC Oil and Gas Commission definition	Critically Sour	CLASS C (Special Sour)	N/A	N/A

IRP 21 – COILED TUBING OPERATIONS
WELL SERVICING PRESSURE CATEGORIES

AS RISK (consequences) INCREASE,
NUMBER OF BARRIERS (backups) INCREASE

Well Servicing Pressure Category	MASP**	Sweet/Sour
Category 0	0 MPa	Sweet
Category 1A	0.1 – 5.5 MPa	Sweet
Category 1B	5.6 – 10.3 MPa	Sweet
Category 2	10.4 – 24.1 MPa	Sweet or Sour
Category 3	24.2 – 51.7 MPa	Sweet or Sour
Category 4	51.8 – 86.2 MPa	Sweet or Sour
Category 5	86.3 – 103.4 MPa	Sweet or Sour
Critical Sour	Release rate and distance to an urban centre	Sour

Category 1 was split to better reflect the nature of shallow gas wells and equipment.

Any level of H_2S automatically makes a well Class 2 as a minimum.

IRP 21 – COILED TUBING OPERATIONS
WELL CONTROL RISK MANAGEMENT PROCESS

AS RISK (consequences) INCREASE,
NUMBER OF BARRIERS (backups) INCREASE

Pressure Related Risks
- Flowline Washouts
- Collapsed Pipe
- Rapid Wash Out of Incomplete (damaged) BOP Ram Seal
- Check Valve Failure
- Explosion and Fire
- Environmental Spill

H_2S Related Risks
- Worker Safety
- Public Safety

IRP 21 – COILED TUBING OPERATIONS
WELL CONTROL RISK MANAGEMENT PROCESS

AS RISK (consequences) INCREASE,
NUMBER OF BARRIERS (backups) INCREASE

Primary Barriers
- Bottom BHA Check Valve
- Stripper Element
- CT Integrity

Secondary Barriers (CT Integrity)
- Upper BHA Check Valve
- BOP pipe Ram

Secondary Barriers (No CT Integrity)
- BOP Blind Ram (requires shear ram and pipe movement)

Tertiary Barriers (CT Integrity)
- Reel Valve
- 2nd BOP pipe Ram or 2nd Stripper

Tertiary Barriers (No CT Integrity)
- 2nd BOP Blind Ram (requires shear ram and pipe movement)

Last Line of Defense
- Shear Seal Ram
- Cuts thru CT or BHA at maximum pressure

IRP 21 – COILED TUBING OPERATIONS
WELL CONTROL RISK MANAGEMENT PROCESS

AS RISK (consequences) INCREASE,
NUMBER OF BARRIERS (backups) INCREASE

Washouts of Seals Faster At Higher Pressures and Rates

- **Any debris stuck in, or damage to a sealing face of a pipe ram or a blind ram will leak and rapidly wash out**
- **Back up for each sealing element addresses this risk**

Collapsed Pipe More Significant At Higher Pressures

- **Original IRP 21 did not consider scenario where collapsed CT at surface is wedged in stripper brass**
- **If CT cannot be pulled up, Blind Rams cannot close**
- **Tertiary (backup) blind/shear ram below addresses this risk**

IRP 21 – COILED TUBING OPERATIONS
WELL CONTROL FUNCTIONS

AS RISK (consequences) INCREASE,
NUMBER OF BARRIERS (backups) INCREASE

Element	Well Servicing Pressure Category						
	0	1A	1B	2	3	4	5
Coiled Tubing Stripper	Y	Y	Y	Y	Y	Y	Y
Blind Ram (Blanking Element)			Y	Y	Y	Y	Y
Shear Ram			Y	Y	Y	Y	Y
Kill Port			Y	Y	Y	Y	Y
Slip Ram				Y	Y	Y	Y
Pipe Ram		Y	Y	Y	Y	Y	Y
Flow Cross/Tee	Y	Y	Y	Y	Y	Y	Y
BLIND/SHEAR Ram					Y	Y	Y
Kill Port #2						Y	Y
PIPE/SLIP Ram						Y	Y
SHEAR/SEAL Ram							Y
Double Check Valve		Y	Y	Y	Y	Y	Y

NOTE: These are suggested configuration. Others are acceptable provided they offer the same number of functions.

IRP 21 – COILED TUBING OPERATIONS
SOUR SERVICE CONSIDERATIONS

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

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

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

INDUSTRY RECOMMENDED PRACTICES:
GOALS

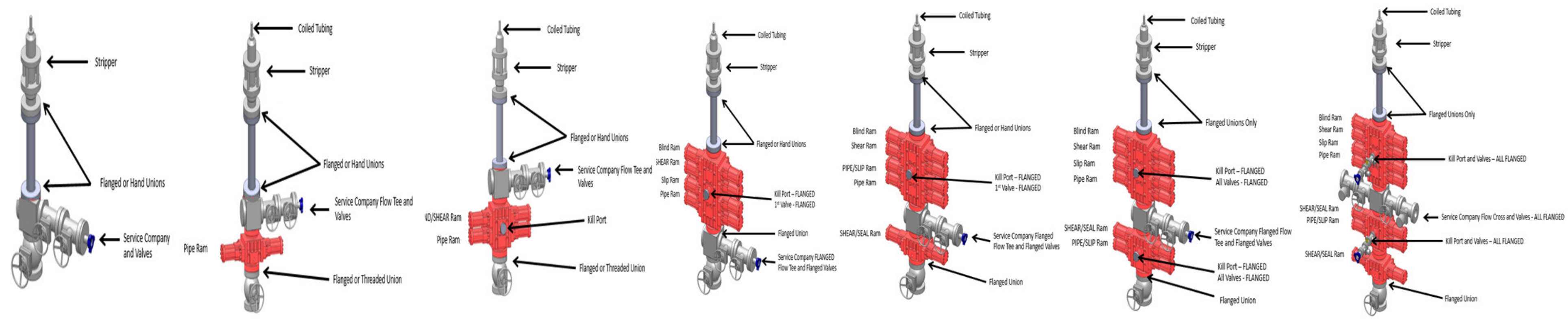
- Simple
- Comprehensive
- Evolving with changing reservoirs
- Regularly Reviewed
  - Feedback on topics outside of the limited scope have been stored for use in the full review
  - Please volunteer for the committee once the full review is scheduled.

IRP 21 – THANK YOU FOR LISTENING:
QUESTIONS?

- To get involved on future IRP’s contact dacc@enform.ca

Intervention & Coiled Tubing Association

IRP 21 R2106 - Proposed changes and impact to the Canadian coiled tubing well servicing industry.



Key Changes

IRP21 2010

- 4 Categories for CT Well Control Equipment
- 6 examples of BOP configuration requirements of which categories 2 and 3 address H2S presence, requiring 4 functions. Blind, Shear, Slip, Pipe
- Critical sour classification requires 3 annular barrier functions in addition to primary stripper to satisfy requirements

Table 1: Well Classification for Well Servicing Blowout Prevention

Classification for IRP 21		Provincial Classifications			
Class	**Description**	**Alberta**	**B.C.**	**Saskatchewan**	**Manitoba**
Class I	Reservoir pressure less than 5.5 MPa, no H_2S and: (i) is a gas well, or (ii) produces heavy oil density >920 kg/m^3, GOR < 70 sm^3/m^3 and produces by primary recovery or is included in a waterflood scheme.	Class I	Class A is the minimum well classification in BC and thus an IRP21 Class II Well Control stack is the minimum acceptable	N/A	N/A
Class II	Pressure rating of casing flange ≤ 21,000 kPa and H_2S < 10 moles/kilomole	Class II Class IIA*	Class A	N/A	N/A
Class III	Pressure rating of casing flange is (i) > 21,000 kPa, or (ii) ≤ 21,000 kPa and H_2S ≥ 10 moles/kilomole	Class III	Class B	N/A	N/A
Class IV	Based on potential H_2S discharge rate and proximity of public as per ERCB and B.C. Oil and Gas Commission definition	Critically Sour	Class C (Special Sour)	N/A	N/A

***NOTE:** A Class IIA well in Alberta is a well that produces heavy oil density > 920 kg/m^3, GOR < 70 sm^3/m^3, a maximum H_2S release rate of < 0.001 m^3/second, and an expected BH pressure of < 21,000 kPa.

IRP21 2016

- 6 Categories for CT Well Control Equipment,
- Category 1 is sub-sectioned into A and B categories and category 5 is additional to API RP 16 STr standard
- 12 examples of BOP configuration requirements
- Category 4 will be the norm, requiring 15K equipment and six functions
- Category 5 will require SEVEN functions
- Shear rams and Blind rams and take priority over tubing rams as additional barriers on level 3 through 5 BOP configurations.
- 21.2.1.2. Coiled Tubing and Jointed Pipe Comparison. IRP 21 2016 when viewed against Well Servicing Directive 37 places Coil Tubing at an distinct dis-advantage in Well classifications and required equipment. Drilling categories are unchanged in this review.

Table 4. Well Servicing Pressure Categories for Blowout Prevention

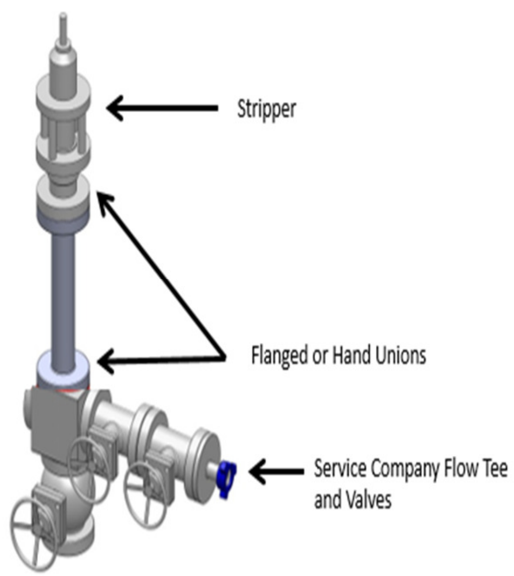
Well Servicing Pressure Category	MASP[1]	Sweet/Sour
Category 0	0 MPa[2]	Sweet
Category 1A[3]	0.1 – 5.5 MPa	Sweet
Category 1B[2]	5.6 – 10.3 MPa	Sweet
Category 2	10.4 – 24.1 MPa	Sweet or Sour
Category 3	24.2 – 51.7 MPa	Sweet or Sour
Category 4	51.8 – 86.2 MPa	Sweet or Sour
Category 5	86.3 – 103.4 MPa	Sweet or Sour
Critical Sour	Release rate and distance to an urban centre	Sour

Well control equipment configuration comparison

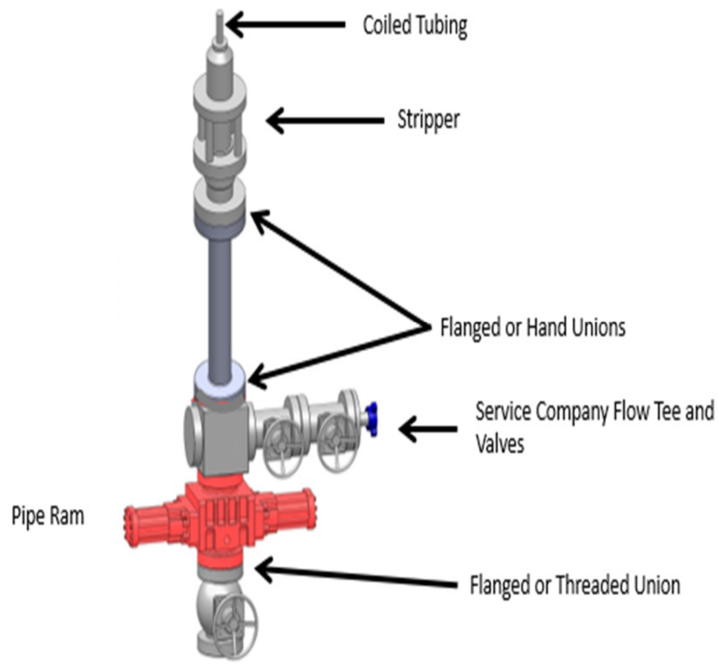
IRP 21 2016

IRP 21 2010

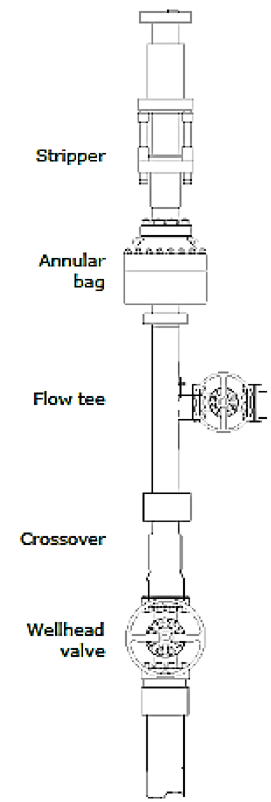
Category 0



Category 1a



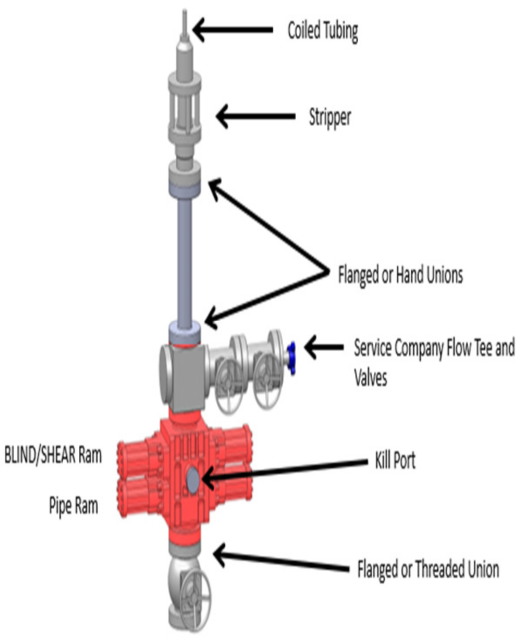
Category 1



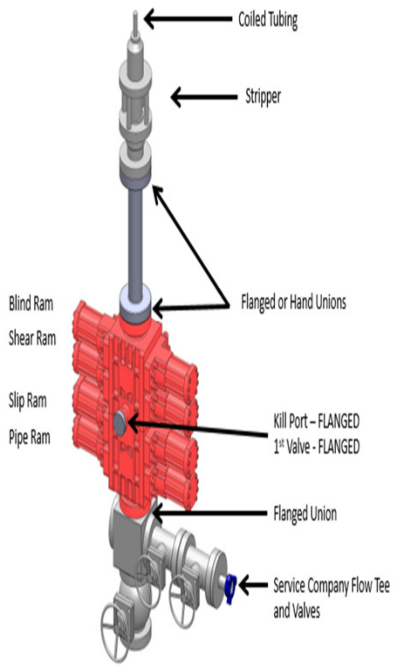
Well control equipment configuration comparison

IRP 21 2016

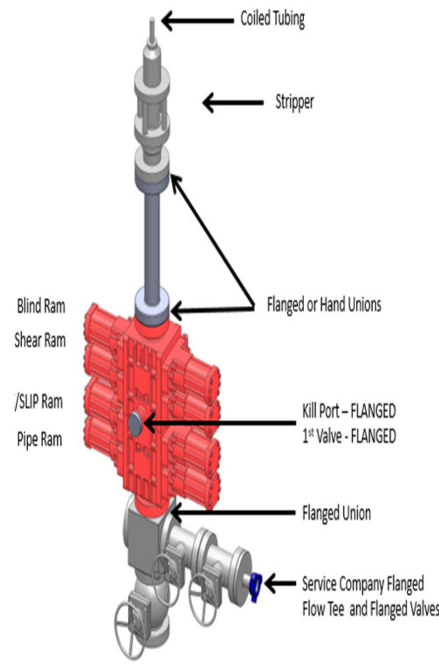
Category 1a



Category 2

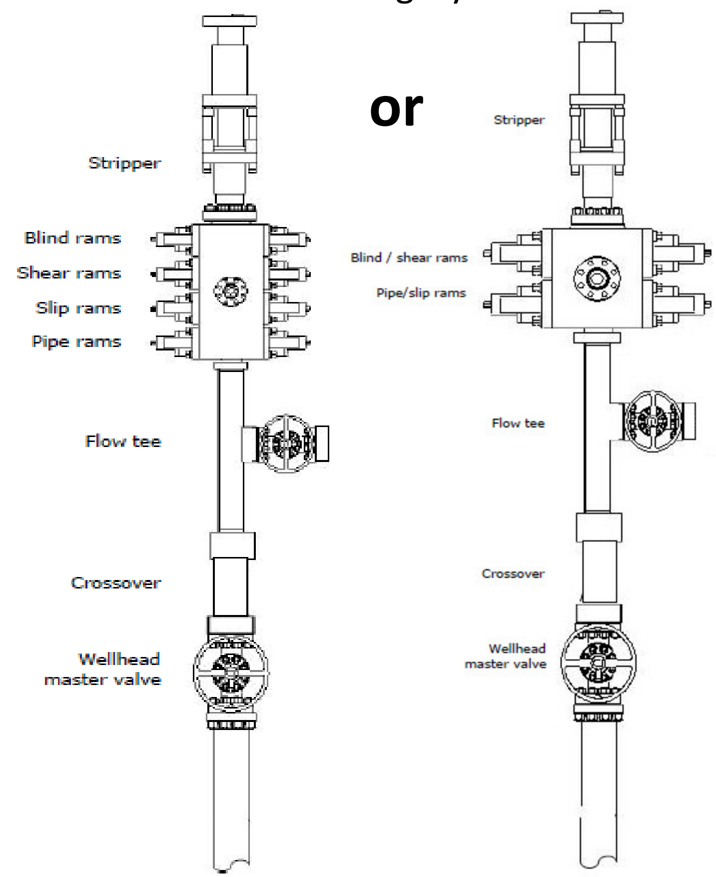


Category 2 Sour



IRP 21 2010

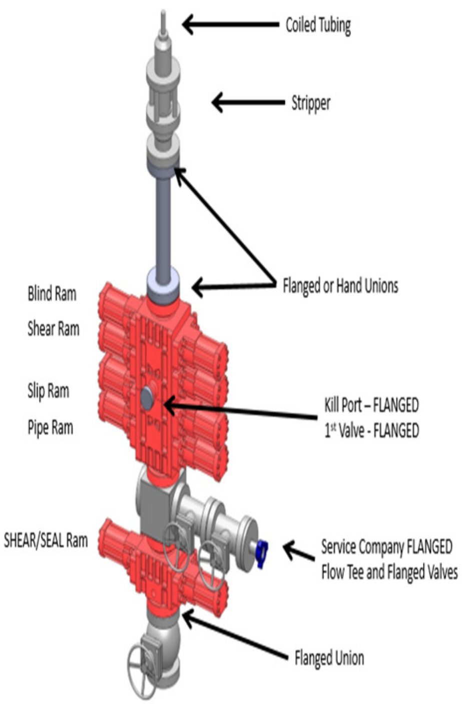
Category 2



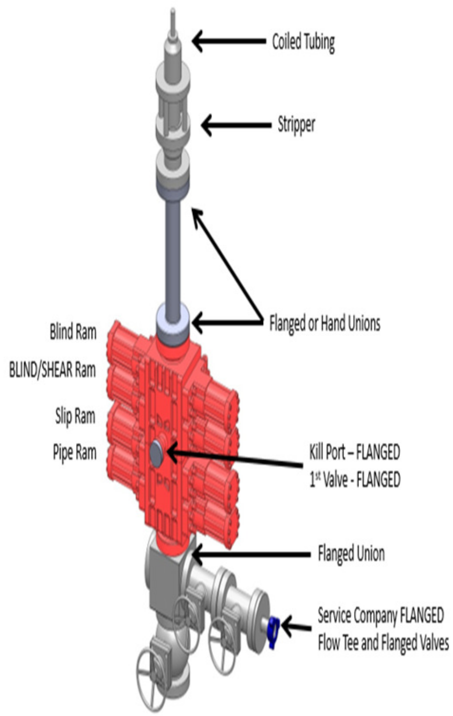
Well control equipment configuration comparison

IRP 21 2016

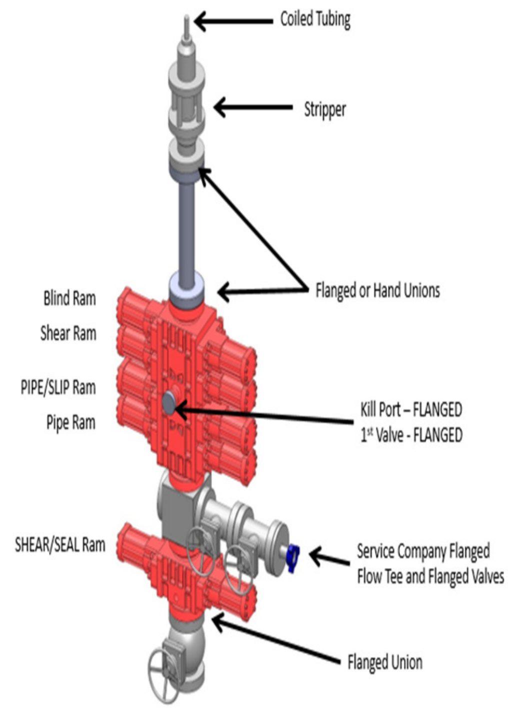
Category 3



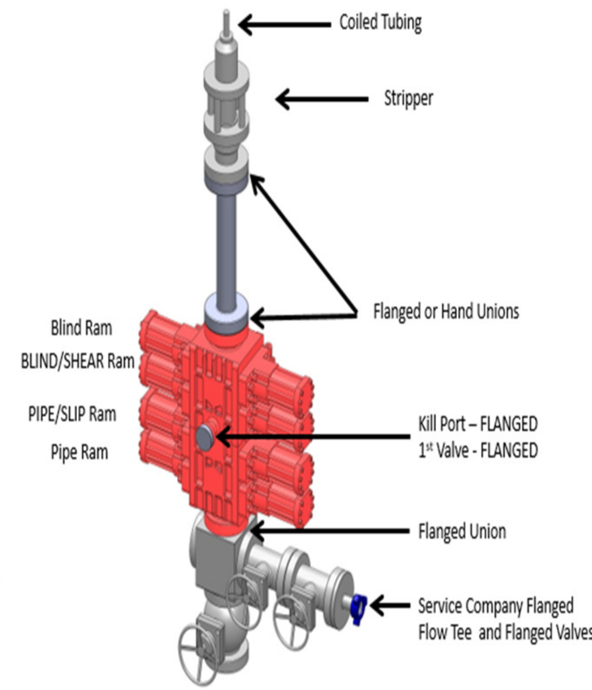
Category 3
option 2



Category 3
Sour



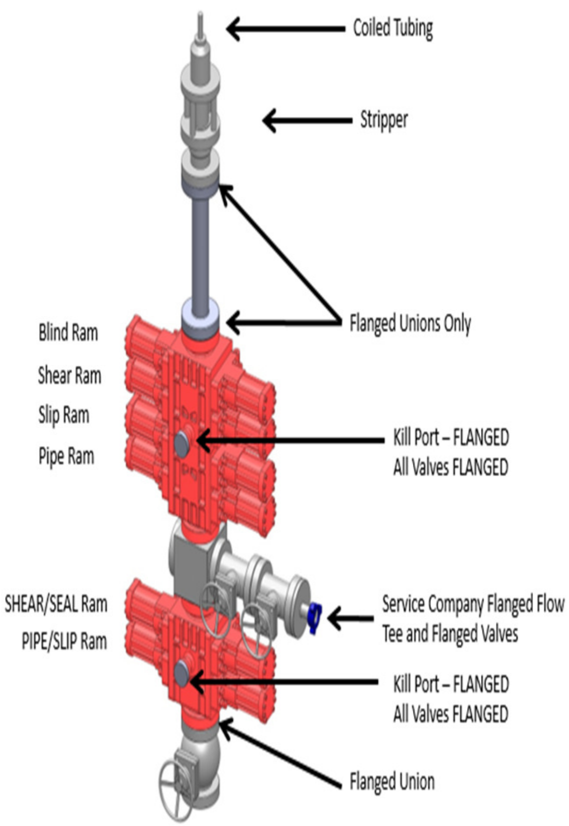
Category 3
Sour option 2



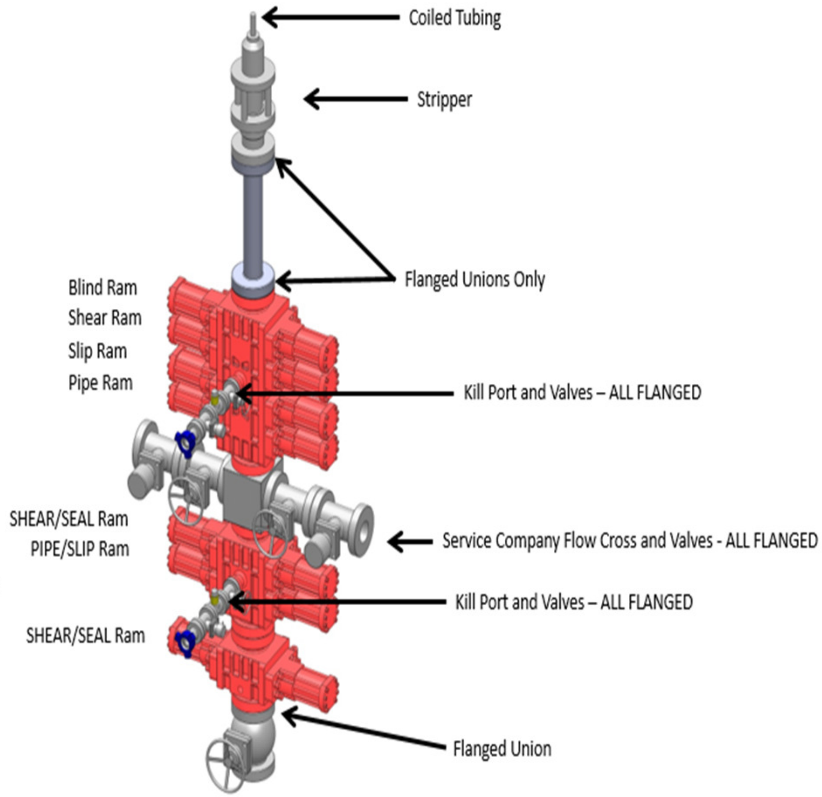
Well control equipment configuration comparison

IRP 21 2016

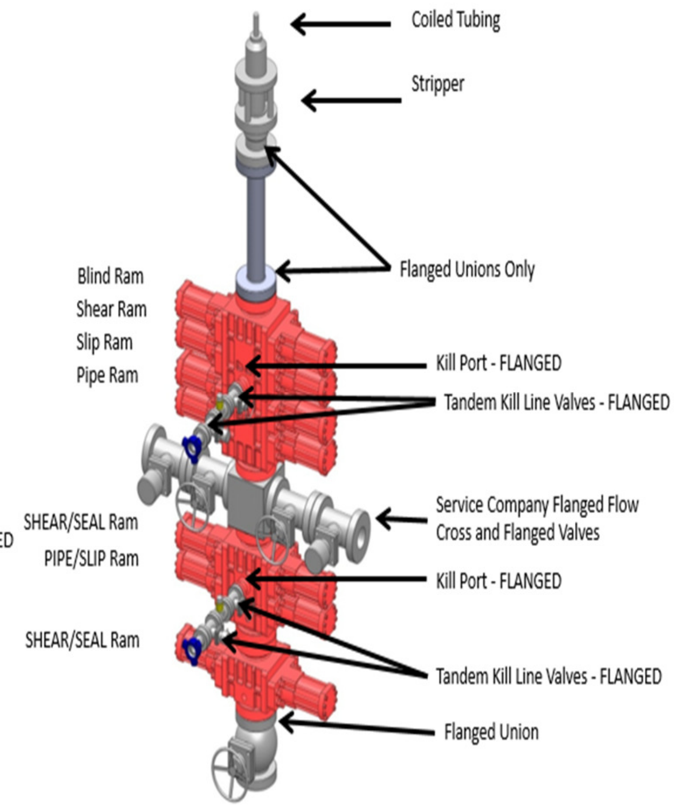
Category 4
Sweet or Sour



Category 5



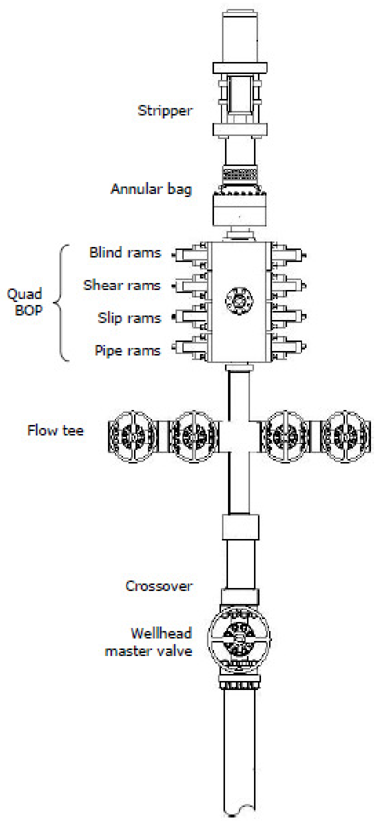
Category 5
Sour



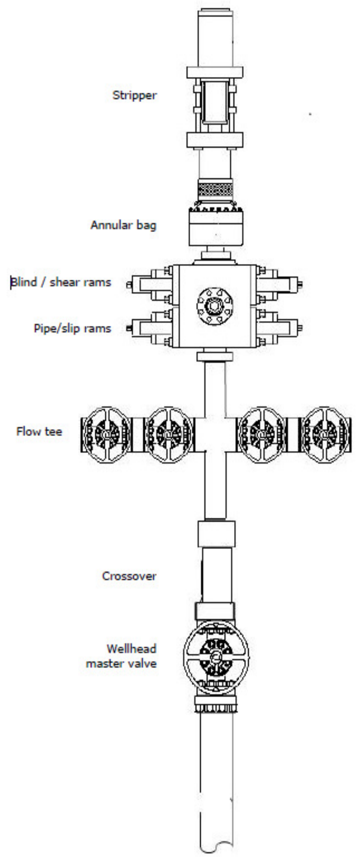
Well control equipment configuration comparison

IRP 21 2010

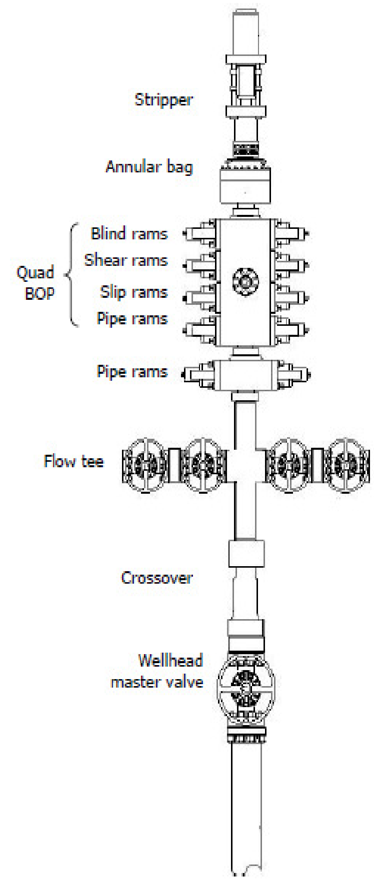
Category 3



Category 3 option

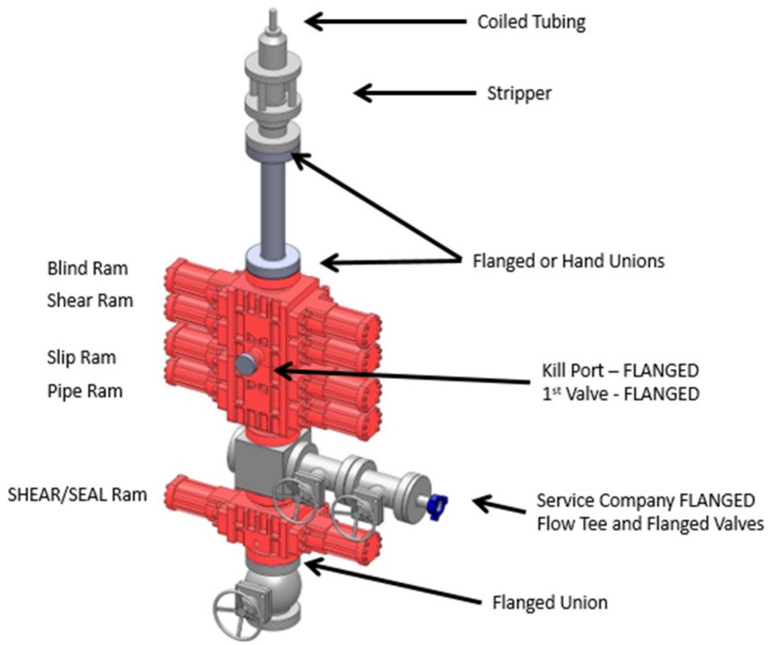


Critical Sour

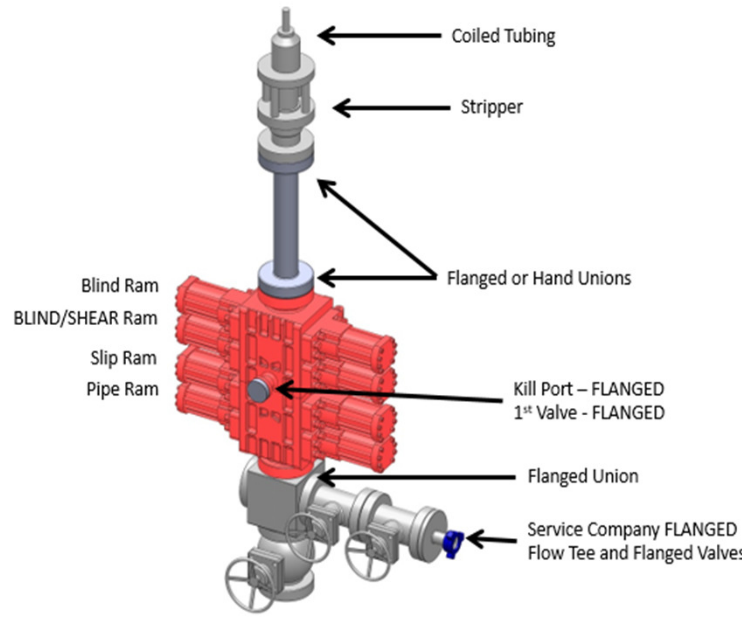


Concerns: Tubing Ram

Category 3, Figure 6 page 32



Optional Category 3, Figure 7 Page 33



What is the point in having a Blind ram, a Shear ram, a Shear / Seal ram and only one tubing ram?
What is the most commonly operated ram on a CT BOP stack?
Where is the redundancy for the tubing ram?

Concerns: Flow Points on all BOP configurations

It is an industry preferred practice to flow below a "BOP". IRP 21 2010 as well as the 2016 revision states that it is acceptable to flow either below or above. See pro's and con's listed in table 11 and 12 on page 18.

Table 11. Pros and Cons of Positioning Flow Tee Above the BOP

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

Table 12. Pros and Cons of Positioning Flow Tee Below BOP

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

How will flowing below a BOP protect the bore of the BOP from solids, wellbore effluent, chemicals, gases etc. from damage?

Pressure surges, slug flow and the resulting "eddying effect" above the flow tee will deposit solids and debris in the BOP bore cavities while flowing through the BOP allows debris and chemicals to be flushed through leaving a much cleaner bore.

Is not the con listed in table 12 as "*Well flow cannot be stopped if flow tee washes out*" sufficient reason to place flow tee above BOP?

Are not the points listed below most examples contradictory to the con arguments: *If there is risk of corrosive or abrasive washout of the flow tee or cross, place an additional pipe ram below the potential washout point.*

A BOP cannot function as the "primary well control mechanism preventing the escape of wellbore fluids and ensuring the safety of onsite personnel" <u>unless used in a manner that enables it to function as such</u>

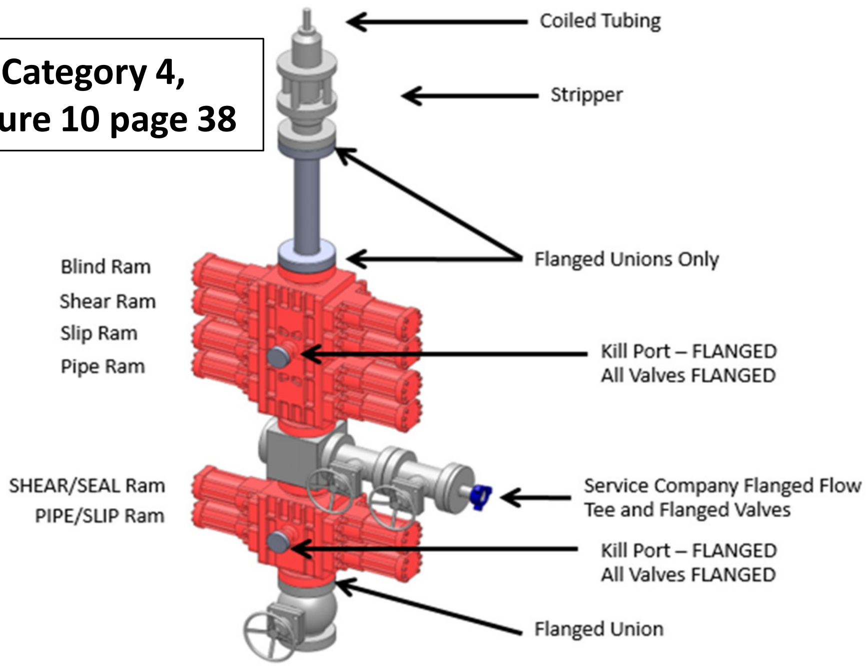
Concerns: ESD / HCR Redundancy

Where is the requirement for an ESD or HCR on the flowline for remote shut in of the wellbore?

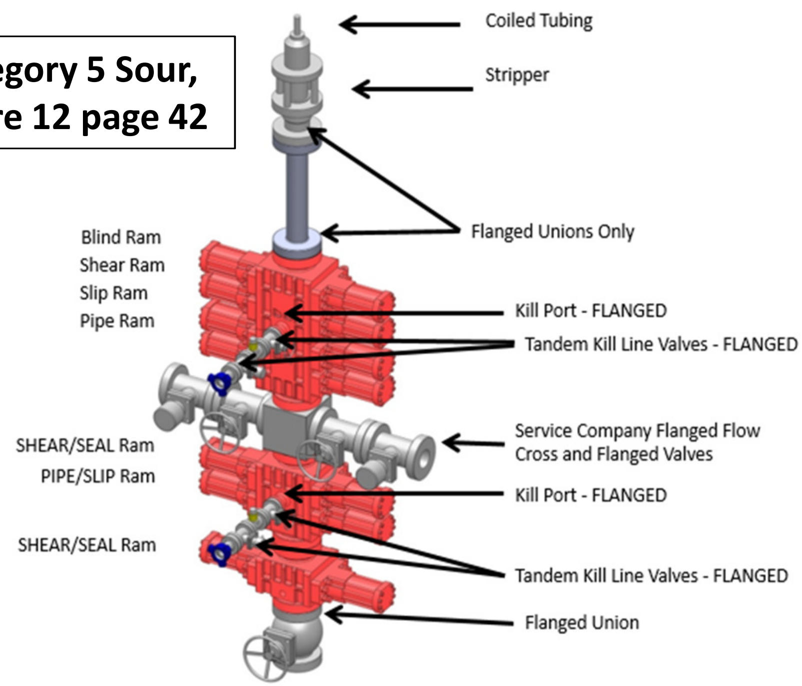
Even with configurations shown in figure 10 through 13, pages 38 through 42 there are only Pipe/ Slip combination rams to shut off flow. <u>There is no redundancy.</u>

Where is the safety consideration when faced with a washout on the flow line that needs a manual activation of a gate valve to fully close?

Category 4, Figure 10 page 38



Category 5 Sour, Figure 12 page 42



Concerns: Category 5

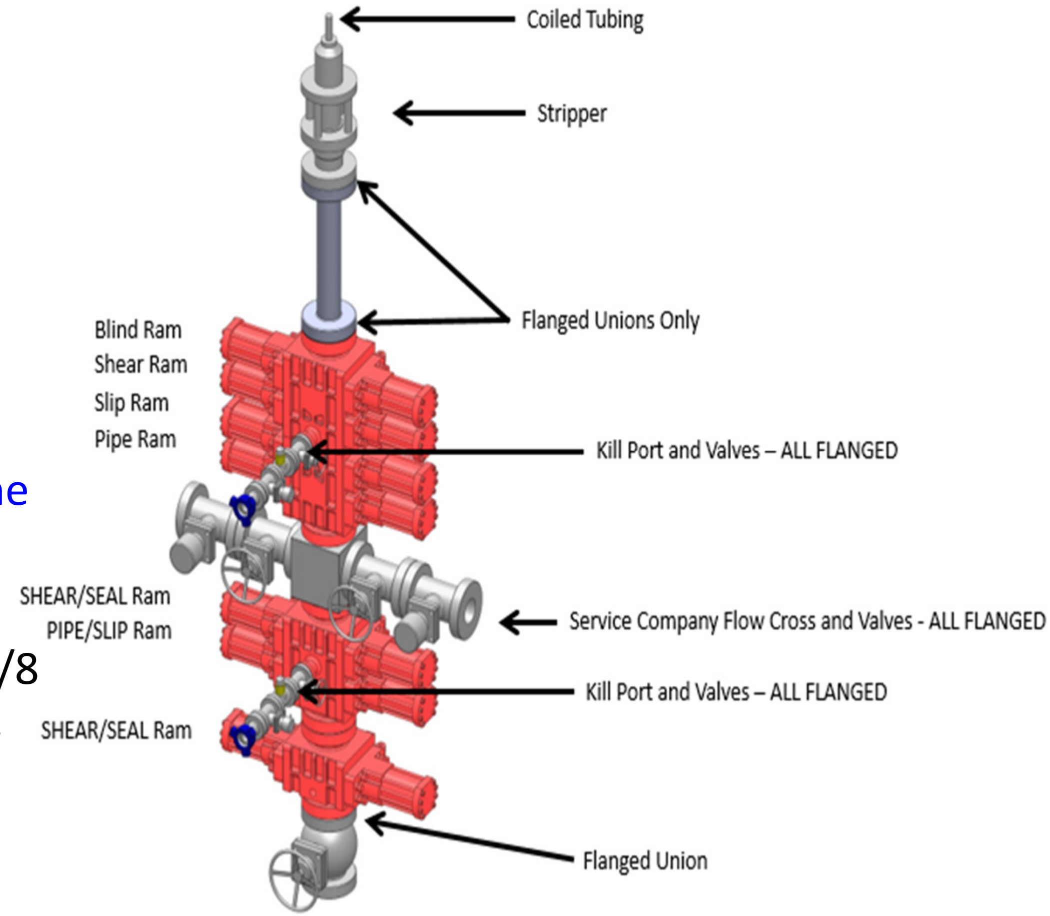
- The complexity of this BOP stack could potentially lead to operating errors.

Which of the three blind rams on Category 5, Figure 12, page 42 would be selected in an emergency well control situation?

See note from Figure 12 on page 42:

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

Consider a 2 7/8 or larger Mud Motor, or a 2 3/8 PAC or Reg tool connection portion of the BHA. Is this a realistic requirement?



Concerns: Coiled Tubing Cycle life Sour Environment

Fig's 5, 8, 9, 10, 11, 12 all have Pipe / Slip Combination ram preferences.

Using a Pipe/Slip ram as a redundant barrier to change out a stripper element will reduce the cycle life of a string of tubing by 50% vs a 2nd pipe ram or a dual stripper function.

In conjunction with Cycle life remaining criteria from Fig 21 below, when operating in a sour environment, Pipe / Slip ram activation will effectively classify even a low fatigue string to scrap metal, or at best not suitable for service in a sour environment.

Table 21. Fatigue Limits for Base Tubing

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

IRP21 2016 Impact to Service Providers

- Additional expense in well control equipment due to the additional equipment requirements for category 3, 4 and 5 configurations.
- Reconfigure Quad BOP's for combination ram options
- Additional dual ram Combi BOP's
- Additional single ram Combi BOP's
- Additional Flow tees and Valves
- Flanged Lubricators only for category 4 and 5 classifications
- Increased cost to service BOP stacks
- Increased cost for 3 year recertification's
- Retrofit CT Units to operate a 7 function well control BOP
- Increase the BOP System hydraulic reservoir capacity
- Add accumulator capacity to accommodate the larger, higher pressure BOP stack requirements
- Accumulator capacity required for pressure category 5, 130 mm 103.4 MPa BOP system:
  - Seven Accumulator bottles, 2 Nitrogen XPR back up (regulated to 21MPa)
  - Accumulator Capacity Requirement = Remote system Independent of CTU
- Increased Coiled Tubing replacement costs due to more frequent Pipe/Slip engagement and resulting cycle life loss

Impact to Operators

- Higher service costs due to increased rig in / rig out times.
- Fewer service providers / less competition. The capital costs associated with IRP 21 2016 compliance may force out small CT companies.
- Additional expense equates to higher service costs as service providers cannot absorb these expenses in current market conditions.
- Increased high pressure charges from service providers.
- Higher trucking costs due to additional well control equipment requirements.
- Higher costs due to the need for 3rd party crane services due to taller rig ups.

Closing statements

- *What are the drivers that have instigated these changes?*
- There have been no serious well control incidents that may have triggered this review and the resulting proposed changes.
- It is recognized that periodic IRP reviews are needed due to factors such as; adapting to market needs, new technologies, improvements in equipment.
- The proposed changes have no safety benefit for Canadian on-shore coiled tubing operations.
- If this revision of IRP21 is implemented in its current form it will be detrimental for the industry *by driving the smaller companies out of the business*
- Competition drives improvements in safe work practices and better process resulting in a more efficient and better work environment for everybody

Acknowledgements

I would like to thank the following companies for their time and answering my questions:

- Nexus Energy Technologies
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- Texas Oil Tools
- Trican Well Service

I also utilized various manuals from each company for reference material as well as API RP 16 ST R2014.

A few caveats to mention:

The opinions, views or statements expressed in this presentation are not representative of any company or person that I contacted and spoke too.

The material presented is intended for the sole purpose of bringing to your attention the contents of the proposed IRP 21 2016, some of the changes, initiate discussion and encourage you to express your opinion to the review committee as well as any of the representatives from the endorsing agencies: DACC, CAODC, CAPP, EPAC and PSAC.

Thank you to the IRP 21 Review Committee for their hard work and dedication to this project.