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Recommendations for Enhancements to Well Control Drills in the Oil and Gas Industry

Acknowledgements

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Revision history

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Scope

This report will help the industry evaluate existing or new well control drill programs that will ensure rig crews possess technical and non-technical competencies. Specifically, the report aims to build proficiency in responding to real world well control events, including those of high consequence but low probability, based on current and anticipated operations. Effective well control drill programs are an essential component of any successful continuing competency management as it represents the operational component of continuing training.

Drills are supervised exercises designed to develop and improve competency where participants diagnose, identify and perform appropriate responses to a simulated situation. Drills can be run in a variety of situations, from a simple 'table top' exercise to a full, 'hands-on' execution in a live operational environment.

This report is intended for industry well control training providers, the entities within an oil and gas company responsible for operational integrity and operational delivery, and for the training of the operational staff and Rig Management Functions responsible for training of their crews and first line managers. This guide will document good practices in the running of effective drills and the specifics of well control drills.

Foreword

The IOGP Wells Expert Committee (WEC), via the Competency and Training Sub-Committee (CTSC), focuses on training, competence, and human factors within the well control environment. Competence management in drilling operations has traditionally focused on the technical aspects of an activity. While being technically competent is essential, experience from other industries has shown that further benefits can be realised by including additional focus on 'non-technical skills'. Non-technical skills are the cognitive and social skills that complement technical skills and contribute to safe and efficient task performance.

Well operational drills are a means of competency development and competency assurance. Regular, structured, and effective drills performed by well operation crews build and re-enforce both technical and non-technical competencies. Effective drills can result in enhanced safety and operational performance at the worksite, particularly regarding safety-critical decision making in a dynamic environment.

Currently, many well control drill programs focus on one area: kick drills while drilling, tripping, and with the bit off the bottom. Current drills often fail to challenge crews with complications that occur during real well control events. A learning from other high-risk industries such as nuclear and aviation, is the need for realistic situational drills introducing complications and complexity.

This document provides guidance in the creation of effective drills, enforcing both technical and non-technical competencies, leading to a step-change improvement in operational safety and efficiency of well operations. The goal is to reduce the potential for occurrence of errors, and if errors do arise, that those involved know how to mitigate and manage the situation.

1. Key Elements of an Effective Drill Program

Well written drill procedures are the foundation for evaluation of crew performance. This is a critical requirement in facilitating human performance and understanding the thought process behind actions taken in response to events.

It is critical that the technical and non-technical proficiencies of participating individuals are understood by the relevant supervisors.

1.1 Characteristics of an effective drill program

A drill should have established learning objectives or identified skills that are assessed during the drill. While planning the drill execution, the learning objective should be tailored to the strengths and weaknesses of the team being observed.

Every effort should be made to ensure drills are executed practically, safely, and in the most realistic manner possible. When it is not possible to allow the participants to operate the equipment, then participants should walk through the actions required. Drills can be announced drills where the participants know the scenario being simulated, or unannounced drills where the participants are evaluated on their abilities to identify and resolve the issues included in the drill.

In the case where either the participant proficiency is low, or the procedure is unable to be performed due to operations underway, then a drill can be walked through or can be performed as a 'table top' drill. Drill scenarios should be developed that are challenging under varying conditions and which introduce complications where the equipment in use either fails or malfunctions.

All drills should be recorded, and analysis performed on the results, to identify areas where additional learning or focus is required to bring the team to a point of fluency.

For every drill, a guide should exist.

Finally, there should be measurement of key performance indicators to quantify the impact of the drills.

1.2 Creation of an effective drill program

Creation of an effective drill requires a map of the workflow: the operational process(es) being covered in the drill. This process map should include the tasks in the workflow, as well as the roles involved in performing tasks within the process. Documented operational procedures should then be associated with the relevant tasks in the workflow.

The workflow and procedures are then used to identify those points where a critical decision or a critical action must be taken. These 'trigger points' are the junctions at which the wrong decision or the wrong action can lead to undesirable outcomes. These trigger points are the decisions which must be emphasised in the drill, so that personnel are competent, fluent in the correct actions and behaviour. For example: a trigger point for a drill involving the Shut-In procedure could be the Driller initially selecting to shut-in the wrong BOP element, such as a shear ram with drill pipe in the hole, rather than the annular or Pipe Ram after spacing out.

The drills should be selected based upon current or upcoming operations to help the team maintain situational awareness and coordination between roles. Performance of the crew and third-party personnel during drills should be evaluated to demonstrate competency in the processes, including the specific procedures. Verbal Assessments should be incorporated as appropriate to assess participant knowledge of their roles and responsibilities in the process. The assessments should be administered to participants on an individual basis and the results documented and evaluated to identify areas potentially requiring additional training or emphasis.

1.3 Frequency of drills

Drills should be conducted at regular intervals, as defined by the organisation. Drills should be linked to the actual risks which could be encountered and the competency of the entire team which could need to respond.

Drills are an "administrative control" or "barrier" in prevention of a well control incident and as such need to be integrated based on risk in all well execution activities.

Frequency of drills at a minimum should be one drill weekly for each crew and more should be performed if the crew performance is less than satisfactory. The drills should be selected based upon the current or upcoming operation to help the rig team maintain situational awareness and coordination between a senior rig contractor representative and the lead Representative of the operator.

1.4 Supporting tools

The primary supporting tool for an effective drill is the drill guide. This guide should outline the drill objectives, restrictions and requirements as well as instructions for briefing, execution and debriefing of the drill.

1.5 Measuring Impact

Effective drill programs should have established grading criteria to evaluate crew performance during the drill and metrics to measure the overall effectiveness of the drills performed over a specified period.

Some crew performance areas to consider are:

- crew diagnosis and identification of a potential problem
- process or work flow knowledge
- supervisory skills, communication
- equipment operational theory

These individually graded areas should be averaged to give an overall grade. Typical grading criteria could be "Not Evaluated", "Unsatisfactory", "Below Average", "Average", and "Above Average" with a numerical assignment to each grading criteria for averaging purposes. Each grading criterion needs to be well defined (e.g., have a grading rubric).

Gaps in competency need to be clearly identified and the focus should be on gap closure as soon as possible. If gaps cannot be closed prior to potential exposure to the risk, then additional measures (e.g. oversight) need to be implemented.

2. Well Operations Drills

Well operation drills assess a rig crew's readiness to manage a well control event. However, to be effective as a measurement of the rig crew competency in managing real world events, the drill program should test human performance under stressful conditions.

To maximise the effectiveness of the drill, it is critical that all procedures are clearly documented. The evaluation of rig crew performance should address the execution of the documented procedures while monitoring the well for kicks and responding to possible and positive kick indicators. Just as importantly, evaluation and facilitation of the human performance component, to understand why actions are taken in, should be incorporated. See Appendix A for the list of rig activities which require documented procedures, to support an effective well operations drill program.

2.1 Characteristics of an effective well control drill

Well control drills are supervised exercises designed to develop and improve well control skills by having the rig crew diagnose simulated well control conditions and identify and exercise the appropriate rig specific well control procedures on the appropriate equipment.

Well control drills can be announced drills where the rig crew knows the drill scenario or unannounced drills where the rig crew is not briefed in the drill scenario and will be evaluated on detecting and identifying the kick and responding with the appropriate rig specific well control procedure. Drill scenarios should be developed that are challenging under varying well conditions which introduce complications where the equipment used in well control response fails or malfunctions (e.g., an annular leak or other BOP element failure, etc.).

Performance of the rig crew and third-party personnel during the drills should be evaluated to ensure knowledge of the rig-specific well control procedures and to demonstrate proficiency. Assessments should be incorporated as appropriate for the crew members in their roles and responsibilities in well control procedures.

2.2 Tools to support an effective well control drill

2.2.1 Documented standard work or operational instructions.

Rig specific well control procedures should be in place to address the roles and associated responsibilities and the required step by step operations, specifically in response to the well control event.

2.2.2 Drill briefing

A drill brief should be held with the team that will execute the drill on the rig crew. At a minimum, this will normally be the Senior Rig Contractor Representative and the Lead Representative of the Operator, but can include other supporting personnel required to effectively simulate the drill exercise and perform monitor intervention requirements.

The well control drill guide content is described in section 2.2.4. This guide, in combination with the related rig specific well control instructions should be utilised to lead the discussion for planning the well control drill. The following items should be covered:

- assignment of responsibilities for simulation of primary event and planned complications, intervention, questions planned to ask rig crew members, recording of rig crew actions and critical operating parameters for each rig operating station planned to be evaluated during the drill
- a discussion of the main learning objective and focus for the drill
- a discussion of each rig crew member's proficiency level and what is needed during the drill to continue to develop everyone's proficiencies
- a discussion of what can go wrong during the drill to include a risk assessment for the drill scenario and plan any necessary mitigations

2.2.3 Drill de-briefing

The initial critique should be held with the team/individual observing the drill. The intent is to review actions taken versus documented/expected process, to ensure identification of all findings (actions that went well and actions that did not go well) prior to the debrief with the rig crew. This should cover:

- the rig crew response and adherence to the rig specific procedures and procedures for any planned complications
- rig crew response to assessment questions
- key measured performance parameters such as time required to diagnose the well control simulated conditions, or time to shut the first BOP element
- agreement on the learning required and the competency gaps, including the grading of the drill
- and any planned remediation activities, individual or at the crew level, to close the competency gaps identified

This discussion should identify lessons learned both positive and areas that require improvement for sharing with the rig crew exercised and all other rig crews.

The rig crew debrief should occur immediately after the critique, before proceeding with drilling operations or at another convenient time, but as early as reasonably possible. This debrief should be performed as a 'retrospect' with the team, where team members identify positive behaviours/actions as well as those which were less than satisfactory, leading to self-identification of their competency gaps. During this debrief, if not brought up by the team members themselves, the team/individual observers should cover any outstanding items identified in their critique.

2.2.4 Well Control Drill Guides

A well control drill guide should be used in conjunction with the respective rig specific well control procedures and the evaluation criteria. The objective of this guide is to ensure all members of the rig team involved in planning and executing the drill have the proper information to lead the drill, while attaining the greatest amount of learning for the operational time committed to performing the drill without any unintended operational consequences or actions.

A typical well control drill guide should cover the intended well control rig specific procedure(s) such as a Hole Monitoring or Shut-in. The well control drill guide should address the following areas:

- Identify the required rig supervisory team members who will be involved in initiating and evaluating the rig crew actions. These supervisory team members will also intervene to prevent undesirable rig crew actions during the conduct of the drill.
- Identify which rig positions, i.e., Driller, Assistant Driller, Derrickman/Shakerhand, Floorhand/Motorman, Mud Logger, Mud Engineer, will participate and be evaluated during the drill.
- Define any cautions or notes to be aware of, such as a shut-in drill being prepared to prevent closing the BOP if it is not safe or desired to do so.
- Address how the drill is to be initiated or simulated. In the case of a shut-in drill, something to the effect of "without notifying the driller ahead of time, simulate an increase in pit volume using a previously specified technique (manually raising the pit level float, draining mud from the degasser, transferring mud from slugging pit, etc.).
- Establish the assessment guidance for evaluating the drill. Some examples are:
  - Record the time required to identify the simulated increase in pit volume or flow rate, and the time required to complete the shut-in
  - Was the crew able to execute their assigned responsibilities?
  - Was communication between crew members effective?
  - Was the rig specific procedure followed and reinforced?
- Identify the assessment questions to ask of the rig crew being evaluated to determine competency of the related well control theory and equipment operational theory. Some examples are:
  - What is our primary and secondary well control barrier?
  - How do you confirm the well is shut-in?
  - What is a hard shut-in?
  - What parameters should be recorded after shutting-in on a well kick?
- Address any planned well control drill complications, such as "The BOP element initially utilised fails to close and the well continues to flow".
- Identify the skills assessed during the drill. These may include: possible kick indicators, positive kick indicators, procedural knowledge, procedural execution, complication knowledge, supervision of subordinates, communications, and well control theory.

2.3 Measuring the impact of running well control drills

Measurement of the established grading criteria and metrics should be performed over a specified period, to measure the effectiveness of the drills.

Metrics should be established to measure the effectiveness of well control drill programs. Some areas to cover could be percentage of drills with an overall score of average or better during a reporting period, type of drills (shut-in, hole monitoring, etc.) performed in a reporting period.

3. Conclusion

Historically, drills have been focused on one area; kick drills while drilling, tripping, and with the bit off the bottom. To more effectively leverage the critical role drills could play in developing and assuring competency, rig crews should be challenged with realistic simulation of well control events.

Every drill should contain the following key elements:

1) The Drill
    a) Established learning objectives, what are the issues being addressed in this drill.
    b) Execution in the most realistic environment possible, practically and safely.
    c) Evaluation of participants on their abilities to identify and resolve the issues included in the drill.
    d) Evaluation of the crew's ability to handle the unexpected.
    e) Recording and analysis of drill used to identify areas for continued development.
    f) Measurement of key performance indicators.
2) Drill Guide which documents the instructions and expectations for planning, briefing, execution and debriefing of the drill.

The drill program should promote reliable human performance under stressful conditions.

Appendix A – Recommendations for rig activity procedures

The following is a list of rig specific activities which require documented procedures.

1) **Hole Monitoring Procedures While Drilling or Milling/Circulating**.
A rig-specific procedure and protocol for monitoring the hole for signs of an influx while drilling or milling/circulating, including the roles and responsibilities of all involved crew members. The procedure should include actions to take in response to alarms, positive kick indicators, possible kick indicators, and communications from rig crew or third-party personnel relating to possible or positive kick indicators, specifically when to conduct a flow check and when to immediately invoke shut-in procedures. The procedures/protocols should include and assign responsibilities for following setting alarms and monitoring the Flow Indicator (Flo-Sho), identifying drilling breaks and other possible kick indicators, monitoring the cuttings on the shakers for potential warning signs, communications between the driller and shaker hand and/or mud engineers, prior to and during any fluid transfers or operations which may impact pit volumes, and communications between driller and the mud logger if the service is provided.

2) **Hole Monitoring Procedures While Tripping**.
A rig specific procedure for monitoring the hole for correct fill-up and displacement during tripping operations to include a standard trip log to be utilised on all trips and retained on site for the duration of the well or other period as specified by rig contractor. The procedure shall also clearly define how abnormal fill-ups or displacements are differentiated from a normal fill-up or displacement and the protocol to communicate and respond to an abnormal fill-up or displacement.

3) **Hole Monitoring Procedures During Wireline Operations.**
A rig specific procedure for monitoring the hole for correct fill-up and displacement during wireline operations.

4) **Hole Monitoring Procedures While Out of the Hole.**
A rig specific procedure for monitoring the hole when pipe is out of the hole.

5) **Hole Monitoring Procedures While Running Casing or Tubing.**
A rig specific procedure for monitoring the hole for correct displacement while running casing/tubing or fill-up while pulling casing/tubing including a standard trip log to be utilised and retained on site for the duration of the well or other period as specified by the rig contractor. The procedure should also clearly define how abnormal displacements are differentiated from a normal displacement and the protocol to communicate and respond to an abnormal displacement.

6) **Shut-in Procedures.**
Rig-specific shut-in procedures for drilling (Milling/Circulating for Cased Hole), tripping (with drill pipe and drill collars across the BOP stack), wireline operations, running casing and tubing, and when out of the hole. The procedures should clearly define roles and responsibilities for all rig crew involved in the shut-in procedures.

7) **Well Kill Procedures.**
A rig specific well kill procedure that includes a BOP element to be used during the well kill procedure, choke outlet to use if multiple options available and choke manifold line-up, monitoring mud gas separator, special considerations such as pipe hang-off and pipe movement, and communications protocol. The procedure should clearly define roles and responsibilities for all rig crew involved in the well kill procedure.

8) **Stack Clearing Procedure.**
All floating rigs should have a rig specific procedure for clearing the stack from gas after well kill operations.

9) **Stripping Procedure.**
All rigs should have a rig specific procedure for stripping operations.

10) **Connection Trend Analysis Procedure.**
A rig specific procedure to monitor and record flowline drain back during connections in order to establish a normal trend and identify abnormalities to normal drain back.

11) **Mud Gas Separator Monitoring Procedure.**
A rig specific procedure to monitor the Mud/Gas Separator (MGS) during well kill operations utilising the MGS including the maximum allowable pressure on the MGS to prevent gas, the method utilised on the rig to monitor the MGS pressure, and the action to take when the MGS pressure limit is approached or exceeded.

12) **Divert Procedures.**
All rigs equipped with a Diverter should have a rig-specific divert procedure that also clearly define roles and responsibilities for all rig crew involved in the divert procedure.

13) **Well Control Procedures for Non-Shearables.**
Rigs equipped with Shear Rams or Blind Shear Rams should have well control procedures for operations when non-shearable tubulars are across the stack and a shear matrix (tubular shearing table) identifying non-shearable tubulars should be posted at the driller's station.

14) **Emergency Disconnect Sequence (EDS) Procedure for floating vessels with subsea BOP.**
Rig-specific procedures for process to update EDS watch circles to respond to changing metocean conditions and define specific actions to be taken by the rig crew for each watch circle alert conditions.

15) **Emergency Disconnect Sequence (EDS). Procedure for floating vessels with subsea BOP.**
Rig specific procedures for process to activate EDS in other emergencies involving uncontrollable well control situations that dictate disconnecting from the well.

Appendix B – Well Control Examples

This appendix lists types of well control drills, along with a description of each. This list has been assembled through the polling of IOGP member companies who are actively running , well control drills.

1) Shut-In Drills for the following operations:
    a) Drilling (Milling/Circulating for Cased Hole)
    b) Tripping (with both drill pipe and drill collars across the BOP stack)
    c) Wireline Operations
    d) Running Casing/Tubing
    e) Out of the hole
2) Hole Monitoring Drills while Drilling (or Milling/Circulating) to evaluate and ensure crew proficiency in all aspects of the procedure for hole monitoring while drilling or milling/circulating.
3) Well Kill Drills utilising the rig specific well kill procedure, including discussion and/or simulation of the procedures, including clearing the stack of gas after the well kill, if conducted on a floating rig.
4) Choke Drills to verify equipment function and develop and evaluate crew proficiency operating the choke.
5) Divert Drills utilising the rig specific divert procedures where a diverter is installed.
6) Stripping Drills utilising the rig specific stripping procedures.
7) Non-Shearable Drills utilising rig specific well control contingency procedures associated with non-shearables across the stack.
8) Emergency Disconnect Sequence (EDS) Drills for drillships utilising rig specific procedures for each of the watch circle alert conditions.

Appendix C – Well Control Drill Assessment Form

Well Control Drill Assessment Record						
Rig			**Crew**			
DSM			**Date**			
Current Op			**Time**			
Assessor Company Off Position Rig						
Participant Rig or Team Name: Position:						
Well Control Drill						
Simulate	Discuss	Both				
Complication						
Simulate	Discuss	Both				
Times: Initiated Detected Confirmed Shut-in						
Skill Area	**NE**	**LTS**	**BLW AVG**	**AVG**	**ABV AVG**	
Potential Indicators						**Potential Indicators** - Are the potential warning signs of a kick understood? Were the indications observed, acknowledged and responded to appropriately?
Positive Indicators						**Positive Indicators** - Are the positive indicators of a kick understood? Were the indications observed, acknowledged and responded to appropriately?
Procedural Knowledge						**Procedural Knowledge** - Was the appropriate procedure selected? Were the procedural steps and their impact understood?
Procedural Execution						**Procedural Execution** - Was the procedure executed correctly? Was the effectiveness of the procedure properly evaluated? Was the written procedure reviewed after positive containment was achieved?
Complication Knowledge						**Complication Knowledge** - Was the complication understood? Was the complication correctly identified? Was the impact of the potential actions understood?

Skill Area	NE	LTS	BLW AVG	AVG	ABV AVG	
Supervision/ Direction						**Supervision/Direction** - Did individuals in supervisory position understand the actions required by subordinates? Did they correct their subordinates to ensure appropriate required actions were accomplished?
Communications						**Communications** - Were communications effective? Was feedback or confirmation received? Were required communications accomplished? Were the efforts and awareness of the rig team synchronised?
Well Control Theory						**Well Control Theory** - Was the cause and impact of the well control event understood? Was the down-hole effect of both appropriate and inappropriate actions understood? Was the impact of timeliness understood?
Evacuation & notification protocol						**Evacuation & notification period** - Were safe muster areas identified, taking into account wind direction? Were emergency shut-downs activated to eliminate ignition sources? Were notifications made to appropriate emergency response personnel?
Effectiveness of Drill						**Effectiveness of Drill** - Were effective responses acknowledged and reinforced? Were areas for improvement addressed and corrected? Was the drill challenging but reasonable?
Column Totals						
Net Score						
Comments:						
Net Score = (AVG x 1) + (AVG x 2) + (ABV AVG x 3) Use Column Totals (9 – NE)						

C.1 Score criteria

NE: Not Evaluated - An area that was supported by the selected drill, but for some reason was not evaluated.

LTS: Less Than Satisfactory (0.0 Score) - Unfamiliar with own role, responsibilities, procedures or well control principles; unable to execute effectively without coaching; makes multiple deviations. Deviations/decisions could result in a loss of well control, or damage to people, the environment, equipment or the wellbore.

BLW AVG: Below Average (1.0 Score) - Familiar with own role, responsibilities and procedures; weak understanding of underlying well control principals; executes satisfactorily but requires some coaching; few deviations. Deviations/decisions would not cause in a loss of well control, or damage people, the environment, equipment or wellbore.

AVG: Average (2.0 Score) - Knows own role, responsibilities and procedures; basic understanding of the underlying well control principles; executes efficiently and correctly with minimal, if any coaching. Deviations are minor and self-corrected; effectively contained and limited the size of any influx.

ABV AVG: Above Average (3.0 Score) - Thorough knowledge of the rig team's roles, responsibilities and procedures, and of the underlying well control principles; no deviations, no coaching required. Rapidly assesses the situation and makes appropriate decisions. Effectively minimised any influx, no deviations. Ready to move up with consistent performance.

Appendix D – Well Control Drill Guide Examples

D.1 Example: Well Control Drill/Rig Specific Procedure: Hole Monitoring (Drilling or Milling/Circulating)

Applicable Drill Participants: 1) Driller, 2) Assistant or Relief Driller, 3) Derrickman/ Shakerhand, 4) Floorman/Motorman, 5) Mud Logger, 6) Mud Engineer

Questions: Select from the following (direct appropriate questions to specific individuals to encourage full team participation) :

1) What is our primary well control barrier? What is our secondary well control barrier?
2) What are the possible warning signs for a kick and why is each warning sign a potential kick indicator?
3) What action should be taken in response to observation of a possible kick indicator?
4) What is a drilling break? What action should you take when you observe a drilling break? Why do you take this action?
5) When conducting a flow check, how do you determine if the well is flowing? How long should you observe the well before you are confident it is not flowing?
6) What is ballooning? What are the indications of ballooning? Is it possible for ballooning to occur if the well has not experienced losses? What action should you take if you suspect the well is ballooning?
7) Under current well conditions is there a potential for the well to kick if massive loss circulation is encountered? If so why, and if not, why not? What action should you take if massive loss circulation occurs and at what point should the well be shut-in?
8) What are the positive indicators of a kick?
9) What action should be taken in response to observation of a positive kick indicator?
10) What action should be taken if the derrickman or shakerhand reports a noticeable change in cuttings volume, size or shape? What could a noticeable change in cuttings indicate from a well control perspective?
11) What action should be taken if the derrickman or shakerhand reports water or base oil being added to the mud pit with no mud engineer in attendance overseeing the addition?
12) What action should be taken if the mud engineer reports he has detected an increase in mud temperature coming out of the well? What could an increase in temperature indicate from a well control perspective?
13) What action should be taken if the mud engineer reports he has detected unexplained contaminants in the mud? What could unexplained contaminants in the mud indicate from a well control perspective?
14) What action should be taken if an increase in pit volume or flow rate from the well is reported by the mud logger and you have not noticed the same on your monitoring equipment?

15) What action should be taken if you notice an increase in pit volume or flow rate from the well?

16) What is the current alarm setting for the PVT equipment? What is the rationale for this setting?

17) What is the current alarm setting for the flow indicator (Flo-Sho)? What is the rationale for this setting?

18) What action should be taken if an H2S alarm goes off at the drill floor or the shale shakers?

19) What is an underground blowout? What are the indications of an underground blowout? What are the first actions you should take if you suspect an underground blowout is occurring?

Learning Objective/Skills Assessed:

- Possible Kick Indicators
- Positive Kick Indicators
- Procedural Knowledge
- Well Control Theory

D.2 Example: Well Control Drill/Rig Specific Procedure: Shut-in (Drilling or Milling/Circulating)

Applicable Drill Participants: 1) Driller, 2) Assistant or Relief Driller, 3) Derrickman/ Shakerhand, 4) Floorman/Motorman, 5) Mud Logger

Exercise: Select one of the following:

1) Without notifying the driller ahead of time, simulate an increase in pit volume using a previously specified technique (manually raising pit level float, draining mud from degasser, transferring mud from slugging pit, etc.).

2) Without notifying the driller ahead of time, simulate an increase in flow rate from the well using a previously specified technique (manually manipulating the flow indicator, using a dedicated "training" line, etc.).

3) Have the driller informed that an influx has been taken.

Caution:

- Be prepared to prevent closing the BOP if it is not desired or safe.
- If a BOP element is closed during the drill, ensure the element is opened prior to resuming operations.

Assessment Guidance

- Record the time required to identify the simulated increase in pit volume of flow rate (if an influx was simulated).
- Record the time required to complete the shut-in.

- Observe rig crew. Was the crew able to execute their assigned responsibilities? Was communication between crew members effective? Were any special instructions from the driller followed?
- Observe the driller. Was the driller's reaction and the direction he provided to the crew members appropriate? Were the driller's communications with other personnel on the rig appropriate and effective?
- Was the rig specific procedure followed and reinforced? Was the rig specific procedure reviewed to ensure compliance once the well/rig was established in a safe or static condition?

Questions: Select from the following (direct appropriate questions to specific individuals to encourage full team participation):

1) What is our primary well control barrier? What is our secondary well control barrier?
2) What are the specific responsibilities for each member of the drilling crew when executing the shut-in procedures while drilling?
3) Which element of the stack should be closed when shutting-in the well due to an influx while drilling? Why is this element used as opposed to another element on the stack?
4) How do you confirm the well has been shut-in?
5) What is a hard shut-in? What is the primary objective of a hard shut-in?
6) What is the distance from the rotary table to the uppermost set of pipe rams?
7) How should the well be monitored during shut-in and prior to executing the well kill procedure? How will you ensure the BOP element closed is not leaking?
8) What parameters should be recorded after shutting-in on a well kick?
9) Where do you monitor the Shut-in Drill Pipe Pressure (SIDPP) and Shut-in Casing Pressure (SICP)?
10) Why is it important to monitor the Shut-in Drill Pipe Pressure (SIDPP) and Shut-in Casing Pressure (SICP)?
11) Should the pipe be moved if the well is shut-in for an extended period of time prior to commencing well kill operations? If so, how?
12) What are the positive indicators of a kick?
13) What action should be taken in response to observation of a positive kick indicator?
14) What are the normal pressure readings for the following gauges on your rig's accumulator system: 1) rig air, 2) accumulator bank, 3) manifold and 4) annular?
15) What is the primary function of the weep holes on a ram type BOP?
16) How will BOP system performance be affected if the nitrogen pre-charge pressure is lost in an accumulator bottle?

Complications: Select from the following:

Well Continues to Flow:

Questions: Select from the following:

1) What action should you take if the well continues to flow after the BOP is initially closed?
2) How will you know if the annular is leaking? What action should you take if the annular is leaking after it is closed?
3) How will you know if the pipe ram is leaking? What action should you take if the pipe ram is leaking after it is closed?
4) (For subsea applications) What action should you take if you close a second element and the well continues to flow?

Gas Migration:

Questions: Select from the following:

1) What effect does gas migration have on a shut-in well?
2) How can you identify gas migration? What should you do if you determine gas is migrating while the well is shut-in?

Gas in Riser (subsea applications only):

Questions: Select from the following:

1) How will you know if there is gas in the riser after shut-in?
2) What action do you take if there is gas in the riser after the well is shut-in?

Learning Objective/Skills Assessed:

- Possible Kick Indicators
- Positive Kick Indicators
- Procedural Knowledge
- Procedural Execution
- Complication Knowledge
- Supervision of Subordinates
- Communications
- Well Control Theory

D.3 Example: Well Control Drill/Rig Specific Procedure: Shut-in (Tripping)

Applicable Drill Participants: 1) Driller, 2) Assistant or Relief Driller, 3) Derrickman/ Shakerhand, 4) Floorman/Motorman, 5) Mud Logger

Exercise: Select one of the following:

1) While tripping and without notifying the driller ahead of time, simulate an increase in pit volume using a previously specified technique (manually raising pit level float, draining mud from degasser, transferring mud from slugging pit, etc.).
2) While tripping, have the driller informed that an influx has been taken.
3) While tripping out of the hole inform the driller the well is experiencing severe losses.

Caution:

- Be prepared to prevent closing the BOP if it is not desired or safe.
- If a BOP element is closed during the drill, ensure the element is opened prior to resuming operations.

Assessment Guidance:

- Record the time required to identify the simulated increase in pit volume (time to detect the influx).
- Record the time required to install and close the safety valve or IBOP, and then close the BOP element (complete the shut-in).
- Observe the crew. Was the crew able to execute their assigned responsibilities? Was communication between crew members effective? Were any special instructions from the driller followed?
- Observe the driller. Was the driller's reaction and the direction he provided to the crew members appropriate? Were the driller's communications with other personnel on the rig appropriate and effective?
- Was the rig specific procedure followed and reinforced? Was the rig specific procedure reviewed to ensure compliance once the well/rig was established in a safe or static condition?

Questions: Select from the following (direct appropriate questions to specific individuals to encourage full team participation):

1) What is our primary well control barrier? What is our secondary well control barrier?
2) What specific procedures do you use to monitor the hole for signs of an influx when tripping in the hole? When are you expected to conduct flow checks during a trip in the hole?
3) What specific procedures do you use to monitor the hole for signs of an influx when tripping out of the hole? When are you expected to conduct flow checks during a trip out of the hole?
4) What action should be taken if there is a discrepancy between the anticipated volume of mud displaced from the hole and the actual volume observed when tripping in the hole?

5) What action should be taken if there is a discrepancy between the anticipated volume of mud required to fill the hole and the actual volume observed when tripping out of the hole?

6) What is the displacement volume of the pipe currently being tripped and is this value based upon open ended or closed pipe?

7) If tripping operations are interrupted (for example due to mechanical issues), how should the well be secured and monitored during this time frame?

8) What are the specific responsibilities for each member of the drilling crew when executing the shut-in procedures while tripping?

9) When should you use the Full Opening Safety Valve (FOSV)?

10) How is the Full Opening Safety Valve (FOSV) picked up and made up? What is the shut-in procedure associated with the FOSV? Where is the wrench used to close the FOSV stored?

11) When should you use the Inside BOP (IBOP)?

12) How is the IBOP picked up and made up? What is the shut-in procedure associated with the IBOP?

13) When should you use an FOSV and an IBOP?

14) Which element of the stack should you close when shutting-in the well due to an influx while tripping? Why is this element used as opposed to another element on the stack?

15) What parameters should be recorded after shutting-in on a well kick?

16) What is the distance from the rotary table to the uppermost set of pipe rams?

17) What are three factors that could impact swabbing or surging?

Complications: Select from the following:

Well Continues to Flow:

Questions:

1) What actions should you take if the well continues to flow after the BOP is initially closed?

2) How will you know if the annular is leaking? What action should be taken if the annular is leaking after it is closed?

3) (For SUBSEA applications) What action should you take if you close a second element and the well continues to flow?

4) How will you know if the pipe ram is leaking? What action should be taken if the pipe ram is leaking after it is closed?

Gas Migration:

Questions: Select from the following:

1) What effect does gas migration have on a shut-in well?
2) How can you identify gas migration? What should you do if you determine gas is migrating while the well is shut-in?

Tripping While Taking Losses:

Questions: Select from the following:

1) Are you allowed to trip out of the hole if the well is taking losses?
2) How do you ensure the well will remain overbalanced?
3) Is there a limit to the loss rate before tripping operations are suspended?

Learning Objective/Skills Assessed:

- Possible Kick Indicators
- Positive Kick Indicators
- Procedural Knowledge
- Procedural Execution
- Complication Knowledge
- Supervision of Subordinates
- Communications
- Well Control Theory

D.4 Example: Well Control Drill/Rig Specific Procedure: Shut-in (Logging)

Applicable Drill Participants: 1) Driller, 2) Assistant or Relief Driller, 3) Derrickman/Shakerhand, 4) Floorman/Motorman, 5) Mud Logger

Exercise: Select one of the following:

1) While logging and without notifying the driller ahead of time, simulate an increase in pit volume using a previously specified technique (manually raising pit level float, draining mud from degasser, transferring mud from slugging pit, etc.).
2) While logging, have the driller informed that an influx has been taken.
3) While logging, inform the driller the hole is experiencing severe losses.

Caution:

- Be prepared to prevent closing of the BOP if it is not desired or safe.
- DO NOT allow the Wireline line to be cut or damaged.

Assessment Guidance:

- Record the time required to identify the simulated increase in pit volume.
- Record the time required to complete simulation of the shut-in.
- Observe the Crew. Was the crew able to execute their assigned responsibilities? Was communication between crew members effective? Were any special instructions from the driller followed?
- Observe the Driller. Was the driller's reaction and the direction he provided to the crew members appropriate? Were the driller's communications with other personnel on the rig appropriate and effective?
- Was the rig specific procedure followed and reinforced? Was the rig specific procedure reviewed to ensure compliance once the well/rig was established in a safe or static condition?

Questions: Select from the following (direct appropriate questions to specific individuals to encourage full team participation):

1) What is our primary well control barrier? What is our secondary well control barrier?
2) What specific procedures do you use to monitor the hole for signs of an influx while logging?
3) What are the proper steps and specific responsibilities for each member of the drilling crew when executing the shut-in procedures while logging?
4) What is the displacement volume of the wireline currently being run? What action should you take if the volume gained while tripping in the hole with wireline exceeds this value?
5) How do you know how much wireline has been run in order to determine how much fluid should be displaced to the trip tank?
6) Do you fill the hole at any point while pulling the wireline tools out of the hole, and if so how do you know if the hole is taking the correct amount of fluid?
7) Are you required to fill the hole while tripping out of the hole with logging tools? If yes, how often? What action should you take if there is a discrepancy between the anticipated volume of mud required to fill the hole and the actual volume required to fill the hole?
8) Can your annular seal on wireline?
9) Can your Blind Rams seal on wireline?
10) Can your Blind Shear Rams cut wireline?
11) How would you cut the wireline if the driller directed you to do so?
12) What parameters should be recorded after shutting-in on a well kick?
13) What is the procedure used when conducting formation fluid sampling (MDT, RFT, etc.) to ensure the formation fluids pumped into the wellbore do not result in an underbalanced condition? Is there a limit on how much formation fluid can be pumped into the wellbore during fluid sampling before a trip is required to circulate the wellbore?

Complications: Select from the following:

Well Continues to Flow:

Questions: Select from the following –

1) What actions should you take if the well continues to flow after the BOP is initially closed?

2) How will you know if the annular is leaking? What action should be taken if the annular is leaking after it is closed?

Gas Migration:

Questions: Select from the following –

1) What effect does gas migration have on a shut-in well?

2) How can you identify gas migration? What should you do if you determine gas is migrating while the well is shut-in?

Logging While Taking Losses:

Questions: Select from the following –

1) Are you allowed to log the well if the well is taking losses?

2) How do you ensure the well will remain overbalanced?

3) Is there a limit to the loss rate before logging operations are suspended?

Learning Objective/Skills Assessed:

- Possible Kick Indicators
- Positive Kick Indicators
- Procedural Knowledge
- Procedural Execution
- Complication Knowledge
- Supervision of Subordinates
- Communications
- Well Control Theory

D.5 Example: Well Control Drill/Rig Specific Procedure: Shut-in (Running Casing/Tubing)

Applicable Drill Participants: 1) Driller, 2) Assistant or Relief Driller, 3) Derrickman/Shakerhand, 4) Floorman/Motorman, 5) Mud Logger

Exercise: Select one of the following:

1) While running casing or tubing and without notifying the driller ahead of time, simulate an increase in pit volume using a previously specified technique (manually raising pit level float, draining mud from degasser, transferring mud from slugging pit, etc.).

2) While running casing or tubing have the driller informed that an influx has been taken.

3) While running casing or tubing inform the driller the well is experiencing severe losses.

Cautions:

- Be prepared to prevent closing the BOP if it is not desired or safe.
- If a BOP element is closed during the drill, ensure the element is opened prior to resuming operations.

Assessment Guidance

- Record the time required to identify the simulated increase in pit volume.
- Record the time required to install and close the safety valve, and then close (or simulate closing) the BOP element (complete the shut-in).
- Observe the crew. Was the crew able to execute their assigned responsibilities? Was communication between crew members effective? Were any special instructions from the driller followed?
- Observe the driller? Was the driller's reaction and the direction he provided to the crew members appropriate? Were the driller's communications with other personnel on the rig appropriate and effective?
- Was the rig specific procedure followed and reinforced? Was the rig specific procedure reviewed to ensure compliance once the well/rig was established in a safe or static condition?

Questions: Select from the following (direct appropriate questions to specific individuals to encourage full team participation):

1) What is our primary well control barrier? What is our secondary well control barrier?

2) What specific procedures do you use to monitor the hole for signs of an influx when running casing/tubing?

3) What specific actions would be taken to shut-in the well in response to recognition of a positive kick indicator while running casing or tubing?

4) What are the specific responsibilities for each member of the drilling crew when executing the shut-in procedures while running casing/tubing?

5) What is the displacement volume of the casing/tubing currently being tripped and is this value based upon open ended or closed pipe?

6) How do you monitor and record the fluid displaced from the hole while running casing/tubing?

7) What action should be taken if there is a discrepancy between the anticipated volume of fluid displaced from the hole while running casing/tubing and the actual volume observed?

8) When are you expected to conduct flow checks while running in the hole with casing/tubing?

9) If the well starts flowing while running casing/tubing, how do you isolate the inside of the casing/tubing to prevent flow? Is a crossover required for this procedure?

10) How is the Full Opening Safety Valve (FOSV) or the tool used to shut-off flow from inside the casing/tubing during a kick on your rig picked up and made up? What is the shut-in procedure?

11) Which element of the stack should you close when shutting-in the well due to an influx while running casing/tubing? Why is this element used as opposed to another element on the stack?

12) Do you make any adjustments to the annular operating pressure on your rig prior to running casing? How do you know what adjustment to make?

13) What parameters should be recorded after shutting-in on a well kick?

14) Can the Blind Shear Rams on your rig shear the casing you are about to run?

15) If operations are interrupted while running casing/tubing (for example due to mechanical issues), how should the well be secured and monitored during this time frame?

16) Identify the barriers (internal [tubular bore] and external [tubular annulus]) that are in place while running/pulling the casing/tubing and explain how the barriers function.

17) If auto-fill float equipment is being utilised, explain how the use of this type of equipment would impact a well control situation and explain what rig specific procedures are in in place to address the use of this type of equipment.

18) If a "standing valve" (a one-way check valve used to test tubing while being installed) is being utilised, explain how the use of this type of equipment would impact a well control situation and explain what rig specific procedures are in in place to address the use of this type of equipment.

Complications: Select from the following:

Gas Migration:

Questions: Select from the following –

1) What effect does gas migration have on a shut-in well?

2) How can you identify gas migration? What should you do if you determine gas is migrating while the well is shut-in?

Running Casing While Taking Losses:

Questions: Select from the following –

1) What action do you take if the well starts taking losses while running casing or tubing?

2) Are you allowed to run casing or tubing if the well is taking losses?

3) Is there a limit to the loss rate before you stop running the casing or tubing?

4) How do you ensure the well will remain overbalanced?

5) What action should be taken if you run out of mud in this situation?

Learning Objective/Skills Assessed:

- Possible Kick Indicators
- Positive Kick Indicators
- Procedural Knowledge
- Procedural Execution
- Complication Knowledge
- Supervision of Subordinates
- Communications
- Well Control Theory

D.6 Example: Well Control Drill/Rig Specific Procedure: Shut-in (Out of Hole)

Applicable Drill Participants: 1) Driller, 2) Assistant or Relief Driller, 3) Derrickman/ Shakerhand, 4) Floorman/Motorman, 5) Mud Logger

Exercise: Select one of the following:

1) While out of the hole and without notifying the driller ahead of time, simulate an increase in pit volume using a previously specified technique (manually raising pit level float, draining mud from degasser, transferring mud from slugging pit, etc.).
2) While out of the hole have the driller informed that an influx has been taken.

Caution:

- Be prepared to prevent closing the BOP if it is not desired or safe.
- If a BOP element is closed during the drill, ensure the element is opened prior to resuming operations.

Assessment Guidance:

- Record the time required to identify the simulated increase in pit volume.
- Record the time required to complete the shut-in.
- Observe the crew. Was the crew able to execute their assigned responsibilities? Was communication between crew members effective? Were any special instructions from the driller followed?
- Observe the Driller. Was the driller's reaction and the direction he provided to the crew members appropriate? Were the driller's communications with other personnel on the rig appropriate and effective?
- Was the rig specific procedure followed and reinforced? Was the rig specific procedure reviewed to ensure compliance once the well/rig was established in a safe or static condition?

Questions: Select from the following (direct appropriate questions to specific individuals to encourage full team participation):

1) What is our primary well control barrier? What is our secondary well control barrier?
2) What specific procedures do you use to monitor the hole for signs of an influx while there is no pipe in the hole?
3) What are the specific responsibilities for each member of the drilling crew when executing the shut-in procedures while out of hole?
4) What specific procedures do you use to ensure the hole is full while there is no pipe in the hole?
5) What do you do if the hole will not remain full while there is no pipe in the hole?
6) Do you close the Blind Rams or Blind Shear Rams on your rig when you are out of the hole? How do you know if the hole is staying full? What procedure do you use to open the Blind Rams or Blind Shear Rams when you are ready to run in the hole?
7) What parameters should be recorded after shutting in on a well kick?

Complications: Select from the following:

Gas Migration:

Questions: Select from the following –

1) What effect does gas migration have on a shut-in well?
2) How can you identify gas migration? What should you do if you determine gas is migrating while the well is shut-in?

Learning Objective/Skills Assessed:

- Positive Kick Indicators
- Procedural Knowledge
- Procedural Execution
- Complication Knowledge
- Supervision of Subordinates
- Communications
- Well Control Theory

D.7 Example: Well Control Drill/Rig Specific Procedure: Well Kill

Applicable Drill Participants: 1) Driller, 2) Assistant or Relief Driller, 3) Derrickman/ Shakerhand, 4) Floorman/Motorman, 5) Mud Engineer, 6) Cementer, 7) Sub Sea Engineer, 8) ROV Operator

Exercise: Select one of the following:

Provide a high level well kill scenario with the following details: bit depth, current mud weight, Shut-in Drill Pipe Pressure (SIDPP), Shut-in Casing Pressure (SICP), Pit Gain and current status of the stack (i.e. which element was closed during the Shut-in Procedure).

Conduct a "walk-through" or "table-top" well kill drill using the rig-specific well kill procedure. Ask each member of the crew, starting with the driller and working down to the floorhands, to explain their responsibilities during a standard well kill procedure providing as many specifics as possible. After all crew members have contributed to the discussion, ask the senior rig contractor representative to conduct a simulated pre-kill meeting outlining the roles and responsibilities of all crew members, re-enforcing the comments made by the individual crew members, and identifying and addressing any gaps. At the conclusion of this exercise, debrief and address any gaps not covered.

The "walk through" drill should cover:

- The BOP element to use during the kill
- Monitoring the BOP element for leaks
- Circulation path for the mud during the well kill operation
- Procedure to monitor the Mud/Gas Separator
- Operation of the pump and choke
- Responsibilities of each crew member and the method of communication between crew members (especially the pump operator and the choke operator)

This discussion can be followed with a Choke Drill to simulate and re-enforce the well kill procedures.

Assessment Guidance:

- Did all crew members participate in the discussion? Was each able to explain their specific responsibilities during a standard well kill operation?
- Did the driller identify the proper BOP element to be used during the kill operation?
- Did the discussion include the circulation path for the mud during the well kill operation? Was the path and valve line up correct?
- Did the discussion include the procedure to monitor the Mud/Gas Separator during the well kill operation?
- Did the discussion include who would operate the pump, who would operate the choke and how they would communicate and coordinate their actions?
- Did the discussion include how the BOP would be monitored for leaks during the kill operation and the action to take if a leak was identified?
- Did the senior rig contractor representative conduct an effective pre-kill meeting and address the specific roles and responsibilities of each crew member? Were any gaps in the information provided by the crew members pointed out and addressed?
- Was the rig specific procedure followed and reinforced? Was the rig specific procedure reviewed to ensure compliance once the well/rig was established in a safe or static condition?

Questions: Select from the following (direct appropriate questions to specific individuals to encourage full team participation):

1) What is our primary well control barrier? What is our secondary well control barrier?
2) What could cause "trapped" pressure during a well shut-in? How do you check for "trapped" pressure?

3) Why is it important to recognise and bleed off "trapped" pressure prior to commencing well kill operations?
4) How do you differentiate between trapped pressure and pressure due to the influx? What is the consequence of bleeding off more than just the trapped pressure?
5) What is your rig-specific procedure used to determine the SIDPP when there is a solid float in the drill string?
6) How is the SIDPP used to determine the Kill Weight Mud?
7) Who is the Person-In-Charge (PIC) during a well kill operation?
8) Explain in detail the responsibility of each of the crew members during a well kill operation.
9) Which element of the BOP should be used to kill the well per your rig-specific procedure?
10) Are there any situations which might require you to use a different element of the BOP during a well kill operation? What are the situations, which alternate BOP element would you use and why?
11) Do you lock the rams during a well kill operation? Why or why not? How?
12) Does your rig-specific procedure require the drill pipe to be hung-off during the well kill operation? Which specific ram is used for the hang-off? What is the hang-off weight limit for the ram?
13) Does your rig-specific procedure allow pipe movement during the well kill operation? What are the guidelines or instructions on when and how to move the pipe?
14) Explain your rig-specific procedure to bring the pumps up to speed to the pre-determined kill rate.
15) What are some reasons that it is preferred to use a slow pump rate when killing a well?
16) Who operates the pump and who operates the choke during a well kill operation?
17) How does the choke operator communicate with the pump operator?
18) Explain your rig-specific procedure to shut the pumps down should it become necessary?
19) How are bathroom and/or meal breaks for the choke and pump operators handled?
20) Is the Mud/Gas Separator (poorboy or atmospheric degasser) monitored during well kill operations? What specifically is monitored?
21) What is the maximum pressure allowed on the Mud/Gas Separator during a well kill operation? How is this pressure monitored? What actions are required if the maximum pressure is approached or exceeded?

Complications: Select from the following:

Choke Plugging:

Questions: Select from the following:

1) What could cause choke plugging?
2) How is it recognised?
3) What actions should you take?
4) What is the consequence of not recognising or reacting?

Choke Wash Out:

Questions: Select from the following:

1) What could cause a choke to wash out?
2) How is it recognised?
3) What actions should you take?
4) What is the consequence of not recognising or reacting?

Bit Nozzle Plugging:

Questions: Select from the following:

1) How is bit nozzle plugging recognised?
2) What actions should you take?
3) What is the consequence of not recognising or reacting?

Mud Pump Problems:

Questions: Select from the following:

1) How are pump problems recognised?
2) What actions should you take?

Drill String Washout:

Questions: Select from the following:

1) How is a drill string washout recognised?
2) What immediate actions should you take (subsequent action will be dependent upon suspected location of the washout, location of the influx in the wellbore, etc. and would require consultation with offsite supervisory personnel)?
3) What is the consequence of not recognising or reacting?
4) How might you estimate the location of the washout?

Choke Line Cuts Out:

Questions: Select from the following:

1) What action should you take if the choke line cuts out?

Loss of Mud Leg on Mud/Gas Separator during Well Kill:

Questions: Select from the following:

1) How is loss of the mud leg on the Mud/Gas Separator recognised?
2) What actions should you take?
3) What is the consequence of not recognising or reacting?

Leaking BOP:

Questions: Select from the following:

1) How would you know if the BOP element closed develops a leak during a well kill operation?
2) What specific action would you take to address a leaking BOP element?

Total Loss of Power during Well Kill:

Questions: Select from the following:

1) What action should you take if the rig has a total loss of power?
2) What are each person's responsibilities in the event of a total power loss?

Learning Objective/Skills Assessed:

- Procedural Knowledge
- Complication Knowledge
- Communications
- Well Control Theory

D.8 Example: Well Control Drill/Rig Specific Procedure: Choke

Applicable Drill Participants: 1) Driller, 2) Assistant or Relief Driller, 3 Derrickman/ Shakerhand, 4) Floorman/Motorman

Exercise: Select from the following:

With the well shut-in on a cased hole (per the rig-specific well kill procedure), pump into the annulus to trap ~200 psi of pressure to simulate a kick (do not put pressure on the drill pipe). Have the responsible personnel (per the rig-specific well kill procedure) in position to execute the well kill procedure. Conduct several or all of the following operations with all instructions issued by the appropriate individual per the rig-specific well kill procedure.

One objective of this drill is to ensure the chain of command and communication procedures are clear and functional.

- Line up through the choke manifold and Mud/Gas Separator.
- Have the pump operator bump the float to determine the Shut-in Drill Pipe Pressure (SIDPP).
- Have the choke operator direct the pump operator to bring the pump up to the pre-determined kill rate.
- After the pump is at kill rate and the casing and drill pipe pressure have stabilised, have the choke operator increase the casing pressure by 100 psi and to observe/record the lag time for the drill pipe pressure to increase by 100 psi.
- Have the choke operator direct the pump operator to increase the kill rate by 10 strokes per minute.
- After the casing and drill pipe pressure stabilise, have the choke operator to direct the pump operator to decrease the kill rate by 5 strokes per minute.
- After the casing and drill pipe pressure stabilise, have the choke operator to direct the pump operator to stop the pump.
- Repeat any of the steps above to ensure proficiency.
- After the pump is stopped at the conclusion of the exercise, have the choke operator bleed off the pressure.
- Line up the BOP and choke manifold for normal operations.

Caution:

- Ensure the circulation path is correctly lined up through the choke manifold and Mud/Gas Separator before the float is bumped.
- Ensure all personnel are in their appropriate stations for the well kill operation (or a discussion is held to ensure all personnel understand their station, if there is a desire for some of the personnel to remain on the rig floor to observe the remainder of the drill) prior to initiating the well kill exercise.
- Ensure pressure is bled off and the BOP and choke manifold are correctly lined up for normal operations upon conclusion of the exercise.

Assessment Guidance:

- Is the circulation path correct and are the appropriate valves opened/closed?
- Are all personnel involved in the drill aware of their roles and responsibilities?
- Was the correct procedure utilised to bump the float and was the communication effective during this operation?
- Is communication between the choke operator and pump operator effective?
- Does the choke operator correctly manipulate the choke to maintain constant casing pressure when the pump rates were changed?
- Does the choke operator manage pressure effectively with the choke?
- Was the rig specific procedure followed and reinforced? Was the rig specific procedure reviewed to ensure compliance once the well/rig was established in a safe or static condition?

Questions: Select from the following (direct appropriate questions to specific individuals to encourage full team participation):

1) What is your rig-specific procedure to determine the Shut-in Drill Pipe Pressure (SIDPP) when there is a solid float in the drill string?
2) Who is the Person-In-Charge (PIC) during a well kill operation on your rig?
3) Explain your rig-specific procedure to bring the pumps up to speed to the pre-determined kill rate.
4) Who operates the pump and who operates the choke during a well kill operation?
5) How does the choke operator communicate with the pump operator?
6) Explain your rig-specific procedure to shut the pumps down should it become necessary?
7) How are bathroom and/or meal breaks for the choke and pump operators handled?

Complications: Select from the following:

Choke Plugging:

Questions: Select from the following:

1) What could cause choke plugging?
2) How is it recognised?
3) What actions should you take?
4) What is the consequence of not recognising or reacting?

Choke Wash Out:

Questions: Select from the following:

1) What could cause a choke to wash out?
2) How is it recognised?
3) What actions should you take?
4) What is the consequence of not recognising or reacting?

Bit Nozzle Plugging:

Questions: Select from the following:

1) How is bit nozzle plugging recognised?
2) What actions should you take?
3) What is the consequence of not recognising or reacting?

Mud Pump Problems:

Questions: Select from the following:

1) How are pump problems recognised?
2) What actions should you take?

Drill String Washout:

Questions: Select from the following:

1) How is a drill string washout recognised?
2) What immediate actions should you take (subsequent action will be dependent upon suspected location of the washout, location of the influx in the wellbore, etc. and would require consultation with offsite supervisory personnel)?
3) What is the consequence of not recognising or reacting?
4) How might you estimate the location of the washout?

Choke Line Cuts Out:

Questions: Select from the following:

1) What action should you take if the choke line cuts out?

Learning Objective/Skills Assessed:

- Procedural Knowledge
- Procedural Execution
- Complication Knowledge
- Supervision of Subordinates
- Communications
- Well Control Theory

D.9 Example: Well Control Drill/Rig Specific Procedure: Diverter

Applicable Drill Participants: 1) Driller, 2) Assistant or Relief Driller, 3) Derrickman/ Shakerhand, 4) Floorman/Motorman, 5) Subsea Engineer

Exercise: Select one of the following:

1) (Surface Stack with Diverter) During a connection or flow check, inform the driller that the well is flowing.
2) (Subsea Stack) After latching the stack and prior to displacing the riser from seawater to mud, close the annular and simulate flow from an influx in the riser using the booster pump.
3) (Subsea Stack) After closing the annular during a shut-in drill, inform the driller the well is continuing to flow.

Assessment Guidance:

- Observe the driller. Were the driller's reaction and the direction he provided to the crew members appropriate? Were the driller's communications with other personnel on the rig appropriate and effective?
- Observe the crew. Was the crew able to execute their assigned responsibilities? Was communication between crew members effective? Were any special instructions from the driller followed?
- Did the driller and crew members demonstrate knowledge of the rig diverter equipment capability and operability? Were the valve(s) to the appropriate diverter line(s) opened. Were the crew members familiar with their muster locations?
- Was the rig specific procedure followed and reinforced? Was the rig specific procedure reviewed to ensure compliance once the well/rig was established in a safe or static condition?

Questions: Select from the following (direct appropriate questions to specific individuals to encourage full team participation):

1) What is our primary well control barrier? What is our secondary well control barrier?
2) Explain and discuss the divert procedures for the rig, including the sequencing of the divert equipment.
3) Explain and discuss the evacuation plan for the rig and specifically when evacuation is required during a divert operation?
4) Explain in detail the responsibility of each of the crew members during a divert situation.
5) What is the maximum pressure rating of your diverter system?
6) What is the maximum flow capacity of your diverter system?
7) Under what circumstances would you close the diverter?
8) What tests/checks do you carry out on the diverter system before starting to drill?
9) Can you line up to divert through the poor boy degasser? Should you ever divert through the poor boy degasser?
10) Where are the control panels for the diverter?
11) If you have more than one diverter line available, how do you select which line to use?
12) What are the main hazards when diverting and how do you manage these hazards?
13) For a Subsea Stack - Under what circumstances would you consider closing the diverter before closing the BOP?
14) For a Subsea Stack - If, after spacing out across the BOP, there was a tool joint across the diverter, what would you do?

Complications: Select from the following:

Diverter Equipment Issues:

Questions: Select from the following:

1) What do you do if the diverter packer starts leaking during a divert situation?
2) What do you do if you are diverting upwind?
3) (Subsea Stack) What do you do if the slip joint leaks during a divert situation?

Learning Objective/Skills Assessed:

- Procedural Knowledge
- Complication Knowledge
- Communications
- Well Control Theory

D.10 Example: Well Control Drill/Rig Specific Procedure: Emergency Disconnect Sequence (EDS)

Applicable Drill Participants: 1) Driller, 2) Assistant or Relief Driller, 3) Derrickman/ Shakerhand, 4) Floorman/Motorman, 5) Subsea Engineer, 6) ROV Operator

Exercise: Select one of the following:

1) Have the Bridge issue a White Advisory to the drill floor, wait 5 minutes and then follow the White Advisory with a Yellow Alert. After the appropriate action is taken for the Yellow Alert, discuss the steps to be taken if the situation progresses to a Red Alert. Do Not Issue a Red Alert to the drill floor! This exercise can be done as an "Announced" or "Unannounced" drill.
2) Have the Bridge issue a Yellow Alert to the drill floor. After the appropriate action is taken for the Yellow Alert, discuss the steps to be taken if the situation progresses to a Red Alert. Do Not Issue a Red Alert to the drill floor! It is recommended to do this **exercise as an "Announced" drill**.

Caution:

- Do Not Issue a Red Alert to the drill floor!
- Ensure personnel involved in conducting the drill are located near all panels capable of initiating the EDS sequence to ensure it is not inadvertently initiated as a result of the drill.

Assessment Guidance:

- Observe the driller. Were the driller's reaction and the direction he provided to the crew members appropriate? Were the driller's communications with other personnel on the rig appropriate and effective?
- Observe the crew. Was the crew able to execute their assigned responsibilities? Was communication between crew members effective? Were any special instructions from the driller followed?

- Was the rig specific procedure followed and reinforced? Was the rig specific procedure reviewed to ensure compliance once the well/rig was established in a safe or static condition?
- Did the driller and crew members demonstrate knowledge of the Emergency Disconnect Procedures and the Well Specific Operation Guidelines.

Questions: Select from the following (direct appropriate questions to specific individuals to encourage full team participation):

1) What is our primary well control barrier? What is our secondary well control barrier?
2) Are you aware of and familiar with the Well Specific Operating Guidelines (or equivalent) in use during the current operation?
3) What conditions can evoke a White Advisory status?
4) Explain and discuss the specific action which must be taken by each crew member when a White Advisory is issued (at a minimum, discuss action to be taken by the DPO, driller and subsea engineer).
5) What conditions can evoke a Yellow Alert?
6) Explain and discuss the specific action which must be taken by each crew member when a Yellow Alert is issued (at a minimum, discuss action to be taken by the DPO, driller and subsea engineer).
7) What conditions can evoke a Red Alert?
8) Explain and discuss the specific action which must be taken by each crew member when a Red Alert is issued (at a minimum, discuss action to be taken by the DPO, driller and subsea engineer).
9) Are there any Emergency Shut Down (ESD) systems on the rig which should be activated during an EDS event? Is there more than one ESD panel and where are they located? What is the purpose of the ESD system, what actually happens when the ESD is activated on the rig and who is responsible for activating the ESD and when should they activate the ESD?
10) How often are the watch circles updated and what evokes a revision to the watch circle?
11) Explain the sequence of events that occur with the BOP stack and riser tensioning system after the EDS is initiated as a result of a Red Alert?
12) Explain how the riser recoil system works on your rig and the potential risks associated with the riser system when the LMRP is disconnected during an EDS event.
13) Is there more than one option available to control the actual Emergency Disconnect Sequence on your rig (such as EDS1, EDS2, etc.)? If so, what are the differences, who decides which EDS option is active and when would the EDS option potentially be revised?
14) Is there a Deadman System (DMS) on your rig? What could potentially active the DMS and what sequence of events occur on the BOP stack if the DMS is activated?
15) Is there an Autoshear system your rig? What could potentially active the Autoshear what sequence of events occur on the BOP stack if the Autoshear is activated?

16) Explain how and when the Deadman and Autoshear systems are tested.
17) Explain what functions on the BOP stack can be operated by the ROV.
18) Describe what equipment is required to activate the ROV functions on the stack.
19) Explain the procedures associated with activating each of the ROV functions on the BOP stack.
20) Explain how and when the ROV functions on the BOP stack are tested.
21) What is the purpose of the Emergency Shut Down (ESD) system? What actually happens when the ESD is activated on the rig and who is responsible for activating the ESD and when should they activate the ESD?

Complications: Select from the following:

Potential Emergency Disconnect Sequence (EDS) Issues:

Questions: Select from the following:

1) What do you do if you are unable to communicate with the bridge when the Yellow Alert is issued? What do you do in this situation if the alert status degrades to a Red Alert?
2) What do you do if the pipe is stuck when a Yellow Alert is issued, and you are unable to space out to the hang-off position? Would the action taken differ if you had a tool joint or an un-shearable tubular across your shear rams?
3) What do you do if you do not have fixed rams identified as hang-off rams and your current string weight below the BOP stack exceeds the capacity of your variable bore rams?
4) What do you do if you are cementing a casing string or liner when the Yellow Alert is issued? Would your action differ if hydrocarbons were being isolated by the casing/liner being cemented?
5) What do you do if you are circulating out an influx when the Yellow Alert is issued? Would this action differ if the influx was in the choke line(s) at the time of the Yellow Alert? What would you do if the influx was in the choke line and the alert status degrades to a Red Alert?
6) What do you do if the rig is heaving heavily when the Yellow Alert is issued?
7) What do you do if a Yellow Alert is issued when the following non-shearables are across the stack: drill collars, thick wall casing, core barrel, perforating guns, others?

Learning Objective/Skills Assessed:

- Procedural Knowledge
- Complication Knowledge
- Communications
- Well Control Theory

D.11 Example: Well Control Drill/Rig Specific Procedure: Contingency – Non-shearables across the BOP

Applicable Drill Participants: 1) Driller, 2) Assistant or Relief Driller, 3) Derrickman/ Shakerhand, 4) Floorman/Motorman, 5) Subsea Engineer, 6) ROV Operator

Exercise: Select one of the following:

Simulate an influx while non-shearable tubulars such as those noted below are across the BOP stack:

- Drill Collars / HWDP
- Casing
- Vacuum Insulated Tubing (VIT) c/w control lines or power cables
- Mud motors / Rotary Steerable Assemblies
- Tubing hangers / Tubing Hanger Running Tool
- Core barrels
- Electrical Submersible Pumps (ESPs)
- Sand screens c/w washpipe
- Other situations as identified in the risk assessment or noted in the drilling/completion/ workover program

Caution:

- This drill should be performed prior to running any known non-shearables across the BOP stack.
- Be prepared to prevent closing the BOP if it is not desired or safe.

Assessment Guidance:

- The rig crews should be made aware of any non-shearables which could be run and should be able to demonstrate that they understand equipment limitations and specifically how the well would be shut-in and secured for each specific non-shearable tubular.
- Observe the crew. Did the driller and crew members demonstrate knowledge of the precautions/actions which must be taken prior to running non-shearables across the stack and the shut-in procedures associated with the non-shearables?
- Was the rig specific procedure followed and reinforced? Was the rig specific procedure reviewed to ensure compliance once the well/rig was established in a safe or static condition?

Questions: Select from the following (direct appropriate questions to specific individuals to encourage full team participation):

1) What is our primary well control barrier? What is our secondary well control barrier?
2) Explain the specific shut-in procedures associated with the non-shearables you are about to run or which are currently across the stack.

3) Explain in detail the responsibility of each of the crew members during the shut-in procedure.
4) If your procedure requires "dropping the pipe", discuss the specific actions required to do this and identify who is responsible for each action. Discuss the practicality of these actions. Could the crew actually conduct these operations? Is the required equipment in place to allow the operation to be conducted? What action is taken if there is no time to conduct the operation?
5) What specific actions do you take prior to running non-shearables across the stack? Include any special pup joints, elevators, bails, etc. which may be required for the contingency procedures. Include any action taken by the ROV operator or bridge, marine, subsea or maintenance departments.
6) Prior to setting the slips, stopping to circulate or "chaining the brake" for any reason, do you consider the location of any non-shearables and take action to ensure they are not across the stack if at all possible?
7) What is the maximum pressure that can be utilised on the operators for the shear ram? Are there any procedural steps which must be taken in order to apply the maximum pressure to the operators on the shear rams?
8) Under what circumstances, if any, would you intentionally close the shear rams when non-shearables are across the stack?
9) Does the ROV operator have any responsibilities associated with your contingency procedures for non-shearables across the stack? What are they?

Complications: Select from the following:

Potential Issues with Non-shearables across the BOP:

Questions: Select from the following:

1) What do you do if the rig loses power when non-shearables are across the stack?
2) What do you do if the pipe is stuck while non-shearables are across the stack?

Learning Objective/Skills Assessed:

- Procedural Knowledge
- Complication Knowledge
- Communications
- Well Control Theory

D.12 Example: Well Control Drill/Rig Specific Procedure: Stripping

Applicable Drill Participants: 1) Driller, 2) Assistant/Relief Driller, 3) Derrickman/ Shakerhand, 4) Floorman/Motorman, 5) Subsea Engineer, 6) Mud Engineer, 7) Mud Logger

Exercise: Select one of the following:

1) Table Top Drill - Provide a high-level stripping scenario with the following details: hole depth, bit depth (or how far off bottom), current mud weight, Shut-in Drill Pipe Pressure (SIDPP), Shut-in Casing Pressure (SICP), Pit Gain and current status of the stack (i.e. which element was closed during the Shut-in Procedure). Conduct a "walk-through" or "table-top" stripping drill using the rig-specific stripping procedure. Ask each of the drill participants to explain their responsibilities during a stripping

   Operation, providing as many specifics as possible. After all participants have contributed to the discussion, ask the senior rig contractor representative to discuss the roles and responsibilities of all crew members using the rig specific procedure, re-enforcing the comments made by the individual crew members, and identifying and addressing any gaps. At the end of this exercise, debrief and address any gaps identified.

   The "walk through" drill should cover:

   - Objectives and Theory – what is the goal and how are we going to get there?
   - The BOP component(s) to use during the drill, any regulator pressure settings/ adjustments, and why the components and pressure settings were selected
   - Appropriate line up of choke manifold and use of trip tank and/or stripping tank
   - Stripping schedule and volumes anticipated as per schedule
   - Potential issues associated with a gas kick and how to address in the stripping schedule: gas migration and elongation of the gas when BHA stripped into the kick
   - Procedures to discharge/empty stripping tank back to active system
   - Expected hookload variation and what variables could affect the hookload

2) Practice Drill (off bottom kick; 300 psi SICP; no gas migration occurring; 100 psi Safety Factor for the stripping operation) - While tripping in/out of a cased hole with a cemented shoe track:

   - Shut-in the well using the FOSV and the annular preventer (per the rig specific shut-in procedure).
   - Install the IBOP and open the FOSV used to shut-in the well. Ensure the choke is closed and open the HCR.
   - Apply 300 psi pressure on the annulus using the kill line. Check to ensure the IBOP is not leaking.
   - Reduce the closing pressure on the annular preventer as low as possible and still maintain a seal. Open valve to surge bottle on annular closing line if one exists.
   - Line up choke manifold to trip/strip tank (tank should be ~ 1/3 full).
   - Make-up next stand. Use a file to remove any tong/slip marks on the pipe and apply mud or suitable lubricant to the bottom upset of the tool joints prior to passing through the rotary table (surface stack only).

- Slowly strip the first stand into the hole with choke closed (i.e. without bleeding mud) until the casing pressure reaches 400 psi (300 psi SICP + 100 psi Safety Factor).
- Continue stripping the first stand into the hole maintaining the casing pressure at 400 psi while stripping by bleeding off through the choke. Measure volume bled to ensure it is equal to the closed end volume stripped (use closed end volume stripped after reaching the 400 psi pressure).
- Install second stand and slowly strip in while maintain pressure at 400 psi. Measure volume bled to ensure it is equal to the closed end volume stripped.
- Fill the inside of the two stripped stands with mud.
- Strip additional stands using same procedure if required to ensure the crew is comfortable with the operation.
- When the stripping operation is finished – bleed off casing pressure through the choke; close valve to annular surge bottle if used; increase annular regulator to normal operation pressure; open annular; close HCR; align choke manifold for normal drilling operations; pull stripped stands to FOSV; close FOSV; remove IBOP (check for trapped pressure); open FOSV (to bleed any trapped pressure); remove FOSV.
- Debrief and address any gaps. Consider pressure testing the annular prior to commencing the tripping operation.

Caution:

- Check for trapped pressure below the IBOP and FOSV prior to breaking out.
- Ensure the BOP and choke manifold are correctly lined up for normal operations upon conclusion of the exercise.

Assessment Guidance:

- Did all crew members participate in the discussion? Was each able to explain their specific responsibilities during a standard stripping operation?
- Did the Subsea Engineer participate and identify proper regulator setting pressures?
- Did the discussion include the circulation path for the mud during the stripping operation? Was the path and valve line up correct?
- Did the discussion include why mud is bled off while stripping and the fundamental concepts associated with the stripping schedule?
- Did the discussion include the procedure to monitor the stripping tank during the stripping operation?
- Did the discussion include who would operate the choke and the communication path?
- Did the discussion include how the BOP would be monitored during the stripping operation and the action to take if a leak was greater than the intended weep?
- Did the senior rig contractor representative conduct an effective pre-stripping meeting and address the specific roles and responsibilities of each crew member? Were any gaps in the information provided by the crew members pointed out and addressed?
- Was the rig specific procedure followed and reinforced?
- Anticipating a successful stripping operation, was the next step in the well control process discussed?

Questions: Select from the following (direct appropriate questions to specific individuals to encourage full team participation):

1) What is our primary well control barrier? What is our secondary well control barrier?
2) Who is the Person-In-Charge (PIC) during a stripping operation?
3) Explain in detail the responsibility of each of the crew members during a stripping operation.
4) Which component(s) of the BOP should be used for stripping operations as per your rig-specific procedure?
5) Is there a surge bottle installed on the annular hydraulic closing line? Does the rig specific procedure require a surge bottle to be installed prior to stripping?
6) What method is used to determine the lowest practical closing pressure (regulator setting) on the annular preventer during a stripping operation? Why is it important to minimise the regulator setting for the annular preventer?
7) Why is the pressure regulator on the annular adjusted to the minimum value that will still allow the annular to seal prior to stripping?
8) Who operates the regulator pressure on the annular during a stripping operation?
9) Does the rig specific stripping procedure require the control line for the opening chamber of the annular to be vented during the stripping operation?
10) Who operates the choke during a stripping operation?
11) How does the choke operator communicate with the other team members?
12) Why is it important to ensure the mud volume returning to the strip/trip tank is carefully monitored and precisely recorded? Is there a means to drain mud that might leak past the annular from the flowline to the trip tank during the stripping operation?
13) Who is responsible for keeping an accurate stripping log?
14) What volume of mud should be used in the trip/strip tank as a starting volume prior to stripping? At what volume is the trip/strip tank pumped out to return to the initial starting volume? Should fresh mud be used in the trip/strip tank?
15) What are possible actions that can be taken if the mud in the trip tank is foamy and hence difficult to accurately read the small volumes associated with the stripping operation?
16) If there is no gas migration, what volume of mud should be bled off for each stand of pipe stripped into the hole? Does this volume change if there is a ported float or no float in the drill pipe?
17) What happens in the wellbore if you accidentally bleed off more volume or more pressure than indicated by the stripping schedule?
18) What happens in the wellbore if you don't bleed off as much pressure/volume as the stripping schedule indicates?
19) Explain how you would fill the string during the stripping operation. How often is the inside of the drill pipe filled during the stripping operation?
20) Is there a maximum recommended stripping speed? If so, what is it and why?

21) Does the rig specific procedure specify a maximum allowable stripping speed? Why is it important to minimise the stripping speed?

22) When was the IBOP last certified? When was the IBOP last pressure tested? Why is it important to have a properly functioning IBOP during a stripping operation?

23) When is the job complete?

24) Subsea Only: If the BOP has a pressure sensor, is information from this sensor monitored and considered during the stripping operation?

Complications: Select from the following:

Potential Stripping Issues:

Questions: Select from the following:

1) Are there any situations which might require you to use a different component of the BOP during a stripping operation? What are the situations? Which alternate BOP component would you use and why?

2) What possible steps could be taken to allow the stripping operation to continue if the annular is providing too much resistance to allow the tool joint to be stripped through it?

3) Are there any situations defined in the rig specific procedure for stripping which would require the stripping operations to stop? What are they?

Learning Objective/Skills Assessed:

- Communications
- Procedural Knowledge
- Procedural Execution (Practice Drill only)
- Supervision of Subordinates (Practice Drill only)
- Well Control Theory

D.13 Example: Well Control Drill/Coiled Tubing Specific Procedure: Leak from CT pressure control equipment (PCE)

Note: API 16ST First Edition, Annex B contains example Well Control Contingencies and Drills that can be used to design more detailed drills and accepted procedures for restoring well control, including crew-member roles & responsibilities. The applicable API 16ST Annex B case number designation follows the exercises below.

Applicable Drill Participants: 1) Coiled Tubing Supervisor/Operator, 2) Coiled Tubing crew

Exercise: Select one of the following:

1) With CT in the hole, CT crew reports leak of wellbore fluids from packoff or stripper assembly (API 16ST B.2 Case A).

2) With CT in the hole, CT crew reports leak of wellbore fluids from pressure control equipment or flange leak below BOP rams (API 16ST B.8 Case G).

3) With CT in the hole, CT crew reports leak of wellbore fluids from pressure control equipment above the BOP rams. (API 16ST B.9 Case H).

Caution:

- Be prepared to prevent closing the BOP if it is not desired or safe.
- Do not allow the tree valves or Sub-Surface Safety Valve (SSSV) to be closed if it is not desired or safe to do so.

Assessment Guidance:

- Record the time required to establish a safe or static condition.
- Observe the Crew. Was the crew able to execute their assigned responsibilities? Was communication between crew members effective? Were any special instructions from the driller followed?
- Observe the CT Supervisor. Was the CT Supervisor's reaction and the direction he provided to the crew members appropriate? Were the CT Supervisor's communications with other personnel in the area appropriate and effective? Were appropriate incident notifications simulated.
- Was the CT unit specific procedure for shutting in the well followed and reinforced?
- Are the procedures for shutting in the well easily accessible and known to all crew members?
- Is an accurate drawing of the BOP and Pressure control equipment available on location?
- Were Well Control Standing Orders posted on the coil unit?
- Once the drill was complete, did the crew conduct a review to identify areas for improvement?

Questions: Select from the following (direct appropriate questions to specific individuals to encourage full team participation):

1) What is our primary well control barrier? What is our secondary well control barrier?
2) What specific procedures do you use to monitor the well for signs of a leak while running CT in the hole?
3) What are the proper steps and specific responsibilities for each member of the CT crew when securing the well after a leak has been identified?
4) Where are the evacuation muster areas in case the incident escalates beyond control? Was wind direction considered in choosing muster area?
5) Who should be immediately notified of the incident?
6) What equipment should be immediately shut-down to eliminate ignition sources?
7) Would it be possible and safe to pump kill weight fluid into the well or bleed wellhead pressure to reduce the leak if BOPs are not effective in shutting in the well? Should the rig-up be altered to allow for this contingency?
8) What parameters should be recorded after securing or stabilizing the well?
9) Did you identify any areas for improvement while conducting the drill? What actions will you take to get better?
10) Were secondary BOP controls considered or discussed during the drill? Have they been function tested?

11) How will BOP system performance be affected if the nitrogen pre-charge pressure is lost in an accumulator bottle?

Complications: Select from the following:

Well Continues to Leak:

Questions: Select from the following:

1) What next steps should you take to secure the well and keep people safe if the initial attempt to stop the leak is not effective? Would the leak rate and fluid type affect the decision?
2) Under what condition would it be safe/unsafe to pull the CT BHA to surface so tree valves or SSSV can be closed?

Collapsed CT:

Questions:

1) What could be done to secure the well if a collapsed section of CT has been pulled into the stripper?

CT is stuck or on bottom:

1) What if the CT will not drop after shearing because it is either stuck or already sitting on bottom?

Loss of BOP accumulator system hydraulics:

1) What would you do if BOP accumulator system hydraulic pressure is lost?

Freezable fluids in CT:

Questions: Select from the following:

1) In freezing weather, what precautions should be taken to prevent freezing of fluids inside the CT, treating iron or return/choke line?
   **Note: the priority should be on securing/shutting in the well, however allowing the fluids to freeze can create additional hazards and complications.*
2) If fluids inside the CT are allowed to freeze, how would that complicate well kill and recovery operations?

Learning Objectives/Skills Assessed:

- Procedural knowledge
- Procedural execution
- Complication knowledge
- Supervision of subordinates
- Communications
- Evacuation & notification protocol
- Well Control theory
- Effectiveness of Drill

D.14 Example: Well Control Drill/Coiled Tubing Specific Procedure: Leak from Coiled Tubing at Surface

Note: API 16ST First Edition, Annex B contains example Well Control Contingencies and Drills that can be used to design more detailed drills and accepted procedures for restoring well control, including crew-member roles & responsibilities. The applicable API 16ST Annex B case number designation follows the exercises below.

Applicable Drill Participants: 1) Coiled Tubing Supervisor/Operator, 2) Coiled Tubing crew

Exercise: Select one of the following:

1) With CT in the hole, a leak is identified in the CT between the tubing guide arch and the reel (API 16ST B.3 Case B).
2) With CT in the hole, a leak is identified in the CT between the tubing guide arch and the stripper assembly (API 16ST B.4 Case C).
3) With CT in the hole, the CT parts between the tubing guide arch and the reel (API 16ST B.5 Case D).
4) With CT in the hole, the CT parts between the tubing guide arch and the stripper assembly (API 16ST B.6 Case E).

Caution:

- Be prepared to prevent closing the BOP if it is not desired or safe.
- Do not allow the tree valves or Sub-Surface Safety Valve (SSSV) to be closed if it is not desired or safe to do so.

Assessment Guidance:

- Record the time required to establish a safe or static condition.
- Observe the Crew. Was the crew able to execute their assigned responsibilities? Was communication between crew members effective? Were any special instructions from the driller followed?
- Observe the CT Supervisor. Was the CT Supervisor's reaction and the direction he provided to the crew members appropriate? Were the CT Supervisor's communications with other personnel in the area appropriate and effective? Were appropriate incident notifications simulated.
- Was the CT unit specific procedure for shutting in the well followed and reinforced?
- Are the procedures for shutting in the well easily accessible and known to all crew members?
- Is an accurate drawing of the BOP and Pressure control equipment available on location?
- Once the drill was complete, did the crew conduct a review to identify areas for improvement?

Questions: Select from the following (direct appropriate questions to specific individuals to encourage full team participation):

1) What is our primary well control barrier? What is our secondary well control barrier?
2) What specific procedures do you use to monitor the well for signs of a leak while running CT in the hole?
3) What are the proper steps and specific responsibilities for each member of the CT crew when securing the well after a leak has been identified?
4) Where are the evacuation muster areas in case the incident escalates beyond control? Was wind direction considered in choosing muster area?
5) Who should be immediately notified of the incident?
6) What equipment should be immediately shut-down to eliminate ignition sources?
7) Would the leak rate/severity have an impact on which course of action to take?
8) Would it be possible and safe to pump kill weight fluid into the well or bleed wellhead pressure to reduce the leak if BOPs are not effective in shutting in the well? Should the rig-up be altered to allow for this contingency?
9) What parameters should be recorded after securing or stabilizing the well?
10) Have exclusion zones been identified for safety of personnel in case the damaged CT parts as it comes over the guide arch or onto the reel?
11) Did you identify any areas for improvement while conducting the drill? What actions will you take to get better?

Complications: Select from the following:

CT check valves are not holding:

Questions: Select from the following:

1) What next steps should you take to secure the well and keep people safe if the CT check valves are not holding and fluids are leaking from the CT?
2) Would it ever be safe or advisable to run the CT leak back into the well below the stripper? What are the risks of doing this?

Hazardous or Freezable fluids in CT:

Questions: Select from the following:

1) What actions should be taken if hazardous or energized fluids are leaking from the CT? Consider different leak rate/severity in your response.
2) How would the well kill be complicated if fluids inside the CT are allowed to freeze? What actions could be taken to reduce the likelihood that this would happen?

Buckled CT:

Question:

1) What could be done to secure the well if the failed CT was caused by buckling between the stripper assembly and injector, assuming the CT has become mechanically stuck at the stripper (Reference API 16ST B.7 Case F)?

BHA or non-shearables across the BOP:

Question:

1) How would the shut-in procedure change if a non-shearable or large OD BHA is positioned across the BOP stack?

Stuck CT:

1) What if the CT will not drop after shearing because it is either stuck or already sitting on bottom?

Loss of BOP accumulator system hydraulics:

1) What would you do if BOP accumulator system hydraulic pressure is lost?

Learning Objectives/Skills Assessed:

- Procedural knowledge
- Procedural execution
- Complication knowledge
- Supervision of subordinates
- Communications
- Evacuation & notification protocol
- Well Control theory
- Effectiveness of Drill

D.15 Example: Well Control Drill/Wireline Specific Procedure: Leak from wireline pressure control equipment (PCE)

Applicable Drill Participants: 1) Wireline Supervisor, 2) Wireline crew

Exercise: Select one of the following:

1) With wireline tools in the hole, wireline crew reports severe leak of wellbore fluids from above the wireline valves.
2) With wireline tools in the hole, wireline crew reports severe leak of wellbore fluids from below wireline valves, but above tree.
3) With wireline tools in the hole, wireline crew reports severe leak of wellbore fluids from below tree.

Caution:

- Be prepared to prevent closing the wireline BOP if it is not desired or safe.
- Do not allow the wireline to be cut or damaged.

Assessment Guidance:

- Record the time required to establish a safe or static condition.
- Observe the Crew. Was the crew able to execute their assigned responsibilities? Was communication between crew members effective? Were any special instructions from the driller followed?
- Observe the Wireline Supervisor. Was the Wireline Supervisor's reaction and the direction he provided to the crew members appropriate? Were the Wireline Supervisor's communications with other personnel in the area appropriate and effective? Were appropriate incident notifications simulated.
- Was the wireline unit specific procedure for shutting in the well followed and reinforced?
- Once the drill was complete, did the crew conduct a review to identify areas for improvement?
- Are the procedures for shutting in the well easily accessible and known to all crew members?

Questions: Select from the following (direct appropriate questions to specific individuals to encourage full team participation):

1) What is our primary well control barrier? What is our secondary well control barrier?
2) What specific procedures do you use to monitor the well for signs of a leak while running wireline tools in the hole?
3) What are the proper steps and specific responsibilities for each member of the wireline crew when securing the well after a leak has been identified?
4) Where are the evacuation muster areas in case the incident escalates beyond control? Was wind direction considered in choosing muster area?
5) Who should be immediately notified of the incident?
6) What equipment should be immediately shut-down to eliminate ignition sources?
7) Would it be possible and safe to pump kill weight fluid into the well or bleed wellhead pressure to reduce the leak if BOPs are not effective in shutting in the well? Should the rig-up be altered to allow for this contingency?
8) How would you cut the wireline if directed by the Wireline Supervisor to do so?
9) What parameters should be recorded after securing or stabilizing the well?
10) Did you identify any areas for improvement while conducting the drill? What actions will you take to get better?

Complications: Select from the following:

Well Continues to Leak:

Questions: Select from the following:

1) What actions should you take to secure the well and keep people safe if the wireline valves are not effective in stopping the leak?
2) Under what condition would it be safe/unsafe to pull the wireline tools to surface so tree valves or Sub-surface Safety Valve (SSSV) can be closed?

Toolstring stuck across the tree:

Questions: Select from the following:

1) How would you secure the well if a leak started while the wireline toolstring is stuck across the tree ?
2) What conditions could lead to having wireline tools or bird-nested wire stuck across the tree?
3) How would you configure contingency valves and lubricator for subsequent fishing operations?

Learning Objectives/Skills Assessed:

- Procedural knowledge
- Procedural execution
- Complication knowledge
- Supervision of subordinates
- Communications
- Evacuation & notification protocol
- Well Control theory
- Effectiveness of Drill

Glossary

Crew Resource Management or non-technical skills: a term that came from the aviation industry and can be defined as the "cognitive, social and personal resource skills that complement technical skills, and contribute to safe and efficient task performance".[1] (Flin et al, 2008).

Drill: Supervised exercises designed to develop and improve competency where participants diagnose, identify and perform appropriate responses to a simulated situation.

Well operations team members: engineers and technicians who perform operational roles in drilling, completion, work-over and intervention operations defined as requiring certification in well control.

[1] Flin R et al. *Safety at the Sharp End: A Guide to Non-Technical Skills*. Boca Raton: CRC Press, 2008.

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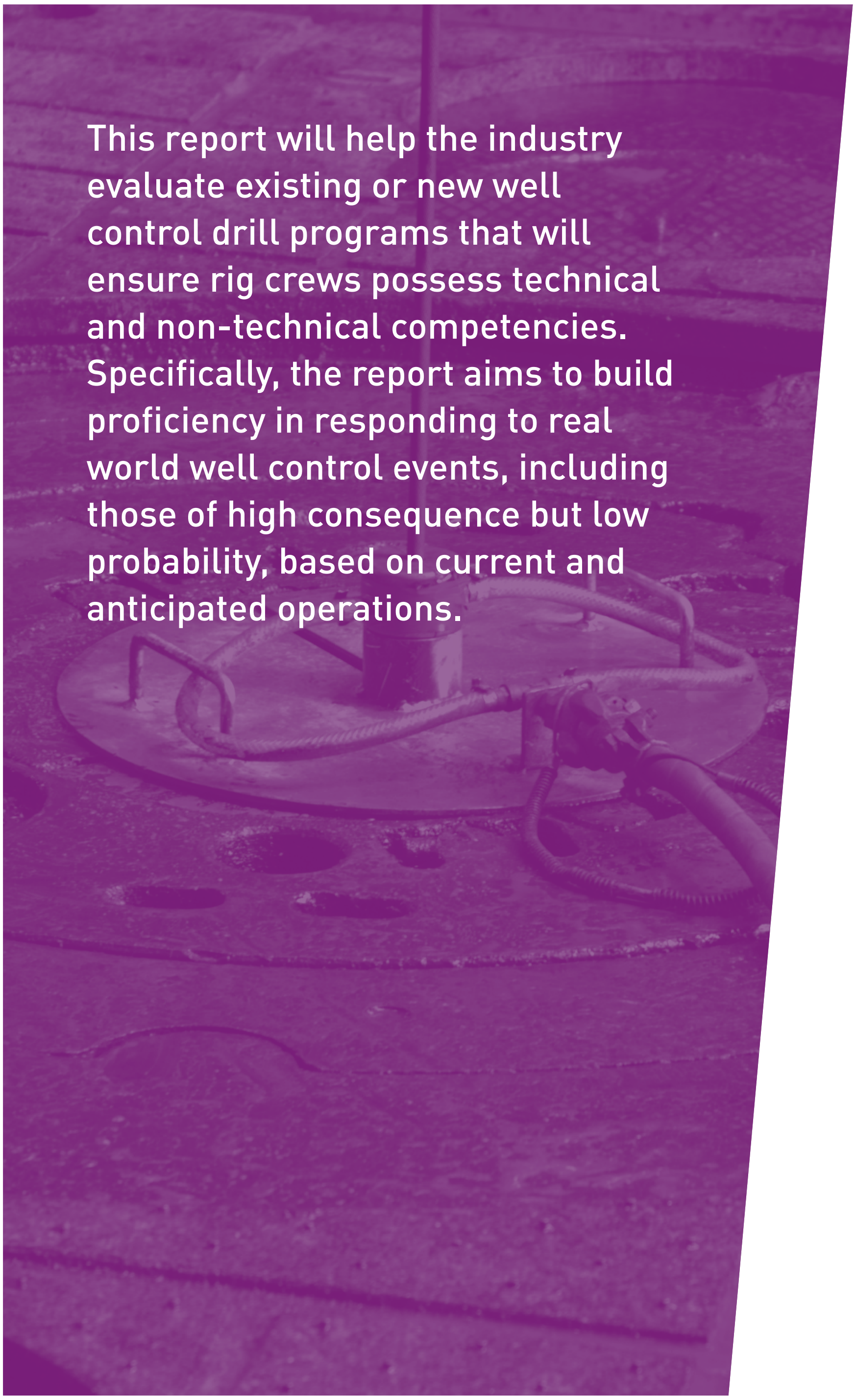

This report will help the industry evaluate existing or new well control drill programs that will ensure rig crews possess technical and non-technical competencies. Specifically, the report aims to build proficiency in responding to real world well control events, including those of high consequence but low probability, based on current and anticipated operations.