

# **EFFECTS OF TRIPPING AND SWABBING IN DRILLING AND COMPLETION OPERATIONS**

# **FINAL REPORT**

**Prepared for**  
**The Department of the Interior,**  
**Bureau of Safety and Environmental Enforcement**

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## **PREFACE**

The body of the report was organized into sections according to the task descriptions in the contract so that those within BSEE interested in a given task can find a complete discussion of the task in one place. Since the tasks are interrelated and consider some of the same topics, the report contains redundant coverage of some topics as required to fully discuss each task.

An Executive Summary is included for management level personnel. A more detailed Technical Summary is also provided along with Summary Table of Findings and Recommendations which provides the complete listing of study recommendations and their key supporting findings.

Since the report is directed primarily to individuals with a technical background, terminology commonly used in the oil and gas industry has been freely used in the interest of brevity. A nomenclature table and a table of abbreviations and acronyms have been provided in Appendix A.

Approval and acceptance of this report does not signify that the contents necessarily reflect the views and policy of BSEE, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

It is important that readers understand that the study's scope of work was focused on tripping operations and swab effects that can result from tripping in a drilling or completions context. All observations, findings, recommendations, and opinions expressed in this report apply only to the scope of the study and cannot necessarily be generalized beyond that scope.

**EXECUTIVE SUMMARY**

The study verified that existing well control practices and procedures in wide use while tripping during drilling and completion operations are sound and sufficiently reduce the risk of a serious well control event when they are properly implemented and a culture of vigilance prevails. No new previously unidentified well control hazards were identified by the study. Though no serious gaps in regulation or practice were identified, the study did identify opportunities for incremental improvements. These entail clarifications to selected regulations, universal implementation of effective practices already widely followed, and other minor improvements. Important incremental improvements that were recommended by the study are:

- Regulations should reflect the fact that shearing the pipe should only be done as a last resort. Shearing pipe can make it much more difficult to circulate fluids into the well and reduce the pressure at the BOP. Reducing pressure in the annulus at the BOP as quickly as practical can significantly improve operational safety when pressures are high.
- Regulations also need to recognize that shearing pipe on a surface BOP stack should only be done to stop ejection of pipe and/or flow at the surface when all other available means have failed. Shearing pipe because of high pressure at the BOPs does not improve operational safety unless an emergency disconnect from a subsea stack is required.
- Continuous improvement requires documenting hazard identification and mitigation communications for review by an audit process. Improvements could be made in documenting *well control hazard communications* made at the rig level that are compatible with existing practices. This could include work instructions, tour handover-over notes, pre-job safety meetings, and pre-tour safety meetings.

*There is redundant coverage of numerous requirements in BSEE regulations and no serious gaps were identified in BSEE regulations regarding tripping and swab effects.*

The most significant observations made by the study are:

- There is redundant coverage of numerous requirements in BSEE regulations and no serious gaps were identified in BSEE regulations regarding tripping and swab effects.
- Prescriptive regulations would be redundant if universal adherence to existing well control practices and policies already known to be effective could be achieved and verified.
- Generally wellbore thermal effects on fluid density do not have to be modelled when conventional safety margins are being used.
- Requiring the use of corrected effective downhole densities instead of traditional uncorrected surface density measurements when unnecessary could lead to confusion and human errors.

*The biggest well control challenge to industry and regulators is ensuring that the effective well control practices already known are universally implemented.*

The Summary Table that follows the Technical Summary provides the complete listing of study recommendations and their key supporting findings.

## TECHNICAL SUMMARY

BSEE Investigation Panels determined that two of the significant well control events that occurred on the U.S. Outer Continental Shelf (OCS) during the last decade were initiated while pulling pipe out of the well. BSEE contracted with Bourgoyne Engineering LLC to conduct a study to: (1) review available information on well control incidents worldwide during 2005-2015, (2) assess best practices and (3) develop recommendations to the agency and industry on the development of industry standards, regulations, and operational procedures to ensure that well control risks are sufficiently minimized in regard to swabbing and safely tripping out of the borehole in drilling and completions operational settings.

### Well Control Incidents while Tripping during Drilling and Completions Operations

An extensive literature search of worldwide well control incidents was conducted and publicly available information about incidents relevant to the study reviewed. The scope of work was limited to incidents that occurred while tripping during drilling and completions operations between 2005 and 2015. Some of the more significant observations resulting from this review are:

- Incident descriptions and reports available in the public domain generally lack sufficient technical detail to determine root causes with a reasonable level of engineering certainty.
- The most detailed technical information found were a few BSEE Panel Reports and incident descriptions from the North Sea. Some BSEE District Reports provided useful operational setting descriptions but few details.
- For offshore areas, multiple incidents occurred that were associated with gravel packs, fracture packs, shallow gas flows, and temporary abandonments.
- Diverters did not fail during shallow gas flow events that required sustained diverter operations.
- Diverter design improvements appear to have overcome the high rate of diverter failures seen prior to 2005.
- Bit balling induced swab effects did result in 36 hours of diverter operations on a shallow gas flow until the well could be killed dynamically in one case history.
- Only three blowout incidents were found during the 2005 to 2015 time period that resulted in a spill of more than 1000 barrels of oil<sup>1</sup> and none of these involved tripping or swabbing.
- Nineteen well control events reported by BSEE were in the Gulf of Mexico OCS Region, which had a much higher level of rig activity than the other OCS regions.
  - Most of the 19 events did not involve significant pollution or personal injury, and were not classified as “historic blowouts” in the incident investigation reports.
  - Only two of the 19 events resulted in loss of life, with the Deepwater Horizon disaster accounting for 11 of the 12 fatalities.
  - Five of the 19 well control incidents were associated with tripping operations. None of these incidents caused a major oil spill or fatalities.
    - Two of the 5 incidents occurred after perforating during frac-pack or gravel-pack completions.

*Swabbing effects induced by unreasonable pulling speed were not identified as a root cause in any of the tripping during drilling or completion operations case histories.*

<sup>1</sup> Montara blowout in Australia (2009), Macondo Blowout in (2010) in the USA, and the Frade Blowout in 2011 in Brazil.



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- One of the 5 incidents occurred while making a short trip during drilling operations.
- One of the 5 incidents occurred when pulling tubing out of a well during a re-completion and the safety valve could not be installed. Control of the well was accomplished by closing the shear rams.
- One of the 5 incidents occurred while making a short trip past a known shallow gas zone.
- Three blowout events related to tripping operations were identified to have occurred in the North Sea. These included the Forties Field Blowout (UK sector), the Visund Field Blowout (Norwegian sector), and the Snorre Field blowout (Norwegian sector). The Snorre Field blowout occurred during an atypical operation when attempting to pull a 7600 ft scab-liner from a well in order to recover a platform slot.
- Several useful undated North Sea case histories were identified in a series called “Sharing to be better”<sup>2</sup>. One of these case histories described a swab induced kick for a shallow gas-sand in which the driller did not properly implement the swab hazard mitigation as instructed.
- Well control events during Frac-pack completion operations and while tripping past a shallow gas zone occurred in both BSEE and North Sea jurisdictions.
- The remaining case histories that were found and that were related to tripping operations did not provide sufficient detail to speculate as to a cause. These were in Texas (15 events, 1 fatality), Louisiana (3 events), North Dakota (9 events), West Virginia (2 events, both involved serious injuries), Mississippi (1 event), Canada (1 event), Kazakhstan (1 event), and India (1 event).

*Frac Pack / Gravel Pack operations along with the presence of Shallow Gas were common to several case histories*

The study did not find any case histories where either depth dependent or time dependent thermal effects were the root cause of a well control event. There are however some accounts in the technical literature of time dependent thermal effects possibly causing kicks in a deep high pressure high temperature well<sup>3</sup> but the case history was outside of the review time frame. Swabbing effects induced by unreasonable pulling speed were also not identified by the study as a root cause of a blowout for any of the case histories found.

*It is likely that proper implementation of existing practices, policies, and/or regulations would have prevented all of the case history events for which a cause could be determined.*

Importantly, it is likely that proper implementation of existing practices, policies, and/or regulations would have prevented all of the case history events for which a cause could be determined. The case history review strongly suggest that on a system wide level, the drilling community understands the hazards related to tripping during drilling and completions along with how to mitigate those hazards. The review also suggests that on a systemic basis, existing practices, policies, and/or regulations are almost always properly implemented. As a result, significant well control events while tripping during drilling and completion operations are rare.

<sup>2</sup> Developed by the Norwegian Shipowners’ Association and Norskolje&gass.

<sup>3</sup> IADC defines a HPHT well as one with a maximum pressure and temperature greater than 300 °F and 10000 psi respectively.

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The challenge is not to identify unknown risks and develop new mitigations. Instead, the challenge is to ensure that the already known to be effective practices, policies, and regulations are universally and properly implemented.

### **Assessment of Best Practices**

All of the Best Practices identified by the study are already in use within BSEE jurisdictions. Some are almost universally practiced. The most significant best practices include:

- Continuous fill-up and monitoring of the wellbore.
- Installing a non-return valve (float) near the bottom of the workstring during drilling operations.
- Ensuring that the top-drive can be screwed into any tubular section of significant length while it is being tripped.
- Use of trip sheets and trip books to monitor the well and quickly identify potential kicks.
- Retaining trip sheets to document proper well monitoring as required for continuous improvement purposes.
- Automated means to perform the trip sheet calculations, monitor the well, and trigger an alarm if a potential well control problem requires investigation.
- Promoting a culture of vigilance. Taking every opportunity when the pipe is not moving to check for flow.
- Providing written work instructions and procedures to the drill crew. Instructions should include a depth schedule of maximum pulling/running speeds and a depth schedule and duration for planned flow checks.
- Verifying a minimum safety margin by some direct means whenever possible. This is especially important when tripping after perforating.
- Determining safety margins and overbalance pressures by comparing surface measurements to other surface measurements, downhole measurements to other downhole measurements, or by applying appropriate corrections when comparing surface measurements to downhole measurements.
- Shear Pipe in a well control situation only when absolutely necessary. Pipe provides a potential means to circulate a column of fluid into the well and reduce surface pressure thereby improving safety.
- For surface BOP Stacks, pipe should be sheared to stop flow or ejection of pipe at the surface only if all other available methods have failed to do so. Shearing will not reduce surface pressure and can make it more difficult to do so. Consideration should be given to orderly rig abandonment instead of shearing pipe if surface pressures approach design limits<sup>4</sup>.
- For subsea BOP stacks shearing pipe could be necessary when an emergency disconnect is required because an imminent BOP failure would allow a large volume of volatile hydrocarbons to enter the marine riser.

Table top well control drills performed during pre-tour safety meetings were not identified by the study as an existing practice but such discussion could be an effective means of hazard communication and enhance crew readiness. Additionally, documenting these drills would enhance well control continuous improvement processes. The same is true for retaining copies of trip sheets for safety audit purposes.

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<sup>4</sup> This situation should not occur if the well has been properly designed.

### **Recommendations on the Development of Industry Standards, Regulations, and Operational Procedures**

BSEE regulatory requirements were more comprehensive than those of the various states and international jurisdictions. At present, there is redundant coverage of numerous requirements in the regulations. No serious gaps in BSEE regulations regarding tripping and swab effects were identified. North Sea regulations are focused on maintaining at least two verified barriers but the final requirements for obtaining a permit are similar to BSEE requirements. This is because the industry is international in scope and similar equipment and procedures are used worldwide. As advancements are made in technology, industry groups develop standards and recommended practices appropriate to the new technology. BSEE regulations have changed to keep pace with the standards and practices in an effort to insure industry wide compliance. BSEE has also sponsored research to address problem areas identified during their regulatory activities and accident reviews.

As a result of the work done in this study, the following recommendations are made:

- Gradual simplification of the regulations should be made as the audit process shows that the offshore industry has successfully embraced and implemented the continuous improvement requirements of Subpart S.
- Universal use should be made of trip books, trip sheets, and written communications to rig crews. Having these types of records available for review could contribute to continuous improvement efforts.
- When seepage is present, BSEE regulations should address the maximum time between hole-fill-up volume checks and not just maximum fluid level reductions.
- BSEE should consider requiring that the well be kept full during tripping operations instead of allowing a 75 psi reduction in hydrostatic pressure between hole-fill-ups.
- BSEE regulations that call for procedures for shearing pipe before maximum anticipated surface pressure is exceeded should be changed to procedures for shearing pipe to stop an uncontrolled flow through the drillstring, workstring, or other failed BOP components.
- The safety margins need to be verified as being sufficient before tripping with exposed perforations during gravel pack or frac pack completions.
- The use of Floats or downhole check valves is recommended as a standard operating procedure for drilling operations with the provision that they could be omitted in a special situation with sufficient justification.
- Methodologies for determining when downhole fluid warming has a significant effect on changes in downhole effective density and when swabbing has a significant effect on changes in downhole effective density should be presented in workshops held at BSEE district offices.
- A study should be conducted regarding possible changes in the requirements of the Safety and Environmental Management System (SEMS) of Subpart S to make it more suitable for well control management.
- A technical paper should be prepared for presentation at an SPE/IADC Well Control Conference that describes the results of this BSEE-funded study.

*A complete listing of recommendations with supporting findings is provided in the Summary Table of Findings and Recommendations Section beginning on page 8.*

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## SUMMARY TABLE OF FINDINGS AND RECOMMENDATIONS

The study scope of work was focused on tripping operations and swab effects that can result from tripping in a drilling or completions context. All observations, findings, recommendations, and opinions expressed in this report apply only to the scope of the study and cannot necessarily be generalized beyond that scope.

**Table 1-1: Recommendations with Supporting Findings**

Finding	Recommendation
<b>1. Sufficiency of Regulations</b>	
<ul style="list-style-type: none"> <li>a) The well control events during tripping identified in this study likely would have been avoided if conventional well control practice had been followed. No serious gaps in BSEE regulations or conventional practice were identified.</li> <li>b) Current BSEE regulations were found to be more comprehensive than the regulations publically available from other national and international jurisdictions.</li> <li>c) BSEE has sponsored research to improve safety and environmental protection based on problem areas identified during their regulatory activities and accident reviews.</li> <li>d) BSEE regulations have largely changed to keep pace with the appropriate standards and practices, which is beneficial in achieving industry-wide compliance. There is room for incremental improvement and alignment.</li> </ul>	<ul style="list-style-type: none"> <li>a) A few minor changes in regulations would insure universal adoption of current industry best practices that have evolved with improvements in rig equipment. The recommended changes are listed below under various topical subheadings.</li> <li>b) Existing continuous improvement efforts need to focus on universal implementation of already known and effective well control policies, procedures and methods.</li> </ul>
<b>2. Well Control and SEMS</b>	
<ul style="list-style-type: none"> <li>a) The gradual move from prescriptive to performance-based regulations, including the requirements of Subpart S, appears to be an effective approach for systematic and continuous improvement.</li> <li>b) At present, there is redundant coverage of numerous requirements in the regulations.</li> <li>c) Written practices and procedures developed by the operator and independently verified implementation of those practices and procedures via BSEE-approved review processes could increasingly serve the needs currently met by prescriptive regulations.</li> <li>d) The regulations do not prescribe that well control during tripping be identified as an activity in the SEMS, but Subpart S is referenced in regard to well control-related training (250.703, 734 and 739) and the SEMS must include a description of well control systems (205.1910). The regulations also require communication of hazards to the crew per Subpart S (250.710a) and a well control plan (250.710b).</li> <li>e) The most significant operative difference between SEMS and most well control plans is the more rigorous SEMS requirements for written communications and record keeping to facilitate oversight and continuous improvement.</li> </ul>	<p>BSEE should gradually remove redundancy and older prescriptive requirements from the regulations as audit processes show that the offshore industry has successfully embraced and implemented the continuous improvement requirements of Subpart S.</p>

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<b>Finding</b>	<b>Recommendation</b>
<b>3. Hazard Analysis and Communication</b>	
<ul style="list-style-type: none"> <li>a) Rig-site safety meetings are commonly held prior to tripping and include a check list entitled JSA and a statement on Stop Work Authority.</li> <li>b) Rig-site safety meetings are being effectively utilized to reduce occupational safety risks but are underutilized with respect to well control risks. Displacement of redundant occupational safety exercises with well control readiness exercises such as table top drills could address this imbalance without increasing the overall time spent in meetings.</li> <li>c) The term “Job Safety Analysis” is being used inconsistently within the drilling community and rig-site JSAs may not fully conform to the definition in Subpart S. This is a source of miscommunication when discussing best practices and regulatory compliance.</li> <li>d) Written work instructions including hazard communication are commonly provided to the crew prior to tripping. Some examples include a depth schedule of maximum pulling/running speeds and a depth schedule and duration for planned flow checks, and identify the individual responsible for trip volume accounting for kick detection (e.g. trip sheets).</li> <li>e) A greater emphasis on written records from rig-site pre-job planning, written communication of hazards, and written work instructions prior to tripping would better facilitate oversight and continuous improvement in this area.</li> </ul>	<ul style="list-style-type: none"> <li>a) BSEE should consider an NTL clarifying JSA terminology and providing the minimum requirements of JSAs conducted prior to tripping. Table 6-1 in Section 6.10 of this report could be included as a resource for identifying hazards and mitigations.</li> <li>b) BSEE should consider an NTL emphasizing the need for written records of rig-site pre-job well control hazard communications and work instructions to facilitate assessment and continuous improvement. The implementation of the NTL can be assessed and reinforced through the rig-site inspection process.</li> </ul>
<b>4. Hole Surveillance</b>	
<ul style="list-style-type: none"> <li>a) The risk of well control events during tripping could be reduced by requiring that personnel charged with continuous surveillance on the rig floor possess the qualifications and authority required to personally respond to the well control event. (The operator’s representative does not normally have the authority to operate equipment and many crew members are not required to be certified in well control.)</li> <li>b) Trip sheets are commonly used and some operator’s well control polices require them to be retained.</li> <li>c) The risk of well control events during tripping could be reduced by universal adoption of trip volume accounting practices, such as trip sheets. Readily available technology could be employed to provide automated trip sheet calculations and alerts. This capability is already available from some service companies.</li> <li>d) Well control training certification courses commonly promote the use of trip sheets and teach the basic math necessary to use them but it is uncommon for the courses to practice kick detection with a trip sheet.</li> <li>e) Seepage losses during pauses in tripping can significantly erode the trip margin if not properly monitored.</li> </ul>	<ul style="list-style-type: none"> <li>a) BSEE should revise CFR 250.703(c) to require that personnel charged with continuous surveillance on the rig floor have the needed qualifications and authority to personally respond to the well control event.</li> <li>b) BSEE should promote or require the use of trip volume accounting methods (e.g. trip sheets) for improved kick identification and their retention to facilitate oversight and continuous improvement.</li> <li>c) BSEE should promote or require well control training programs to emphasize kick detection with trip volume accounting methods (e.g., trip sheets, automated software).</li> <li>d) When seepage is present, BSEE regulations should address the maximum time between hole-fill-up volume checks and not just maximum fluid level reductions.</li> </ul>

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<b>Finding</b>	<b>Recommendation</b>
<b>5. BOP Equipment (including DSSV)</b>	
<p>a) Using MASP as the condition to shear pipe is not appropriate in most cases.</p> <p>b) Pipe should not be sheared in a well control situation unless absolutely necessary. Pipe provides a means to circulate a column of fluid into the well which can reduce surface pressure thereby improving safety.</p> <p>c) For surface BOP stacks, pipe should be sheared to stop flow at the surface or ejection of pipe only if all other available methods have failed to do so. Shearing will not reduce surface pressure at the BOP and can make it significantly more difficult to do so. Consideration should be given to orderly rig abandonment instead of shearing pipe if surface pressures approach design limits.</p> <p>d) For subsea BOP stacks shearing pipe could be necessary when an emergency disconnect is required because an imminent BOP failure would allow a large volume of volatile hydrocarbons to enter the marine riser.</p> <p>e) Longstanding misunderstandings persist in the industry regarding the meaning of MASP and the perceived risk associated with exceeding MASP.</p> <p>f) Well control decisions are situational and performance-based requirements are more effective than prescriptive regulations regarding evaluations of safety or when to shear pipe. Review or audit of well control policies and procedures is the most effective approach to effective regulation and oversight.</p> <p>g) Risks are reduced when well control procedures clearly define the relevant maximum allowable pressures and the proper course of action if each limit is approached or exceeded.</p> <p>h) Uncontrolled flow up the drillstring was a factor in two blowouts related to tripping identified in this study. Manually stabbing and closing the DSSV under flow and other adverse conditions is one of the more problematic operations in well control.</p> <p>i) Many operators install a check valve (float) near the bottom of the workstring during drilling operations as a matter of well control policy in order to mitigate the risk of not being able to stab and close the DSSV.</p> <p>j) Many operators and drilling contractors require that the top-drive can be screwed into any tubular section above the BHA being tripped as a matter of well control policy in order to mitigate the risk of not being able to stab and close a DSSV.</p> <p>k) At least one well control event during tripping was made worse by a delay in the decision to shear pipe. This may reflect inadequate situation-specific decision making under time pressure.</p>	<p>a) The reference to MASP should be removed from BSEE regulation 250.710(b).</p> <p>b) BSEE regulation 250.456(f) should be revised to remove the implied association between “the maximum pressure that you may safely contain under a shut-in BOP,” and “the surface pressure at which the shoe would breakdown,” recognizing that allowing the shoe to breakdown may be consistent with “safely containing pressure” and is usually the lowest risk course of action once surface casing has been set, cemented and the shoe tested.</p> <p>c) BSEE should continue current practice of checking the proposed casing program, cementing program, and BOP equipment prior to issuing well permit to insure the well can withstand the maximum anticipated surface pressure.</p> <p>d) BSEE should continue current practice of requiring casing wear to be periodically monitored to insure maximum anticipated surface pressure rating has not been compromised.</p> <p>e) BSEE and IADC should consider developing a framework of pressure definitions for use in well control plans and procedures. The framework should distinguish between diagnostic pressures and safety critical pressure limits.</p> <p>f) BSEE should require the use of floats or downhole check valves for drilling operations with the provision that they could be omitted in special situations with sufficient justification.</p> <p>g) BSEE and IADC should develop brief rig-site well control planning exercises (e.g., table top drills) that can be conducted within the constraints of a rig-site safety meeting and allow the crew to consider their response beforehand in scenarios specific to the actual operational environment, crew and equipment. The initial offerings could focus on the decision to shear in a tripping context.</p>



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<b>Finding</b>	<b>Recommendation</b>
<b>6. Fluid Column Barrier</b>	
<ul style="list-style-type: none"> <li>a) Use of an appropriate safety margin between the fluid density and the formation pore pressure is an important means of preventing blowouts when tripping pipe during drilling and completion operations.</li> <li>b) Safety margins and overbalance pressures are commonly determined by comparing surface measurements to other surface measurements, downhole measurements to other downhole measurements, or by applying appropriate corrections when comparing surface measurements to downhole measurements.</li> <li>c) Risks can be reduced by directly verifying the adequacy of the trip margin prior to tripping in some cases.</li> <li>d) The loss of hydrostatic pressure due to downhole warming after circulation is stopped is generally small because the average fluid temperature in the well does not change significantly with time. The fluid is cooling in the shallow part of the well while warming in the deeper part of the well.</li> <li>e) Common practice for managing temperature effects on fluid density is adequate in most cases. On those wells where common practice could be insufficient (HTHP, Extended Reach, MPD, etc.) temperature modeling is already used.</li> <li>f) Well control risks during tripping may be reduced by ensuring properly conditioned mud prior to tripping.</li> <li>g) The measured mud weight exiting the well when conditioning the mud is less affected by entrained gas when a pressurized mud balance is used.</li> <li>h) Circulating trip tanks are commonly used to keep the hole continuously full while monitoring fill-up volumes as a matter of well control policy for many operators and drilling contractors.</li> <li>i) Well control risks during tripping may be reduced by minimizing the time the hole is not completely full. Rigs in BSEE jurisdiction now have trip tank arrangements capable of keeping the wellbore full continuously while tracking mud volume gains and losses.</li> </ul>	<ul style="list-style-type: none"> <li>a) Methodologies for determining when downhole fluid warming has a significant effect on changes in downhole effective density and when swabbing has a significant effect on changes in downhole effective density should be presented in workshops held at BSEE district offices.</li> <li>b) The safety margin needs to be verified as being sufficient before tripping with exposed perforations during gravel pack or frac pack completions.</li> <li>c) BSEE regulation 250.456(2) should be revised to reduce or qualify the allowed disparity between the measured surface density of mud entering and exiting the hole, to avoid tripping with insufficiently conditioned mud.</li> <li>d) BSEE should consider requiring that the well be kept full during tripping operations instead of allowing a 75 psi reduction in hydrostatic pressure between hole-fill-ups.</li> </ul>
<b>7. Information Sharing</b>	
<ul style="list-style-type: none"> <li>a) Worldwide, the inconsistent level of detail reported for well control incidents impedes industry-wide performance assessment and continuous improvement. Fear of negative attention and undue legal repercussions is a likely source of the apparent reluctance to share information.</li> <li>b) Presentations providing details of actual well control events are highly effective and well received in training and continuing education.</li> </ul>	<ul style="list-style-type: none"> <li>a) A technical paper should be prepared for presentation at an SPE/IADC Well Control Conference that describes the results of this BSEE-funded study.</li> <li>b) Consider expanding well control event reporting requirements and using BSEE's authority to require well documented incident investigations under the Subpart S (SEMS) 250.1919.</li> <li>c) IADC or the Offshore Operators Committee should consider duplicating Norway's "Sharing to be Better" case history program.</li> </ul>

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## 1 BACKGROUND

BSEE Investigation Panels determined that two of the significant well control events that occurred in the U.S. Outer Continental Shelf (OCS) during the last decade were initiated while pulling pipe out of the well. In Panel Report BSEE 2015-02, the panel indicated that the operator's failure to consider the effect of downhole temperature on the density of the completion fluid could have been a major factor leading to the blowout. Request for Proposals (RFP) E16PS00001 was issued on April 1, 2016 entitled, "Effects of Tripping and Swabbing in Drilling and Completion Operations" in order to fully understand the engineering and operational factors which can contribute to a loss of well control during these operations. Bourgoyne Engineering LLC was awarded a contract to complete the requested study on August 1, 2016. This report provides the results of the study that was conducted.

### 1.1 Study Objective

The primary objectives of the study were to review available information on well control incidents worldwide during 2005-2015, assess best practices, and develop recommendations to the agency and industry on the development of industry standards, regulations, and operational procedures in regards to swabbing and in regard to safely tripping out of the borehole.

### 1.2 Project Key Personnel

The Key Project Personnel that conducted this Project were:

- Dr. Adam T. (Ted) Bourgoyne, Jr., (Senior Principle Investigator) P.E., *Bourgoyne Engineering LLC*, Baton Rouge, LA.;
- Mr. Darryl Bourgoyne, (Project Manager and Co-Principle Investigator) *Darryl Andrew Bourgoyne, LLC*, Baton Rouge, LA.;
- Dr. Dwayne Bourgoyne, (Co-Principle Investigator, Project Engineer), P.E., *Bourgoyne Enterprises, Inc.*, Golden, CO.

Ted Bourgoyne and Darryl Bourgoyne both have extensive education and experience in Petroleum Engineering with emphases on drilling and blowout prevention training and research.

Dwayne Bourgoyne has many years of experience with safety systems and protocols while working as a mechanical engineer in an Exxon refinery and as a research engineer working on new tanker design for carrying liquefied natural gas. Dwayne also has a general knowledge of drilling and well control and taught these topics in undergraduate and graduate level petroleum engineering courses while at Colorado School of Mines.

Biographical information summarizing education, work experience, and professional accomplishments of each technical investigator is provided in **Appendix B**.

### 1.3 Subject Matter Experts

Subject matter experts that participated in the project were:

- John Knowles, *Louisiana State University*, Baton Rouge, LA.;
- Dr. John Smith, P.E., *John Rogers Smith Petroleum Consulting, LLC*, Baton Rouge, LA.;
- John Shaughnessy, P.E., *JMS Consultants LP*, Houston, TX.;
- Dr. William L. Koederitz, P.E., *GK Plus Innovations LLC*, Austin, TX.



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- Shelby White, P.E., *Completion Specialists, Inc.*, Lafayette, LA;
- Don Hannegan, P.E., *Managed Pressure Drilling LLC*, Fort Smith, Arkansas;
- Dr. Otto Santos, P.E., *Petroleo Brasileiro SA, Petrobras (Retired)*, Salvador, Bahia, Brazil.

John Knowles has 20 years of international drilling and completion experience in Algeria, Germany, Brazil, Vietnam, Russia, U.K. North Sea, Argentina, Texas, and the Gulf of Mexico. He has been involved in well planning and supervision of rig operations as well as field operations as a service company representative and as an operator's representative. He is currently teaching well control classes at LSU.

Dr. John Smith recently retired from LSU where he was responsible for graduate and undergraduate courses in Drilling and Well Control and for graduate research activities in Well Control. Prior to joining LSU, he had 23 years of experience with Amoco Production Company as an engineer, researcher, and as an engineering supervisor working primarily in Gulf of Mexico operations.

John Shaughnessy worked as a drilling engineer with Amoco and BP for 33 years on HTHP wells in Louisiana and other areas and deepwater wells in the Gulf of Mexico. He was on one of the deepwater rigs drilling relief wells drilled during the Macondo Blowout. Since retiring from BP, he has been consulting and teaching industry schools on drilling HTHP wells and Deepwater wells.

Dr. Bill Koederitz worked 9 years as a drilling engineer and 20 years for National Oilwell Varco developing rig instrumentation and well monitoring equipment and services. He is currently the Chief Technology Officer with GK Plus Innovations, LLC.

Shelby White has 35 years of experience in planning and executing completions, workovers, and remedial well work primarily in the Gulf of Mexico and South Louisiana. He has directly planned and supervised 40 new completions and 7 workovers in federal and state waters since 2003 with Completion Specialists, Inc., in addition to 122 projects while at Ocean Energy between 1994 and 2003 he handled several critical "firsts" at Ocean Energy including the first horizontal well completion, the first one-trip completion, and the first subsea completion.

Don Hannegan recently retired from Weatherford International as Director of Drilling Hazard Mitigation Technology Development. He authored the MPD Chapter in SPE's new textbook *Advanced Drilling & Well Construction*, was the lead author of the Pressure Management chapter in the current edition of the IADC Drilling Manual, and author of the MPD Option section in the Well Planning chapter of the 2015 edition of IADC's Deepwater Well Control Guidelines. He has written numerous SPE, IADC, AADE & OTC technical papers and presently is co-authoring a textbook entitled *Drilling Hazards Mitigation Tools & Technology*.

Dr. Otto Santos has 40 years of experience with Petrobras, has worked as a drilling engineer in both onshore and offshore operations. He rose to the top of the technical ladder within Petrobras to serve as Master Technical Advisor at the time of his retirement. He served as Petrobras' representative of the IADC WellCAP Governance Board from 2012 to 2014 and was a member of the Well Control Training Subcommittee for the IADC Deepwater Well Control Guidelines. He was a recent SPE Distinguished Lecturer on "*Ways to Successfully Reduce Well Blowout*

*Events.*” He provided non-proprietary information to project Key Personnel regarding well control guidelines and recommended practices and information regarding well control incidents in Brazil.

### 1.4 Methodology

The methodology of the study was controlled by task descriptions provided by BSEE. Eight tasks pertaining to tripping and swabbing in drilling and completion operations were specified. The tasks accomplished were to:

1. Hold post award meeting and provide monthly progress reports.
2. Perform comparative analysis of national and international regulatory requirements, standards, best practices, and operating procedures as they relate to:
  - a. Maintaining well control while tripping,
  - b. Developing tripping hazard analysis and risk mitigation processes, and
  - c. Fully understanding the effect of drilling fluid density parameters and fluid monitoring techniques on well control while tripping.
3. Provide recommendations for improvement of safety and reduction of hazards.
4. Provide recommendations for improvement of BSEE regulations.
5. Assess operator’s job pre-planning procedures and drilling crew communication.
6. Assess potential causes of loss of well control and mitigation procedures.
7. Compile well control incidents for 2005 through 2014.
8. Prepare draft and final reports.

Key Project Personnel were supported in the data collection phase of the project by undergraduate petroleum engineering students with some operational field experience hired through the LSU Petroleum Engineering Research and Technology Transfer Laboratory (PERTTL). Under the supervision of a petroleum engineering consultant with extensive international drilling experience, these petroleum engineering undergraduates surveyed and summarized existing regulatory requirements as found on the internet in a wide range of jurisdictions. Information was also collected regarding industry standards, recommended practices, best practices, and industry operating procedures. Publicly available well control incident reports that were associated with tripping were also collected. Additional supervision of the data collection phase of the project was provided through periodic meetings held at the PERTTL facility with project key personnel.

BSEE determined that *The Paperwork Reduction Act of 1995* limited solicitation of information for the contract to less than 10 persons. Solicitation of information regarding regulations and well control events during tripping operations were sent to nine state regulatory agencies. Access to BSEE’s E-Wells system by key personnel was requested to allow review of recent operator procedures sometimes attached to Application for Permits to Drill (APD) or Application for Permit to Modify (APM). Access to operator Weekly Activity Reports (WARs) was also requested. A link was provided by BSEE that allowed review of APD and APM information prior to 2014, but not the WARs.

Project personnel and contracted Subject Matter Experts (SMEs) also had access to considerable technical libraries as part of their ongoing consulting activities. These libraries include publicly

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available industry publications such as American Petroleum Institute (API) Standards, Recommended Practices, International Association of Drilling Contractors (IADC) Manuals, Guidelines, Training Curriculums, Society of Petroleum Engineers (SPE) Textbooks and Monographs just to name a few examples. The project key personnel and SMEs also had considerable knowledge based on their combined professional experience in developing, reviewing, and teaching from a wide range of well planning documents, operator's well control manuals, and training materials. The SMEs retained also had considerable offshore, national, and international operational experience as rig site operator's representatives.

The assessment and recommendation aspects of the study were performed by the project key personnel. Computer model studies were performed as needed to better quantify the magnitude of changes in downhole equivalent mud weight for a variety of well conditions and to develop illustrative examples. A draft report was first prepared by the project key personnel. An internal peer review team, made up of contracted SMEs, reviewed the draft report and provided comments and suggestions which were then incorporated by project key personnel into a draft final report for review by BSEE. Comments from BSEE received by teleconference were also addressed in the Final Report.

## 2 COMPARATIVE ANALYSES OF TRIPPING RULES AND GUIDELINES

A comparative analysis of current onshore and offshore requirements from the international (e.g. International Regulators' Forum members), national (e.g. Bureau of Land Management), and state level (e.g. California, Alaska, Texas) on the regulations, standards (e.g. American Petroleum Institute, NORSOK (Norwegian Oil and Gas Association), International Standards Organization), best practices, and industry operating procedures related to well control during tripping was conducted a part of this study. The study focused on three areas for the comparative analysis:

- Maintaining well control while tripping out of the borehole and preventing swabbing from resulting in a loss of well control;
- Developing hazard analysis and risk mitigation processes addressing the well control risks associated with tripping out of the borehole and preventing swabbing from resulting in a loss of well control; and
- Fully understanding drilling fluid density parameters and drilling fluid monitoring techniques and their effect on maintaining well control while tripping out of the borehole and how drilling fluids can minimize the risks of swabbing in a well.

Information compiled by the LSU Petroleum Engineering Research and Technology Transfer Laboratory (PERTTL) allowed key project personnel to conduct a comparative analysis of BSEE regulations and the publicly-available worldwide regulations, standards, rules, and guidelines.

The results are presented in the following sections. First, the jurisdictions selected for the comparison are identified based on major oil and gas activity. Following the relevant regulations in the US Code of Federal Regulations (CFR) are identified and the distinction between performance-based and prescriptive regulation is discussed. The regulations are then described and compared. Following, each of the three focus areas identified above is addressed in a dedicated section describing the relevant industry practices.

### 2.1 Jurisdictions included in the search for Regulations and Practices

The regulatory search effort was in part directed by the recent history of rig activity as published in the historical Baker Hughes Oil and Gas Drilling Rig Count; other sources reflecting rig activity were also used for non-free-world countries.

**Figure 2-1** is a map illustrating international offshore rig activity and

**Figure 2-2** illustrates the rig activity in the United States. Only limited publicly available material was identified for some international jurisdictions. The jurisdictions included in the comparative analysis are listed in the tables in **Appendix D**.

EFFECTS OF TRIPPING AND SWABBING IN DRILLING AND COMPLETION OPERATIONS

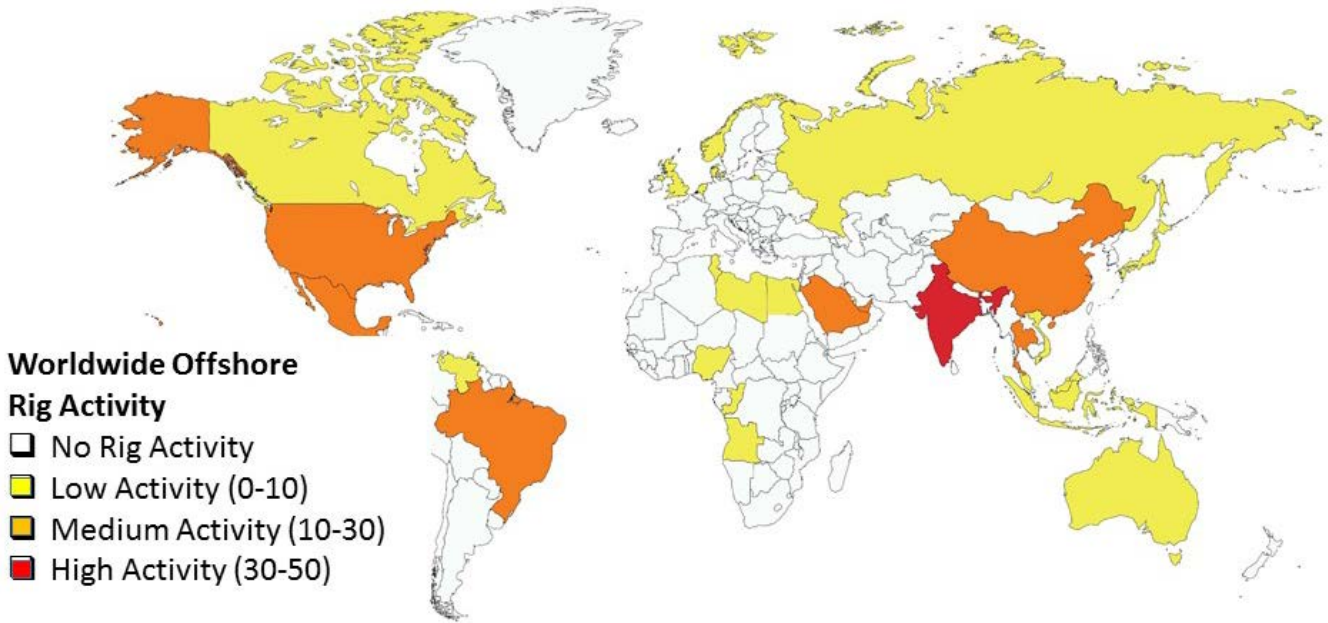


Figure 2-1: Map showing International Offshore Rig Activity Levels (December 2016)

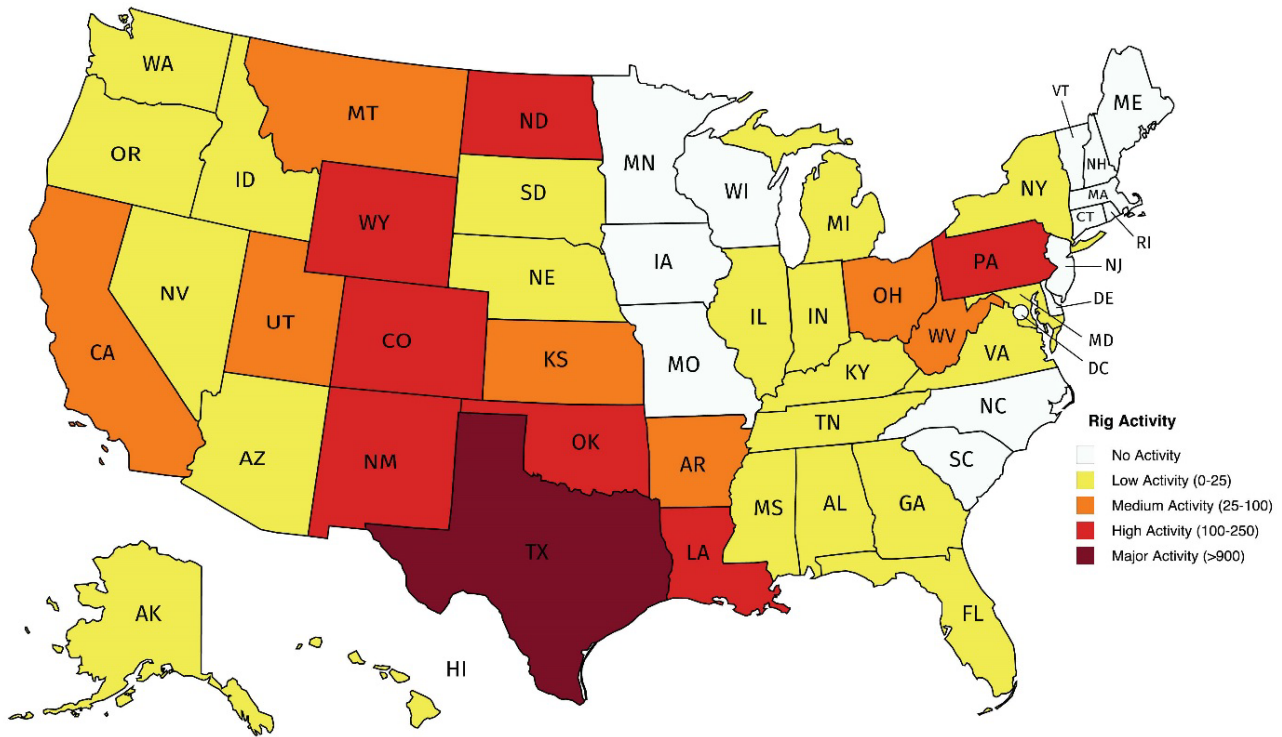


Figure 2-2: Map showing Maximum Rig Activity Levels in U.S. (2000-2016)

## 2.2 CFR Title 30 Chapter II Subchapter B Part 250

A review of the Code of Federal Regulations (CFR), Part 250 on oil and gas and operations in the outer continental shelf identified a number of sections related to tripping and swabbing in drilling and completion operations. CFR subparts relevant to this study include selected sections from Subpart A – *General*, Subpart D – *Oil and Gas Operations*, Subpart E – *Oil and Gas Well-Completion Operations*, Subpart G – *Well Operations and Equipment*, Subpart O – *Well Control and Production Training*, and Subpart S – *Safety and Environmental Management Systems (SEMS)*. The relevant sections from these subparts are reproduced from the CFR in **Appendix C**. As indicated in the title of the BSEE Request for Proposals and subsequent Contract, regulations regarding *Oil and Gas Well-Workover Operations* (Subpart F) were not included in the study. All CFR references shown below are in Title 30, Subchapter B (Offshore), e.g. CFR 250.107 means 30 CFR 250.107.

The regulations relevant to well control during tripping are shown in **Figure 2-3**, and have been organized into four groupings. The first group is “*General Requirements and Hazard Management*” and includes sections 107, 400, 500 and all of Subpart S. All give general requirements or apply to the general management of hazards. The second group in Figure 2-3 is “*Well Control*” and includes regulations for well control in general. The third and fourth groups cover sections relevant to the hydrostatic fluid column and wellbore mechanical containment using the BOPE, which serve as the primary and secondary well control barriers during tripping.

The requirements in the first two groups are more general and tend to be performance-based in nature while the requirements in the last two groups are more specific and prescriptive in nature. The use of performance-based rules under an HSE hazard management framework reflects the movement by BSEE (previously MMS) toward performance-based regulation over the past 25 years.<sup>5</sup> The use of a general performance-based framework complemented by prescriptive rules for specific technologies is very similar to the regulatory framework for well control used in Norway. A description of the Norwegian approach and a discussion of performance-based versus prescriptive regulation are provided in **Section 2.3.1** of this report.

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<sup>5</sup> Federal Register Volume 71, Number 98 (Monday, May 22, 2006)

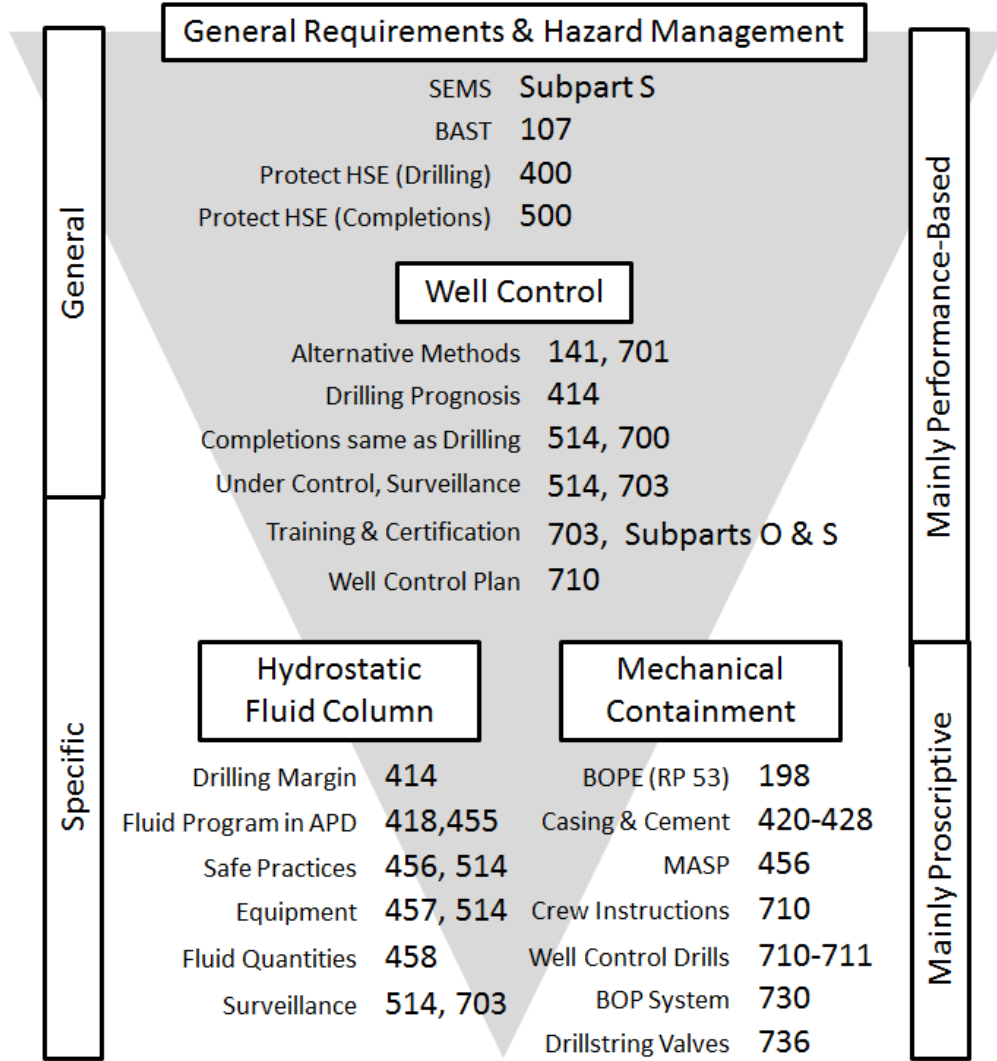


Figure 2-3: Organization of the CFR sections relevant to Well Control during tripping

### 2.3 Performance vs. Prescriptive Rules

In a comparative analysis it is important to understand performance-based and prescriptive rules as alternative and complementary approaches to regulation. Prescriptive rules attempt to achieve an outcome by specifying a technical solution to a particular problem. Performance-based rules “express functional or goal setting requirements as far as practicable, i.e. they [state] the purposes of the requirements rather than specifying the technical solution” (Finnestad 2005). The approach employed by the Norwegian Petroleum Directorate (NPD) provides a good example of a performance-based regulatory framework and is discussed in the following section.

#### 2.3.1 The Norwegian Regulatory Approach

The Norwegian Petroleum Directorate (NPD) is the regulatory body that grants drilling permits for oil and gas wells in Norway and in the portion of the North Sea within Norway’s jurisdiction. “When the petroleum exploration production industry started up in Norway in the late 1960s, no framework of health, safety and environmental regulations existed. Consequently, when the [NPD] was established by

# EFFECTS OF TRIPPING AND SWABBING IN DRILLING AND COMPLETION OPERATIONS

*the Norwegian Parliament in June 1972, its first task was to develop such a frame-work” (Finnestad 2005). (On January 1, 2004, the Petroleum Safety Authority was established under the Ministry of Labor and Social Affairs as separate from NPD and responsible for safety, emergency preparedness, and working environment.)*

*“The first approach to regulating the oil and gas industry was to prescribe specific requirements with regard to health, safety and environment. Most were copied from rules and regulations existing in Canada and the United States, and thus included references to American codes and standards.” While this approach had some benefits, it grew difficult to maintain and keep in step with technical advances. This led to revisions beginning in 1985 and extended in 1991 toward a performance-based framework which “offers the freedom to choose technical solutions that are optimal in regard to field developments, and compatible with corporate philosophies.” (Finnestad 2005).*

Although performance-based rules do not directly incorporate the prescriptive requirements found in other standards, these standards serve to supplement and guide consideration of the performance-based rules. *“Those who have to implement [the performance-based standards]...need some guidance in assessing what the regulator sees as being acceptable technical solutions or prudent operation. This is achieved by referencing National and International Standards. The point is to make it absolutely clear that the particulars of such recommended standards are not compulsory requirements. They only describe solutions which are acceptable to the regulator... In general, standards...give to support and complement [the] goal-setting regulations...by providing authoritative definitions of what is good practice” (Finnestad 2005).*

### 2.3.2 The NORSOK Standards

The petroleum industry standards developed since 1994 by Norwegian regulators in cooperation with the industry are the NORSOK standards. The main NORSOK standard relevant to this study is D-010, *Well Integrity in Drilling and Well Operations*, and includes by reference three additional NORSOK standards listed in **Table 2-1**.

**Table 2-1: NORSOK Standards relevant to Well Control while Tripping**

<b>Standard</b>	<b>Title</b>
D-010	Well integrity in drilling and well operations
	<i>D-010 normative references:</i>
D-001	Drilling facilities
D-002	System requirements well intervention equipment
D-SR-007	Well testing system

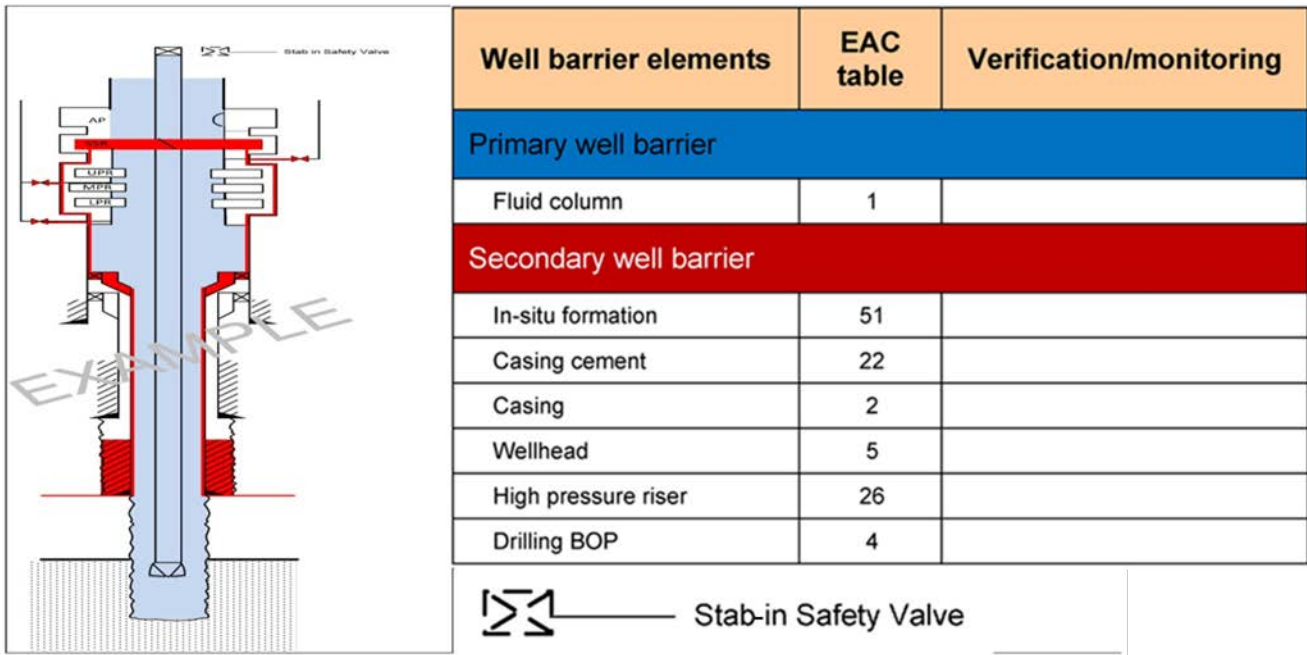
D-001, D-002, and D-SR-007 are all incorporated in D-010 as “*normative*” references meaning that compliance with these references are a requirement of D-010. BSEE’s incorporation of API standards and recommended practices by reference is analogous to a NORSOK normative reference. In contrast, D-010 lists API and other international standards as “*informative*” references to provide guidance on acceptable approaches to meeting the performance-based rules without incorporating them as requirements of D-010.



**2.3.3 Well Control Barrier Elements**

NORSOK D-010 follows a “barrier” approach to well control. Instead of prescribing how well control is to be maintained during tripping operations, D-010 broadly specifies that two independent and verifiable barriers be used in operations where hydrocarbon-bearing or abnormally-pressured formations capable of flow are exposed.

“...well barriers shall be defined prior to commencement of an activity or operation by identifying the required well barrier elements (WBE) to be in place, their specific acceptance criteria and monitoring method...Well barrier element acceptance criteria shall be in place for all WBEs used.” (D-010, Sections 4.2.1 and 4.2.4)



**Figure 2-4: Example WBD for tripping with a Shearable String from NORSOK D-010**

The specific barrier elements to be used in a given situation are not specified. However, there are general prescriptive rules regarding the characteristics and implementations of barriers, and the documentation required in the plan submitted for approval. Well Barrier Diagrams (WBD) with a specified format serve as the chief method of communicating the barriers in the plan. Guidance on acceptable approaches is provided through example WBDs for common situations. The example WBD for tripping with a shearable string is shown in **Figure 2-4**.

In this case, the primary well barrier is the fluid column. The secondary well barrier is the drilling BOP and wellbore integrity elements such as the casing and casing shoe. The stab-in safety valve (shown in schematic) is not listed in the table and is not required if the pipe is sheared, but would serve in the secondary barrier if successfully installed and closed along with the pipe rams or annular. The Stab-in SV is explicitly included as a secondary well barrier element for tripping with a non-shearable string.

## 2.3.4 Barrier Element Acceptance Criteria

Acceptance criteria and recommendations for WBEs used commonly in practice, including those specified in Figure 2-4, are provided in Element Acceptance Criteria (EAC) tables. For barriers that are not listed in D-010, the operator is required to propose an EAC for approval.

*“General technical and operational requirements and guidelines relating to WBEs are collated in the EAC tables in Section 15, which shall be applicable for all type of activities and operations. A new EAC table shall be developed in cases where an EAC table does not exist for a specific WBE....The described acceptance criteria and listed references in the tables are for selection and installation purposes and do not replace the technical and functional requirements that standards or the operating company specify for the equipment. The references listed in column ‘See’ is intended for information purposes.”*

The EAC tables for the Fluid Column, Stab-in SV and Drilling BOP WBEs are provided in

**Table 2-2, Table 2-3, and Table 2-4.** In

Table 2-2, the “*See*” column lists the fluid system requirements in D-001 (a normative reference specified in D-010 Section 2.2) and fluid testing guidance in ISO 10414, 10416 (informational references). The requirement to continuously monitor the fluid level in the well appears in the EAC “*Monitoring*” section. The requirement to maintain necessary weighting materials on site appears in the EAC “*Use*” section.

The requirement for shear rams appears in Table 2-4, under “*Design construction selection*”. There is a normative reference to D-001 and an informational reference to API Spec 53 and API Spec 16RCD. There is a requirement for the BOP configuration to be determined through risk assessment, and component requirements in D-001. The inclusion of a shear ram is specified in D-001 and is expanded in item 4 under “*C. Design/construction/selection*”. The inclusion of a pipe ram or annular preventer for each tubular size in the drillstring is prescribed in item 5 of the same section.

The use of two barriers for well control during tripping, with the fluid column providing the primary barrier and mechanical containment by the BOPE providing the secondary barrier is identical to the BSEE approach illustrated in Figure 2-3. However, D-010 does not require the operator to use these two particular barrier elements to meet the two-barrier requirement. In accordance with a performance-based approach, the regulation defines general requirements for well control and barrier elements and gives examples of elements acceptable to the regulator, but stops short of specifying which barrier elements to employ. Acceptance criteria for standard barrier elements are specified, but there is also room for alternative acceptance criteria to be proposed. Ultimately, the proposed approach must be approved by the regulatory authority through the acceptance of the application for permit to drill.

**Table 2-2: Well Barrier EAC Table for Fluid Column from NORSOK D-010**

Features	Acceptance criteria	See
<b>A. Description</b>	This is the fluid in the wellbore.	NORSOK D-001
<b>B. Function</b>	The purpose of the fluid column as a well barrier/WBE is to exert a hydrostatic pressure in the wellbore that will prevent well influx/inflow (kick) of formation fluid.	
<b>C. Design construction selection</b>	<ol style="list-style-type: none"> <li>1. The hydrostatic pressure shall at all times be equal to the estimated or measured pore/reservoir pressure, plus a defined safety margin (e.g. riser margin, trip margin).</li> <li>2. Critical fluid properties and specifications shall be described prior to any operation.</li> <li>3. The density shall be stable within specified tolerances under down hole conditions for a specified period of time when no circulation is performed.</li> <li>4. The hydrostatic pressure should not exceed the formation fracture pressure in the open hole including a safety margin or as defined by the kick margin.</li> <li>5. Changes in wellbore pressure caused by tripping (surge and swab) and circulation of fluid (ECD) should be estimated and included in the above safety margins.</li> </ol>	ISO 10416
<b>D. Initial test and verification</b>	<ol style="list-style-type: none"> <li>1. Stable fluid level shall be verified.</li> <li>2. Critical fluid properties, including density shall be within specifications.</li> </ol>	
<b>E. Use</b>	<ol style="list-style-type: none"> <li>1. It shall at all times be possible to maintain the fluid level in the well through circulation or by filling.</li> <li>2. It shall be possible to adjust critical fluid properties to maintain or modify specifications.</li> <li>3. Acceptable static and dynamic loss rates of fluid to the formation shall be pre-defined. If there is a risk of lost circulation, lost circulation material should be available.</li> <li>4. There should be sufficient fluid materials, including contingency materials available on the location to maintain the fluid well barrier with the minimum acceptable density.</li> <li>5. Simultaneous well displacement and transfer to or from the fluid tanks should only be done with a high degree of caution, not affecting the active fluid system.</li> <li>6. Parameters required for re-establishing the fluid well barrier shall be systematically recorded and updated in a "killsheet".</li> </ol>	
<b>F. Monitoring</b>	<ol style="list-style-type: none"> <li>1. Fluid level in the well and active pits shall be monitored continuously.</li> <li>2. Fluid return rate from the well shall be monitored continuously.</li> <li>3. Flow checks should be performed upon indications of increased return rate, increased volume in surface pits, increased gas content, flow on connections or at specified regular intervals. The flow check should last for 10 min. HTHP: All flow checks should last 30 min.</li> <li>4. Measurement of fluid density (in/out) during circulation shall be performed regularly.</li> <li>5. Measurement of critical fluid properties shall be performed every 12 circulating hours and compared with specified properties.</li> <li>6. Parameters required for killing of the well.</li> </ol>	ISO 10414-1 ISO 10414-2
<b>G. Common well barrier</b>	None	

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**Table 2-3: Well Barrier EAC Table for the Stab-in SV from NORSOK D-010**

Features	Acceptance criteria	See
<b>A. Description</b>	This element consists of a housing with a bore and a ball valve.	
<b>B. Function</b>	Its purpose is to allow mounting and closure at the top of any free tubular joint sitting in the rotary table.	
<b>C. Design, construction and selection</b>	<ol style="list-style-type: none"> <li>1. The valve shall be rated to WDP.</li> <li>2. The valve shall have an easily accessible and operable closure mechanism for use once the valve is installed on the string.</li> </ol>	
<b>D. Initial test and verification</b>	The valve shall have a documented and accepted test performed within the last 14 days.	
<b>E. Use</b>	<ol style="list-style-type: none"> <li>1. The stab-in safety valve shall be made up with threaded connections to match the tubing joint sitting in the rotary table at any time.</li> <li>2. The valve shall be possible to make up hand-tight in less than 15 seconds.</li> </ol>	
<b>F. Monitoring</b>	Visual observation during use	
<b>G. Common well barrier</b>	None	

**Table 2-4: Well Barrier EAC Table for Drilling BOP from Norsok D-010**

Features	Acceptance criteria	See
<b>A. Description</b>	The element consists of the wellhead connector and drilling BOP with kill/choke line valves.	NORSOK D-001
<b>B. Function</b>	The function of wellhead connector is to prevent flow from the bore to the environment and to provide a mechanical connection between drilling BOP and the wellhead. The function of the BOP is to provide capabilities to close in and seal the wellbore with or without tools/equipment through the BOP.	
<b>C. Design construction selection</b>	<ol style="list-style-type: none"> <li>1. The drilling BOP shall be constructed in accordance with Norsok D-001.</li> <li>2. A risk analysis shall be performed to decide the best BOP configuration for the location in question. The risk analysis should take the following into account:                             <ol style="list-style-type: none"> <li>a) position of different ram types;</li> <li>b) choke and kill line access position;</li> <li>c) ability to hang off pipe and retain ability to close shear ram, including contingency closure of rams if available;</li> <li>d) ability to centralize pipe prior to closing shear ram;</li> <li>e) back-up shear ram.</li> </ol> </li> <li>3. The BOP WP shall exceed the WDP including a margin for killing operations.</li> <li>4. It shall be documented that the shear/seal ram can shear the drill pipe, tubing, wireline, CT or other specified tools, and seal the wellbore thereafter. If this can not be documented by the manufacturer, a qualification test shall be performed and documented.</li> <li>5. When running non-shearable items, there shall be minimum one pipe ram or annular preventer able to seal the actual size of the non-shearable item. Other activities should be coordinated in order to minimize the overall risk level on the installation while running non-shearable items through the BOP.</li> <li>6. For floaters the wellhead connector shall be equipped with a secondary release feature allowing release with ROV.</li> <li>7. When using tapered drill pipe string there should be pipe rams to fit each pipe size. Variable bore rams should have sufficient hang off load capacity.</li> <li>8. There may be an outlet below the LPR. This outlet shall not be used as a choke line unless a proper risk analysis has been performed. The number of flanges shall be minimized.</li> <li>9. HPHT: The BOP shall be furnished with surface readout pressure and temperature.</li> <li>10. Deep water:                             <ol style="list-style-type: none"> <li>a) The BOP shall be furnished with surface readout pressure and temperature.</li> <li>b) The drilling BOP shall have two annular preventers. One or both of the annular preventers shall be part of the LMRP. It should be possible to bleed off gas trapped between the preventers in a controlled way.</li> <li>c) Bending loads on the BOP flanges and connector shall be verified to withstand maximum bending loads (e.g. highest allowable riser angle and highest expected drilling fluid density.)</li> <li>d) From a DP vessel it shall be possible to shear full casing strings and seal thereafter, by use of a combination of casing shear ram and blind shear ram. Otherwise, the casings should be run as liners.</li> </ol> </li> </ol>	NORSOK D-001 API Spec 53 API Spec 16RCD ISO 13533
<b>D. Initial test and verification</b>	See Annex A, Table .38. <ol style="list-style-type: none"> <li>1. Components shall be visually inspected for internal wear during installation and removal.</li> </ol>	
<b>E. Use</b>	The drilling BOP elements shall be activated as described in the well control action procedures.	

## 2.3.5 Comparison to the BSEE Regulatory Approach

Though the Norwegian approach more clearly defines a performance-based framework within which the operator can innovate by proposing alternative barrier elements and acceptance criteria, the approach provided by the CFRs is very similar and also provides room for alternative methods. Both approaches employ a general performance-based framework complemented by requirements for specific technologies (e.g., a fluid column). In the case of the CFRs, the specific requirements are implemented through prescriptive rules that must be followed unless an exception is granted through alternative methods<sup>6</sup>. In the case of D-010, the requirements are presented in the form of examples acceptable to the regulator and a framework for similar methods. Though the latter approach may be more inviting to innovation, the result of the regulations are likely very similar in the majority of field applications. In both systems, the methods used whether standard or innovative are ultimately proposed by the applicant and reviewed for approval by the regulator through the permitting process.

## 2.4 Comparative Analysis of Regulations

In the following sections, each grouping of regulations in Figure 2-3 is discussed and compared to similar rules in other jurisdictions and to industry practice. This comparative analysis is then summarized in **Section 2.4.5**.

### 2.4.1 Regulations pertaining to General Requirements and Hazard Management

As shown in Figure 2-3, regulations with general requirements and pertaining to the management of hazards relevant to tripping include CFR 250.107, 250.400, 250.500, and Subpart S. These requirements are described in the following section. (Note: The authors interpret “operator must” to mean “operator must direct the contractor to” for actions that are performed by a contractor under the operator’s direction.)

**CFR 250.107** indicates that the well operator must protect health, safety, property and the environment by performing all operations in a safe and workmanlike manner and maintaining all equipment and work areas in a safe condition. Further, it requires that the operator must immediately control, remove or otherwise correct any hazardous oil and gas accumulation or other health, safety or fire hazard; in addition, the operator must use the Best Available and Safest Technology (BAST) whenever practical on all exploration, development and production operations. Use of BAST is considered to have been achieved when the proposed operations are in compliance with BSEE regulations. The BSEE director can require the operator to use measures in addition to those in the published regulations to avoid the failure of equipment that would have a significant effect on safety, health, or the environment if it is economically feasible and the benefits outweigh the costs.

Requirements added with the implementation of new drilling safety rules, effective July 28, 2016, included requirements to utilize recognized engineering practices that reduce risks to the lowest level practicable when conducting design, fabrication, installation, operation, inspection, repair and maintenance activities; and compliance with all lease, plan, and permit terms and conditions. Also added was an enforcement provision that BSEE may issue orders to ensure compliance with this part, including, but not limited to, orders to produce and submit records and to inspect, repair, and/or replace equipment. BSEE may also issue orders to shut in operation of a component or facility because of a

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<sup>6</sup> Generally exceptions must be shown to be as safe or safer than the prescriptive rules.

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threat of serious, irreparable, or immediate harm to health, safety, property or the environment posed by those operations or because the operations violate law, including a regulation, order or provision of a lease, plan or permit.

**CFR 250.400** is a general performance-based requirement to conduct drilling operations in a safe manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the Outer Continental Shelf (OCS), including any mineral deposits (in areas leased and not leased), the national security or defense, or the marine, coastal, or human environment. Tripping operations are a part of drilling operations and would be included under this general requirement. Most regulatory state and international jurisdictions have similar requirements.

**CFR 250.500** states the same general performance based requirement as 250.400 but applies to completions operations.

A review of national regulations and laws at the state level as well as regulations and laws of various countries with active drilling programs found similar requirements to this regulation in almost all jurisdictions. The Health, Safety and Environmental (HSE) mission and guiding principles of industry organizations and their members, such as API and IADC, as well as the professional ethics codes of professional engineering societies and state engineering registration boards also subscribe to these same guiding principles. Most states have similar provisions granting them the authority to inspect, to have access to records, and to shut-in operations that are found to be in violation of their regulations, are unsafe, or are a threat to the environment.

**Subpart S** is a requirement for a Safety and Environmental Management System (SEMS). A major objective of sections 107, 400 and 500 can be summarized as “*protect HSE by managing hazards.*” Subpart S serves the same objective and further specifies a systematic approach for meeting that objective.

The regulations do not prescribe that well control during tripping be identified as an activity in the SEMS, but Subpart S is referenced in regard to well control-related training (250.703, 734 and 739) and the SEMS must include a description of well control systems (205.1910). The regulations also require communication of hazards to the crew per Subpart S (250.710a) and a well control plan (250.710b). Subpart S further requires the review of stop work authority procedures in all meetings focusing on safety (250.1930) which could include rig-site safety meetings held prior to tripping and requires the investigation of all incidents with serious safety or environmental consequences (250.1919) which could include some well control events related to tripping.

Subpart S largely follows the American Petroleum Institute's Recommended Practice for *Development of a Safety and Environmental Management Program for Offshore Operations and Facilities* (API RP 75) which is incorporated by reference in CFR 250.198. Subpart S requires operators to develop, implement and maintain a properly documented SEMS program. The program must include at minimum the program elements listed below

**Table 2-5: The Seventeen SEMS Elements**

1. General
2. Safety and Environmental Information
3. Hazards Analysis
4. Management of Change
5. Operating Procedures
6. Safe Work Practices
7. Training
8. Mechanical Integrity
9. Pre-startup Review
10. Emergency Response and Control
11. Investigation of Incidents
12. Auditing
13. Recordkeeping
14. Stop Work Authority (SWA)
15. Ultimate Work Authority (UWA)
16. Employee Participation Plan (EPP)
17. Reporting Unsafe Working Conditions

Within element 3 “Hazard Analysis” the SEMS regulation prescribes that a job safety analysis (JSA) must be conducted for OCS activities identified or discussed in the SEMS program and which must meet or exceed the standards of HSE protection of API RP 75<sup>7</sup>. In 1911(4)(b) a JSA is described as a technique to identify and mitigate risks to personnel which “*identifies, analyzes, and records:*

- (i) *The steps involved in performing a specific job;*
- (ii) *The existing or potential safety, health, and environmental hazards associated with each step; and*
- (iii) *The recommended action(s) and/or procedure(s) that will eliminate or reduce these hazards, the risk of a workplace injury or illness, or environmental impacts.”*

The three attributes describing a JSA in the CFR are very similar to the OSHA description of a JSA that is derived from the Occupational Health and Safety profession and evolved from the Job Analysis technique. See **Section 5.2.2.2** for a more in depth discussion of how the term JSA appears to be interpreted by the drilling and regulatory communities.

If tripping is identified as an activity in the SEMS, then all SEMS requirements must be met for the activity including a JSA per 250.1911. The hazards and mitigations identified in the JSA could involve well control during tripping. The exercises commonly performed in rig-site safety meetings prior to tripping and referred to as JSAs in the drilling community typically do not meet all the requirements of 1911, and a SEMS-compliant JSA would likely be impractical to implement within the time available in these meetings. Since tripping is a recurring activity the operator could elect to develop a single JSA for multiple trips under 1911(b)(4).

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<sup>7</sup> Though the CFR makes references to JSAs, API RP 75 does not have a single reference to JSA or Job Safety Analyses. The term safety analysis (not job safety analysis) is used once in RP 75 and only in the broadest context, not as a term of art as is the case with the CFR. Subpart S includes requirements for a JSA and a description of a JSA.



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One goal of SEMS is to provide an auditable record of hazard communications. Written auditable records that already exist within operator and contractor organizations include job descriptions, operational manuals, on-the-job-training programs, well control manuals, and well control policies. Further discussion of operator preplanning is provided in **Section 5**.

The review of other US regulatory jurisdictions did not reveal requirements comparable to Subpart S. Internationally, the Norwegian standard related to well control is NORSOK Standard D-010, *Well integrity in drilling and well operations*. D-010 does require a SEMS-like program which is more narrowly defined to cover well integrity management and has individual SEMS-like elements embedded in other requirements. NORSOK Z-013, Risk and Emergency Preparedness Assessment, is an informational reference in D-010 and gives requirements for effective planning and execution of risk and/or emergency preparedness assessments. Although not referenced in D-010, NORSOK does provide standards for systems like SEMS, which serve to protect HSE by managing hazards. Those most relevant to Subpart S are listed in **Table 2-6**.

**Table 2-6: NORSOK Standards related to SEMS**

<b>Standard</b>	<b>Title</b>
S-001	Technical safety (Edition 4, February 2008)
S-002	Working environment (Rev. 4, August 2004)
S-003	Environmental care (Rev. 3, December 2005)
S-006	HSE evaluation of contractors (Rev. 2, December 2003)

Together, these standards impose requirements similar to Subpart S. The technical safety design process specified by NORSOK S-001 begins with hazard identification and mitigates the hazard with “safety performance standards.” This parallels the use of hazard analysis and written procedures in SEMS.

## **2.4.2 Regulations pertaining to Well Control**

As shown in Figure 2-3, regulations pertaining to well control and relevant to tripping operations include CFR 250.141, 250.414, 250.514, 250.700, 250.703, 250.710, Subpart O, and Subpart S. These requirements are described in the following section.

**CFR 250.141 and 250.701** provide provisions for the use of alternative procedures or equipment to those commonly used in current practice. Mud Lift Drilling (MLD), Dual Gradient Drilling (DGD)<sup>8</sup>, and other Managed Pressure Drilling (MPD) techniques are examples of the use of alternative procedures and equipment. The District Manager’s or Regional Supervisor’s written approval must be given before alternate procedures or equipment can be used. To receive approval, the site-specific application, performance characteristics, and safety features of the proposed procedure or equipment must be submitted to the appropriate Regional Supervisor, demonstrating a level of safety and environmental protection that equals or surpasses current BSEE requirements. Such a documented presentation would include detailed descriptions of the specialized equipment, procedures, and guidelines that would be followed during all operations involved, including tripping operations. An independent third party

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<sup>8</sup> MLD and DGD can increase the safety margin between fracture gradient and mud density through the use of pumps near the seafloor to return the drilling fluid to the surface mud tanks. These techniques require significant changes from conventional drilling practice in both equipment and procedures.

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verification agent could be required as part of the approval process. This type of performance-based regulation, in which the operator writes site specific rules, guidelines, and procedures that will be followed and submits them in detail for approval, was not seen in state regulations but is similar to the regulatory approach used in Europe and by NOPSEMA, Australia's regulatory body. CFR 250.701 was added July 28, 2016 in the new Subpart G, which basically re-states these requirements.

**CFR 250.414** requires that a Drilling Prognosis submitted with the Application for Permit to Drill (APD) include a brief description of the procedures that will be followed in drilling the well. Item (c) gives requirements regarding the drilling margin which are discussed in **Section 2.5** of this report. Item (h) requires the prognosis to include *“a list and description of all requests for using alternate procedures or departures from the requirements of this subpart in one place in the APD. You must explain how the alternate procedures afford an equal or greater degree of protection, safety, or performance, or why the departures are requested.”*

**CFR 250.514 and 250.700.** CFR 250.514 is in Subpart E, Oil and Gas Well-Completion Operations that covers well-control fluids, equipment, and operations. Well-completion operations means the work conducted to establish the production of a well after the production casing string has been set, cemented and pressure-tested. The requirements of 250.514 with regard to tripping and swabbing are virtually the same as those of Subpart D on drilling operations and will be discussed later. CFR 250.700 indicates that Subpart G, Well Operations and Equipment, applies to both drilling and completion activities. Together 250.514 and 250.700 indicate that, in regards to well control during tripping, the requirements for drilling and completions are the same. 250.514(a) also requires that well control will be utilized to control the well in all conditions and circumstances, similar to the requirement in 250.703, which is discussed below.

**CFR 250.703** contains both performance-based and prescriptive regulations requiring that the well is to be kept under control at all times. (CFR 250.703 replaced CFR 250.401 after implementation of the new Drilling Safety Rules effective July 28, 2016.) Regulations include:

- (a) Use recognized engineering practices to reduce risks to the lowest level practicable when monitoring and evaluating well conditions and to minimize the potential for the well to flow or kick;*
- (b) Have a person onsite during operations who represents your interests and can fulfill your responsibilities;*
- (c) Ensure that the toolpusher, operator's representative, or a member of the rig crew maintains continuous surveillance on the rig floor from the beginning of operations until the well is completed or abandoned, unless you have secured the well with blowout preventers (BOPs), bridge plugs, cement plugs, or packers;*
- (d) Use personnel trained according to the provisions of subparts O and S of this part;*
- (e) Use and maintain equipment and materials necessary to ensure the safety and protection of personnel, equipment, natural resources, and the environment; and*
- (f) Use equipment that has been designed, tested, and rated for the maximum environmental and operational conditions to which it may be exposed while in service.*

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This regulation applies to tripping operations because tripping is a routine part of drilling and completion operations and it requires the well to be under control at all times. The wording of provisions (a), (b), (c), and (f) above was not found in the regulations and laws of the various states and countries reviewed as part of this study. However, these provisions would fall under the general heading of following normal good practice and would be generally enforceable in federal and state civil courts if failure to follow these practices resulted in damage to life, property, or the environment.

Provision (e) was a performance-based regulation that is common in many other regulatory jurisdictions. It provides the basis for reviewing the required submission of a drilling prognosis and mud program as part of the well permitting process. Equipment and material suppliers tend to be international in scope and the available equipment and material is essentially the same everywhere in the free world. The equipment important to well control operations are included in the Blowout Prevention Equipment Systems described in API Standard 53 discussed in **Section 2.4.4** and **Section 4.4**.

**Subparts O and S.** CFR 250.703(d) explicitly incorporates Subpart O, Well Control and Production Safety Training, and Subpart S, Safety and Environmental Management Systems (SEMS). About half of the regulatory jurisdictions reviewed required the use of personnel trained in well control procedures; however, the required training varied considerably and in some cases was based only on work experience and on-the-job training. Most state regulatory agencies placed more emphases on training in emergency procedures associated with encountering H<sub>2</sub>S than on well control training. Alaska and Texas are examples of states for which International Association of Drilling Contractors (IADC) certified Well Cap well control training was accepted as meeting the well control training requirements. The International Well Control Forum (IWCF) and International Alliance for Well Control (IAWC) are other international accreditation organizations that can be adopted by operators to meet their well control training certification requirements. Adding the requirements of Subpart S, which is the Safety and Environmental Management Systems (SEMS), moves the training requirements more in the direction of those used in Europe, where the responsibility to develop rules, guidelines, and standard operating procedures are placed on the operator and then verified by BSEE and independent verification agents.

The replacement of CFR 250.401 with CFR 250.703 is in keeping with moving the responsibility of developing and adopting rules, standards, and guidelines to the operator, who then submits them to BSEE as part of their SEMS program. It does not mean that the rules being removed from the regulations will no longer be used in practice. BSEE will continue to verify that appropriate rules, standards and guidelines are in the operator's submissions as part of the audit and permit approval processes.

**CFR 250.710** requires that prior to engaging in well operations, personnel must be instructed in:

(a) *Hazards and safety requirements. Personnel must be instructed regarding the safety requirements for the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment as required by subpart S of this part (SEMS). The date and time of safety meetings must be recorded and available at the facility for review by BSEE representatives.*

(b) *Well control. A well-control plan is required for each well. Each well-control plan must contain instructions for personnel about the use of each well-control component of your BOP, procedures that describe how personnel will seal the wellbore and shear pipe before maximum anticipated surface pressure (MASP) conditions are exceeded, assignments for each crew*

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*member, and a schedule for completion of each assignment. A copy of the well-control plan must be kept on the rig at all times, and made available to BSEE upon request. A copy of the well-control plan must be posted on the rig floor.*

CFR 250.710 refers to (a) hazard communication per Subpart S and (b) a well control plan. Subpart S was discussed in the previous section. A well control plan is the conventional and widely-used vehicle for managing and communicating well control policy and practices. The association between shearing and Maximum Anticipated Surface Pressure (MASP) in part (a) is problematic and changes are recommended in **Section 4.4**.

### **2.4.3 Regulations pertaining to the Hydrostatic Fluid Column (Primary Barrier)**

In normal practice, the hydrostatic fluid column serves as the primary well control barrier during tripping operations. As shown in Figure 2-3, regulations pertaining to the hydrostatic fluid column include CFR 250.414, 250.418, 250.455-458, 250.514, and 250.703. These requirements are described in the following section.

**CFR 250.414** was discussed in the previous section and requires that a drilling prognosis submitted with the Application for Permit to Drill (APD) includes the planned safe drilling margin between proposed equivalent downhole drilling fluid weights and estimated pore pressures. In item (c) the regulation requires the planned safe drilling margin to be based on a “*risk assessment consistent with expected well conditions and operations.*” The regulation states further that the equivalent downhole mud weight must be greater than the pore pressure (c)(1)(i) and a minimum of 0.5 ppg less than the lower of the casing shoe integrity test or the estimated fracture gradient (c)(1)(ii). Item c(2) allows an exception to (c)(1)(ii) with sufficient documented justification. Item (c)(3) requires consideration of offset well data in the pore pressure estimate.

In regulatory practice, a 0.5 ppg safe drilling margin between the equivalent fluid weight and the estimated pore pressure has been commonly accepted by BSEE in their regulatory review process. A 0.3 ppg minimum safe drilling margin has sometimes been accepted by BSEE in their regulatory review process with special case-specific justification. It is also common for regulators to accept gradient-based criterion (e.g., 0.5 ppg) at shallow depths, and a pressure-based criterion (e.g., 250 psi) at greater depths where the gradient-based criterion becomes excessive.

BLM, Alaska, and California were the only other US jurisdictions that require a drilling prognosis be submitted with the application for permit to drill. Most of the states were primarily concerned with a certified description of the well location and notification of affected land owners and municipalities. A well prognosis could be required in environmentally sensitive areas such as wetlands or if the regulatory agency decided to hold a public hearing before issuing a permit to drill. The Australian regulating body NOSEPMA requires an operator to provide a Well Construction Environmental plan summary. Other countries have no such requirement.

**CFR 250.418** requires that the drilling fluids program submitted with the APD include the minimum quantities of drilling fluids and drilling fluid materials, including weight materials, to be kept at the site. Materials needed to treat downhole zones that are taking mud and to establish well static conditions could be needed in some cases to allow tripping operations to be conducted. Materials needed to adjust the rheological properties of the mud could also be needed at the site to control swab and surge

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pressures. Regulations of the Bureau of Land Management, Alaska, Florida and Texas had similar provisions.

**CFR 250.455** is a performance-based regulation that requires that the operator design and implement their drilling fluid program to prevent the loss of well control. The drilling program submitted must address drilling fluid safe practices, testing and monitoring equipment, drilling fluid quantities, and drilling fluid-handling areas. The states vary widely, from not including this requirement to placing the primary responsibility of well control in the mud program. For example, Alaska requires the drilling program to be submitted and the regulations require that the drilling program must make provisions to continuously observe, monitor and record gas entrained in the mud, fluid density, fluid salinity, ROP and hydrogen sulfide.

**CFR 250.456 and 250.514.** CFR 250.456 requires a prescriptive list of safe practices that must be included in the drilling fluid program that, among other topics, includes the core regulations directly related to tripping operations and swabbing in drilling and completion operations. The required safe practices associated with tripping operations include:

*(a) Before starting out of the hole with drill pipe, you must properly condition the drilling fluid. You must circulate a volume of drilling fluid equal to the annular volume with the drill pipe just off-bottom. You may omit this practice if documentation in the driller's report shows:*

*(1) No indication of formation fluid influx before starting to pull the drill pipe from the hole;*

*(2) The weight of returning drilling fluid is within 0.2 pounds per gallon (1.5 pounds per cubic foot) of the drilling fluid entering the hole; and*

*(3) Other drilling fluid properties are within the limits established by the program approved in the APD.*

*(b) Record each time you circulate drilling fluid in the hole in the driller's report;*

*(c) When coming out of the hole with drill pipe, you must fill the annulus with drilling fluid before the hydrostatic pressure decreases by 75 psi, or every five stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure. You must calculate the number of stands of drill pipe and drill collars that you may pull before you must fill the hole. You must also calculate the equivalent drilling fluid volume needed to fill the hole. Both sets of numbers must be posted near the driller's station. You must use a mechanical, volumetric, or electronic device to measure the drilling fluid required to fill the hole;*

*(d) You must run and pull drill pipe and downhole tools at controlled rates so you do not swab or surge the well;*

*(e) When there is an indication of swabbing or influx of formation fluids, you must take appropriate measures to control the well. You must circulate and condition the well, on or near-bottom, unless well or drilling-fluid conditions prevent running the drill pipe back to the bottom;*

The Safe Practices prescribed list then goes on to provide some well control safe practices of the drilling fluid program that are not directly related to tripping operations. One of these is related to well testing and tripping operations after well testing, as follows:

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*(h) Before pulling drill-stem test tools from the hole, you must circulate or reverse-circulate the test fluids in the hole. If circulating out test fluids is not feasible, you may bullhead test fluids out of the drill-stem test string and tools with an appropriate kill weight fluid;*

BSEE's written prescriptive requirements tend to include more items than those of the states and other countries. Only Texas and Brazil appear to have more restrictive requirements in that they require that the well be kept full at all times during tripping operations, i.e., the maximum allowed decrease in fluid level is zero.

CFR 250.514 is in Subpart E, Oil and Gas Well-Completion Operations which covers well-control fluids, equipment and operations. The requirements of 250.514 with regard to the fluid column are similar to 250.703 to keep the well under control and monitored, and to 250.456(c) regarding backfilling with fluid while tripping. CFR 250.514 states the following:

*(a) Well-control fluids, equipment, and operations shall be designed, utilized, maintained, and/or tested as necessary to control the well in foreseeable conditions and circumstances, including subfreezing conditions. The well shall be continuously monitored during well-completion operations and shall not be left unattended at any time unless the well is shut in and secured.*

*(b) The following well-control-fluid equipment shall be installed, maintained, and utilized:*

*(1) A fill-up line above the uppermost BOP;*

*(2) A well-control, fluid-volume measuring device for determining fluid volumes when filling the hole on trips; and*

*(3) A recording mud-pit-level indicator to determine mud-pit-volume gains and losses. This indicator shall include both a visual and an audible warning device.*

*(c) When coming out of the hole with drill pipe, the annulus shall be filled with well-control fluid before the change in such fluid level decreases the hydrostatic pressure 75 pounds per square inch (psi) or every five stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure. The number of stands of drill pipe and drill collars that may be pulled prior to filling the hole and the equivalent well-control fluid volume shall be calculated and posted near the operator's station. A mechanical, volumetric, or electronic device for measuring the amount of well-control fluid required to fill the hole shall be utilized.*

**CFR 250.457 and 250.514.** CFR 250.457 provides requirements for equipment used to monitor the drilling fluid that apply during tripping operations as well as drilling operations.

*(a) Pit level indicator to determine drilling fluid-pit volume gains and losses. This indicator must include both a visual and an audible warning device;*

*(b) Volume measuring device to accurately determine drilling fluid volumes required to fill the hole on trips;*

*(c) Return indicator devices that indicate the relationship between drilling fluid-return flow rate and pump discharge rate. This indicator must include both a visual and an audible warning device; and*

*(d) Gas-detecting equipment to monitor the drilling fluid returns. The indicator may be located in the drilling fluid-logging compartment or on the rig floor. If the indicators are only in the logging compartment, the equipment must be continually manned and have a means of immediate*

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*communication with the rig floor. If the indicators are on the rig floor only, you must install an audible alarm.*

CFR 250.514 is in Subpart E, Oil and Gas Well-Completion Operations which covers well-control fluids, equipment, and operations. The requirements 250.514 with regard to the fluid column equipment are similar to 250.457:

*(b) The following well-control-fluid equipment shall be installed, maintained, and utilized:*

- (1) A fill-up line above the uppermost BOP;*
- (2) A well-control, fluid-volume measuring device for determining fluid volumes when filling the hole on trips; and*
- (3) A recording mud-pit-level indicator to determine mud-pit-volume gains and losses. This indicator shall include both a visual and an audible warning device.*

The requirement to monitor fill-up volumes during tripping operations is common in state regulations and almost universal in the international regulations reviewed.

**CFR 250.458** gives requirements concerning the quantities of drilling fluid that are required at the site. You must use, maintain and replenish quantities of drilling fluid and drilling fluid materials at the drill site as necessary to ensure well control. You must record the daily inventories in the drilling fluid report. If you do not have sufficient quantities of drilling fluid and drilling fluid material to maintain well control, you must suspend drilling operations.

### **2.4.4 Regulations pertaining to Mechanical Containment with the BOPE (Secondary Barrier)**

In normal practice, mechanical containment of the wellbore with the BOPE serves as the secondary well control barrier during tripping operations. As shown in Figure 2-3, regulations pertaining to mechanical containment and relevant to tripping include CFR 250.198, 250.420-428, 250.456, 250.710, and 250.710-711, 250.730, and 250.736. These requirements are described in the following section.

**CFR 250.198** incorporates Industry Standards and Guidelines by reference. API Recommended Practice (RP) 53 and API Standard 53 are now both included in this regulation after implementation of the new Drilling Safety Rules effective July 28, 2016. These documents pertain to the Blowout Preventer (BOP) equipment and auxiliary equipment that can be employed during tripping operations in the event that the well begins to flow. Rams must be available to fit all pipe sizes present in a tapered drill pipe string. Both API Standard 53 and API RP 53 address all of the auxiliary equipment that can stop flow through the inside of the drill pipe; these include upper and lower kelly valves, safety valves to fit pipe being pulled (with accessible wrench for operation), and inside blowout preventer valves to fit size of pipe being pulled. Blind Shear Rams (BSR's)<sup>9</sup> or Blind Rams (BR's) above Shear Rams (SR's) are the last line of defense against blowouts through the drill string or work string if the kelly valves, safety valves or inside blowout preventers fail or cannot be installed. API Standard 53 now requires the use of Blind Shear Rams (BSR) on both high pressure (15,000 psi or greater) surface stacks and on subsea BOP

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<sup>9</sup> A BSR can both shear the pipe and seal the annulus above the sheared pipe. SR's shear the pipe but do not seal to stop flow. The seal would have to be accomplished with an additional Blind Ram (BR).

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stacks<sup>10</sup>. Two shear rams (SR) are now required on subsea stacks unless use of one BSR can be justified by conducting a prescribed risk assessment.

API Standard 53 also requires the use of trip tanks of 100 bbl or less in capacity that can be used to measure the volume of fluid returned from the annulus of the well with an accuracy of +/- 0.5 bbl. The tank volume readout may be either direct or remote, with both direct and remote together being preferred.

Most other states and countries do not include API Standard 53 by reference, although Texas, Pennsylvania, Canada, and Mexico are notable exceptions that do include API Standard 53 by reference. More jurisdictions will likely follow BSEE's lead and include API Standard 53 by reference in the future.

**CFR 250.420-428** sets forth requirements for casing and cement that apply directly to tripping operations and swabbing in that the casing and cement form a portion of the mechanical containment barrier when the BOPs are closed. In addition, for wells with a subsea BOP, CFR 250.420 requires a barrier to flow up the annulus during subsequent well operations, including tripping operations:

"On all wells that use subsea BOP stacks, two independent barriers, including one mechanical barrier, in each annular flow path are required."<sup>11</sup>

Similar barrier analyses requirements were not found in any of the state regulatory agencies of the U.S. or in the rules published by the Bureau of Land Management. Instead, prescriptive requirements for casing setting depths and cement barrier lengths are provided for the various casing strings to insure well integrity. However, performance-based barrier analyses and the requirement of two independent barriers are heavily relied on in the regulatory approach used by the various countries bordering the North Sea. The NORSOK Standard D-010, which is widely used in Europe, relies heavily on barrier analyses to maintain well integrity and operators must follow this standard in their permit application process.

**CFR 250.456** covers safe practices for the drilling fluid program. It also includes one requirement that relates directly to the activation of the BOPE:

*(f) You must calculate and post near the driller's console the maximum pressures that you may safely contain under a shut-in BOP for each casing string. The pressures posted must consider the surface pressure at which the formation at the shoe would break down, the rated working pressure of the BOP stack, and 70 percent of casing burst (or casing test as approved by the District Manager). As a minimum, you must post the following two pressures:*

*(1) The surface pressure at which the shoe would break down. This calculation must consider the current drilling fluid weight in the hole; and*

*(2) The lesser of the BOP's rated working pressure or 70 percent of casing-burst pressure (or casing test otherwise approved by the District Manager);*

These allowable pressures are commonly referred to as versions of the Maximum Allowable Surface Pressure (MASP), Maximum Anticipated Working Pressure (MASP) and Maximum Allowable Annular

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<sup>10</sup> Surface BOP Stacks are generally used on bottom-supported rigs such as jackups and platform rigs, and Subsea BOP stacks located near the ocean floor are generally used on floating drilling vessels such as semi-submersibles and drillships.

<sup>11</sup> Examples of barriers include, but are not limited to, primary cement job and seal assembly.



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Surface Pressure (MAASP). These terms are commonly used in industry and well control planning and training. However, the author's experience in well control training has shown that the meaning of the MASP is often poorly understood in the field, and can impair good decision making during well control events. A more complete discussion of this issue is provided in **Section 4.4** under CFR 250.710(b).

Providing a new distinct term for each of these pressure limits should be considered. Limits related to shoe fracture pressure should be posted as a diagnostic, not an actionable parameter. If the approved well control plan includes bull-heading for example, the pressure described in item (f)(1) above may be intentionally exceeded. Also, shoe fracture is almost always preferred over diverting through the choke (unless a shallow casing rupture is indicated or the surface casing is set too shallow).

The same is the case for item (f)(2) above. Exceeding 70 percent of the casing burst may be the best way to mitigate risk in a wide range of unplanned situations. It is important to note that if 70 percent of burst is used as a design parameter and during the course of operations that pressure must be exceeded to contain the well, the design is flawed.

Item (f)(1) could be called Casing Pressure to Fracture or Choke Pressure to Fracture (CPF, or CsgPressFrac, or CkPressFrac) and Item (f)(2) could be Casing Rated Working Pressure (CRWP). Using Rated Working Pressure would fit with API and IADC usage of the term for BOPs and BOP components.

### **CFR 250.710 and 250.711**

CFR 250.710(b) requires a well control plan containing *“instructions for personnel about the use of each well-control component of your BOP, procedures that describe how personnel will seal the wellbore and shear pipe before maximum anticipated surface pressure (MASP) conditions are exceeded, assignments for each crew member, and a schedule for completion of each assignment.”*

The problem with using the term MASP is described in under CFR 250.456 above. The problem with attaching shearing to MASP is discussed in **Section 4.4** along with recommended changes to the regulation.

CFR 250.711 gives the requirement of well control training drills.

*You must conduct a weekly well-control drill with all personnel engaged in well operations. Your drill must familiarize personnel engaged in well operations with their roles and functions so that they can perform their duties promptly and efficiently as outlined in the well-control plan required by §250.710.*

*(a) Timing of drills. You must conduct each drill during a period of activity that minimizes the risk to operations. The timing of your drills must cover a range of different operations, including drilling with a diverter, on-bottom drilling, and tripping. The same drill may not be repeated consecutively with the same crew.*

*(b) Recordkeeping requirements. For each drill, you must record the following in the daily report:*

- (1) Date, time, and type of drill conducted;*
- (2) The amount of time it took to be ready to close the diverter or use each well-control component of BOP system; and*
- (3) The total time to complete the entire drill.*

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*(c) A BSEE ordered drill. A BSEE representative may require you to conduct a well-control drill during a BSEE inspection. The BSEE representative will consult with your onsite representative before requiring the drill.*

CFR 250.198 incorporates by reference API Standard 53 which refers to API RP 59 for recommendations regarding pit drills. (API RP 59 is not incorporated by reference in 250.198.)

**CFR 250.730** contains general requirements for BOP systems and system components and incorporates the BOP requirements of API Standard 53 (incorporated by reference in 250.198). API 53 requirements most relevant to tripping operations include the ram requirements for tapered strings and the requirement for Shear Rams or Blind Shear Rams. Shear rams would be needed during tripping operations if drillstring or casing safety valves could not be successfully used to seal the flow-path through the tubular.

**CFR 250.736** provided prescriptive regulations regarding requirements for Kelly valves, inside BOPs and drill-string safety valves. (This material was previously covered in the removed CFR 250.445.) The portions of these CFR's that pertain to tripping operations included reference to those auxiliary BOP system components for stopping flow up the drillstring that would apply if the well had to be shut-in during tripping operations. The portions related to tripping operations include:

- (1) The applicable kelly-type valves as described in API Standard 53 (incorporated by reference in § 250.198);*
- (2) On a top-drive system equipped with a remote-controlled valve, a strippable kelly-type valve must be installed below the remote-controlled valve;*
- (3) An inside BOP in the open position located on the rig floor and be able to install an inside BOP for each size connection in the pipe;*
- (4) A drill string safety valve in the open position located on the rig floor and have a drill-string safety valve available for each size connection in the pipe;*
- (5) When running casing, a safety valve in the open position available on the rig floor to fit the casing string being run in the hole;*
- (6) All required manual and remote controlled kelly-type valves, drillstring safety valves, and comparable type valves (i.e., kelly-type valve in a top-drive system) that are essentially full opening; and*
- (7) A wrench to fit each manual valve that is readily accessible to the drilling crew.*

The importance of having this equipment available during tripping operations is recognized in the regulations of most of the important oil producing states and countries. Jurisdictions that do not have rules requiring this equipment generally rely more on performance-based regulations and written operator plans and procedures that can be reviewed and compared to the available industry standards and recommended practices. The actual difference in tripping operational practices is probably not significant.

**CFR 250.737-739** cover BOP testing, special situations, maintenance and inspection. CFR 250.739 references Subpart S regarding the training of personnel who inspect or maintain BOPs. These topics are only tangentially related to well control during tripping and are beyond the scope of this assessment.

## 2.4.5 Comparative Analysis Summaries

Tables in Appendix D summarize the comparative analysis of the requirements of BSEE, BLM, various oil and gas producing states, and international jurisdictions that were discussed in the sections above. A short description of each regulatory element is provided along with the CFR in which the regulation element is found. The organization of the tables follow that of the previous sections, addressing general requirements and hazard management, well control, the hydrostatic fluid column, and mechanical containment using the BOPE. The general requirements are summarized in Table D1 without jurisdictional comparisons. All general elements except the last row (SEMS) are believed to be universally required.

## 2.5 Common Industry Practice for Maintaining Well Control while Tripping

In this section of the report, common industry practice for maintaining well control while tripping will be discussed. In normal practice, well control during tripping is accomplished using the hydrostatic fluid column as the primary barrier and mechanical containment with the BOPE as the secondary barrier. The inherent high reliability of the fluid column arises from its technological simplicity and passive nature; once in place it requires no activation. The inherent limitation of the fluid barrier is the uncertainty in selecting the appropriate density margin. In addition, when an influx does occur there is potential for the barrier to progressively degrade. If the influx is identified quickly and the secondary barrier is activated to arrest further influx, the density reduction is small and an adequate fluid barrier can be restored without complication. The inherent limitation of the secondary barrier is that it requires activation.

The most important aspects of maintaining well control while tripping during drilling and completion operations arise from the challenges of fluid density selection and timely BOP activation. Important procedural aspects include: (1) accurate determination of formation pore pressure or safety margin that is present, (2) selection of an appropriate safety margin, (3) starting with a stable well, (4) early swab kick detection, and (5) crew training.

### 2.5.1 Pore Pressure Gradient Estimation

Pore pressure estimation during well planning is generally based primarily on records of nearby wells, including mud density vs. depth records, formation pressure data gathered during formation evaluation fluid and pressure testing, well kick records, well perforation and completion records, well production records, and from pore pressure correlations that can be applied using well logs and seismic records. Pore pressure at a given depth is generally converted to the equivalent mud density that would be needed to hydrostatically balance the pore pressure and prevent flow from the formation into the well with the well open to the atmosphere. Pore pressure gradient is commonly expressed as an Equivalent Mud Weight (EMW). Pore pressure gradient information and mud weights from nearby wells are generally plotted versus true vertical depth and an estimated pore pressure gradient versus depth line is fitted by the well planner using the available data. Emphasis is placed on data derived from measured downhole formation pressure points when they are available. An example mud density data plot is shown in **Figure 2-5** and the corresponding pore pressure gradient estimate plot prepared during well planning is shown in **Figure 2-6**. Also shown in Figure 2-6 is an example of planned mud weights that maintain a safety margin of at least 0.5 lb/gal over the estimated pore pressure.

Note that the example of Figure 2-5 shows that the wells in the area could be drilled with about a 9.0 lb/gal mud down to a depth of about 13,000 ft. Formations in the Gulf Coast Area with a pore pressure that is approximately equal to the vertical depth of the formation times 0.465 psi/ft are said to be

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normally pressured. This is equivalent to a hydrostatic gradient of pore fluid in the formations having an average density of 8.94 lb/gal and being in hydrostatic equilibrium with the surface.

Formations with higher than normal pressure are said to be abnormally pressured. Below 13,000 ft, a transition to abnormally-pressured formations is seen in this example. Pore fluids below this depth could not be expelled through a thick shale layer fast enough to reach hydrostatic equilibrium with the surface as the sediment thickness in the area increased over geologic time. Increasing weight of the overburden as sediments are buried deeper causes sediment compaction and reduced pore space. Clay diagenesis is also thought to occur in which water of hydration is released from the clay interlayers to pore water.

Below about 19,000 ft, the formation pore pressure gradient in the example area regresses to lower values. This is thought to occur due to geochemical processes that take place at high temperatures and pressures present at great depth, especially in older sediments of the Cretaceous and Jurassic age with higher limestone content. The geochemical processes that occur are thought to result in a more compact and cemented matrix crystalline structure that provides increased space for pore fluids to occupy. In areas that have been previously produced, depleted zones of very low pore pressure gradient may also be encountered. Formation fracture gradient is also lowered in a depleted zone. A partially depleted sandstone is present in the example at 19,800 ft.

The shape of a pore pressure gradient versus depth plot can generally be characterized as having a shallow normal pore pressure region, followed by a transition to abnormal pore pressure gradient, followed by a regression to lower pore pressure gradients. These general characteristics are seen in most if not all of the sedimentary basins in which oil and gas exploratory drilling is conducted. In the Gulf Coast Area, the depth at which the transition to abnormal pore pressure gradient begins often occurs at more shallow depths as one moves farther offshore and into the deeper water of the continental slope and ocean basin floor.

Locally high pore pressure gradients can occur within a depth range that is generally characterized as normal pressure sediments. When the continuous pore fluid phase is gas instead of water, the pore pressure at the gas-water interface would be expected to be normal, but if the drill bit encounters a gaseous zone at a significant elevation above the gas-water interface, an abnormal pore pressure gradient will be present. The taller the gas column, the higher the pore pressure gradient will be above normal.

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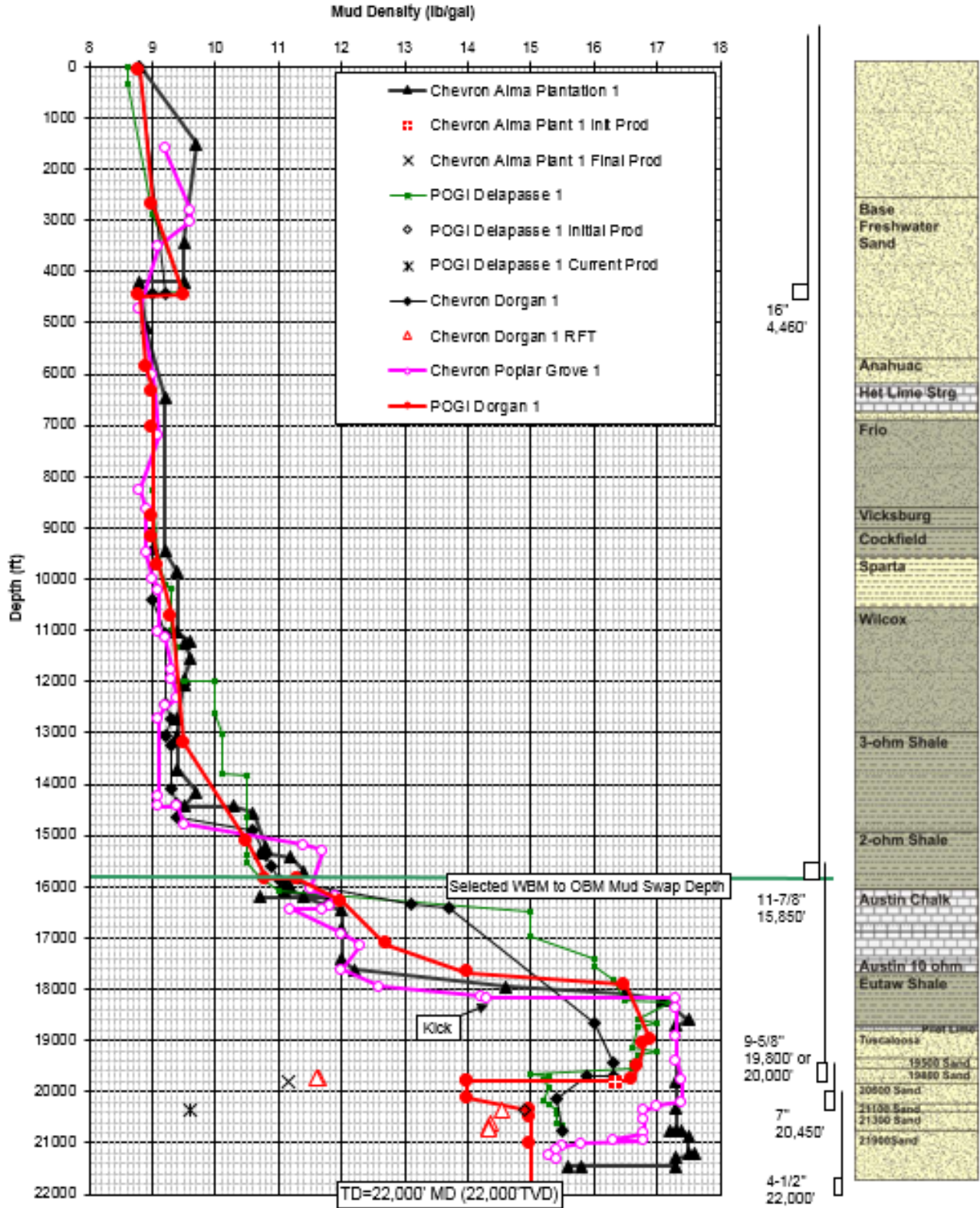


Figure 2-5: Example Pore Pressure Data Plot (False River Field, Pointe Coupe Parish, Louisiana)

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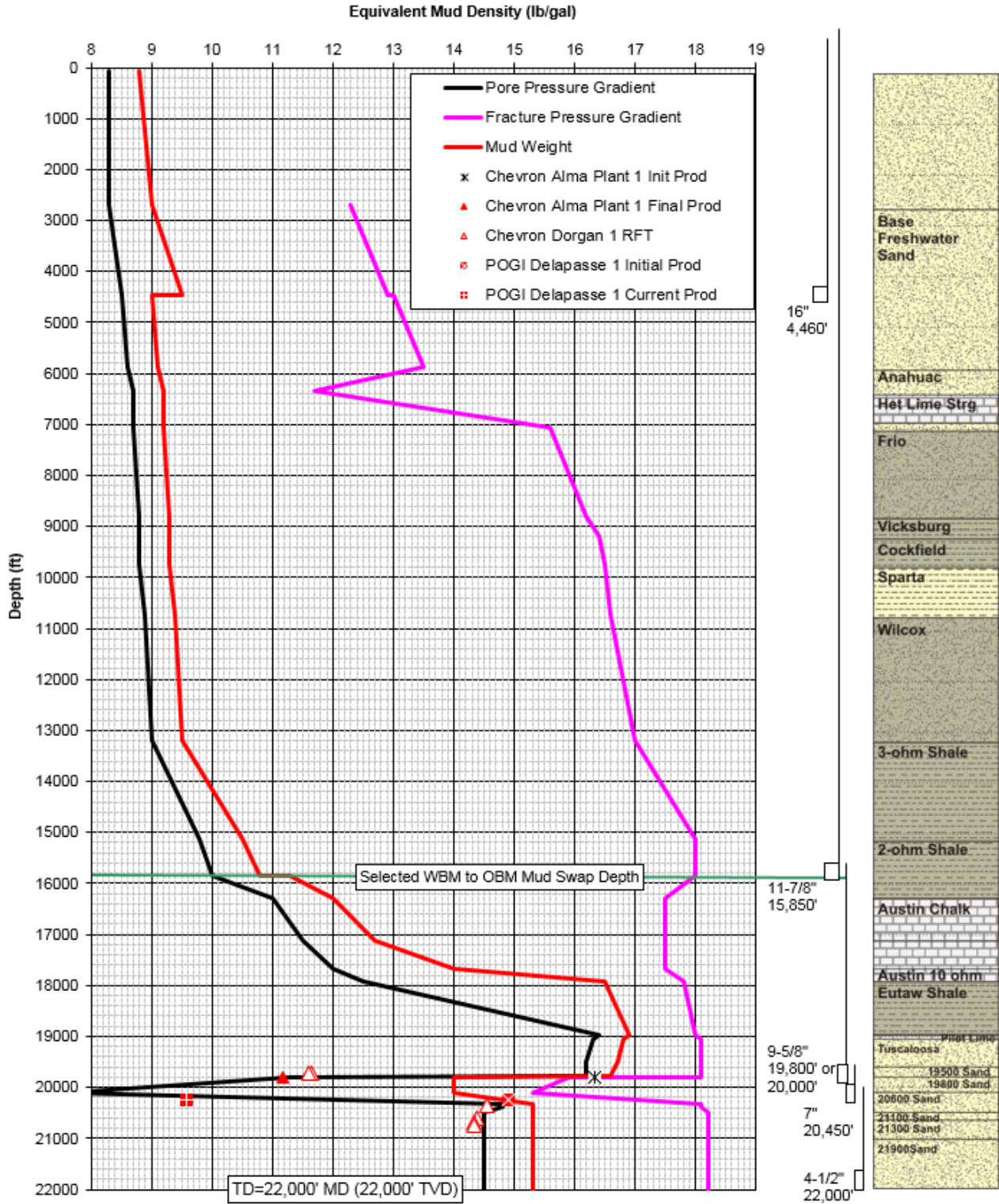


Figure 2-6: Example Pore Pressure, Mud Density, and Fracture Gradient Plot for Well Planning<sup>12</sup>

<sup>12</sup> False River Field, Pointe, Coupe Parish, Louisiana



### **2.5.2 Pore Pressure Gradient Verification while Drilling**

Once drilling is underway, data gathered during drilling can sometimes be used to verify or update the pore pressure gradient estimate plot. If the pore pressure is increasing with depth faster than estimated, the safety margin will decrease accordingly. If the rocks being drilled do not have significant permeability, the well will not flow, even if the well becomes underbalanced at the bit, until a permeable zone is cut. In this situation, variations in rock cuttings, mud logging information and drill bit performance can usually allow the unexpected increase in pore pressure gradient to be detected. The bit will drill more efficiently as overbalance decreases. Drill bit penetration rate in shale, normalized for any changes in the drilling parameters, such as bit weight, rotary speed, and pump rate, can be used to detect a decreasing overbalance in bottom-hole pressure. Increases in mud gas concentration that corresponds to bottoms up after a trip (Trip Gas) or after the pump was stopped to make a connection (Connection Gas) is an indication of down-hole gas seepage into the mud when circulation is stopped. The density versus depth trend of shale in a transition zone will show a reversal from the normal compaction trend line. This can sometimes be detected by the mud logger through measuring the density of shale cuttings recovered from the mud. LWD companies often provide pore pressure estimates based on their resistivity curves when these tools are available. High-cost deepwater wells sometimes obtain direct pore pressure measurements from LWD companies by using a formation test tool in the drill string. The appearance of large spalling shale fragments in the returning mud is also a warning of an underbalanced condition. Adjustments in mud density can be made based on observations made while drilling.

Indirect observations to evaluate pore pressure while drilling may be more challenging in deepwater. In deepwater wells the bottoms up time can be hours and the rate of penetration can be rapid; thus cuttings analysis and gas trends may significantly lag the conditions at the bit. Under reamers may add further confusion to cuttings analysis. However, logging while drilling (LWD) and pressure-while-drilling (PWD) tools are commonly used on deepwater wells, so that bottom-hole data relevant to the pore pressure is directly available.

When the well design and fracture pressure will permit only a small safety margin during tripping operations just prior to running casing, slower pipe pulling speeds can be used. The adequacy of the available safety margin can be verified using a “short trip”, in which the BHA is pulled up into the casing and above the liner top (if one is present), and then returned to bottom. The well is then circulated clean again to evaluate the amount of trip gas observed.

### **2.5.3 Pore Pressure Verification during Completion Operations**

Verification of the formation pore pressure when the well is perforated is a common practice during completion operations. For a conventional non-gravel packed completion, production tubing is run inside of the casing with a packer near the bottom of the tubing and above the interval to be perforated. The tubing, packer, wellhead and tree are installed before the productive interval is perforated. When the perforating gun is run on electric line, a bottom-hole pressure and temperature (BHP/T) gauge may be run with the gun. It is a common practice to perforate the well underbalanced so that the completion fluid and perforation debris do not flow into the perforation holes and formation causing completion damage. Instead, there is an instantaneous flow from the formation through the perforation holes and into the wellbore that helps flush perforation debris from the perforated interval, and improve the productivity of the completion. The hazards of pipe tripping operations are avoided because the tubing is

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already installed and pipe does not have to be pulled from the well. Pulling the gun assembly on electric line can be done under pressure using wireline BOP equipment installed above the tree. The shape of the pressure build-up vs time curve recorded with the BHP gauge can be analyzed using Perforation Inflow Transient Analysis (PITA) methods to determine the formation pore pressure and also estimate the permeability of the formation. PITA methods are particularly useful in cases with low permeability and significant wellbore storage effects in which full reservoir pressure is not measured before tripping out of the hole.

In many cases, a larger diameter perforating gun is desirable because it can create larger holes that penetrate deeper into the formation. The larger guns can be run on the bottom of the installed tubing, with sufficient cased hole below the perforated interval being available to catch the perforation debris, and in some cases the gun, after it has fired and released from the bottom of the tubing string. Again, the tubing, packer and wellhead are already in place when the gun fires, and the tubing pressure is adjusted to allow the formation to be perforated in an underbalanced condition. The BHP/T gauge can be run on wireline inside of the tubing as discussed above, or a memory tool can be set in a sub in the tubing and retrieved after perforating.

There are situations for which the operator decides to run a tubing conveyed perforating (TCP) assembly on a workstring that has to be pulled out of the well after perforating. This is often done when additional work needs to be done in the perforated interval or above in another zone. A common situation would be when there is a need to install a screen and gravel pack in a poorly consolidated sand formation, which is often the case for Gulf of Mexico completions. The perforating and subsequent gravel packing of intervals most often results in a trip of the workstring between operations. Memory BHP/T gauges are commonly run in the TCP assembly to provide accurate BHP/T data after the assembly is pulled to surface, which is valuable information for subsequent trips, but not for the initial trip out after perforating. A method has been identified to provide an accurate computation of safety margin, or overbalance pressure exerted by the completion fluid over the formation pore pressure, prior to pulling the workstring from the well<sup>13</sup>. This can be done by conducting a series of operations after perforating in which fresh water (or seawater) is pumped down the workstring, downhole valves are closed and opened, and surface pressures indicating the underbalance of the fresh water to the completion fluid and the formation are compared. This sequence of operations is illustrated in **Figure 2-7** and **Figure 2-8**. The safety margin is measured using the completion fluid in the well and thus accounts for the effect of temperature and pressure on the downhole density of the completion fluid. If the test yields an acceptable safety margin, the fresh water is reverse circulated from the workstring, and operations proceed to measure the loss of completion fluid to the formation. If the safety margin needs to be changed (increased or decreased), the completion fluid density is adjusted at the surface and the new completion fluid circulated into the well, before or after measuring fluid loss. If a fluid loss pill is required, it is typically pumped down the workstring and spotted on bottom, prior to tripping out with the TCP assembly.<sup>14</sup> This method of accurately determining safety margin is only applicable for perforated intervals with a formation pressure higher than the hydrostatic pressure exerted by a column

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<sup>13</sup> This technique for verifying the safety margin after perforating during a conventional gravel pack or frac pack completion has been used routinely by Completion Specialists, Inc.

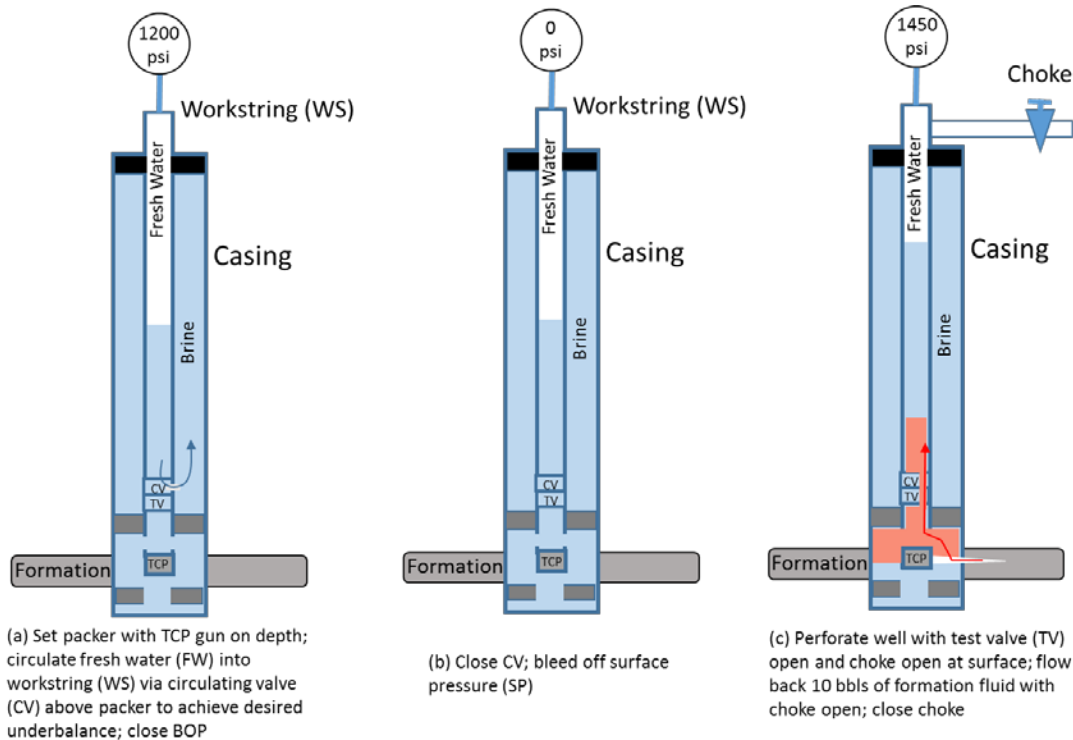
<sup>14</sup> A multistep gravel pack completion operation was underway for the blowout of Walter Oil & Gas Corporation South Timbalier Block 220, Well #A003ST01BP03 on July 23, 2013. This was one of the two blowouts cited by BSEE in the call for proposals to study the effects of tripping and swabbing in drilling and completion operations.



# EFFECTS OF TRIPPING AND SWABBING IN DRILLING AND COMPLETION OPERATIONS

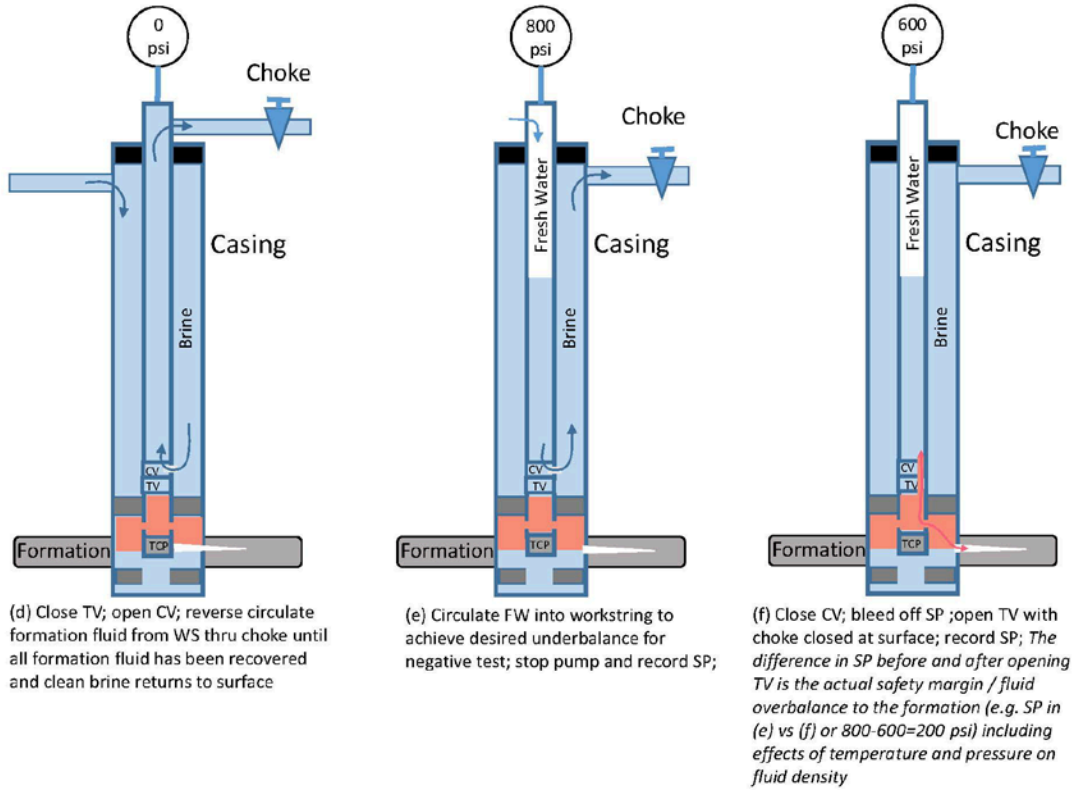
of fresh water (0.433 psi/ft), and with a TCP assembly that includes a packer and test/circulating valve(s). However, both requirements are common for offshore gravel packed completions in which the well is perforated underbalanced. PITA methods can also be employed when perforating underbalanced with a TCP assembly to provide an estimate of formation pressure and permeability and completion skin.

In some cases, the operator may decide to perforate the productive interval in an overbalanced condition, i.e., with the pressure in the well higher than the formation pressure. This may be done when potential formation damage is not expected to be significant, or because of safety concerns about bringing even a small influx of formation fluids to the surface during the cleaning process. Overbalanced perforating is also more common in partially depleted formations having a pore pressure gradient less than an 8.5 lb/gal completion fluid. In this situation, it could be more difficult to get an accurate estimate of the formation pore pressure from bottom-hole pressure measurements if the perforated interval temporarily plugs off with perforation debris after perforating. However, the trip margin present if the well is kept full of fluid should be more than enough to prevent swabbing. In this situation, seepage fluid loss will generally be present during the tripping operation and can be monitored through use of the trip tank and recorded in the trip book. Seepage loss during completion operations in a cased well with a short perforated interval and a large overbalance will not have the ability to hide an influx as would be the case in drilling operations with an interval of open hole below the casing shoe or in a thick perforated interval perforated in an almost balanced condition. The magnitude of the seepage losses provide an indication of the amount of overbalance when perforating overbalanced. No seepage loss may be viewed as an indication of less than expected overbalance for this situation.



**Figure 2-7: Method for Verifying Safety Margin during Conventional Gravel Pack Operation**

EFFECTS OF TRIPPING AND SWABBING IN DRILLING AND COMPLETION OPERATIONS



**Figure 2-8: Method for Verifying Safety Margin during Conventional Gravel Pack Operation Continued**

#### 2.5.4 Selection of Appropriate Trip Margin

The safety margin between equivalent mud density and the maximum formation pore pressure gradient in the open-hole or in perforated intervals is sometimes called the trip margin<sup>15</sup>. Too low a trip margin could result in a kick and too high a trip margin could result in a fractured formation and loss of drilling fluid, increasing fluid costs and possibly damaging the formation. As the safety margins of *mud weight less pore pressure gradient* on one hand and *fracture gradient less mud weight* on the other are both increased, more casing strings are needed to reach the target. Each casing string requires a decrease in bit size and a decrease in the size of the next casing string. Use of unnecessarily high safety margin can make it impossible to reach the planned well depth with a large enough casing size for an economically viable production rate. The operator could be forced to abandon the well without reaching the potentially productive target of interest. As the well approaches a planned casing setting depth, the allowable mud weight operating window becomes smaller. As the operating EMW window narrows, it can be important to understand how the EMW will change with pipe movement during tripping operations as the BHA passes through the different sections of the well and to select appropriate pipe pulling speed limits through the different sections of the well.

Calculations can be made based on the mud properties, drillpipe sizes, bottom hole assembly sizes, casing sizes and hole size to estimate the magnitude of the minimum EMW that will occur due to pipe movement during tripping. These calculations are typically done for a range of pipe pulling speeds, expressed in minutes per stand and bit depths. The Equivalent Mud Weight during the drilling operations just prior to tripping can also be computed. This is called the Equivalent Circulating Density (ECD).<sup>16</sup> The Trip Margin can be selected such that the mud density is increased *by an amount that would keep the minimum EMW during tripping at the same value as the ECD during drilling*. If the well tolerated the ECD during drilling without problems, a similar EMW during tripping should also not cause problems. The amount of an increase in mud weight just prior to tripping is called the Extra Trip Margin (ETM). When an ETM is used, the mud weight is increased when circulating the well clean before tripping operations begin.

Mathematical models that describe the rheological behavior of drilling fluids and computer models for calculating downhole pressures at various points in the well system while drilling and while tripping have been the subject of extensive research and development over the last 75 years. Shown in the bibliography at the end of this section of the report are some of the technical papers that have been written on this subject. The models range greatly in complexity, with the simpler models considering only steady-state behavior for a concentric inner pipe at a given pipe speed and the more complex models that try to predict pressure transient behavior. The models that focus on tripping operations are called surge and swab models. A downward pipe movement produces an increase in pressure below the bit called the surge pressure. Basically, the surge pressure occurs because the drilling fluid is forced to

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<sup>15</sup> This definition of trip margin is used in this report. Trip margin is also sometimes used in practice to mean an increase in mud weight made just prior to the trip. Swab margin is also sometimes used in practice to mean the safety margin between equivalent mud density and the maximum formation pore pressure gradient.

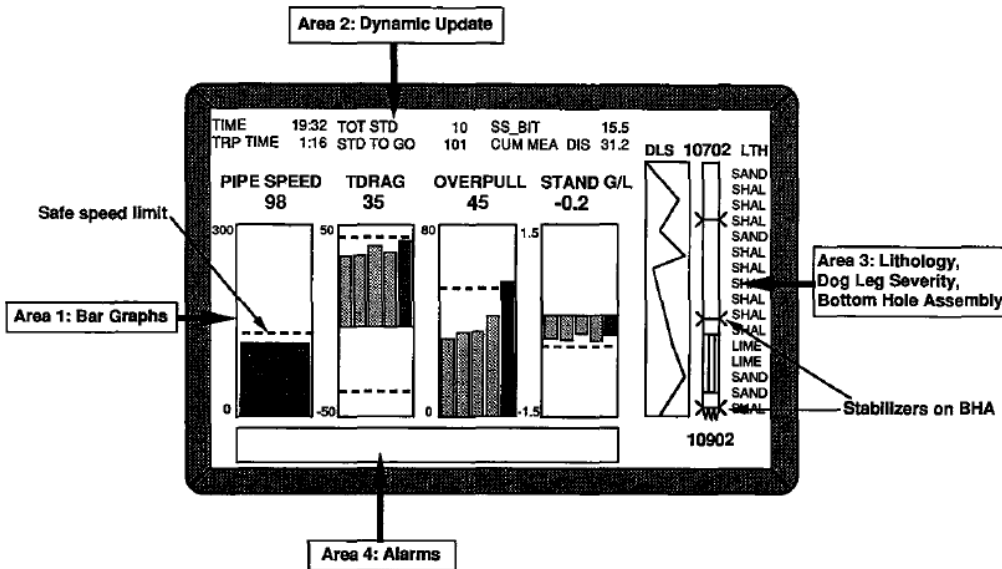
<sup>16</sup> On the larger, more expensive rigs used for drilling in deep water, the ECD or Pressure While Drilling (PWD) is routinely measured with a downhole sensor, and the data encoded and transmitted to the surface using mud pulse telemetry as part of a Measurements While Drilling (MWD) system. The EMW or downhole pressure at the Bottom Hole Assembly (BHA) is also measured during tripping operations. EMW data records can be transmitted by the MWD tool and also can be downloaded from a memory tool when the BHA reaches the surface.

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move upward past the pipe to make room for the BHA to move down. The decrease in pressure below the bit in response to upward pipe movement is called the swab pressure. The swab or suction pressure change is caused by the mud having to move downward past the pipe and BHA to fill the space previously evacuated by the BHA. Dynamic effects or mud pulses are created when the pipe is accelerated or decelerated. Pulling the pipe out of the slips and breaking the mud gel creates a negative swab pulse or pressure wave. Applying the brakes to stop the pipe before breaking a connection can create a positive surge pulse as the mud flowing down past the pipe has to stop. Pressure pulses move up and down the fluid column at the speed of sound in the drilling fluid and attenuate with distance moved. It has been the experience of key personnel in this project that pressure pulses are not a significant problem because the driller generally starts and stops at a reasonable speed and because of the short duration of the dynamic pressure changes as a pressure wave moves past a given point in the well.

When the well design and fracture pressure will permit only a small safety margin during tripping operations, such as just prior to running casing, very slow pipe pulling speeds can be used as the larger BHA is pulled in the smaller hole size and in smaller liner sizes. A swab pressure model can be used to calculate a schedule of the maximum pipe pulling speed for each stand pulled.

As rigs have become more computerized and pipe position, hook load, and mud volume sensors have become more dependable, efforts have been made to develop real time swab and surge models that can provide an instantaneous readout of the EMW to the driller during tripping operations. An example trip monitor is shown in **Figure 2-9**. The accuracy of the real time models can be checked and improved using Pressure While Drilling (PWD) sensors in the BHA. Well monitoring service companies can provide the equipment and personnel needed to provide real time trip monitoring. Even on low cost land rigs, unmanned programmable rig monitoring systems are generally used and have become dependable enough to allow real time trip monitoring to be performed.



**Figure 2-9: Example Trip Monitor Driller's Display<sup>17</sup>**

<sup>17</sup> Bible and Choo, 1991

In Managed Pressure Drilling (MPD) Operations, a backpressure on the casing can be applied dynamically because the drill-string is being pulled through a Rotating Control Device (RCD) located above the BOP stack. A trip margin can be dynamically applied and varied during the tripping operations to obtain the desired EMW as pipe pulling speed changes during the tripping operations.<sup>18</sup> This can be accomplished by pumping fluid from an instrumented trip tank into the fill-up line and taking returns through an automatic hydraulic choke<sup>19</sup> from just below the RCD back into the trip tank. MPD operations have created a renewed interest in developing improved mathematical modelling of ECD and EMW for surge and swab situations; numerous technical papers have recently been published regarding this area of research. Some of these have been included in the bibliography provided at the end of this section. MPD is considered to be an alternative procedure that requires special approval by BSEE under CFR 250.141.

### 2.5.5 Starting with a Stable Well

Prior to starting a tripping operation to change the drill bit or to log, it is good practice to first check the well for flow by direct visual observation of the fluid level in the well at the bell nipple or flowline with all pumping stopped. If the average fluid density in the annulus is a little higher than the average density in the drill-string due to the presence of rock cuttings, a falling fluid level may be observed. If the fluid level rises and overflows into the flowline, the well is underbalanced with the pumps off due to the loss of ECD. The next step is to circulate the well clean of cuttings and fluids that have entered the mud from the rock destroyed by the bit and establish a uniform mud density throughout the well. If an Extra Trip Margin (ETM) is needed, the new mud density, which includes the ETM, is used to circulate the well clean. Pipe rotation and slow reciprocation while circulating can enhance the removal of cutting beds in a directional well and help to prevent the pipe from becoming stuck. After circulating the well clean and verifying that the fluid density returning from the well is equal to the mud density being pumped, the well is again checked for flow. The volume of fluid in the well should be static (neither increasing nor decreasing) and without flow into the flowline.

A successful flow check provides an indication that the well is sufficiently stable, i.e. formation fluids are not entering the well and drilling fluid is not being lost to a formation at an unacceptable rate. A slight instability may persist while the average fluid density in the well is changing due to heat flow from the formation after circulation is stopped or while background gas bubbles in the well are rising and expanding. Thus a single short flow check should not be accepted as positive proof that the well is completely stable. A common practice is to periodically perform additional flow checks during tripping operations, usually when the bit reaches the shoe and when the BHA reaches surface.

When the flow check indicates unacceptable seepage is occurring, a fluid loss pill is circulated into the well and placed at the depth of the suspected thief zone to slow the seepage rate to an acceptable level. A well with a long interval of open hole that contains thick intervals of permeable formations will have a small rate of seepage of mud filtrate into the permeable zones that may have to be tolerated. Fluid loss pills should be effective at stopping mud seepage into formation fractures, mud leakage past the casing shoe and seepage of completion fluid into perforated intervals.

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<sup>18</sup> Elvin Mammadov, 2015. Kristian Gjerstad et al, 2013,

<sup>19</sup> An example of an automatic hydraulic choke with a sensitive pressure set point is the Cameron Automatic Choke.

## EFFECTS OF TRIPPING AND SWABBING IN DRILLING AND COMPLETION OPERATIONS

In some cases, seepage is observed when the ECD increases due to circulating the well, but when the pumps are stopped to perform a flow check, a slight flow from the well is observed. This may indicate a condition called “*hole-ballooning*” in which the well takes mud when the pumps are on, but gives most of it back when the pumps are turned off. One explanation sometimes given for this phenomenon is that the borehole diameter through a shale zone or salt zone that deforms in a pseudo-plastic manner can increase slightly when pumping and then decrease in response to the reduced stress when pumping is stopped. Another explanation sometimes given is that a fracture in an impermeable shale opens and takes mud when the pumps are on and closes to give mud back when the pumps are turned off. When hole-ballooning is suspected, an extended flow check is generally performed. If the mud return flow rate decreases with time, hole-ballooning is indicated. This will be verified upon pumping bottoms-up if formation fluids are not seen in the mud returns. The ECD can be reduced when pumping bottoms-up by pumping at 50-75% of the normal circulating rate to reduce the mud seepage rate. When the pumps are stopped after circulating bottoms-up, the hole-ballooning cycle could be seen again. An extended flow check should be performed to again verify that the mud return flow rate decreases with time.

It is now current practice to use “finger-printing,” sometimes called connection flow monitoring, to distinguish ballooning from a well control event. When the driller shuts off the pump, flow from the well is measured versus time. Ballooning usually follows a repeating trend at each connection that can be recognized. Also flow from a ballooning formation will slow with time while flow from a kick will typically speed up.

When hole-ballooning is observed and is thought to be fracture related, current BSEE regulations require that the information is included in the weekly report and could require either casing to be set before deepening the well or special provisions approved for MPD operations to be used.

A common practice is to pump a heavy slug of mud into the drill string before starting tripping out so that the fluid level inside the drillpipe will stay below the rig floor when a connection is broken to rack back a stand of pipe in the derrick. Otherwise, mud could flow out of the connection as it is unscrewed and tend to splash onto the rig crew, requiring a mud bucket to be placed around each connection. When mud flows out of the connection when the connection is broken, it is called “*pulling wet*” and the purpose of the slug is to insure “*pulling dry*.” A full stand of drillpipe is typically about 93 ft in length. As the stand is pulled up above the flowline, the fluid inside the pipe will need to fall fast enough by flowing through the drillpipe and BHA as the pipe is pulled up, so that the fluid level is below the connection when it is broken. If the fluid level inside the pipe is lowered to about 200 ft below the rig floor before pulling the stand, the fluid level inside the drillpipe tends to stay below the rig floor. A common practice is to mix and pump a 10 to 20 barrel pill of heavy mud in a small “*slugging pit*” to depress the fluid level in the top of the drillpipe by about 200 ft. The process of pumping a slug of heavy mud into the top of the drillpipe is called “*slugging the pipe*.”

When slugging the pipe prior to tripping, the volume of mud returning from the well as the slug falls should be determined as part of the hole fill-up volume calculations. In addition, the effect of changes in slug height during the tripping operations as the slug enters a tapered section of the pipe string or the BHA should be included in the well fill-up calculations so that the rig crew will know how the slug is expected to affect the fill-up volumes measured throughout the tripping operations.

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The primary flow check should be performed prior to pumping the weighted slug. A second flow check (which can be of shorter duration) should be performed after slugging the pipe to verify that the well is static after the slug reaches the depth of equilibrium.

## 2.5.6 Early Swab Kick Detection

Early detection of a kick minimizes the amount of formation fluid that enters the well and greatly lowers the maximum surface pressures that will be required to control the well. Avoiding large kick volumes also avoids complications that make well control procedures more difficult to implement. Early kick detection is a key aspect of blowout prevention. Accurately monitoring the volume of mud needed to replace the volume of steel removed from the well as pipe is pulled is the key aspect of early kick detection during tripping operations. Flow from a formation into the well can be occurring on each upstroke of the pipe without flow from the flowline at the surface. The rig crew also needs to know the expected fill-up volume to be able to compare it to the fill-up volume being accurately monitored. Using trip tanks in a continuous fill mode improves the ability to identify kicks early.

**Table 2-7: Example of a Completed Trip Sheet**

RIG:	<u>Confidential</u>		WELL:	<u>Confidential</u>		DATE:	<u>09/10/16</u>	
BHA:	<u>No. 14</u>		BIT SIZE:	<u>8 1/2"</u>		DEPTH:	<u>2641 m</u>	

DP	inch	Bbl/std	Displac	lit/m	Capacity	lit/m	Total	lit/m
5		4.13		8.61		12.74		
5		9.06		4.61		13.67		
6.5		17.33		3.98		21.3		

size	STAND		TRIP TANK			CALCULATED		MEASURED		gain/loss.	REMARKS
	number	from	to	VOLUME	VOLUME	TOTAL	VOLUME	TOTAL			
									m3		
				6.05							
5" DP	79	75		5.59	0.48	0.48	0.46	0.46	+0.02		
"	75	70		5.10	0.60	1.08	0.49	0.95	+0.13	FC @ Site	
"	70	65		4.45	0.60	1.68	0.65	1.60	+0.08		
"	65	60		3.85	0.60	2.28	0.60	2.20	+0.08		
"	60	55		3.25	0.60	2.88	0.60	2.80	+0.08		
"	55	50		2.65	0.60	3.48	0.60	3.40	+0.08		
"	50	45		2.04	0.60	4.08	0.61	4.01	+0.07		
"	45	40		1.42	0.60	4.68	0.62	4.63	+0.05		
"	40	35		0.82	0.60	5.28	0.60	5.23	+0.05		
"	35	30		0.53	0.60	5.88	0.60	5.83	+0.05	FILL TT	
"	30	25		4.93	0.60	6.48	0.60	6.43	+0.05	FC ✓	
"	25	20		4.30	0.60	7.08	0.63	7.06	+0.02		
"	20	15		3.71	0.60	7.68	0.59	7.65	+0.03		
"	15	10		3.11	0.60	8.28	0.60	8.25	+0.03		
"	10	05		2.51	0.60	8.88	0.60	8.85	+0.03		
"	05	0		1.91	0.60	9.48	0.60	9.45	+0.03		
				6.09							FC @ BHA
5" HW	05	0		4.79	1.28	10.76	1.30	10.75	+0.01	FILL TT	
6 3/4 DC	7	6		4.30	0.49	11.25	0.49	11.24	+0.01		
	6	5		3.80	0.49	11.74	0.50	11.74	-		
	5	4		3.30	0.49	12.23	0.50	12.24	-0.01		
	4	3		2.81	0.49	12.72	0.49	12.73	-0.01		
	3	2		2.32	0.49	13.21	0.49	13.22	-0.01		
	2	1		1.83	0.49	13.70	0.49	13.71	-0.01		
	1	0		1.34	0.49	14.19	0.49	14.20	-0.01		
											FC ✓

## EFFECTS OF TRIPPING AND SWABBING IN DRILLING AND COMPLETION OPERATIONS

A good practice for blowout prevention during tripping operations is to prepare a trip book that provides written instructions that includes the sequence of operations<sup>20</sup> to be followed and a stand-by-stand description of the desired maximum pipe pulling speed and expected hole fill-up volumes, both incremental and cumulative. The trip book should be based on information in the master pipe tally book that identifies each stand number and stand description. API RP 59 includes an example form from a trip book that includes a stand by stand comparison of the current trip with the last trip made in the current hole-section. It is good practice for both the Assistant Driller and the mud logging or well monitoring contractor to watch for signs of a kick and record observed fill-up volumes in redundant trip books or on trip sheets. Recognize, however, that there is a natural tendency to be less vigilant when another person is charged with the same responsibility. Periodically comparing values removes this tendency and reveals errors. The trip book should include flow checks after pulling the first five stands, after pulling the BHA into the casing and prior to pulling the top of the BHA into the BOP stack. Shown in **Table 2-7** is an example Trip Sheet completed for a trip from 2641 m (8,665 ft) during drilling operations.

Bit and stabilizer balling with sticky clay or shale can cause the swab pressure to be higher than calculated because of a tighter clearance between the BHA and the borehole or liner. This can cause formation fluids to be swabbed into the bottom of the well if the balled condition is not detected. Early detection should be possible by checking fill-up volumes against the expected volumes provided in the trip book. In an extreme case, it may be necessary to pump slowly while pulling pipe through a low clearance section of the well to prevent swabbing formation fluid into the well. This gets drilling fluid below the bit without the fluid having to flow down on the outside of the BHA. Fortunately, top drives are now available on almost all rigs and facilitate pumping down the drillpipe when pulling pipe.

Small amounts of hydrocarbons swabbed in when tripping out of the well will tend to rise through the drilling fluid column as small bubbles. The swabbed volume will increase as it rises due to the decreasing hydrostatic pressure with decreasing depth. At some point, the volume could increase sufficiently to cause a formation to become underbalanced and begin to flow into the well. This can happen after the BHA has been pulled all the way to the surface and removed from the well. When permeable formations are exposed in the open-hole or in a perforated interval, the time spent with the pipe out of the hole should be kept to a minimum by performing operations such as routine repairs and slipping and cutting of the drill-line with pipe at the casing shoe. The trip tank gain and loss volume alarms should be set as narrowly as practical when the pipe will be static for a prolonged period or there is no pipe in the hole. On rigs with little wave induced motion and small seepage losses these alarms can be set as tight (+/- ) 1/2 of a barrel without generating an unreasonable frequency of nuisance alarms.

Whenever operator policy<sup>21</sup> requires closing the blind rams when out of the well, the Driller and the Assistant Driller should open the rams and check the fluid level at least every half hour, fill the hole as required and report any losses or gains to the Drilling Supervisor. The choke should be opened to check for pressure before opening the blind rams.

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<sup>20</sup> Flow checks, circulation of bottoms up, single shot surveys, slugging pipe, etc.

<sup>21</sup> This policy is not common except on rigs operated by Petrobras. In most cases, the well is monitored on a trip tank with a hole cover used to prevent accidentally dropping tools into the open well.



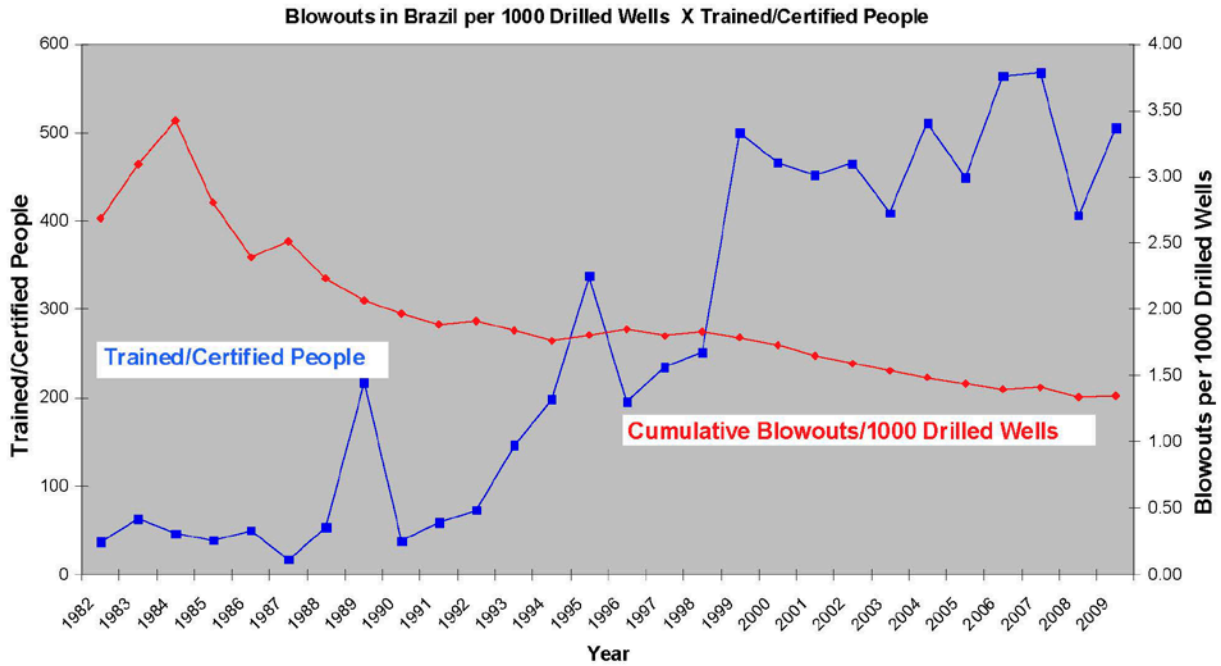
# EFFECTS OF TRIPPING AND SWABBING IN DRILLING AND COMPLETION OPERATIONS

During logging operations, the trip tank should be circulated continuously to keep the hole full. The volumes should be recorded every 15 minutes and any losses or gains reported to the Drilling Supervisor.

Whenever the mud pumps are turned off with the pipe still in hole, the trip tank should be circulated continuously. The volume should be recorded every 15 minutes and any losses or gains reported to the Drilling Supervisor.

## 2.5.7 Crew Training

Crew training is one of the most important aspects of well control and blowout prevention. A recent SPE Distinguished Lecturer reported a significant drop in blowouts in Brazil in response to an extensive well control training program by Petrobras that was started in 1982. Shown in **Figure 2-10** are comparative plots of the cumulative number of blowouts in Brazil per 1,000 wells drilled and the number of well control certified rig workers.



**Figure 2-11: Plot of Number of Trained/Certified Workers and Cumulative Blowouts/1000 Drilled Wells**

## 2.5.8 Well Control Training Recommendations with Regard to Tripping

As a result of this study of the effects of tripping and swabbing on drilling and well control operations, it is recommended that well control training should include:

- Calculation of the required volume to re-fill the well per unit length of pipe pulled from the well and the volume displaced from the well per unit length of pipe lowered into the well;
- Calculations associated with pumping a heavy slug of drilling fluid in the top portion of the drill pipe so that mud does not flow out of the drill pipe when a connection is unscrewed;

## EFFECTS OF TRIPPING AND SWABBING IN DRILLING AND COMPLETION OPERATIONS

- Proper gravity feed and circulating trip tank piping arrangements<sup>22</sup> for measuring the volume used to fill the well or volume displaced from the well as pipe is raised or lowered;
- Description of proper procedures to check for flow and return to bottom and circulate the well clean when the measured fill-up volume does not agree with the calculated fill-up volume, but the well is not flowing;
- Description of auxiliary well control equipment and procedures needed to prevent flow up the drill string when the well begins to flow;
- Description of BOP equipment and procedures needed to prevent flow from the well annulus when a begins to flow;
- Description of well shut-in procedure to follow when the well begins to flow during tripping operations and the use of pit drills during tripping operations to practice the procedure;
- Use of trip sheet and procedure for handling complications caused by drilling fluid lost during trip because of mud-filtrate seepage into permeable formations and mud seepage into fractures;
- Use of trip book and “fingerprinting<sup>23</sup>” trend analysis procedure for handling complications caused by “hole-ballooning<sup>24</sup>”;
- Consequence of rapid well unloading rates that can result if a flowing gas well is not detected quickly;
- Procedure for handling pipe-light<sup>25</sup> condition that can result if a flowing gas well is not detected in a timely manner;
- Proper protocol for shearing the drill string in order to close the well when the auxiliary well control equipment fails or cannot be employed;
- Pit drill / BOP drill for normal tripping operations;
- Pit drill / BOP drill for tripping operations with bottom hole assembly or tool joint in rotary table;
- Pit Drill /BOP drill for tripping operations with pipe string out of well;
- Accumulator drill to verify bottle sizing and correct remote panel usage;
- Choke manipulation drill (could be done with small amount of trapped pressure before drilling out casing shoe);
- Determining formation pore pressure after perforating;
- Determining appropriate Trip (Safety) Margin.
- Methods to verify Trip Margin.

It is also important to reinforce the training program with pre-trip planning meetings with the rig crew held prior to tripping operations to go over written instructions as to the sequence of operations that will be followed during the trip and to ensure that everyone is familiar with their duties and have an

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<sup>22</sup> Improper piping arrangements on gravity feed trip tanks have resulted in wells blowing out through the trip tank.

<sup>23</sup> Fingerprinting is a term used to establish a hole fill-up volume trend line during a short trip in which hole-ballooning is shown to have occurred by subsequent circulation of bottom hole fluids to the surface.

<sup>24</sup> Hole-Ballooning is a term used to describe a well condition in which drilling fluid is lost when the downhole pressure is elevated because of mud circulation, but the drilling fluid returns to the well when the pump is turned off and pipe is pulled from the well.

<sup>25</sup> The weight of the remaining drill string in the well is too low to prevent the pressure in the well from causing the drill string to be forced upward by well pressure when the annular BOP is closed. Blowouts have occurred in which the drill string was completely ejected from the well.

opportunity to ask questions and voice concerns. Periodic drills to reinforce an understanding of various emergency procedures are also an important part of rig crew training. Crew well control training is addressed in API RP 59 in Chapter 7.15 where seven items are listed, including developing appropriate training intervals and drill intervals. Some oilfield operators have policies to perform drills on a bi-weekly basis and when approaching high pressure zones. API RP 59 recommends that these meetings should be documented and analyzed to identify areas where improvement is needed. API RP 59 also recommends a number of drills but does not specify normal or acceptable response times. Some operators also include drills in their well control manuals that aren't found in API RP 59; common examples are an Accumulator drill and a Diverter drill.

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## 2.6 Common Industry Practice for Hazard Analyses and Risk Mitigation

A major performance-based goal of CFR sections 250.107, 400, and 500 can be summarized as “protect HSE by managing hazards.” The requirement of API RP 75 and Subpart S (SEMS) serve the same basic objective but further specify that a systematic management-based approach be used, and define the minimum elements of the system. The Hazard Analysis element of the SEMS regulation entails (a) identifying the hazard, (b) evaluating the risks posed, and (c) identifying appropriate risk mitigation (i.e., control measures). Implementation of the mitigation is achieved through written safe practice and procedures. Hazard Analysis and risk mitigation processes are also used within the industry outside of a formal SEMS but serving the same purpose. Common industry practice in the use of hazard analysis and risk mitigation processes for well control during tripping and to prevent swabbing is addressed in this section.

### 2.6.1 The Role of Hazard Analysis in Regulating Safe Practice

CFR 250.107 requires “utilizing *recognized engineering practices* that reduce risks to the lowest level practicable” when conducting activities, and the use of the “*best available and safest technologies (BAST)*” with certain exceptions. CFR 250.107 further states that “...conformance with BSEE regulations will be presumed to constitute the use of BAST unless and until the Director determines that other technologies are required...” CFR 250.400 and 500 require that operations must be “conducted in a safe manner.” While the general intent is clear and “*recognized industry practice*” can often be derived from published standards and industry norms, the meaning of “*lowest [risk] level practicable*,” “*BAST*”, and “*safe manner*” can be problematic to quantify in practice. In the opinion of a Norwegian regulatory expert, following the standards is not always enough to fulfil the objective:

*“[Standards] are vehicles for promoting good practice by providing authoritative definitions of what is good practice. However, compliance with good practice as defined by standards is not necessarily sufficient to ensure that risks are as low as reasonably practicable; this needs to be reinforced by explicit assessment of hazards, associated risks and their control measures.”* (Finnestad, 2005)

The SEMS requirements of API RP 75 and Subpart S help to determine and enforce good practice for a specific situation through hazard analysis and risk mitigation processes. Regulations would quickly grow to be unmanageable and impede innovation if specific methods or technologies were defined as BAST or safest for every situation encountered. Instead SEMS requires operators to systematically address these questions and distill the HSE objectives into documented safe practices and procedures. Done correctly, these practices and procedures capture the knowledge and experience of those most qualified and are field tested and continuously improved. The SEMS documentation provides a means for oversight by management and regulators. Regulators can further promote dissemination of the best practices industry-wide and use proven methods to inform the development of new regulation where required.

API RP 75 requires the identification and management of safety hazards and environmental impacts in design, construction, start-up, *operation*, inspection, and maintenance, *of new, existing, or modified drilling and production facilities*. Subpart S further requires that “a hazards analysis (facility level) and a JSA (operations/task level) are developed and implemented for all...facilities and activities identified or discussed in.... the SEMS.” Hazard analysis and JSAs are address in the following sections.

## 2.6.2 Hazard Analysis in SEMS

Regarding hazard analysis, API RP 75 states: *“The purpose of the analysis is to identify, evaluate, and where unacceptable, reduce the likelihood and/or minimize the consequences of uncontrolled releases and other safety or environmental incidents. Human factors should be considered in this analysis.”*

A Hazard Analysis consists primarily of:

- identifying hazardous incidents or conditions that are believed to be possible,
- evaluating the likelihood that the hazard would actually occur,
- evaluating the consequences if the hazard actually occurred,
- reviewing existing verified safeguards for reducing the likelihood and or consequences if the hazard actually occurred,
- evaluating possible additional alternatives or safeguards for mitigating the risk, and
- identifying any recommended additional safeguards or alternatives for risk mitigation.

A Hazard Analysis for an offshore drilling unit would be most effective when conducted by a team having the needed background and experience in engineering, well design, drilling and completion operations. API RP 75 states that at least one person on the team should be proficient in the hazard analysis methodology being employed. The findings of the Hazard Analysis should be presented in a written report to the appropriate personnel and be kept on file for the life of the rig or mobile unit. The report should describe the hazards that have been identified and the recommended steps to be taken to mitigate them. Qualitative assessments of the severity of the findings should be made as appropriate and, when immediate action is required, the management program should mandate that the remedial action is taken or that the hazardous conditions are otherwise remedied.

CFR 250.1911 in Subpart S requires hazard analyses to address the following:

*(i) Hazards of the operation;*

*(ii) Previous incidents related to the operation you are evaluating, including any incident in which you were issued an Incident of Noncompliance or a civil or criminal penalty;*

*(iii) Control technology applicable to the operation your hazards analysis is evaluating; and*

*(iv), A qualitative evaluation of the possible safety and health effects on employees, and potential impacts to the human and marine environments, which may result if the control technology fails.*

Similar to API RP 75, CFR 250.1911 states that the hazards analysis must be performed by persons with experience in the operations being evaluated. These individuals also need to be experienced in the hazards analysis methodologies being employed. Recommendations in the hazards analysis should be resolved and the resolution documented.

API RP 75 specified that both the likelihood and consequence of the hazard shall be considered. Commonly in hazard analysis, the combination of likelihood (i.e., probability) and consequence provide a more formal definition of “risk”. Likelihood and consequence are usually impossible to accurately quantify and are often evaluated qualitatively using a numerical ranking system with high numbers assigned to low likelihoods and consequences and low numbers assigned to high likelihoods and consequences. With this system, a ranking of 1-1 indicates the most serious risk ranking that requires immediate action to mitigate before allowing the operations being reviewed to proceed. Example “Likelihood Ranking” descriptions are shown in **Table 2-8** and example “Consequence Ranking”

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descriptions are shown in **Table 2-9**. The number of rankings shown is five but this number could be increased or decreased as determined to be appropriate by the Hazard Analysis Team.

**Table 2-8: Example Likelihood Ranking Descriptions for Hazard Analysis of Drilling Unit**

Likelihood Ranking	General Description	Additional Description of Likelihood
1	Likely	Consequence is likely to occur one or more times in current drilling or completion project.
2	Occasional	Consequence has occurred previously for this rig on other projects.
3	Seldom	Consequence has occurred previously on rigs within the rig contractors' experience base.
4	Rare	Consequence has never occurred for rig contractor but is known to have occurred within the industry.
5	Unheard of	Consequence unheard of or never reported within industry.

**Table 2-9: Example Consequence Ranking Descriptions for Hazard Analysis of Drilling Unit**

Consequence Ranking	General Description	Health (H)	Safety (S)	Environment (E)	Financial (F)
1	Catastrophic	Life altering Exposures	Loss of Life	Major Oil Spill reaches shoreline	Loss of Well & Rig; Loss of facility
2	Serious	Life Altering Exposure	Serious disabling Injury	Major Oil Spill; Does not reach shoreline	Loss of Well; Cannot complete well
3	Moderate	Requires long term medical treatment	Requires long term medical treatment	Moderate oil spill; Required dispersants	Loss of Hole Section
4	Minor	Requires medical attention & lost work time	Requires medical attention & lost work time	Release of gas and small amount of condensate	Loss confined to non-productive rig time
5	Inconsequential	No lingering effect or lost time	No lingering effect or lost time	No oil spilled; minor gas venting	Loss of less than 0.5 days of rig time

Though not precise, the broad qualitative rankings of likelihood and consequence usually are sufficient to determine whether further mitigation is needed. Selection of the proper ranking requires the participation of personnel experienced with the specific activity and with comparable activities. When technical specialists, responsible management and experienced field personnel are present, there is usually a ready consensus regarding the proper category of likelihood and consequence. Participation in these discussions is also highly instructive for less experienced personnel.

Since the rig contractor has overall responsibility and authority for the rig crew and rig equipment, a Hazard Analysis for the drilling unit that is part of the contractors' SEMS package is best performed by the rig contractor with assistance if necessary from consultants with operator experience. Tripping during drilling and completion is just one of the possible operations that could be covered in the SEMS



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package for the drilling unit. An undetected gas kick from a thick, high permeability formation is a recognized hazard having potentially catastrophic consequences. Shown in **Table 2-10** is an example of how tripping operations could be included in a facility level or drilling and completion operations level Hazard Analysis as part of SEMS. Note that the Consequence Risk Ranking estimated by the Hazard Analysis Team should consider the mitigation safeguards that are already in place in the SEMS. The Hazard Analysis is periodically updated to include additional safeguards put in place and to incorporate recent experience.

**Table 2-10: Example illustrating Hazard Analysis Process for Tripping Operations**

No.	HAZARD Scenario Identified	CONSEQUENCES	Mitigating Safeguard(s) in Place and Verified	Likelihood Ranking (1-6) with Existing Safeguards in Place	Consequence Ranking (1-6) With Existing Safeguard(s) in Place	RISK RESPONSE (Accept, Mitigate, or Avoid)
<b>1.00 Trip Out of Hole</b>						
1.01	Swab Gas Kick goes undetected because of unstable well conditions or Human Error; Gas Kick expands due to bubble rise velocity; Well becomes underbalanced and starts flowing with BHA halfway out of the well;	Well must be shut-in off bottom; Pipe string will likely have to be stripped in or staged in to return to bottom and clean out influx of formation fluids.	Safety Margin appropriately selected and verified; Seepage losses limited to acceptable level; Continuous Hole fill-up and monitoring every 5 stands; Verify training in Shut-in Procedures while tripping ; Verify rig procedures for returning to bottom and cleaning well.	3	H - 5 S - 5 E - 5 F - 4	Mitigate
1.02	Well becomes underbalanced and starts flowing; Early flow not detected because of human error; Safety Valve cannot be installed.	Well must be shut-in using shear rams to stop flow thru pipe string; Blowout Control Specialists must be brought on board.	Safety Margin appropriately selected and verified; Seepage losses limited to acceptable level; Continuous Hole fill-up and monitoring every 5 stands; Verify training in Shut-in Procedures while tripping ; Verify rig procedures for returning to bottom and cleaning well.	4	H - 5 S - 5 E - 5 F - 3	Mitigate
<b>2.00 Out of Hole</b>						
2.01	Swab Gas Kick goes undetected because of unstable well conditions or Human Error; Gas Kick expands due to bubble rise velocity; Well becomes underbalanced and starts flowing while pipe and BHA out of the well	Well must be shut-in using Blind Rams or Blind/Shear Rams; Snubbing unit may be required. Blowout Control Specialists must be brought on board.	Safety Margin appropriately selected and verified; Seepage losses limited to acceptable level; Continuous Hole fill-up and monitoring every 5 stands; Verify training in Shut-in Procedures while tripping ; Verify rig procedures for returning to bottom and cleaning well.	4	H - 5 S - 5 E - 5 F - 4	Accept
<b>3.00 Trip in Well</b>						
3.01	Surge Pressure initiates unstable well condition; Well starts flowing during trip in well.	Well must be shut-in off bottom; Off bottom well control procedure required; Underground blowout control procedure could be required; Blowout Control Specialists must be brought on board.	Safety Margin appropriately selected and verified; Seepage losses limited to acceptable level; Continuous Hole fill-up and monitoring every 5 stands; Verify training in Shut-in Procedures while tripping ; Verify rig procedures for returning to bottom and cleaning well.	4	H - 5 S - 5 E - 5 F - 4	Accept

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**2.6.3 Hazard Analysis in NORSOK D-010**

NORSOK D-010 requires a well integrity management system which is similar to SEMS though not as broad in scope. In addition, SEMS-like elements are embedded throughout the standard with hazard analysis appearing in numerous sections. NORSOK D-010 uses the terminology of “risk analysis” instead of “hazard analysis” but the terms appear to be interchangeable. The relevant definitions in D-010 are reproduced in **Table 2-11** below:

**Table 2-11: Risk Assessment Terminology in NORSOK D-010**

<b>3.1.44 risk</b>	combination of the probability of occurrence of harm and the severity of that harm  NOTE, Risk may be expressed qualitatively as well as quantitatively. Probability may be expressed as a probability value (0-1, dimensionless) or as a frequency, with the inverse of time as dimension.
<b>3.1.45 risk analysis</b>	structured use of available information to identify hazards and to describe risk  NOTE 1, The risk analysis term covers several types of analyses that will all assess causes for and consequences of accidental events, with respect to risk to personnel, environment and assets. Examples of the simpler analyses are SJA, FMEA, preliminary hazard analysis, HAZOP, etc.  NOTE 2, Quantitative analysis may be the most relevant in many cases, involving a quantification of the probability and the consequences of accidental events, in a manner which allows comparison with quantitative RAC. [“RAC” is not defined in D-010 but is believed to be “risk assessment criteria”]
<b>3.1.46 risk assessment</b>	overall process of performing a risk assessment including: Establishment of the context, performance of the risk analysis, risk evaluation, and to assure that the communication and consultations, monitoring and review activities, performed prior to, during and after the analysis has been executed, are suitable and appropriate with respect to achieving the goals for the assessment

The following requirements for hazard analysis relevant to well control during tripping were identified in NORSOK D-010:

**Table 2-12: Hazard Analysis Requirements in NORSOK D-010 Relevant to Well Control during Tripping**

Section	Requirement
<b>4 General principles</b>	
4.2.3.4 Common well barrier elements	When a common WBE <sup>26</sup> exists, a risk analysis shall be performed and risk reducing measures applied.
4.2.3.7 Well barrier monitoring	All parameters relevant for preventing uncontrolled flow from the well shall be monitored. Methods and frequency for verifying the condition of the well barrier or WBEs shall be defined and documented. Volume control of fluid shall be maintained at all times when the fluid is a well barrier. The pressure in all accessible annuli shall be monitored and recorded. All instrumentation used for required monitoring of parameters shall be frequently checked and calibrated. Use of alarms, automated sequences and shut down shall be evaluated based on risk and needed response time. Human Machine Interface assessments should be performed in design.
4.3.2 Design basis, premises and assumptions	...a drilling and well design basis shall be prepared...The following should be assessed and documented:...aa) risk analysis.

<sup>26</sup> A common well barrier element (WBE) is a well barrier that is not entirely independent from a second well barrier and is addressed through risk assessment. A cement plug can be a common WBE in some situations.

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4.4 Risk assessment and risk verification methods	An assessment of well integrity risks associated with the intended operation shall be performed. The risk of a well integrity failure or well control incident shall be assessed.... Onsite safe job analysis should be conducted for: (f) new or non-standard operations; (g) operations involving use of new technology or modified equipment; (h) hazardous operations; (i) change in actual conditions which may increase the risk. See NORSOK Z-013, Risk and emergency preparedness assessment [informational reference].
4.5 Simultaneous and critical activities	Acceptance of simultaneous and critical activities...shall be quality assured through risk assessments.
4.7.2 Management of change	A proposed change shall be supported by a documented approval of the following:... l) updated risk assessment in line with the proposed change.... Changes...shall be approved...at a level proportionate with the assessed risk of the change.
4.10.1 Experience transfer	The results of, and the experience from well activities and operations shall be collected, documented and made available... The experience transfer and reporting system should comprise of:... e) risk register for monitoring of risks;
4.10.3 Well integrity management	A systematic approach shall be established to manage the well integrity in all stages of the life cycle of the well, from construction phase to final abandonment. The system should consist of the following elements...risk status.
<b>5. Drilling activities</b>	
5.7.3 Pore and formation integrity pressure estimation	The risk of a change in pore pressure compared to the original pore pressure due to injection of water, gas, cuttings and slop in other wells shall be assessed.
<b>13 Under balanced and managed pressure drilling and completion operations</b>	
13.3.1 General well barrier acceptance criteria in underbalanced and managed pressure drilling	c) A risk assessment shall be done to assess common WBEs.
13.7.1 Procedures	Well specific procedures shall be developed for MPD/UBD operations. The procedures shall be based on risk analysis.

The requirements in **Table 2-12** are mostly general requirements for well barriers, the drilling design basis, well integrity, procedures and management of change. Requirement 5.7.3 applies to pore-pressure estimation which is relevant to selecting the correct tripping margin, and requires “risk” to be “assessed” but does not specify a formal hazard analysis. A JSA is required in Section 4.4 for non-standard and hazardous activities. Depending on the operational situation, tripping could be defined as a hazardous activity. This is the only specific requirement for a JSA identified in NORSOK D-010.

## 2.6.4 Job Safety Analysis

API RP 75 does not specifically differentiate Hazard Analysis from Job Safety Analysis<sup>27</sup>. CFR 250.1911 in Subpart S describes a JSA as a subset of hazard analysis performed at the task or operational level with the following requirements:

*(b) JSA. You must ensure a JSA is prepared, conducted, and approved for OCS activities that are identified or discussed in your SEMS program. The JSA is a technique used to identify risks to personnel associated with their job activities. The JSAs are also used to determine the appropriate mitigation measures needed to reduce job risks to personnel. The JSA must include all personnel involved with the job activity.*

<sup>27</sup> As previously noted, no API documents relevant to tripping (including API RP 75) use or formally define the term Job Safety Analysis.

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(1) *You must ensure that your JSA identifies, analyzes, and records:*

*(i) The steps involved in performing a specific job;*

*(ii) The existing or potential safety, health and environmental hazards associated with each step; and*

*(iii) The recommended action(s) and/or procedure(s) that will eliminate or reduce these hazards, the risk of a workplace injury or illness, or environmental impacts.*

(2) *The immediate supervisor of the crew performing the job onsite must conduct the JSA, sign the JSA, and ensure that all personnel participating in the job understand and sign the JSA.*

(3) *The individual you designate as being in charge of the facility must approve and sign all JSAs before personnel start the job.*

(4) *If a particular job is conducted on a recurring basis, and if the parameters of these recurring jobs do not change, then the person in charge of the job may decide that a JSA for each individual job is not required. The parameters you must consider in making this determination include, but are not limited to, changes in personnel, procedures, equipment and environmental conditions associated with the job.*

CFR 250.1915 requires that all personnel are trained to recognize and identify hazards and how to construct and implement JSAs per CFR 250.1911. CFR 250.1911(c) requires that all personnel, including contractors, must be trained in accordance with the requirements of CFR 250.1915. Operators must also verify that contractors are trained in accordance with CFR 250.1915 prior to performing a job. CFR 250.1930 requires stop work authority procedures and expectations are included as a standard statement in all JSAs.

JSAs as described in CFR 250.1911(1)(i-iii) are not commonly conducted onsite and pre-job for well control hazards associated with tripping activities. This may be because well control has traditionally been addressed with well control policies, manuals, and training. In addition, the issue of well control might be addressed effectively and in a much more practical manner with the well control plan required by CFR 250.710(b). Many of the approaches used in SEMS were adapted from the occupational safety field and require modification to be applied to well control. This topic is also discussed in **Section 2.4.1** and **Section 5.2.2.2**.

It should also be noted that effective methods for mitigating well control hazards while tripping have been developed and improved over decades. Already existing well control policies, manuals, on-the-job training, certification training, procedure, practices and traditions mitigate risks to an acceptable level when they are *properly implemented and followed*.

The intent of the JSA requirement in CFR 250.1911(1)(i-iii) in part appears to be to create an auditable paper trail to insure procedures and policies are properly implemented and followed. This type of requirement and practical methods for implementing it are discussed for well control hazard communications at a rig site level throughout this report.

### 2.6.5 Checklists and Flowcharts

Tripping operations are routinely conducted many times on each well, so that the needed mitigating safeguards that flow from a hazard analysis are well known and are handled more often with company safe practice and procedural guidelines than with step-by-step procedures. Well control incidents that do occur invariably involve breakdowns in training and failure to implement known safeguards. Checklists, flowcharts and drills are extremely valuable in insuring that crew training remains effective and that intended safeguards are verified to remain in place. Job Safety Analysis (JSA) meetings or daily operations meetings held just prior to a planned tripping operation being conducted in a high risk situation provide a good opportunity to review checklists, flowcharts, planned drills and the trip book discussed in **Section 4.2.6**. High risk situations are those involving exposure to highly productive zones through open borehole or open perforations with a narrow operating window of safety margins.

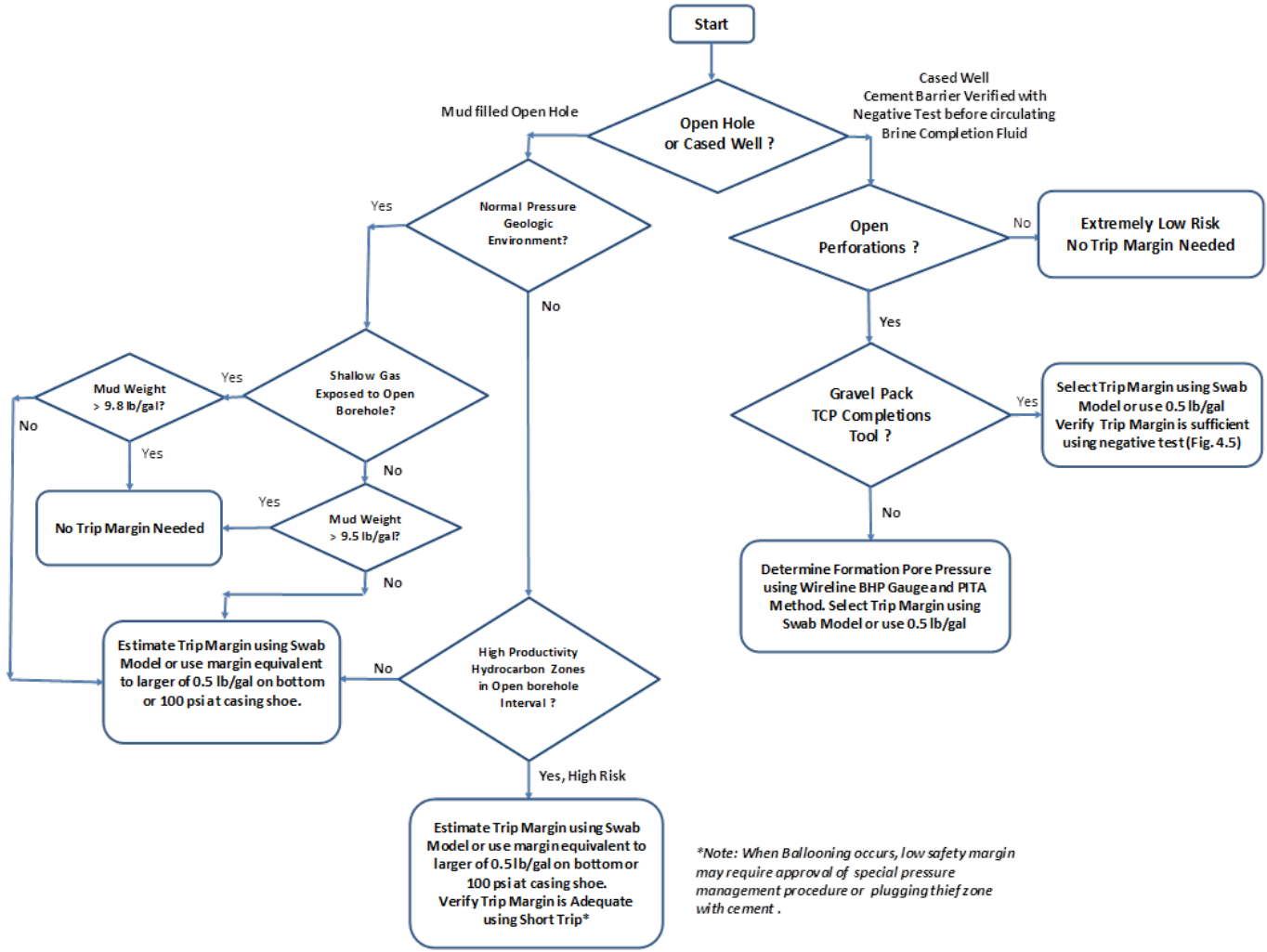
An example checklist that could be made part of a contractor’s SEMP package is shown in **Table 2-13**. This checklist is well control related and could be used in addition to the checklists that are more operational safety related and aimed at preventing injuries while tripping.

**Table 2-13: Example Checklist for High Risk Tripping Operations**

- Ensure appropriate Trip Margin and Pipe Pulling Speeds have been determined. (See Trip Margin Flow Sheet)
- Ensure trip tank is clean of solids that could cause circulating pump to fail or inaccurate volume measurements.
- Ensure safety valves with closing wrench and correct threads are available for all connections in pipe string.
- For Top Drive Rigs, ensure cross over subs are available to dress kelly valve for each section of a tapered string.
- Ensure Shut-in Procedure while tripping is posted and includes contingency instructions for pipe-lite condition and for inability to stab safety valve or screw in top drive kelly valve.
- Ensure all kick detection devices have been tested and calibrated. Set alarms at appropriate levels.
- Print trip sheet using appropriate software and master pipe tally.
- Perform pre-job safety meeting with personnel involved in operation. Review operational sequence, trip sheet, flow-check schedule, shut-in procedures, shut-in practice drills scheduled to be performed.
- Verify the correct line up for blowout preventer and diverter equipment and controls.
- Verify the correct line up from mud pumps to the rig floor.
- Verify the correct line-up for trip tank.
- Toolpusher and/or Operators Representative stay on rig floor for at least first 10 stands to monitor operations.
- Assistant Driller records fill-up volume every five stands; Returns trip sheet to Toolpusher for filing after trip.
- Record Pick-up weight for each stand and display for trend analysis.
- Do not trip when filling trip tank; Perform Flow-Check when filling trip tank.
- Perform Flow-Check when reaching the casing/liner shoe.
- Perform Flow-check prior to pulling heavy weight drill pipe or BHA.
- Report any abnormal drag to Operator’s representative and Toolpusher; Do not continue pulling pipe if drag reaches 30,000 lbs over current pick-up weight. Back reaming may be required to eliminate tight spots.

# EFFECTS OF TRIPPING AND SWABBING IN DRILLING AND COMPLETION OPERATIONS

An example flowchart<sup>28</sup> that could be used to develop well control policies for selecting an appropriate Trip Margin is shown in **Figure 2-12**. The first branch in the flowsheet separates mud filled open-hole conditions from a cased well with a verified cement barrier in place. The cased-hole branch also has a branch for Gravel Pack TCP completions. This is one of the highest risk tripping situations that is commonly experienced on the OCS because it typically involves abnormal pressure, high permeability formations, gaseous hydrocarbons, and open perforations. The mud filled open-hole branch distinguishes between normal and abnormal pressure environments. Many but not all wells on the OCS of the United States experience abnormal pressure at a shallow depth. Wells on land in the United States are more likely to be in a normal pressure environment.

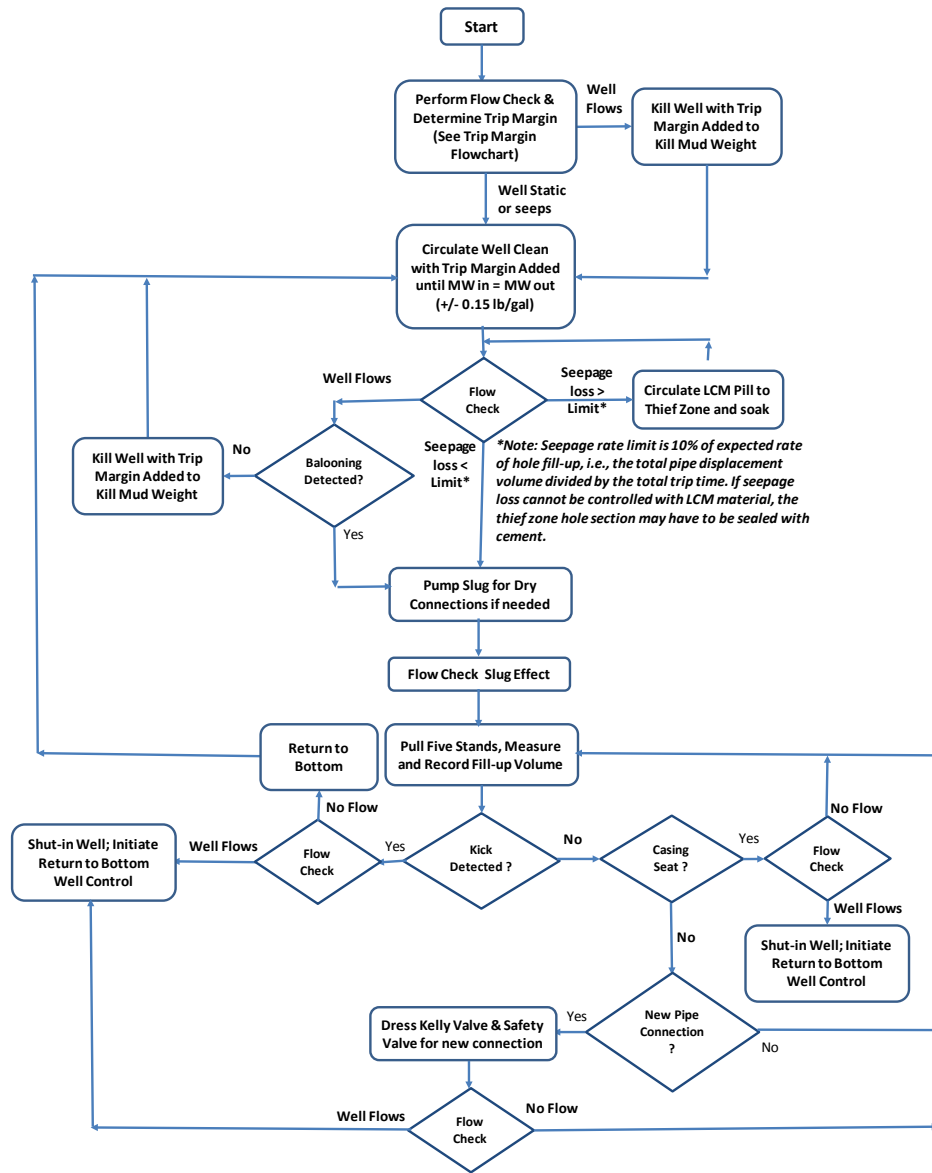


**Figure 2-12: Example Flowchart that Provides Guidance in Determining Trip Margin**

<sup>28</sup> Subject matter experts have advised that flow charts are not the most effective method for communicating with field personnel.

# EFFECTS OF TRIPPING AND SWABBING IN DRILLING AND COMPLETION OPERATIONS

An example Flowchart that could be used to develop well control policies for safe tripping in a high risk environment is shown in **Figure 2-13**. It includes consideration of the sequence of steps that would be needed during the tripping operations with instructions to shut in or return to bottom based on the results of flow checks made at various points during a trip. This flowchart could provide the basis for programming an unmanned real time instrumentation package, such as those<sup>29</sup> commonly seen on land rigs and lower cost platform rigs and jack-ups.



**Figure 2-14: Example Guidance Flowchart for Safe Tripping in High Risk Geologic Environments**

<sup>29</sup> Example lower cost unmanned rig instrumentation systems include those available from Pason Systems, Inc. and MD Totco Instrumentation Products of National Oilwell Varco. Fully integrated mud logging and well monitoring services tend to be found on the larger rigs.

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## 2.7 Understanding Effective Drilling/Completion Fluid Density

The density of drilling muds and completion fluids are affected by both temperature and pressure. Generally, temperature effects decrease the effective density, while pressure effects increase the effective density. A loss of well control incident cited<sup>30</sup> in the contract will be used as a specific example to illustrate the effects of temperature and pressure on drilling and completion fluid density. Determining how the effective equivalent density of a fluid column changes over time due to changes in wellbore temperature requires a fairly complex calculation that must account for both temperature and pressure. In actuality, the loss of hydrostatic pressure due to downhole warming after circulation is stopped is usually small in comparison with a typical safety margin. This is because the *average* fluid temperature in the well does not change significantly with time. This section of the report will review the important literature regarding the effect of temperature and pressure on the density of drilling and completion fluids and the proper procedure for computing the resulting changes in safety margins used for well control considerations.

The issue of whether to use fluid density as measured at the surface or effective fluid density as measured downhole when calculating and reporting safety margins arose because of the development and more frequent use of Pressure While Drilling (PWD) tools in the more expensive deepwater drilling operations. The measured average or effective fluid density controlling hydrostatic pressure on bottom is often 0.1 to 0.2 lb/gal different than the fluid density measured from a sample taken from the surface pits. It has been understood in the deepwater operations community that absent fluid stability issues, downhole temperature and compressibility effects on fluid density can usually be treated as a constant offset for a given hole-section. For this reason when equivalent or effective density measurements are made using both surface and downhole pressure gauges, care is taken to characterize the equivalent density determination being quoted as either *surface* or *downhole*. Surface equivalent densities can be compared to other surface density determinations and downhole equivalent densities can be compared with other downhole equivalent density determinations but significant errors can occur if the two types of measurements are mixed without applying the appropriate correction.

Past BSEE policy recognized that safety margins can be based on either surface measurements or downhole measurements, as long as the same basis is used when determining pore pressure gradient, fluid density, and formation fracture gradient. This concept will be illustrated further with a deepwater example in **Section 2.7.6**. A safety margin equal to the difference between fluid density and pore pressure would be essentially the same, as long as both values are based on surface measurements or both values are based on downhole measurements. The same is true for a safety margin between the formation fracture gradient and the fluid density. What was previously not allowed is to reduce the effective safety margin below the approved limit by mixing surface and downhole density determinations. BSEE was the only regulator identified in the study that currently characterized a safety margin requirement<sup>31</sup> in terms of equivalent downhole density.

Determining the effect of downhole temperature and pressure on safety margins during drilling and completion operations involves complex calculations that will be easier to understand if presented in a step-by-step manner for a specific example. Example calculations will first be presented for the well

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<sup>30</sup> The loss of well control and fire which occurred on the South Timbalier 220 A-platform during tripping operations (July 23, 2013).

<sup>31</sup> See discussion of CFR 250.414 in **Section 2.4.3** of this report.

conditions present prior to the blowout on ST 220 Well A3<sup>32</sup>. It will be shown that density changes due to warming were not a significant factor in the ST 220, Well A3 blowout. This will be followed by a description of how the calculation procedure could be applied to other situations. Some general comments will also be made about fluid properties other than density that can be of concern in a deepwater or cold weather climate. The last portion of this section will discuss how safety margins are used to account for uncertainties in how the downhole borehole pressures change with time during various drilling operations using a deepwater well example.

### 2.7.1 Effect of Downhole Temperature and Pressure on Safety Margin for Shallow Water Example

Example calculations are presented for the conditions present during tripping operations prior to the blowout on South Timbalier 220-A3. The events leading to the blowout and fire were initiated while tripping perforating guns out of the hole on July 23, 2013. The trip was part of planned and approved operations to recomplete the A3 well in a gas bearing sand that had been perforated the previous day.

#### 2.7.1.1 Temperature Modeling Input Data

The A3 well was directionally drilled in 154 ft of water about 84 miles south of Houma, Louisiana. Prior to perforating the 8,800-ft sand, the well was displaced to a 15.7 ppg tri-salt completion brine blend. The 15.7 ppg (surface) density was expected to provide a 0.9 ppg safety or trip margin above the estimated 14.8 ppg (surface) pore pressure gradient. The pore pressure estimate was based on surface mud density records when the sand was drilled.

A 5 in. by 3.5 in. tapered workstring was used to trip Tubing Conveyed Perforating (TCP) guns along with a packer and downhole circulation valve into the well. The sand was perforated underbalanced and about 13 barrels were displaced from the workstring before the choke was closed. The workstring was then killed by isolating the perforations downhole and reverse circulating 15.7 ppg brine at 84 gpm for about 2.068 hrs. Surface pressure data collected when the choke was closed prior to reversing was not of sufficient quality to verify the 14.8 ppg (surface) pore pressure gradient estimate.

When the perforations were exposed to the full 15.7 ppg (surface) fluid column, the fluid loss rate observed was determined to be unmanageable. About 1.816 hrs elapsed from when reverse circulation of the 15.7 ppg brine stopped until forward circulation of 15.3 ppg brine began at a rate of 197.4 gpm. It took about 3.634 hrs to fully displace the 15.7 ppg brine and spot the Hydroxyl Ethyl Cellulose (HEC) loss circulation treatment above the circulation valve. Once the HEC pill reached the perforations, the loss rate dropped to a manageable level. The well was monitored for almost 2 hrs before preparations to trip out of the hole were begun. At this time the trip tank was drained and refilled in order to be able to replace seepage losses and pipe displacement with 15.1 ppg brine.

About 9.120 hrs elapsed after the last circulation before the first attempt is made during the tripping operations to shut in the well by closing the annular preventer. During this period the well was essentially static except for the effects of seepage losses and pipe removal. **Table 2-14** is a summary of the well geometry and geothermal data when the 15.7 ppg brine was displaced with the 15.3 ppg brine. **Figure 2.15** is from Geothermal Gradients and Subsurface Temperatures in the Northern Gulf of Mexico and shows that mean average water temperature in the shallow Gulf of Mexico varies between 50 and 90°F.

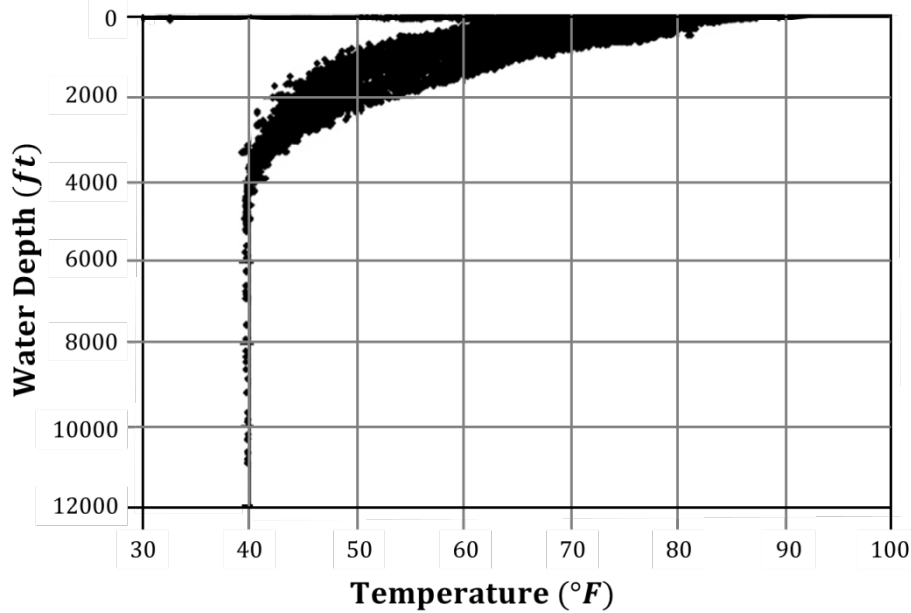
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<sup>32</sup> Case cited in report of BSEE Panel 2015-02 and in contract.

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**Table 2-14: Well A3 Geometry and Temperature Data**

Item	Measured Depth	True Vertical Depth
	<i>ft-RKB</i>	<i>ft-RKB</i>
<b>Rotary</b> (70°F assumed air temperature)	0	0
<b>Waterline</b> (70°F assumed water temperature)	114	114
<b>Mudline</b> (70°F assumed water temperature)	268	268
<b>24" x 0.75" conductor</b> (driven)	568	568
<b>18-5/8" 87.5-ppf casing</b> to surface inside a 22" hole-section with cement to surface.	1525	1525
<b>13-3/8" 68-ppf casing</b> to surface inside a 17.5" hole-section with cement to surface.	4600	4496
<b>Bottom of 5" 19.5-ppf drillpipe</b> ; Crossover to 3-1/2" 13.3-ppf drillpipe	6975	6869
<b>7-5/8" 39-ppf liner top</b> inside 9-5/8" 53.5-ppf casing.	7127	7021
<b>9-5/8" 53.5-ppf casing</b> to surface inside a 12.25" hole section with cement to surface	8300	8192
<b>Circulation port in tapered workstring</b> , 3-1/2" 13.3-ppf drillpipe down to this depth. Packer, guns and snap-latch below this depth.	8719	8599
<b>Top Perforation</b> (188°F reservoir temperature, Geothermal gradient, $g_G = 1.4^\circ\text{F}/100\text{ ft}$ )	8835	8715
<b>Bottom Perforation</b>	8880	8758
<b>Sump packer</b> set inside 7-5/8" 39-ppf liner inside an 8.5" hole section with cement to the top of the liner	8890	8768



**Figure 2.15: Mean Annual Temperature of Water vs. Depth for U.S. GoM<sup>33</sup>**

<sup>33</sup> 3495 profiles (70,000 measurements) in the Northern Gulf of Mexico. Data from the NOAA World Ocean Database. (Forrest, Marcucci, and Scott, 2007)

### 2.7.1.2 Estimating Temperature Effects on Clear Brine Density

The clear brine completion fluid in use when initial well control was lost in the A3 well was a 15.3 ppg Zinc Bromide (ZnBr<sub>2</sub>) / Calcium Bromide (CaBr<sub>2</sub>) / Calcium Chloride (CaCl<sub>2</sub>) blend. The change in brine density caused by a temperature change can be estimated (like most other liquids and mixtures) by using the fluid's coefficient of thermal expansion. The density change can be calculated by:

$$\Delta\rho_T = \rho_0\beta(T_0 - T)$$

#### Equation 2.1: Change in Density due to Change in Temperature

Where:

$\Delta\rho_T$  = the change in density due to a change in temperature;

$\rho_0$  = a reference density measured at a reference temperature of  $T_0$ ;

$\beta$  = coefficient of thermal expansion of the fluid;

$T$  = the temperature of the fluid.

For the specific case of the 15.3 ppg tri-salt blend completion fluid used in the A3 well, an appropriate value for the coefficient of thermal expansion available in SPE Monograph Volume 19 (Bridges, 2000) is  $2.27 \times 10^{-4}$  bbl/(bbl·°F).<sup>34</sup> Assuming the 15.3 ppg density measurement was for a temperature of 70°F, the equation can be simplified to:

$$\Delta\rho_T = 15.3(2.27 \times 10^{-4})(70 - T)$$

$$\Delta\rho_T = 3.47 \times 10^{-3}(70 - T), \text{ where } \Delta\rho_T \text{ is in ppg; and } T \text{ is in } ^\circ\text{F}$$

#### Equation 2.2: Change in Density due to Temperature Change for Well A3 Example

In order to simplify the calculations and make them easier to follow, calculations will first be made assuming the wellbore fluids have been static long enough to be in thermal equilibrium with the surrounding formations. The complicating effects of fluid circulation will be presented after this initial discussion.

Using **Equation 2.2** and neglecting compressibility effects, the density of the 15.3 ppg (surface) brine when it comes into equilibrium with the 188°F reservoir temperature would change by:

$$\Delta\rho_{188} = 3.47 \times 10^{-3}(70 - 188) = (-)0.409 \text{ ppg}$$

Adding this (-) 0.409 ppg correction for temperature effects to the reference density results in a brine density of:

$$\rho_{188} = \rho_0 + \Delta\rho_T = 15.3 - 0.409 = 14.89 \text{ ppg}$$

<sup>34</sup> Coefficient of thermal expansion value for 16.01 ppg Three Salt Brine in Table 6.17, Expansibility of Heavy Brine Fluids at 12,000 psi from 76 to 198°F, SPE Monograph Volume 19, Completion and Workover Fluids. The same coefficient of thermal expansion value for the same brine can be found in Table 5, *Temperature Compensation Factors in USC units* in API Recommended Practice 13J, Fifth Edition.

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This brine density occurs only at the perforations. As discussed by Bridges (2000) and in API RP 13J (2014), the temperature of the entire column of brine in the wellbore is not constant and varies with depth.

Assuming a linear geothermal temperature distribution in the specific case of Well A3, and assuming the brine is in thermal equilibrium with the surrounding sediments, the temperature of the brine at any depth can be estimated using:

$$T = 70 + \frac{1.4}{100}(D - 268)$$

### Equation 2.3: Geothermal Temperature at Depth for Well A3 Example

Where

When  $D > 268$  ft:

$T$  = temperature in °F at true vertical depth  $D$

When  $D \leq 268$  ft:

$$T = 70^\circ\text{F.}$$

**Equation 2.2** and **Equation 2.3** were used to construct **Table 2-15** which shows how brine density would have changed with depth in the A3 once the completion fluid temperature reached equilibrium with the surrounding sediments (neglecting compressibility effects). It is important to note that brine density is 14.89 ppg only at 8835 ft-MD-RKB and not throughout the entire wellbore.

**Table 2-15: Density versus Depth for 15.3 ppg (surface) tri-salt brine at Geostatic Temperatures (Well A3)**

Measured Depth	True Vertical Depth	Temp	Density Change due to Temp Only	Brine Density
$D_{MD}$ <i>ft-RKB</i>	$D_{TV}$ <i>ft-RKB</i>	$T$ <i>°F</i>	$\Delta\rho_T$ <i>ppg</i>	$\rho$ <i>ppg</i>
0	0	70	0.00	15.30
114	114	70	0.00	15.30
268	268	70	0.00	15.30
1500	1500	87	-0.06	15.24
3000	2950	108	-0.13	15.17
4483	4379	128	-0.20	15.10
6000	5894	149	-0.27	15.03
7500	7393	170	-0.35	14.95
8835	8715	188	-0.41	14.89

Both Bridges (2000) and API RP 13J (2014) recommend using an average density approach to calculate the equivalent or effective density controlling the hydrostatic pressure of the brine at a given depth. An average density approach can also be implemented by calculating the density at the average wellbore

temperature. Zamora et al (2012) presents a more complex stepwise integration approach when an effective static density profile is desired.

For the specific case of the 15.3 ppg (surface) brine in well A3, the average density change due to temperature (in ppg) can be calculated using an average wellbore temperature in °F using **Equation 2.2**. **Equation 2.3** can be used to calculate a depth weighted average wellbore temperature when thermal equilibrium is reached for the entire fluid column. Thus the average equilibrium wellbore temperature above a given depth D can be computed using:

$$\bar{T} = \frac{70(D) + \left[ \frac{1.4 (D - 268)}{100} \right] (D - 268)}{D}$$

$$\bar{T} = 0.007D + \frac{502.768}{D} + 66.248$$

**Equation 2.4: Average Temperature at a given Depth for Example Well A3**

**Equation 2.4** is valid for values of  $D > 268$  ft. For  $D \leq 268$  ft,  $T = 70^\circ\text{F}$ .

Using **Equation 2.4** to calculate the mathematically exact average geothermal equilibrium temperature of the brine in the fluid column above the top perforation ( $D = 8715$  ft-TVD-RKB) yields:

$$\bar{T} = 0.007(8715) + \frac{502.768}{8715} + 66.248 = 127^\circ\text{F}$$

The density offset required to correct surface density to an effective density at the top of the perforations can then be estimated with **Equation 2.2**.

$$\Delta\bar{\rho}_{8715} = 3.47 \times 10^3 (70 - 127) = (-)0.198\text{ppg}$$

Applying this average density change correction to the surface brine density yields an *equivalent* fluid density<sup>35</sup> of 15.10 ppg that can be used to calculate the hydrostatic pressure at the bottom of the well. Recall that a value of 14.89 ppg was previously obtained for the actual fluid density at the bottom of the well.

**2.7.1.3 Apparent Average Method for Estimating Average Temperature**

Bridges (2000) describes calculating a mid-point density by correcting surface brine density to mid-point temperature and pressure. This mid-point density can then be used as an approximation for the equivalent density of the entire fluid column. Using a mid-point density for average density assumes the changes in temperature and pressures are linear over the length of the wellbore.

Bridges' (2000) approach is similar to estimating the average temperature by adding the surface wellbore temperature to the downhole temperature and dividing by two. This simplification results in:

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<sup>35</sup> Compressibility effects were neglected for illustrative purposes only. Both Bridges (2000) and API RP 13J (2014) recommend correcting brine density for pressure effects if temperature effects are being taken into account.

$$\tilde{T} = \frac{T_s + T}{2}$$

**Equation 2.5: Apparent Average Temperature**

Where

$\tilde{T}$  = apparent average temperature;

$T_s$  = the wellbore fluid temperature at surface and;

$T$  = wellbore fluid temperature at the depth of interest.

For the specific case of well A3 prior to the loss of well control, the apparent average geothermal temperature (in °F) of the brine at true vertical depth D (in ft-RKB) can be calculated by substituting **Equation 2.3** for the wellbore fluid temperature at the depth of interest, which results in:

$$\tilde{T} = \frac{70 + \left[ 70 + \frac{1.4}{100} (D - 268) \right]}{2}$$

$$\tilde{T} = 70 + 0.007(D - 268)$$

**Equation 2.6: Apparent Average Temperature for a given Depth for Example Well A3**

**2.7.1.4 Numerical Method for Determining Average Temperature**

Because temperature does not always follow a simple linear relationship with depth, using a spreadsheet to compute average temperature numerically can prove useful.

Both Bridges (2000) and API RP 13J (2014) point out that in practice, computer-based methods are often used to estimate an average brine density. While neither Bridges (2000) nor API RP 13J (2014) provide more than a general description of this solution method, API RP 13J (2014) does note:

*“Most completion brine service companies and fluid engineers have sophisticated computer models<sup>36</sup> to calculate the average brine density in the wellbore. These models typically divide the wellbore into 20 or more slices and iterate the changes to the density caused by temperature and pressure at each wellbore interval.”*

Calculating a depth-weighted numerical temperature average and then correcting brine density to that average temperature is another approach that can be used. Average temperature can be estimated by dividing the fluid column into n depth increments and implementing:

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<sup>36</sup> The computer models attempt to model the unsteady state changes in fluid temperature with time due to heat flow between the pipe and annulus and between the annulus and the surrounding casing strings and earth. Most of these models evolved from a program called “GEOTEMP” that was developed through a research grant funded by DOE. Example proprietary computer models with this capability include Halliburton’s LANDMARK™ software and Wooley and Associates, Inc.’s WELSIM™ software.



$$\bar{T} = \frac{\sum_{i=1}^{n-1} \frac{T_i + T_{i+1}}{2} (D_{i+1} - D_i)}{D_n}$$

**Equation 2.7: Numerical Average Temperature for a given Depth**

Where:

$\bar{T}$  = average temperature for the entire fluid column down to true vertical depth,  $D_n$ ;

$T_i$  = brine temperature at true vertical depth  $D_i$ ; and

$T_{i+1}$  = brine temperature at true vertical depth  $D_{i+1}$ .

**2.7.1.5 Accounting for Compressibility**

The compressibility constant for liquids is normally two orders of magnitudes smaller than the coefficient of thermal expansion for the same liquid. However, when temperature changes are small and pressure changes are large, the effect of compressibility on fluid density can be as significant as, or even more significant than, the effect of temperature. Both Bridges (2000) and API RP 13J (2014) do not neglect compressibility effects when correcting surface brine density to wellbore conditions.

The change in density caused by a change in pressure can be estimated using:

$$\Delta\rho_P = \rho_0 c (P - P_0)$$

**Equation 2.8: Change in Density due to Change in Pressure**

Where:

$\Delta\rho_P$  = the change in fluid density due to pressure;

$\rho_0$  = the fluid density measured at the reference pressure,  $P_0$ ;

$c$  = the compressibility of the fluid; and

$P$  = the pressure of the fluid.

For the specific case of the 15.3 ppg (surface) tri-salt blend used in the A3 well, the most appropriate value of compressibility available in SPE Monograph 19 (Bridges, 2000) is  $1.39 \times 10^{-6}$  bbl/(bbl-psi)<sup>37</sup>. Assuming a reference pressure of 0 psig and substituting the specific values of compressibility and reference density into **Equation 2.8** yields:

$$\Delta\rho_P = 1.39 \times 10^{-6} \rho_0 P$$

**Equation 2.9: Density Change due to Pressure for Example Well A3**

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<sup>37</sup> Compressibility value for 16.01 ppg Three Salt Brine in Table 6.16, Compressibility of Heavy Brine Fluids at 198°F from 2,000 to 12,000 psia, SPE Monograph Volume 19, Completion and Workover Fluids. The same value for compressibility for the same brine can be found in Table 6, *Pressure Compensation Factors in USC Units* in API Recommended Practice 13J, Fifth Edition.

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Where

$\Delta\rho_p$  and  $\rho_0$  are in lb/gal; and

$P$  is in psig.

Bridges (2000) recommends calculating the average density change at the mid-point pressure in the same manner as correcting for temperature. This method is particularly valid for any slightly compressible liquid which has a linear relationship between pressure and depth.

The average pressure is calculated by:

$$\bar{P} = \frac{P_s + P}{2}$$

### Equation 2.10: Average Pressure

Where:

$\bar{P}$  = the average pressure;

$P_s$  = the wellbore pressure at surface; and

$P$  = the pressure at the depth of interest;

The relationship between pressure and depth for a slightly compressible fluid can be expressed by:

$$P = P_s + (\rho_0 + \Delta\bar{\rho}_p + \Delta\bar{\rho}_T)D$$

### Equation 2.11: Pressure at Depth corrected for Temperature and Compressibility Effects

Where:

$\rho_0$  = the surface or reference density of the brine at reference temperature and pressure;

$\Delta\bar{\rho}_p$  = density change for average wellbore pressure;

$\Delta\bar{\rho}_T$  = density change for average wellbore temperature; and

$D$  = the true vertical depth of interest.

Substituting **Equation 2.11** into **Equation 2.10**, converting to field units and assuming a wellbore pressure of 0 psig at surface yields the following expression for average wellbore pressure:

$$\bar{P} = 0.052(\rho_0 + \Delta\bar{\rho}_T + \Delta\bar{\rho}_p) \frac{D}{2}, \text{ where } D \text{ is in ft-RKB}$$

### Equation 2.12: Corrected Pressure vs Depth converted to Field Units

It is useful to note that the pressure at the depth of interest is dependent on the density corrections for pressure and temperature. Because the compressibility correction to density will be small in the specific case of ST 220 Well A3, employing either iterative or numerical approaches will not significantly improve the accuracy of the bottom-hole pressure calculation for this example. The average pressure can be computed basing  $\Delta\bar{\rho}_p$  on the surface density in Equation 2.9.

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For the A3 well case, the surface pressure was 0 psig and the brine density was measured at 0 psig. It can also be shown that neglecting the density changes due to temperature and pressure will not result in a significant error in calculating the density correction for compressibility. Specifically for the A3 well prior to the loss of initial well control, the average density correction for any true vertical depth of interest can be estimated by:

$$\Delta\rho_p = 1.39 \times 10^{-6} (15.3) \left[ 0.052(15.3 + 0 + 0) \frac{D}{2} \right]$$
$$\Delta\bar{\rho}_p = 8.45 \times 10^{-6} D$$

### Equation 2.13: Average Change in Density at a given Depth for Example Well A3

Using a true vertical depth of 8,715 gives a density correction for pressure of 0.07 ppge for the brine having a surface density of 15.3 lb/gal. Applying density corrections for both temperature and pressure yields:

$$\rho_0 + \Delta\bar{\rho}_T + \Delta\bar{\rho}_p = 15.3 - 0.198 + 0.07 = 15.17$$

Rounding to the nearest tenth of a lb/gal, which is the expected accuracy of the density measurement, gives a corrected downhole equivalent mud weight of 15.2 lb/gal. This falls within the 0.1 to 0.2 lb/gal expected difference between a surface measured density and an equivalent static downhole measured density.

#### 2.7.1.6 Summary of Downhole Effective Density Estimates for ST 220 Well A3

Summarized in **Table 2-16** are the bottom-hole pressure errors for different methods of correcting the 15.3 ppg (surface) completion fluid density for pressure and temperature effects when the fluid is in thermal equilibrium with the surrounding formations.

It is of particular interest that in the specific case of Well A3, simply not correcting brine density for pressure and temperature effects results in only a 57 psi overestimation of wellbore pressure at the top perforation while incorrectly correcting brine density to reservoir temperature and neglecting the effect of compressibility results in a 128 psig underestimation of wellbore pressure at the top perforation.

Table 2-16 also shows that in the case of Well A3, the linear temperature distribution assumed for the wellbore temperature results in negligible errors for the previously discussed simplified methods of computing average fluid temperature.

**Table 2-16: Comparison of Equivalent Density Calculations for ST220 A3**

Equivalent Density Calculation Method	Value Estimated for Average Temp.	Equivalent Density Correction for Temp. and Press.	Equivalent Density Corrected for Temp. and Press.	Bottom Hole Press using Corrected Eq. Density	Btm-hole Press Error
$D = 8715$ <i>ft-TVD-RKB</i>	$^{\circ}F$	<i>ppg</i>	<i>ppge</i>	<i>psig</i>	<i>psi</i>
Mathematically exact average for temp. and iterative solution for average press.	127.31	-0.1258	15.1741	6869.8	0.0
Numerical average for temp and simple average for press. (53 Cells)	127.32	-0.1252	15.1748	6870.0	0.2
Apparent average for temp and simple average press. After Bridges (2000)	129	-0.131	15.169	6867	-2
Equation 25 from API RP 13J (2014)	Not directly calculated	-0.138 <sup>38</sup>	15.162	6865	-5
Uncorrected Surface Density.	<del>                    </del>	0.000	15.3	6926	57
<b>Incorrectly</b> using bottom-hole temp. and neglecting compressibility	188	-0.409 <sup>39</sup>	14.9	6741	-128

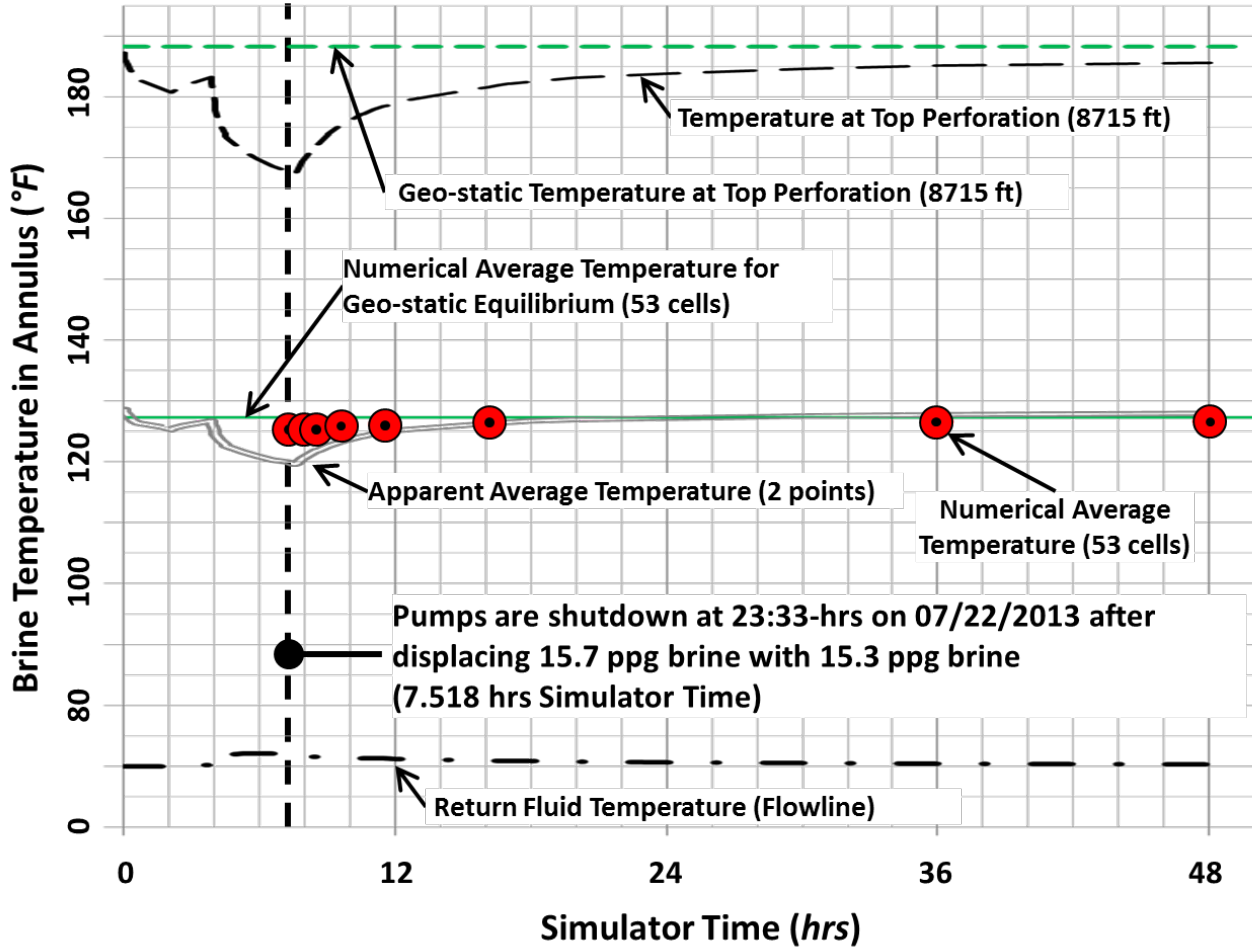
### 2.7.1.7 Estimating the Effect of Time-Dependent Downhole Heating on Brine Density

In reality, the wellbore fluid temperature in a well approaches thermal equilibrium with the surrounding formations only after being static for several days. Even the bottom-hole temperature recorded when logging will be a little lower than the formation temperature a significant distance from the wellbore. Thus, the calculations discussed above provide only a first approximation of the downhole fluid properties at any given point in time. What is needed to understand the effect of thermal warming on the needed safety margin when tripping is a knowledge of how much the equivalent downhole density will change after the trip margin was verified. This generally requires the use of a wellbore simulator computer program that includes unsteady state heat flow modelling as well as fluid flow modelling. As before, the use of a simulator is easier to understand through the use of example calculations. This will be done continuing the example trip that was made prior to the ST 220 A3 blowout.

After perforating the 8,800 ft sand, the A3 well was reverse circulated to kill the well, observed, and then forward circulated to displace the well from a 15.7 ppg (surface) brine density to a 15.3 ppg (surface) brine density before tripping operations were started.

<sup>38</sup> Equation 25 from API RP 13J (2014), section 6.6.4 calculates equivalent bottom-hole density directly.

<sup>39</sup> Temperature density correction only.



**Figure 2-16: WELLSIM™ Output for Time Period prior to Loss of Well Control in ST 220 - A3**

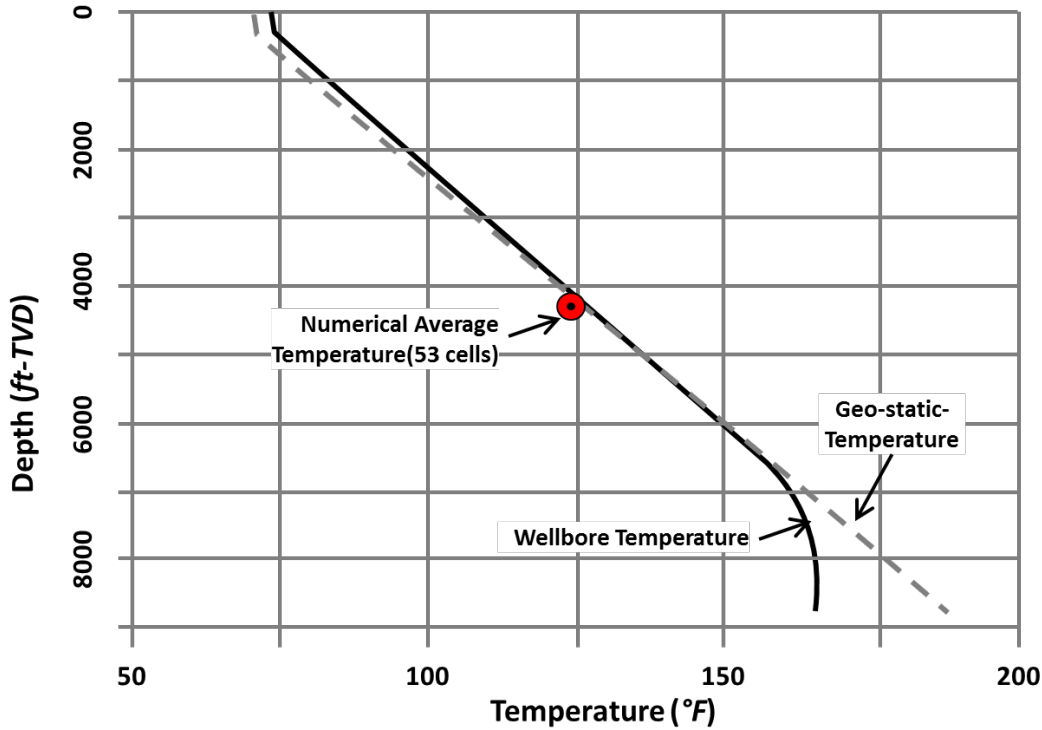
The results of a temperature simulator<sup>40</sup> (WELLSIM™) run which modeled how wellbore brine temperature would have varied with time in the A3 prior to the initial loss of well control are summarized in Figure 2-16. The simulation start time corresponds to when the workstring was reverse circulated to kill the workstring after the well was perforated underbalanced. Geothermal equilibrium was assumed for the initial temperature distribution because the well had been static for almost 24 hrs prior to perforating. In addition, relatively little sustained circulation had been done for a prolonged period while the lower section of wellbore was abandoned, the remaining wellbore section displaced to completion fluid, and the pits cleaned.

**Figure 2-16** shows that the largest temperature reduction occurs just before the pumps are stopped for the last time. While the bottom-hole temperature drops 22°F, the numerical average temperature for the entire wellbore drops by only 2°F over the 8 hrs and 35 min the well was open to the atmosphere before the first attempt to control the well was made at 0840-hrs on July 23, 2013. A maximum average wellbore brine temperature increase of 2°F corresponds to a 3 psi loss in bottom-hole pressure at the top perforation. Thus, if the bottom-hole pressure or trip margin was verified by measurements made with

<sup>40</sup> Proprietary WELLSIM™ thermal modelling software provided by Wooley & Associates, Inc.

the 15.3 ppg fluid in the well, thermal warming would have virtually no effect on the needed trip margin.

**Figure 2-17** shows the reason why very little change in the depth-weighted, numerically-averaged temperature occurred.



**Figure 2-17: WELLSIM2000™ Temperature Distribution when the Pumps are stopped for the Last Time**

**2.7.2 Generalizing the Determination of Downhole Fluid Density**

The calculation procedure illustrated with an example in the previous section can be generalized by using appropriate values for the thermal coefficient of expansion and compressibility of the wellbore fluid under consideration and the known temperature profile for the well. Equation 2.1 and Equation 2.8 presented in **Section 2.7.1** can be used for any drilling or completion fluid with an appropriate value for surface fluid density, thermal coefficient of expansion and fluid compressibility. **Table 2-17** shows representative values for thermal coefficient of expansion,  $\alpha$ , and fluid compressibility,  $c$ , for other brines and for other common liquids used in constructing drilling and completion fluids<sup>41</sup>. Note that the values of  $\alpha$  and  $c$  do not vary greatly for different brines. Thus the changes in density for a given temperature change, when expressed as a fraction or percentage of the initial density is very similar for

<sup>41</sup> Non-linear correlations for coefficient of thermal expansion for some brines and oils that are more accurate at high temperatures and pressures are presented by Zamora et al (2012) and based on API RP 13D (2010). Isotherms for diesel oil, some mineral oils, synthetic oils, and brines are presented by Zamora et al (2012) for pressures up to 30,000 psi and temperatures up to 450°F.

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different brines. The example discussed in the previous section is in the middle of the available brine density range and is representative of typical temperature effects after perforating with brines.

**Table 2-17: Coefficients of Exp and Comp for Drilling and Completion Fluid and Components**

Brine	Density (lb/gal)	Thermal Coefficient of Expansion ( $\alpha$ ) [vol/vol/°F]	Compressibility (c) [vol/vol/psi]
Fresh Water	8.33	$1.0 \times 10^{-4}$	$2.7 \times 10^{-6}$
Seawater	8.5	$1.4 \times 10^{-4}$	$2.5 \times 10^{-6}$
Diesel	7.1	$3.8 \times 10^{-4}$	$6 \times 10^{-6}$
Synthetic Base Oil	6.6	$4.0 \times 10^{-4}$	$5 \times 10^{-6}$
NaCl	9.42	$2.54 \times 10^{-4}$	$1.98 \times 10^{-6}$
CaCl <sub>2</sub>	10.0	$2.89 \times 10^{-4}$	$1.8 \times 10^{-6}$
CaCl <sub>2</sub>	11.45	$2.39 \times 10^{-4}$	$1.50 \times 10^{-6}$
NaBr	12.48	$2.67 \times 10^{-4}$	$1.67 \times 10^{-6}$
CaBr <sub>2</sub>	14.3	$2.33 \times 10^{-4}$	$1.53 \times 10^{-6}$
ZnBr <sub>2</sub> /CaBr <sub>2</sub> /CaCl <sub>2</sub>	16.01	$2.27 \times 10^{-4}$	$1.39 \times 10^{-6}$
ZnBr <sub>2</sub> /CaBr <sub>2</sub>	19.25	$2.54 \times 10^{-4}$	$1.64 \times 10^{-6}$
Low SG Solids	22	$0.6 \times 10^{-4}$	$0.2 \times 10^{-6}$
Barite	35	$0.2 \times 10^{-4}$	$0.1 \times 10^{-6}$

Drilling muds are mixtures of a base fluid, low specific gravity solids (clay and drilled solids), and barite. The base fluid is generally fresh water, seawater, diesel oil, or more environmentally compatible synthetic oil. The thermal coefficient of expansion and fluid compressibility can be computed using a volume weighted average value for the various components of the mud. Thus, the effective thermal coefficient of expansion of a clean and gas free mud can be computed using:

$$\alpha_m = f_{lg_s} \alpha_{lg_s} + f_B \alpha_B + f_o \alpha_o + f_w \alpha_w$$

**Equation 2.14 : Effective Coefficient of Thermal Expansion for Drilling Mud Mixtures**

Where:

$\alpha_m$  = the coefficient of thermal expansion of the mud;

$\alpha_{lg_s}$  = the coefficient of thermal expansion of the low specific gravity solids in the mud;

$\alpha_B$  = the coefficient of thermal expansion of the barite in the mud;

$\alpha_o$  = the coefficient of thermal expansion of the oil phase of the mud;

$\alpha_w$  = the coefficient of thermal expansion of the water phase of the mud;

$f_{lg_s}$  = the volume fraction of low gravity solids in the mud;

$f_B$  = the volume fraction of barite in the mud;

$f_o$  = the volume fraction of oil in the mud; and

$f_w$  = the volume fraction of water in the mud.

Similarly, the effective compressibility of the mud can be computed using:

$$c_m = f_{lg_s} c_{lg_s} + f_B c_B + f_o c_o + f_w c_w$$

**Equation 2.15: Effective Compressibility of Drilling Mud Mixture**

Where:

- $c_m$  = the compressibility of the mud;
- $c_{lg_s}$  = the compressibility of the low specific gravity solids in the mud;
- $c_B$  = the compressibility of the barite in the mud;
- $c_o$  = the compressibility of the oil phase of the mud; and
- $c_w$  = the compressibility of the water phase of the mud;

The mud density and volume fraction of the various components are routinely measured and reported on the daily mud reports and daily operations reports. This information can be used with Table 2-17 to calculate the effective thermal coefficient of expansion and effective compressibility of a gas free mud.

**Example Problem 2-1: Effective Thermal Coefficient and Compressibility for Drilling Mud**

A 15.0 lb/gal fresh water base mud containing no oil has a total volume fraction of solids of 0.28, which includes a volume fraction of low gravity solids of 0.06. Calculate the effective thermal coefficient of expansion and effective compressibility of the mud. Also, estimate the mud density at a vertical depth of 10,000 ft if the surface reference temperature for the mud check was 120 °F, the temperature at 10,000 ft was 220 °F, and the pressure at 10,000 ft was 7,831 psi.

**Solution:** The fraction of Barite is  $0.28 - 0.06 = 0.22$  and the fraction of water is  $1.0 - 0.28 = 0.72$ . The thermal coefficients of expansion for fresh water, low gravity solids, and barite from Table 2-25 are  $1.0 \times 10^{-4}$ ,  $0.6 \times 10^{-4}$ , and  $0.2 \times 10^{-4}$  respectively. Use of Equation 2.14 yields:

$$\alpha_m = f_{lg_s} \alpha_{lg_s} + f_B \alpha_B + f_o \alpha_o + f_w \alpha_w = 0.06(0.6 \times 10^{-4}) + 0.22(0.2 \times 10^{-4}) + 0 + 0.72(1.0 \times 10^{-4}) = 0.8 \times 10^{-4} \text{ or } 0.00008 \text{ } ^\circ\text{F}^{-1}$$

The mud density change at 10,000 ft due to heating is computed from Equation 2.1 to be

$$\Delta\rho_T = \rho_0 \beta (T_0 - T) = 15.0 (0.00008) (120 - 220) = -0.12 \text{ lb/gal.}$$

The average mud density change due to heating from 0 to 10,000 ft is

$$\Delta\rho_T = \rho_0 \beta (T_0 - T_{avg}) = 15.0 (0.00008) (120 - 170) = -0.06$$

The compressibility for fresh water, low gravity solids, and barite from Table 2-17 are  $2.7 \times 10^{-6}$ ,  $0.2 \times 10^{-6}$ , and  $0.1 \times 10^{-6}$  respectively. Equation 2.15 yields:

$$\begin{aligned} c_m &= f_{lg_s} c_{lg_s} + f_B c_B + f_o c_o + f_w c_w = 0.06(0.2 \times 10^{-6}) + 0.22(0.1 \times 10^{-6}) + 0 + 0.72(2.7 \times 10^{-6}) \\ &= 1.98 \times 10^{-6} \text{ or } 0.00000198 \text{ psi}^{-1} \end{aligned}$$

The mud density change at 10,000 ft due to compressibility is computed from Equation 2.8 to be

$$\Delta\rho_P = \rho_0 c (P - P_0) = 15.0 (0.00000198) (7831) = 0.23 \text{ lb/gal}$$



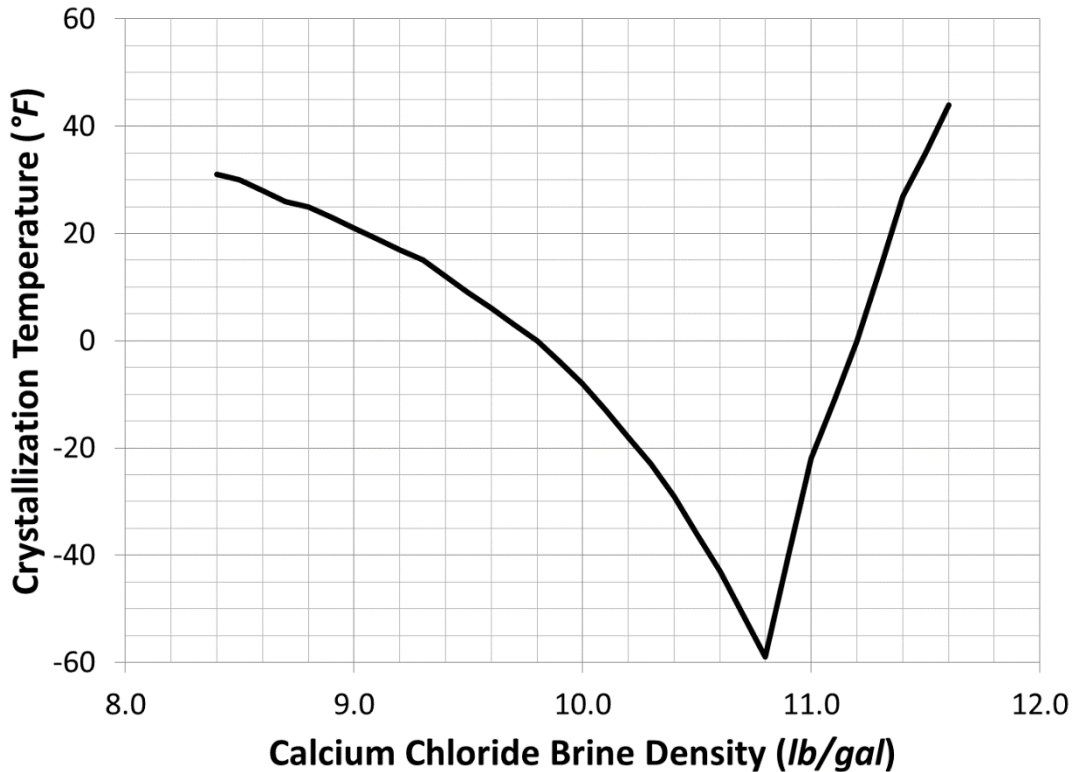
And the average mud density change due to compressibility from 0 to 10,000 ft is

$$\Delta\rho_p = \rho_0 c(P_{avg} - P_0) = 15.0 (0.00000198) (3916) = 0.12$$

The mud density at 10,000 ft would be  $15.0 - 0.12 + 0.23 = 15.11$  lb/gal. Note that this would be the density only at this one vertical depth and would not be the effective mud density at 10,000 ft. The effective density at 10,000 ft would be  $15.0 - 0.06 + 0.12 = 15.06$  lb/gal for clean mud with no gas or rock cuttings and a linear temperature profile from 120 °F at the surface to 220 °F at 10,000 ft.

**2.7.3 Complications in Deepwater Locations and Artic Locations**

Heat transfer in deep water between the mud in the marine riser or return flowline and the seawater is an efficient process, such that the mud temperature in the return mud flow path can be nearly the same as the seawater temperature. Figure 2.15 shows data collected on ocean temperature at various water depths. Note that below about 4,000 ft, the seawater temperature becomes almost constant at about 40 °F. Low fluid temperatures can cause precipitation of brine crystals, hydrate formation and/or freezing. Plugging of BOP components is a potential major problem that requires careful attention during the well planning phase in both deepwater and in cold weather locations. When freezing is possible below ground level, special consideration must also be given to the casing design and completion fluids left outside of casing and between pipe strings.



**Figure 2-18: Crystallization Temperature of Calcium Chloride Brine Density (Bridges 2000)**

Fluid specialists generally have software that can predict these problems and provide brine concentrations, chemical inhibitors, and/or procedures for mitigating the potential problems identified. API recommends that brine used in an application should be selected to have a *crystallization*

temperature<sup>42, 43</sup> below the lowest anticipated operating temperature. **Figure 2-18** is an example crystallization temperature plot that shows the crystallization temperature of Calcium Chloride solutions with densities ranging from 8.4 to 11.6 lb/gal. Calcium chloride brines should be limited to applications that always fall significantly above the line shown in the plot. While this recommendation is explicitly made in API RP 13J for completion fluids (particularly for heavy brine blends), the recommended practice should be followed for all fluids used for well control purposes including fluids used in the hydraulic control circuits of the BOP system.

Clear completion brines have a reputation for being difficult to understand among some professionals in the drilling and completion service sector. The BSEE Panel Report 2015-02 cites references referring to such complexity. Most of this perception arises from the complex nature of the brine selection process during job planning. Complex compositional computer models can be used to estimate important properties such as density and crystallization temperature of heavy brine blends. Assuming ideal mixing when salts are involved can lead to significant errors. The final volume of the solution is often significantly different from the sum of the component volumes that were mixed together. Mixing tables determined experimentally have been published and can also be used.

Some additives commonly used to convert from drilling mud to a completion fluid react negatively with some brines but not others. Furthermore, concerns about corrosion and scale dropout must be addressed along with formation compatibility. In addition, the reputation of clear fluid complexity is reinforced by the complexity of compositional models used to predict final brine and/or brine blend properties.

All of these complexities are addressed during the pre-job planning phase when the fluid is selected. In the field, fluid densities do not have to be predicted, instead they are directly measured. As has been shown correcting a measured surface density to effective downhole density is a relatively simple process even for heavy brines as long as the lowest temperatures are above the freezing/crystallization temperature.

#### **2.7.4 Complications when using Oil Base Mud**

As can be seen in Table 2-17, the compressibility of the base fluid of an oil base mud is about twice the compressibility of the base fluid for a water-base mud and for brine completion fluids. The downhole density of an oil-base mud can also be significantly affected by dissolved natural gas. At pressures above 8,000 psi and temperatures above 100 °F, natural gas becomes miscible with base oils used in drilling muds in all proportions (Figure 2-19). An analogy would be how alcohol and water mix together freely at room temperature and atmospheric pressure in all proportions. When drilling through formations containing natural gas, the gas from the rock that was destroyed by the bit dissolves in the base oil and lowers the mud density. Gas seeping into the well from a high-pressure zone that has a very low permeability also dissolves in the base oil and can have an even more pronounced effect. The effect of dissolved natural gas on the density of an example synthetic base oil is shown in Figure 2.20 As the mud is circulated to the surface and the pressure of the mud becomes lower, the gas breaks out of

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<sup>42</sup> “The crystallization temperature for normally formulated brine is the temperature at which the brine is saturated with one or more components that it contains. At this temperature, the solubility of the least soluble component is exceeded and it crystallizes as the salt or salt hydrate, or ice.

<sup>43</sup> Crystallization temperature has also been referred to as the *salt-out* or *freezing* temperature (King, Brines, Fluids, and Filtration, 2009 Presentation).

solution from the base oil to become free gas. Thus, it can be especially important to circulate the mud clean of drilled gas prior to tripping operations when using an oil base mud.

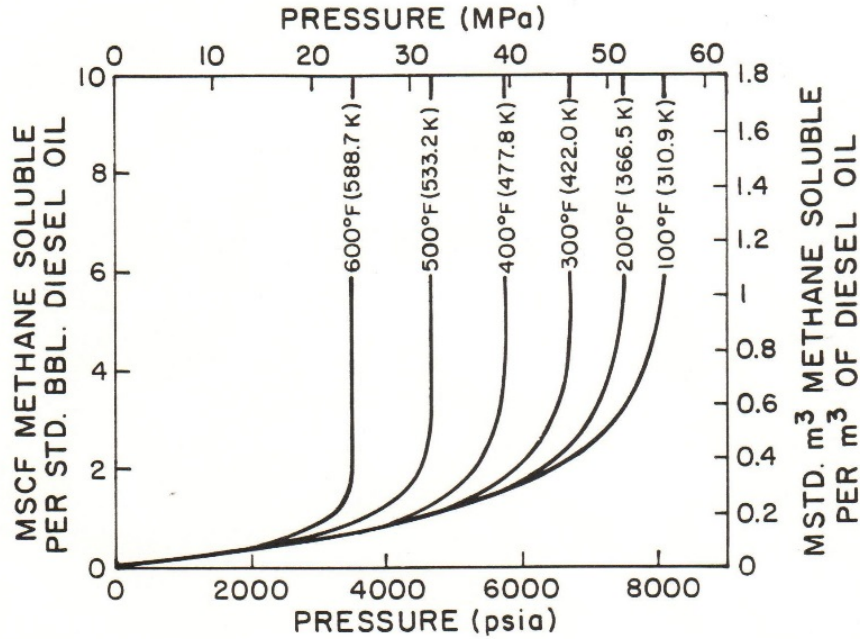


Figure 2-19: Methane Solubility in Diesel Oil (After Thomas, Lea and Turek (1984))

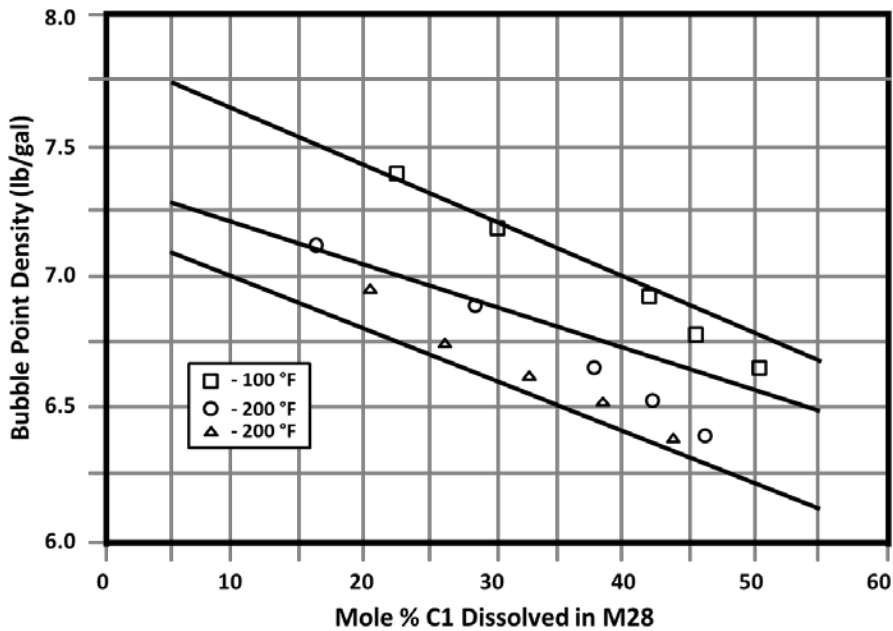


Figure 2-20: Experimental and Predicted Synthetic Base Oil Density with dissolved Methane<sup>44</sup>

<sup>44</sup> After O'Bryan 1985

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Oil base muds also contain a significant volume fraction of brine that is emulsified into small droplets in the base oil. A  $\text{CaCl}_2$  brine is commonly used for the emulsified water phase to reduce the sensitivity of shale formations to the water phase in the mud.

**Example Problem 2-2: Temperature and Compressibility Effects on Equivalent Static Density**

A deepwater well in 4,000 ft of water is being drilled with a 14.0 lb/gal mud at a depth of 25,000 ft subsea. The formation temperature is 40 °F at the mudline and 315 °F at 25,000 ft. The surface flowline temperature at which the mud density was measured is 52 °F.  $\text{CaCl}_2$  brine having a density of 9.8 lb/gal is emulsified in the base oil. Calculate the static density at the seafloor and on bottom when the well fluids are in thermal equilibrium with the surrounding formations and water column, and the equivalent hydrostatic density of the entire column.

**Solution:** The flow path should be broken into at least two sections with the first section being the column thru the water and the second section being the section thru the sediments. This was done in **Table 2-18** and the overall average temperature of both sections was determined to be 156 °F, so that the average temperature change was  $52-156 = -104^\circ\text{F}$ . The average pressure of the entire column in the well was 9,087 psig, so that the average pressure change was  $9,087-0 = 9,087$  psig.

**Table 2-18: Determination of Average Pressure and Temperature for Example Problem 2-2**

Section Component	Vertical Depth (ft)	Temp (°F)	Pressure (psi)	Density (lb/gal)	Section Length (ft)	Avg Temp (oF)
Sea level	0	52	0			
Seafloor	4000	40	2904	14.15	4000	46
Top of Sediments	4000	40	2904			
Total Depth	25000	315	18148	13.73	21000	178
Overall Average			9074			156

The density of the mud at 25,000 ft is shown in Table 2-18 to be 13.73 lb/gal which would round to 13.7 lb/gal. The density of the mud at the seafloor is calculated to be slightly under 14.15 lb/gal, which would round to 14.1 lb/gal. The equivalent downhole hydrostatic density on bottom is shown in **Table 2-19** to be essentially the same as the mud density measured at the surface.

Table 2-19 computes the Thermal Coefficient of Expansion and Compressibility of the mud and calculates the density change caused by the average change in temperature and pressure of the entire column. Note that for thermal equilibrium with the surrounding formations, the average decrease in density due to the average temperature change is essentially offset by the average increase in density due to the average pressure change. The effective hydrostatic density of the mud is the same as the surface mud density. Of course, as soon as pumping is started, thermal equilibrium is disturbed, and the Equivalent Circulating Density, Equivalent Static Density and Equivalent Tripping Density would all begin to increase in response to cool mud being pumped downhole. As heat flowed between the surrounding casing strings, cement, and formations and the circulating mud, a zone around the bottom of the wellbore would also cool. After circulation is stopped, a gradual warming would take place that

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would decrease the density back towards the values calculated for thermal equilibrium. One purpose of the safety margins is to allow for such changes.

**Table 2-19: Density Change on Bottom due to downhole Temperature and Pressure**

Major Component	Volume Fraction	Density (lb/gal)	Thermal Coef of Expansion ( $^{\circ}\text{F}^{-1}$ )	Compressibility ( $\text{psi}^{-1}$ )	Density Change Due to Temp (lb/gal)	Density Change Due to Pressure (lb/gal)
Base Oil	0.54	6.6	4.00E-04	5.00E-06		
CaCl <sub>2</sub> Brine	0.2	9.8	2.89E-04	1.80E-06		
Low SG Solids	0.05	22	6.00E-05	2.00E-07		
Barite	0.21	35	2.00E-05	1.00E-07		
Surface Mud		13.97	2.81E-04	3.09E-06	-0.41	0.39

**2.7.5 Effect of Downhole Temperature and Pressure on Safety Margin for Deepwater Example**

Because a great deal of technical information about the Macondo well is available to the public in the form of official reports and trial documents<sup>45</sup> a Macondo drilling example will be used to illustrate the effect of downhole temperature and pressure on effective bottom-hole density in a deepwater setting.

**Table 2-20** is a summary of the WellSim 2000 well geometry and temperature input data used to model the temperature history for a hypothetical final bit trip for a Macondo type well. Though simplifications were required to make a successful modeling run, it will be shown that the magnitude of time dependent thermal effects on effective downhole density is small in this example and that the impact of the simplifications can therefore be neglected.

<sup>45</sup> Link to materials related to US District Court Eastern District of Louisiana CIVIL ACTION NO. 10-MD-2179 "J" <http://www.mdl2179trialdocs.com/index.php?page=phase1>

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**Table 2-20: Simplified WellSim 2000 Geometry Inputs for Macondo Drilling Case**

<b>Item</b>	<b>Measured Depth</b>	<b>True Vertical Depth</b>
	<i>ft-RKB</i>	<i>ft-RKB</i>
<b>Rotary</b> (65°F air temperature, 10 mph wind speed)	0	0
<b>Waterline</b> (65°F water temperature, 8 mph current)	67	67
Water Column (42°F geostatic)	3000	3000
<b>21” Riser from Mudline to Rotary</b> (40°F geostatic )	5067	5067
Sediment Column (48°F geostatic)	5321	5321
Sediment Column (65°F geostatic)	6217	6217
<b>6-5/8” drillpipe to Rotary</b>	6700	6700
Sediment Column (94°F geostatic)	7937	7937
Sediment Column (122°F geostatic)	9989	9989
<b>16” 109-ppf casing to mudline</b> (162°F geostatic)	11,585	11,585
<b>13-5/8” 88.2-ppf liner to 16” casing</b>	13,145	13,145
<b>11-7/8” 71.8-ppf liner to 13-5/8” liner. 5-1/2” drillpipe to 6-5/8” drillpipe.</b>	17,200	17,200
<b>9-7/8” 62.8-ppf liner to 11-7/8” liner. 5-1/2” heavy weight to 5-1/2” drillpipe.</b> (262°F geostatic)	18,360	18,360

The 14.0 ppg synthetic based drilling fluid modeled is described in *Example Problem 2-2* and the estimated thermal coefficient of expansion along with the estimated compressibility for the SBM are given in Table 2-19.

The simulation was started with the fluids in the well bore in thermal equilibrium with the surrounding water column and geostatic temperatures. Four days of continuous circulation at 300 gal/min followed by 4 days of no circulation was modeled in order to estimate the maximum effect of downhole temperature changes on effective bottom hole density.

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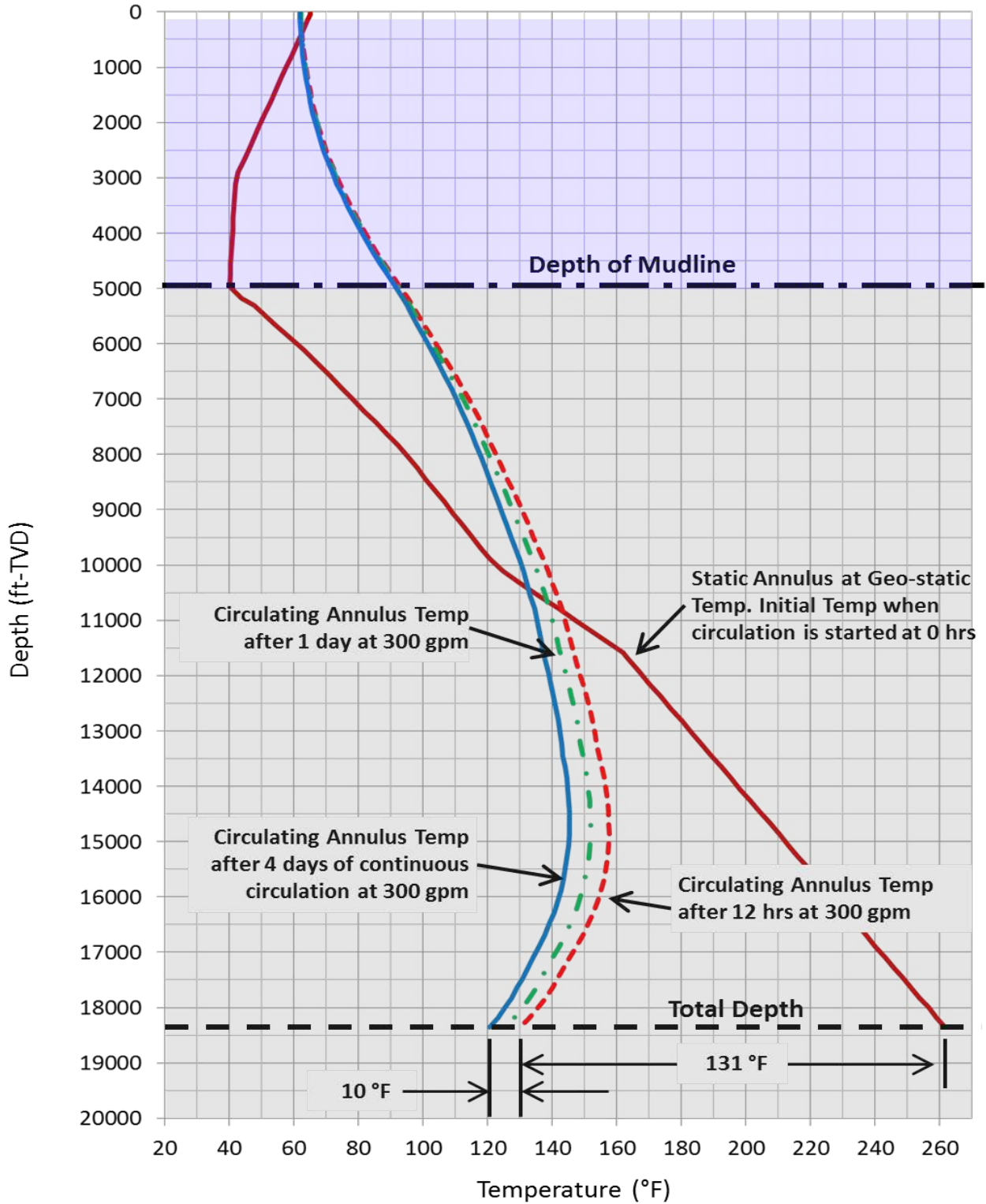


Figure 2-21: Wellbore Circulating Temperatures for Deepwater Example Case<sup>46</sup>

<sup>46</sup> calculated using WellSim 2000

**Figure 2-21** summarizes the 4 day circulation period as a series of annular temperature verses depth curves. The figure shows that a stable wellbore circulating temperature profile is established quickly. For this case the bottom-hole temperature fell by 131 °F during the first 12 hours of circulation. Then after the stable circulating profile is established it changes very little with time. Only an additional 10 °F of bottom-hole temperature decrease after circulating for an additional 3-1/2 days.

It is also useful to note that while circulating has a significant cooling effect on bottom-hole temperature relative to geostatic temperatures; circulation also warms a significant portion of the wellbore at shallower depths relative to geostatic and water column temperatures.

Instead of using an average temperature and average pressure approach described in **Section 2.7.1**, a *boot-strap* type spreadsheet model was written to use temperature verses depth output tables from WellSim for selected time steps and estimate both local annular downhole fluid densities and effective downhole densities.

First a density correction for temperature is calculated using the WellSim estimated temperature for the next depth interval (or depth cell) with **Equation 2.16**<sup>47</sup>

$$\Delta\rho_{T(i+1)} = \rho_0\beta(T_0 - T_{i+1})$$

**Equation 2.16: Density Correction for Local Temperature**

Where:

$i$  = depth interval number or depth cell number;  $i=0$  is at the surface.

$\Delta\rho_{T(i+1)}$  = density correction for local temperature in cell  $i+1$ ;

$\rho_0$  = a reference density measured at a reference temperature of  $T_0$ ;

$\beta$  = coefficient of thermal expansion of the fluid;

$T$  = the local annulus fluid temperature

Because the pressure for the next cell is unknown and is dependent on the density of the fluid in the next cell, the density correction for pressure in the next cell is approximated by using the pressure in the current cell<sup>48</sup>. This approximation is appropriate because the change in pressure from cell to cell is small resulting in even smaller changes to the correction.

$$\Delta\rho_{P(i+1)} = \rho_0c(P_i - P_0)$$

**Equation 2.17: Density Correction for Local Pressure**

<sup>47</sup> Equation 2.16 is Equation 2.1 in a numerical form of notation.

<sup>48</sup> **Equation 2.17** is Equation 2.8 in a numerical form of notation.



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Where:

$i$  = depth interval number or depth cell number;  $i=0$  is at the surface.

$\Delta\rho_{P(i+1)}$  = density correction for local pressure in cell  $i+1$ ;

$\rho_0$  = the fluid density measured at the reference pressure,  $P_0$ ;

$C$  = the compressibility of the fluid; and

$P$  = the pressure of the fluid

The total density correction and local fluid density for the next cell can then be calculated.

$$\Delta\rho_{i+1} = \Delta\rho_{T(i+1)} + \Delta\rho_{P(i+1)}$$

**Equation 2.18: Total Density Correction for Local Pressure and Temperature**

$$\rho_{i+1} = \rho_0 + \Delta\rho_{i+1}$$

**Equation 2.19: Local Fluid Density corrected for Pressure and Temperature**

Where:

$\Delta\rho_{i+1}$  = total density correction for cell pressure and temperature

$i$  = depth interval number or depth cell number;  $i=0$  is at the surface.

$\rho_{i+1}$  = local fluid density corrected for pressure and temperature; and

$\rho_0$  = the fluid density measured at the reference temperature and pressure;

Once the density of the fluid in the next cell is calculated, the pressure in the next cell can be calculated by boot-strapping the current cell pressure down into the next cell. Note that the exact constant of 12/231 psi/(ft-ppg) for field units conversion was chosen for **Equation 2.20** because the commonly used value of 0.052 psi/(ft-ppg) is given to only two significant figures.

$$P_{i+1} = P_i + (12/231)(D_{i+1} - D_i)\rho_{i+1}$$

**Equation 2.20: Local Pressure**

Where

$i$  = depth interval number or depth cell number;  $i=0$  is at the surface.

$P$  = pressure in lb/in<sup>2</sup>;

$D$  = true vertical depth in ft; and

$\rho$  = density in lb/gal.

Once the pressure in the next cell has been determined, the current depth is indexed to the next depth interval in the WellSim output table and the process repeated until the depth of interest or total depth ( $i=n$ ) is reached.

Finally, the effective density for each cell can be calculated using

$$\bar{\rho}_i = \frac{P_i}{(12/231)D_i}$$

**Equation 2.21: Effective Downhole Density**

Where

$i$  = depth interval number or depth cell number;  $i=0$  is at the surface.

$P$  = pressure in lb/in<sup>2</sup>;

$D$  = true vertical depth in ft; and

$\rho$  = effective density in ppge (pounds per gallon equivalent).

**Example Problem 2-3: Boot-strap Method for Modeling Temperature and Compressibility Effects**

Estimate (1) the local density and (2) the effective downhole density at a depth of 1010-ft by boot-strapping pressure estimates from a shut-in surface choke pressure of 250-psig to the pressure in the annulus at 1010 ft-TVD.

Assume the density of the SBM is measures 14.0 at 70°F and atmospheric pressure. The thermal coefficient of expansion and compressibility for the drilling fluid is estimated to be  $2.81 \times 10^{-4} \text{ } ^\circ\text{F}^{-1}$  and  $3.09 \times 10^{-6} (\text{psi})^{-1}$  respectively. **Table 2-21** provides temperature estimates verses depth for the first seven depth cells down to 1010 ft-TVD.

**Solution:** Because the depth intervals are relatively small the boot-strapping process can be simplified by ignoring the annular fluid temperature of 61.9°F at the choke. The density correction for temperature for the 0 to 45 ft-TVD depth interval is calculated using Equation 2.16 and density correction for pressure is calculated using Equation 2.17,

$$14.0(2.81 \times 10^{-4})(70 - 65.0) = 0.0319 \text{ lb/gal}$$

Adding the two corrections (Equation 2.18) results in a total density correction of:

$$0.0318 + 0.0108 = 0.0427 \text{ lb/gal}$$

Adding the total density offset to the reference density (Equation 2.19) then yields an approximate local density over the 0 to 45 ft-TVD depth interval

$$14.0 + 0.0427 = 14.0427 \text{ lb/gal}$$

$$14.0(3.09 \times 10^{-6})(250 - 0) = 0.0108 \text{ lb/gal}$$

**Table 2-21: Annular Fluid Temperature versus Depth after 4 days of circulation**

Depth	Temperature
<i>ft-TVD</i>	<i>°F</i>
0	61.9
45	61.9
172	62.0
381	62.2
591	62.5
800	62.8
1010	63.3

Once a corrected density is determined, the pressure at the bottom of the 0 to 45 ft-TVD depth interval can be calculated using Equation 2.20

$$250 + (12/231)14.0427(45 - 0) = 282.83 \text{ lb/in}^2$$

The process is then repeated for each subsequent depth interval. **Table 2-22** summarizes the local densities and pressures calculated for each of the upper seven cells.

**Table 2-22: Boot-strapped Pressure versus Depth**

Depth	Local Density	Annulus Pressure
<i>ft-TVD</i>	<i>lb/gal</i>	<i>psig</i>
0		250
45	14.043	282.83
172	14.044	375.48
381	14.047	527.99
591	14.052	681.29
800	14.058	833.91
1010	14.062	987.32

Using this method and grid size, the local density at 1010 ft-TVD calculates to be 14.062 lb/gal. This density should not be confused with the effective density of the fluid column above 1010 ft-TVD along with the 250-psi of trapped surface pressure. The effective downhole density at 1010 ft-TVD is calculated by plugging the annulus pressure at 1010 ft-TVD into Equation 2.21

$$\frac{987.32}{(12/231)1010} = 18.818 \text{ ppge}$$

It is important to note that the 18.818 is a calculated equivalent density or pressure gradient that assumes atmospheric pressure at the surface and is not an estimate a physical property of the fluid like the local density is.

*In conclusion, it is left to the reader to calculate the pressure and corresponding effective downhole density at 1010 ft-TVD if the choke is opened and the 250 psi surface pressure is allowed to bleed off (answer: 736.75 psig and 14.042 ppge). Note: subtracting 250 psi from 987.32 psig results in a value of 737.32 psig which is 0.57 psi different. While this error is insignificant in practical terms, it is noticeable when calculations are carried out to 5 significant figures as is required when accounting for temperature and pressure effects on drilling fluid density.*

**Figure 2-22** summarizes the WellSim 2000 temperature verses depth outputs when the pumps are stopped after 4 days of continuous circulation in the Deepwater Example Case. The model was run for an additional 4 simulation days without circulation and while the model predicts wellbore temperatures do not fully return to geo-static thermal equilibrium in that time, it does show that in practical terms 2 days of static time returns the well to geo-static thermal equilibrium. Also, the bottom-hole temperature rises about 71 °F within the first 4 hours of static time. This is about half of the 141 °F bottom hole temperature increase required to restore bottom-hole annulus temperature to geo-static equilibrium.

The maximum impact of wellbore temperature changes on local annular fluid density and effective downhole density for the Example Case are summarized in **Figure 2-23**. The temperature profile in the wellbore annulus immediately after the pumps are stopped is plotted along with the geo-static temperature profile in **Figure 2-23a**. It is again important to note that 4 days of circulation cooled the deeper section of the wellbore while warming the upper section and that at a depth of about 10,500 ft-TVD, (crossover point) WellSim predicts no difference in temperature for the two conditions.

**Figure 2-23b** shows the local density verses depth for both the pumps off and geo-static conditions. These densities were estimated by boot-strapping pressure and density down the annulus from a surface pressure of 0 psig and a reference density of 14.0 lb/gal at 70 °F and atmospheric pressure (as described previously in this section). While not shown in Figure 2-23, it was necessary to calculate the pressure at each depth interval in order to generate Figure 2-23b. Those pressures were used to calculate the effective down-hole density exerted by the total annular fluid column assuming the annulus is open to the atmosphere (see Equation 2.21) and the results are shown in **Figure 2-23c**.

The WellSim temperature modeling for this example indicates that the local bottom-hole density of the fluid in the annulus could decrease as much as 0.56 lb/gal<sup>49</sup> after the pumps are stopped. At first glance this may appear to indicate the potential for a significant loss in bottom-hole pressure during the course of a trip. However, focusing only on local density at the bottom of the hole ignores the fact that local density generally increased in the upper half of the wellbore. In fact when the bottom-hole pressures for the “*just after 4 days of circulation*” condition and the “*geo-static equilibrium*” condition are correctly calculated, the actual maximum possible loss in bottom-hole pressure is approximately 50 psi or 0.05 ppge at 18,360 ft-TVD.

The reader should take particular note that the two values of effective density at total depth (14.06 ppge when the pumps are stopped and 14.11 ppge when the well returns to geo-static equilibrium, *see Figure 2-23c*) both round to 14.1 ppge and the traditional accuracy with which density is measured in a drilling and completions setting is one tenth of a pound per gallon.

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<sup>49</sup> From 14.38 to 13.82 lb/gal, see Figure 2-23b.

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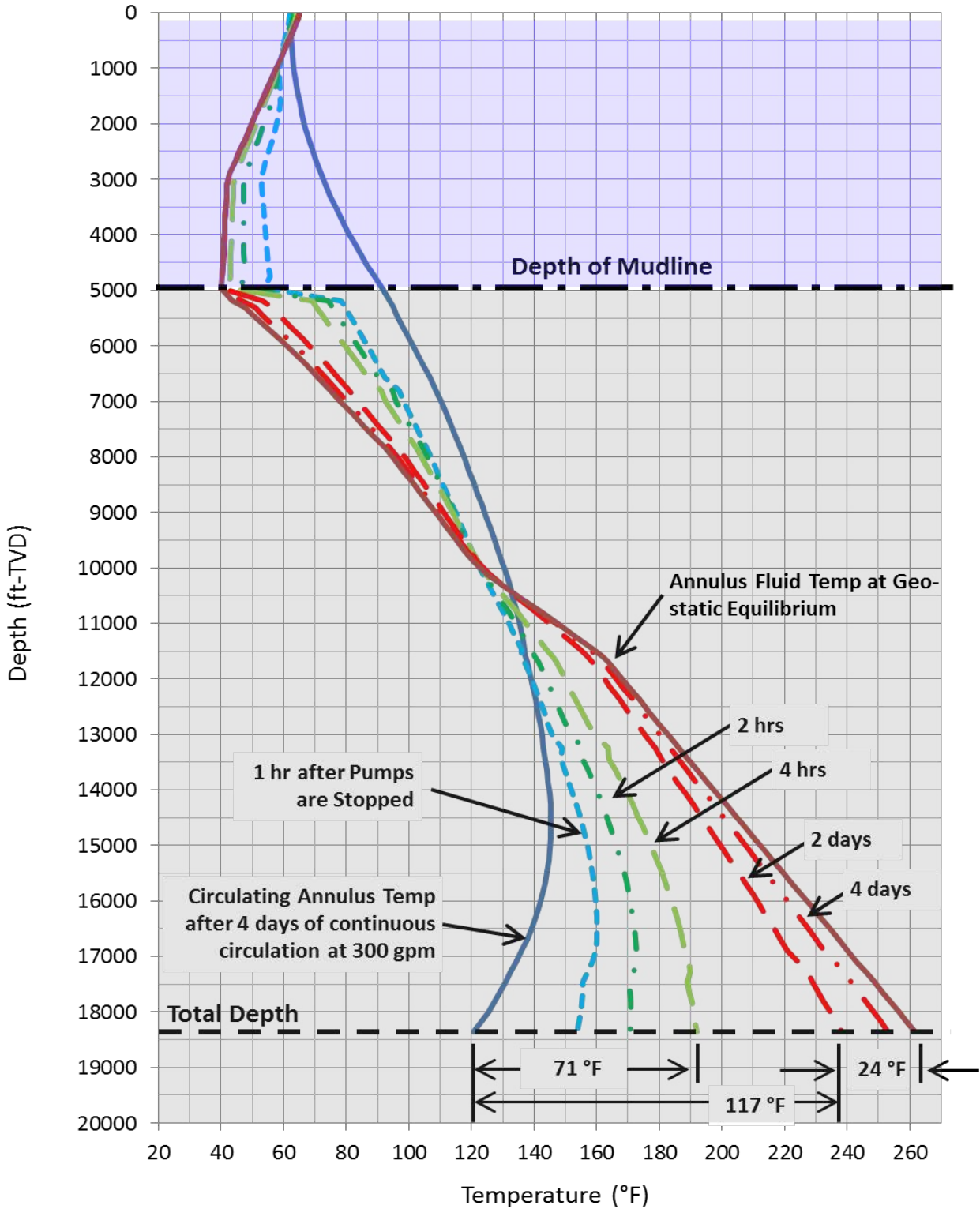


Figure 2-22: Wellbore Temperatures after Pumps are Stopped<sup>50</sup> for Deepwater Example Case

<sup>50</sup> Well continuously circulated for 4 days. Calculated using WellSim 2000

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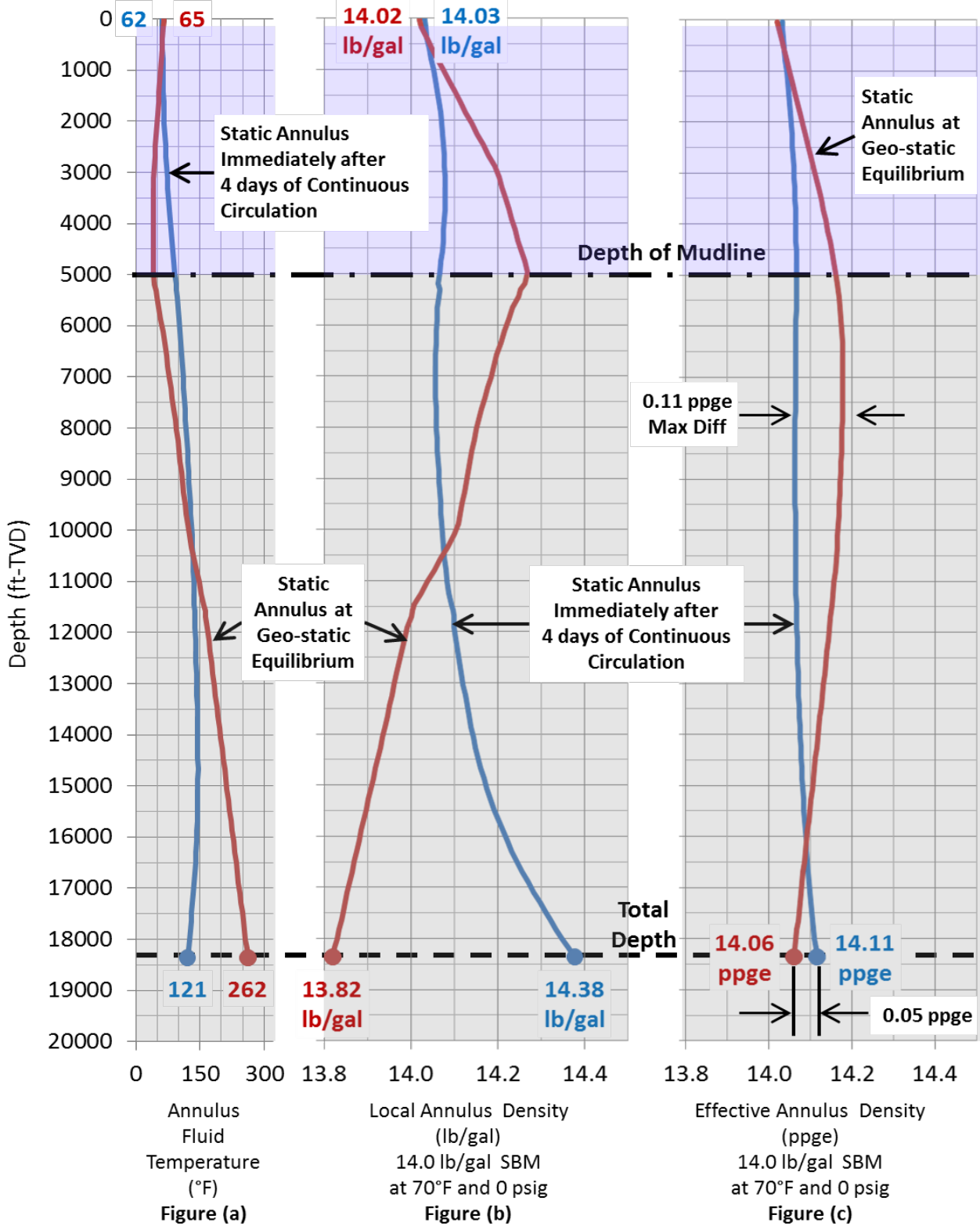


Figure 2-23: Effect of Downhole warming on Local Fluid Density and Effective Downhole Density<sup>51</sup>

<sup>51</sup> For Deepwater Example Case and Calculated using WellSim 2000.

### 2.7.6 Discussion of Safety Margins

An obvious question is: *Why not require the current bottom-hole pressure, which could be expressed as a current downhole equivalent static density, to always be used in safety considerations instead of equivalent surface mud density?* Theoretically, this would reduce uncertainty and would allow only the needed safety margin to be applied. This approach is very desirable because it could reduce the number of casing strings required to reach a given target depth and make more targets accessible in high pressure environments. This is a difficult goal to achieve and for most wells would be neither practical nor necessary. Managed pressure drilling techniques are a step in this direction and considerable research and development efforts are being expended in developing computer models that could achieve this goal as part of a managed pressure drilling process. This effort will always be hampered by the complex behavior of unsteady state flow of non-Newtonian drilling fluids with complex flow geometry and boundary conditions. Wells containing many casing strings will generally have insufficient known information about the heat transfer coefficients, thermal conductivity and heat capacity of the various layers outside of the wellbore fluids, as well as insufficient information about non-uniform formation properties. The models currently available generally use a layer cake approach and do not account for the effect of vertical heat flow in the high conductivity steel casing or vertical heat flow between formations.

At present, the goal of precisely predicting downhole equivalent density is closest to being achieved when a Pressure While Drilling (PWD) system is used. The cost of PWD tools is more easily justified on a routine basis for the large drilling vessels used for deepwater wells. Data transmission rates to send information to the surface are slow and other downhole information regarding directional surveys and formation properties may take precedence over downhole pressure information. Current practice is to transmit PWD pressures using MWD technology occasionally and also store the PWD information in a memory tool that can be downloaded after the BHA is pulled to the surface at the end of a bit run. Equivalent downhole static density can be determined at various depths and times after the fact and then used to calibrate and improve the computer models.

**Figure 2-24** is a graphical depiction of the drilling fluid density, important pressure gradients expressed as equivalent densities and safety margins for a deepwater example case. All of the values are based on un-corrected surface measurements as is traditionally done when PWD data is not available. After casing was cemented and tested new formation was drilled and a FIT performed. The casing shoe tested to a surface pressure of 1465 psi with a column of 13.4 lb/gal<sup>52</sup> (surface) drilling fluid to a depth of 17600 ft-TVD. Using this information the fracture pressure gradient would be:

$$13.4 + \frac{1465}{0.052(17600)} = 15.0 \text{ ppge (surface)}$$

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<sup>52</sup>For the purposes of this discussion when density units are written in the form “lb/gal” an actual physical density is indicated. When “ppge” is used, a pressure gradient at a point in the well is indicated.

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Normally if a PWD tool is not in use the “*surface*”<sup>53</sup> designation is omitted because there are no “*downhole*”<sup>54</sup> based measurements. The 15.0 ppge (surface) fracture gradient limit is depicted as a solid green line in Figure 2-25 and a 0.5 ppge fracture safety margin is labeled and depicted as a gray band.

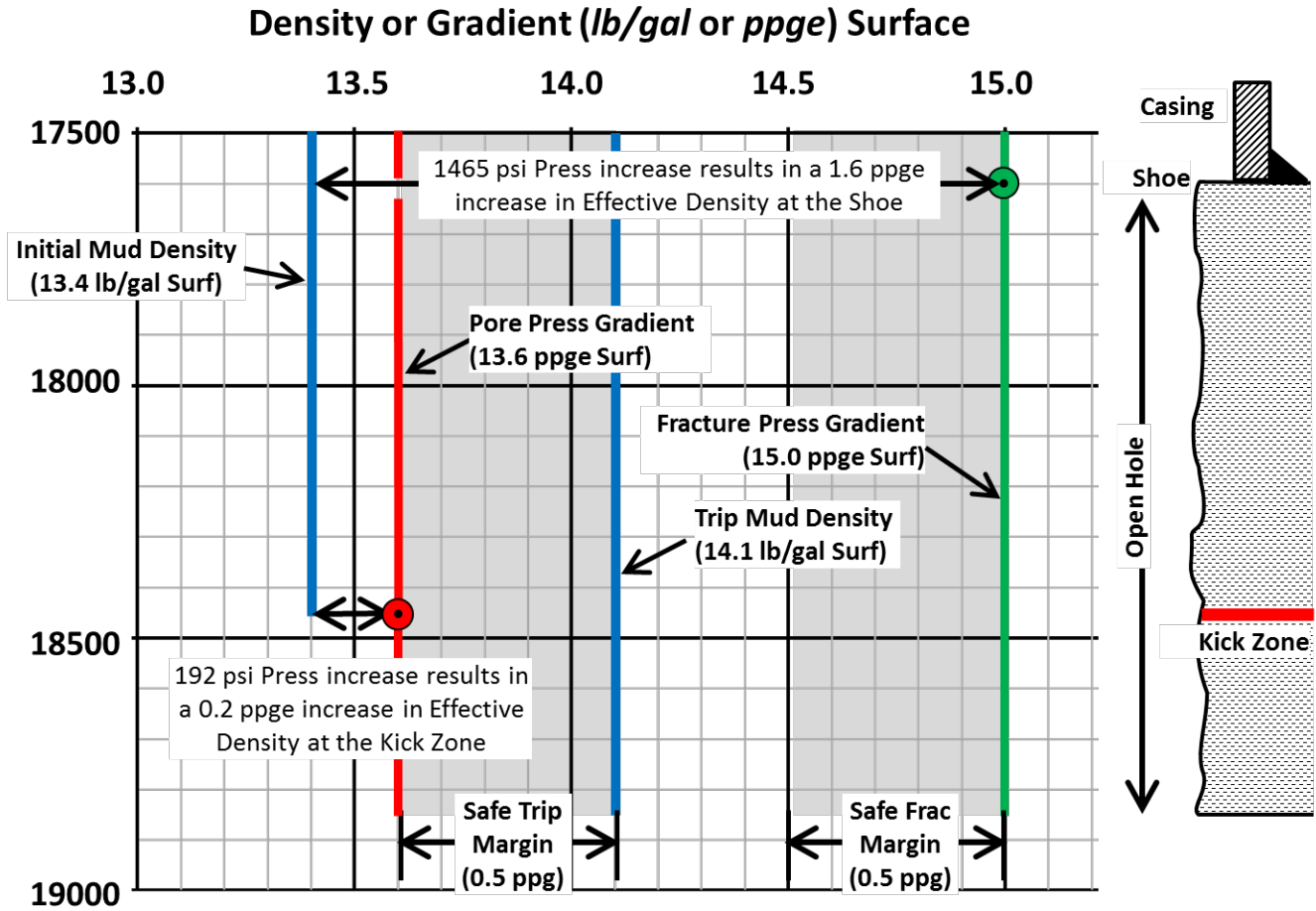


Figure 2-26: Example Pressure Gradients and Safety Margins expressed in terms of Surface Measurements

Once the fracture limit was verified with the FIT, drilling began. After drilling 850 ft a drilling break occurred and as per operator and contractor well control policy the driller performed a precautionary flow check. The flow check was positive and the well was promptly shut-in on a small gain. The pore pressure can be calculated using the 192 psi shut-in drillpipe measurement, 13.4 lb/gal (surface) mud density and 18450 ft-TVD fluid column height.

$$13.4 + \frac{192}{0.052(18450)} = 13.6 \text{ ppge (surface)}$$

<sup>53</sup> Surf and S are also commonly used to indicate a surface based determination.

<sup>54</sup> DH is commonly used to indicate down hole based measurements.



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Kill mud with a density greater than the 13.6 ppge (surface) pore pressure gradient was then used to finish the hole section at a total depth of 18950 ft. After reaching TD, the mud was conditioned and a safe trip margin of 0.5 ppge established by increasing the mud density to 14.1 lb/gal (surface). Figure 2-27 depicts the pore pressure gradient as a solid red line and the safe trip margin as a labeled grey band.

When PWD data are available, safety margins can be based on either equivalent surface densities or on equivalent downhole densities. **Figure 2-28** shows PWD data for the deepwater well example previously discussed. The data downloaded from the PDW tool is shown as orange circles and corresponds to measurements recorded during the trip out of the hole after reaching TD. The drill string is was pumped out due to hole conditions and in order to mitigate potentially high swab effects. The mud had been in the well long enough for temperatures to stabilize allowing an accurate equivalent downhole static density determination of 14.2 ppge (downhole) to be made for the 14.1 lb/gal (surface) mud in the well. It is important to note that for this case the effect of increasing pressure was measured as 0.1 ppg greater on effective fluid density than the effect of increasing temperature.

If a PWD tool had been run for the previously discussed FIT in this example review of the downhole pressure data would likely have shown about a 1465 psi pressure increase from 12,400 psia to 13,835 psia. The downhole equivalent mud weight for the FIT would then calculate to be:

$$\frac{13835 - 15}{0.052(17600)} = 15.1 \text{ ppge (downhole)}$$

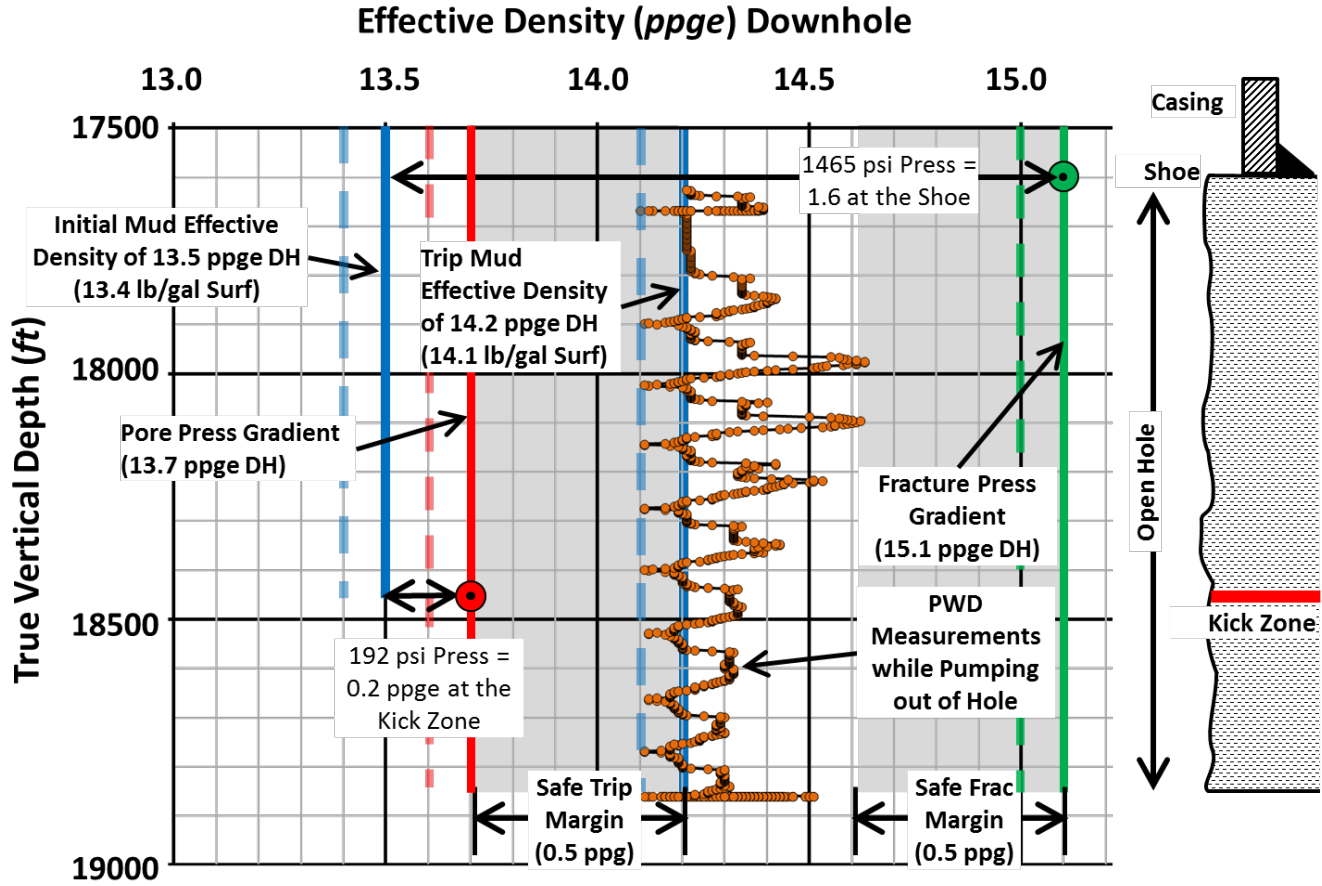
This downhole fracture limit is depicted as a labeled solid green line in Figure 2-28 with the corresponding surface fracture limit indicated as an unlabeled dashed green line. The 0.5 ppg fracture safety margin is shown as a labeled gray band.

Similarly review of the PWD data for the previously discussed kick in this example would likely also show a pressure increase of 192 psi from 12,967 to 13,159 psia for a downhole equivalent mud weight of :

$$\frac{13159 - 15}{0.052(18450)} = 13.7 \text{ ppge (downhole)}$$

This downhole pore pressure gradient determination is indicated by a labeled solid red line in Figure 2-28 with the corresponding surface determination as a red unlabeled dashed line and the 0.5 ppg safe trip margin as a labeled gray band.

Figure 2-28 shows that the effective mud weight measured by the PWD tool varies over a significant range in response to pumping and pipe movement. When pumping, the effective equivalent downhole mud density increased to as much as 14.63 ppge. When pulling pipe to break connections, it fell to as low as 14.1 ppge.



**Figure 2-28: Example PWD Data for Pumping out of the Hole Expressed as Down Hole Gradients**

The Trip Safety Margin and the Fracture Safety Margin for the example of Figure 2-28 were both 0.5 ppge. The pumps were used and the pipe rotated when pulling pipe out of the open-hole section so that a large trip margin was not needed in this example. However, if the safe operating window of surface mud weights between the Trip Safety Margin and the Fracture Safety Margin was not as large, the equivalent downhole mud density could have been allowed to move further into the Trip Safety Margin and the Fracture Safety Margin ranges as long as the entire 0.5 ppge margin was not broached. When drilling in an abnormal pressure transition zone, the safe operating window diminishes as the depth of the next approved casing seat is approached.

## 2.7.7 Selection of Safety Margin needed to account for Mud Warming

For most wells, warming of wellbore fluids does not play a significant role in the selection of the appropriate Trip Margin. No blowout case history in which warming was demonstrated to cause the blowout was found in the review of blowouts done in this study. The usual controlling factors in the selection of the Trip Margin are uncertainties in regard to the pore pressure gradients of the exposed permeable zones and the possible effect of swabbing due to upward pipe movement. However, possible exceptions in which warming could have a significant effect are for drilling and completion operations in very deep wells. There have been incidents reported in the literature in which a well began flowing after all pipe was out of the well, and also incidents reported when the well began flowing when tripping pipe into a High Temperature High Pressure (HTHP) well. Several recent papers have focused on modelling dynamic swab pressures that occur when tripping pipe into the well to explain the reported incidents. Such incidents could also have been caused by swabbing small amounts of gas into the wellbore when leaving bottom, and this gas expanding sufficiently during upward gas migration to reduce the bottom-hole pressure below the formation pore pressure. Small hydrocarbon bubbles migrate slowly and would not have a significant effect until the migrating bubbles were close to the surface. A third possible explanation is loss of hydrostatic pressure due to a decrease in fluid density resulting from a gradual warming of the well fluids after circulation is stopped.

The situations in which the effect of fluid warming is most likely to be significant during tripping are deep HTHP drilling operations conducted with an oil-base mud and deep completion operations conducted with a clear brine completion fluid. The main completion operation that could involve tripping with open perforations after perforating is a frac-pack or gravel-pack operation. Most well completions are designed so that tripping operations with newly opened perforations are avoided. In the event it will be necessary to trip pipe out of the well with open perforations, thermal modelling could be performed by the completion fluid specialist. On deep HTHP wells, the drilling fluid specialist could perform the thermal modelling calculations. Such modelling is often done on deep HTHP wells by the drilling fluid and/or well monitoring Service Company as part of well planning and well monitoring services. The calculated circulating temperature profile is generally updated during drilling operations for each bit run. Temperature can frequently be obtained from MWD tools. An example of a calculated circulating temperature profile is shown in **Figure 2-29**. The maximum average density change due to fluid warming can be easily estimated based on the average temperature difference between the geothermal temperature profile and the circulating temperature profile just prior to the tripping operations. The trip margin could then be selected based on calculated swab pressures and maximum possible density loss due to warming of wellbore fluids.

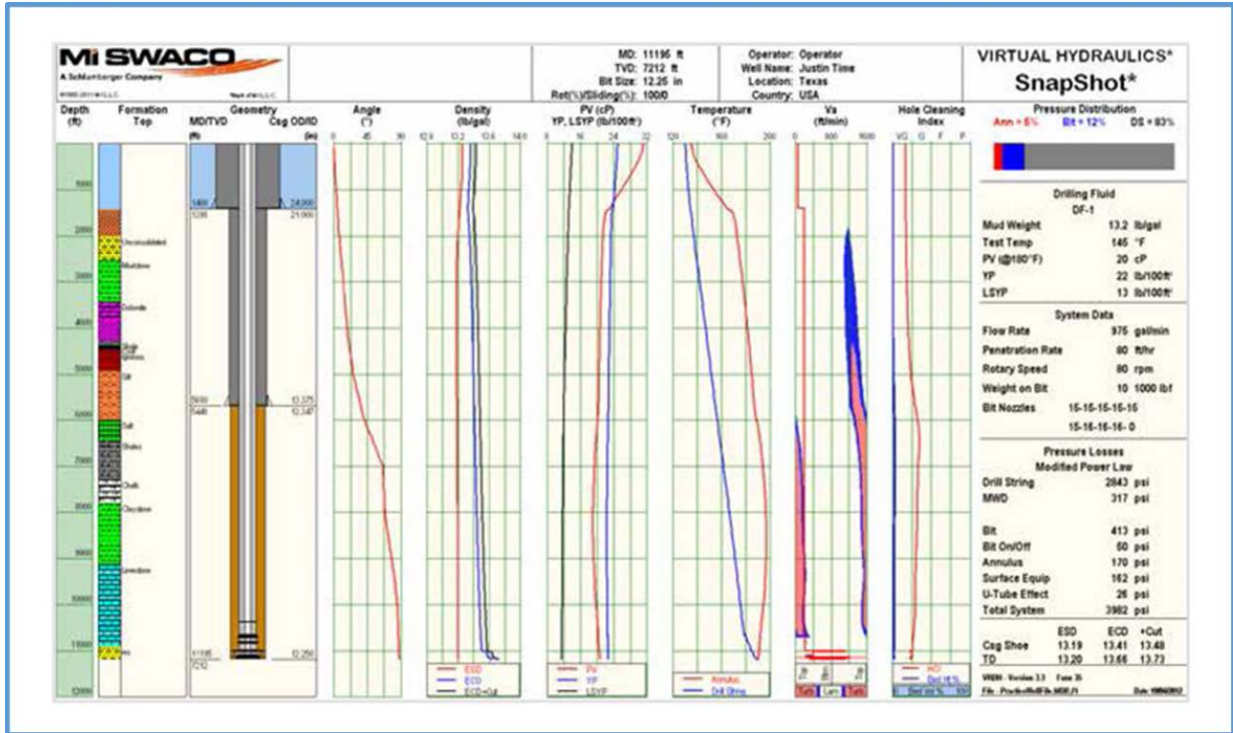


Figure 2-29: Example Virtual Hydraulics Snapshot showing computed ECD, ESD, and Circ Temp Profile<sup>55</sup>

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<sup>55</sup> Courtesy of Schlumberger

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### 3 RECOMMENDATIONS RESULTING FROM COMPARATIVE ANALYSIS

The review of industry standards, guidelines, recommended practices, training programs and regulations made by this study indicated a vast improvement in the safety processes used by the oil and gas industry for blowout prevention since the 1970's when the first open enrollment available training program with hands-on live well training was started at LSU<sup>56</sup>. In these early training schools, it was recognized that more than half of all blowouts were initiated during tripping operations when pulling pipe out of the well. The story was told in early schools about the driller that was called on the carpet after his rig burned down during tripping operations and was told to fill the well and keep it full when pulling out of the hole. When the next well in the field also experienced a blowout during a trip, he was called on the carpet again and reminded that he was told to be sure and fill the well when pulling out of the hole. He explained, "*I didn't have to keep the hole full, it stayed full by itself.*"

This apocryphal story not only highlights the lack of organized training in the early oil field, it also highlights an interesting facet of well control culture and terminology. While "*be sure to keep the hole full*" can be interpreted literally to mean always keep the hole full, it has also evolved into a range of figurative admonitions. It is most often said as a reminder to be vigilant and continuously monitor the well for a kick. In this case, it is not only the act of keeping the hole full that is important, but rather keeping the hole full so that a kick can be detected as quickly as possible and the well shut-in to minimize shut-in pressures. The phrase can also be intended as a reminder to do anything in general carefully and correctly. It is likely that this meaning evolved from the fact that there are several virtuous benefits to keeping the well full with regard to well control.

Training today is much more effective and the frequency of blowouts initiating during tripping operations in the OCS has clearly been reduced. Three of the 19 (16%) well control events on the OCS identified in this study during the 2005 to 2015 time period were related to tripping during drilling and completion operations (*see Section 7*). An additional two (11%) occurred during workover and recompletion operations. It is important to understand that while useful, these observations are not rigorously determined from a statistically representative sample. Of equal importance is the fact that training remains an area where additional improvements can be achieved.

The LSU petroleum engineering faculty has maintained close ties with Petrobras in Brazil and has participated in some of their education and training efforts. A recent SPE distinguished lecture by Dr. Otto Santos has pointed out that Brazil has achieved a more than a 50% reduction in the cumulative number of blowouts per 100,000 wells drilled since initiating an intensive training effort in 1982. This program has increased the number of well control trained and certified rig workers by more than 500%. Petrobras experienced eleven blowouts during drilling and completion operations during the 2005 to 2015 study period, none of which occurred while tripping pipe. Petrobras did experience two blowout events during this period related to tripping operations during workovers.

Improved well control equipment is another area where the offshore oil and gas industry has made significant improvements. This is also true for safety-related equipment for tripping operations. Essentially all rigs operating on the OCS now have the capability of continuously filling the well when

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<sup>56</sup> Most of the well-control training available at that time was in-house training and all of the training programs that utilized field scale wellbores, circulating, and choke systems were available to only the personnel employed by or sub-contracted to the companies that owned and operated the facilities.

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tripping out of the hole. The antiquated approach of filling the hole every five stands or before hydrostatic pressure is decreased by 75 psi as per CFR 250.456 is a hold-over from when the most accurate instrumentation on the rig was a stroke counter. Today, the hole can be kept full continuously and the required fill-up volume checked every five stands.

A 75 psi decrease in hydrostatic pressure is equivalent to 1.4 ppge at 1000 ft and 0.14 ppge at 10,000 ft. This provides a perspective on the relationship between hydrostatic pressure loss and its effect in reducing equivalent mud density.

As a result of the work done in this study, the following recommendations for the improvement of safety and reduction of hazards as related to well control were reached.

- Enhanced use of trip books and trip sheets are recommended for further reducing human errors and kick size when kicks are swabbed during tripping operations.
- When seepage is present, BSEE regulations should address the maximum time between hole-fill-up volume checks and not just maximum fluid level reductions.
- Most rigs in BSEE jurisdiction now have trip tank arrangements capable of keeping the hole full all of the time. BSEE should consider requiring that the well be kept full during tripping operations instead of allowing a 75 psi reduction in hydrostatic pressure between hole-fill-ups.
- Trip margins need to be verified as being sufficient before tripping after perforating in gravel pack or frac pack completions.
- The use of floats or downhole check valves is recommended as a standard operating procedure for drilling and completion operations with the provision that they could be omitted in a particular situation with sufficient justification.
- Presentations describing methodologies for determining when the effect of temperature and pressure on drilling and completion fluid density has a significant effect on changes in downhole equivalent density and when the effect of swabbing has a significant effect on changes in downhole equivalent density should be presented to BSEE field operations personnel in workshops held at BSEE district offices.
- No large gaps in BSEE regulations regarding tripping and swab effects have been identified. The gradual move from prescriptive regulations to performance-based rules and guidelines developed by the operator and verified by BSEE appears to be an effective approach for systematic improvement.
- A technical paper should be prepared for presentation at an SPE/IADC Well Control Conference describing the results of this BSEE-funded study.



#### **4 EVALUATE 30 CFR 250.455, 250.401, 250.107, AND 250.500**

30 CFR 250.455, 250.401, 250.107 and 250.500 with regard to well control during tripping and swabbing were evaluated to identify any gaps and recommend any improvements to BSEE. The requirement to evaluate CFR 250.401 was been met by evaluating 250.703 which replaced it in the most recent revision to the regulations. Other related sections were also included in the evaluation, as explained below.

BSEE has regulations and policies that utilize performance-based (goal-oriented) rules in addition to prescriptive (experienced-based) rules. A performance-based regulation specifies the outcome required but does not specify how to reach the outcome. By focusing on outcomes, performance-based standards allow more technological innovation for solving challenges such as blowout prevention. Conformance with prescriptive rules is easier to evaluate. Risk-based analysis is widely used for assessing compliance with performance-based goals and objectives and in the evaluation of a new methodology. Risk-based analysis can be used to help evaluate if changes in a planned procedure are as safe as, or safer than, the alternative conventional methodology.

The BSEE regulations reviewed in this work are supplemented in practice by prescriptive policies implemented by the various BSEE regional offices. Prescriptive policies in regard to “safe tripping margins” are important and are being addressed in several other sections of this report.

##### **4.1 Evaluation of CFR 250.107**

CFR 250.107 is a general requirement to protect HSE and is shown below. Paragraphs (a)(3-4), (c)(3) and (d) are new items effective July 28, 2016.

###### **§250.107 What must I do to protect health, safety, property, and the environment?**

(a) You must protect health, safety, property, and the environment by:

(1) Performing all operations in a safe and workmanlike manner;

(2) Maintaining all equipment and work areas in a safe condition;

(3) Utilizing recognized engineering practices that reduce risks to the lowest level practicable when conducting design, fabrication, installation, operation, inspection, repair, and maintenance activities; and

(4) Complying with all lease, plan, and permit terms and conditions.

(b) You must immediately control, remove, or otherwise correct any hazardous oil and gas accumulation or other health, safety, or fire hazard.

(c) *Best available and safest technology.* (1) On all new drilling and production operations and, except as provided in paragraph (c)(3) of this section, on existing operations, you must use the best available and safest technologies (BAST) which the Director determines to be economically feasible whenever the Director determines that failure of equipment would have a significant effect on safety, health, or the environment, except where the Director determines that the incremental benefits are clearly insufficient to justify the incremental costs of utilizing such technologies

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(2) Conformance with BSEE regulations will be presumed to constitute the use of BAST unless and until the Director determines that other technologies are required pursuant to paragraph (c)(1) of this section.

(3) The Director may waive the requirement to use BAST on a category of existing operations if the Director determines that use of BAST by that category of existing operations would not be practicable. The Director may waive the requirement to use BAST on an existing operation at a specific facility if you submit a waiver request demonstrating that the use of BAST would not be practicable.

(d) BSEE may issue orders to ensure compliance with this part, including, but not limited to, orders to produce and submit records and to inspect, repair, and/or replace equipment. BSEE may also issue orders to shut-in operations of a component or facility because of a threat of serious, irreparable, or immediate harm to health, safety, property, or the environment posed by those operations or because the operations violate law, including a regulation, order, or provision of a lease, plan, or permit.

As stated previously in the comparative analysis section of this report, requirements similar to CFR 250.107 are believed nearly universal among the jurisdictions evaluated. The Health, Safety, and Environmental (HSE) mission and guiding principles of industry organizations and their members, such as API and IADC, as well as the professional ethics codes of professional engineering societies and state engineering registration boards also subscribe to similar principles. Most states have similar provisions for authority to inspect, access records and shut down operations determined to be unsafe or otherwise in violation of regulations.

The phrases “safe and workmanlike manner” and “safe condition” appearing in (a)(1-2) have legal meanings; their full interpretation is outside the scope of this report. These terms depend to some extent on established industry norms, as does the term “recognized engineering practices” which appears in (a)(3).

The phrase “*reduce risks to the lowest level practicable*” in (a)(3) conveys a general idea that would be difficult to define or enforce on a technical level. Applying risk analysis in a mathematical manner to an oil and gas operation is a very inexact process because it is impossible to gather the needed statistical base, given the wide diversity of operations and geologic conditions. Invariably, the activities grouped together in attempting to define the risk of a similar occurrence have so many differences in the conditions that led to the event being analyzed, that the mathematical process does not produce meaningful results.

The term “*best available and safest technology*” would pose the same challenges of interpretation except that (c)(2) states that “conformance with BSEE regulations will be presumed to constitute the use of BAST unless and until the Director determines that other technologies are required...” The existing BSEE regulations provide a starting point for defining BAST but also reserve the Director’s authority to expand or modify the determination on a case-by-case basis.

The requirements of Subpart S for a SEMS program also address most of the HSE objectives in 250.107 relevant to well control during tripping when the activity is identified in the SEMS program. The advantages of addressing the objectives like “*reduce risks to the lowest level practicable*” and BAST through a SEMS approach were discussed previously in **Section 2.6**.

SEMS and BAST provide overlapping layers of protection and alternative tools through which the same regulatory objectives can be achieved. The SEMS approach is consistent with a performance-based

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approach to regulation while the BAST approach is more prescriptive in that the Director has the responsibility to define BAST. The SEMS approach requires the SEMS owner to use hazard analysis to develop a proposed method of work with written practice and procedures, effectively proposing the BAST for the given activity. This “*proposed BAST*” is subject to BSEE review and approval through audits and permit applications. By contrast, CFR 250.107 presents the regulation as the starting point for BAST. It is impractical for the regulation to cover every aspect of BAST for every possible activity or to remain entirely current, as the regulation will always lag technological advance. The dependence on the regulation as the starting point for BAST can therefore create “friction” that opposes the intent of the regulation, which is to use the best available solution. In addition, SEMS provides a more systematic approach to both identify and implement BAST, including defined controls for management, oversight and continuous improvement.

### 4.2 Evaluation of CFR 250.703 (replaced CFR 250.401)

The evaluation of CFR 250.401 requirement has been met by evaluating 250.703 which replaced 250.401 in the most recent revision to the regulations.

#### **§250.703 What must I do to keep wells under control?**

You must take the necessary precautions to keep wells under control at all times, including:

- (a) Use recognized engineering practices to reduce risks to the lowest level practicable when monitoring and evaluating well conditions and to minimize the potential for the well to flow or kick;
- (b) Have a person onsite during operations who represents your interests and can fulfill your responsibilities;
- (c) Ensure that the toolpusher, operator's representative, or a member of the rig crew maintains continuous surveillance on the rig floor from the beginning of operations until the well is completed or abandoned, unless you have secured the well with blowout preventers (BOPs), bridge plugs, cement plugs, or packers;
- (d) Use personnel trained according to the provisions of subparts O and S of this part;
- (e) Use and maintain equipment and materials necessary to ensure the safety and protection of personnel, equipment, natural resources, and the environment; and
- (f) Use equipment that has been designed, tested, and rated for the maximum environmental and operational conditions to which it may be exposed while in service.

The language in 250.703(e) requiring provisions “*necessary to ensure the safety and protection*” is similar to the language in 250.107 discussed in the previous section. The same observations made in Section 2.6 regarding SEMS and regulating good practice are relevant to this requirement.

Paragraph (c) creates a potential gap by being overly specific and naming the operator’s representative as someone who could provide continuous surveillance on the rig floor. Though the operator’s representative has to maintain well control qualifications, operator’s representatives are not normally considered qualified to operate the drilling contractor’s equipment except in extraordinary circumstances. In practice, only when the need to act is urgent and no qualified contractor personnel are

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available to take action would an operator's representative be expected to secure a well in a drilling or completions setting.

Naming the toolpusher position is another potential gap if the contractor's job description for that position does not universally require holders of that job title to be qualified to have the authority to secure the well.

The primary intent of the requirement is first to ensure that the rig floor is under continuous surveillance, second that the person providing the surveillance has the authority to secure the well, and third that the individual is qualified and capable of securing the well in a timely manner.

A secondary intent of the requirement is to indicate when continuous surveillance is not required. Again, the wording of the requirement creates a potential gap by being overly specific and stating that the well could be secured with BOP's alone. For example, a narrow interpretation of the requirement would suggest that continuous rig floor surveillance would not be required if the well were shut-in on a kick, even if surface pressure were high.

Referencing proper methods for securing the well by downhole isolation methods and methods for suspending operations (for example, prior to a storm evacuation) could eliminate this potential gap.

### **4.3 Evaluation of CFR 250.455**

CFR 250.455 is the lead requirement under the "Drilling Fluid Requirements" section of Subpart D. The requirements of this section most relevant to well control during tripping are 250.455, 456, and 457.

#### **§250.455 What are the general requirements for a drilling fluid program?**

You must design and implement your drilling fluid program to prevent the loss of well control. This program must address drilling fluid safe practices, testing and monitoring equipment, drilling fluid quantities, and drilling fluid-handling areas.

#### **§250.456 What safe practices must the drilling fluid program follow?**

Your drilling fluid program must include the following safe practices:

(a) Before starting out of the hole with drill pipe, you must properly condition the drilling fluid. You must circulate a volume of drilling fluid equal to the annular volume with the drill pipe just off-bottom. You may omit this practice if documentation in the driller's report shows:

(1) No indication of formation fluid influx before starting to pull the drill pipe from the hole;

(2) The weight of returning drilling fluid is within 0.2 pounds per gallon (1.5 pounds per cubic foot) of the drilling fluid entering the hole; and

(3) Other drilling fluid properties are within the limits established by the program approved in the APD.

(b) Record each time you circulate drilling fluid in the hole in the driller's report;

(c) When coming out of the hole with drill pipe, you must fill the annulus with drilling fluid before the hydrostatic pressure decreases by 75 psi, or every five stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure. You must calculate the number of stands of drill pipe and drill collars that you may pull before you must fill the hole. You must also calculate the equivalent drilling fluid volume

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needed to fill the hole. Both sets of numbers must be posted near the driller's station. You must use a mechanical, volumetric, or electronic device to measure the drilling fluid required to fill the hole;

(d) You must run and pull drill pipe and downhole tools at controlled rates so you do not swab or surge the well;

(e) When there is an indication of swabbing or influx of formation fluids, you must take appropriate measures to control the well. You must circulate and condition the well, on or near-bottom, unless well or drilling-fluid conditions prevent running the drill pipe back to the bottom;

(f) You must calculate and post near the driller's console the maximum pressures that you may safely contain under a shut-in BOP for each casing string. The pressures posted must consider the surface pressure at which the formation at the shoe would break down, the rated working pressure of the BOP stack, and 70 percent of casing burst (or casing test as approved by the District Manager). As a minimum, you must post the following two pressures:

(1) The surface pressure at which the shoe would break down. This calculation must consider the current drilling fluid weight in the hole; and

(2) The lesser of the BOP's rated working pressure or 70 percent of casing-burst pressure (or casing test otherwise approved by the District Manager);

(g) You must install an operable drilling fluid-gas separator and degasser before you begin drilling operations. You must maintain this equipment throughout the drilling of the well;

(h) Before pulling drill-stem test tools from the hole, you must circulate or reverse-circulate the test fluids in the hole. If circulating out test fluids is not feasible, you may bullhead test fluids out of the drill-stem test string and tools with an appropriate kill weight fluid;

(i) When circulating, you must test the drilling fluid at least once each tour, or more frequently if conditions warrant. Your tests must conform to industry-accepted practices and include density, viscosity, gel strength, hydrogen ion concentration, filtration, and any other tests the District Manager requires for monitoring and maintaining drilling fluid quality, prevention of downhole equipment problems and kick detection. You must record the results of these tests in the drilling fluid report; and

(j) In areas where permafrost and/or hydrate zones are present or may be present, you must control drilling fluid temperatures to drill safely through those zones.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50894, Aug. 22, 2012; 81 FR 26020, Apr. 29, 2016]

### **§250.457 What equipment is required to monitor drilling fluids?**

Once you establish drilling fluid returns, you must install and maintain the following drilling fluid-system monitoring equipment throughout subsequent drilling operations. This equipment must have the following indicators on the rig floor:

(a) Pit level indicator to determine drilling fluid-pit volume gains and losses. This indicator must include both a visual and an audible warning device;

(b) Volume measuring device to accurately determine drilling fluid volumes required to fill the hole on trips;

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(c) Return indicator devices that indicate the relationship between drilling fluid-return flow rate and pump discharge rate. This indicator must include both a visual and an audible warning device; and

(d) Gas-detecting equipment to monitor the drilling fluid returns. The indicator may be located in the drilling fluid-logging compartment or on the rig floor. If the indicators are only in the logging compartment, you must continually man the equipment and have a means of immediate communication with the rig floor. If the indicators are on the rig floor only, you must install an audible alarm.

It is recommended that BSEE should consider requiring enhanced use of trip books and trip sheets; use of these could further reduce human errors and kick size when kicks are swabbed during tripping operations.

It is also recommended that BSEE should consider requiring that the well be kept full during tripping operations instead of allowing a 75 psi reduction in hydrostatic pressure between hole-fill-ups. While this regulation is still appropriate for many land rigs that do not have modern trip tanks, rigs operating in BSEE jurisdiction now have trip tank arrangements capable of keeping the hole full all of the time. In the comparative analysis, other regulatory jurisdictions were found that do require the well to be kept full when tripping.

When seepage is present, BSEE regulations should address the maximum time between hole-fill-up volume checks instead of the maximum fluid level reductions. A maximum time between hole-fill-up checks of about one-half hour is recommended. This is about the amount of time required to pull five stands. The results of these checks should be recorded on the trip sheets.

Project SMEs suggested that the 0.2 ppg allowable disparity in 250.456(2) is too large if the cause is not entrained gas. It is recommended that BSEE revised to reduce or qualify the allowed disparity between the measured surface density of mud entering and exiting the hole, to avoid tripping with insufficiently conditioned mud. The measured mud weight is less affected by entrained gas when a pressurized mud balance is used.

As discussed in the next section, this study identified well control events that could have been avoided if either the formation pore pressure or the trip margin had been verified prior to tripping in certain completions operations.

### **4.4 Evaluation of CFR 250.500 (and 250.400)**

CFR 250.500 gives general requirements for Subpart E, Oil and Gas Well-Completion Operations, and further incorporates the applicable requirements of Subpart G. The requirements of subpart G that apply most directly to tripping during completion operations include CFR 250.703, 710, 711, and 736. CFR 250.703 was discussed above. CFR 250.736 pertains to the BOP system components used to prevent flow up the drillstring when using the BOP in a non-shearing mode. Additional requirements for these components are found in API Standard 53 (incorporated per CFR 250.198) and are included in this evaluation.

CFR 250.400 gives general requirements for Subpart D, Oil and Gas Drilling Operations, and is otherwise identical to CFR 250.500, including the incorporation of Subpart G. The following discussion therefore applies equally to both drilling and completion operations.

CFR 250.514 within Subpart E is relevant to well control during tripping and is also included in this evaluation. The requirements in this section are a subset of the requirements given for drilling activities.

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## **§250.500 General requirements.**

Well-completion operations must be conducted in a manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the OCS, including any mineral deposits (in areas leased and not leased), the National security or defence, or the marine, coastal, or human environment. In addition to the requirements of this subpart, you must also follow the applicable requirements of subpart G of this part.

[§250.400 is identical to 250.500 except that 250.400 applies to drilling operations.]

CFR 250.500 and 400 reference Subpart G and therefore include the requirements of 250.703 discussed above. The language in 250.500 and 400 requiring operations to be “conducted in a manner to protect against harm or damage” is similar to the language in 250.107 and 703 discussed in the previous sections. The same observations made in **Section 2.6** regarding SEMS and specifying good practice are relevant to this requirement. No regulatory gaps that could be reduced by adding to this regulation were identified during the study.

The requirements of CFR 250.514 are a subset of the requirements given for drilling activities in other sections.

## **§250.514 Well-control fluids, equipment, and operations.**

(a) Well-control fluids, equipment, and operations shall be designed, utilized, maintained, and/or tested as necessary to control the well in foreseeable conditions and circumstances, including subfreezing conditions. The well shall be continuously monitored during well-completion operations and shall not be left unattended at any time unless the well is shut in and secured.

(b) The following well-control-fluid equipment shall be installed, maintained, and utilized:

(1) A fill-up line above the uppermost BOP;

(2) A well-control, fluid-volume measuring device for determining fluid volumes when filling the hole on trips; and

(3) A recording mud-pit-level indicator to determine mud-pit-volume gains and losses. This indicator shall include both a visual and an audible warning device.

(c) When coming out of the hole with drill pipe, the annulus shall be filled with well-control fluid before the change in such fluid level decreases the hydrostatic pressure 75 pounds per square inch (psi) or every five stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure. The number of stands of drill pipe and drill collars that may be pulled prior to filling the hole and the equivalent well-control fluid volume shall be calculated and posted near the operator's station. A mechanical, volumetric, or electronic device for measuring the amount of well-control fluid required to fill the hole shall be utilized.

The recommendations regarding keeping the hole full made for 250.456 for drilling activities also apply to 250.514(3)(c) for completion activities.

This study identified well control events after perforating that could have been avoided if either the formation pore pressure or the trip margin had been verified prior to tripping operations. It is recommended that trip margins be verified as being sufficient before tripping after perforating in gravel pack or frac pack completions, and that a negative pressure test be used to provide this verification when the formation pore pressure is not sub-normal.

## §250.710 What instructions must be given to personnel engaged in well operations?

Prior to engaging in well operations, personnel must be instructed in:

(a) *Hazards and safety requirements.* You must instruct your personnel regarding the safety requirements for the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment as required by subpart S of this part. The date and time of safety meetings must be recorded and available at the facility for review by BSEE representatives.

(b) *Well control.* You must prepare a well-control plan for each well. Each well-control plan must contain instructions for personnel about the use of each well-control component of your BOP, procedures that describe how personnel will seal the wellbore and shear pipe before maximum anticipated surface pressure (MASP) conditions are exceeded, assignments for each crew member, and a schedule for completion of each assignment. You must keep a copy of your well-control plan on the rig at all times, and make it available to BSEE upon request. You must post a copy of the well-control plan on the rig floor.

CFR 250.710(a) refers to hazard communication according to Subpart S (SEMS). The relevance of SEMS to well control is discussed in **Section 2.4.1**. It is unclear whether the regulatory intent is to require well control to be identified as an activity in SEMS or to manage it separately under the well control plan requirement in CFR 250.710(b). The most significant operative difference between SEMS and a well control plan is the more formalized SEMS requirements for, job planning hazard analysis, written communications, and record keeping to facilitate oversight and continuous improvement. The conventional approach to well control through a well control plan was found to be sufficient within the scope of this study, with only incremental improvements recommended.

CFR 250.710(b) requires a well control plan, the conventional vehicle for communicating and managing well-control-related hazards that is subject to approval by BSEE through the permitting process. The only area for improvement in 250.710(b) identified in this study involves the language linking the decision to shear pipe to exceeding MASP. Revision of the phrase “*and shear pipe before maximum anticipated surface pressure (MASP) conditions are exceeded*” is recommended for the reasons discussed below.

First, the term maximum anticipated surface pressure (MASP) has a history of being misunderstood and confused with other similar terms. While API defines the acronym MASP with the same wording as the regulation and further defines it as a design pressure, a significantly older use of the acronym is maximum *allowable* surface pressure. The maximum allowable surface pressure was dependent on mud density and was defined as the surface casing pressure that would initiate fracturing at the casing shoe with clean mud above the shoe. The term maximum allowable annular surface pressure (MAASP) has replaced maximum allowable surface pressure.

The MAASP is simply a diagnostic parameter. It was originally intended to indicate when “low choke pressure” methods should be considered. Experience has since shown that effective implementation of the low choke pressure method is impractical for high permeability formations and will often result in higher surface pressures.

Once surface casing is set and the BOP’s are nipped-up, it is preferable to allow the surface casing pressure to exceed the MAASP even if doing so results in fracturing the shoe (unless there is an



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indication of a shallow casing failure). Bullheading the kick into the open-hole formations even if exceeding the MAASP is required to do so is an effective well control technique in some situations.

Second, the design pressure MASP as defined by API is intended to reduce wear caused by testing on BOP components and is not necessarily the rated working pressure of the systems. It is a common practice to test annular BOP's to pressures less than their rated working pressure because high test pressure can have a negative impact on the sealing element life. When the MASP is less than the rated working pressure of the BOP system and the lower MASP value is used for the routine BOP high pressure field tests, significant improvements in BOP reliability can be realized.

While the MASP should never be intentionally exceeded, it is by no means an indication of imminent equipment failure. In many cases the risk profile of a situation will be made worse if the pipe is sheared because casing pressure exceeded the MASP but was below the BOP/casing pressure containment system rating.

Third, shearing is likely to be an undesirable action even if surface casing pressures exceed rated working pressure. The design calculations for all pressure containment equipment incorporate substantial safety factors. It is common practice for many components to be shop tested to values significantly higher than the rated working pressure. For this reason, there may be considerably less risk in allowing casing pressure to exceed rated BOP/casing working pressure if the value is less than the shop test pressure.

Fourth, the actual failure pressure of a BOP/casing pressure containment system will be significantly higher than shop test pressure because the value for shop test pressure is based on the maximum pressure the component can be subjected to without damage. The difference between shop test pressure and failure pressure will be less for sealing elements, but since sealing elements failures result in leaks it may be worth the risk of waiting for a leak to occur before shearing. Especially if downhole pressures could be approaching fracture pressure, the rig has been evacuated, and the shears can be triggered remotely.

Fifth, in the case of excessive casing pressure, shearing reduces risk only in a deepwater setting where the pipe can be sheared and the riser disconnected. In the case of a surface stack, shearing does not reduce risk because the shear rams are rated to the same pressure as the pipe rams. An abandoned jack-up rig with the well contained by pipe rams and a drillstring safety valve poses essentially the same environmental risk as the same abandoned rig with the shear rams sealing the well.

In the case of a subsea stack, the risk posed by a BOP leak caused by excessive casing pressure can be mitigated by being prepared to divert if a leak develops, then shear and disconnect if the risk of explosion and fire become significant.

The diverter is normally removed when the BOP stack is installed in the case of a surface stack, so pre-emptive diversion through the choke is the only other option available (as opposed to keeping the well shut-in) for excessive shut-in casing pressure. There are many examples where the well control risk profile was degraded by diverting through the choke because surface casing pressures were perceived as too high. The study found no cases where excessive surface casing pressure caused a blowout during tripping or any other operation.

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Finally, the weakest component in the BOP/casing pressure containment system can easily be the casing below the entire BOP stack. As a result, closing the shear rams will not mitigate the risk of casing failure due to excessive pressure.

For the case of tripping operations, some of the most likely hazards that can be mitigated by shearing the pipe are:

- Pipe light conditions and pipe ram cannot seal or do not stop ejection of pipe (several examples of pipe light occurring.)
- Drillpipe cannot be sealed (case history example of this cited in contract).

### **§250.711 What are the requirements for well-control drills?**

You must conduct a weekly well-control drill with all personnel engaged in well operations. Your drill must familiarize personnel engaged in well operations with their roles and functions so that they can perform their duties promptly and efficiently as outlined in the well-control plan required by §250.710.

(a) *Timing of drills.* You must conduct each drill during a period of activity that minimizes the risk to operations. The timing of your drills must cover a range of different operations, including drilling with a diverter, on-bottom drilling, and tripping. The same drill may not be repeated consecutively with the same crew.

(b) *Recordkeeping requirements.* For each drill, you must record the following in the daily report:

- (1) Date, time, and type of drill conducted;
- (2) The amount of time it took to be ready to close the diverter or use each well-control component of BOP system; and
- (3) The total time to complete the entire drill.

(c) *A BSEE ordered drill.* A BSEE representative may require you to conduct a well-control drill during a BSEE inspection. The BSEE representative will consult with your onsite representative before requiring the drill.

The requirements of 250.711 are in keeping with API recommended practice RP 59. The study did not identify any regulatory gaps that could be closed by adding to this regulation.

### **§250.736 What are the requirements for choke manifolds, kelly-type valves inside BOPs, and drill string safety valves?**

(a) Your BOP system must include a choke manifold that is suitable for the anticipated surface pressures, anticipated methods of well control, the surrounding environment, and the corrosiveness, volume, and abrasiveness of drilling fluids and well fluids that you may encounter.

(b) Choke manifold components must have a RWP at least as great as the RWP of the ram BOPs. If your choke manifold has buffer tanks downstream of choke assemblies, you must install isolation valves on any bleed lines.

(c) Valves, pipes, flexible steel hoses, and other fittings upstream of the choke manifold must have a RWP at least as great as the RWP of the ram BOPs.

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(d) You must use the following BOP equipment with a RWP and temperature of at least as great as the working pressure and temperature of the ram BOP during all operations:

(1) The applicable kelly-type valves as described in API Standard 53 (incorporated by reference in §250.198);

(2) On a top-drive system equipped with a remote-controlled valve, a strippable kelly-type valve must be installed below the remote-controlled valve;

(3) An inside BOP in the open position located on the rig floor. You must be able to install an inside BOP for each size connection in the pipe;

(4) A drill string safety valve in the open position located on the rig floor. You must have a drill-string safety valve available for each size connection in the pipe;

(5) When running casing, a safety valve in the open position available on the rig floor to fit the casing string being run in the hole;

(6) All required manual and remote-controlled kelly-type valves, drill-string safety valves, and comparable-type valves (*i.e.*, kelly-type valve in a top-drive system) that are essentially full opening; and

(7) A wrench to fit each manual valve. Each wrench must be readily accessible to the drilling crew.

The requirements of 250.736 are believed to be representative of the best currently available practice and equipment to minimize the chances of having a well control incident through the inside of the drillstring while tripping out of the borehole and swabbing.

The only additional equipment that could reduce the risk of a blowout through the inside of the drill string would be to use a float, or check valve, in the BHA above the bit. Having a check valve on bottom stops flow up the drillpipe and would have likely prevented some of the blowouts that have occurred in the past when a safety valve could not be successfully stabbed onto the drillstring during flow up the drillstring.

A disadvantage of the downhole check valve is that often a high capacity rig pump is all that is available to equalize the pressure across the check valve in order to determine the shut-in drill pipe pressure. This critical measurement is required to calculate the proper kill mud weight after the well is shut-in on a kick. Some argue that this reduces the accuracy of this critical pressure reading. This problem can be mitigated by the use of a ported float that has a small orifice in it that would greatly slow the flow but not stop it completely. Also having a low capacity high pressure pump like those used to test BOPs readily available would provide a more accurate method for "*bumping the float*"

Other disadvantages of the float are that the surge pressure when running in the well is higher, which increases the risk of formation fracture, and that the drillstring has to be periodically filled by pumping mud into the top of the drillstring. This problem can be mitigated by propping the float valve open with some easily removable item (a piece of soap is often used for this purpose) so that the float is held open until the first time the well is circulated. Drop-in floats are also available that can be dropped in the drillstring after tripping into the well and pumped to a receiver receptacle in the drillstring. Of course, this has to be compatible with Measurement While Drilling (MWD) tools, mud motors, turbines, jars,

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etc., that may also be in the drillstring. Neither the key personnel nor the subject matter experts on this study had direct experience using a drop-in float.

In some well completion situations, it is desirable to be able to reverse circulate up the workstring, and this would not be possible with a float unless a circulating port is also in the workstring above the float.

There have been endless arguments in well control classes as to whether or not a float should be used. Many operators use them routinely in drilling operations while others almost never use them. BSEE/MMS has not required the use of downhole floats to date. Key personnel on this study recommend the use of floats in drilling operations as the standard, with the provision that they could be omitted in a specific case with sufficient justification.

Perhaps one of the service companies or equipment manufacturers will design a smart float that could be put in either a locked open or check valve status at will and that does not cause other problems that would prevent universal acceptance in the drilling industry.

## **5 EVALUATE OPERATOR'S JOB PREPLANNING PROCEDURES REGARDING TRIPPING OPERATIONS**

The purpose of this project task is to provide an evaluation and assessment of typical pre-planning procedures used in the field before performing tripping operations (e.g. job safety analysis, pre-job safety meetings, and agreed upon incident procedures) as well as drilling crew communication when tripping out of the borehole with regard to the potential risks posed by swabbing effects. Hazard mitigation methods available during the well planning phase are not covered by this section of the report. The scope of this discussion will be limited to practical planning and hazard mitigation options available at the rig and near the time of actual trip execution.

Tripping is a common and very routine operation in drilling and completion operations. It is estimated that on the order of 15 tripping operations are being conducted in US OCS waters every day. In periods of high oil prices and drilling activity, the number increases to about 50 tripping operations each day. Most of these trips are in situations where the risks are well understood and the methods used to mitigate those risks have already been identified and are being routinely implemented. By their nature these routine situations do not require a lot of preplanning before beginning a trip, as long as it can be verified that the nature of the hazard profile is unchanged and is still fully understood. In those instances where it can be established that the trip to be conducted is essentially the same as the last trip conducted, hazard mitigations and safety planning remain the same.

In routine tripping situations with mud densities well in excess of known pore pressure, once a decision is made to begin tripping, the operator's representative will likely have a brief discussion with the tool pusher in regard to hole conditions, any scheduled drills, training exercises, etc. The tool pusher will then communicate the necessary orders to his crew to implement the tripping operation. Every crew member knows their duties during routine tripping operations because the procedure will be the same as on the last trip. The operator's representative and/or tool pusher will generally go to the rig floor during the beginning of the trip to verify that proper procedures are being followed by the crew and to observe the flow checks being made before tripping is started. Even for the most routine trips, it is considered good form for an operator's representative to be on the rig floor when the first 10 stands are pulled, especially if the representative is unfamiliar with the driller or the driller is new to the position.

The primary well control focus of the operator's representative with regard to tripping operations is to ensure that an overbalance to the formation pore pressure is maintained. The magnitude of this overbalance condition is often referred to as the trip margin and is normally expressed in units of equivalent mud density. Pore pressure estimates are generally included in the initial well prognosis prepared by the operator's engineering staff or consultants during the well planning phase and are continuously updated based on data collected during drilling.

If the well is a *keeper* (as opposed to a dry hole), completion operations begin after the necessary casing/liner/tie-back system for production is run and has been cemented in place. Care must be taken to verify that the well bore is isolated from the surrounding sub-surface pore/fracture pressure environment and that it has pressure integrity. Methods for confirming this verification are discussed at length in other sections of this report. By their nature, completion operations are tripping intensive. Several complete trips along with additional short trips are normally required to convert from the mud used to drill the well to the clear brine used to complete the well. Only simple straight-forward hazard

mitigations are required for the well control aspects of these *bottled-up* cased hole tripping operations before the well is perforated.

On land the well control risks posed by perforating operations are routinely mitigated by installing the production tubing and packer prior to conducting the perforating operations. Once the well is setup for production (the BOP has been replaced by the tubing hanger and production tree), well integrity is verified and then the well is perforated. Tree-on methods of perforating eliminate the risk of a blowout while tripping after perforating because the need for a post-perforation trip is eliminated. Later, after depleting the zone, through-tubing methods are used to isolate the zone, usually with cement. Properly abandoning the perforations before removing the tree and beginning workover operations is another common strategy for mitigating the risks posed by active perforations during tripping operations.

The need for post-perforating trips cannot always be eliminated. Many productive formations in the US OCS are thick, highly productive, unconsolidated sands that cannot be produced without some type of sand control. The most effective and commonly used sand control systems require at least one post-perforation trip along with several other operations. This study was unable to identify any written mitigation strategies for the risks posed by post-perforating tripping in the available source materials. Operators and drilling contractors appear to mitigate the risk posed by tripping with open perforations with written procedures and on a well-by-well basis.

### **5.1 Evolution of Operator and Drilling Contractor Roles and Responsibilities**

It is a common misconception to many outside the drilling sector that the operator's representative is in charge of every aspect of a drilling or completion operation and that the operator's representative has final word on any and all matters. In practical terms this may have been true in the past because most drilling methods and procedures were originally developed and refined by the operators. During the early years of exploration on the OCS, drilling contractors were relatively small companies that owned specialized equipment and employed personnel trained only as necessary to operate and maintain that equipment. It was not at all uncommon for drilling contractors to have little, if any, well control expertise within their organizations.

During this time of fundamental technological development, many techniques and methodologies that are considered common knowledge today were considered competitive advantages by some operators. The reputation for operators to be so protective of their information that they would provide as little information as possible to even the drilling contractor they hired comes out of this time. There is little reason to doubt that the phrase "*you are tight hole'ing me*<sup>57</sup>" was first uttered by a frustrated tool pusher who could not get any useful details from a tight-lipped operator's representative.

Over time, drilling contractors became increasingly more involved in the planning and decision making processes required to drill and complete wells. Operators and contractors now align operational policies and procedures through bridging documents and management of change processes. The IADC, a drilling contractor organization, accredits well control training providers and it is now the drilling contractors and service companies who are developing a considerable amount of the new technology and methodologies.

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<sup>57</sup> The term "*tight hole*" is a term of art used to indicate that the information related to a well is confidential and that the contractors and service companies cannot share it with anyone outside their organization. It has also become a way to say someone is keeping you in the dark by not telling you everything they know.

Today, it is widely recognized that while the operator has wide latitude when it comes to what is done to the well; the drilling contractor retains a veto in all safety-related matters. Though it is still not uncommon for there to be a perceived conflict between these two interests, more and more it is the drilling contractor that has the expertise to identify the hazard mitigation provisions required to allow the operator's well plan to be implemented safely and efficiently.

### 5.2 Operational and Incident Procedures

Prior to starting a well, the operator and contractor normally develop bridging documents that merge the operational policies of the two companies. The policies and procedures that apply to tripping operations typically focus most explicitly on the well control equipment and procedures required to shut-in the well quickly. Once unified procedures are adopted by the operator and contractor, they are communicated to the field level for implementation.

#### 5.2.1 Authority to Secure the Well

A keystone of well control training and company well control policies is communicating to the individual responsible for monitoring the well the clear understanding that they have the authority to use their judgment and take whatever actions are required to secure the well. This policy is usually described as the *Authority to Shut-in*. This authority is usually discussed in the context of the driller's well control responsibilities because in the past it was not uncommon for drillers to be required (often tacitly) to consult with rig site management before shutting-in, even if it was clear to the driller that delaying shut-in for a consultation put the rig and crew at additional risk.

While this Shut-in Authority is not addressed in any of the regulations reviewed by the study, in drilling safety culture it is no longer considered acceptable to require the driller to consult with his/her supervisor before closing the BOP's when a kick is identified or suspected.

Experience indicates that with regard to shutting-in the well most operators and drilling contractors not only document (or adopt by some other means) a written Authority to Shut-in policy but also require management to reinforce this philosophy when interacting with field personnel. This active reinforcement of written policy is often described as *not only talking the walk, but also walking the talk*.

As a policy matter it appears that the Authority to Secure the Well philosophy is widely accepted among operators and drilling contractor management. Anecdotal evidence indicates that drillers are confident in this authority when it comes to shutting the well in and the number of precautionary shut-ins has increased, especially since the Macondo disaster. This authority seems to also be understood by drillers when it comes to diverting overboard.

The authority to shear is different in several ways. Most significantly, an unnecessary shut-in (often called a precautionary shut-in) is not likely to have long term impact on the well operations. Often the only operational consequence of a precautionary shut-in is the small amount of rig time spent evaluating and resolving the situation before resuming normal operations. The same is essentially true for a precautionary divert overboard, with the undesirable exception that some amount of mud will be discharged into the environment. If the divert is unnecessary, the consequences of diverting overboard will be limited to reporting the discharge, the mud lost, lost rig time, and in the US OCS possible enforcement action (Operator may receive an INC (Incident of Non-Compliance) from BSEE).

It is likely that some small number of unplanned precautionary shut-ins is a positive thing. It shows that the rig crew is being vigilant and gives them practice executing a shut-in under conditions that are more

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realistic than those during well control drills. The improved safety risk profile of a shut-in well is the main advantage that shutting-in has over both diverting overboard and shearing.

Diverting is a conscious trade-off between reducing the chance of broaching (or riser ruptures in deepwater) and a reduction in hydrostatic pressure in the well. An unnecessary divert can be called precautionary because if it is indeed unnecessary the situation will quickly resolve itself without degrading the safety risk profile of the operation. Both industry and BSEE recognize that divers overboard should be kept to an absolute minimum. As a result there are several industry efforts around resolving Riser Gas Management issues and BSEE has even requested proposals for a Riser Gas Management study.

The term “*precautionary*” cannot be applied to unnecessary shearing. It is not a simple matter to return to normal operations after a shear. Most significantly, unnecessarily shearing degrades the safety risk profile of the operation.

While the authority to shear may be given to the driller by written policy, as a practical matter a well-trained, qualified, conscientious driller who cares about the safety and well-being of the rig and crew is going to be reluctant to shear the pipe even after exhausting all contingencies available to him or her. Absent the clear and imminent risk of fire and explosion, there is going to be a natural tendency for the driller to seek guidance in the hopes that consultation with knowledgeable crew members might illuminate prudent alternative actions that would re-establish well control without the need to shear the pipe. In practice, by the time that well events have proceeded to the point where the driller feels compelled to consider shearing, the driller would normally have already been involved in extensive discussions with knowledgeable crew members.

Very little was found about operator and contractor policies that addressed the differences between the authority to shut-in and the authority to shear. It appears that the authority to shut-in is a well-established drilling cultural norm. While this is also true for the authority to divert, industry and BSEE are working to reduce the number of both necessary and precautionary overboard divers.

Though the authority to shear may be provided to the driller, little explicit guidance for the driller about what conditions could lead to the need to shear was found. This guidance may be necessary for the driller to understand what conditions might require him/her to take this action on their authority alone.

Through the research process of this study no information was found in any pre-job safety meeting planning materials or job safety analysis templates or drilling crew communication procedures that reinforced at a rig level the driller’s authority to secure the well and the job-specific conditions that could lead to the driller having to activate the shear rams on his/her authority alone.

This is not necessarily unexpected, as the authority to shut-in has been part of well control training for many years and is widely covered in accredited well control training courses. The same is not true for the authority to shear. In the past, the ability to shear was provided for floating rigs to maintain well control in case of drive-offs, not to re-establish well control in case other BOP components failed. Prior to Macondo, bottom supported rigs usually had blind rams only and could not shear.



## 5.2.2 Tripping Pre-planning Procedures

Pre-planning methods and crew hazard communication generally fall into two categories. The first are traditional well control policies and procedures. The second originated from the field of occupational safety and focuses on a hazard analysis approach.

### 5.2.2.1 Well Control Policies for Tripping Operations

Important and nearly universal (company-wide or division-wide) well control hazard mitigations are normally communicated through well control policies. **Table 5-1** is an example of a traditional well control policy for tripping operations. The example shown is for a contractor with larger rigs that work almost exclusively in narrow drilling margin environments. Ensuring that well control policies are followed is the responsibility of the tool pusher and the operator's representative at the rig site. While these policies are not usually routinely reviewed on the rig with the rig crew, they are normally communicated as part of the crew's training and are usually implemented as work instructions issued by the tool pusher.

Experience indicates that the example Tripping Well Control Policy is unusually detailed compared to the typical practices of companies that work in more forgiving operational environments. It is interesting to note that even with the high level of detailed instruction provided; the use of a trip sheet is not explicitly specified by the policy. Most tripping-related well control policies available to the study tended to focus more on shut-in procedures and well kill procedures. **Table 5-2** is an example a companywide shut-in procedure that is more representative of the tripping well control policies of smaller drilling contractors.

Both examples suggest that well monitoring methods while tripping tended to be lightly covered in well control policies. Policies that specified the use of trip sheets were not found. However, accredited well control training curriculums do cover the skill set and methods necessary to monitor the well while tripping, including the skills needed to properly use trip sheets.

It is most notable that example trip sheets and the most effective ways to use trip sheets were not found in a majority of the training materials and the technical literature available to the study. API RP 59 *Recommended Practice for Well Control Operations* does mention the use of a trip book and provides an example blank trip book form (Section 11.6 of RP 59). The RP 59 trip sheet example is essentially the same as that described in the only other source found that commented significantly on trip sheets, that being Grace (1994) in *Advanced Blowout and Well Control*.

**Table 5-1: Example Tripping Policy for Offshore Drilling Contractor**

1. Maintain records of mud properties, excessive cuttings, caving's, pump pressure fluctuations, gas readings, etc.
2. Trip Tank Calibration should be checked weekly.
3. A swab/surge calculation shall be carried out before tripping.
4. Tubulars and tools shall be run in and pulled out of the hole at moderate and justified speeds to minimize pressure surges that may cause an influx or mud losses.
5. Both drill string and annulus should be circulated out in expected hydrocarbon bearing formations, and in top holes with expected shallow gas. Ensure that the mud volume pumped is based on the actual hole volume and pump factor and not on the bit size. Do not allow mud to be transferred from or into the active mud pit.
6. The hole must be kept full at all times during trips.
7. Mud volume changes in the hole when running in or pulling out must be equal to the pipe displacement.
8. If Hole Fill-up Volume indicates swabbing, run back to bottom circulate and condition the mud.
9. Flow checks shall be performed on bottom, before pulling out from the last casing shoe and before pulling the Bottom Hole Assembly (BHA) into the Blowout Preventer (BOP) stack.
10. Minimize the time that the pipe is out of the hole. If possible, the string should be positioned at the casing shoe before slipping and cutting the drilling line or before other repairs are carried out.
11. Slipping and cutting drill line will be carried out with the drill string positioned above the BOP on DP vessels whenever possible.
12. Circulating bottoms up after a trip.
13. Recognize the effects of swabbed-in gas being circulated to the surface. At first, the gas will expand slowly. But when the gas approaches the surface, the expansion will accelerate and will unload mud. Primary control may be lost.

It was noted during the study that very little detail was available in training and policy materials about how to track fill-up volumes and even less about interpreting fill-up behaviors. The literature review did however find technical papers about fingerprinting techniques for ballooning.

The traditional well control policy is a system-based approach designed to improve operational efficiency, outcome quality and safety. This method depends heavily on having experienced, qualified professionals at the rig site specifying what needs to be done (operator's representative's primary role) and providing clear work instructions to the rig crew (tool pusher's primary role). In practice, the process is considerably more interactive than this simplified description.

It is not uncommon for field level supervisors to be asked to review and comment on operational planning documents (i.e. written operational procedures) well before operations begin and when there is still time to make necessary logistical changes.

Perhaps the most useful aspect of the well control policy approach to well control and operational safety is that the policy is a general guide and is available during all phases of drilling and completion, including the planning phase when fundamental choices about equipment and well design are being made.

**Table 5-2: Example Shut-in while Tripping Procedure**

**WELL CONTROL PROCEDURE DURING  
TRIPPING OPERATION**

1. Detect Kick, alert drill crew.
  2. Position drill pipe where safety valve can be installed by floorman as soon as possible. After valve is installed, close valve.
  3. Install inside BOP valve and open safety valve.
  4. Driller: Close hydrill, open HCR valve, close adjustable choke. Record time and casing pressure.
  5. Notify Company Representatives OIM/Toolpusher.
  6. Floorman (Backup Tong): Check all valves on choke manifold and BOP system for correct position.  
Floorman (Lead Tong): Check for leaks on BOP system and choke manifold.  
Floorman (Shakerman): Check flow line and choke exhaust lines for flow.  
Derrickman: Check accumulator pressure.
  7. Prepare to extinguish source of ignition.  
Mechanic, Electrician or Motorman: Stand by SCR Room.  
Welder: Secure welding machine and equipment.
  8. Crane Operator: Alert standby boat or prepare safety capsule for launching. Ensure bulk system is charged & ready for use.
  9. Crane Operator On Duty: Stand by crane for possible personnel evacuation.
  10. On-Duty Roustabout: Prepare to lower escape ladders and prepare other abandonment devices for possible use.
  11. Prepare to strip back to bottom.
  12. Alert galley and all off-duty personnel to stand by for orders. 13.
- Record time it takes to complete the kill procedure on driller's report.

### **5.2.2.2 Job Safety Analysis for Tripping Operations**

A brief history of the occupational safety origins of the Job Safety Analysis (JSA) is necessary to understand the wide range of meanings the term has evolved to embody in the drilling sector of the oil industry.

Early in the 20<sup>th</sup> century scientific methods were first being applied to a wide range of manufacturing processes in the form of time and motion studies. One prominent example is Henry Ford's hiring of motion-study expert Frederick Taylor to further improve the efficiency of his moving assembly line in 1913.

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The scientific management practice of job analysis (JA) grew out of the use of time-motion study techniques. By breaking a larger job down into elementary movements, jobs could be standardized and worker skill sets better matched to work requirements. By the 1920's observations about the beneficial effect of the systematic JA approach on accident prevention were being noted in the professional literature. Eventually the JA's use as a tool to improve safety was documented in 1927 in an article entitled "*Job Analysis for Safety*" in a magazine published by National Safety Council.

The benefits of a thoroughly detailed JA are clearly described in a safety text book from 1945:

*Job analysis is an essential part of production control and as such its technique has become well developed and widely established in American manufacturing practice. It involves the accurate and detailed description of each job in terms of duties, tools required, methods, sequence of operations, and working conditions. As would be expected, such a procedure of itself eliminates a high proportion of accident hazards. When, to adequate job analysis, the other necessary factors of successful mass production are added, namely, planning, supervision, training and continuous control, we get a high degree of safety as an inherent part of quantity production. (Blake)*

It is interesting to note that if some of the terminology is changed, the same passage could be used to describe the processes by which most, if not all, drilling contractors operating in the US OCS now train and supervise their personnel, document work duties, align well control policies with operators, and the way operators interact with contractors to develop written well plans. A major difference is that the JA was developed to analyze a discreet, narrowly defined repetitive job and not the integration of a wide range of jobs that change as part of a larger system that moves through a cycle of processes. JA as historically defined is well suited to linear work processes like stamping out car fenders or operating a street car, just to name a few.

While not called the JA process, the methodology naturally worked its way into the drilling sector. Though one would be hard pressed to find a detailed description of the drillers job duties from 1945, most major operators had extensive well control manuals developed by the late 1980's and systematic approaches to job descriptions for all positions on a drilling rig were written into major drilling contractor operations manuals by the 1990's. Approaches like the Hazard and Operability Study (HAZOP) which make use of a JA-like structured and systematic method have been widely adopted in the drilling sector. The HAZOP approach is better suited for use on larger more complex systems than a single job or task.

A brief literature review in the safety professional field indicates that the safety professional community has yet to develop an organized set of universally accepted definitions for the term Job Safety Analysis (JSA). For example, the American Society of Safety Engineers (ASSE) and OSHA define JSA analysis as a process and that Job Hazard Analysis (JHA) is a different name for the same process. Googling the terms locates a 2015 article posted for a Safety Summit which is entitled, "What's the difference between Job Safety Analysis and Job Hazard Analysis?" and it describes the JHA as a related to, but still a different process than a JSA.

It is therefore no surprise that JSA has come to have many different meanings and uses within the drilling and completions safety culture. Its meaning is consistent in only the loosest and most general terms.

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API RP 54, *Recommended Practice for Occupational Safety for Oil and Gas Well Drilling and Servicing Operations*, does not define or use the term Job Safety Analysis. The RP does identify the need for pre-job safety meetings before conducting certain operations (i.e. cementing, perforating, etc.). It is interesting to note that the RP does not treat tripping as a distinct operation and as a result does not make a recommendation about pre-job safety meetings prior to starting a routine trip. It does recommend holding a pre-job safety meeting prior to commencing stripping or snubbing operations.

Though the term JSA is not used in the *IADC Deepwater Well Control Guidelines* (2015), the Operational Risk Management section provides a discussion on hazard communication along with pre-job and pre-tour safety meetings.

The *IADC Drilling Manual* (2015) uses the term JSA to refer to what might otherwise be described as a pre-job safety meeting and lists occupational safety considerations as topics for discussion. In addition, IADC provides what it calls Safety Meeting Topics for JSAs or other meetings both on the internet (*IADC Safety Tool Box*) and as a published hand book (*IADC Safety Meeting Topics*, 2015). **Table 5-3** was the only safety meeting topic available on the Safety Tool Box website that specifically addressed tripping operations. The study found this to be a typical example of how only occupational safety issues are covered by processes developed in the occupational safety field. There are no well control hazard mitigations or considerations listed as part of the checklist.

Additional Safety Meeting Topics (*Responsibilities of the Driller* for example) also have useful Occupational Safety risk mitigations but do not address well control for any operation listed.

The only detailed and rigorous JSA materials related to tripping operations found by the study were developed by the Occupational Safety and Health Administration (OSHA) and are available on its website. The OSHA JSA's are a form that uses the 3-heading format recognized widely as a distinguishing feature of a JSA in the safety professional community. These headings are: 1) Basic Job Steps, 2) Potential Hazards, and 3) Recommended Safe Job Procedure. Review of the tripping JSA provided by OSHA showed no well control hazard mitigations or communications. The JSA was more extensive and detailed than any other JSA found, but again focused on occupational safety hazards and mitigations. The content was very similar to what can be found in an operations and training manual of just about any modern drilling contractor organization.

It appears that the rigorous application of the JA and the related JSA have yet to be widely understood in drilling culture. Even the OSHA materials developed for tripping during drilling operations do not achieve the level of detail and comprehensiveness that the occupational safety community historically envisioned for a JA. Most striking is the fact that JA's were originally described as necessarily being developed by experienced supervisors with input from experienced workers to make them as comprehensive as possible (much like the HAZOP approach). The results of the JA were then used to provide quality instruction and guidance to new workers as well as to remind experienced workers of hazards and mitigations related to the job they would be performing. The OSHA website specifically states that completing a JSA is a valuable exercise, especially for new employees.

## EFFECTS OF TRIPPING AND SWABBING IN DRILLING AND COMPLETION OPERATIONS

**Table 5-3: IADC Example "JSA Meeting Topic" entitled *Safety while Tripping Pipe***

The highest incidence of accidents occurs around the rotary table when workers are making a trip. The reason for this is worker exposure to the hazards for a greater length of time than they would experience while making a single connection.

### Pre-Trip Checklist

1. The rotary table and surrounding work area should have a mat or covering to prevent slips or falls.
2. Pick up all tools and items from around the rotary table that could cause a fall.
3. Inspect tong jaws, tong pins, tong dies, tong snub and pull back lines.
  - a. Be sure the tong dies are sharp and not broken.
  - b. Be sure the tong jaws and elevator are well lubricated and that all pins, nuts and bolts are in place.
4. Always wear goggles when changing tong dies.
5. Inspect elevator hinge, ears and securing bolts, and service the elevators latch and hinge pin.
6. Inspect the mud bucket.
7. Inspect slip dies, die keepers, handles and handle attachment pins and lubricate back of slip body.
8. Inspect the drill collar clamp.
  - a. Be sure all pins are in place with the proper keepers.
  - b. Check the dies to ensure they are sharp and keepers are in place.
9. Be sure all crewmen are mentally alert and ready to work.
10. The derrickman is responsible to check the derrick board and derrick for loose objects that might become dropped objects.
11. Be sure proper PPE is being worn:
  - a. Hard hat
  - b. Safety glasses
  - c. Safety boots or shoes
  - d. Work gloves
  - e. Proper clothing
  - f. No loose fitting clothing or jewelry

### Precautions while making a trip:

1. During the trip, keep the surface of the work area as clean and dry as possible.
2. Stand on the rotary guard, not the rotary.
3. Keep feet clear of slip handles.
4. Prevent horseplay of any kind.
5. Be alert. Watch the driller and other co-workers for signals.
6. Keep feet off the rotary when it is turning.
7. Keep feet clear when setting slips.
8. Grip slip handles with palms facing up.
9. Do not stand under elevators or between pipe being hoisted and the joint of pipe in rotary table when picking up or laying down drill pipe or drill collars.
10. Never let drill pipe or drill collars swing free. If necessary use a tagline.
11. Keep feet from under pipe, drill collars, and installed safety clamps.
12. Keep hands off the elevator bail eyes.
13. Keep hands off the stump of pipe in the rotary or mouse hole.
14. Only place hands on tong handles.
15. Keep hands off of the tong latch except to open the tongs.
16. Keep an eye on swinging tongs at all times.
17. Stand clear of the spinning chain.
18. Never put your hand on top of the drill pipe or collar box at any time.
19. Always stand clear of tongs and elevators when the driller is making up a connection.
20. Use extreme care when placing hands on pipe, collars and tongs
21. Maintain coordination between the driller and crewmembers at all times.
22. Use sufficient help when setting and pulling slips.



# EFFECTS OF TRIPPING AND SWABBING IN DRILLING AND COMPLETION OPERATIONS

The lack of widespread consensus on what a JSA is and how the process is implemented likely has three equally important causes. First, within the safety professional community there is very little consensus about what a JSA is and how one should be developed. The occupational safety literature provides many examples of academic discussions about both the shortcomings and benefits of the JSA approach, along with alternative and competing approaches. Frequently, the occupational safety professionals working in the drilling sector have very little direct experience with the interwoven job responsibilities of a rig crew. Early JA emphasized that the individual doing the JA must be experienced with the job being analyzed. Expertise in the analysis process employed was not required. JA was originally intended to be a simple and systematic tool applied by experienced job practitioners, not safety process experts.

A second reason for the lack of consensus regarding the JSA process in drilling safety culture is that it duplicates other traditional and effective methods of hazard identification and mitigation. This is most evident by the fact that no JSA's were found that either replaced or enhanced well control policies. JSA's appear to be overlaid on top of the existing training, procedural and safety policy structure common to most drilling contractors and operators.

**Table 5-4: IADC Drilling Manual References to JSA (2015)**

<p><b><i>Personal safety</i></b>          Job Safety Analysis (JSA) is widely used by contractors, operators and service companies to identify and mitigate safety hazards. By co-conducting preliminary job reviews, employees and managers can gain a shared ownership in a safety program that reduces and helps control risk.</p> <p><b><i>JSA topics to consider</i></b></p> <ul style="list-style-type: none"> <li>• Driving safety: traveling to land location or offshore load out point;</li> <li>• Personal protection Equipment: hard hats, safety glasses, gloves, etc;</li> <li>• Lock out tag out: equipment maintenance;</li> <li>• Rig-up and rig-down procedures and assignments;</li> </ul>	<ul style="list-style-type: none"> <li>• Hand tools: equipment maintenance;</li> <li>• Work permit: hot work, high pressure, noise;</li> <li>• Confined space: working in pits or tanks;</li> <li>• Working at heights: rigging up equipment, iron, plug containers;</li> <li>• Dropped objects: hand tools, service iron;</li> <li>• Lifting and handling: iron, chemicals, related materials;</li> <li>• Stop Work authority: when in doubt, STOP;</li> <li>• Slips, trips and falls;</li> <li>• Pressurized equipment;</li> <li>• Chemical handling: movement, mixing of fluids (e.g., drilling mud, cement).</li> </ul>
<p>The IADC Safety Toolbox is easy to use. Users can narrow their search by type of operation (rigging up, lifting, etc), incident classification (LTI, equipment damage, etc.), body part, location (rig type, etc.), incident type (slip, etc.) and equipment.</p> <p>The Online Safety Toolbox provides a practical, user-friendly resource that will seamlessly integrate into daily drilling operations. Contents include:</p> <ul style="list-style-type: none"> <li>• 700 IADC Safety Alerts;</li> <li>• 125 Safety Meeting Topics for JSAs or other meetings;</li> <li>• Near Miss/Hit Report forms for both drilling and well servicing/workover;</li> <li>• 60 IADC Safety Posters.</li> </ul> <p>The Online Safety Toolbox puts critical safety related tools and resources directly in the hands of the rig crew, and is one of several IADC initiatives aimed at enhancing safety in the industry. Access it today!</p>	

Third and likely the most significant reason for a lack of consensus is that completion of a thorough and rigorous JSA is not practical within the context of the pre-job safety meeting. It would take far too long and would repeat work that is likely to have been done much more thoroughly and completely by experienced personnel when developing operational training manuals and work descriptions.

**Table 5-5: OSHA Guidance on JSA Process (Website)**

Everyone involved in implementing a job or task should be present when the JSA is written! The JSA should be reviewed, approved, and signed by the supervisor before the task is started. Understanding every job step is very important! Whenever a job step changes or a new step is introduced, the JSA must be reviewed and updated.

Remember, the key reasons for completing a JSA are to encourage teamwork (especially with new employees), to involve everyone performing the job in the process, and to elevate awareness!

Serious considerations should be given to abandoning the use of the confusing and often misused term JSA. Early on during the course of this study, project team members and subject matter experts realized they were often talking past each other because they were using the term JSA to mean totally different safety concepts. **Table 5-4** illustrates use of the term JSA in the IADC Drilling Manual which is significantly different than the definition provided by OSHA and provided in **Table 5-5**.

### **5.3 Daily Operations Meeting**

Drilling crews work a twelve hour shift called a tour (traditionally pronounce *tower*). The pre-tour meeting is a method for daily communication among all parties on the rig. Typically tool pushers or company men lead pre-tour meetings where the “*hands*” are briefed on the current situation of the well and the activity forecast for the tour. Prior to this pre-tour meeting, the company man ideally provides written work instructions to the tool pusher which would be passed on to the rig hands and service companies as necessary. When practical, the review of planned operations is done with all crew members and a representative from each of the service companies during the pre-tour meeting. This meeting is an opportunity to review and discuss potential hazards of any type (Occupational, Well Control and others). The crew is frequently reminded in these meetings that anyone can stop work if they feel they are witnessing an unsafe activity. Worker responsibilities and the authority to fulfill those responsibilities, like the stop work authority or the driller’s shut-in authority, are often highlighted in these meetings.

### **5.4 Pre-Job Safety Meetings (PJSM)**

Short Pre-Job Safety Meetings (often called *toolbox talks*) are usually held with the rig crew prior to trips. The typical practice is to identify and address mitigation methods for the personal injury risks, often with little discussion about well control related risks and mitigations.

Well control is heavily covered in specific accredited well control training courses and on-the-job training throughout a crew member’s career. Well control drills also provide communication of well control hazards and mitigation methods.



### 5.5 Crew Communication when Tripping out of the Bore Hole and Swabbing

Traditionally, a chain of command approach is used to communicate between the driller, who is normally running the rig floor, and the operator's representative. The operator's representative is responsible for developing tripping instructions in close collaboration with the tool pusher. This working relationship is based on combining two strengths; the operator's representative has the best access to the details behind the well plan and how it mitigates well control hazards posed by the sub-surface environment, and the tool pusher's detailed understanding of the rig's capabilities, well control policies, and occupational safety hazard mitigations.

Often, in non-routine or particularly challenging cases it would not be unusual to include the driller and other specialty service company experts in developing work instructions. Normally very little documentation is required to accurately communicate these very operationally-specific instructions if all the participants are highly qualified and experienced.

For example, experienced operators, tool pushers, and drillers develop an understanding of well geometries for which a reasonable trip margin is all that is required to account for swabbing effects at any reasonable pulling speed and what those reasonable pulling speeds are. In such cases, swabbing hazards are seldom discussed and standard well monitoring methods are used to mitigate the very small potential of swabbing in parallel with other perhaps more significant risks that are mitigated by the same monitoring methods.

Those conditions that might be conducive to swabbing are readily identifiable to competent and experienced drilling professionals; in most of those cases the operator will have already had swab modeling performed and a maximum pulling speed selected, or the slowest practical running speed will be used, or in extreme cases the string may be pumped out of the hole.

Once a work plan has been agreed to by the operator's representative and the tool pusher (perhaps even with input from the driller) it is implemented by the driller and the crew.

A significant shortcoming of this traditional method of risk mitigation through work planning is that it tends to be informal and lacks documentation that can be reviewed by off-rig management and regulators. The appeal of the occupational safety approach of the formal job analysis methods are that the planning of the work and how the plan is communicated to the workers is well documented and available for later review and evaluation.

The most significant risk posed by this informal work plan communication method is in the quality of its implementation. Because the work planning and instruction methods used at the time of operational implementation are informal and undocumented, only the work product and outcomes can be used to *infer* the quality of work instruction and communication.

While these methods are known to be effective tools, it is difficult to evaluate if these traditional informal rig site hazard communication and mitigation are being implemented by a review process. For example the tool pusher and operator's representative may have a very in depth discussion about an upcoming trip without formally documenting that conversation. Another example is the 10 minute *hand-over* discussion between the driller going off tour and his/her relief. It is also not uncommon for rig crew supervisors like the driller and tool pusher to start work early so that they can talk their on-tour counterparts about a difficult trip in progress. Sometimes they will then go to the rig floor early (i.e. sometime before tour change) to get a feel for the operation. All of these practices can be highly

effective but are difficult to track and review by management as is required for continuous improvement and universal implementation.

Stop-cards, JSA's, and any number of programs derived from other industries have been overlaid on top of drilling safety culture traditional practices and policies in attempts to provide a way of objectively evaluating how effectively the culture is working for a particular rig or organization. These programs have worked well to improve occupational safety (as they were originally designed to do) but have yet to improve on the competent implementation of traditional communication practice when it comes to well control during tripping operations.

One significant exception to these observations with regard to tripping is the challenge of communicating the degree to which the pore pressure regime is known. In an exploration drilling context, pore pressure is almost always an estimate based on indirect measurements and trip margins are treated as potentially unreliable. Great efforts go into "*letting the hole talk to you*" where many parameters and indicators of hole conditions are used to both prevent and detect the potential of a kick. In completion operations, pore pressures provided by the operator are usually assumed to be known pore pressures and not estimated pore pressures by field personnel. If the estimate is not verified by some means unintentionally small trip margins can result.

### **5.6 Documenting Rig Level Work Instructions Electronically**

Modern data acquisition systems are being used to document daily reports, BHA reports, pipe tallies, and a wide range of paperwork in addition to data logging. Some contractors even have the rig crew sign the IADC reports electronically in the data logging system. Consideration should be given to having pre-job safety meeting and pre-tour safety meeting agendas written, communicated and stored using these systems. Tool pushers and operator's representatives could include work instructions and hazard communications that will be covered at the meeting (or that have been covered in a more informal way). The crew could then sign the agenda electronically at the end of the meeting.

### **5.7 Well Control Drills**

Perhaps one of the most underutilized methods of hazard communication and mitigations is the well control drill. There seems to be a perception in the drilling culture that well control drills are only useful for verifying crew readiness and competency.

Well control drills customarily stop once all the actions needed to secure the well have either been physically executed and/or verbally described.

#### **5.7.1 Readiness Drills**

Crew readiness is usually measured by their response time to an unannounced drill. As a practical matter these drills are best done during routine operational situations. For example, an unannounced drill while trying to diagnose a potential underground cross flow would be imprudent because it would confuse diagnostic information. Unannounced drills normally address only the first layer of response (it is assumed no complications preventing the shut-in are encountered). If complications are added in, response times (time to activate shut-in) are delayed and apples-to-apples comparisons of response times over time would be difficult.

## 5.7.2 Competency Drills

Announced drills are better suited to evaluating crew competency with the equipment available at the rig. These drills can benefit from pre-planning. Time can be taken to quickly run through a scenario with the individual running the drill asking questions to measure the crews understanding of the reasons behind their actions. Because these well control drills are conducted with the on-tour crew, they must be short as a practical matter, especially if there is open hole. Keeping the number of open-hole days to a minimum is one of the most effective hazard mitigation methods available.

As with readiness drills, the time it would take to discuss unexpected complications in securing the well is not available in most situations for competency drills because of time considerations. For example, adding 15 minutes to a competency drill to discuss what actions the crew should take if the drillstring safety valve cannot be stabbed would not be a prudent use of time if the well has 2000 feet of open hole.

## 5.7.3 Table Top Shut-in Drills

The study found no evidence that operators and/or drilling contractors conduct detailed, multilayered, situation specific table top drills. An important exercise for emergency management organizations is the table top drill. It is normally a scenario that could occur within the purview of the organization and is designed to clarify the roles of participating members.

While table top drills in the emergency preparedness field can take days to run, table top drills designed for rig site personnel conducting tripping operations during drilling and completions operations should take less than 15 minutes to run. These drills would start with detecting the kick and end when the well was secured. If these drills were designed to communicate potential hazards that arise when complications are added to the routine kick detection and shut-in process, and then to illuminate to the crew how that complication can be mitigated and the drill was well documented, the table top drill could be an effective pre-planning tool to document hazards communicates and mitigations.

The most important feature of a tripping table top drill would be that it is conducted close in time to actual tripping operations and the scenarios run parallel to the operational situation present on the rig.

The pre-tour safety meeting before and during tripping operations would be an ideal time to run a table top tripping drill.

## 5.8 Assessment of Offshore Operator's Preplanning Procedures for Tripping Operations

The potential for the effectiveness of job preplanning for tripping operations vary over a wide spectrum for various operators. This can also be said about the spectrum of drilling contractors, and even the spectrum of rigs working under different operator/contractor combinations.

Because tripping is so routine, it is easy for an operator to fall into a pattern of little to no preplanning even in moderate or high risk situations. This is also true for a drilling contractor or a specific rig. A review of well control incidents that have occurred over the past ten years has shown that crew preparation was insufficient in the incidents that resulted in a blowout. Human error is almost always involved when a blowout occurs during tripping operations.

No reviewable methods for effectively documenting the pre-planning and well control related hazard mitigations for tripping operations at the implementation level (rig level) were identified by this study. Without some form of reviewable documentation, operator management, drilling contractor

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management and regulators have no way to verify that the pre-planning communications with regard to tripping operations on any rig are sound. Direct observations like inspections and field visits provide a snapshot, but do not provide a long term picture.

JSA forms currently provide auditable documentation of occupational safety hazard communications and mitigations prior to implementing tripping operations but do not normally address well control hazards. Well control policies communicate well control hazards and mitigations effectively, but do not provide documentation as to how thoroughly or how effectively they are implemented in any specific case.

On a systemic level, operators have strong drilling safety cultures and implement a wide array of methods to mitigate the hazards posed by tripping during drilling and completion operations. The challenge is identifying those relatively few instances where job pre-planning has become lax. This challenge is the same for operator management, drilling contractor management and regulators.

The assessment of the Project Team is that the industry has sound and effective preplanning tools, technology, and cultural traditions available and that the vast majority of operators make use of all of these to conduct safe efficient tripping operations. The difficulty is ensuring they are universally applied on all rigs, all of the time.

## 6 ASSESS POTENTIAL CAUSES FOR LOSS OF WELL CONTROL WHILE TRIPPING

The purpose of this section of the report is to evaluate and assess the potential technical causes for losses of well control while tripping out of the borehole and swabbing (e.g. mud properties, pulling speed, larger outer diameter of drilling tools, and swelling/heaving of formations). Based on this analysis, recommendations to BSEE were developed for relevant mitigation procedures.

Some operators and drilling contractors now maintain a well kick database for their internal use and have records for past well control operations. This information is proprietary and was not available to the study. It was hoped that the BSEE Weekly Activity Reports (WARs) database might contain similar useful information about causes of kicks and kick sizes on the US OCS. Though requested early in the project, access was not made available.

Most of the causes for losses of well control while tripping have already been identified and discussed in other sections of the report. The focus of this section of the report is to present, as completely as possible, a list of all possible causes and their relevant mitigation procedures.

Each cause identified will be discussed in a separate section. The discussion will include the relevant mitigation actions. A summary table of the potential causes and mitigations for losses of well control while tripping that have been identified by this study is provided at the end of this section (*Table 6-1*). The table also summarizes the recommend mitigating actions that should be considered for each cause. It is important to realize that most blowouts involve multiple contributing causes that would involve more than one of the causes discussed below. Many of the causes are interrelated.

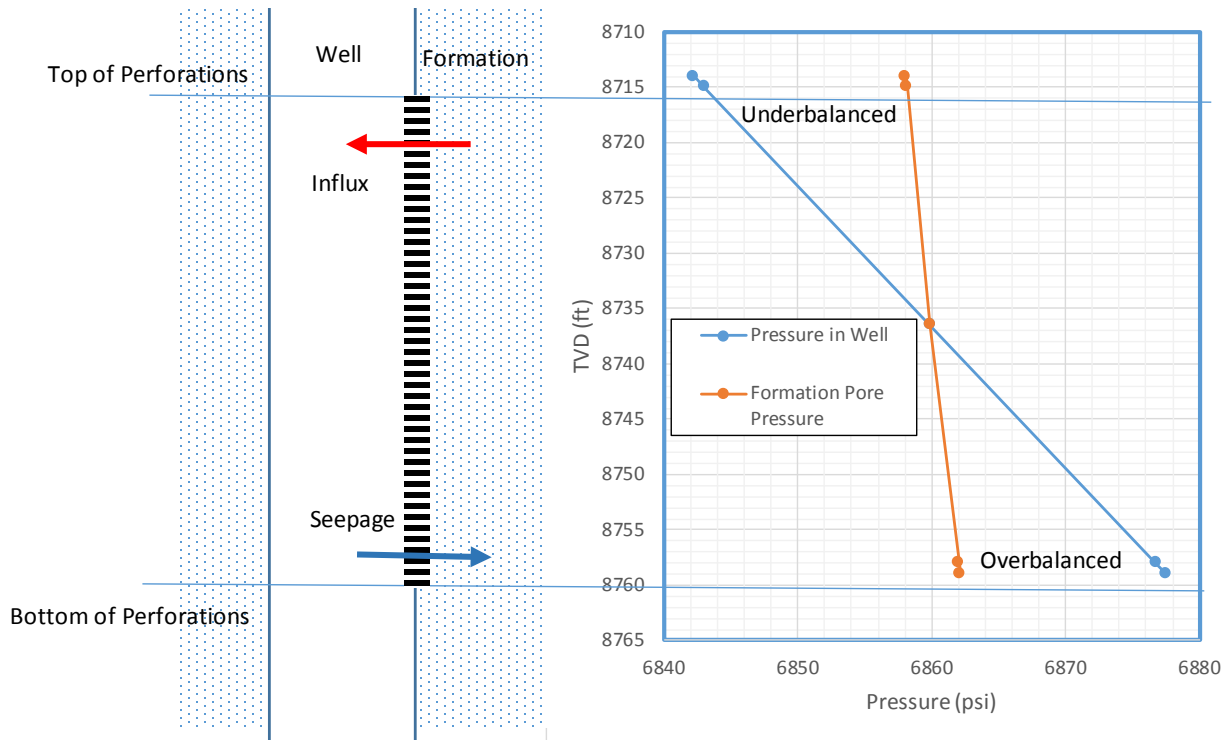
### 6.1 Higher Pore Pressure than Expected

Formation pore pressure gradients are generally estimated when the well is planned based on available information from other wells in the area and from seismic velocity profiles. Efforts are made to update the estimated pore pressure gradient versus depth profile as the well is drilled, but the pore pressure gradient is often not known with a high level of precision. Measurements of formation pore pressure are generally not made until the hole-section has been drilled and formation evaluation tools have been deployed. In many cases, an exact formation pressure of a productive zone is not known until the well is perforated and bottom hole pressure measurement records are recovered at the surface. The mud density during tripping is generally at least 0.2 to 0.5 ppge higher than the maximum exposed formation pressure gradient. If the formation pore pressure gradient is higher than anticipated, mud density used during tripping operations may be too low to accommodate even a small swab pressure loss on bottom due to pulling the pipe during a trip.

Tall gas zones will cause abnormally higher formation pressure gradients at the top of the zone penetrated by the bit as compared to the formation pressure gradient at the gas/water interface. Even if a normal formation pressure gradient is found at a gas/water interface, an abnormal formation pressure gradient will be seen at the top of the gas zone. An example situation is shown in **Figure 6-1** in which differential density effects can cause underbalance and influx to be experienced at the top of a perforated interval at the same time that overbalance and seepage is occurring at the bottom of the perforated interval.

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The best way to mitigate uncertainty about the exact magnitude of the formation pore pressure is to either measure the pore pressure or verify the trip margin is adequate to prevent an influx.



**Figure 6-1: Example Effect of Differential Density between Gas Sand and Well Fluid Density**

Measuring the pore pressure before a trip is only practical when perforating on electric line with a bottom-hole pressure and temperature tool above the gun, or when a PWD tool is in the drill string that is MWD capable. In most cases, use of trip sheets, flow checks, and short trips is the only practical mitigation procedure during drilling operations. The Trip margin can be verified using a negative test for trips with open perforations during completion operations when the pore pressure has not been directly measured.

### 6.2 Insufficient Trip Margin

An insufficient Trip Margin can occur because the operator does not accurately know the formation pore pressure or does not know the magnitude of the swab pressure loss, or both. This can result in the mud weight being too low to safely trip pipe out of the well. This situation can be mitigated by adjusting the mud properties and / or pipe pulling speeds and then verifying that the resulting Trip Margin will be more than adequate to maintain an overbalanced condition during the tripping operation.

The first step in this process would be to calculate the maximum loss in pressure at the formation face due to swabbing for the well conditions, fluid properties, and tripping speeds that are planned. If, for example, the maximum calculated pressure loss due to swabbing when pulling pipe from 9,000 ft will be 47 psi (0.1 ppge), then a conventional Trip Margin of 0.5 ppge or 234 psi could be selected if the operating window between pore pressure gradient and fracture

gradient is large enough. If a Frac Pack Operation is being conducted<sup>58</sup>, a negative pressure test of 234 psi could then be conducted as discussed in **Section 2.5.3** and shown in **Figure 2-8**.

If the trip is being conducted during drilling operations, then a precise verification of the Trip Margin cannot be established. However, a trip margin can be selected that is equal to the difference between the Equivalent Circulating Density and the Static Downhole Density. The mud weight could then be increased prior to pulling pipe. Pulling speeds can be limited so that swabbing effects are no greater than half the Trip Margin. This will insure that the equivalent mud weight during the trip never falls below the effective static mud weight that was present when conducting the flow check prior to circulating the extra trip margin into the well. An additional verification step can be completed by performing a short trip at higher pulling speeds than will be used in the complete trip. Pulling speeds for the short trip can be selected to produce a decrease in equivalent mud weight equal to 75% of the Trip Margin. Once the trip has been completed and drilling is resumed, some operators will decrease the mud weight back to what it was prior to adding the extra trip margin.

Some possible reasons for having an insufficient Trip Margin include:

- Swab calculation not performed
- Tripping speed too high
- Mud Weight in Trip Tank not maintained
- Contaminated and Flocculated Mud
  - High Plastic Viscosity
  - High Effective Viscosity
  - High Gel Strength
  - Progressive Gel Strength
- Gumbo Attack due to high concentration of easily hydrated formation clays
- Balled Bit or Bottom Hole Assembly
- Narrow Window between Pore Pressure Gradient and Fracture Gradient
- Seepage Loss hides Gas Influx
- Upward Gas Migration
- Downhole Density Decrease due to Warming

Each one of these possible causes and possible mitigation activities will be discussed separately below.

### **6.2.1 Swab Calculation Not Performed**

On low risk wells of the shelf, mud logging or well monitoring company specialists with the capability to perform surge and swab calculations may not be used by the operator and the operator's representative may also not have this capability. Swab surge calculations may have been omitted due to resource time constraints, or the belief that this well is similar enough in nature to an offset well that didn't experience problems.

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<sup>58</sup> Recall that Tripping Operations during Frac Pack Completions appeared to be a problem area from a review of blowout events that occurred during tripping operations during 2005 to 2015.

## 6.2.2 Tripping Speed Too High

Software has been developed to assist drilling contractors to use recorded drilling data to improve their drilling efficiency, by computing the amount of time spent in each rig activity. Time spent tripping is a major drilling cost contributor and rig crews are sometimes ranked by drilling contractors on their average trip time performance. There is a natural tendency for rig crews to want to trip efficiently and, when instructions are not given otherwise, pipe pulling speeds of 30 seconds per stand are fairly normal. In extreme cases where the tripping time is one of the dominant key performance indicators, this incentivizes the rig crew to trip as fast as possible. Rapid acceleration of the pipe when it is picked up out of the slips and rapid deceleration of the pipe prior to breaking a connection can also create dynamic pressure waves similar to a water hammer effect. Pressure waves pass by a given point in the well quickly and attenuate with distance travelled. The effects of the dynamic pressure waves on influx or formation fracture, if any, are not well understood

Too high a tripping speed for the well conditions can be easily avoided by performing swab and surge calculations and providing written instructions to the driller prior to the trip. This is also true when running or pulling casing, because small clearances will likely be present over a longer length of moving pipe.

## 6.2.3 Mud Weight in Trip Tank not maintained

There have been some reports of mud weight in the trip tank not being maintained. Trip tanks are generally not agitated and reports of fluid returning from the well containing oil were seen in this study. In one case, the density of the fluid in the trip tank was intentionally reduced in an effort to reduce the seepage loss rate. Generally, the Trip Margin is large enough to accommodate the minor loss in hydrostatic head from changes in mud weight of the fill fluid at the top of the well.

Following normal drilling practice should mitigate this potential problem. If the well is circulated clean from bottom before tripping operations are started, the fluid returning from the well should not contain formation fluids. The drilling fluid specialist can provide written instructions to monitor and maintain the mud weight at the specified value

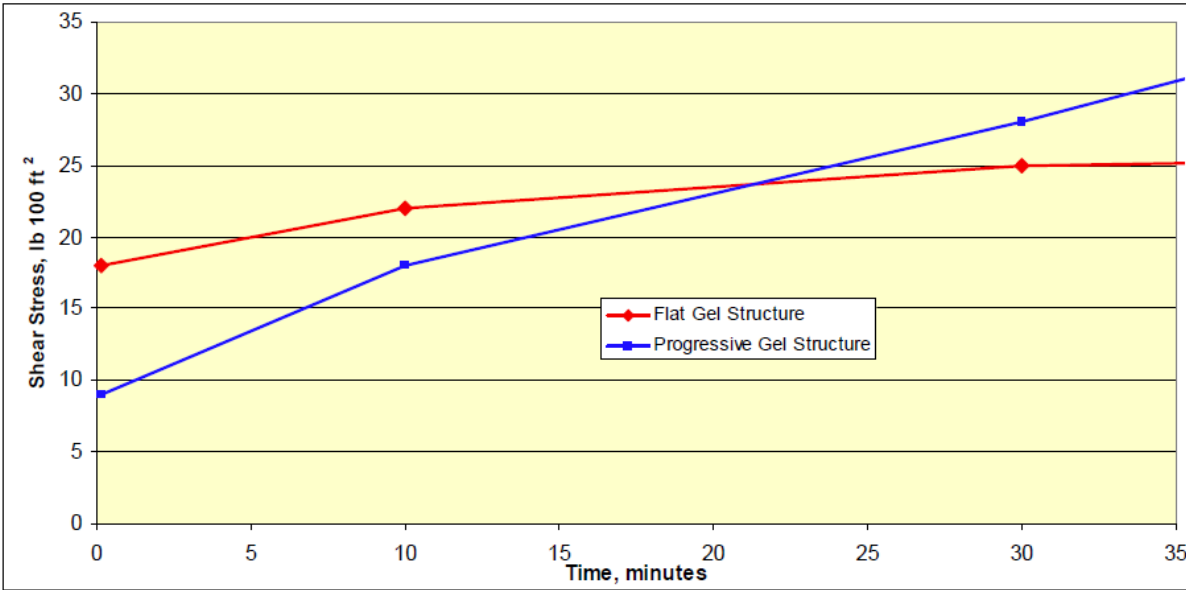
## 6.2.4 Contaminated and Flocculated Mud

Swab and surge pressure when moving pipe can be significantly increased when the mud has a high plastic viscosity, effective viscosity, yield point or gel strength. These conditions are worsened by the mud becoming contaminated or flocculated. Gel strength when pipe movement is started after making or breaking a connection can be especially important when the operating window between pore pressure gradient and fracture gradient is small. A fragile gel rather than a progressive gel (See **Figure 6-2**) is desirable to minimize the pressure spike caused when initiating pipe movement. Moore and Gillikin reported (2010) that in a deepwater well in Mississippi Canyon, an operator encountered pressure spikes while drilling the 22-in. hole with a conventional clay-based synthetic-based mud. After connections, data from the pressure-while-drilling (PWD) tool showed pressure spikes 0.5-1.2 ppg higher than the drilling ECD. It was reported that this “mini-fracing” of the formation led to lost returns and ultimately wellbore collapse.



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Following normal drilling practice should mitigate this potential problem during tripping operations. The drilling fluid specialist normally will condition the mud and treat for acceptable rheology when the well is circulated clean from bottom before tripping operations are started. The drilling fluid specialist can be provided written instructions to monitor and maintain the mud properties in a specified range.



**Figure 6-2: Example of Fragile and Progressive Gel Strengths (After Moore & Gillikin, 2010)**

An equation for estimating the fluid pressure gradient for breaking the gel is given by Bourgoyne et. al (1986) as:

$$\frac{dP_f}{dL} = \frac{\tau_g}{300(d_2 - d_1)}$$

### Equation 6.1: Pressure Gradient to Break Gel

Where:

$\frac{dP_f}{dL}$  = The pressure gradient required to break the gel, psi/ft,

$\tau_g$  = the effective gel strength at the time the gel is broken, lb/100 ft<sup>2</sup>,

$d_2$  = the diameter of the borehole or inner diameter of the casing in the annular section, in,

$d_1$  = the outer diameter of the BHA or pipe in the annular section, in.

### **Example Problem 6-1: Calculating Swab Press due to Gel Strength**

Calculate the swab pressure surge due to breaking the gel after a five minute quiescent period inside casing having an internal diameter of 10.05” for a 5” drillstring having a total length of

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10,000 ft with 500 ft of BHA having an outer diameter of 6.0". The gel strength after five minutes is estimated to be 20 lb/100 ft<sup>2</sup>.

**Solution:** The required pressure gradient is computed by applying Equation 6.1 to each of the two annular sections and then summing the results.

$$\frac{dP_f}{dL} = \frac{\tau_g}{300(d_2 - d_1)} =$$
$$\frac{20}{300(10.05 - 5.0)} \left(\frac{9500}{10000}\right) + \frac{20}{300(10.05 - 6.0)} \left(\frac{500}{10000}\right)$$
$$= 0.0132 \text{ psi/ft} (0.95) + 0.0165 (0.05) = 0.0134 \text{ psi/ft or } 134 \text{ psi at } 10,000 \text{ ft}$$

Converting to an equivalent density in lb/gal yields:

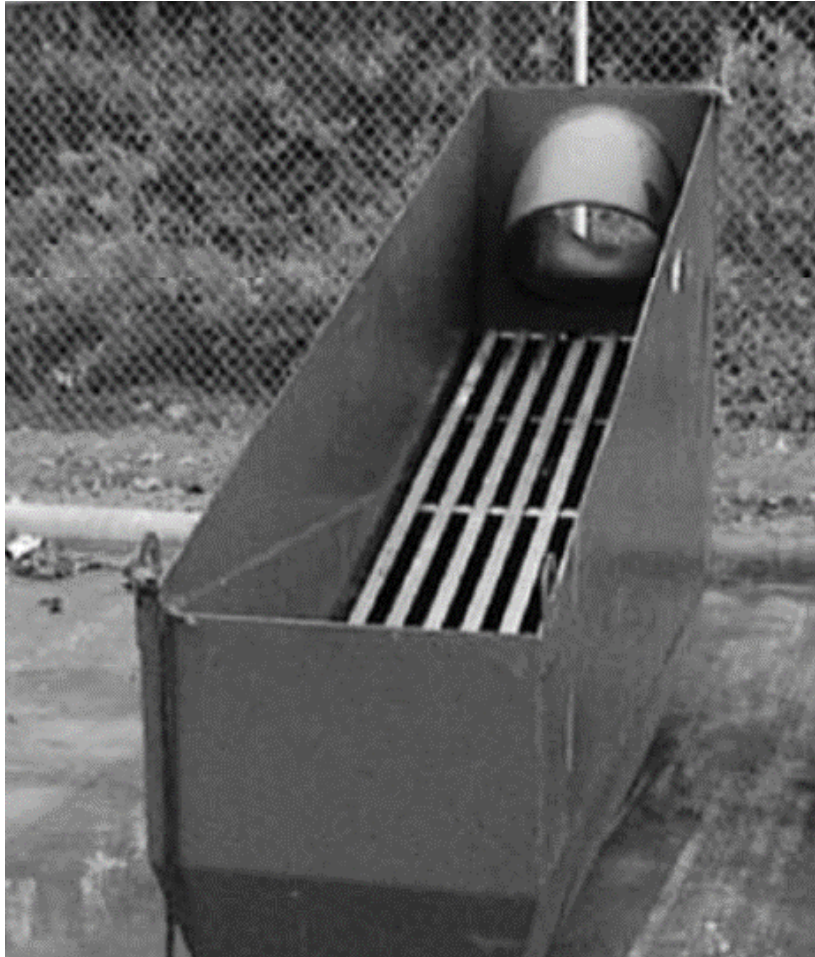
$$0.0134 / 0.052 = 0.26 \text{ ppge}$$

### 6.2.5 Gumbo Attack due to high Concentration of easily hydrated Formation Clay

Clays near the surface are often easily hydrated by water base muds and can form viscous plugs if introduced to the mud in too high a concentration by high penetration rates in large diameter boreholes. Gumbo can plug surface flowlines and has been reported to push the rotary bushings out of the rotary table and flow onto the rig floor. A gumbo box (**Figure 6.4**) is often installed in the flowline that provides an open top and a metal grate for removing gumbo from the flowline upstream of the shale shaker. Vertical movement of pipe with gumbo in the well would be expected to create unusually high surge and swab pressures, as the gumbo plugging the annulus acts as a piston.



**Figure 6-3: Gumbo attack photo from internet (probably staged)**

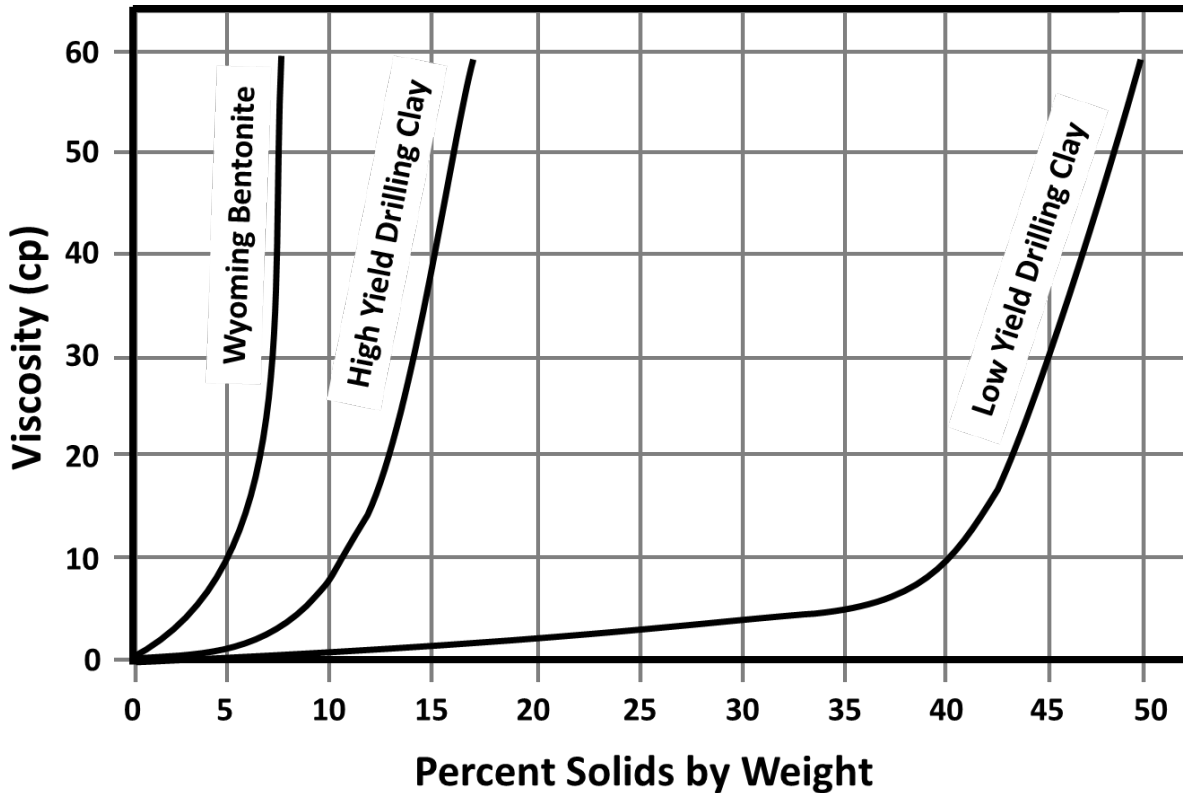


**Figure 6-4: Example Gumbo Removal Device (mud passes between bars)**

Gumbo is best mitigated by preventing its formation. This can be accomplished using an oil base mud when this choice of mud system is practical after consideration of environmental risks and operational costs. Gumbos are formed when the concentration of active clay in a water base mud becomes too high.

Active clays have a microscopic sheet-like structure that can disperse into individual platelets as water is absorbed between the platelets. Electrical charges along the edge of the platelets cause them to link together and build viscosity. The viscosity building tendency increases slowly at very low clay concentrations because the platelets are highly dispersed and do not link together effectively. Sodium montmorillonite clay, which is a very active clay, is added to a fresh-water-base mud to increase the viscosity of the mixture to about 15 to 20 cp so that the mud has sufficient viscosity to efficiently lift rock cuttings to the surface. However, once sufficient clay is present to obtain the desired mud viscosity, further increases in active clay concentration will cause a very rapid increase in viscosity as the clay platelets link together, causing the mixture to begin to gel and form “gumbo” even while being pumped. **Figure 6.5** shows how viscosity increases rapidly with clay content once a viscosity of 20 cp has been reached. The effect is more pronounced when high yield clays similar to Wyoming Bentonite are being drilled. Gumbo formation in a water base mud can be prevented by limiting the concentration of drilled solids in the annulus being generated by the bit to less than 1% when drilling through the active clay

section. This can be accomplished by control drilling to limit the penetration rate or by using an oil base mud. If the water base mud contains thinners that inhibit active clay hydration, higher concentrations of solids can be tolerated. The mud must also be treated at the surface to prevent the buildup of the active clay concentration to an unacceptable level.



**Figure 6.5: Viscosity of Water and Clay Mixtures as a function of Clay Concentration**

The rate of penetration by the bit for a specified fraction of formation solids being added to the mud by the drilling process can be estimated using:

$$R_p = 1029.4 \left( \frac{q_m}{d_b^2} \right) \left( \frac{f_s}{1 - f_s} \right)$$

**Equation 6.2: Estimating ROP from Cuttings Fraction**

Where

$R_p$  = the rate of penetration of the bit, ft/min,

$q_m$  = the circulating flow rate of the mud pumps, bbl/min,

$d_b$  = the diameter of the bit, in, and

$f_s$  = the fraction of formation solids being added to the mud.

Borehole enlargement due to caving and hole-washout can also contribute to increasing the volume fraction of solids in the annulus as well as inefficient transport of the more stable rock cuttings to the surface. An annular velocity in excess of 90 ft/min is usually desired to

compensate for downward slippage of cuttings through the mud and to maintain an acceptable average upward cuttings transport velocity.

The average annular mud velocity achieved by a given circulating flow rate of the mud pumps is given by:

$$\bar{v}_a = 1029.4 \frac{q_m}{(d_b^2 - d_p^2)}$$

**Equation 6.3: Average Annular Velocity**

Where

$\bar{v}_a$  = the average annular velocity, ft/min

$q_m$  = the circulating flow rate of the mud pumps, bbl/min,

$d_b$  = the diameter of the bit, in, and

$d_p$  = the outer diameter of the drill pipe, in.

The maximum circulating rate that can be achieved will depend on the available pump horsepower, the maximum pressure rating of the pump and the total frictional pressure loss in the circulating system.

**Example Problem 6-2: Control Drill to Limit Cuttings Fraction**

*Calculate the maximum rate of penetration and average annular velocity when drilling with a 20” bit using 5.5” drillpipe and a water base mud if the mud pumps are capable of pumping at 35 bbl/min and the maximum fraction of solids being generated at the bit is limited to 1%.*

**Solution:** *The maximum rate of penetration for a 1% fraction of solids being generated by the bit can be estimated using Equation 6.2.*

$$R_p = 1029.4 \left( \frac{q_m}{d_b^2} \right) \left( \frac{f_s}{1 - f_s} \right) = 1029.4 \left( \frac{35}{20^2} \right) \left( \frac{0.01}{0.99} \right) = 0.91 \text{ ft/min or } 55 \text{ ft/hr}$$

*The average annular velocity achieved opposite the drillpipe is*

$$\bar{v}_a = 1029.4 \frac{35}{(20^2 - 5.5^2)} = 97 \text{ ft/min}$$

*which can be expected to provide an efficient cuttings transport to the surface in the absence of a large borehole washout and enlargement. These conditions would be expected to prevent a major gumbo problem.*

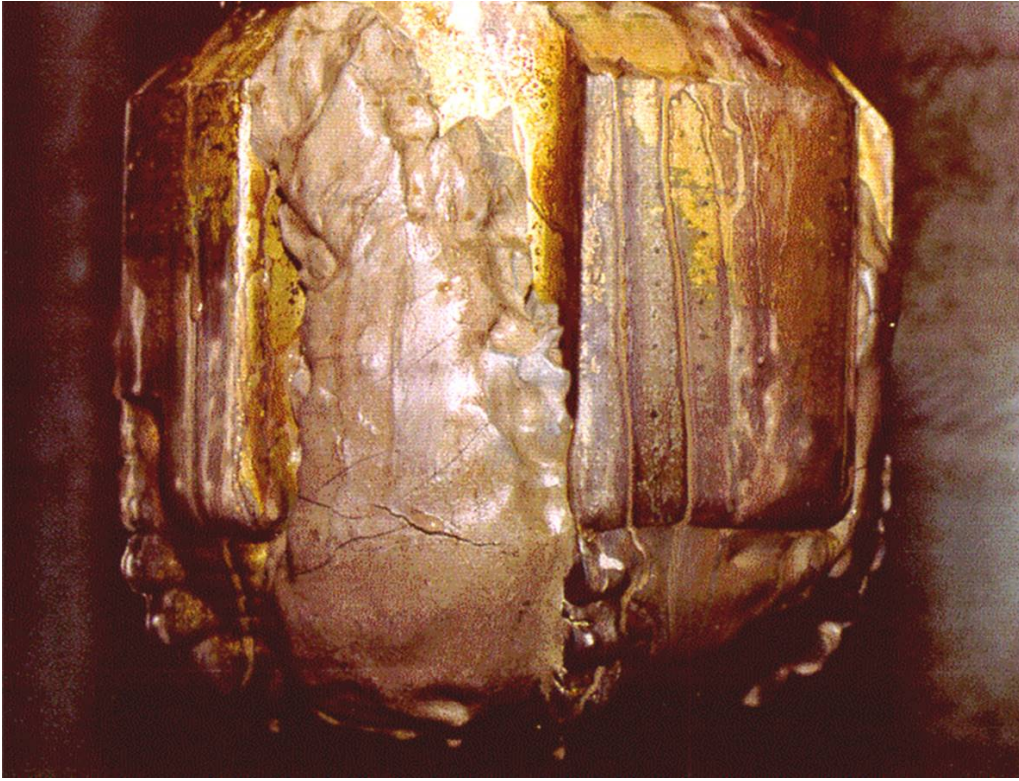
**6.2.6 Balled Bit or Bottom-hole Assembly**

Clays and shales can also stick to the bit and BHA and increase the effective diameter by plugging the slots cut for normal mud passage around the bit (**Figure 6-6**) or other BHA component. The problem is more severe when drilling shallow sediments with water base drilling fluids. A badly balled bit or stabilizer can act as a plunger and thus can greatly increase the swab or surge pressure resulting from vertical pipe movement. It is generally not possible to



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use oil base mud prior to running the marine riser, because the mud is discarded at the seafloor. Shown in **Figure 6-7** is a subsea camera picture of a balled stabilizer that has just been removed from the wellhead after drilling a shallow section of hole.



**Figure 6-6: Photograph of Balled PDC Bit Flow Passage**



**Figure 6-7: Balled Stabilizer when Drilling Shallow Sediments prior to Running Marine Riser**

The problem of a balled bit and/or BHA is generally eliminated or at least made much less severe when using an oil base mud. Problems such as the one shown in Figure 6.5 where it is necessary to drill with a water base system can be mitigated by using the top drive to circulate and back ream when pulling out of the well. Control drilling can also reduce the balling tendency, but this will significantly increase drilling fluid costs when the mud is being discarded at the seafloor.

### **6.2.7 Narrow Window between Pore Pressure Gradient and Fracture Gradient**

**CFR 250.414** requires that the equivalent downhole mud density must be a minimum of 0.5 pound per gallon below the lower of the casing shoe pressure integrity test or the lowest estimated fracture gradient, except that an equivalent downhole mud weight as specified and approved in the APD can be used if adequate documentation (such as risk modeling data, off-set well data, analog data, seismic data) is provided to justify an alternative equivalent downhole mud weight. If unexpected lost returns indicating fracture of a weak formation are encountered near the bottom of a planned hole-section, it may not be possible to use a Trip Margin when pulling pipe out of the well and still maintain the required fracture safety margin. This problem can be mitigated by obtaining BSEE approval to use a reduced fracture safety margin when tripping out of the well. The approval request can be justified by pointing out that the fracture safety margin based on the casing shoe pressure integrity test is still being maintained. The casing shoe is the critical point for preventing a formation fracture from extending upward into weaker sediments.

Another mitigation option would be to use the top drive to pump while pulling out of the well so as to prevent any swab pressure loss from pipe movement. Keeping the hole continuously full also minimizes swings in the downhole pressure which is an advantage when the window is narrow.

### **6.2.8 Downhole Density Decrease due to Warming**

The equivalent downhole density will generally decrease by a small amount after mud cooling due to circulation of fresh mud from the surface is stopped and tripping operations are started. This density decrease due to warming is almost always small enough to be easily accommodated by the mud weight being higher than the pore pressure by an appropriate trip margin. As discussed previously, simulations of the loss in downhole effective mud weight due to warming after circulation is stopped. The effect of fluid warming will generally not be a problem when the pore pressure or the trip margin is verified prior to starting tripping operations. The effect of fluid warming is almost always small compared to the swab pressure loss due to pulling pipe.

The effect of fluid warming on equivalent downhole mud density can be estimated by running computer simulations capable of accounting for heat flow between the drilling fluid and the formation. Many of the drilling fluid and well monitoring service companies have computer software designed to calculate the effective density decrease. It could be necessary to calibrate the computer model for the local well conditions using PWD data taken in the hole-section of interest in order to achieve a high level of accuracy.

Zamora et al (2012) presented calculated changes in equivalent downhole mud density for a deepwater well and a HTHP well using proprietary Schlumberger software. Their results show a

0.1 ppg increase in equivalent downhole mud density could occur for a deepwater well due to warming after circulation is stopped, even though the local density at the bottom of the well is decreasing due to warming. Their results for the HTHP wells showed a decrease in equivalent downhole mud density due to temperature effects for all mud types<sup>59</sup>.

### 6.3 Seepage Losses Hide Gas Influx

Formation pore pressure gradient can vary from point to point within an open-hole section. This makes it possible for the wellbore to be overbalanced at some points and at the same time be underbalanced at other points. This most commonly occurs when drilling through an abnormally high-pressure shale section above permeable sands that exhibit a pressure gradient regression towards more normal values. Stringers of silty shale within the high-pressure shale section may be capable of bleeding gas into the borehole at a low rate that is not noticed when the well is being circulated but cause a noticeable increases in local mud-gas concentration when circulation is stopped. The region of higher mud gas concentration is observed when it is pumped to the surface and is reported as connection gas, trip gas, etc. based on the circulation time between peaks in mud gas concentration. Generally, the permeability of the zones causing gas to bleed into the mud is too low to cause the well to kick, unless circulation is stopped for a long period of time. Barite sag<sup>60</sup> can also occur when circulation is stopped for a long period of time. When performing extended well logging and other formation evaluation activities that may require several days to complete, it is common to interrupt these activities to make a hole-conditioning trip to allow the wellbore fluids to be circulated to a more uniform condition. Hole-conditioning trips after well logging and before running casing are a common practice.

Another situation in which pore pressure gradient can vary from point to point is within a thick sand in which gas is the continuous pore fluid. This can occur within a perforated interval as shown in Figure 6-1 as well as in an open-hole section. Note that in the example of Figure 6-1, the top perforation is slightly underbalanced while the bottom perforation is slightly overbalanced. If the gas sand has a high permeability and the wellbore fluid does not have effective filtrate loss characteristics, significant fluid movements can occur even at low differential pressures.

The volume required to fill the well is equal to the volume of steel removed, plus any seepage loss that is occurring, minus any influx volume, and minus any gas expansion volume due to bubbles of gas rising in the well (see **Equation 6.4**).

$$V_{fill} = V_{steel} + V_{seep} - V_{influx} - V_{exp}$$

#### **Equation 6.4: Fill Volume with Gas Influx (Overbalanced)**

The cumulative influx volume plus any expansion of a previous influx swabbed in due to pipe movement is the volume of formation fluids in the well.

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<sup>59</sup> The possible change in equivalent downhole mud density after circulation was stopped was not reported for the HTHP well example.

<sup>60</sup> Barite sag refers to downward migration of the barite particles due to gravity that causes the mud density to become non uniform.



The purpose of a trip sheet is to help with an early detection of a kick. Normally, an apparent influx volume is calculated assuming there is no seepage loss or rising gas bubbles (**Equation 6.5**).

$$V_{influx\ app} = V_{steel} - V_{fill}$$

**Equation 6.5: Apparent Influx Volume**

A positive apparent influx volume is an indication that the well is flowing. When the apparent influx volume is negative, seepage is indicated and the apparent seepage loss rate is obtained simply by reversing the sign (**Equation 6.6**).

$$V_{seep\ app} = V_{fill} - V_{steel}$$

**Equation 6.6: Apparent Seepage Volume**

When the apparent seepage loss is negative, this is an indication that the well is flowing. However, if actual seepage losses are present and increasing, the well could be starting to flow even when the apparent seepage loss is positive. Combining Equation 6.4 and Equation 6.6 gives

$$[V_{influx} + V_{exp}] = V_{seep} - V_{seep\ app}$$

**Equation 6.7: Actual Seepage vs Apparent Seepage (Possible Underbalance)**

**Equation 6.7** shows that whenever the actual seepage loss is greater than the apparent seepage loss, the well may be starting to flow.

This potential problem is best mitigated by controlling seepage losses to an acceptable level prior to starting the trip and then monitoring hole-fill-up data using a trip sheet for indications that seepage losses are increasing. Setting a limit on seepage loss rate during a trip is somewhat analogous to setting an alarm on pit gain volume. When seepage losses are occurring, even at a low rate, time between fills becomes an important factor as well as the number of stands and “best practice” is to *keep the hole full all of the time while monitoring the fill-up volume all of the time*. A small seepage rate over a long time interval between fills can remove a significant volume from the well that makes room for a kick influx volume to go undetected.

If seepage loss cannot be controlled to an acceptable level with LCM material, a risk analysis of the tripping operations should be conducted that take into account known hole conditions. More frequent flow checks can be performed to mitigate the increased risk of an undetected influx. In an extreme case, where permeable high pressure gas zones are known to be present and the safe operating window between fracture gradient and pore pressure gradient is small, the hole-section containing the thief zone may have to be sealed with cement.

#### 6.4 Gas Migration

Gas migration due to rising gas bubbles in the fluid column can cause kicks during tripping operations. In some cases, a small volume of high pressure gas that is trapped in the well below a packer is released at the beginning of tripping operations. In other cases, small volumes of gas are swabbed into the bottom portion of the well at the beginning of the trip when the clearance around the outside of the BHA tends to be small. The gas initially has a negligible effect on the effective downhole mud density because the gas volume is small. However, as the gas bubbles rise in the wellbore to more shallow depths, the gas volume increases as the pressure exerted on the gas by the wellbore fluid decreases.

The ideal gas law, which states that the volume of a gas is inversely proportional to its pressure, is frequently used in well control training to explain the increase in gas volume as it moves towards the surface. Hence a one bbl gas volume at 10,000 ft would be expected to increase to 2 bbl at 5000 ft, to 4 bbl at 2500 ft, to 8 bbl at 1250 ft, to 16 bbl at 625 ft, and to 32 bbl at about 300 ft<sup>61</sup>. Gas volume expansion as it nears the surface can cause a significant decrease in the bottom-hole pressure and effective downhole fluid density. If the decrease in effective downhole fluid density exceeds the Trip Margin, the well will begin to flow. There can be a large time delay from when the gas entered the fluid column on bottom to when the well begins to flow because of the time required for the gas bubbles to migrate to near the surface. This delayed loss of hydrostatic bottom-hole pressure is similar to the delay that would be observed from gradual warming of downhole fluids<sup>62</sup>.

Migration of small gas volumes in oil base mud will usually stop as a result of the gas bubbles being dissolved as they rise through the mud. The reduction in density of the mud will depend on the volume of gas dissolved. However, if the mud is circulated to the surface, the gas will rapidly come out of solution when the bubble point is reached at the top of the gas contaminated region of mud. Once gas starts coming out of solution, the pressure of the mud below is reduced, allowing the flash point to quickly move down the column of gas contaminated mud. This has been studied and modelled by O'Bryan and Bourgoyne (1988, 1989).

Migration of small gas volumes in water base muds is only slightly affected by gas solubility. A volume of gas released at the bottom of a column of water base mud tends to break up into small bubbles as it rises (Casariego, V., and Bourgoyne, A.T., 1988). In a static mud, the smallest bubbles are arrested by mud gelation and remain in place until the well is circulated (Rader, D. W., Bourgoyne, A.T. and Ward, R. E. (1975)). Gas migration rates vary greatly with bubble size and bubble size depends in large measure on the gas influx rate and drilling fluid velocity when the gas is introduced. Measurements made in a 6.065" by 2.375" fully eccentric annulus at LSU (Bourgoyne, Koederitz, and Bacca, 2002) show that the measured gas rise velocity varied from about 0.4 ft/s to about 1 ft/s for the larger bubbles in a vertical annulus with a mixture velocity

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<sup>61</sup> In reality, the gas bubbles are dispersed over a significant depth range, and while the volume does expand, it does not expand as rapidly as indicated in this simplified treatment.

<sup>62</sup> For the specific case of the ST 220 Well A3 blowout, the calculated magnitude of the decrease in bottom-hole pressure due to migration of trapped gas that was released when the packer was unseated was much greater than the calculated effect of fluid warming over time. However, neither of these effects would have been large enough to initiate a kick if the intended Trip Margin was actually present.

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near zero. Downward muds annular velocities in excess of 0.35 ft/sec were found to be necessary to successfully reverse circulate a gas slug down a test well having a 5.92” by 2.375” annulus.

Migration of small gas volumes in clear completion fluid will continue until the gas reaches the surface. For typical annular geometries, the gas volume will break up into bubbles. Measurements made in a 6.065” by 2.375” fully eccentric annulus at LSU (Bourgoyne, Koederitz, and Bacca, 2002) show that the measured gas rise velocity was about 0.7 ft/s for the larger bubbles in a vertical annulus with a mixture velocity near zero. A downward water annular velocity in excess of 0.7 ft/sec was found to be necessary to successfully reverse circulate 100% of a gas slug down a test well having a 5.92” by 2.375” annulus.

Gas migration after an incomplete reverse circulation or after a possible release of gas that was trapped below a packer is best mitigated by performing a complete circulation in the normal direction prior to starting tripping operations. Possible migration of a small gas influx that was swabbed in at the beginning of a trip is best mitigated by using a Trip Margin of twice the expected effect of swabbing and by careful monitoring of fill-up volumes using a trip sheet.

## 6.5 Rapid Influx from High Productivity Gas Zone

A gas zone with a high productivity is capable of unloading wellbore fluids very quickly, which greatly reduces the amount of time during which the rig crew must successfully implement the well shut-in procedure. This was true for most of the significant events that occurred in the OCS during 2005-2015, in that they involved either a shallow gas flow or flow from a high productivity gas zone.

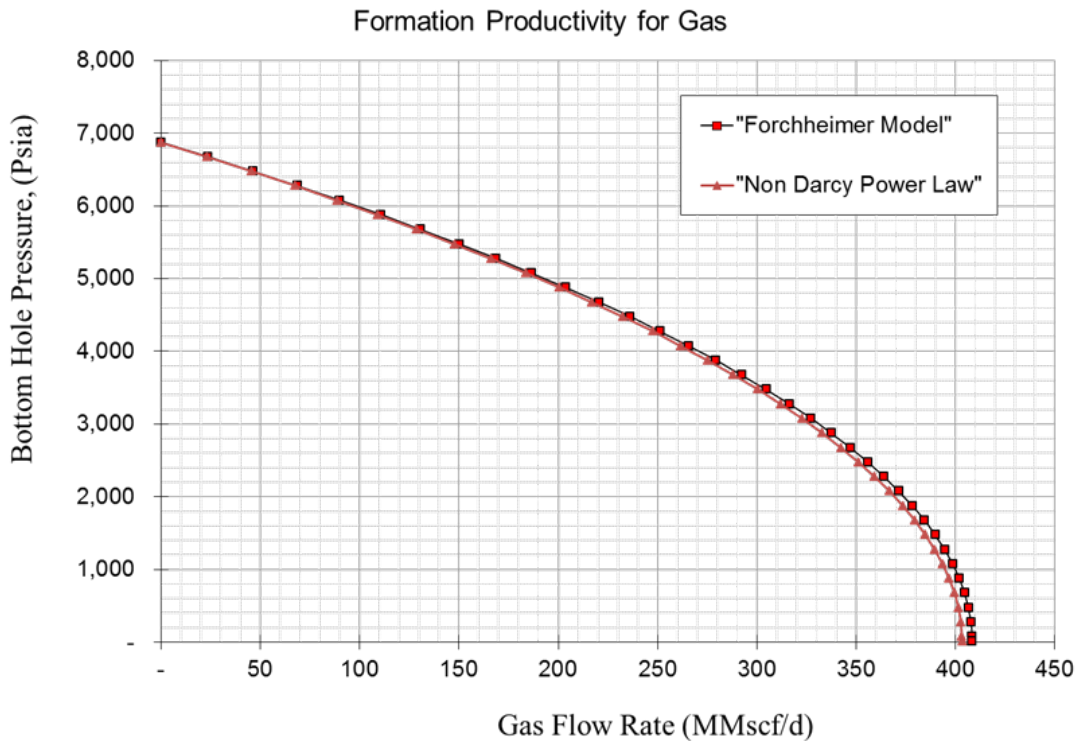
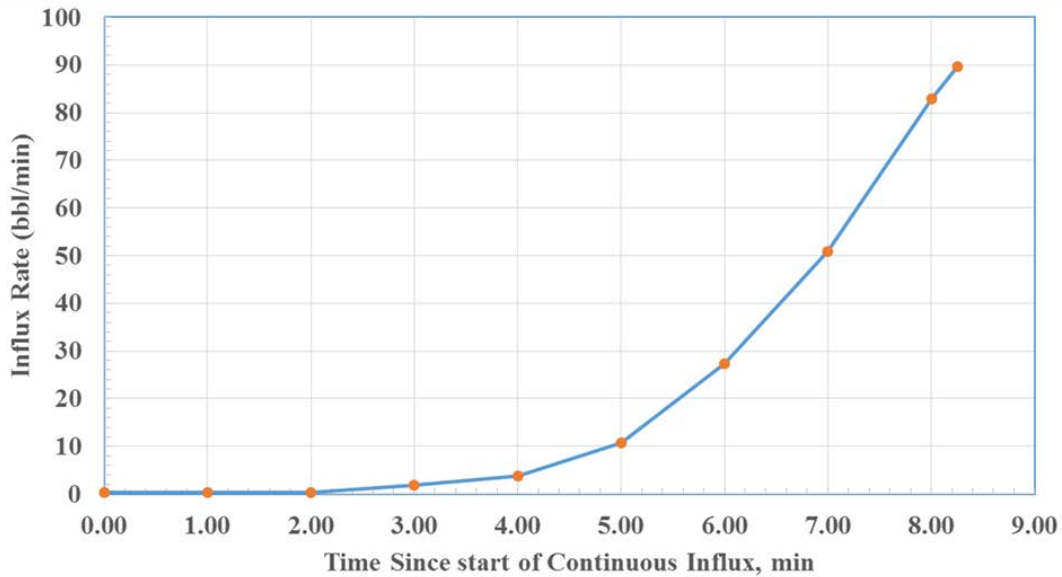


Figure 6-8: Formation Productivity Calculated for ST 220 A3 Blowout

The Formation productivity for the gas zone involved in the ST 220 A3 blowout is shown in **Figure 6-8** as modelled using the Forchheimer Model and the Non-Darcy Power Law Model. This gas zone at a depth of about 8,800 ft had a calculated open flow potential of about 400 Million Standard Cubic Feet per Day. The resulting well unloading rate calculated for this formation productivity is shown in **Figure 6-9**. Note that the rig crew had only about three minutes to react after the flow rate exceeded 1 bbl/min in order for it to be detected before the flow rate exceeded 10 bbl/min. Successful installation of a Safety Valve on the drill string is very difficult once the flow rate reaches such a high value.

The best mitigation for a rapidly unloading well is having a well-trained crew that is capable of early kick detection using a trip sheet and that has practiced the appropriate shut-in procedures for a rapidly unloading well when early kick detection does not occur. Dressing the top drive so that it can be stabbed into the drillstring as a back-up to installing a safety valve provides an additional alternative prior to making a decision to shear the drillpipe.



**Figure 6-9: Rate of Well Unloading Calculated for ST 220 A3 Blowout**

**6.6 Failure to Shut-in**

Failure to shut-in in a timely manner is generally caused by human factors related to kick detection and to a timely and appropriate response after the kick is detected. Very late kick detection can lead to equipment failures and loss of the ability to shut-in the well. Mitigation of this problem is best accomplished by developing appropriate policies, written communications, crew training, readiness drills, and review processes as has been discussed in other sections of this report.

**6.6.1 Shut-in Procedure Complications**

Almost all training and well control drills assume that the shut-in procedure will go as planned. Seldom are the many scenarios that can occur addressed further than a brief discussion in a training class, if at all. The most common of these while tripping is complications which prevent or encumber installing the drillstring safety valve. If, for example, heavy completion brine (a

known skin and eye irritant) is splashing over the bell nipple, the driller may be tempted to close the annular and attempt to divert flow through the choke until the safety valve is installed. Though this action may seem like a good (and safer) idea in the moment, careful consideration before matters became so dire would likely have revealed that this action would not have made it easier to stab the drillstring safety valve.

Drilling floats are an effective mitigation for the specific complication of inability to seal the drillstring (i.e. prevent backflow) when operational conditions allow them to be used.

Table top drills that highlight the options available and actions to consider for overcoming other shut-in complications could be mitigation for the more general case (see **Section 5.7.3**)

An organized catalog of past incidents arising out of complications during the shut-in process would be useful for developing such drills.

### **6.6.2 Outrunning the kick**

Maintaining a trip sheet is an important tool for diagnosing a well influx due to swab pressure loss when pulling pipe. A flow check is an important diagnostic procedure used to check for an underbalanced well condition when the well is static.

Standard procedure taught in well control training programs is to return to bottom and circulate the well clean if the apparent influx volume detected from measuring hole-fill-up volume is too small to create an underbalance condition when the well is static. However, when a flow check indicates the well is flowing, the standard procedure is to shut-in the well.

Trying to kill the well with the drill string off bottom can cause additional problems. An influx volume below the drill string cannot be circulated out and the kill mud cannot be placed on bottom. Well control procedures are only capable of maintaining a constant pressure at the bottom of the drill string and bottom-hole pressure might not be maintained at the desired value.

Stripping back to bottom is not a routine practice and is also not always a trouble-free operation. Thus, there is a natural tendency to want to run back to bottom if it can be done safely without taking a large influx volume. The procedure of running back to bottom quickly before shutting in the well is sometimes called “*outrunning the kick*.”

A similar dilemma can occur if a kick with a very slow influx rate is detected when the drillstring is almost completely out of the well. There is a natural tendency to want to get the BHA out of the blowout preventers before closing the blind rams or get the BHA below the blowout preventers before closing the annular preventer.

Serious well control events can occur if a large gas influx volume is taken while trying to outrun a kick. A large influx volume can cause the surface pressure to build to a high value when the blowout preventers are activated. The unloading rate may also have increased to a high rate that can make it difficult to stab a safety valve and increase the tendency to flow-cut a seal when shutting in. High surface pressures also increase the risk of a “pipe-lite” condition when shutting in the well.

Because the solutions to the above-described dilemmas can be dependent on the given well conditions, well design and local geology, it is recommended that a written plan be prepared prior to drilling that provides guidance when such conditions are encountered. While this plan

may not address all possible conditions, the fore-thought in developing such a plan and the guidance it provides should assist the rig crew in making these more challenging decisions.

### **6.7 Lack of attention**

Lack of attention by the rig crew to kick indicators is another possible cause for taking a large kick. A review of recent well control events indicate that the industry has a good record of preventing blowouts, but a possible “lack of attention” problem was indicated in at least one case during the past 10 years when the well flowed after it was believed that a verified primary barrier of cemented casing was in place.

Drills and training in addition to assigning monitoring duties to multiple crew members are common mitigations for this hazard. Additional mitigations include not making transfers to the active pit during a trip or flow check; if transfers have to be made, to stop tripping while transferring and closely observe the hole and pits. Keeping the hole full at all times with a continuous fill trip tank design also reduces the chances of skipping, or missing a hole fill-up.

The often highly-repetitive nature of tripping operations can also contribute to a lack of attention. An occasional quality review of tripping practices conducted either at the rig or via remote monitoring, is an additional mitigation for this cause.

### **6.8 Improper operation of BOP Control System**

There is strong evidence to suggest that in at least one blowout case studied improper operation of the BOP Control System could have been one of the contributing causes of the blowout. For the accumulator system being used, an incomplete actuation of the selector valve could allow the accumulator pressure to bleed down due to “valve interflow.”

Valve interflow allows the stored accumulator pressure to be vented to the hydraulic fluid storage tank. If power is shut-off to both the air compressor and the electric accumulator hydraulic fluid pump, the accumulator pressure needed for proper BOP and HCR valve operation cannot be maintained when valve interflow is taking place. When operating the accumulator from a remote panel, the operator must push and hold a Master Control Pushbutton while operating other control buttons to close various BOP components. If the Master Control Button is released too quickly, it is possible to leave the selector valve in a position of incomplete actuation in which valve interflow is occurring.

Signage on similar remote panels specifies holding both the Master Control Function and BOP Function for at least two seconds when operating the BOP system from the remote panel.

Mitigation of this potential problem can be accomplished by crew training and the use of shut-in practice drills. Shut-in drills should include practicing well shut-in procedures from the remote panel as well as from the rig floor. This was previously discussed in the section of the report on crew training. Good signage on all control panels can provide reminders for proper operating procedures.

### **6.9 Failure to keep the hole full**

The failure to keep the hole full could occur while tripping if not actively using a continuous fill trip tank by missing the fill up after pulling 5 stands of pipe for example. Another possibility to fail to keep the hole full could result from losses, seepage, or otherwise, where the hole is not kept full.

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This could be exacerbated if the rig pauses during a trip for any reason (rig repair) and the rig crew does not carefully monitor the hole over this period of time. This could be addressed by always maintaining a full hole with a continuous filling trip tank. Hole losses should be recorded over time if the trip is paused for any reason including the time the rig is static while making a flow check.

## 6.10 Tripping Well Control Hazzard and relevant Mitigations Summary

**Table 6-1: Potential Cause and Mitigation Summary Table**

<b>Potential Cause for Loss of Well Control while Tripping</b>	<b>Mitigation(s)</b>
Higher Pore Pressure than Expected (6.1)	Verify trip margin is sufficient. Use of Trip sheets, flow checks, and short trips.
Insufficient Trip Margin (6.2)	Increase Density by ECD to provide extra trip margin. Use Pulling Speed that produces Swab Pressure less than 50% of ECD. Short trip at pulling speed that produces 25% higher swab pressure than planned pulling speed to test safety margin.
Swab Calculation Not Performed (6.2.1)	Use a swab screening tool.
Tripping Speed Too High (6.2.2)	Written instruction specifying maximum pulling and running speeds verses depth.
Mud Weight in Trip Tank Not Maintained (6.2.3)	Follow good fluid conditioning practices. If intentionally filling with lighter fluid to reduce loss rate, verify that the lighter fluid provides adequate trip margin if it fills the well.
Contaminated and Flocculated Mud (6.2.4)	Follow good fluid conditioning practices Calculate Pressure required to break the gel. Adjust mud properties if needed (Example Problem 6.1)
Gumbo Attack due to High Concentration of easily hydrated Formation Clay (6.2.5)	Use of synthetic and oil based mud systems will eliminate possibility. Use of salt saturated water based mud systems reduces possibility Use of surfactants can reduce possibility. Control drill to keep cutting concentration low (Example Problem 6.2)
Balled Bit or Bottom-hole Assembly (6.2.6)	Same mitigations as gumbo attack Back-ream while circulating to mitigate swab

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<b>Potential Cause for Loss of Well Control while Tripping</b>	<b>Mitigation(s)</b>
Narrow Window between Pore Pressure Gradient and Fracture Gradient (6.2.7)	Approval to allow smaller fracture margin during trip. Pump out of hole
Downhole Density Decrease due to Warming (6.2.8)	In most cases mitigated by a verified trip margin. Apply a screening criteria (HPHT, ultra-deepwater) Model temperature behavior, estimate magnitude of effect.
Seepage Losses Hide Gas Influx (6.3)	Control seepage losses Use trip sheet to monitor trend in losses Use of continuous fill trip tank Increase flow check frequency Plug back open hole above thief zone
Gas Migration (6.4)	Full circulation after releasing packer Trip margin twice the calculated swab pressure Continuous fill trip tank, monitor with trip sheet.
Rapid Influx from High Productivity Gas Zone (6.5)	Continuous fill trip tanks, trip sheet. Ability to stab top drive into the majority of drillstring connections Float in BHA
Failure to Shut-in (6.6)	Well control polices Written communications Training Readiness drills Review and verification that good practices or being implmented
Shut-in Procedure Complications (6.6.1)	Table top Drills (Section 5.7.3) Use of a drilling float Top drive dressed to stab into the majority of drillstring connections
Outrunning the Kick (6.6.2)	Strip back to bottom Written Communication Training
Lack of Attention (6.6.3)	Readiness drills Multiple crew members monitoring (more than one set of eyes) External review of tripping practices



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<b>Potential Cause for Loss of Well Control while Tripping</b>	<b>Mitigation(s)</b>
Improper Operation of BOP Control System (6.7)	Training Review of specific control system on rig Clear and deliberate activation practices Monitoring manifold and accumulator pressure Competency drills
Failure to Keep the Hole Full (6.8)	Continuous fill trip tank Monitor for hole losses during extended static periods

Regarding the state of the art of the technology available to operators, following are additional observations were made in this study:

1. The current state of well control monitoring during tripping is sufficient, given that it is properly implemented and monitored.
2. The current state of models (e.g. for surge/swab pressures, ECD, downhole fluid densities, etc.) are sufficiently accurate for the typical applications to which they are applied. In situations where more precise higher-confidence estimations are needed, operators will normally either calibrate the models with relevant measured data or apply measurement instead of modelling.
3. The calculation methods used for Trip Sheets are generally accurate enough. When errors occur it is most often due to misinterpretation of trip tank data or failure to monitor. This is especially important in cases where earlier detection would have minimized the well control consequences.
4. Universal use of trip tanks in a continuous-fill mode with proper fill-volume accounting will reduce well control risks compared to a conventional periodic-filling mode.

Given the above findings and current practices, it is recommended that wider use of continuous fill trip tanks would improve the safety of drilling operations. Further, automated monitoring of trip tank volume versus calculated pipe displacement with alarms for abnormal behavior may provide earlier detection and improved detection during routine operations, particularly where long pauses in tripping occur.

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## 7 ANALYSES OF BLOWOUT INCIDENTS WHILE TRIPPING

A major effort was made by students and staff at the LSU Petroleum Engineering Research and Technology Transfer Laboratory to compile available worldwide information about well control incidents *that initiated during tripping operations during the 10 year time period of 2005 to 2015*. This section of the report summarizes the available information regarding the well control incidents for which records were available. This information was used in other sections of the report to make recommendations to BSEE regarding prevention of similar events in the future.

For offshore areas, multiple incidents occurred during the time period of the study that were associated with gravel pack or fracture pack completions, shallow gas flows, and temporary abandonment operations. It was noted that diverter operations were sustained for several events without diverter failures. Improvements in diverter designs appear to have overcome the high rate of diverter failures seen prior to 2005.

Only three blowout incidents were found during the 2005 to 2015 time period that resulted in a spill of more than 1000 barrels of oil. These included the Montara blowout in Australia in 2009, the Macondo Blowout in 2010 in the USA, and the Frade Blowout in 2011 in Brazil. The estimated volume of the Macondo blowout spill was two orders of magnitude greater than the Montara Spill and three orders of magnitude greater than the Frade spill. None of these blowouts were associated with tripping during drilling and completion operations.

### 7.1 Blowout Incidents on the United States Outer Continental Shelf

BSEE listings of Incident Investigations, District Investigation Reports and Panel Investigation Reports for the time period 2005 to 2015 were reviewed to identify blowout incidents that initiated during tripping operation. A brief description of these well control events that occurred during the 2005 to 2015 time period will be followed by more detailed descriptions of each of the events. All of the events reported by BSEE during the 2005 to 2015 time period were in the Gulf of Mexico OCS Region. Most of the 19 well control events reported during this 11-year period were relatively minor, did not involve significant pollution or personal injury, and were not classified as “historic blowouts” in the incident investigation reports. Only two events resulted in loss of life, with the infamous Deepwater Horizon disaster accounting for 11 of the 12 fatalities.

BSEE reported that 4 blowouts occurred in 2005 but none involved tripping operations and no significant oil pollution or injuries were reported. On March 8, 2005, a wellhead leak resulted in a saltwater flow into the Gulf at South Timbalier Block 242. On May 16, 2005, a packer failure during a workover caused an extended well control event in Green Canyon Block 236, but the resulting kick was successfully controlled and no blowout occurred. On May 28, 2005, shallow gas was encountered at Eugene Island Block 205, and the well was placed on the diverter for 1.5 hours before the well bridged. On November 30, 2005, a shallow gas zone caused flow after cementing the surface casing at South Timbalier Block 230, and the well was placed on a diverter for about 14 hours before the flow stopped. A light sheen was observed but the spill volume was estimated to be less than 1 gallon. On December 1, 2005, shallow gas was encountered in South Timbalier Block 135 and the well was placed on a diverter and killed using a Barite Pill.

One blowout, which occurred at High Island Block A-466, was reported in 2006 and the incident resulted in one fatality. Plug and abandonment operations were being conducted and tubing was

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being stripped through the annular preventer using hydraulic casing jacks. The tubing became stuck and was pulled in two when the yield strength of the pipe was exceeded. Tragically, the recoil and well pressure ejected the slips which struck and killed the operator's representative. A brief loss of well control was reported.

Two blowouts were reported in 2007 without injuries or pollution. On August 23, 2007, gas leaked in Main Pass Block 91 from a failed casing that had been experiencing sustained casing pressure. No visible pollution was observed. The well was killed using a relief well. The second event occurred in Eugene Island Block 28 on December 3, 2007 when tubing was pulled in two during a workover. Well control was quickly re-established by closing the annular preventer and the pipe rams. The well was killed using a snubbing unit.

Two events were reported in 2008 without injuries or pollution. On February 13, 2008, a seal ring below the master valve leaked natural gas after an acid job was performed during wireline operations being conducted at South Pelto Block 10 to remove scale buildup inside of the tubing. On May 6, 2008, shallow gas was encountered at Eugene Island Block 342 at 1,679 ft and the well was placed on diverter. The open hole below the conductor was cemented off and bypassed successfully.

Two events were reported in 2009. While neither of these events involved an uncontrolled release of formation fluids at the surface, they both involved well control situations initiated by pipe movement and were considered pertinent to this study. They will be discussed individually in the sections below.

In 2010, the disastrous Macondo blowout in Mississippi Canyon Block 252 occurred on the Deepwater Horizon rig on April 20, 2010. The explosion and fire caused 11 fatalities and the blowout caused very serious oil pollution. This event was initiated by a cementing failure followed by a number of human errors and equipment failures. Tripping operations (or associated swabbing effects) were not identified as contributing factors in causing this blowout.

No blowouts were reported in 2011.

Three blowouts were reported in 2012, of which the event at High Island Block A-443 involved tripping operations. This High Island incident will be discussed in more detail in a section below. A second well control incident was reported in High Island Block A-7 on May 15, 2012 during a well abandonment operation which involved repairing a sustained casing pressure problem before abandonment. While drilling out a cast-iron bridge plug, pressure was encountered causing the work string to be ejected from the well. The blowout preventers were closed and successfully secured the well. The third event occurred at South Pelto Block 93 on May 29, 2012. Wireline swabbing operations were underway with returns being taken to an unapproved open top flow-back tank when the tank caught fire. One person was injured.

Two incidents were reported in 2013. Well control was lost in Ship Shoal Block 225 on July 7, 2013 during a well abandonment operation when a tubing plug was released using coil tubing, without checking for pressure below the plug before releasing it. Well control was temporarily lost due to leaks in the tubing, production casing, and surface casing to an unsealed annulus. The second incident was a blowout in South Timbalier Block 220 that was initiated during tripping operations and is discussed in more detail in a section below.

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Two incidents were reported in 2014. An incident that occurred in Vermilion Block 356 on January 30, 2014 involved tripping operations and is discussed in more detail in a section below. A second well control incident occurred in Walker Ridge Block 578 in October 27, 2014 and involved approximately 55 barrels of mud being blown out on to the rig floor when drilling in salt. Rafts of sediments enclosed in salt are known to become highly pressurized due to salt creep. The well was shut in and pressures above the verified strength of the casing seat were experienced. Mud was lost when starting well control operations. Noise and temperature logs were later run and indicated an underground blowout was not in progress. An open-hole plug was set to secure the zone that had produced the kick.

### **7.1.1 Ship Shoal Block 349 Incident on March 21, 2009**

This incident occurred on a platform rig that was drilling in 375 feet of water. A 7-inch liner had been set at about 15,600 ft (14,583 ft TVD) and tested to an equivalent surface mud weight of 17.8 ppge. After drilling the 6-1/2 inch hole-section to 16,539 ft MD (15,434 ft TVD) (drilling operation was permitted to 17,636 ft MD (16,655 ft TVD)), a short trip was performed. With the bit at 16,256 ft, a drill pipe connection was made to wash and ream back down to 16,288 ft. While making the connection, the well was observed to have a slight flow. The well was washed down to 16,288 ft when returns were lost totaling 30 barrels. The bit was picked up to 16,258 ft where returns were regained and a pit gain of 30 barrels was observed. The well was then shut-in on the Annular Preventer where the Initial Shut-In Casing Pressure (ISICP) reached 1200 psi and the Initial Shut-In Drillpipe Pressure (ISIDP) was 0 psi. An underground blowout appeared likely with crossflow from the open-hole section to the liner shoe. The Annular Blowout Preventer remained closed during the entire event with no problems holding pressure.

The well's condition went back and forth between influxes and losing returns until the well was determined to be in a static condition and the bit tripped out of the hole on 4/4/2009.

The well was reentered to test the BOP's, condition the open-hole section, and run logs. The open hole section was then isolated with a cement retainer at 15,524 ft and an additional 100 ft of cement spotted on top of the retainer on 4/8/2008. Permitted operations to complete the well for production followed.

The use of improved training and drills regarding well control during tripping operations would have likely avoided this accident. The crew may have interpreted the pit gain as hole-ballooning and allowed too large a kick to be taken before shutting in the well. This apparently resulted in the formation fracture pressure being exceeded.

### **7.1.2 Mississippi Canyon Block 72 Incident on April 19, 2009.**

This incident occurred on a semisubmersible rig in 2013 ft of water during a frac-pack completion operation. The approved completion plan is shown in **Figure 7-1**. The plan called for perforating from 12,680 to 12,755 ft and to perforate about 250 psi overbalanced in 14.3 ppg CaBr<sub>2</sub> completion brine using tubing conveyed guns. The intermediate 9-5/8" casing was set at 11,442 ft TVD. Fluid loss was to be monitored and treated if necessary. The well was reverse circulated after perforating the 7-5/8" liner and was reported to be in a static condition. *No detail was provided as to whether or not the planned safety margin of 250 psi was verified before the well was reversed circulated.* The workstring was picked-up with 5000 lbs of over-pull to release

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the CHAMP IV Packer and the workstring was set in the slips to rig down the surface return lines.

Within minutes of rigging down surface lines, a 10 bbl trip tank gain was observed. The workstring was picked-up higher for proper space-out across the Subsea BOP stack. Both the Drill String Safety Valve (DSSV) at the rig floor and Upper Annular BOP near the sea floor were closed but the riser continued to flow. The diverter elements were closed and both 12-inch diverter valves opened, while the riser was continuously boosted with 14.4 ppg CaBr<sub>2</sub> to prevent riser collapse. The Lower Annular and Upper Pipe Ram were then closed with the well continuing to flow.

The Middle Ram was then closed with an initial choke manifold pressure of 6,700 psi. Drilling personnel estimated that approximately 200 bbl of riser brine was discharged through both 12-inch diverter lines into the GOM within 20 minutes of closing the Upper Annular. The gas-cut CaBr<sub>2</sub> blew the master rotary bushing out of the rotary table onto its side on the rig floor (rotary bushings are made out of solid steel) and non-essential personnel were mustered at the stern life boat stations donning life jackets as the general evacuation alarm sounded. No actual rig evacuation was required. The rig's personnel described the diverter flow noise and vibration as increasing to a "deafening roar".

<p><b>OBJECTIVE:</b> Complete as a single, gas well with a frac pack in the 3900 ms Sand. Run 4-1/2" production tubing with SCSSV and DHPT gauges.</p> <p><b>NOTE:</b> Well drilled &amp; T&amp;A with the Ocean America</p> <p><b>PROCESS 1: MOB RIG / SET ANCHORS LATCH / TEST BOP'S</b></p> <ul style="list-style-type: none"> <li>• Mobilize the Lorris Bouzigard</li> <li>• Position rig to run anchors</li> <li>• Run 10 anchor pattern per Delmar Mooring Design.</li> <li>• Stump test BOP's to 10,000 psi on VBR &amp; B/S and 3,000 psi on annular</li> <li>• Offline: Set Alignment Slot in BOP Wellhead Connector</li> </ul> <p><b>PROCESS 2: RUN BOP ON MARINE RISER / LATCH &amp; TEST BOP'S</b></p> <ul style="list-style-type: none"> <li>• Run BOP's on marine riser to latch FMC, 18-3/4", 15K wellhead at 2,085' ORKB</li> <li>• Test BOP connector to 8,500 psi</li> <li>• Test blind/shear ram to 7,600 psi on 8.6 ppg SW (8,500 psi at BSR)</li> <li>• Run test plug with test tool to test upper and middle VBR's for 3-1/2" x 5" to 8,500 psi. Test upper and lower 5K annulars to 3,500 psi.</li> <li>• Test surface manifold, choke/kill lines and BOP equipment to 8,500 psi.             <ul style="list-style-type: none"> <li>◦ MASP @ the VXT = 7,975 psi with .12 psi/ft gas gradient</li> </ul> </li> </ul> <p><b>PROCESS 3: PREPARE WELLBORE, DISPLACE 14.5 SBM WITH 14.3 CaBr2</b></p> <ul style="list-style-type: none"> <li>• Run to TOC &amp; displace Riser with 14.5 ppg SBM</li> <li>• Drill cement plug and CIH to TOL @ ~10,896'</li> <li>• Clean out to PBTD. Test 9-5/8" x 7-5/8" to 4,000 psi on 14.5 ppg</li> <li>• Negative test TOL to 10 ppg EMMV</li> <li>• Displace 14.5 ppg SBM with filterer 14.3 ppg CaBr2</li> <li>• RU EL. Run CBL. Set Sump packer at 12,874' ELM. RD EL.</li> </ul> <p><b>PROCESS 4: PERFORATE 3900 ms SAND WITH TCP</b></p> <ul style="list-style-type: none"> <li>• Run TCP assembly on 5-1/2" x 4" DP.</li> <li>• Locate sump packer to place guns in position to perf the 3900 ms Sand (12,780' – 12,866' MD / 12,680' – 12,755' TVD)</li> <li>• Perforate in 14.3 ppg CaBr2 with ~ 250 psi overbalance.</li> <li>• Monitor fluid loss and stabilize wellbore. POOH with TCP assembly</li> </ul>	<p><b>PROCESS 5: FRAC PACK THE 3900 ms SAND</b></p> <ul style="list-style-type: none"> <li>• Run GP packer to land base of screen in Sump packer</li> <li>• Set GP packer and test to 2,000 psi.</li> <li>• Pump frac pack - Fluid loss controlled through hydraulic fluid loss device</li> <li>• POOH with service tool.</li> <li>• Run Scoop Head Assembly on DP to cover frac closing sleeve</li> <li>• Displace the 14.3 CaBr2 with 11 ppg CaCl2</li> </ul> <p><b>PROCESS 6: RUN PRODUCTION TUBING / ACCESSORIES</b></p> <ul style="list-style-type: none"> <li>• Pull wear bushing and test BOP's</li> <li>• Run LIT (Lead Impression Tool). Run Adapter Sleeve.</li> <li>• Run Muleshoe bushing</li> <li>• Run 4-1/2" x 3-1/2" Production tubing with DHPT, SCSSV</li> <li>• MU FMC Hanger on THRT / Spanner joint on Dual Riser (landing string).</li> <li>• Land hanger with Production Seals in Packer set at ~12,650'.</li> <li>• Test Production packer to 2,000 psi</li> <li>• RU SL to set hanger plugs and secure well for tree installation.</li> <li>• Pull Dual Riser</li> <li>• Pull Muleshoe bushing</li> </ul> <p><b>PROCESS 7: INSTALL FMC SUBSEA TREE</b></p> <ul style="list-style-type: none"> <li>• Unlatch and pull BOP's on Marine Riser             <ul style="list-style-type: none"> <li>◦ Jump ROV to verify post orientation</li> </ul> </li> <li>• Run FMC - VXT on TRT / LWRP and Dual riser. Latch and test VXT</li> <li>• RU SL to pull hanger plugs</li> </ul> <p><b>PROCESS 8: WELL TEST</b></p> <ul style="list-style-type: none"> <li>• Flowback to clean up the 3900 ms Sand.</li> <li>• Displace Dual Riser with SW</li> </ul> <p><b>PROCESS 9: DEMOB RIG</b></p> <ul style="list-style-type: none"> <li>• Pull Dual riser with TRT / LWRP</li> <li>• Set Corrosion Cap on VXT with ROV.</li> <li>• Pull anchors</li> <li>• Demob rig.</li> </ul>
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**Figure 7-1: Completion Procedure for MC 72 Incident (April 19, 2009)**

Bull heading operations were initiated down the kill line utilizing the 14.4 ppg CaBr<sub>2</sub> completion fluid.

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The DSSV was discovered to be pressure-locked. A hot tap beneath the DSSV was installed by Wild Well Control Inc. (WWCI) below a 5 inch drill pipe tool joint and 3,000 psi was bled off. Approximately 1-1/2 workstring volumes of 14.4 ppg CaBr<sub>2</sub> was circulated down the workstring and up the annulus, while the riser was continuously filled with completion fluid, until the well was determined to be static. Approximately 1,200 psi of trapped pressure was bled from between the middle ram and upper pipe ram through the choke line. Well kill operations were completed with the SBOP stack swept of any remaining gas and the riser was continuously filled to remain static.

Subsequent to well kill operations the well was frac packed and the remaining completion operations performed without any further incident.

Detailed sensor data were not available for review, but key personnel on this project believe this could be another case of seepage losses offsetting a slowly flowing well because the well was much closer to balance than originally thought. Given that assumed cause, then closer monitoring of trip tank level may have provided an earlier warning of the gain. Since the record has no mention as to if the 250 psi overbalance was verified, it is unknown as to if an insufficient Trip Margin may have also been a cause. This possibility is reinforced by the key personnel's belief that the well was much closer to balance than originally thought.

### **7.1.3 High Island Block A-443 Incident on September 27, 2012**

This incident occurred on a platform rig in 182 ft of water performing a recompletion. As the rig was pulling 2 7/8" tubing out of the well, the well started flowing and wellbore fluids spewed out to a height of 30 to 40 feet in the air. The safety valve could not be installed on the tubing and the shear rams were activated in order to shut-in the well. Approximately nine gallons of oil was estimated to have been released into the Gulf waters. Three floor hands sustained injuries and were sent to shore for treatment; all returned to full duty in less than three days.

The BSEE investigation panel concluded that the probable cause of this incident was that the Lessee failed to maintain the proper mud weight of 9.0 ppg to control the well. The Mud Engineer noticed condensate or oil mixed with the returns in the trip tank but failed to stop the operation or re-weigh the mud used to fill the well as the 2 7/8" tubing was being pulled. The use of improved training and drills regarding well control during tripping operations would have likely avoided this accident.

### **7.1.4 South Timbalier Block 220 Incident on July 23, 2013**

This well control incident occurred during a gravel pack recompletion operation on a jackup rig in 154 ft of water cantilevered over an unmanned braced caisson platform.

The well was being recompleted to the 8,800 ft Sand when well control was lost. Drillpipe was being pulled out of the well when flow from the well started and could not be stopped. All personnel on the rig were successfully evacuated without any loss of life. The resulting oil pollution was limited because the produced fluid was primarily natural gas with just a small amount of associated liquid condensate and because the blowout ignited about 13 hours after control was lost (see **Figure 7-2**).

A large amount of formation sand was being produced along with the formation fluids and as a result the well flow path to the surface bridged off naturally; this occurred within a few days



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after event initiation. This blowout is well documented in a SEMS accident investigation report provided by the operator that is published on the BSEE website. The use of improved training and drills regarding well control during tripping operations and better verification of the use of an adequate trip margin would have likely avoided this accident.



**Figure 7-2: ST 220 A3 Blowout prior to and after Ignition (BSEE Panel Report 2015-2)**

### 7.1.5 Vermilion Block 356 Incident on January 30, 2014

This well control incident occurred during drilling operations on a platform rig in 262 ft of water. The well design included setting 13-3/8" casing above a known shallow gas zone at 1,309' TVD that was found while drilling an earlier well. The geologic review indicated that shallow gas might be encountered at 1,309 ft and 2,069 ft TVD. As planned, 13- 3/8" conductor casing was set at 1,217' MD (1,200' TVD) and drilling had progressed to a depth of 2,217' MD (1,935' TVD). During drilling, "gumbo" clay was being encountered and the drillpipe was moved in and out of the wellbore every 1000 feet to gauge if the hole was clean. After reaching 2,217' MD



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(1,935' TVD) the Driller began to clean the hole or “circulate bottoms up”. Then he stopped circulating and started a “short trip” which consisted of pulling the drill pipe and the BHA into the casing. The short trip operation was going as planned and the hole was taking proper fill-up until the BHA reached the shoe.



**Figure 7-3: VB 356 – A7 Diverter Operation (BSEE Panel Report 2015-01)**

When the first BHA stand with the first stabilizer came into the shoe, the driller noticed a 30K pound over-pull on his weight indicator and a 1 bbl gain in the trip tanks. A flow check was performed and the well was observed to be static. The short trip was continued, and when the drill bit was pulled into the shoe, the driller noticed another 30K pound over-pull on his weight indicator and a 10 bbl gain in the trip tanks. Another flow check was performed and the well was again static. The 11 bbl gain indicated that formation fluids had already entered the well on bottom.

Instead of returning to bottom as per normal well control practice, the top drive system was used to begin circulating. The Driller made the connection, slacked back down 20-30 feet, and began circulating mud by pumping approximately 15 strokes a minute with 300-400 psi pressure. After about 15 minutes of pumping, the well came in shooting mud “*about 8 feet above the rotary*”. The Driller closed the annular and placed the rig on diverter directing the unexpected flow through the port and starboard diverter lines then overboard. Once wind direction was determined, the starboard diverter line was closed subsequently diverting the entire flow overboard through the port line as seen in **Figure 7-3**

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The production operators activated the platform's Emergency Shut-Down (ESD) system, which safely shut in all the wells. All platform personnel were evacuated to the rig and later both rig and production non-essential personnel were evacuated by boat. A well control consultant was then brought on location as well as a resupply of kill weight mud. The well control crew used a "Dynamic Kill Procedure" by pumping sea water and eventually mud into the wellbore at high rates in order to stop the flow. The well flow stopped after flowing on diverter for approximately 36 hours. The well was then secured using a cement retainer, and by squeezing cement below and placing cement above the cement retainer. Sufficient cement was squeezed through the retainer to fill the open hole.

The use of improved training and drills regarding well control during tripping operations would have likely avoided this accident. Improved planning for inhibiting gumbo balling of the BHA, more effective use of the top drive to avoid swabbing, and safely returning to bottom when a swab kick is indicated would likely have avoided this incident. Additionally, carefully back-reaming into the shoe is a precaution (risk mitigation action) that could have been taken if bit balling is suspected (likely). By rotating and circulating while slowly pulling the BHA into the shoe, the incident-initiating kick may have been prevented. The increased risk of fracturing the casing shoe caused by back-reaming could be mitigated by pulling slowly and carefully, simultaneously monitoring pump pressure and hook load.

### 7.2 Offshore Blowouts in North Sea Areas

Twelve blowout events were identified to have occurred in the Oil and Gas Fields of the North Sea during the 2005 to 2015 time frame<sup>63</sup>. Three of these events were related to swabbing during tripping operations, those being a Snorre Field blowout that occurred in the Norwegian sector, a Forties Field Blowout in the UK Sector, and a recent Visund Field Blowout in the Norwegian sector. In addition to these blowouts, the LSU Team identified several undated case histories in a series called "Sharing to be better" developed by the Norwegian Shipowners' Association and Norskolje&gass that presented swabbing case histories.

#### 7.2.1 Snorre Field Blowout (Norway)

This blowout was a major event that eventually broached to the seafloor and is well documented in a confidential report by Marit Brattbakk (Investigation Leader), Lorents-Øystein Østvold, Claas van der Zwaag, and Hallvard Hiim (2005) of T1-StatoilGassco. The well was on a tension leg platform in about 310 m (1,017 ft) of water. The planned workover was to abandon the existing directional well and recover use of the platform slot so that a new well could be drilled. A schematic of the existing well is shown in **Figure 7-4** and the workover plan was to include:

1. Perforation of the tail pipe.
2. Replacement of brine with oil-based mud.
3. Cutting and pulling the 5 ½" tubing.
4. Cutting and pulling the 7 5/8" scab-liner.
5. Properly abandoning (cementing) the well's reservoir sections.

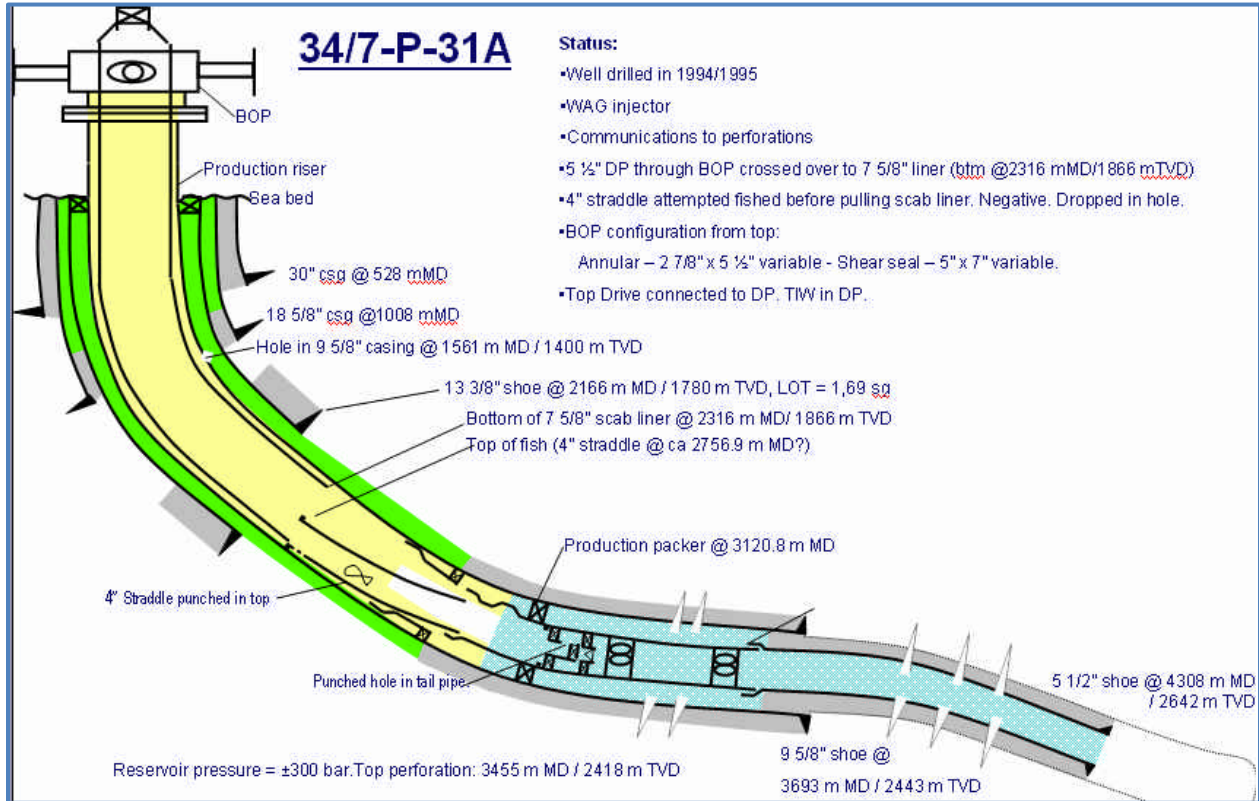
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<sup>63</sup> The time period was increased slightly to include a major event related to tripping operations that occurred late in 2004 and carried over into 2005. Another was included

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## 6. Cutting and pulling the 9 5/8" casing.

The incident occurred during Step 4 of this plan. Note that the original purpose of the scab liner was to repair a hole in the 9-5/8" casing at 1,561 m (5,121 ft).



**Figure 7-4: Status of 34/7-P-31A prior to Sidetrack Workover to Reclaim Platform Slot**

After the scab-liner was freed, tripping operations to pull the liner out of the hole were begun. Early in the trip, swabbing was indicated by a gain of about 1.25 bbl when the 2<sup>nd</sup> and 3<sup>rd</sup> stand were pulled. A single then was pulled and swabbing continued. An attempt to circulate mud down the workstring / liner and up the annulus resulted in an abnormally low pump pressure. The pack-off at the top of the liner was thought to be leaking. The volume balance of mud in compared to mud out<sup>64</sup> was reported to be satisfactory.

When the top of the scab liner reached the BOP, a flow check was performed and the well was static at the surface. Pulling the liner through the BOP stack continued while recognizing the liner was too strong to be cut by the shear rams. Trip records indicated apparent gains as high as 25 bbl and losses as high as 195 bbl being observed. However, flow checks continued to show the well stable at the surface. The crew continued to rely on the flow checks and continued pulling the liner after each flow check until the well was flowing at the surface.

When the well started flowing, a Kelly cock was installed, the top drive was screwed in and the annular blowout preventer was closed. After a brief period of pressure buildup, the pressure bled

<sup>64</sup> The volume of mud pumped into the well compared to the volume of mud returned from the well.

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to zero. The annular preventer was opened and mud was pumped in an attempt to offset for mud losses, but no mud was returning from the well. About 240 bbl of mud was lost over a 2.5 hour period. An unsuccessful attempt was made to reverse circulate the well.

The well started flowing at the surface again and the annular preventer was again closed. This time the pressure built up to about 2,000 psi over the next two hours. The Kelly cock was now covered by the bell housing or skirts below the top drive and could no longer be accessed, so stripping back into the well was no longer an available option. The platform emergency response team was activated in the emergency center.

Gas was detected in the cooling water for the platform compressors; this was presumed to be due to an internal leak. However, the central control room operator blocked the gas detectors to prevent the main platform power from being shut down. Production passing through the platform was shut down. Required notifications were made and the general alarm sounded to muster non-essential personnel to lifeboats. Gas detectors in a room on a lower level detected gas at 60% LEL and the closing pressure on the annular preventer was increased, which stopped the gas leakage.

Well control was attempted by pumping down the work string and down the casing annulus. The surface pressure fell to a range of about 60-150 psi. The skirts on the top drive were removed and the Kelly cock closed. External gas alarms starting going off and personnel were sent to check the area. They reported that the sea was boiling with gas. All platform power systems were shut down, except for emergency power. Helicopter evacuations were briefly halted.

Later, power was restored to allow mud to be pumped at a higher flow rate and oil base mud to be mixed. After exhausting all of the oil-base mud supplies on board, the well was monitored while water-base mud having a density of about 15 ppg was mixed. Once mixed, the water-base mud was bullheaded into the well. The pressure fell to zero on both the workstring and the annulus after pumping about 1,000 barrels of the water base mud, bringing the well under control.

Improved training and drills would likely have resulted in the crew dealing with the swab kick when it was initially detected, instead of continuing to trip out, mitigating the difficulty of the well control situation.

### **7.2.2 Forties D Blowout on July 15, 2007 (United Kingdom)**

The Forties Well 21/10-D8 Blowout occurred on a platform rig in about 122 meters (400 ft) of water. The blowout initiated while pulling tubing during a workover. Swabbing due to tight clearance around a packer was thought to have initiated the well control event. Oil was observed in the trip tank, so the well may not have been thoroughly circulated with kill fluid before tripping operations were started. This was not a major well control event.

Potential mitigating actions that could have been employed are to verify that well is thoroughly displaced with kill fluid after circulation and actions to reduce the swab pressure loss below the workstring as it was pulled (for example, reduced pulling speed).

### **7.2.3 Visund Field well control incident on March 16, 2016 (Norway)**

This well control incident apparently occurred during a temporary abandonment operation. The operator believed that the cement job on a 7" liner had been verified with a negative pressure

test. Although the incident happened shortly after the drillstring was picked-up, it is not clear that swabbing played any role in initiating the kick.

Shortly after the mud washing process was completed and the well was filled with seawater, the drillstring was raised and a pit gain was observed. The blowout preventer (BOP) was closed and surface pressure was observed in the well, which eventually stabilized at 1,260 psi. While trying to kill the well, it was discovered that the Kelly cock valve below the top drive could not be opened. This prevented the use of normal kill procedures. Alternative kill methods were assessed, while attempts were made to operate the valve. Production at Visund was shutdown. No injuries to persons, material damage, or emissions to the external environment were registered as a result of the inflow into the well.

The regulatory authority reported that what made this incident significant is that normal well-control methods for killing the well were prevented by a jammed valve below the top drive<sup>65</sup>, and that there was originally assumed to be a verified barrier in the well, based on the confirmed negative pressure test. There was concern that in slightly different circumstances, the well kick might have led to a complicated and long-lasting kill operation with the potential for escalation of risk. Furthermore, possible improvements were identified with respect to well barriers, risk register documents, and crew training and drills.

### **7.2.4 Case History Presentation, “Workover Operations Pulling Upper Completion String”**

This case history training presentation was prepared by a joint industry task force and distributed by the Norwegian Shipowners’ Association and Norskolje&gass (2014). The expressed intent of the presentation was “communicating actual well control incidents that have recently occurred on the NCS so lessons are shared and understood”.

The well configuration and operational sequence for this case history is shown in Figure 7-5 and Figure 7-6. The planned operation was to pull and replace a failed completion string. The lessons learned included the need to circulate a homogeneous fluid throughout the wellbore and not depend on bull heading. Additional lessons included the need for continuous monitoring of the trip tank and maintaining the control umbilical to the valves that are part of the barrier system. Recommended corrective actions included:

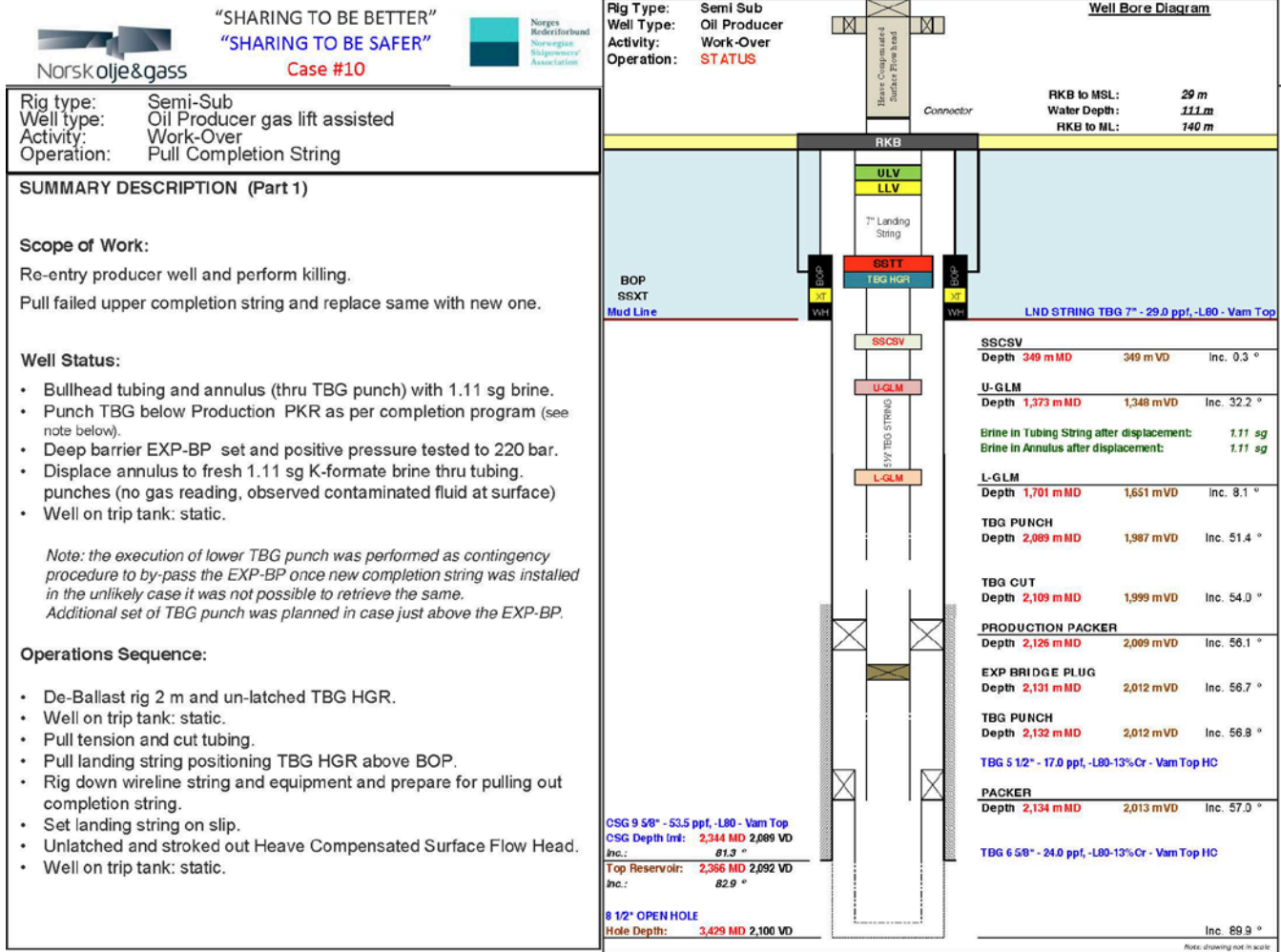
- Revising bull-head program/sequence to reduce the time between completion of pumping operations and setting of the deep barrier, and
- Revising procedures to adequately circulate the well and use the observed returns (density, contamination and in balance fluid column) as guidance to ensure a homogenous fluid is an effective barrier.

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<sup>65</sup> Pressure locking of drill string safety valves is a well-known potential problem and has been the subject of previous studies sponsored by BSEE (MMS).

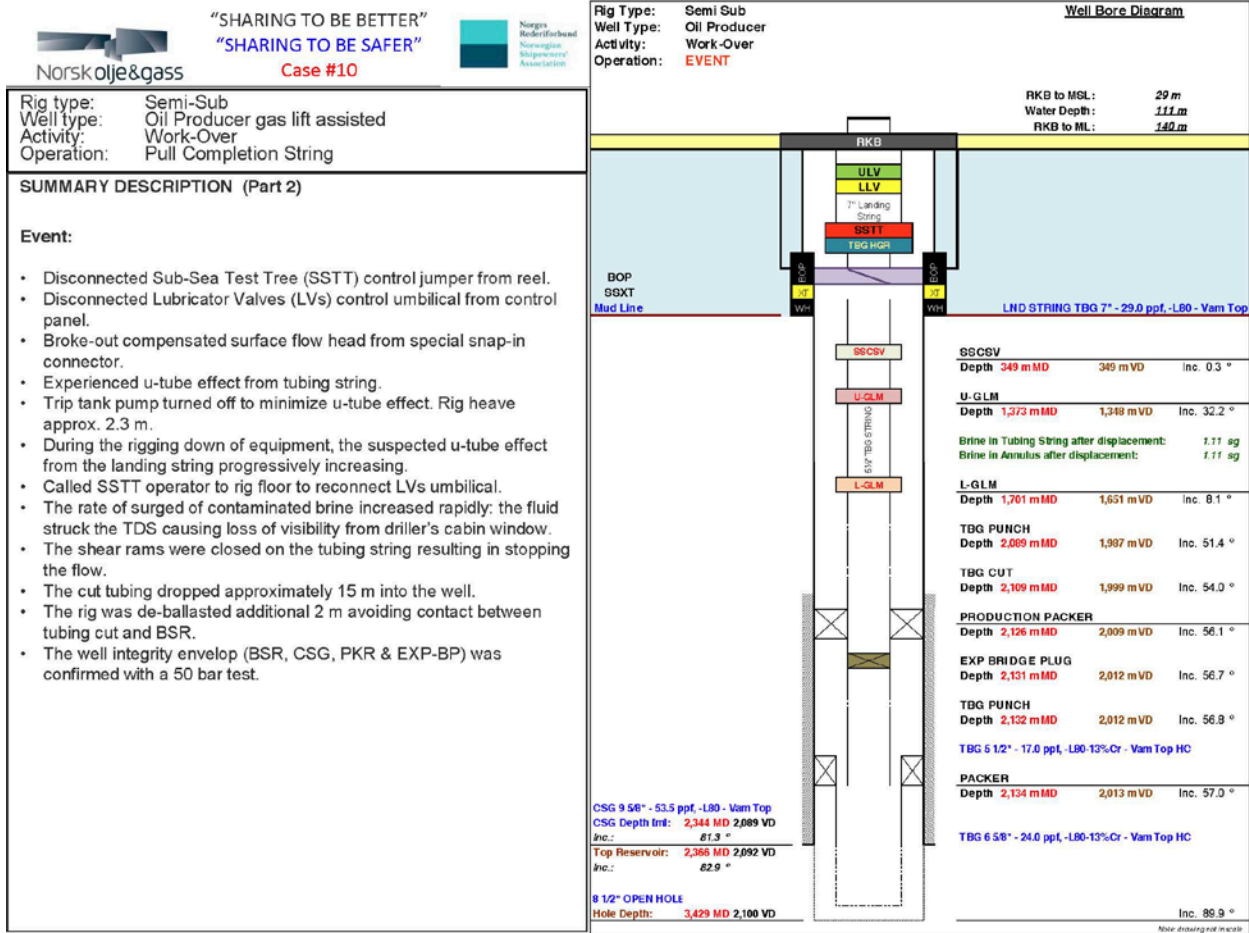


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**Figure 7-5: Scope of Case 10 Workover and Well Schematic**

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**Figure 7-6: Case 10 Summary of Event and Well Schematic**

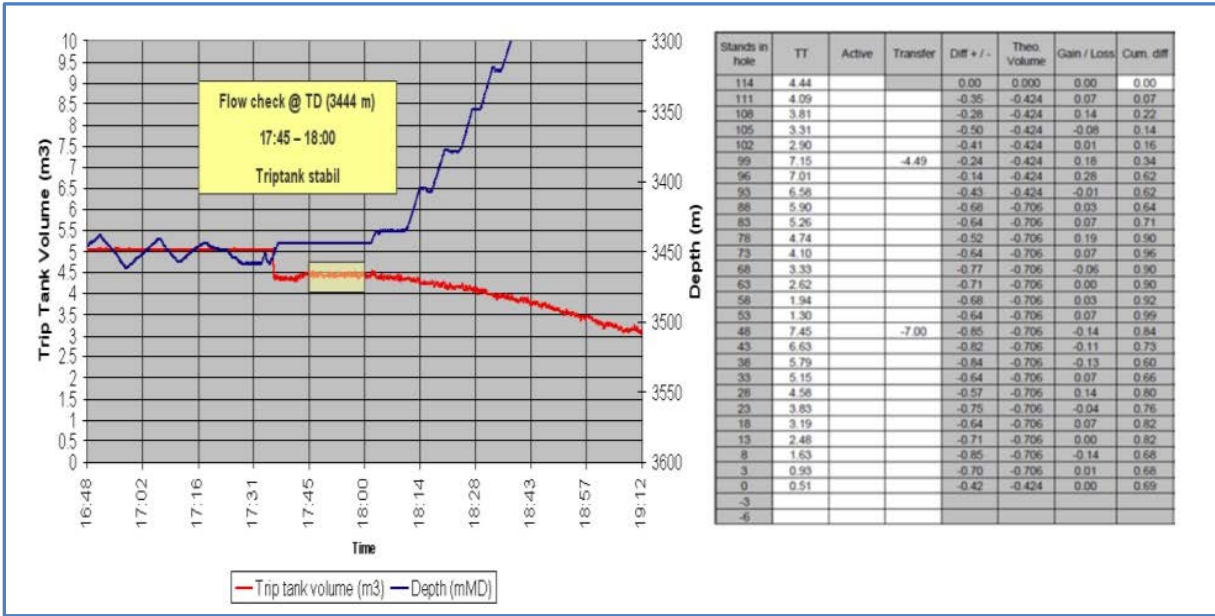
## 7.2.5 Case History Presentation, “Offshore Semisubmersible Rig Well Control Incident”

This case history training presentation discusses a swab kick taken during deep drilling operations on a semisubmersible rig in about 1,300 ft of water. The well had reached a depth of 11,300 ft MD (about 9,200 ft TVD) and penetrated a known producing horizon having a 6 md permeability at an inclination angle of 84 degrees. The well monitoring and mud logging specialist was preparing a swab calculation prior to the trip and contacted the wellsite geologist to determine the pore pressure of the formation penetrated. The geologist was busy describing cuttings and told the well monitoring specialist to look it up in the drilling program. The swab computer program was run; its output recommended there should be no problem pulling pipe during the trip at 43 sec/stand at the start of the trip and 35 sec/stand at the end of the trip. The driller, toolpusher, and Operator’s representative did not question the input data going into the computer program or the resulting high tripping speeds.

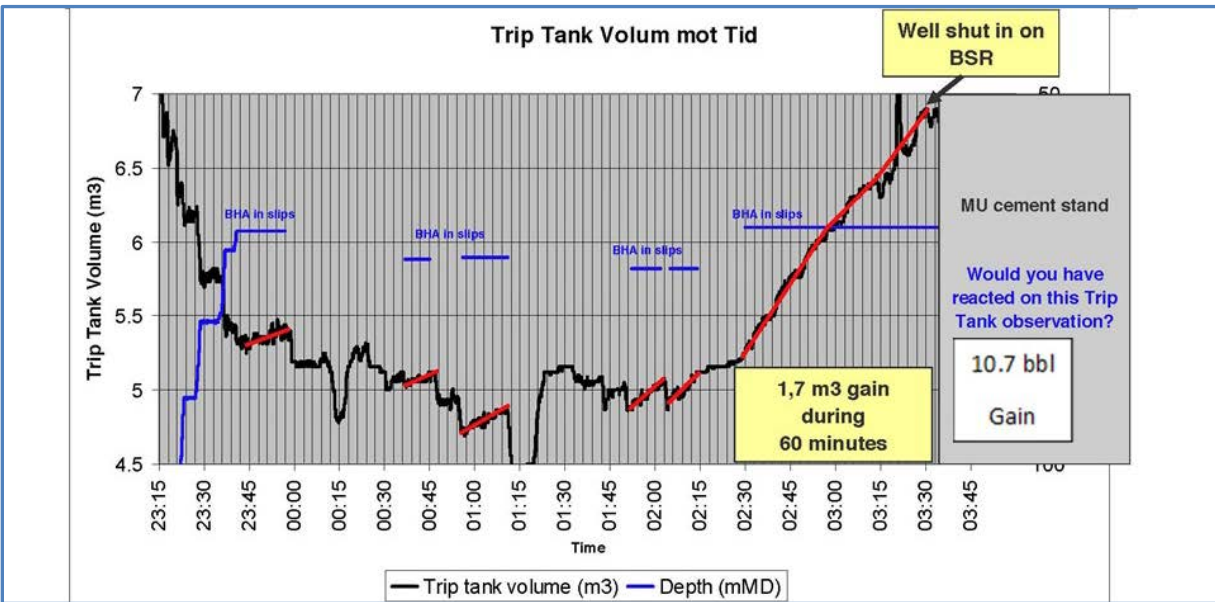
Figure 7-7 shows the trip tank volume while circulating the well clean, during the flow check prior to tripping, and during the trip. Note that the well appeared stable at the beginning of the trip. Note also that there was a slow but steady increase in the cumulative pit gain that could have been observed. After pulling 6 stands, the cumulative gain was 0.22 m<sup>3</sup> (1.4 bbl). After pulling 6 stands inside the 9-5/8” casing (Stand 96), the cumulative gain was 0.62 m<sup>3</sup> (3.9 bbl). A

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flow check was not performed before pulling the BHA through the blowout preventer. **Figure 7-8** shows that the kick became apparent when pulling BHA at surface. The blind rams were then closed in the subsea stack.



**Figure 7-7: Trip Tank Volume while Circulating and at Beginning of Trip (Courtesy of Olf)**



**Figure 7-8: Trip Tank Volume when Pulling BHA (Courtesy of Olf)**



## EFFECTS OF TRIPPING AND SWABBING IN DRILLING AND COMPLETION OPERATIONS

The shut-in pressure observed at the surface was only about 100 psi. After closing the blind rams, the marine riser was weighted up from 10.8 lb/gal to 12.7 lb/gal by pumping down the kill line and up the riser. This provided 125 psi of hydrostatic pressure, which was enough to overcome the 100 psi surface pressure. A bull-heading assembly was run in the well in the event it was needed, but the well was easily killed by staging in the well, circulating the 12.7 lb/gal mud around at 1,000 m, 1,500m, 2,200m, and 3,150 m.

This example shows an advantage of subsea BOP stacks over surface BOP stacks in overcoming a late detection of a swabbed kick when the BHA is at the surface. The marine riser serves as a long lubricator in this situation, allowing the well to be closed below the BHA using blind rams. This well control incident occurred mainly because neither the true formation pore pressure gradient nor the trip margin had been verified prior to the trip, and very high pipe pulling speeds were used. Flow checks were not performed after pulling inside the 9-5/8" casing or before pulling the BHA through the blowout preventer stack. In this case, more information was known about the formation pore pressure gradient than was used, and there was no quality control of the swab calculations to catch the error. The true pore pressure gradient was equivalent to a 10.7 lb/gal mud and the assumed pore pressure gradient was equivalent to a 9.7 lb/gal mud. The swab calculation assumed a 1.1 ppge safety margin was available, when in reality, the safety margin was only 0.1 ppge.

Relevant mitigating actions are to verify pore pressure and trip margin before starting a trip and to quality-check all values from calculations and models, which includes checking that the inputs are suitably accurate.

### **7.2.6 Case History Presentation, "Swabbed Kick from shallow reservoir in exploration well"**

This case history training presentation discusses a swab kick taken from a shallow gas reservoir on a semisubmersible rig in about 1,500 ft of water. The well had reached a TVD of about 5,230 ft and penetrated through known shallow gas sands. **Figure 7-9** provides a well schematic and operational summary for this example.

A Formation Integrity Test was conducted, indicating a formation integrity equivalent to a 12.0 lb/gal mud at the 9-5/8" casing shoe at 2,516 ft subsea. An 8-1/2" bit was then used to drill through several gas sands using water-base mud having a density of 9.7 to 9.8 lb/gal. Intervals were cored from 2,625 to 2,713 ft, from 2,736 to 2,817 ft, and from 2,817 ft to 2,916 ft. A trip was made after reaching a depth of 5,230 ft with a 900 ft bottom-hole assembly. The bit was back-reamed into the casing to 2,500 ft using the top drive; pumping and back-reaming were used to avoid swab pressure loss. However, swabbing was a concern while pulling the bit from 2,500 ft to the seafloor.

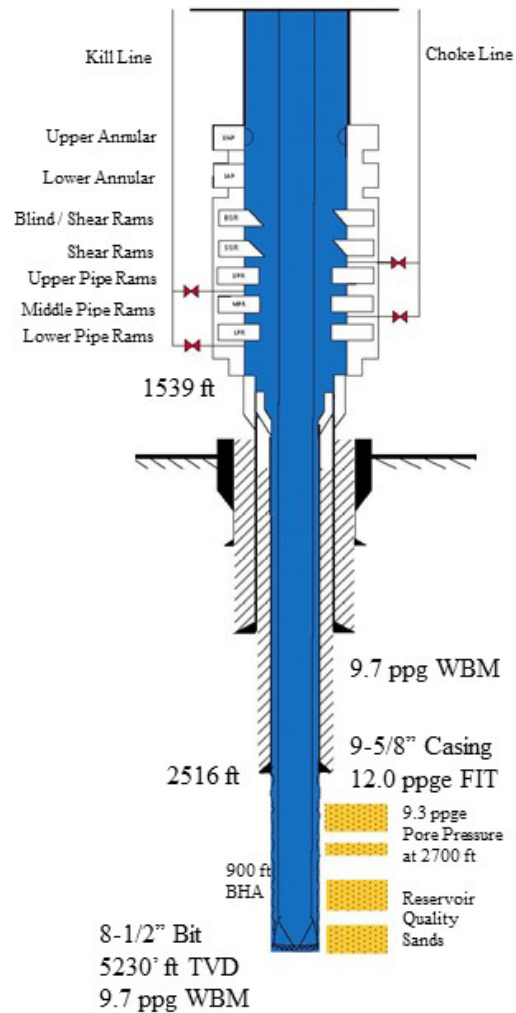
The mud density was 9.7 lb/gal and the estimated pore pressure gradient of a gas-sand at 2,700 ft was 9.3 lb/gal, so that the Trip margin was 0.4 ppge. Swab calculations were made prior to the trip from 2,500 ft, and maximum pipe pulling speeds were estimated for a minimum equivalent trip density of 9.5 lb/gal, which was about 0.2 ppg above the estimated pore pressure gradient. Thus, the maximum pipe pulling speed was estimated for a 0.2 ppge loss in equivalent mud weight at 2700 ft. A maximum pipe pulling speed of about 2 minutes per stand was calculated with the 900 ft of bottom-hole assembly above the sand at 2700 ft. However, swab calculations and pulling speeds were not discussed with the driller prior to continuing to pull out of the well.

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The driller was under the impression that the calculations applied only to when the BHA was passing the sand.

### Incident Summary

- Back-ream bit into 9-5/8" Casing.
- Flow Check; Well Static.
- Pump 19 bbl of 12.2 lb/gal Slug
- Pull Bit to 1742 ft; Well Flowing.
- Trip Sheet shows gain. Attributed to Slug.
- Pulled three more stands.
- Well starts flowing; Rapid Gain.
- Close Lower Annular Preventer on 6-3/4" Spiral Drill Collar.
- DP Press = 240 psi; Choke Press = 383 psi; Pit Gain = 35 bbl.
- Jar and Accelerator above Lower Annular Preventer.
- Make up Top Drive and Pick-up off slips.
- Bled 5 bbl from Choke Line; Choke Press increases to 675 psi; Gas in Choke Line.
- Perform off bottom kill @ 1742 ft.
- Circulated 5 well volumes; Erratic returns and large gas volumes circulated out.
- When well dead, trip back to bottom and circulate well clean.



**Figure 7-9: Case History of Swabbed Shallow Gas Kick**

A flow check was made and the well was static with the bit at 2,500 ft. A 19 bbl slug of 12.2 lb/gal mud was pumped into the top of the drill pipe just before starting to trip out of the well to prevent pulling a wet string. Pulling speeds of 1/2 to one minute per stand were used. The bit was pulled to 1,742 ft and the trip sheet consistently showed that the well was taking less mud to fill the well than the volume of steel removed. The discrepancy was attributed to the slug not being in balance. It was decided to pull three more stands slowly to verify the "slug effect." However, the well started flowing rapidly and the annular preventer was closed with a 35 bbl pit gain. The shut-in drill pipe pressure was 240 psi and the choke pressure was 383 psi. Because of the high flow rate, the driller closed the lower annular blowout preventer on a 6-3/4" spiral drill collar; a jar and accelerator were located just above the closed blowout preventer. The drill string was secured by making up the top drive and lifting the drill string out of the slips. The BHA contained a drill string float (check valve) above the bit.

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Five barrels were bled from the choke line, and the choke pressure increased to 675 psi, which indicated that gas had collected below the blowout preventer. The option to strip back to bottom was not available because the jar and accelerator section was above the annular preventer. Also, the drill collars had a spiral groove cut in them<sup>66</sup> which could have damaged the sealing element of the annular preventer during stripping operations. An off bottom kill procedure was implemented that would sweep out the gas above the bit. In this situation, it can take a long time for gas in the well below the bit to migrate up past the bit. It took five complete well circulations before the well was dead. A heavier mud of up to about 11.5 lb/gal could have been used once most of the gas had been circulated to the surface. Had that been done, the bit could also then be tripped back to bottom and the well circulated clean with a 10 lb/gal mud.

Relevant mitigating actions are better communication of trip speeds to driller and improved monitoring of pit gain, both of which could be addressed by improved training and drills.

### **7.3 Other Offshore Areas**

The availability and quality of public information about well control events was found to be much more limited outside of the areas discussed above. For some areas, blowout data were found but were outside of the 2005-2015 time interval of interest or was for events that did not initiate during tripping in drilling and completion operations.

#### **7.3.1 Brazil**

Eleven blowout events were identified in Brazil during drilling, well completion, and workover and recompletion operations during the time period of interest. Three occurred during drilling operations but none of these were initiated during tripping operations. Of the eight non-drilling events, two occurred during completion operations, and one of these was during a frac pack operation. Two occurred during temporary abandonments. Four blowouts occurred during workover or workover/recompletion activities, of which one of these initiated during tripping operations. In one of the events in 2006, the well blew out after pulling the perforating guns from the well after perforating for a re-completion. The eight non-drilling events were all reported to be quickly controlled without major adverse consequences.

### **7.4 Blowouts on Land related to Tripping during Drilling and Completion Operations**

The availability and quality of public information about well control events was found to be very limited in the various applicable regulatory agencies. Blowout reports generally do not have a lot of information about on-going operations when the blowout occurred. Not all paper files are scanned to the on-line databases, but are held in regional offices. Not all of the states in the United States even require blowouts to be reported to the agency. This section summarizes the results of the search conducted by the LSU Team assembled for this task.

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<sup>66</sup> The tendency of drill collars to become stuck when making a connection can be reduced by cutting a spiral groove in the outer wall of the drill collars. When the mud pressure is higher than the pore pressure in a porous and permeable zone, the mud pressure can force the drill collar into the mud cake on the borehole wall and cause the pipe to become stuck by the pressure differential. The groove makes it less likely that the mud cake can form an effective seal when the pipe wall contacts the formation face in the side of the borehole wall.

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### 7.4.1 Texas

The following information was taken from reports of well control events:

- SN 613867 – 03/01/2006 – tripping out of the hole with a core string. No Fire, H<sub>2</sub>S, Injuries, or deaths.
- SN 611891 – 08/12/2006 - tripping out of the hold to make a logging run. No Fire, H<sub>2</sub>S, Injuries, or deaths.
- SN 623583 – 08/21/2006 - tripping out of the hold to change bits. Fire but no H<sub>2</sub>S, Injuries, or deaths.
- SN 636406 – 04/25/2007 - Operator was tripping the drill pipe. No Fire, H<sub>2</sub>S, Injuries, or deaths.
- LN 192685 – 04/15/2008 - swabbed well in, blew cement out, well shut-in. No Fire, H<sub>2</sub>S, Injuries, or deaths.
- SN 641830 – 04/23/2009 - Rig was on well pulling coiled tubing after clean out job; tubing became stuck and well started flowing. Injured person passed away at later time. No Fire, H<sub>2</sub>S, or Injuries, 1 death.
- SN 689970 – 04/02/2010 - Operator was tripping the drill pipe and gas began to kick. No Fire, H<sub>2</sub>S, Injuries, or deaths.
- SN 693949 – 05/17/2010 - While pulling out 2 joints the well came in and unloaded. No Fire, H<sub>2</sub>S, Injuries, or deaths.
- LN 015298 – 11/10/2010 - Well kicked when pulling out tubing. Able to gain control of well by pumping mud and with Blowout preventer. H<sub>2</sub>S present, No Fire, Injuries, or deaths.
- SN 765921 – 08/25/2013 - After tripping out of the hole and laying down all 4 1/2" drill pipe and four 6-1/4" drill collars of a total of 12, the well started to flow. No Fire, H<sub>2</sub>S, Injuries, or deaths.
- SN 771261 – 10/27/2013 - While coming out of the hole to do a wiper trip, the well came in on them and was flowing water up to the crown on the mast of the rig and is spraying the location with 5800 mg/l chloride water. No Fire, H<sub>2</sub>S, Injuries, or deaths.
- SN 761331 – 11/03/2013 - A gassy water kick was encountered on a recently spudded well at approximately 2300'. The blowout preventer was shut around the drill pipe in order to control the well. While attempting to kill the well, the fluid began to breakout at the surface approximately 100' feet from the well, outside the surface casing. The breakout areas were immediately “bermed” to contain the fluid. No Fire, H<sub>2</sub>S, Injuries, or deaths.
- LN 05204 – 05/13/2014 - Well took a kick while pulling out of the hole. Gas reached the diesel engine and caused a runaway. Fire but no H<sub>2</sub>S, Injuries, or deaths.
- LN 17854 – 05/30/2014 - Pulled tubing. Removed BOP and the well began to blow. One Injury, No Fire, H<sub>2</sub>S, or deaths.
- SN 813672 – 05/03/2016 - Well blowing mud ~ 7 ft. above the rig floor, with mud around the well bore. They were pulling out of the hole preparing to RIH with casing. TD of the well is 994'. There is 450' of drill collars in the hole with a wiper rubber on the drill pipe. Southwest fluids from Abilene are on location with additional mud to kill the well. Well is located ~ 150' north of CR 504. This is a single string completion. The cementers and casing are on location. No Fire, H<sub>2</sub>S, Injuries, or deaths.

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### 7.4.2 Louisiana

The following information was taken from blowout reports:

- SN 69457 – 12/18/2007 – Pulled out of the hole with Gravel Pack Packer; closed blind rams; Well Control Company removed BOP and allowed upward flow; Well Bridged; Installed capping stack and closed blind rams; Bull head 10.6 ppg CaCl<sub>2</sub>; Nipple up frac valve; Well blowing gas around BOP; Flow 1.8 MMscf/D to sales to relieve pressure; No Fire; Only gas released.
- SN 192876 – 10/01/2009 – Well became underbalanced when pulling pipe; Pumped 400 bbl of 14.0 lb/gal mud to kill well; No Fire, Only Gas released.
- SN 247823 – 11/07/2014 – Lost returns when drilling; pulled 14 stands; well started flowing; could not install drill string safety valve.

### 7.4.3 North Dakota

North Dakota maintains a data base that tracks all releases and spills. A query of the database indicated there were 104 releases during the 2005 – 2015 period. However, most of these were very minor releases or spills. Eighteen of the spills were for oil volumes of 20 bbl or more, and the two largest releases reported were 2,525 bbl and 3,600 bbl. Most of the wells are horizontal wells into low permeability Bakken shale and dolomite formations at about 11,000 ft TVD that have to be fractured to yield commercial flow rates. Typical mud weights are about 10 lb/gal. Snubbing operations are sometimes used for well completions after flow-back and well testing in casing.

The on-going operation being conducted at the time of the well control event was not a database item, but a review of the well files located some comments made on the spill reports or work resumes. The following events were identified as being associated with tripping operations or swabbing for the time period 2012 to 2015:

- SN 14865 – 02/03/2012 – while tripping out of well with production tubing; 4 bbl oil released.
- SN 20484 – 01/03/2013 – swabbed well; 200 bbl oil and 100 bbl Salt water released.
- SN 18756 – 01/23/2013 – while tripping out of well with tubing; 5 bbl oil and 5 bbl saltwater released.
- SN 17099 – 01/29/2013 – while stripping pipe out of well; 5 bbl oil and 5 bbl saltwater released.
- SN 16480 – 03/15/2013 – while pulling fishing tools out of hole; 0.75 bbl of oil released.
- SN 24217 – 05/19/2014 – while pulling 286 joints; 25 bbl oil and 5 bbl salt water released.
- SN 17893 – 05/23/2014 – while pulling packer; 20 bbl of oil released.
- SN 18987 – 06/01/2014 – pulling drillpipe out of the hole, 5 bbl of oil released
- SN 17924 – 03/24/2015 – while tripping in hole; 8 bbl of oil and 1 bbl of salt water released.

### **7.4.4 West Virginia**

A gas well being drilled in Harrison County, West Virginia on 8/19/2012 suffered an explosion and fire that injured three workers and damaged the rig and wellsite equipment. The well was being drilled in the Cottrill-3 Marcellus shale. A spark ignited the natural-gas hole as the drillstring was being pulled.

A gas well being drilled in Doddridge County, West Virginia has exploded on 7/8/2013 during a flow-back operation that has left eight field workers injured, five severely burned and flown to a Pittsburg, Pennsylvania hospital.

### **7.4.5 Mississippi**

A gas well in Wayne County, Mississippi suffered a blowout on July 19, 2012 while running tubing into the wellbore during a workover. There were no injuries as a result of the blowout, but the surrounding area had to be evacuated from the Chicora area due to hydrogen sulfide gas escaping from the well.

### **7.4.6 Canada**

An ERCB Report (2009) presented the result of an investigation into a loss of well control (blowout) that occurred while performing workover activities on a suspended sweet well located on Canadian Forces Base (CFB) Suffield, 14 kilometers southeast of Jenner, Canada. A coil tubing unit was used to complete the well workover, which involved removing 1-inch coil tubing and downhole tools from the wellbore and running in a larger tubing string. Potassium chloride (KCL) fluid was used to kill the well, and a tubing dart had been installed and pressure tested to establish a dead well condition.

The coil tubing unit pulled the 1-inch coil tubing to within 100 meters from the surface without incident. In order to remove a blast joint near the bottom of the 1-inch tubing, the lubricator assembly was disconnected at a union above the annular blowout preventer. When the lubricator was picked up with a crane to expose the blast joint, the annular blowout preventer failed, which resulted in a blowout.

The blowout released natural gas, produced water, and formation fracturing (frac) fluid from the wellhead, which was located below ground level in a cellar. The gas was dispersed by light winds, while the produced water (approximately 3-4 m<sup>3</sup>) and the frac fluids were contained in the cellar. No H<sub>2</sub>S was released. The well was controlled by Well Control specialists by reconnecting the lubricator. The well was then killed by pumping kill weight fluid into the well.

### **7.4.7 Kazakhstan**

An uncontrolled gas influx in the Condor Petroleum Shoba-7 appraisal well in Kazakhstan's Zharkamys West 1 contract area was reported on 8/20/2012. The well was drilled to core point at about 2400 ft and while tripping out of the hole to pick up a core barrel assembly, the gas influx occurred. Shut in pressure was higher than anticipated so the gas was diverted to a flare. Gas also broached to the surface adjacent to the well site. A relief well was being planned at the time of the report.

**7.4.8 India**

A blowout was reported 8/12/2007 by India’s Oil Industry Safety Directorate for a well being drilled in Block CB-ONN-2000/1in the Olpad area of Ankelshwar, Gujarat. The blowout was attributed to inadequate monitoring of well volume during tripping out and failure to detect flow of formation fluid into the well. The well was drilled to a depth of about 2300 ft and logging was carried out. Additional logging was to have been done by Schlumberger the following day, but after most of the drillstring was pulled out of the hole, heavy flow of drilling fluid and gas commenced on the drill floor and the crew left without installing the safety valve on the drillstring or closing the blowout preventer. As a result, the well blew out.

Following the incident, the annular blowout preventer was closed, but flow of well fluid continued through the drill collars. The well was successfully killed by pumping 15 lb/gal mud into the annulus through the kill line. There were no injuries but the well and structure were damaged.

**7.5 Summary of Incidents and Mitigation Procedures**

The well control case history information developed for this task was used to in part to fulfill recommendation requirements for other project tasks and are in those sections of the report.

A brief summary of the well control events reviewed by the study and relevant mitigations are provide in **Table 7-1**.

**Table 7-1: Well Control Events Reviewed and Relevant Mitigations**

Incident	Relevant Mitigations
2009 – Ship Shoal Block 349	Improved training and drills
2009 – Mississippi Canyon Block 72	Closer monitoring of trip tank
2012 – High Island Block A-443	Improved training and drills
2013 – South Timbalier Block 220	<ul style="list-style-type: none"> <li>• Improved training and drills</li> <li>• Better verification of Trip Margin</li> </ul>
2014 – Vermilion Block 356	<ul style="list-style-type: none"> <li>• Improved training and drills</li> <li>• Better planning to inhibit gumbo formation</li> <li>• Use top drive to avoid swabbing</li> <li>• Return to bottom when swab kick is indicated</li> </ul>
2004 – Snorre Field (Norway)	Improved training and drills
2007 – Forties Field (UK)	Circulate well sufficiently prior to trip out
2016 – Visund Field (Norway)	Verify well integrity prior to trips
NSA Case History – Workover Operations	<ul style="list-style-type: none"> <li>• Verify well fluid is homogenous after circulating well prior to trip out</li> <li>• Continuously monitor trip tank</li> </ul>
NSA Case History – Offshore Semisubmersible Rig	<ul style="list-style-type: none"> <li>• Verify formation pressure gradient and trip margin prior to trip out</li> <li>• Verify inputs to calculations before making use of outputs</li> </ul>

EFFECTS OF TRIPPING AND SWABBING IN DRILLING AND COMPLETION OPERATIONS

Incident	Relevant Mitigations
NSA Case History – Swabbed Kick	<ul style="list-style-type: none"> <li>• Communicate all trip requirements to driller</li> <li>• Monitor trip tank volume</li> <li>• Improved training and drills</li> </ul>
Various US states	<i>Tripping well control incidents occurred, but insufficient evidence to determine cause and mitigating actions</i>
Canada (coil tubing)	<i>Caused by equipment failure</i>
Kazakhstan	<i>A tripping well control incident occurred, but insufficient evidence to determine cause and mitigating actions</i>
India	Monitor trip tank volume

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APPENDIX A

ABBREVIATIONS, ACRONYMS, AND  
NOMENCLATURE

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## Appendix A - Abbreviations, Acronyms, and Nomenclature

	accumulator	The accumulator is a pressure vessel that holds in reserve the volume a pressurized gas needed to operate critical well control devices. When rig power is interrupted, the energy stored in the accumulator is sufficient to close all blowout preventer components.
	annular preventer	The annular preventer is a subcomponent of the BOP that allows the well to be shut in while pipe is within the BOP using an elastomeric gland to grip the pipe and seal the annulus. The annular preventer is similar in purpose to the pipe rams with two important differences: the annular preventer can seal against a range of pipe sizes but cannot hold as much pressure as the pipe rams.
<b>ANP</b>	Agência Nacional do Petróleo (Brazilian)	Brazilian regulatory authority, which depends heavily on Petrobras, the Brazilian national oil company for rules and guidelines.
<b>APD</b>	application for permit to drill	Application to BSEE for Permit to Drill.
	aquifer	An aquifer is a permeable formation containing almost entirely water in its pore space, as contrasted to a hydrocarbon-bearing formation which typically contains some hydrocarbon and some water.
	ballooning	A term used to describe a well condition in which drilling fluid is lost when the downhole pressure is elevated because of mud circulation, but the drilling fluid returns to the well when the pump is turned off and pipe is pulled from the well.
	balanced cement plug	A balanced cement plug is a volume of cement circulated into the well according to a pre-designed schedule of fluid volumes and densities such that the fluid system is in hydrostatic balance when the cement reaches the desired location. The hydrostatic balance reduces the likelihood of cement movement before it hardens to form the desired plug against pressure and flow.
	bails	Two long slender rods with an eyelet on each end to provide a yoke-like connection between the top drive or traveling block and the elevators. The arrangement provides room below the top drive and between the bails to screw in connections, i.e., a drill pipe safety valve, into the top of the work string.
<b>bph</b>	barrels per hour	Unit of flow rate.

	bit balling	Bit balling is a condition in which wellbore cuttings, usually clay, agglomerate on the bit forming a “ball.” A balled bit can act as a piston and create high swab or surge pressures.
	bell-nipple	A bell nipple is piece of pipe, with inside diameter equal to or greater than the BOP bore, connected to the top of the BOP or marine riser with a side outlet to direct the drilling fluid returns to the shale shaker or pit. Usually has a second side outlet for the fill-up line connection.
	best practice	A best practice is a commonly observed industry practice that meets highest industry standards for drilling, completion and well control operations known to report authors from years of interaction with Well Site Managers in well control training classes.
<b>BSR</b>	blind shear rams	The blind shear rams are a subcomponent of the BOP that allows the well to be shut in while pipe is within the rams by shearing through the pipe and sealing the opening.
	block, block position	The block is the travelling component of the block-and-pulley system used on a derrick to raise and lower pipe. The traveling block travels between the derrick or mast floor and the crown block. The position of the block is measured and recorded in the rig digital time series data.
	blow-out	A blow-out is an uncontrolled release of formation fluids to the surface. An uncontrolled flow from one subsurface zone to another, is called an underground blowout.
<b>BOP</b>	blowout preventer	The blowout preventer is a device that allows the well to be shut-in to prevent flow from the well. It is fundamentally a set of specialty valves that are designed to be closed even when a section of pipe is within the BOP.
	bonnet	A bonnet is the portion of a BOP ram wherein the hydraulic fluid acts against a piston-like mechanism to drive the ram open or closed.
<b>BHA</b>	bottom hole assembly	The bottom-hole assembly is the drilling or well completion assembly of down-hole tools run below the drillpipe or work string.
<b>BHP</b>	bottom hole pressure	The bottom-hole pressure is the wellbore pressure at the bottom of the well.
<b>BOEMRE</b>	Bureau of Ocean Energy Management, Regulation and Enforcement	BOEMRE replaced The Minerals Management Service (MMS) after the Macondo Blowout of 2010. In fiscal year 2012 BOEMRE was divided into two bureaus – BOEM and BSEE.

<b>BOEM</b>	Bureau of Ocean Energy Management	Bureau of Ocean Energy Management which handles offshore leases.
<b>BSEE</b>	Bureau of Safety and Environmental Enforcement	BSEE is responsible for safety and environmental oversight of offshore oil and gas operations, including permitting and inspections, of offshore oil and gas operations.
	braced caisson	A braced caisson platform is a fixed structure composed of a single vertical column where the lowermost portion of column is laterally braced to one or more foundation piles.
	bridge plug	A bridge plug is a downhole device that seals the inside of a tubular or wellbore, isolating pressure and flow below the plug from that above the plug.
	bridge, bridging, bridged-off	A bridge is a spontaneously formed plug of formation solids that acts to isolate pressure and flow below the plug from that above the plug.
	brush	See "scraper-brush."
	buildup	See "pressure build-up test."
	bull-heading	Bull-heading is a method of well control in which fluids are pumped from the surface down the annulus between the drillstring and casing and into a formation.
<b>BWPD</b>	barrels of water per day	Units of water production.
	caliper	A caliper is a downhole tool that measures the inside diameter of a tubular or wellbore.
	casing	Casing is a tubular or pipe that is used to line the wellbore to provide hole stability and isolate the wellbore from the formations outside the casing.
	casing pressure	Pressure in the casing at the surface that is usually measured with a sensor in the choke manifold.
	cellar	In an onshore well a sub-grade excavated space located below the rig.
	cementing pump	See "Halliburton pump."
	cement retainer	A cement retainer is downhole device similar to a bridge plug used to impede the movement of cement to keep it in place until it hardens. A cement retainer does not itself hold significant pressure but facilitates the placement of a cement plug which holds pressure once hardened.

	chart	A chart is a mobile data recording device that produces a hardcopy of a signal versus time. Charts are typically used to provide documentation of data not otherwise captured on the rig's data acquisition system.
	check for flow	See "flow check."
	check valve	A check valve is a specialized valve that allows the transmission of pressure and flow only in one direction.
	choke	The choke is a specialty valve designed to safely control the rate of a high-pressure flow from the well.
	choke line	The choke line is the high-pressure piping between BOP outlets or wellhead outlets and the choke manifold.
	choke manifold, choke/kill manifold	The choke manifold is an assembly of valves, chokes, gauges, and lines used to control the rate of flow and pressure from the well when the BOPs are closed.
	circulate, circulating, circulation	To circulate a well is to pump fluids from the surface, to a target depth in the well, and back to the surface. The normal flow path down the work string and back up the annulus to surface. Circulating in the opposite flow direction is called reverse circulation.
	circulating pump	Centrifugal pump used in a circulating trip tank arrangement.
	circulating valve	The circulating valve is a valve in the work string that when opened allows fluid communication between the work string and the annulus.
	closing ratio	The closing ratio is the ratio of the hydraulic pressure required to close a valve to the pressure of the fluids inside the valve which oppose closing.
	completion(s)	Oil well construction is by convention divided into a first phase called 'drilling' and a second phase 'completion.' The 'completion begins phase begins after production casing has been installed and tested.
	condensate	Condensate is hydrocarbon liquid that is in the gaseous phase at reservoir conditions and condenses into the liquid phase at surface conditions.
	correlate, correlation	See "depth correlation."
	depth-control, depth correlation	Depth control or correlation is to accurately relate the location of a downhole tool relative to a desired reference depth in the formation.

	development well	A development well is drilled to produce known reserves as compared to an exploration well which is drilled to locate or quantify reserves.
	displacement	Displacement is the volume occupied by an object when submerged in a liquid. When drillpipe is lowered into a well that is full of fluid, a volume of fluid equal to the volume of the drillpipe will be displaced and flow out of the well. If the drillpipe is open-ended, the displacement is the volume of the steel. If the drillpipe is close-ended, the displacement volume is the volume of the steel plus the volume inside the drillpipe.
	diverter	A well control system that includes piping to safely diverts flow away from rig when it is unsafe to stop the flow. A diverter is the designed well control device for handling a shallow gas flow encountered before sufficient casing is set to allow blowout preventers to be used. For floating rigs diverters can also be used to manage riser gas.
	double-rams	Double rams have two sets of rams within a single ram body between top and bottom flange connections.
	driller	The driller is a first-line supervisor for the drilling contractor responsible for operating the drilling and hoisting equipment and directing the rig crew. The driller reports to the toolpusher. The driller has the primary responsibility for shutting in the well.
	drillpipe, drillstring	Drillpipe is pipe comprised of joints that screw together end to end and is used to connect downhole drilling tools to the rig at the surface. A length of drillpipe is called a drillstring.
	drillpipe safety valve	See “drillstring safety valve.”
<b>DSV, DSSV</b>	drill-string safety valve, safety valve	The drillstring safety valve is a specialty valve designed to be manually screwed into the top of the work string to provide the capability to shut-in the work string. The drillstring valve is used when a well control event occurs while tripping. Can also be called a drillpipe safety valve because it is normally screwed into drillpipe. TIW valve is an older branded term used for this type of valve because Texas Iron Works manufactured a large proportion of the valves used early in the oil and gas industry.
	dump bailer	A dump bailer is a long hollow container that can be deployed downhole on wireline and opened remotely to discharge its contents.

<b>EZSV</b>	easy squeeze packer	An EZSV is an easily drillable squeeze packer. It's primarily used for squeeze cementing but can also be used as bridge plug for zonal isolation or abandonment. This tool can be run on wireline or drill pipe and is designed to offer little resistance to drill out.
	electric line, e-line	Electric line is a kind of wireline that includes an electrical conductor from transmission of power and data between the surface and downhole tools.
	elevators	Elevators are a mechanical yoke like device attached to the traveling block that latches around and supports the pipe during hoisting or lowering operations.
	effective density or effective mud weight	Same meaning as equivalent density or equivalent mud weight.
<b>ECD</b>	equivalent circulating density	The fluid density at static conditions that would create the same pressure at a given depth in the well as experienced while circulating. Calculated values can vary depending on method used to determine the pressure at the reference depth.
<b>EMW</b>	equivalent mud weight; equivalent downhole mud weight	Mud weight required to cause observed or calculated subsurface pressure at a given depth with atmospheric pressure at the surface. Calculated values can vary depending on method used to determine the pressure at the reference depth.
<b>ESD</b>	equivalent static density	The fluid density that would create the same pressure at the reference point in the well as measured at reference point using a downhole gauge with well static.
<b>ft/min</b>	feet per minute	Unit of velocity.
	fingerboards	The fingerboards are a rack inside the derrick for stowing stands of pipe in the vertical orientation on the outer edge of the drill floor.
	fingerprinting	Monitoring drilling fluid loss and gain versus time to establish a trend from which hole-ballooning can be identified.
	fish	A fish is an object or assembly lost in a well.
	float; ported float	A check valve that can be installed in the drillstring bottom-hole assembly that allows forward circulation but prevents flow up the drillstring. A ported float allows a restricted flow up the drillstring.

	flow check	A flow check is a procedure designed to identify whether a kick is in progress as evidenced by wellbore fluids flowing from the well. During a flow check, pumps in communication with the well are turned off and pipe movement is suspended.
	flow indicator, flow out sensor, flow paddle	The flow indicator is the flow sensing device that measures the presence of flow out of the annulus. It is not designed to accurately quantify flow rate.
	flowback	Flowback is flow from the well back to surface, typically driven by formation flow into the well.
	flowline	The flowline is the piping that exits the bell nipple and conducts drilling fluid and cuttings to the shale shaker and drilling fluid pits.
<b>FIT</b>	formation integrity test	A formation integrity test is a procedure to determine the pressure integrity of the casing seat, expressed as an equivalent fluid density, in which the pressure is increased to a predetermined approved value and the test stopped prior to any leakage being initiated into a formation fracture or cement channel.
<b>FIV</b>	formation isolation valve	A valve placed in the downhole tubulars that can be closed to isolate an exposed formation to the tubulars above the valve.
<b>FG</b>	fracture gradient	The fracture gradient is the EMW that would cause the formation to hydraulically fracture.
	frac-pack	A completion entailing the simultaneous hydraulic fracturing of a reservoir and the placement of a gravel pack.
	gamma ray	Gamma ray refers to a downhole measurement of naturally occurring gamma radiation used to characterize the type of rock in a formation. Features in the gamma ray signature as a function of depth can be used effectively for depth correlation.
	gas specific gravity, gas gravity	See "specific gravity."
<b>GOM</b>	Gulf of Mexico	
	gravel pack	A gravel pack is a completion method in which the annulus adjacent perforations is packed with sand or gravel of a controlled size to help retain solids within the formation and reduce the production of sand.



	Halliburton pump, cementing pump	The cementing pump (also called a Halliburton pump) is an auxiliary triplex piston type pump on the rig used for cementing and other fluid or slurry displacements requiring high displacement volume accuracy.
	loss circulation material, loss circulation pill	Loss circulation material or a loss circulation pill is a discrete volume of fluid loss control material (often HEC) that is pumped to bottom and plates out on the formation wall to reduce wellbore fluid loss to the formation.
<b>HCR</b>	high closing ratio	The high closing ratio valve is a hydraulically actuated valve on the choke/kill lines leading from the blow out preventers that can be operated remotely. The valve stem extends out both the top and bottom of the valve so that internal pressure does not act effectively to change the valve position.
<b>HP</b>	high pressure	A well drilled into formations with a pore pressure capable of causing a surface pressure in excess of 10,000 psi.
<b>HPHT</b>	high pressure high temperature	A well drilled into formation having a temperature in excess of 300°F with a pore pressure capable of causing a surface pressure in excess of 10,000 psi.
	hole ballooning	See “ballooning.”
	hook, hook load	The hook is a device such as a top drive that is attached to the traveling block and from which the elevator links (bails) or other equipment is attached. The hook load is measured and recorded in the rig's digital time data.
	hydrostatic, hydrostatic pressure	The hydrostatic pressure is the pressure exerted at a point due the weight of the fluid column above that point.
<b>HEC</b>	hydroxyethylcellulose	HEC is a modified, high molecular weight polymer used as a fluid loss control material.
	HEC pill	See “Loss circulation pill” and “HEC”
<b>HSE</b>	health, safety, and environment	Pertaining to protection of Health, Safety, and the environment.
<b>IADC</b>	International Association of Drilling Contractors	The IADC is a worldwide oil and gas drilling industry association that seeks to advance drilling and completion technology and improve industry health, safety, environmental and training practices.

<b>IBOP</b>	inside blowout preventer valve	A check valve normally installed above a drill string safety valve during well control operations. The check valve function allows fluid to be pumped down the drillstring but does not allow fluid to flow up the drillstring. With an IBOP installed, the drillstring safety valve can be opened and the drillstring stripped back into the well under pressure.
	jack-up rig	A jack-up rig is mobile offshore unit with a buoyant hull and one or more legs that can be moved up and down relative to the hull. A jack-up reaches its operational mode by lowering the leg(s) to the seabed and then raising the hull to the required elevation.
<b>JSA</b>	job safety analysis	Usage of this term varies. A JSA per Subpart S identifies, analyzes, and records: (i) The steps involved in performing a specific job; (ii) The existing or potential safety, health, and environmental hazards associated with each step; and (iii) the recommended action(s) and/or procedure(s) that will eliminate or reduce these hazards, the risk of a workplace injury or illness, or environmental impacts.
	kelly hose, rotary kelly hose	The kelly hose is the section of hose between the swivel and the top of the standpipe.
	kick	A kick is an influx of formation fluids into the wellbore.
	kill line	The kill line is a high-pressure line from the mud pumps to a connection below a BOP that allows fluid to be pumped into the well or annulus with the BOP closed during well control operations.
	liquid condensate	See "condensate."
	liquid specific gravity	See "specific gravity."
	logging	Logging is acquisition of downhole measurements, typically reported as a continuous plot of measurements versus tool depth called a "log."
<b>LWD</b>	logging while drilling	A downhole logging tool run in the bottom hole assembly capable of measuring one or more downhole formation parameters while drilling.
<b>LOT</b>	leak off test	A Leak-off Test is a procedure to determine the pressure integrity of the casing seat, expressed as an equivalent fluid density, in which leakage is first initiated into a formation fracture or cement channel.

<b>LMRP</b>	lower marine riser package	The portion of the marine riser that is below a connection that allows the upper portion of the riser to be disconnected, leaving blowout preventer capability installed on a seafloor wellhead.
<b>LPR</b>	lower pipe ram	The lower pipe ram in a double pipe ram assembly.
<b>LCM</b>	loss circulation material	LCM is a specialty mixture pumped into the well to reduce wellbore fluid loss to the formation.
	loss, losses	Loss is the volume of fluid loss from the wellbore to the formation.
<b>MMscf/D</b>	millions of standard cubic feet per day	Units of gas flow rate.
<b>MOC</b>	management of change	MOC is a process for approving and managing deviations from or revisions to critical technical documents, operating procedures, policies, or guidelines.
<b>MPD</b>	managed pressure drilling	An advanced drilling process in which annular pressure is held at the surface with a rotating control device providing more control on the annular pressure profile throughout the wellbore.
	manifold	A manifold is an assembly of pipe with multiple connections for collecting or distributing drilling fluid.
	mat rig, mat-supported jack-up	A mat-supported jack-up rig is a jack-up unit with the legs rigidly connected by a foundation structure, such that the legs are raised and lowered in unison.
<b>MD</b>	measured depth	Depth measured along the well path.
<b>MSL</b>	mean sea level	Average elevation of sea level often used as reference elevation for water depth and other important depths.
<b>MPR</b>	middle pipe ram	Pipe ram in the middle of a blowout preventer containing three rams.
<b>MMS</b>	Minerals Management Service	Predecessor regulatory agency of BOEM and BSEE.
<b>MDT</b>	modular (formation) dynamics test	Formation pressure test conducted with a downhole tool that inserts a probe into the borehole wall.
	normal practice	Meets minimum industry standards for prudent drilling, completion, and well control operations and complies with BSEE regulations.
<b>NPD</b>	Norwegian Petroleum Directorate	Norwegian regulatory agency that grants drilling permits.

<b>NTL</b>	notice to lessees	Supplementary regulatory policy to cover situations not sufficiently addressed in the published Code of Federal Regulations.
<b>OCS</b>	outer continental shelf	
	oil shrinkage	Produced liquid hydrocarbons generally shrink in volume in the stock tank due to evaporation of lighter hydrocarbons before it is sold. Oil volume sold is generally measured in stock tank barrels (STB) corrected to a standard temperature and atmospheric pressure.
<b>OIM</b>	offshore installation manager	The offshore installation manager is the Rig Owner's representative appointed to manage the offshore activities of the vessel. The OIM is the person responsible for the safety of all the personnel on an offshore installation when the installation/vessel does not require a maritime crew.
<b>OEM</b>	original equipment manufacturer	Original equipment manufacturer or OEM-authorized parts on safety critical equipment.
	"outrunning a kick"	Past field practice when a small kick is suspected of attempting to trip pipe back to bottom before shutting in the well; or attempting to get BHA completely out of well before shutting-in the well.
	packer	A packer is a downhole device that seals the annulus formed between two concentric strings of pipe, typically the tubing and casing strings.
	packer bypass	The packer bypass is a flow path that when open allows fluid communication between the annulus above and below the packer. It can be opened and closed remotely from the surface, i.e. by vertical pipe movement.
	pay, pay interval	The pay interval is the vertical span of formation that has been estimated to contain economically recoverable hydrocarbons.
	perforating gun	The perforating gun is a downhole tool containing explosive charges or other means used to cut holes in the casing and adjacent cement and rock to provide fluid communication with the formation. The perforating gun can be conveyed on wireline or on a tubing string or work string, in which case it is called a tubing-conveyed perforating gun (TCP).
	perforations	Perforations are holes shot or cut through pipe or casing in the well, usually with shaped charges in a perforating gun.

	permeability	Permeability is a measure of the capacity of a porous medium to allow flow of fluids or gases. Permeability is usually expressed in millidarcy, mD.
<b>PSA</b>	Petroleum Safety Authority (Norway)	Regulatory Agency in Norway responsible for safety.
	pill	A pill (also called a “slug”) is a discrete volume of fluid introduced to the wellbore and circulated to a target depth for a special purpose such as a sweep or to reduce fluid loss. See “loss circulation pill.”
	pipe-light	A condition in which the weight of the work string is insufficient to offset the upward force created by the pressure acting over the cross sectional area of the pipe.
	pipe rams	The pipe rams are a subcomponent of the BOP that allows the well to be shut in while pipe is within the rams by sealing around the outer surface of the pipe.
	plugback operation	A downhole procedure in which the well is plugged at a lesser depth than its total depth so that the well beneath the plug is isolated and inaccessible.
	pore pressure	The pressure of the fluid contained within the pore spaces of the formation. Pore pressure is often expressed as EMW or pore pressure gradient.
	porosity	Porosity is a measure of the void spaces in a material, and is a fraction of the volume of voids over the total volume. In oil and gas formations, all the void space is filled with fluids.
<b>ppg</b>	pounds per gallon	Unit of fluid density.
<b>ppge</b>	pounds per gallon equivalent	Units used for a pressure gradient expressed as an equivalent fluid density.
<b>PWD</b>	pressure while drilling	Measurement of downhole pressure while drilling with a downhole sensor in the BHA.
	Prescriptive rules (regulations)	Prescriptive rules specify how a goal is to be accomplished in contrast to performance-based rules which specify the goal.
	pressure support	Pressure support refers to a geologic mechanism which acts to sustain the pore pressure when formation fluids are produced. When a formation with pressure support is produced more quickly than the pressure support mechanism can act and then taken off production, the pore pressure can recharge over time.
<b>psi, psia, psig</b>	pounds per square inch (absolute, gauge)	Units of pressure or pressure differential.

	production history	The production history of a well entails the measured pressures and flow rates over a period of time and other associated data used to monitor the well performance and track the volumes of oil, water, and gas produced.
	production tubing	Production tubing is the string of tubing that carries the produced fluids from the perforated interval to the surface.
<b>QA</b>	quality assurance	The management of a desired level of quality in a service or product, especially by means of attention to every stage of the process of delivery or production.
	racking, racking back	Racking refers to transferring stands of pipe from elevators to the fingerboards when tripping out of a well.
	rams	See "Pipe Rams" or "Shear Rams."
	re-completion	See "completion."
	remote panel	The remote panel is a set of controls and instruments remote from the rig floor from which the BOPE can be actuated and monitored.
	returns, return flow	Return flow is flow from the well, through the flowline, to the mud tanks.
	reverse circulating	See "circulating."
<b>RKB</b>	reference kelly bushing	Before the use of top drives, kelly bushings mounted in the rotary table to rotate pipe. The top of the kelly bushings was a common reference elevation for zero well depth. The term is still commonly used but now references the top of the rotary table.
<b>RPM</b>	revised permit to modify	An RPM form must be filed and approved by BSEE before making any changes in previously approved drilling and completion procedures.
	riser	In an offshore well the riser is the tubular connecting the BOP at the mudline to the drilling facilities at the surface.
<b>RCD</b>	rotating control device	A rotating sealing device used in managed pressure drilling that holds pressure on the drillpipe/casing annulus while allowing the drillpipe to rotate.
<b>RCI</b>	root cause investigation	A method of failure investigation in which the failure is traced through a consecutive series of causal events back to the initiating event.
	rotary, rotary table	The rotary table is a device used to apply torque to the drill string during drilling and normally located in the center of the drill floor.

<b>SFM</b>	safe fracture margin	The difference between the lower of either(1)the Formation Integrity Test (FIT) or Leak-off Test (LOT) at the Casing Seat and (2)the open hole formation fracture gradient (FFG) and the well fluid density.
	safety valve	Synonymous with drillstring safety valve. See “drillstring safety valve.”
<b>SEMP</b>	safety and environmental management program	The Safety and Environmental Management Program as described in API RP 75.
<b>SEMS</b>	safety and environmental management system	The Safety and Environmental Management System is a system prescribed by BSEE to manage safety and environmental concerns in the offshore oil and gas industry.
	sand control screens	Sand control screens are screens placed in the wellbore adjacent to the perforations to mitigate the production of sand from the formation.
	saver sub	The first connection to the bottom of the top drive used to reduce the wear of the top drive threads and adapt the top drive to various threaded connections.
	scraper, scraper-brush	A scraper, brush, or combination scraper-brush is a downhole tool mounted in the work string that scrapes and bushes the inside of the casing to remove debris.
	seepage	Seepage refers to slow loss of wellbore fluid to the pore spaces of the formation.
	seismic	Seismic refers to geological data acquired by measuring the reflections of sound waves within the earth.
	shallow gas flow, shallow gas hazard	A shallow gas hazard is a gas zone that is encountered before setting surface casing and installing the blowout preventers. A shallow gas flow is a gas flow from a shallow gas zone. Shallow gas flows can be managed with a diverter.
	shear rams	See “blind shear rams.”
	short trip	A short trip is an abbreviated recovery of pipe out of, and then the replacement of same back into the wellbore. Since the short trip is drillpipe only (no bottom-hole assembly), and is limited in length it can be accomplished quickly. A short trip often is used to gauge whether a hole is clean or whether the mud weight is sufficient to permit a full trip out of the hole.
	shut-in	A shut-in is a procedure to isolate the wellbore volume within a pressure-containing boundary, typically by closing a valve or well control device at the surface.

	slug, slugging	A slug usually refers to a heavy mud pill introduced into the drill string before tripping so that the fluid level inside the drillpipe remains below the rig floor. This prevents mud from spilling on the rig floor when each connection is broken. For wider usage, see “pill”.
<b>SIDP or SIDPP</b>	shut-in drillpipe pressure	Shut-in drillpipe pressure is the surface pressure in the drillpipe with the well shut-in.
	slack off	To slack-off is to lower the hook.
	slips	Slips are devices on the rotary table on the rig floor that can be engaged to carry the weight of the work string so that the string can be disconnected from the elevators.
	snapping	Snapping is a method of depth control similar to tagging, but in which the bottom of the work string includes a keyed device that "snaps" into or onto a fixed downhole device, providing a positive identification of the feature. At the surface, the apparent weight of the work string will increase and then decrease an expected amount when the work string snaps on and off the device.
<b>SPE</b>	Society of Petroleum Engineers	
	space-out	To space-out is to position the work string such to ensure that a tool joint does not reside within the BOPE where it might interfere with its proper BOPE function.
	spacers	A spacer is a discrete volume of wellbore fluid placed in between other fluids to prevent mixing or other undesirable interactions.
	specific gravity	Specific gravity is the ratio of the density of a substance to the density of a reference substance at specified conditions. The specific gravity of liquids are stated a liquid specific gravity for which the reference substance is water. Gases are stated as gas specific gravity in which the reference substance is air.
	spot	To spot is to pump a discrete volume of fluid to a target location within the well.
	stabilizer	A stabilizer is a component of the bottomhole assembly used to stabilize the bit trajectory.
	stack	See “BOP.”



	stand	A stand is a section of pipe comprised of several work string joints connected together. The length of the stand is determined by the height of the derrick and is typically three joints or approximately 90 feet. A work string is often tripped in or out of the well by stands in lieu of individual joints.
	standpipe, standpipe manifold	The standpipe is a vertical pipe which joins the rotary hose to the circulating system through the standpipe manifold.
	sticking	Sticking refers to intermittent resistance to motion by the work string.
<b>STB</b>	stock tank barrel	The stock tank barrel is the unit of volume used for sale purposes and is the volume of the oil at a standard temperature and atmospheric pressure.
	sub	A sub is a subcomponent of a string of pipe that serves a specific purpose or contains a tool.
	sump packer	A sump packer is a packer located below the perforations as contrasted with the isolation packer located above the perforations. In a gravel pack completion, the sump packer serves as the lower boundary of the gravel pack. The isolation packer serves as the upper boundary of the gravel pack as well as isolates the annulus above the perforations from the production.
<b>SCSSV</b>	surface-controlled subsurface safety valve	A subsurface valve installed in the production tubing that is designed to close and stop flow from the well in the event the surface wellhead or tree fails and allows a release of surface pressure.
	surface tree	The surface tree is a manifold of surface mounted pressure components and valves used to control the production stream and manage annular fluids. It is installed near the end of completion activities before the well is placed on production.
	surge, surging, surge pressure	Surging is an increase in pressure due to tool movement and is the counterpart to swabbing.
	swab, swabbing, swab pressure loss	Swabbing is the reduction in pressure below the drillstring or work string when it is being pulled upward. The swab pressure loss can be estimated given the wellbore and work string clearances and the wellbore fluid properties.
	sweep	A sweep is a circulation of the wellbore fluids conducted to transfer targeted material out of the well. Typically a high viscosity pill is prepared to enhance the efficacy of a sweep.

	tag, tagging, tagged	Tagging is method of measuring the depth of a downhole object or feature by lowering a work string until its lowermost end contacts the feature, as indicated by a sudden reduction of the weight of the work string measured at the surface. The length of the work string is known and directly indicates the depth of the feature.
	tapered work string	A tapered work string is a work string comprised of pipe segments of varying diameter, typically smallest at the lowermost end and increasing stepwise in size toward the upmost end.
	test valve	Valve in the perforating assembly that allows communication through the tubing with the perforated interval below the packer.
<b>TIW valve</b>	Texas Iron Works valve	See "drillstring safety valve."
	tool joint	A tool joint is a threaded connection at the ends of joint of pipe. The male section (pin) is attached to one end and the female section (box) is attached to the other end.
	toolpusher	The toolpusher is a rig operation supervisor for the drilling contractor. The driller reports to the toolpusher.
	top drive	The top drive is drilling rig machinery that provides the capability to simultaneously rotate, vertically translate, and control flow through the work string. The top drive attaches to the top of the work string and drives its motion.
	top drive bell guide	The top drive bell guide is a bell-shaped component attached to the bottom of the top drive that serves to guide connections to the connection point on the drive.
<b>TD</b>	total depth	Total well depth to bottom of well below surface reference point as measured along the path of the well.
<b>TVD</b>	true vertical depth	True vertical well depth or change in elevation below the surface reference elevation to well bottom.
	traveling block	See "block."
	tripping	Pulling the drillpipe or work string out of the well to change the bottom assemble and then running the drillpipe or work string back into the well.
	trip margin	The difference between the fluid density in the well and the formation pore pressure gradient, usually expressed in pounds per gallon.

	trip sheet (book)	Trip sheet and books are an accounting record that compares the volume of pipe removed from the well to the volume of drilling fluid added to the well to return it to a full condition. This exercise enables timely detection of an influx or loss.
	trip tank	The trip tank is a gauged and calibrated vessel used to account for fill and displacement volumes as pipe is pulled from and run into the hole. Close observation allows early detection of formation fluid entering a wellbore and of fluid loss to a formation.
	tubing	Tubing is a pipe used to convey production from the perforated interval to the surface tree.
<b>TCP</b>	tubing-conveyed perforating gun	A tubing conveyed perforating gun is a perforating gun mounted on a tubing string as opposed to another means of conveyance such as wireline.
	tuned spacer	A tuned spacer is a cement spacer with an engineered rheology (set of fluid flow properties) that promotes efficient displacement of the wellbore fluid with minimum contamination.
<b>USCG</b>	United States Coast Guard	
<b>VBR</b>	variable bore ram	A VBR is a specialized subcomponent of the pipe rams that allows the rams to close and seal on a range of pipe sizes. See "pipe rams."
	wash, washing	To wash is to lower or raise the work string while circulating to promote removal of debris from the bottom of the wellbore.
	water saturation	Water saturation is the fraction of pore space in the rock that contains water. 100% water saturation indicates that all the pore space contains water.
<b>WSM</b>	well site manager	Lease Operator's well site representative.
	well test	A well test is a procedure conducted to determine reservoir performance by allowing the formation to flow and measuring flow rates and pressures.
	working pressure	The working pressure is the maximum pressure a component is designed to see in operation.

	work string	A work string is a generic term applied to a length of pipe inserted into the wellbore, often with specialized tool or tools mounted near its lowermost end, for the purpose of doing work on the well. Work strings can be comprised of tubing, drillpipe, or casing. During drilling operations the work string is referred to as the drillstring.
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APPENDIX B

BIOGRAPHIC INFORMATION OF  
KEY PERSONNEL

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## **ADAM T. (TED) BOURGOYNE, JR., PH.D., P.E.**

Ted has BS and MS degrees in Petroleum Engineering from LSU (1966, 67) and a PhD in Petroleum Engineering from the University of Texas at Austin (1969). He is a registered professional Petroleum Engineer in Louisiana. His work experience in the oil and gas industry began through participation in summer/co-op programs while in college. He worked for Mobil Oil Company three months as an onshore roustabout and three months as an offshore roustabout. After reaching senior status at LSU, he worked three months as an Engineering Assistant involved with offshore drilling and well work-over planning. After receiving his B.S. Degree and prior to entering graduate school, Ted worked three months for Texaco as an Assistant Drilling Engineer involved with offshore field operations, well planning, and drilling optimization. His training for this position included working as a floor hand on the first semi-submersible rig, the "Ocean Driller." After entering graduate school, he worked three months for Chevron at their research laboratory in La Habra, California and three months for Conoco at their research laboratory in Ponca City, Oklahoma.

In 1969, after completion of his course work at the University of Texas at Austin (UT-Austin), Ted joined Conoco in Houston as a Senior Systems Engineer in their Production Engineering Services Group. There, he participated in several drilling and production projects including an offshore drilling project involving real-time drilling data acquisition and estimation of formation pore pressure.

In 1971, Ted joined LSU as an Assistant Professor. For the next 29 years, he worked in the undergraduate, graduate, and continuing education programs of the LSU Petroleum Engineering Department and in administration of the College of Engineering. He had primary responsibility for the drilling engineering and drilling fluids laboratory courses, but taught production engineering and reservoir engineering courses as well. Ted served as Chairman of the Petroleum Engineering Department from 1977 to 1983. At the time of his retirement from LSU in December of 1999, he was the Campanile Charities Professor of Offshore Mining and Petroleum Engineering and Dean of the College of Engineering.

Ted has been especially active in the area of blowout prevention. Soon after joining LSU in 1971, he began participating in teaching LSU's industry short-courses on well control for onshore and bottom-supported offshore drilling rigs. LSU had founded the first blowout prevention training program with open enrollment. The program was enthusiastically received by the industry and several hundred industry participants per year attended the program during the 1970s. Discussions held with a wide cross-section of industry participants provided Ted valuable insight into the complications that can arise during well control operations. He became particularly interested in complications associated with deepwater drilling operations with the blowout preventer at the seafloor.

Starting in 1979, Ted guided the development of a multi-million dollar research and training well facility at LSU to support work on deepwater well control and to complement the older training well. The newer facility was funded through the combined support of 13 major oil companies, 40 service companies, and the Minerals Management Service (MMS) (now the Bureau of Safety and Environmental Enforcement or BSEE). The facility was initially

centered around a 6000-foot well specially configured to model the full-scale well control flow geometry of a floating drilling rig in 3000 feet of water. Extensive surface equipment provided for “hands on” training as well as highly-instrumented well control experiments. Gas could be injected into the bottom of the well to initiate the conditions of a threatened blowout. The goal of the research was the development of improved well control procedures and training for deepwater drilling operations.

The facility was later expanded to include additional wells and model diverter components for experimental study of flow erosion and pressures seen during diverter operations. This research was aimed at reducing the incidence of failures in diverters used to handle a shallow gas flow that could not be safely shut-in. Under sponsorship of Amoco (now BP) and the Drilling Engineers Association (DEA), the facility was further expanded to include an additional 6000-foot well to study kick detection and other potential well control complications associated with gas solubility in oil base muds.

In addition to serving as Principal Investigator for more than a decade on Offshore Blowout Prevention research supported by the US Minerals Management Service, Ted also served as an advisor on technology for deep water oil and gas development to the Office of Technology Assessment (OTA) of the US Congress. He also chaired a workshop panel on the use of risk analysis in offshore oil and gas operations for the National Bureau of Standards and chaired a workshop session on the reliability of offshore operations for the National Institute of Standards and Technology. Ted also served two years as Chairman of the Technical Advice Working Group to the Integrated Ocean Drilling Program for scientific deepwater drilling and core retrieval.

Between 1981 and his retirement in 1999, Ted supervised the graduate research of 19 MS theses and 12 PhD dissertations on various well control topics of interest to industry and the MMS (now BSEE). Numerous Well Control Research Workshops were held at LSU during this period and were well attended by both MMS and industry personnel. The research has resulted in more than 50 publications related to well control and including formation pore pressure estimation, fracture gradient correlations, leak-off test data, modeling well control and relief well operations, and improved procedures for safe removal of a gas influx. During this period Ted also organized and helped to teach specialized deepwater well control schools for Amoco, Exxon, Shell, Conoco, Phillips, and Zapata as well as numerous open enrollment schools.

Ted is the lead author of the Society of Petroleum Engineers (SPE) Drilling Engineering Textbook, entitled “Applied Drilling Engineering” which was developed for petroleum engineering college curriculums. This textbook is widely accepted and has been a “top seller” for SPE since it was first published in 1986. Ted also wrote “Drilling Practices,” a chapter in the Encyclopedia of Chemical Processing and Design and “Shallow Gas Blowouts,” a chapter in Firefighting and Blowout Control. He also wrote several chapters in a well control manual used in LSU’s well control schools. Ted served as chairman of the SPE reprint series on “Pore pressure and Fracture Gradient Determination” and also for another reprint series on “Well Control.” He is a past recipient of the SPE Distinguished Achievement Award for Petroleum Engineering Educators and received the SPE Drilling

Engineering Award “for distinguished contributions to petroleum engineering in the area of drilling technology.”

In 1990, Ted was selected as a Distinguished Member of SPE. In 1997-98, he was selected as a Distinguished Lecturer by the SPE and gave lectures at about 30 locations in the U.S., Europe, and Middle East. During 1998, he also served on a steering committee of the International Association of Drilling Contractors (IADC) that coordinated the development of a manual on well control practices for deepwater drilling operations. Ted also served on an ad hoc committee of SPE to review the exam leading to professional registration of Petroleum Engineers. Upon retirement from LSU, he was recognized by the House of Representatives of the State of Louisiana in House Concurrent Resolution No. 33 of the First Extraordinary Session, 2000, commending him for “achievements in scholarly research and writing in the field of petroleum engineering and for highly significant contributions to higher education in Louisiana.” In December of 2001, Ted was recognized as a Distinguished Graduate of the College of Engineering at the University of Texas at Austin. In 2006, he was inducted into the LSU Engineering Hall of Distinction. In 2013 he became a Legion of Honor Member of SPE and in 2014 he was elected as to Honorary Membership in both SPE and AIME, which the highest honor presented by SPE to individuals.

Ted is currently President of Bourgoyne Engineering LLC, which offers Petroleum Engineering consulting services to the Oil and Gas Industry. He has consulted extensively with Pennington Oil and Gas, LLC in their drilling and completion of deep, high-temperature, high-pressure wells in the Tuscaloosa Trend Area of Louisiana. He also consulted with BP following the Deepwater Horizon Accident. He has served as an expert witness on blowout and well control matters and as a BSEE approved Certified Verification Agent (CVA) for evaluating alternative drilling technology for deepwater drilling. Ted continues to serve LSU as a Professor Emeritus of Petroleum Engineering.

### **DARRYL A. BOURGOYNE, B.S., M.S., PETE**

Darryl completed his BS degree in Petroleum Engineering at LSU in 1991. His work experience in the oil and gas industry began through participation in summer and winter/co-op programs with Chevron USA in drilling operations on both offshore and in inland waters while in college. He completed his MS degree in Petroleum Engineering at LSU in 1995 while working part time as a Teaching Assistant and Research Associate. This work involved instructing simulator and live well exercises in LSU’s Well Control Certification Courses, assisting with the instruction of undergraduate courses in drilling and well control, and participating in well control research projects and annual LSU/MMS well control workshops funded by MMS. It also involved developing full-scale well control exercises with facilities and equipment available at LSU’s Petroleum Engineering and Technology Transfer Laboratory.

In 1996, Darryl joined Chevron USA in their Gulf of Mexico drilling operations. He worked as a Well Site Supervisor both on the continental shelf on platform and jack-up rigs and on the continental slope on deepwater drilling operations. He became MMS Supervisory Well Control Certified through training provided by Chevron. While working offshore for



Chevron, he participated in gravel pack recompletions very similar to the operations being conducted by Walter Oil & Gas on ST220, Well A3 at the time of the well control incident.

In 1998, Darryl joined and became a principal officer in Bourgoyne Enterprises, Inc, and participated in offering consulting services to the oil and gas industry. He helped develop procedures and new equipment designs for deepwater applications of underbalanced drilling technology for Williams Tool Company. He participated in Well Control software development projects for Wild Well Control, Mobil and for Deep Star. In addition, he assisted the well control training group at Diamond Offshore and audited their WellCap accredited well control classes.

In 2003, Darryl joined LSU as Director of the Petroleum Engineering Research and Technology Transfer Laboratory. There he served as an instructor for full-scale, hands-on petroleum engineering undergraduate laboratories, as lead instructor and designer for specialized industry training courses for blowout prevention, assisted with federally funded research projects, and principle investigator for a state funded well control training research project. In addition he assisted Shell, BP, Chevron, MI Swaco, and others in training and equipment testing activities conducted at the facility. In 2010, he testified before the National Commission on the Deepwater Horizon Oil Spill and Offshore Drilling as an expert on oil well drilling operations and advised the Louisiana Commissioner of Conservation regarding the resulting offshore drilling moratorium.

In 2013, Darryl started his own consulting company and is currently retained by Bourgoyne Engineering, LLC. Clients have included Pennington Oil and Gas Company, Walter Oil & Gas Corporation, Helis Oil & Gas Company, and Vulcan Minerals.

### **DWAYNE A. BOURGOYNE, PH.D., P.E.**

Dwayne has a BS in Mechanical Engineering from LSU (1992) and an MS and PhD in Mechanical Engineering from the University of Michigan (2000, 2003). He is a registered professional Mechanical Engineer in Louisiana. Dwayne is the author of three peer-reviewed journal papers and several industry conference proceedings and is a member of the Society of Petroleum Engineers and American Society of Mechanical Engineers.

Dwayne's work experience in the oil and gas industry began as an undergraduate summer worker at the LSU Petroleum Engineering Research and Technology Transfer Laboratory in 1988. Dwayne then entered the cooperative education program at LSU and worked for three terms between 1989 and 1991 with the Rockwell Space Operations Company on assignments at the Johnson Space Center in Houston, Texas involving thermal-fluid control systems.

Upon graduation with his BS degree in 1992, Dwayne returned to the oil industry and joined Bourgoyne and Associates, Inc., in Baton Rouge, Louisiana as a Research and Development Engineer. There Dwayne conducted experimental research and development on a fluidics valve application for use as a directional drilling telemetry source. In 1995, Dwayne took a position as a Mechanical Contact Engineer at the ExxonMobil Baton Rouge Refinery to provide mechanical engineering support for the refinery's distillation units. Dwayne later served as a refinery Rotating Equipment Reliability Engineer where he specified new

equipment, engineered repairs and addressed reliability issues on refinery pumps and turbo-machinery. As part of these assignments Dwayne received technical training in Risk Assessment and Root-Cause Failure Analysis and applied these methods extensively in the field.

In 1998, Dwayne left industry to return to graduate school at the University of Michigan. While completing his degree Dwayne worked as a graduate student research assistant on the High Reynolds Number Hydrofoil project, an experimental investigation of the fundamental fluid dynamics of a full-scale submarine propeller blade. This experimental work was conducted in the largest acoustic water tunnel in the world, operating by the Office of Naval Research. The result of these experiments formed the basis of his PhD thesis and several peer-reviewed papers in the Journal of Fluid Mechanics. Dwayne graduated in 2003 with his PhD in Mechanical Engineering with an emphasis on Fluid Mechanics.

In 2003 Dwayne joined the ExxonMobil Upstream Research Company in Houston, Texas as a Research Engineer in the Marine Section of the Offshore Division. There he participated in an extensive research effort to evaluate Liquefied Natural Gas ship tanks for internal sloshing loads, including large scale model testing at a world-class test basin. During this period Dwayne served a term as a Professional Development Advisor reporting to a committee of division managers and stewarding employee career development for the Offshore Job Family within ExxonMobil worldwide.

In 2008, Dwayne took a position as Assistant Professor of Petroleum Engineering at the Colorado School of Mines in Golden, Colorado. At CSM Dwayne specialized in drilling and completions and taught undergraduate courses in Drilling, Completions, Reservoir Fluids, a graduate course in Drilling Fluids, and received certified industry training in well control. Dwayne also pursued externally-funded research with a focus in experimental fluid mechanics, drilling and stimulation, and gyroscopic wellbore surveying.

In 2011, Dwayne returned to industry as a principal officer of Bourgoyne Enterprises, Inc. in Baton Rouge, Louisiana to offer private consulting services to the oil and gas industry. There Dwayne consulted on development of new downhole tools aimed at reducing cost and improving safety of oil and gas well drilling, evaluated well control aspects of emerging alternative drilling methods, supported well planning and economic analysis for unconventional resource development, and designed hydro-fracture treatments. During this period, Dwayne also worked for LSU on developing well control protocols for use in Managed Pressure Drilling.

In 2013, Dwayne started his own consulting company pursuing similar work while supporting projects undertaken by Bourgoyne Engineering, LLC, including well planning and economic analysis for unconventional resource development, hydro-fracture treatment design and analysis, and training for the oil and gas industry. Dwayne also consulted for Blue Heron Environmental Services, LLC in Columbia, Louisiana on developing flowback water recycling technology and for a multinational oil company on the well control aspects of an advance offshore drilling technology program.

# APPENDIX C

Sections of Title 30 Chapter II Subchapter B Part 250 Relevant  
to Well Control during Tripping in Drilling and Completion  
Operations

Current 02/23/2017

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## 2016 Regulatory Changes relevant to Study Objectives

Removed Section:		Now Covered By:	
<b>250.401</b>	What must I do to keep wells under control?	<b>250.703</b>	What must I do to keep wells under control?
<b>250.440</b>	What are the general requirements for BOP systems and system components?	<b>250.730</b>	What are the general requirements for BOP systems and system components?
<b>250.445</b>	What are the requirements for kelly valves, inside BOPs, and drill-string safety valves?	<b>250.736</b>	What are the requirements for choke manifolds, kelly-type valves inside BOPs, and drill string safety valves?
<b>250.462</b>	What are the requirements for well-control drills?	<b>250.710</b>	What instructions must be given to personnel engaged in well operations?
		<b>250.711</b>	What are the requirements for well-control drills?
<b>250.506</b>	Crew instructions. (Completions)	<b>250.710</b>	What instructions must be given to personnel engaged in well operations?
<b>250.516</b>	Blowout prevention equipment. (Completions)	<b>250.730</b>	What are the general requirements for BOP systems and system components?

## Current BSEE Regulations relevant to Study Objectives

Contract Says:	Interpreted meaning using <i>prior</i> CFR		Interpreted meaning using <i>current</i> CFR and Included in Study	
107	107	What must I do to protect health, safety, property, and the environment?	107	What must I do to protect health, safety, property, and the environment?
<b>Not in Contract</b>	400	General requirements.	400	General requirements & relevant sections of Subpart G (Same as with 500 below).
401	401	What must I do to keep wells under control?	<b>703</b>	What must I do to keep wells under control? <b>(training per Subpart O and S)</b>
455	455	What are the general requirements for a drilling fluid program?	455	What are the general requirements for a drilling fluid program?
	456	What safe practices must the drilling fluid program follow?	456	What safe practices must the drilling fluid program follow?
	457	What equipment is required to monitor drilling fluids?	457	What equipment is required to monitor drilling fluids?
	458	What quantities of drilling fluids are required?	458	What quantities of drilling fluids are required?
500	500	General requirements.	500	General requirements & relevant Subpart G.
			<b>703</b>	See above
			<b>710</b>	What instructions must be given to personnel engaged in well operations?
			<b>711</b>	What are the requirements for well-control drills?
			<b>736</b>	What are the requirements for choke manifolds, kelly-type valves inside BOPs, and drill string safety valves?
			<b>API 53</b>	API Standard 53 (incorporated by reference in §250.198)
	506	Crew instructions.	<b>710</b>	See above
	514	Well-control fluids, equipment, and operations.	514	Well-control fluids, equipment, and operations.
516(d)	516 Blowout prevention equipment. 516(d) applies to inside BOPs & workstring SV)	<b>736</b>	See above	



## Subpart A—General

### PERFORMANCE STANDARDS

#### §250.107 What must I do to protect health, safety, property, and the environment?

(a) You must protect health, safety, property, and the environment by:

(1) Performing all operations in a safe and workmanlike manner;

(2) Maintaining all equipment and work areas in a safe condition;

(3) Utilizing recognized engineering practices that reduce risks to the lowest level practicable when conducting design, fabrication, installation, operation, inspection, repair, and maintenance activities; and

(4) Complying with all lease, plan, and permit terms and conditions.

(b) You must immediately control, remove, or otherwise correct any hazardous oil and gas accumulation or other health, safety, or fire hazard.

(c) *Best available and safest technology.* (1) On all new drilling and production operations and, except as provided in paragraph (c)(3) of this section, on existing operations, you must use the best available and safest technologies (BAST) which the Director determines to be economically feasible whenever the Director determines that failure of equipment would have a significant effect on safety, health, or the environment, except where the Director determines that the incremental benefits are clearly insufficient to justify the incremental costs of utilizing such technologies.

(2) Conformance with BSEE regulations will be presumed to constitute the use of BAST unless and until the Director determines that other technologies are required pursuant to paragraph (c)(1) of this section.

(3) The Director may waive the requirement to use BAST on a category of existing operations if the Director determines that use of BAST by that category of existing operations would not be practicable. The Director may waive the requirement to use BAST on an existing operation at a specific facility if you submit a waiver request demonstrating that the use of BAST would not be practicable.

(d) BSEE may issue orders to ensure compliance with this part, including, but not limited to, orders to produce and submit records and to inspect, repair, and/or replace equipment. BSEE may also issue orders to shut-in operations of a component or facility because of a threat of serious, irreparable, or immediate harm to health, safety, property, or the environment posed by those operations or because the operations violate law, including a regulation, order, or provision of a lease, plan, or permit.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26014, Apr. 29, 2016; 81 FR 61015, Sept. 7, 2016]

### SPECIAL TYPES OF APPROVALS

#### §250.141 May I ever use alternate procedures or equipment?

You may use alternate procedures or equipment after receiving approval as described in this section.

(a) Any alternate procedures or equipment that you propose to use must provide a level of safety and environmental protection that equals or surpasses current BSEE requirements.

(b) You must receive the District Manager's or Regional Supervisor's written approval before you can use alternate procedures or equipment.

(c) To receive approval, you must either submit information or give an oral presentation to the appropriate Regional Supervisor. Your presentation must describe the site-specific application(s), performance characteristics, and safety features of the proposed procedure or equipment

## REFERENCES

### §250.198 Documents incorporated by reference.

(partial list)

(63) API Standard 53, Blowout Prevention Equipment Systems for Drilling Wells, Fourth Edition, November 2012, incorporated by reference at §§250.730, 250.735, 250.737, and 250.739;

(79) API RP 75, Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities, Third Edition, May 2004, Reaffirmed May 2008; incorporated by reference at §§250.1900, 250.1902, 250.1903, 250.1909, 250.1920;

(90) ANSI/API Specification 16A, Specification for Drill-through Equipment, Third Edition, June 2004, Reaffirmed August 2010, incorporated by reference at §250.730

(91) ANSI/API Specification 16C, Specification for Choke and Kill Systems, First Edition, January 1993, Reaffirmed July 2010; incorporated by reference at §250.730;

(92) API Specification 16D, Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment, Second Edition, July 2004, Reaffirmed August 2013, incorporated by reference at §250.730;

## Subpart D—Oil and Gas Drilling Operations

### GENERAL REQUIREMENTS

#### §250.400 General requirements.

Drilling operations must be conducted in a safe manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the Outer Continental Shelf (OCS), including any mineral deposits (in areas leased and not leased), the National security or defense, or the marine, coastal, or human environment. In addition to the requirements of this subpart, you must also follow the applicable requirements of subpart G of this part.

[81 FR 26017, Apr. 29, 2016]

#### §250.401 Replaced by §250.703.

#### §250.408 May I use alternative procedures or equipment during drilling operations?

You may use alternative procedures or equipment during drilling operations after receiving approval from the District Manager. You must identify and discuss your proposed alternative procedures or equipment in your Application for Permit to Drill (APD) (Form BSEE-0123) (see §250.414(h)). Procedures for obtaining approval are described in §250.141 of this part.

#### §250.413 What must my description of well drilling design criteria address?

Your description of well drilling design criteria must address:

- (a) Pore pressures;
- (b) Formation fracture gradients, adjusted for water depth;
- (c) Potential lost circulation zones;
- (d) Drilling fluid weights;
- (e) Casing setting depths;

(f) Maximum anticipated surface pressures. For this section, maximum anticipated surface pressures are the pressures that you reasonably expect to be exerted upon a casing string and its related wellhead equipment. In calculating maximum anticipated surface pressures, you must consider: drilling, completion, and producing conditions; drilling fluid densities to be used below various casing strings; fracture gradients of the exposed formations; casing setting depths; total well depth; formation fluid types; safety margins; and other pertinent conditions. You must include the calculations used to determine the pressures for the drilling and the completion phases, including the anticipated surface pressure used for designing the production string;

(g) A single plot containing curves for estimated pore pressures, formation fracture gradients, proposed drilling fluid weights, planned safe drilling margin, and casing setting depths in true vertical measurements;

(h) A summary report of the shallow hazards site survey that describes the geological and manmade conditions if not previously submitted; and

(i) Permafrost zones, if applicable.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26017, Apr. 29, 2016]

#### **§250.414 What must my drilling prognosis include?**

Your drilling prognosis must include a brief description of the procedures you will follow in drilling the well. This prognosis includes but is not limited to the following:

(a) Projected plans for coring at specified depths;

(b) Projected plans for logging;

(c) Planned safe drilling margin that is between the estimated pore pressure and the lesser of estimated fracture gradients or casing shoe pressure integrity test and that is based on a risk assessment consistent with expected well conditions and operations.

(1) Your safe drilling margin must also include use of equivalent downhole mud weight that is:

(i) Greater than the estimated pore pressure; and

(ii) Except as provided in paragraph (c)(2) of this section, a minimum of 0.5 pound per gallon below the lower of the casing shoe pressure integrity test or the lowest estimated fracture gradient.

(2) In lieu of meeting the criteria in paragraph (c)(1)(ii) of this section, you may use an equivalent downhole mud weight as specified in your APD, provided that you submit adequate documentation (such as risk modeling data, off-set well data, analog data, seismic data) to justify the alternative equivalent downhole mud weight.

(3) When determining the pore pressure and lowest estimated fracture gradient for a specific interval, you must consider related off-set well behavior observations.

(d) Estimated depths to the top of significant marker formations;

(e) Estimated depths to significant porous and permeable zones containing fresh water, oil, gas, or abnormally pressured formation fluids;

(f) Estimated depths to major faults;

(g) Estimated depths of permafrost, if applicable;

(h) A list and description of all requests for using alternate procedures or departures from the requirements of this subpart in one place in the APD. You must explain how the alternate procedures afford an equal or greater degree of protection, safety, or performance, or why the departures are requested;

(i) Projected plans for well testing (refer to §250.460);

(j) The type of wellhead system and liner hanger system to be installed and a descriptive schematic, which includes but is not limited to pressure ratings, dimensions, valves, load shoulders, and locking mechanisms, if applicable; and

(k) Any additional information required by the District Manager needed to clarify or evaluate your drilling prognosis.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26017, Apr. 29, 2016]

#### **§250.418 What additional information must I submit with my APD?**

You must include the following with the APD:

(a) Rated capacities of the drilling rig and major drilling equipment, if not already on file with the appropriate District office;

(b) A drilling fluids program that includes the minimum quantities of drilling fluids and drilling fluid materials, including weight materials, to be kept at the site;

(c) A proposed directional plot if the well is to be directionally drilled;

(d) A Hydrogen Sulfide Contingency Plan (see §250.490), if applicable, and not previously submitted;

(e) A welding plan (see §§250.109 to 250.113) if not previously submitted;

(f) In areas subject to subfreezing conditions, evidence that the drilling equipment, BOP systems and components, diverter systems, and other associated equipment and materials are suitable for operating under such conditions;

(g) A request for approval, if you plan to wash out or displace cement to facilitate casing removal upon well abandonment. Your request must include a description of how far below the mudline you propose to displace cement and how you will visually monitor returns;

(h) Certification of your casing and cementing program as required in §250.420(a)(7); and

(i) Such other information as the District Manager may require.

(j) For Arctic OCS exploratory drilling operations, you must provide the information required by §250.470.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50892, Aug. 22, 2012; 81 FR 26018, Apr. 29, 2016; 81 FR 46561, July 15, 2016]

#### **§250.420 What well casing and cementing requirements must I meet?**

You must case and cement all wells. Your casing and cementing programs must meet the applicable requirements of this subpart and of subpart G of this part.

(a) *Casing and cementing program requirements.* Your casing and cementing programs must:

(1) Properly control formation pressures and fluids;

(2) Prevent the direct or indirect release of fluids from any stratum through the wellbore into offshore waters;

- (3) Prevent communication between separate hydrocarbon-bearing strata;
- (4) Protect freshwater aquifers from contamination;
- (5) Support unconsolidated sediments;
- (6) Provide adequate centralization to ensure proper cementation; and

(7)(i) Include a certification signed by a registered professional engineer that the casing and cementing design is appropriate for the purpose for which it is intended under expected wellbore conditions, and is sufficient to satisfy the tests and requirements of this section and §250.423. Submit this certification with your APD (Form BSEE-0123).

(ii) You must have the registered professional engineer involved in the casing and cementing design process.

(iii) The registered professional engineer must be registered in a state of the United States and have sufficient expertise and experience to perform the certification.

(b) *Casing requirements.* (1) You must design casing (including liners) to withstand the anticipated stresses imposed by tensile, compressive, and buckling loads; burst and collapse pressures; thermal effects; and combinations thereof.

(2) The casing design must include safety measures that ensure well control during drilling and safe operations during the life of the well.

(3) On all wells that use subsea BOP stacks, you must include two independent barriers, including one mechanical barrier, in each annular flow path (examples of barriers include, but are not limited to, primary cement job and seal assembly). For the final casing string (or liner if it is your final string), you must install one mechanical barrier in addition to cement to prevent flow in the event of a failure in the cement. A dual float valve, by itself, is not considered a mechanical barrier. These barriers cannot be modified prior to or during completion or abandonment operations. The BSEE District Manager may approve alternative options under §250.141. You must submit documentation of this installation to BSEE in the End-of-Operations Report (Form BSEE-0125).

(4) If you need to substitute a different size, grade, or weight of casing than what was approved in your APD, you must contact the District Manager for approval prior to installing the casing.

(c) *Cementing requirements.* (1) You must design and conduct your cementing jobs so that cement composition, placement techniques, and waiting times ensure that the cement placed behind the bottom 500 feet of casing attains a minimum compressive strength of 500 psi before drilling out the casing or before commencing completion operations. (If a liner is used refer to §250.421(f)).

(2) You must use a weighted fluid during displacement to maintain an overbalanced hydrostatic pressure during the cement setting time, except when cementing casings or liners in riserless hole sections.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50892, Aug. 22, 2012; 81 FR 26018, Apr. 29, 2016]

**§250.440 Replaced by §250.730.**

**§250.445 Replaced by §250.736.**

## **DRILLING FLUID REQUIREMENTS**

### **§250.455 What are the general requirements for a drilling fluid program?**

You must design and implement your drilling fluid program to prevent the loss of well control. This program must address drilling fluid safe practices, testing and monitoring equipment, drilling fluid quantities, and drilling fluid-handling areas.

## §250.456 What safe practices must the drilling fluid program follow?

Your drilling fluid program must include the following safe practices:

(a) Before starting out of the hole with drill pipe, you must properly condition the drilling fluid. You must circulate a volume of drilling fluid equal to the annular volume with the drill pipe just off-bottom. You may omit this practice if documentation in the driller's report shows:

(1) No indication of formation fluid influx before starting to pull the drill pipe from the hole;

(2) The weight of returning drilling fluid is within 0.2 pounds per gallon (1.5 pounds per cubic foot) of the drilling fluid entering the hole; and

(3) Other drilling fluid properties are within the limits established by the program approved in the APD.

(b) Record each time you circulate drilling fluid in the hole in the driller's report;

(c) When coming out of the hole with drill pipe, you must fill the annulus with drilling fluid before the hydrostatic pressure decreases by 75 psi, or every five stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure. You must calculate the number of stands of drill pipe and drill collars that you may pull before you must fill the hole. You must also calculate the equivalent drilling fluid volume needed to fill the hole. Both sets of numbers must be posted near the driller's station. You must use a mechanical, volumetric, or electronic device to measure the drilling fluid required to fill the hole;

(d) You must run and pull drill pipe and downhole tools at controlled rates so you do not swab or surge the well;

(e) When there is an indication of swabbing or influx of formation fluids, you must take appropriate measures to control the well. You must circulate and condition the well, on or near-bottom, unless well or drilling-fluid conditions prevent running the drill pipe back to the bottom;

(f) You must calculate and post near the driller's console the maximum pressures that you may safely contain under a shut-in BOP for each casing string. The pressures posted must consider the surface pressure at which the formation at the shoe would break down, the rated working pressure of the BOP stack, and 70 percent of casing burst (or casing test as approved by the District Manager). As a minimum, you must post the following two pressures:

(1) The surface pressure at which the shoe would break down. This calculation must consider the current drilling fluid weight in the hole; and

(2) The lesser of the BOP's rated working pressure or 70 percent of casing-burst pressure (or casing test otherwise approved by the District Manager);

(g) You must install an operable drilling fluid-gas separator and degasser before you begin drilling operations. You must maintain this equipment throughout the drilling of the well;

(h) Before pulling drill-stem test tools from the hole, you must circulate or reverse-circulate the test fluids in the hole. If circulating out test fluids is not feasible, you may bullhead test fluids out of the drill-stem test string and tools with an appropriate kill weight fluid;

(i) When circulating, you must test the drilling fluid at least once each tour, or more frequently if conditions warrant. Your tests must conform to industry-accepted practices and include density, viscosity, and gel strength; hydrogenion concentration; filtration; and any other tests the District Manager requires for monitoring and maintaining drilling fluid quality, prevention of downhole equipment problems and for kick detection. You must record the results of these tests in the drilling fluid report; and

(j) In areas where permafrost and/or hydrate zones are present or may be present, you must control drilling fluid temperatures to drill safely through those zones.

**§250.457 What equipment is required to monitor drilling fluids?**

Once you establish drilling fluid returns, you must install and maintain the following drilling fluid-system monitoring equipment throughout subsequent drilling operations. This equipment must have the following indicators on the rig floor:

- (a) Pit level indicator to determine drilling fluid-pit volume gains and losses. This indicator must include both a visual and an audible warning device;
- (b) Volume measuring device to accurately determine drilling fluid volumes required to fill the hole on trips;
- (c) Return indicator devices that indicate the relationship between drilling fluid-return flow rate and pump discharge rate. This indicator must include both a visual and an audible warning device; and
- (d) Gas-detecting equipment to monitor the drilling fluid returns. The indicator may be located in the drilling fluid-logging compartment or on the rig floor. If the indicators are only in the logging compartment, you must continually man the equipment and have a means of immediate communication with the rig floor. If the indicators are on the rig floor only, you must install an audible alarm.

**§250.458 What quantities of drilling fluids are required?**

- (a) You must use, maintain, and replenish quantities of drilling fluid and drilling fluid materials at the drill site as necessary to ensure well control. You must determine those quantities based on known or anticipated drilling conditions, rig storage capacity, weather conditions, and estimated time for delivery.
- (b) You must record the daily inventories of drilling fluid and drilling fluid materials, including weight materials and additives in the drilling fluid report.
- (c) If you do not have sufficient quantities of drilling fluid and drilling fluid material to maintain well control, you must suspend drilling operations.

**§250.462 Replaced by §250.710 and §250.711**

**SUBPART E—OIL AND GAS WELL-COMPLETION OPERATIONS**

**§250.500 General requirements.**

Well-completion operations must be conducted in a manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the OCS, including any mineral deposits (in areas leased and not leased), the National security or defense, or the marine, coastal, or human environment. In addition to the requirements of this subpart, you must also follow the applicable requirements of subpart G of this part.

[81 FR 26021, Apr. 29, 2016]

**§250.514 Well-control fluids, equipment, and operations.**

- (a) Well-control fluids, equipment, and operations shall be designed, utilized, maintained, and/or tested as necessary to control the well in foreseeable conditions and circumstances, including subfreezing conditions. The well shall be continuously monitored during well-completion operations and shall not be left unattended at any time unless the well is shut in and secured.
- (b) The following well-control-fluid equipment shall be installed, maintained, and utilized:

(1) A fill-up line above the uppermost BOP;

(2) A well-control, fluid-volume measuring device for determining fluid volumes when filling the hole on trips; and

(3) A recording mud-pit-level indicator to determine mud-pit-volume gains and losses. This indicator shall include both a visual and an audible warning device.

(c) When coming out of the hole with drill pipe, the annulus shall be filled with well-control fluid before the change in such fluid level decreases the hydrostatic pressure 75 pounds per square inch (psi) or every five stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure. The number of stands of drill pipe and drill collars that may be pulled prior to filling the hole and the equivalent well-control fluid volume shall be calculated and posted near the operator's station. A mechanical, volumetric, or electronic device for measuring the amount of well-control fluid required to fill the hole shall be utilized.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50894, Aug. 22, 2012; 81 FR 26021, Apr. 29, 2016]

**§250.516 Replaced by §250.730**

## **Subpart G—Well Operations and Equipment**

SOURCE: 81 FR 26022, Apr. 29, 2016, unless otherwise noted.

### **GENERAL REQUIREMENTS**

#### **§250.700 What operations and equipment does this subpart cover?**

This subpart covers operations and equipment associated with drilling, completion, workover, and decommissioning activities. This subpart includes regulations applicable to drilling, completion, workover, and decommissioning activities in addition to applicable regulations contained in subparts D, E, F, and Q of this part unless explicitly stated otherwise.

#### **§250.701 May I use alternate procedures or equipment during operations?**

You may use alternate procedures or equipment during operations after receiving approval as described in §250.141. You must identify and discuss your proposed alternate procedures or equipment in your Application for Permit to Drill (APD) (Form BSEE-0123) (see §250.414(h)) or your Application for Permit to Modify (APM) (Form BSEE-0124). Procedures for obtaining approval of alternate procedures or equipment are described in §250.141.

#### **§250.703 What must I do to keep wells under control?**

You must take the necessary precautions to keep wells under control at all times, including:

(a) Use recognized engineering practices to reduce risks to the lowest level practicable when monitoring and evaluating well conditions and to minimize the potential for the well to flow or kick;

(b) Have a person onsite during operations who represents your interests and can fulfill your responsibilities;

(c) Ensure that the toolpusher, operator's representative, or a member of the rig crew maintains continuous surveillance on the rig floor from the beginning of operations until the well is completed or abandoned, unless you have secured the well with blowout preventers (BOPs), bridge plugs, cement plugs, or packers;

(d) Use personnel trained according to the provisions of subparts O and S of this part;

(e) Use and maintain equipment and materials necessary to ensure the safety and protection of personnel, equipment, natural resources, and the environment; and



(f) Use equipment that has been designed, tested, and rated for the maximum environmental and operational conditions to which it may be exposed while in service.

## **RIG REQUIREMENTS**

### **§250.710 What instructions must be given to personnel engaged in well operations?**

Prior to engaging in well operations, personnel must be instructed in:

(a) *Hazards and safety requirements.* You must instruct your personnel regarding the safety requirements for the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment as required by subpart S of this part. The date and time of safety meetings must be recorded and available at the facility for review by BSEE representatives.

(b) *Well control.* You must prepare a well-control plan for each well. Each well-control plan must contain instructions for personnel about the use of each well-control component of your BOP, procedures that describe how personnel will seal the wellbore and shear pipe before maximum anticipated surface pressure (MASP) conditions are exceeded, assignments for each crew member, and a schedule for completion of each assignment. You must keep a copy of your well-control plan on the rig at all times, and make it available to BSEE upon request. You must post a copy of the well-control plan on the rig floor.

### **§250.711 What are the requirements for well-control drills?**

You must conduct a weekly well-control drill with all personnel engaged in well operations. Your drill must familiarize personnel engaged in well operations with their roles and functions so that they can perform their duties promptly and efficiently as outlined in the well-control plan required by §250.710.

(a) *Timing of drills.* You must conduct each drill during a period of activity that minimizes the risk to operations. The timing of your drills must cover a range of different operations, including drilling with a diverter, on-bottom drilling, and tripping. The same drill may not be repeated consecutively with the same crew.

(b) *Recordkeeping requirements.* For each drill, you must record the following in the daily report:

(1) Date, time, and type of drill conducted;

(2) The amount of time it took to be ready to close the diverter or use each well-control component of BOP system;  
and

(3) The total time to complete the entire drill.

(c) *A BSEE ordered drill.* A BSEE representative may require you to conduct a well-control drill during a BSEE inspection. The BSEE representative will consult with your onsite representative before requiring the drill.

### **§250.724 What are the real-time monitoring requirements?**

(a) No later than April 29, 2019, when conducting well operations with a subsea BOP or with a surface BOP on a floating facility, or when operating in an high pressure high temperature (HPHT) environment, you must gather and monitor real-time well data using an independent, automatic, and continuous monitoring system capable of recording, storing, and transmitting data regarding the following:

(1) The BOP control system;

(2) The well's fluid handling system on the rig; and

(3) The well's downhole conditions with the bottom hole assembly tools (if any tools are installed).

(b) You must transmit these data as they are gathered, barring unforeseeable or unpreventable interruptions in transmission, and have the capability to monitor the data onshore, using qualified personnel in accordance with a real-time monitoring plan, as provided in paragraph (c) of this section. Onshore personnel who monitor real-time data must have the capability to contact rig personnel during operations. After operations, you must preserve and store these data onshore for recordkeeping purposes as required in §§250.740 and 250.741. You must provide BSEE with access to your designated real-time monitoring data onshore upon request. You must include in your APD a certification that you have a real-time monitoring plan that meets the criteria in paragraph (c) of this section.

(c) You must develop and implement a real-time monitoring plan. Your real-time monitoring plan, and all real-time monitoring data, must be made available to BSEE upon request. Your real-time monitoring plan must include the following:

(1) A description of your real-time monitoring capabilities, including the types of the data collected;

(2) A description of how your real-time monitoring data will be transmitted onshore during operations, how the data will be labeled and monitored by qualified onshore personnel, and how it will be stored onshore;

(3) A description of your procedures for providing BSEE access, upon request, to your real-time monitoring data including, if applicable, the location of any onshore data monitoring or data storage facilities;

(4) The qualifications of the onshore personnel monitoring the data;

(5) Your procedures for, and methods of, communication between rig personnel and the onshore monitoring personnel; and

(6) Actions to be taken if you lose any real-time monitoring capabilities or communications between rig and onshore personnel, and a protocol for how you will respond to any significant and/or prolonged interruption of monitoring or onshore-offshore communications, including your protocol for notifying BSEE of any significant and/or prolonged interruptions.

## **BLOWOUT PREVENTER (BOP) SYSTEM REQUIREMENTS**

### **§250.730 What are the general requirements for BOP systems and system components?**

(a) You must ensure that the BOP system and system components are designed, installed, maintained, inspected, tested, and used properly to ensure well control. The working-pressure rating of each BOP component (excluding annular(s)) must exceed MASP as defined for the operation. For a subsea BOP, the MASP must be taken at the mudline. The BOP system includes the BOP stack, control system, and any other associated system(s) and equipment. The BOP system and individual components must be able to perform their expected functions and be compatible with each other. Your BOP system (excluding casing shear) must be capable of closing and sealing the wellbore at all times, including under anticipated flowing conditions for the specific well conditions, without losing ram closure time and sealing integrity due to the corrosiveness, volume, and abrasiveness of any fluids in the wellbore that the BOP system may encounter. Your BOP system must meet the following requirements:

(1) The BOP requirements of API Standard 53 (incorporated by reference in §250.198) and the requirements of §§250.733 through 250.739. If there is a conflict between API Standard 53, and the requirements of this subpart, you must follow the requirements of this subpart.

(2) Those provisions of the following industry standards (all incorporated by reference in §250.198) that apply to BOP systems:

(i) ANSI/API Spec. 6A;

(ii) ANSI/API Spec. 16A;

(iii) ANSI/API Spec. 16C;

(iv) API Spec. 16D; and

(v) ANSI/API Spec. 17D.

(3) For surface and subsea BOPs, the pipe and variable bore rams installed in the BOP stack must be capable of effectively closing and sealing on the tubular body of any drill pipe, workstring, and tubing (excluding tubing with exterior control lines and flat packs) in the hole under MASP, as defined for the operation, with the proposed regulator settings of the BOP control system.

(4) The current set of approved schematic drawings must be available on the rig and at an onshore location. If you make any modifications to the BOP or control system that will change your BSEE-approved schematic drawings, you must suspend operations until you obtain approval from the District Manager.

(b) You must ensure that the design, fabrication, maintenance, and repair of your BOP system is in accordance with the requirements contained in this part, Original Equipment Manufacturers (OEM) recommendations unless otherwise directed by BSEE, and recognized engineering practices. The training and qualification of repair and maintenance personnel must meet or exceed any OEM training recommendations unless otherwise directed by BSEE.

(c) You must follow the failure reporting procedures contained in API Standard 53, ANSI/API Spec. 6A, and ANSI/API Spec 16A (all incorporated by reference in §250.198), and:

(1) You must provide a written notice of equipment failure to the Chief, Office of Offshore Regulatory Programs, and the manufacturer of such equipment within 30 days after the discovery and identification of the failure. A failure is any condition that prevents the equipment from meeting the functional specification.

(2) You must ensure that an investigation and a failure analysis are performed within 120 days of the failure to determine the cause of the failure. You must also ensure that the results and any corrective action are documented. If the investigation and analysis are performed by an entity other than the manufacturer, you must ensure that the Chief, Office of Offshore Regulatory Programs and the manufacturer receive a copy of the analysis report.

(3) If the equipment manufacturer notifies you that it has changed the design of the equipment that failed or if you have changed operating or repair procedures as a result of a failure, then you must, within 30 days of such changes, report the design change or modified procedures in writing to the Chief, Office of Offshore Regulatory Programs.

(4) You must send the reports required in this paragraph to: Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, VA 20166.

(d) If you plan to use a BOP stack manufactured after the effective date of this regulation, you must use one manufactured pursuant to an API Spec. Q1 (as incorporated by reference in §250.198) quality management system. Such quality management system must be certified by an entity that meets the requirements of ISO 17011.

(1) BSEE may consider accepting equipment manufactured under quality assurance programs other than API Spec. Q1, provided you submit a request to the Chief, Office of Offshore Regulatory Programs for approval, containing relevant information about the alternative program.

(2) You must submit this request to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, Virginia 20166.

### **§250.731 What information must I submit for BOP systems and system components?**

For any operation that requires the use of a BOP, you must include the information listed in this section with your applicable APD, APM, or other submittal. You are required to submit this information only once for each well, unless the information changes from what you provided in an earlier approved submission or you have moved off location from the well. After you have submitted this information for a particular well, subsequent APMs or other submittals for the well should reference the approved submittal containing the information required by this section and confirm that the information remains accurate and that you have not moved off location from that well. If the information changes or you have moved off location from the well, you must submit updated information in your next submission.

<b>You must submit:</b>	<b>Including:</b>
(a) A complete description of the BOP system and system components,	(1) Pressure ratings of BOP equipment;
	(2) Proposed BOP test pressures (for subsea BOPs, include both surface and corresponding subsea pressures);
	(3) Rated capacities for liquid and gas for the fluid-gas separator system;
	(4) Control fluid volumes needed to close, seal, and open each component;
	(5) Control system pressure and regulator settings needed to achieve an effective seal of each ram BOP under MASP as defined for the operation;
	(6) Number and volume of accumulator bottles and bottle banks (for subsea BOP, include both surface and subsea bottles);
	(7) Accumulator pre-charge calculations (for subsea BOP, include both surface and subsea calculations);
	(8) All locking devices; and
	(9) Control fluid volume calculations for the accumulator system (for a subsea BOP system, include both the surface and subsea volumes).
(b) Schematic drawings,	(1) The inside diameter of the BOP stack;
	(2) Number and type of preventers (including blade type for shear ram(s));
	(3) All locking devices;
	(4) Size range for variable bore ram(s);
	(5) Size of fixed ram(s);
	(6) All control systems with all alarms and set points labeled, including pods;
	(7) Location and size of choke and kill lines (and gas bleed line(s) for subsea BOP);
	(8) Associated valves of the BOP system;
	(9) Control station locations; and
	(10) A cross-section of the riser for a subsea BOP system showing number, size, and labeling of all control, supply, choke, and kill lines down to the BOP.

(c) Certification by a BSEE-approved verification organization (BAVO),	Verification that: (1) Test data demonstrate the shear ram(s) will shear the drill pipe at the water depth as required in §250.732; (2) The BOP was designed, tested, and maintained to perform under the maximum environmental and operational conditions anticipated to occur at the well; and (3) The accumulator system has sufficient fluid to operate the BOP system without assistance from the charging system.
(d) Additional certification by a BAVO, if you use a subsea BOP, a BOP in an HPHT environment as defined in §250.807, or a surface BOP on a floating facility,	Verification that: (1) The BOP stack is designed and suitable for the specific equipment on the rig and for the specific well design; (2) The BOP stack has not been compromised or damaged from previous service; and (3) The BOP stack will operate in the conditions in which it will be used.
(e) If you are using a subsea BOP, descriptions of autoshear, deadman, and emergency disconnect sequence (EDS) systems,	A listing of the functions with their sequences and timing.
(f) Certification stating that the MIA Report required in §250.732(d) has been submitted within the past 12 months for a subsea BOP, a BOP being used in an HPHT environment as defined in §250.807, or a surface BOP on a floating facility	

**§250.732 What are the BSEE-approved verification organization (BAVO) requirements for BOP systems and system components?**

(a) BSEE will maintain a list of BSEE-approved verification organizations (BAVOs) on its public website that you must use to satisfy any provision in this subpart that requires a BAVO certification, verification, report, or review. You must comply with all requirements in this subpart for BAVO certification, verification, or reporting no later than 1 year from the date BSEE publishes a list of BAVOs.

(1) Until such time as you use a BAVO to perform the actions that this subpart requires to be performed by a BAVO, but not after 1 year from the date BSEE publishes a list of BAVOs, you must use an independent third-party meeting the criteria specified in paragraph (a)(2) of this section to prepare certifications, verifications, and reports as required by §§250.731(c) and (d), 250.732 (b) and (c), 250.734(b)(1), 250.738(b)(4), and 250.739(b).

(2) The independent third-party must be a technical classification society, or a licensed professional engineering firm, or a registered professional engineer capable of providing the certifications, verifications, and reports required under paragraph (a)(1) of this section.

(3) For an organization to become a BAVO, it must submit the following information to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, Virginia, 20166, for BSEE review and approval:

(i) Previous experience in verification or in the design, fabrication, installation, repair, or major modification of BOPs and related systems and equipment;

(ii) Technical capabilities;

(iii) Size and type of organization;

(iv) In-house availability of, or access to, appropriate technology. This should include computer programs, hardware, and testing materials and equipment;

(v) Ability to perform the verification functions for projects considering current commitments;

(vi) Previous experience with BSEE requirements and procedures; and

(vii) Any additional information that may be relevant to BSEE's review.

(b) Prior to beginning any operation requiring the use of any BOP, you must submit verification by a BAVO and supporting documentation as required by this paragraph to the appropriate District Manager and Regional Supervisor.

<b>You must submit verification and documentation related to:</b>	<b>That:</b>
(1) Shear testing,	(i) Demonstrates that the BOP will shear the drill pipe and any electric-, wire-, and slick-line to be used in the well, no later than April 30, 2018;
	(ii) Demonstrates the use of test protocols and analysis that represent recognized engineering practices for ensuring the repeatability and reproducibility of the tests, and that the testing was performed by a facility that meets generally accepted quality assurance standards;
	(iii) Provides a reasonable representation of field applications, taking into consideration the physical and mechanical properties of the drill pipe;
	(iv) Ensures testing was performed on the outermost edges of the shearing blades of the shear ram positioning mechanism as required in §250.734(a)(16);
	(v) Demonstrates the shearing capacity of the BOP equipment to the physical and mechanical properties of the drill pipe; and
	(vi) Includes relevant testing results.
(2) Pressure integrity testing, and	(i) Shows that testing is conducted immediately after the shearing tests;
	(ii) Demonstrates that the equipment will seal at the rated working pressures (RWP) of the BOP for 30 minutes; and
	(iii) Includes all relevant test results.
(3) Calculations	Include shearing and sealing pressures for all pipe to be used in the well including corrections for MASP.

(c) For wells in an HPHT environment, as defined by §250.807(b), you must submit verification by a BAVO that the verification organization conducted a comprehensive review of the BOP system and related equipment you propose to use. You must provide the BAVO access to any facility associated with the BOP system or related equipment during the review process. You must submit the verifications required by this paragraph (c) to the appropriate District Manager and Regional Supervisor before you begin any operations in an HPHT environment with the proposed equipment.

<b>You must submit:</b>	<b>Including:</b>
(1) Verification that the verification organization conducted a detailed review of the design package to ensure that all critical components and systems meet recognized engineering practices,	

(2) Verification that the designs of individual components and the overall system have been proven in a testing process that demonstrates the performance and reliability of the equipment in a manner that is repeatable and reproducible,	(i) Identification of all reasonable potential modes of failure; and (ii) Evaluation of the design verification tests. The design verification tests must assess the equipment for the identified potential modes of failure.
(3) Verification that the BOP equipment will perform as designed in the temperature, pressure, and environment that will be encountered, and	
(4) Verification that the fabrication, manufacture, and assembly of individual components and the overall system uses recognized engineering practices and quality control and assurance mechanisms.	For the quality control and assurance mechanisms, complete material and quality controls over all contractors, subcontractors, distributors, and suppliers at every stage in the fabrication, manufacture, and assembly process.

(d) Once every 12 months, you must submit a Mechanical Integrity Assessment Report for a subsea BOP, a BOP being used in an HPHT environment as defined in §250.807, or a surface BOP on a floating facility. This report must be completed by a BAVO. You must submit this report to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, VA 20166. This report must include:

- (1) A determination that the BOP stack and system meets or exceeds all BSEE regulatory requirements, industry standards incorporated into this subpart, and recognized engineering practices.
- (2) Verification that complete documentation of the equipment's service life exists that demonstrates that the BOP stack has not been compromised or damaged during previous service.
- (3) A description of all inspection, repair and maintenance records reviewed, and verification that all repairs, replacement parts, and maintenance meet regulatory requirements, recognized engineering practices, and OEM specifications.
- (4) A description of records reviewed related to any modifications to the equipment and verification that any such changes do not adversely affect the equipment's capability to perform as designed or invalidate test results.
- (5) A description of the Safety and Environmental Management Systems (SEMS) plans reviewed related to assurance of quality and mechanical integrity of critical equipment and verification that the plans are comprehensive and fully implemented.
- (6) Verification that the qualification and training of inspection, repair, and maintenance personnel for the BOP systems meet recognized engineering practices and any applicable OEM requirements.
- (7) A description of all records reviewed covering OEM safety alerts, all failure reports, and verification that any design or maintenance issues have been completely identified and corrected.
- (8) A comprehensive assessment of the overall system and verification that all components (including mechanical, hydraulic, electrical, and software) are compatible.
- (9) Verification that documentation exists concerning the traceability of the fabrication, repair, and maintenance of all critical components.
- (10) Verification of use of a formal maintenance tracking system to ensure that corrective maintenance and scheduled maintenance is implemented in a timely manner.
- (11) Identification of gaps or deficiencies related to inspection and maintenance procedures and documentation, documentation of any deferred maintenance, and verification of the completion of corrective action plans.
- (12) Verification that any inspection, maintenance, or repair work meets the manufacturer's design and material specifications.

(13) Verification of written procedures for operating the BOP stack and Lower Marine Riser Package (LMRP) (including proper techniques to prevent accidental disconnection of these components) and minimum knowledge requirements for personnel authorized to operate and maintain BOP components.

(14) Recommendations, if any, for how to improve the fabrication, installation, operation, maintenance, inspection, and repair of the equipment.

(e) You must make all documentation that supports the requirements of this section available to BSEE upon request.

### **§250.733 What are the requirements for a surface BOP stack?**

(a) When you drill or conduct operations with a surface BOP stack, you must install the BOP system before drilling or conducting operations to deepen the well below the surface casing and after the well is deepened below the surface casing point. The surface BOP stack must include at least four remote-controlled, hydraulically operated BOPs, consisting of one annular BOP, one BOP equipped with blind shear rams, and two BOPs equipped with pipe rams.

(1) The blind shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that include heavy-weight pipe or collars), workstring, tubing provided that the capability to shear tubing with exterior control lines is not required prior to April 30, 2018, and any electric-, wire-, and slick-line that is in the hole and sealing the wellbore after shearing. If your blind shear rams are unable to cut any electric-, wire-, or slick-line under MASP as defined for the operation and seal the wellbore, you must use an alternative cutting device capable of shearing the lines before closing the BOP. This device must be available on the rig floor during operations that require their use.

(2) The two BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, except for tubing with exterior control lines and flat packs, a bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools.

(b) If you plan to use a surface BOP on a floating production facility you must:

(1) For BOPs installed after April 29, 2019, follow the BOP requirements in §250.734(a)(1).

(2) For risers installed after July 28, 2016, use a dual bore riser configuration before drilling or operating in any hole section or interval where hydrocarbons are, or may be, exposed to the well. The dual bore riser must meet the design requirements of API RP 2RD (as incorporated by reference in §250.198), including appropriate design for the maximum anticipated operating and environmental conditions.

(i) For a dual bore riser configuration, the annulus between the risers must be monitored for pressure during operations. You must describe in your APD or APM your annulus monitoring plan and how you will secure the well in the event a leak is detected.

(ii) The inner riser for a dual riser configuration is subject to the requirements at §250.721 for testing the casing or liner.

(c) You must install separate side outlets on the BOP stack for the kill and choke lines. If your stack does not have side outlets, you must install a drilling spool with side outlets. The outlet valves must hold pressure from both directions.

(d) You must install a choke and a kill line on the BOP stack. You must equip each line with two full-bore, full-opening valves, one of which must be remote-controlled. On the kill line, you may install a check valve and a manual valve instead of the remote-controlled valve. To use this configuration, both manual valves must be readily accessible and you must install the check valve between the manual valves and the pump.

### **§250.734 What are the requirements for a subsea BOP system?**

(a) When you drill or conduct operations with a subsea BOP system, you must install the BOP system before drilling to deepen the well below the surface casing or before conducting operations if the well is already deepened beyond the surface casing point. The District Manager may require you to install a subsea BOP system before drilling or conducting



operations below the conductor casing if proposed casing setting depths or local geology indicate the need. The following table outlines your requirements.

<b>When operating with a subsea BOP system, you must:</b>	<b>Additional requirements:</b>
(1) Have at least five remote-controlled, hydraulically operated BOPs;	You must have at least one annular BOP, two BOPs equipped with pipe rams, and two BOPs equipped with shear rams. For the dual ram requirement, you must comply with this requirement no later than April 29, 2021.
	(i) Both BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, except tubing with exterior control lines and flat packs, a bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools.
	(ii) Both shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies such as heavy-weight pipe or collars), workstring, tubing provided that the capability to shear tubing with exterior control lines is not required prior to April 30, 2018, appropriate area for the liner or casing landing string, shear sub on subsea test tree, and any electric-, wire-, slick-line in the hole no later than April 30, 2018; under MASP. At least one shear ram must be capable of sealing the wellbore after shearing under MASP conditions as defined for the operation. Any non-sealing shear ram(s) must be installed below a sealing shear ram(s).
(2) Have an operable redundant pod control system to ensure proper and independent operation of the BOP system;	
(3) Have the accumulator capacity located subsea, to provide fast closure of the BOP components and to operate all critical functions in case of a loss of the power fluid connection to the surface;	The accumulator capacity must: (i) Operate each required shear ram, ram locks, one pipe ram, and disconnect the LMRP. (ii) Have the capability of delivering fluid to each ROV function i.e., flying leads. (iii) No later than April 29, 2021, have bottles for the autoshear, and deadman that are dedicated to, but may be shared between, those functions. (iv) Perform under MASP conditions as defined for the operation.
(4) Have a subsea BOP stack equipped with remotely operated vehicle (ROV) intervention capability;	The ROV must be capable of opening and closing each shear ram, ram locks, one pipe ram, and LMRP disconnect under MASP conditions as defined for the operation. The ROV panels on the BOP and LMRP must be compliant with API RP 17H (as incorporated by reference in §250.198).
(5) Maintain an ROV and have a trained ROV crew on each rig unit on a continuous basis once BOP deployment has been initiated from the rig until recovered to the surface. The ROV crew must examine all ROV-related well-control equipment (both surface and subsea) to ensure that it is properly maintained and capable of carrying out appropriate tasks during emergency operations;	The crew must be trained in the operation of the ROV. The training must include simulator training on stabbing into an ROV intervention panel on a subsea BOP stack. The ROV crew must be in communication with designated rig personnel who are knowledgeable about the BOP's capabilities.
(6) Provide autoshear, deadman, and EDS systems for dynamically positioned rigs; provide autoshear and deadman systems for moored rigs;	(i) Autoshear system means a safety system that is designed to automatically shut-in the wellbore in the event of a disconnect of the LMRP. This is considered a rapid discharge system.

	(ii) Deadman system means a safety system that is designed to automatically shut-in the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods. This is considered a rapid discharge system.
	(iii) Emergency Disconnect Sequence (EDS) system means a safety system that is designed to be manually activated to shut-in the wellbore and disconnect the LMRP in the event of an emergency situation. This is considered a rapid discharge system.
	(iv) Each emergency function must close at a minimum, two shear rams in sequence and be capable of performing its expected shearing and sealing action under MASP conditions as defined for the operation.
	(v) Your sequencing must allow a sufficient delay for closing the upper shear ram after beginning closure of the lower shear ram to provide for maximum sealing efficiency.
	(vi) The control system for the emergency functions must be a fail-safe design once activated.
(7) Demonstrate that any acoustic control system will function in the proposed environment and conditions;	If you choose to use an acoustic control system in addition to the autoshear, deadman, and EDS requirements, you must demonstrate to the District Manager, as part of the information submitted under §250.731, that the acoustic control system will function in the proposed environment and conditions. The District Manager may require additional information as appropriate to clarify or evaluate the acoustic control system information provided in your demonstration.
(8) Have operational or physical barrier(s) on BOP control panels to prevent accidental disconnect functions;	You must incorporate enable buttons, or a similar feature, on control panels to ensure two-handed operation for all critical functions.
(9) Clearly label all control panels for the subsea BOP system;	Label other BOP control panels, such as hydraulic control panel.
(10) Develop and use a management system for operating the BOP system, including the prevention of accidental or unplanned disconnects of the system;	The management system must include written procedures for operating the BOP stack and LMRP (including proper techniques to prevent accidental disconnection of these components) and minimum knowledge requirements for personnel authorized to operate and maintain BOP components.
(11) Establish minimum requirements for personnel authorized to operate critical BOP equipment;	Personnel must have: (i) Training in deepwater well-control theory and practice according to the requirements of Subparts O and S; and (ii) A comprehensive knowledge of BOP hardware and control systems.
(12) Before removing the marine riser, displace the fluid in the riser with seawater;	You must maintain sufficient hydrostatic pressure or take other suitable precautions to compensate for the reduction in pressure and to maintain a safe and controlled well condition. You must follow the requirements of §250.720(b).
(13) Install the BOP stack in a well cellar when in an ice-scour area;	Your well cellar must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.
(14) Install at least two side outlets for a choke line and two side outlets for a kill line;	(i) If your stack does not have side outlets, you must install a drilling spool with side outlets. (ii) Each side outlet must have two full-bore, full-opening valves. (iii) The valves must hold pressure from both directions and must be remote-controlled. (iv) You must install a side outlet below the lowest sealing shear ram. You may have a pipe ram or rams between the shearing ram and side outlet.

(15) Install a gas bleed line with two valves for the annular preventer no later than April 30, 2018;	(i) The valves must hold pressure from both directions; (ii) If you have dual annulars, you must install the gas bleed line below the upper annular.
(16) Use a BOP system that has the following mechanisms and capabilities;	(i) A mechanism coupled with each shear ram to position the entire pipe, completely within the area of the shearing blade and ensure shearing will occur any time the shear rams are activated. This mechanism cannot be another ram BOP or annular preventer, but you may use those during a planned shear. You must install this mechanism no later than May 1, 2023;
	(ii) The ability to mitigate compression of the pipe stub between the shearing rams when both shear rams are closed;
	(iii) If your control pods contain a subsea electronic module with batteries, a mechanism for personnel on the rig to monitor the state of charge of the subsea electronic module batteries in the BOP control pods.

(b) If operations are suspended to make repairs to any part of the subsea BOP system, you must stop operations at a safe downhole location. Before resuming operations you must:

(1) Submit a revised permit with a verification report from a BAVO documenting the repairs and that the BOP is fit for service;

(2) Upon relatch of the BOP, perform an initial subsea BOP test in accordance with §250.737(d)(4), including deadman. If repairs take longer than 30 days, once the BOP is on deck, you must test in accordance with the requirements of §250.737; and

(3) Receive approval from the District Manager.

(c) If you plan to drill a new well with a subsea BOP, you do not need to submit with your APD the verifications required by this subpart for the open water drilling operation. Before drilling out the surface casing, you must submit for approval a revised APD, including the verifications required in this subpart.

**§250.735 What associated systems and related equipment must all BOP systems include?**

All BOP systems must include the following associated systems and related equipment:

(a) An accumulator system (as specified in API Standard 53, and incorporated by reference in §250.198) that provides the volume of fluid capacity (as specified in API Standard 53, Annex C) necessary to close and hold closed all BOP components against MASP. The system must operate under MASP conditions as defined for the operation. You must be able to operate the BOP functions as defined in API Standard 53, without assistance from a charging system, and still have a minimum pressure of 200 psi remaining on the bottles above the pre-charge pressure. If you supply the accumulator regulators by rig air and do not have a secondary source of pneumatic supply, you must equip the regulators with manual overrides or other devices to ensure capability of hydraulic operations if rig air is lost;

(b) An automatic backup to the primary accumulator-charging system. The power source must be independent from the power source for the primary accumulator-charging system. The independent power source must possess sufficient capability to close and hold closed all BOP components under MASP conditions as defined for the operation;

(c) At least two full BOP control stations. One station must be on the rig floor. You must locate the other station in a readily accessible location away from the rig floor;

(d) The choke line(s) installed above the bottom well-control ram;

(e) The kill line must be installed beneath at least one well-control ram, and may be installed below the bottom ram;

(f) A fill-up line above the uppermost BOP;

(g) Locking devices for all BOP sealing rams (*i.e.*, blind shear rams, pipe rams and variable bore rams), as follows:

(1) For subsea BOPs, hydraulic locking devices must be installed on all sealing rams;

(2) For surface BOPs:

(i) Remotely-operated locking devices must be installed on blind shear rams no later than April 29, 2019;

(ii) Manual or remotely-operated locking devices must be installed on pipe rams and variable bore rams; and

(h) A wellhead assembly with a RWP that exceeds the maximum anticipated wellhead pressure.

**§250.736 What are the requirements for choke manifolds, kelly-type valves inside BOPs, and drill string safety valves?**

(a) Your BOP system must include a choke manifold that is suitable for the anticipated surface pressures, anticipated methods of well control, the surrounding environment, and the corrosiveness, volume, and abrasiveness of drilling fluids and well fluids that you may encounter.

(b) Choke manifold components must have a RWP at least as great as the RWP of the ram BOPs. If your choke manifold has buffer tanks downstream of choke assemblies, you must install isolation valves on any bleed lines.

(c) Valves, pipes, flexible steel hoses, and other fittings upstream of the choke manifold must have a RWP at least as great as the RWP of the ram BOPs.

(d) You must use the following BOP equipment with a RWP and temperature of at least as great as the working pressure and temperature of the ram BOP during all operations:

(1) The applicable kelly-type valves as described in API Standard 53 (incorporated by reference in §250.198);

(2) On a top-drive system equipped with a remote-controlled valve, a strippable kelly-type valve must be installed below the remote-controlled valve;

(3) An inside BOP in the open position located on the rig floor. You must be able to install an inside BOP for each size connection in the pipe;

(4) A drill string safety valve in the open position located on the rig floor. You must have a drill-string safety valve available for each size connection in the pipe;

(5) When running casing, a safety valve in the open position available on the rig floor to fit the casing string being run in the hole;

(6) All required manual and remote-controlled kelly-type valves, drill-string safety valves, and comparable-type valves (*i.e.*, kelly-type valve in a top-drive system) that are essentially full opening; and

(7) A wrench to fit each manual valve. Each wrench must be readily accessible to the drilling crew.

**§250.737 What are the BOP system testing requirements?**

Your BOP system (this includes the choke manifold, kelly-type valves, inside BOP, and drill string safety valve) must meet the following testing requirements:

(a) *Pressure test frequency.* You must pressure test your BOP system:

(1) When installed;

(2) Before 14 days have elapsed since your last BOP pressure test, or 30 days since your last blind shear ram BOP pressure test. You must begin to test your BOP system before midnight on the 14th day (or 30th day for your blind shear rams) following the conclusion of the previous test;

(3) Before drilling out each string of casing or a liner. You may omit this pressure test requirement if you did not remove the BOP stack to run the casing string or liner, the required BOP test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test, and the time elapsed between tests has not exceeded 14 days (or 30 days for blind shear rams). You must indicate in your APD which casing strings and liners meet these criteria;

(4) The District Manager may require more frequent testing if conditions or your BOP performance warrant.

(b) *Pressure test procedures.* When you pressure test the BOP system, you must conduct a low-pressure test and a high-pressure test for each BOP component. You must begin each test by conducting the low-pressure test then transition to the high-pressure test. Each individual pressure test must hold pressure long enough to demonstrate the tested component(s) holds the required pressure. The table in this paragraph (b) outlines your pressure test requirements.

You must conduct a . . .	According to the following procedures . . .
(1) Low-pressure test	All low-pressure tests must be between 250 and 350 psi. Any initial pressure above 350 psi must be bled back to a pressure between 250 and 350 psi before starting the test. If the initial pressure exceeds 500 psi, you must bleed back to zero and reinitiate the test.
(2) High-pressure test for blind shear ram-type BOPs, ram-type BOPs, the choke manifold, outside of all choke and kill side outlet valves (and annular gas bleed valves for subsea BOP), inside of all choke and kill side outlet valves below uppermost ram, and other BOP components	The high-pressure test must equal the RWP of the equipment or be 500 psi greater than your calculated MASP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP plus 500 psi, the District Manager must have approved those test pressures in your APD.
(3) High-pressure test for annular-type BOPs, inside of choke or kill valves (and annular gas bleed valves for subsea BOP) above the uppermost ram BOP	The high pressure test must equal 70 percent of the RWP of the equipment or be 500 psi greater than your calculated MASP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP plus 500 psi, the District Manager must have approved those test pressures in your APD.

(c) *Duration of pressure test.* Each test must hold the required pressure for 5 minutes, which must be recorded on a chart not exceeding 4 hours. However, for surface BOP systems and surface equipment of a subsea BOP system, a 3-minute test duration is acceptable if recorded on a chart not exceeding 4 hours, or on a digital recorder. The recorded test pressures must be within the middle half of the chart range, i.e., cannot be within the lower or upper one-fourth of the chart range. If the equipment does not hold the required pressure during a test, you must correct the problem and retest the affected component(s).

(d) *Additional test requirements.* You must meet the following additional BOP testing requirements:

You must . . .	Additional requirements . . .
(1) Follow the testing requirements of API Standard 53 (as incorporated in §250.198)	If there is a conflict between API Standard 53, testing requirements and this section, you must follow the requirements of this section.

<p>(2) Use water to test a surface BOP system on the initial test. You may use drilling/completion/workover fluids to conduct subsequent tests of a surface BOP system</p>	<p>(i) You must submit test procedures with your APD or APM for District Manager approval.  (ii) Contact the District Manager at least 72 hours prior to beginning the initial test to allow BSEE representative(s) to witness testing. If BSEE representative(s) are unable to witness testing, you must provide the initial test results to the appropriate District Manager within 72 hours after completion of the tests.</p>
<p>(3) Stump test a subsea BOP system before installation</p>	<p>(i) You must use water to conduct this test. You may use drilling/completion/workover fluids to conduct subsequent tests of a subsea BOP system.</p>
	<p>(ii) You must submit test procedures with your APD or APM for District Manager approval</p>
	<p>(iii) Contact the District Manager at least 72 hours prior to beginning the stump test to allow BSEE representative(s) to witness testing. If BSEE representative(s) are unable to witness testing, you must provide the test results to the appropriate District Manager within 72 hours after completion of the tests.</p>
	<p>(iv) You must test and verify closure of all ROV intervention functions on your subsea BOP stack during the stump test.</p>
	<p>(v) You must follow paragraphs (b) and (c) of this section.</p>
<p>(4) Perform an initial subsea BOP test</p>	<p>(i) You must perform the initial subsea BOP test on the seafloor within 30 days of the stump test.</p>
	<p>(ii) You must submit test procedures with your APD or APM for District Manager approval.</p>
	<p>(iii) You must pressure test well-control rams according to paragraphs (b) and (c) of this section.</p>
	<p>(iv) You must notify the District Manager at least 72 hours prior to beginning the initial subsea test for the BOP system to allow BSEE representative(s) to witness testing.</p>
	<p>(v) You must test and verify closure of at least one set of rams during the initial subsea test through a ROV hot stab.</p>
	<p>(vi) You must pressure test the selected rams according to paragraphs (b) and (c) of this section.</p>
<p>(5) Alternate testing pods between control stations</p>	<p>(i) For two complete BOP control stations:</p>
	<p>(A) Designate a primary and secondary station, and both stations must be function-tested weekly;</p>
	<p>(B) The control station used for the pressure test must be alternated between pressure tests; and</p>
	<p>(C) For a subsea BOP, the pods must be rotated between control stations during weekly function testing and 14 day pressure testing.</p>
	<p>(ii) Remote panels where all BOP functions are not included (e.g., life boat panels) must be function-tested upon the initial BOP tests and monthly thereafter.</p>

(6) Pressure test variable bore-pipe ram BOPs against pipe sizes according to API Standard 53, excluding the bottom hole assembly that includes heavy-weight pipe or collars and bottom-hole tools	
(7) Pressure test annular type BOPs against pipe sizes according to API Standard 53	
(8) Pressure test affected BOP components following the disconnection or repair of any well-pressure containment seal in the wellhead or BOP stack assembly	
(9) Function test annular and pipe/variable bore ram BOPs every 7 days between pressure tests	
(10) Function test shear ram(s) BOPs every 14 days	
(11) Actuate safety valves assembled with proper casing connections before running casing	
(12) Function test autoshear/deadman, and EDS systems separately on your subsea BOP stack during the stump test. The District Manager may require additional testing of the emergency systems. You must also test the deadman system and verify closure of the shearing rams during the initial test on the seafloor	<p>(i) You must submit test procedures with your APD or APM for District Manager approval. The procedures for these function tests must include the schematics of the actual controls and circuitry of the system that will be used during an actual autoshear or deadman event.</p> <p>(ii) The procedures must also include the actions and sequence of events that take place on the approved schematics of the BOP control system and describe specifically how the ROV will be utilized during this operation.</p> <p>(iii) When you conduct the initial deadman system test on the seafloor, you must ensure the well is secure and, if hydrocarbons have been present, appropriate barriers are in place to isolate hydrocarbons from the wellhead. You must also have an ROV on bottom during the test.</p> <p>(iv) The testing of the deadman system on the seafloor must indicate the discharge pressure of the subsea accumulator system throughout the test.</p> <p>(v) For the function test of the deadman system during the initial test on the seafloor, you must have the ability to quickly disconnect the LMRP should the rig experience a loss of station-keeping event. You must include your quick-disconnect procedures with your deadman test procedures.</p> <p>(vi) You must pressure test the blind shear ram(s) according to paragraphs (b) and (c) of this section.</p> <p>(vii) If a casing shear ram is installed, you must describe how you will verify closure of the ram.</p> <p>(viii) You must document all your test results and make them available to BSEE upon request.</p>

(e) Prior to conducting any shear ram tests in which you will shear pipe, you must notify the District Manager at least 72 hours in advance, to ensure that a BSEE representative will have access to the location to witness any testing.

**§250.738 What must I do in certain situations involving BOP equipment or systems?**

The table in this section describes actions that you must take when certain situations occur with BOP systems.

<b>If you encounter the following situation:</b>	<b>Then you must . . .</b>
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(a) BOP equipment does not hold the required pressure during a test;	Correct the problem and retest the affected equipment. You must report any problems or irregularities, including any leaks, on the daily report as required in §250.746.
(b) Need to repair, replace, or reconfigure a surface or subsea BOP system;	(1) First place the well in a safe, controlled condition as approved by the District Manager (e.g., before drilling out a casing shoe or after setting a cement plug, bridge plug, or a packer).
	(2) Any repair or replacement parts must be manufactured under a quality assurance program and must meet or exceed the performance of the original part produced by the OEM.
	(3) You must receive approval from the District Manager prior to resuming operations with the new, repaired, or reconfigured BOP.
	(4) You must submit a report from a BAVO to the District Manager certifying that the BOP is fit for service.
(c) Need to postpone a BOP test due to well-control problems such as lost circulation, formation fluid influx, or stuck pipe;	Record the reason for postponing the test in the daily report and conduct the required BOP test after the first trip out of the hole.
(d) BOP control station or pod that does not function properly;	Suspend operations until that station or pod is operable. You must report any problems or irregularities, including any leaks, to the District Manager.
(e) Plan to operate with a tapered string;	Install two or more sets of conventional or variable-bore pipe rams in the BOP stack to provide for the following: two sets of rams must be capable of sealing around the larger-size drill string and one set of pipe rams must be capable of sealing around the smaller size pipe, excluding the bottom hole assembly that includes heavy weight pipe or collars and bottom-hole tools.
(f) Plan to install casing rams or casing shear rams in a surface BOP stack;	Test the affected connections before running casing to the RWP or MASP plus 500 psi. If this installation was not included in your approved permit, and changes the BOP configuration approved in the APD or APM, you must notify and receive approval from the District Manager.
(g) Plan to use an annular BOP with a RWP less than the anticipated surface pressure;	Demonstrate that your well-control procedures or the anticipated well conditions will not place demands above its RWP and obtain approval from the District Manager.
(h) Plan to use a subsea BOP system in an ice-scour area;	Install the BOP stack in a well cellar. The well cellar must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.
(i) You activate any shear ram and pipe or casing is sheared;	Retrieve, physically inspect, and conduct a full pressure test of the BOP stack after the situation is fully controlled. You must submit to the District Manager a report from a BSEE-approved verification organization certifying that the BOP is fit to return to service.
(j) Need to remove the BOP stack;	Have a minimum of two barriers in place prior to BOP removal. You must obtain approval from the District Manager of the two barriers prior to removal and the District Manager may require additional barriers and test(s).
(k) In the event of a deadman or autoshear activation, if there is a possibility of the blind shear ram opening immediately upon re-establishing power to the BOP stack;	Place the blind shear ram opening function in the block position prior to re-establishing power to the stack. Contact the District Manager and receive approval of procedures for re-establishing power and functions prior to latching up the BOP stack or re-establishing power to the stack.
(l) If a test ram is to be used;	The wellhead/BOP connection must be tested to the MASP plus 500 psi for the hole section to which it is exposed. This can be done by:
	(1) Testing wellhead/BOP connection to the MASP plus 500 psi for the well upon installation;



	(2) Pressure testing each casing to the MASP plus 500 psi for the next hole section; or
	(3) Some combination of paragraphs (l)(1) and (2) of this section.
(m) Plan to utilize any other well-control equipment (e.g., but not limited to, subsea isolation device, subsea accumulator module, or gas handler) that is in addition to the equipment required in this subpart;	Contact the District Manager and request approval in your APD or APM. Your request must include a report from a BAVO on the equipment's design and suitability for its intended use as well as any other information required by the District Manager. The District Manager may impose any conditions regarding the equipment's capabilities, operation, and testing.
(n) You have pipe/variable bore rams that have no current utility or well-control purposes;	Indicate in your APD or APM which pipe/variable bore rams meet these criteria and clearly label them on all BOP control panels. You do not need to function test or pressure test pipe/variable bore rams having no current utility, and that will not be used for well-control purposes, until such time as they are intended to be used during operations.
(o) You install redundant components for well control in your BOP system that are in addition to the required components of this subpart (e.g., pipe/variable bore rams, shear rams, annular preventers, gas bleed lines, and choke/kill side outlets or lines);	Comply with all testing, maintenance, and inspection requirements in this subpart that are applicable to those well-control components. If any redundant component fails a test, you must submit a report from a BAVO that describes the failure and confirms that there is no impact on the BOP that will make it unfit for well-control purposes. You must submit this report to the District Manager and receive approval before resuming operations. The District Manager may require you to provide additional information as needed to clarify or evaluate your report.
(p) Need to position the bottom hole assembly, including heavy-weight pipe or collars, and bottom-hole tools across the BOP for tripping or any other operations.	Ensure that the well is stable prior to positioning the bottom hole assembly across the BOP. You must have, as part of your well-control plan required by §250.710, procedures that enable the removal of the bottom hole assembly from across the BOP in the event of a well-control or emergency situation (for dynamically positioned rigs, your plan must also include steps for when the EDS must be activated) before MASP conditions are reached as defined for the operation.

### §250.739 What are the BOP maintenance and inspection requirements?

(a) You must maintain and inspect your BOP system to ensure that the equipment functions as designed. The BOP maintenance and inspections must meet or exceed any OEM recommendations, recognized engineering practices, and industry standards incorporated by reference into the regulations of this subpart, including API Standard 53 (incorporated by reference in §250.198). You must document how you met or exceeded the provisions of API Standard 53, maintain complete records to ensure the traceability of BOP stack equipment beginning at fabrication, and record the results of your BOP inspections and maintenance actions. You must make all records available to BSEE upon request.

(b) A complete breakdown and detailed physical inspection of the BOP and every associated system and component must be performed every 5 years. This complete breakdown and inspection may be performed in phased intervals. You must track and document all system and component inspection dates. These records must be available on the rig. A BAVO is required to be present during each inspection and must compile a detailed report documenting the inspection, including descriptions of any problems and how they were corrected. You must make these reports available to BSEE upon request. This complete breakdown and inspection must be performed every 5 years from the following applicable dates, whichever is later:

- (1) The date the equipment owner accepts delivery of a new build drilling rig with a new BOP system;
- (2) The date the new, repaired, or remanufactured equipment is initially installed into the system; or
- (3) The date of the last 5 year inspection for the component.

(c) You must visually inspect your surface BOP system on a daily basis. You must visually inspect your subsea BOP system, marine riser, and wellhead at least once every 3 days if weather and sea conditions permit. You may use cameras to inspect subsea equipment.

(d) You must ensure that all personnel maintaining, inspecting, or repairing BOPs, or critical components of the BOP system, are trained in accordance with applicable training requirements in subpart S of this part, any applicable OEM criteria, recognized engineering practices, and industry standards incorporated by reference in this subpart.

(e) You must make all records available to BSEE upon request. You must ensure that the rig unit owner maintains the BOP maintenance, inspection, and repair records on the rig unit for 2 years from the date the records are created or for a longer period if directed by BSEE. You must ensure that all equipment schematics, maintenance, inspection, and repair records are located at an onshore location for the service life of the equipment

## **RECORDS AND REPORTING**

### **§250.746 What are the recordkeeping requirements for casing, liner, and BOP tests, and inspections of BOP systems and marine risers?**

You must record the time, date, and results of all casing and liner pressure tests. You must also record pressure tests, actuations, and inspections of the BOP system, system components, and marine riser in the daily report described in §250.740. In addition, you must:

(a) Record test pressures on pressure charts or digital recorders;

(b) Require your onsite lessee representative, designated rig or contractor representative, and pump operator to sign and date the pressure charts or digital recordings and daily reports as correct;

(c) Document on the daily report the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. For subsea BOP systems, you must also record the closing times for annular and ram BOPs. You may reference a BOP test plan if it is available at the facility;

(d) Identify on the daily report the control station and pod used during the test (identifying the pod does not apply to coiled tubing and snubbing units);

(e) Identify on the daily report any problems or irregularities observed during BOP system testing and record actions taken to remedy the problems or irregularities. Any leaks associated with the BOP or control system during testing must be documented in the WAR. If any problems that cannot be resolved promptly are observed during testing, operations must be suspended until the District Manager determines that you may continue; and

(f) Retain all records, including pressure charts, daily reports, and referenced documents pertaining to tests, actuations, and inspections at the rig unit for the duration of the operation. After completion of the operation, you must retain all the records listed in this section for a period of 2 years at the rig unit. You must also retain the records at the lessee's field office nearest the facility or at another location available to BSEE. You must make all the records available to BSEE upon request.

## **SUBPART O—WELL CONTROL AND PRODUCTION SAFETY TRAINING**

### **§250.1500 Definitions.**

*(selected terms)*

*Deepwater well control* means well control when you are using a subsea BOP system.

*Well completion/well workover* means those operations following the drilling of a well that are intended to establish or restore production.

*Well-control* means methods used to minimize the potential for the well to flow or kick and to maintain control of the well in the event of flow or a kick. Well-control applies to drilling, well-completion, well-workover, abandonment, and well-

servicing operations. It includes measures, practices, procedures and equipment, such as fluid flow monitoring, to ensure safe and environmentally protective drilling, completion, abandonment, and workover operations as well as the installation, repair, maintenance, and operation of surface and subsea well-control equipment.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50896, Aug. 22, 2012]

#### **§250.1501 What is the goal of my training program?**

The goal of your training program must be safe and clean OCS operations. To accomplish this, you must ensure that your employees and contract personnel engaged in well control, deepwater well control, or production safety operations understand and can properly perform their duties.

#### **§250.1503 What are my general responsibilities for training?**

(a) You must establish and implement a training program so that all of your employees are trained to competently perform their assigned well control, deepwater well control, and production safety duties. You must verify that your employees understand and can perform the assigned well control, deepwater well control, or production safety duties.

(b) If you conduct operations with a subsea BOP stack, your employees and contract personnel must be trained in deepwater well control. The trained employees and contract personnel must have a comprehensive knowledge of deepwater well control equipment, practices, and theory.

(c) You must have a training plan that specifies the type, method(s), length, frequency, and content of the training for your employees. Your training plan must specify the method(s) of verifying employee understanding and performance. This plan must include at least the following information:

(1) Procedures for training employees in well control, deepwater well control, or production safety practices;

(2) Procedures for evaluating the training programs of your contractors;

(3) Procedures for verifying that all employees and contractor personnel engaged in well control, deepwater well control, or production safety operations can perform their assigned duties;

(4) Procedures for assessing the training needs of your employees on a periodic basis;

(5) Recordkeeping and documentation procedures; and

(6) Internal audit procedures.

(d) Upon request of the District Manager or Regional Supervisor, you must provide:

(1) Copies of training documentation for personnel involved in well control, deepwater well control, or production safety operations during the past 5 years; and

(2) A copy of your training plan.

#### **§250.1504 May I use alternative training methods?**

You may use alternative training methods. These methods may include computer-based learning, films, or their equivalents. This training should be reinforced by appropriate demonstrations and “hands-on” training. Alternative training methods must be conducted according to, and meet the objectives of, your training plan.

#### **§250.1505 Where may I get training for my employees?**

You may get training from any source that meets the requirements of your training plan.

### **§250.1506 How often must I train my employees?**

You determine the frequency of the training you provide your employees. You must do all of the following:

- (a) Provide periodic training to ensure that employees maintain understanding of, and competency in, well control, deepwater well control, or production safety practices;
- (b) Establish procedures to verify adequate retention of the knowledge and skills that employees need to perform their assigned well control, deepwater well control, or production safety duties; and
- (c) Ensure that your contractors' training programs provide for periodic training and verification of well control, deepwater well control, or production safety knowledge and skills.

### **§250.1507 How will BSEE measure training results?**

BSEE may periodically assess your training program, using one or more of the methods in this section.

(a) *Training system audit.* BSEE or its authorized representative may conduct a training system audit at your office. The training system audit will compare your training program against this subpart. You must be prepared to explain your overall training program and produce evidence to support your explanation.

(b) *Employee or contract personnel interviews.* BSEE or its authorized representative may conduct interviews at either onshore or offshore locations to inquire about the types of training that were provided, when and where this training was conducted, and how effective the training was.

(c) *Employee or contract personnel testing.* BSEE or its authorized representative may conduct testing at either onshore or offshore locations for the purpose of evaluating an individual's knowledge and skills in perfecting well control, deepwater well control, and production safety duties.

(d) *Hands-on production safety, simulator, or live well testing.* BSEE or its authorized representative may conduct tests at either onshore or offshore locations. Tests will be designed to evaluate the competency of your employees or contract personnel in performing their assigned well control, deepwater well control, and production safety duties. You are responsible for the costs associated with this testing, excluding salary and travel costs for BSEE personnel.

## **SUBPART S—SAFETY AND ENVIRONMENTAL MANAGEMENT SYSTEMS (SEMS)**

### **§250.1900 Must I have a SEMS program?**

You must develop, implement, and maintain a safety and environmental management system (SEMS) program. Your SEMS program must address the elements described in §250.1902, American Petroleum Institute's Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities (API RP 75) (as incorporated by reference in §250.198), and other requirements as identified in this subpart.

(a) If there are any conflicts between the requirements of this subpart and API RP 75; COS-2-01, COS-2-03, or COS-2-04; or ISO/IEC 17011 (incorporated by reference as specified in §250.198), you must follow the requirements of this subpart.

(b) Nothing in this subpart affects safety or other matters under the jurisdiction of the Coast Guard.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20440, Apr. 5, 2013]

### **§250.1902 What must I include in my SEMS program?**

You must have a properly documented SEMS program in place and make it available to BSEE upon request as required by §250.1924(b).

(a) Your SEMS program must meet the minimum criteria outlined in this subpart, including the following SEMS program elements:

- (1) General (see §250.1909)
- (2) Safety and Environmental Information (see §250.1910)
- (3) Hazards Analysis (see §250.1911)
- (4) Management of Change (see §250.1912)
- (5) Operating Procedures (see §250.1913)
- (6) Safe Work Practices (see §250.1914)
- (7) Training (see §250.1915)
- (8) Mechanical Integrity (Assurance of Quality and Mechanical Integrity of Critical Equipment) (see §250.1916)
- (9) Pre-startup Review (see §250.1917)
- (10) Emergency Response and Control (see §250.1918)
- (11) Investigation of Incidents (see §250.1919)
- (12) Auditing (Audit of Safety and Environmental Management Program Elements) (see §250.1920)
- (13) Recordkeeping (Records and Documentation) and additional BSEE requirements (see §250.1928)
- (14) Stop Work Authority (SWA) (see §250.1930)
- (15) Ultimate Work Authority (UWA) (see §250.1931)

(16) Employee Participation Plan (EPP) (see §250.1932)

(17) Reporting Unsafe Working Conditions (see §250.1933).

(b) You must include a job safety analysis (JSA) for OCS activities identified or discussed in your SEMS program (see §250.1911).

(c) Your SEMS program must meet or exceed the standards of safety and environmental protection of API RP 75 (as incorporated by reference in §250.198).

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20440, Apr. 5, 2013]

#### **§250.1909 What are management's general responsibilities for the SEMS program?**

You, through your management, must require that the program elements discussed in API RP 75 (as incorporated by reference in §250.198) and in this subpart are properly documented and are available at field and office locations, as appropriate for each program element. You, through your management, are responsible for the development, support, continued improvement, and overall success of your SEMS program. Specifically you, through your management, must:

(a) Establish goals and performance measures, demand accountability for implementation, and provide necessary resources for carrying out an effective SEMS program.

(b) Appoint management representatives who are responsible for establishing, implementing and maintaining an effective SEMS program.

(c) Designate specific management representatives who are responsible for reporting to management on the performance of the SEMS program.

(d) At intervals specified in the SEMS program and at least annually, review the SEMS program to determine if it continues to be suitable, adequate and effective (by addressing the possible need for changes to policy, objectives, and other elements of the program in light of program audit results, changing circumstances and the commitment to continual improvement) and document the observations, conclusions and recommendations of that review.

(e) Develop and endorse a written description of your safety and environmental policies and organizational structure that define responsibilities, authorities, and lines of communication required to implement the SEMS program.

(f) Utilize personnel with expertise in identifying safety hazards, environmental impacts, optimizing operations, developing safe work practices, developing training programs and investigating incidents.

(g) Ensure that facilities are designed, constructed, maintained, monitored, and operated in a manner compatible with applicable industry codes, consensus standards, and generally accepted practice as well as in compliance with all applicable governmental regulations.

(h) Ensure that management of safety hazards and environmental impacts is an integral part of the design, construction, maintenance, operation, and monitoring of each facility.

(i) Ensure that suitably trained and qualified personnel are employed to carry out all aspects of the SEMS program.

(j) Ensure that the SEMS program is maintained and kept up to date by means of periodic audits to ensure effective performance.

#### **§250.1910 What safety and environmental information is required?**

(a) You must require that SEMS program safety and environmental information be developed and maintained for any facility that is subject to the SEMS program.

(b) SEMS program safety and environmental information must include:

(1) Information that provides the basis for implementing all SEMS program elements, including the requirements of hazard analysis (§250.1911);

(2) process design information including, as appropriate, a simplified process flow diagram and acceptable upper and lower limits, where applicable, for items such as temperature, pressure, flow and composition; and

(3) mechanical design information including, as appropriate, piping and instrument diagrams; electrical area classifications; equipment arrangement drawings; design basis of the relief system; description of alarm, shutdown, and interlock systems; description of well control systems; and design basis for passive and active fire protection features and systems and emergency evacuation procedures.

#### **§250.1911 What hazards analysis criteria must my SEMS program meet?**

You must ensure that a hazards analysis (facility level) and a JSA (operations/task level) are developed and implemented for all of your facilities and activities identified or discussed in your SEMS. You must document and maintain a current analysis for each operation covered by this section for the life of the operation at the facility. You must update the analysis when an internal audit is conducted to ensure that it is consistent with your facility's current operations.

(a) *Hazards analysis (facility level)*. The hazards analysis must be appropriate for the complexity of the operation and must identify, evaluate, and manage the hazards involved in the operation.

(1) The hazards analysis must address the following:

(i) Hazards of the operation;

(ii) Previous incidents related to the operation you are evaluating, including any incident in which you were issued an Incident of Noncompliance or a civil or criminal penalty;

(iii) Control technology applicable to the operation your hazards analysis is evaluating; and

(iv) A qualitative evaluation of the possible safety and health effects on employees, and potential impacts to the human and marine environments, which may result if the control technology fails.

(2) The hazards analysis must be performed by a person(s) with experience in the operations being evaluated. These individuals also need to be experienced in the hazards analysis methodologies being employed.

(3) You should assure that the recommendations in the hazards analysis are resolved and that the resolution is documented.

(4) A single hazards analysis can be performed to fulfill the requirements for simple and nearly identical facilities, such as well jackets and single well caissons. You can apply this single hazards analysis to simple and nearly identical facilities after you verify that any site-specific deviations are addressed in each of your SEMS program elements.

(b) *JSA*. You must ensure a JSA is prepared, conducted, and approved for OCS activities that are identified or discussed in your SEMS program. The JSA is a technique used to identify risks to personnel associated with their job activities. The JSAs are also used to determine the appropriate mitigation measures needed to reduce job risks to personnel. The JSA must include all personnel involved with the job activity.

(1) You must ensure that your JSA identifies, analyzes, and records:

(i) The steps involved in performing a specific job;

(ii) The existing or potential safety, health, and environmental hazards associated with each step; and

(iii) The recommended action(s) and/or procedure(s) that will eliminate or reduce these hazards, the risk of a workplace injury or illness, or environmental impacts.

(2) The immediate supervisor of the crew performing the job onsite must conduct the JSA, sign the JSA, and ensure that all personnel participating in the job understand and sign the JSA.

(3) The individual you designate as being in charge of the facility must approve and sign all JSAs before personnel start the job.

(4) If a particular job is conducted on a recurring basis, and if the parameters of these recurring jobs do not change, then the person in charge of the job may decide that a JSA for each individual job is not required. The parameters you must consider in making this determination include, but are not limited to, changes in personnel, procedures, equipment, and environmental conditions associated with the job.

(c) All personnel, which includes contractors, must be trained in accordance with the requirements of §250.1915. You must also verify that contractors are trained in accordance with §250.1915 prior to performing a job.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20441, Apr. 5, 2013]

### **§250.1912 What criteria for management of change must my SEMS program meet?**

(a) You must develop and implement written management of change procedures for modifications associated with the following:

- (1) Equipment,
- (2) Operating procedures,
- (3) Personnel changes (including contractors),
- (4) Materials, and
- (5) Operating conditions.

(b) Management of change procedures do not apply to situations involving replacement in kind (such as, replacement of one component by another component with the same performance capabilities).

(c) You must review all changes prior to their implementation.

(d) The following items must be included in your management of change procedures:

- (1) The technical basis for the change;
- (2) Impact of the change on safety, health, and the coastal and marine environments;
- (3) Necessary time period to implement the change; and
- (4) Management approval procedures for the change.

(e) Employees, including contractors whose job tasks will be affected by a change in the operation, must be informed of, and trained in, the change prior to startup of the process or affected part of the operation; and

(f) If a management of change results in a change in the operating procedures of your SEMS program, such changes must be documented and dated.



**§250.1913 What criteria for operating procedures must my SEMS program meet?**

(a) You must develop and implement written operating procedures that provide instructions for conducting safe and environmentally sound activities involved in each operation addressed in your SEMS program. These procedures must include the job title and reporting relationship of the person or persons responsible for each of the facility's operating areas and address the following:

(1) Initial startup;

(2) Normal operations;

(3) All emergency operations (including but not limited to medical evacuations, weather-related evacuations and emergency shutdown operations);

(4) Normal shutdown;

(5) Startup following a turnaround, or after an emergency shutdown;

(6) Bypassing and flagging out-of-service equipment;

(7) Safety and environmental consequences of deviating from your equipment operating limits and steps required to correct or avoid this deviation;

(8) Properties of, and hazards presented by, the chemicals used in the operations;

(9) Precautions you will take to prevent the exposure of chemicals used in your operations to personnel and the environment. The precautions must include control technology, personal protective equipment, and measures to be taken if physical contact or airborne exposure occurs;

(10) Raw materials used in your operations and the quality control procedures you used in purchasing these raw materials;

(11) Control of hazardous chemical inventory; and

(12) Impacts to the human and marine environment identified through your hazards analysis.

(b) Operating procedures must be accessible to all employees involved in the operations.

(c) Operating procedures must be reviewed at the conclusion of specified periods and as often as necessary to assure they reflect current and actual operating practices, including any changes made to your operations.

(d) You must develop and implement safe and environmentally sound work practices for identified hazards during operations and the degree of hazard presented.

(e) Review of and changes to the procedures must be documented and communicated to responsible personnel.

**§250.1914 What criteria must be documented in my SEMS program for safe work practices and contractor selection?**

Your SEMS program must establish and implement safe work practices designed to minimize the risks associated with operations, maintenance, modification activities, and the handling of materials and substances that could affect safety or the environment. Your SEMS program must also document contractor selection criteria. When selecting a contractor, you must obtain and evaluate information regarding the contractor's safety record and environmental performance. You must ensure that contractors have their own written safe work practices. Contractors may adopt appropriate sections of your SEMS program. You and your contractor must document an agreement on appropriate contractor safety and environmental policies and practices before the contractor begins work at your facilities.

(a) A contractor is anyone performing work for you. However, these requirements do not apply to contractors providing domestic services to you or other contractors. Domestic services include janitorial work, food and beverage service, laundry service, housekeeping, and similar activities.

(b) You must document that your contracted employees are knowledgeable and experienced in the work practices necessary to perform their job in a safe and environmentally sound manner. Documentation of each contracted employee's expertise to perform his/her job and a copy of the contractor's safety policies and procedures must be made available to the operator and BSEE upon request.

(c) Your SEMS program must include procedures and verification for selecting a contractor as follows:

(1) Your SEMS program must have procedures that verify that contractors are conducting their activities in accordance with your SEMS program.

(2) You are responsible for making certain that contractors have the skills and knowledge to perform their assigned duties and are conducting these activities in accordance with the requirements in your SEMS program.

(3) You must make the results of your verification for selecting contractors available to BSEE upon request.

(d) Your SEMS program must include procedures and verification that contractor personnel understand and can perform their assigned duties for activities such as, but not limited to:

(1) Installation, maintenance, or repair of equipment;

(2) Construction, startup, and operation of your facilities;

(3) Turnaround operations;

(4) Major renovation; or

(5) Specialty work.

(e) You must:

(1) Perform periodic evaluations of the performance of contract employees that verifies they are fulfilling their obligations, and

(2) Maintain a contractor employee injury and illness log for 2 years related to the contractor's work in the operation area, and include this information on Form BSEE-0131.

(f) You must inform your contractors of any known hazards at the facility they are working on including, but not limited to fires, explosions, slips, trips, falls, other injuries, and hazards associated with lifting operations.

(g) You must develop and implement safe work practices to control the presence, entrance, and exit of contract employees in operation areas.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20441, Apr. 5, 2013]

### **§250.1915 What training criteria must be in my SEMS program?**

Your SEMS program must establish and implement a training program so that all personnel are trained in accordance with their duties and responsibilities to work safely and are aware of potential environmental impacts. Training must address such areas as operating procedures (§250.1913), safe work practices (§250.1914), emergency response and control measures (§250.1918), SWA (§250.1930), UWA (§250.1931), EPP (§250.1932), reporting unsafe working conditions (§250.1933), and how to recognize and identify hazards and how to construct and implement JSAs (§250.1911). You must document your instructors' qualifications. Your SEMS program must address:

(a) Initial training for the basic well-being of personnel and protection of the environment, and ensure that persons assigned to operate and maintain the facility possess the required knowledge and skills to carry out their duties and responsibilities, including startup and shutdown.

(b) Periodic training to maintain understanding of, and adherence to, the current operating procedures, using periodic drills, to verify adequate retention of the required knowledge and skills.

(c) Communication requirements to ensure that personnel will be informed of and trained as outlined in this section whenever a change is made in any of the areas in your SEMS program that impacts their ability to properly understand and perform their duties and responsibilities. Training and/or notice of the change must be given before personnel are expected to operate the facility.

(d) How you will verify that the contractors are trained in the work practices necessary to understand and perform their jobs in a safe and environmentally sound manner in accordance with all provisions of this section.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20441, Apr. 5, 2013]

**§250.1916 What criteria for mechanical integrity must my SEMS program meet?**

You must develop and implement written procedures that provide instructions to ensure the mechanical integrity and safe operation of equipment through inspection, testing, and quality assurance. The purpose of mechanical integrity is to ensure that equipment is fit for service. Your mechanical integrity program must encompass all equipment and systems used to prevent or mitigate uncontrolled releases of hydrocarbons, toxic substances, or other materials that may cause environmental or safety consequences. These procedures must address the following:

(a) The design, procurement, fabrication, installation, calibration, and maintenance of your equipment and systems in accordance with the manufacturer's design and material specifications.

(b) The training of each employee involved in maintaining your equipment and systems so that your employees can implement your mechanical integrity program.

(c) The frequency of inspections and tests of your equipment and systems. The frequency of inspections and tests must be in accordance with BSEE regulations and meet the manufacturer's recommendations. Inspections and tests can be performed more frequently if determined to be necessary by prior operating experience.

(d) The documentation of each inspection and test that has been performed on your equipment and systems. This documentation must identify the date of the inspection or test; include the name and position, and the signature of the person who performed the inspection or test; include the serial number or other identifier of the equipment on which the inspection or test was performed; include a description of the inspection or test performed; and the results of the inspection test.

(e) The correction of deficiencies associated with equipment and systems that are outside the manufacturer's recommended limits. Such corrections must be made before further use of the equipment and system.

(f) The installation of new equipment and constructing systems. The procedures must address the application for which they will be used.

(g) The modification of existing equipment and systems. The procedures must ensure that they are modified for the application for which they will be used.

(h) The verification that inspections and tests are being performed. The procedures must be appropriate to ensure that equipment and systems are installed consistent with design specifications and the manufacturer's instructions.

(i) The assurance that maintenance materials, spare parts, and equipment are suitable for the applications for which they will be used

### **§250.1919 What criteria for investigation of incidents must be in my SEMS program?**

To learn from incidents and help prevent similar incidents, your SEMS program must establish procedures for investigation of all incidents with serious safety or environmental consequences and require investigation of incidents that are determined by facility management or BSEE to have possessed the potential for serious safety or environmental consequences. Incident investigations must be initiated as promptly as possible, with due regard for the necessity of securing the incident scene and protecting people and the environment. Incident investigations must be conducted by personnel knowledgeable in the process involved, investigation techniques, and other specialties that are relevant or necessary.

(a) The investigation of an incident must address the following:

- (1) The nature of the incident;
- (2) The factors (human or other) that contributed to the initiation of the incident and its escalation/control; and
- (3) Recommended changes identified as a result of the investigation.

(b) A corrective action program must be established based on the findings of the investigation in order to analyze incidents for common root causes. The corrective action program must:

- (1) Retain the findings of investigations for use in the next hazard analysis update or audit;
- (2) Determine and document the response to each finding to ensure that corrective actions are completed; and
- (3) Implement a system whereby conclusions of investigations are distributed to similar facilities and appropriate personnel within their organization.

### **§250.1920 What are the auditing requirements for my SEMS program?**

(a) Your SEMS program must be audited by an accredited ASP according to the requirements of this subpart and API RP 75, Section 12 (incorporated by reference as specified in §250.198). The audit process must also meet or exceed the criteria in Sections 9.1 through 9.8 of Requirements for Third-party SEMS Auditing and Certification of Deepwater Operations COS-2-03 (incorporated by reference as specified in §250.198) or its equivalent. Additionally, the audit team lead must be an employee, representative, or agent of the ASP, and must not have any affiliation with the operator. The remaining team members may be chosen from your personnel and those of the ASP. The audit must be comprehensive and include all elements of your SEMS program. It must also identify safety and environmental performance deficiencies.

(b) Your audit plan and procedures must meet or exceed all of the recommendations included in API RP 75 section 12 (as specified in §250.198) and include information on how you addressed those recommendations. You must specifically address the following items:

- (1) Section 12.1 General.
- (2) Section 12.2 Scope.
- (3) Section 12.3 Audit Coverage.

(4) Section 12.4 Audit Plan. You must submit your written Audit Plan to BSEE at least 30 days before the audit. BSEE reserves the right to modify the list of facilities that you propose to audit.

(5) Section 12.5 Audit Frequency. You must have your SEMS program audited by an ASP within 2 years after initial implementation and every 3 years thereafter. The 3-year auditing cycle begins on the start date of each comprehensive audit (including the initial implementation audit) and ends on the start date of your next comprehensive audit. For exploratory drilling operations taking place on the Arctic OCS, you must conduct an audit, consisting of an onshore portion and an offshore portion, including all related infrastructure, once per year for every year in which drilling is conducted.

(6) Section 12.6 Audit Team. Your audits must be performed by an ASP as described in §250.1921. You must include the ASP's qualifications in your audit plan.

(c) You must submit an audit report of the audit findings, observations, deficiencies identified, and conclusions to BSEE within 60 days of the audit completion date. For exploratory drilling operations taking place on the Arctic OCS, you must submit an audit report of the audit findings, observations, deficiencies and conclusions for the onshore portion of your audit no later than March 1 in any year in which you plan to drill, and for the offshore portion of your audit, within 30 days of the close of the audit.

(d) You must provide BSEE with a copy of your CAP for addressing the deficiencies identified in your audit within 60 days of the audit completion date. Your CAP must include the name and job title of the personnel responsible for correcting the identified deficiency(ies). The BSEE will notify you as soon as practicable after receipt of your CAP if your proposed schedule is not acceptable or if the CAP does not effectively address the audit findings. For exploratory drilling operations taking place on the Arctic OCS, you must provide BSEE with a copy of your CAP for addressing deficiencies or nonconformities identified in the onshore portion of the audit no later than March 1 in any year in which you plan to drill, and for the offshore portion of your audit, within 30 days of the close of the audit.

(e) BSEE may verify that you undertook the corrective actions and that these actions effectively address the audit findings.

(f) For exploratory drilling operations taking place on the Arctic OCS, during the offshore portion of each audit, 100 percent of the facilities operated must be audited while drilling activities are underway. You must start and close the offshore portion of the audit for each facility within 30 days after the first spudding of the well or entry into an existing wellbore for any purpose from that facility.

(g) For exploratory drilling operations taking place on the Arctic OCS, if BSEE determines that the CAP or progress toward implementing the CAP is not satisfactory, BSEE may order you to shut down all or part of your operations.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20442, Apr. 5, 2013; 81 FR 36151, June 6, 2016; 81 FR 46563, July 15, 2016]

### **§250.1930 What must be included in my SEMS program for SWA?**

(a) Your SWA procedures must ensure the capability to immediately stop work that is creating imminent risk or danger. These procedures must grant all personnel the responsibility and authority, without fear of reprisal, to stop work or decline to perform an assigned task when an imminent risk or danger exists. Imminent risk or danger means any condition, activity, or practice in the workplace that could reasonably be expected to cause:

(1) Death or serious physical harm; or

(2) Significant environmental harm to:

(i) Land;

(ii) Air; or

(iii) Mineral deposits, marine, coastal, or human environment.

(b) The person in charge of the conducted work is responsible for ensuring the work is stopped in an orderly and safe manner. Individuals who receive a notification to stop work must comply with that direction immediately.

(c) Work may be resumed when the individual on the facility with UWA determines that the imminent risk or danger does not exist or no longer exists. The decision to resume activities must be documented in writing as soon as practicable.

(d) You must include SWA procedures and expectations as a standard statement in all JSAs.

(e) You must conduct training on your SWA procedures as part of orientations for all new personnel who perform activities on the OCS. Additionally, the SWA procedures must be reviewed during all meetings focusing on safety on facilities subject to this subpart.

[78 FR 20443, Apr. 5, 2013]

**§250.1931 What must be included in my SEMS program for UWA?**

(a) Your SEMS program must have a process to identify the individual with the UWA on your facility(ies). You must designate this individual taking into account all applicable USCG regulations that deal with designating a person in charge of an OCS facility. Your SEMS program must clearly define who is in charge at all times. In the event that multiple facilities, including a MODU, are attached and working together or in close proximity to one another to perform an OCS operation, your SEMS program must identify the individual with the UWA over the entire operation, including all facilities.

(b) You must ensure that all personnel clearly know who has UWA and who is in charge of a specific operation or activity at all times, including when that responsibility shifts to a different individual.

(c) The SEMS program must provide that if an emergency occurs that creates an imminent risk or danger to the health or safety of an individual, the public, or to the environment (as specified in §250.1930(a)), the individual with the UWA is authorized to pursue the most effective action necessary in that individual's judgment for mitigating and abating the conditions or practices causing the emergency.

[78 FR 20443, Apr. 5, 2013]

**§250.1932 What are my EPP requirements?**

(a) Your management must consult with their employees on the development, implementation, and modification of your SEMS program.

(b) Your management must develop a written plan of action regarding how your appropriate employees, in both your offices and those working on offshore facilities, will participate in your SEMS program development and implementation.

(c) Your management must ensure that employees have access to sections of your SEMS program that are relevant to their jobs.

[78 FR 20443, Apr. 5, 2013]

**§250.1933 What procedures must be included for reporting unsafe working conditions?**

(a) Your SEMS program must include procedures for all personnel to report unsafe working conditions in accordance with §250.193. These procedures must take into account applicable USCG reporting requirements for unsafe working conditions.

(b) You must post a notice at the place of employment in a visible location frequently visited by personnel that contains the reporting information in §250.193.

[78 FR 20443, Apr. 5, 2013]

# APPENDIX D

## Regulatory Comparative Analysis Tables

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**Table D1 –Regulations in various Jurisdictions Pertaining to General and HSE Requirements**

	Shorthand	Description of Essential Elements	BSEE (CFR §250)
G1	HSE required	Must protect health, safety, property, and the environment	107
G2	BAST	Must perform operations in a safe and workmanlike manner; must follow applicable regulations. (The requirements of this regulation is implicit in state and federal law in USA)	107
G3	Well Specific Regulations	Regulatory Organization has authority to require additional measures when indicated by local conditions.	107
G4	HSE Required	Must protect health, safety, property, environment, and national security during drilling and completion operations.	400 500
G5	SEMS	Specifies SEMS program with minimum defined elements.	S

**Table D2 –Regulations in various Jurisdictions Pertaining to General Well Control**

	Shorthand	Description of Essential Elements	BSEE (CFR §250)	BLM	Alabama	Alaska	Arkansas	California	Colorado	Florida	Kansas	Louisiana	Mississippi	Montana	North Dakota	Oklahoma	Pennsylvania	Texas	Utah	West Virginia	Australia	Brazil	Canada	Norway	Russia	
C1	Completions same as Drilling	Completions use same well-control approach during tripping as Drilling.	514 700	X	X	X		X	X	X		X	X					X				X	X	X	X	X
C2	Alternative Equipment of Procedures	Must submit requests and justification for Alternative Drilling Procedures such as MPD (which includes tripping operations)	141			X																WOMP	X			
C3	Drilling Prognosis	Must submit Drilling Prognosis with request for permit to drill. Includes request for Alternative Equipment and Procedures such as MPD.	414	X		X		X														WOMP Safety Case	X		X	X
C4	2-Barrier Approach	Two independent barriers, including one mechanical barrier in each annular flow path.	420														X					X	X		X	X
C5	Well Control Plan	Require a well control plan and post on rig floor.	710																					X		
C6	Maintain Well Control	Must keep wells under control at all times; Use and maintain necessary equipment and materials.	703	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X		X	X	X	X	X
C7	Onsite Supervision	Use onsite supervision during drilling and completion operations to fulfil responsibilities.	703																			X	X	X	X	X
C8	Well Control Training	Require well control training certification.	703, O & S			X						X	X				X	X	X	X		X	X	X	X	X
C9	Hazard Analysis	Crew members shall be instructed in the safety requirements of the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment.	710					X															X		X	
C10	Safety Meetings	Date and time of safety meetings shall be recorded and available at the facility for review.	710																							

**Table D3 –Regulations in various Jurisdictions Pertaining to the Fluid Column (Primary Barrier)**

	Shorthand	Description of Essential Elements	BSEE (CFR §250)	BLM	Alabama	Alaska	Arkansas	California	Colorado	Florida	Kansas	Louisiana	Mississippi	Montana	North Dakota	Oklahoma	Pennsylvania	Texas	Utah	West Virginia	Australia	Brazil	Canada	Norway	Russia
F1	Drilling Fluid Program	Design and implement drilling fluid program to prevent the loss of well control and submit with request for permit to drill well.	418	X		X		X														X		X	X
F2	Fluid Density Margin	Safe drilling margin (Fluid Gradient less Pore pressure Gradient) is required and must be maintained during all operations including tripping operations.	414	X	X	X	X	X		X		X						X					X	X	X
F3	0.5 ppg Margin	Fluid Density Margin generally acceptable in Regulatory Review Practice. In past Regulatory Review Practice 0.3 ppg Fluid Density Margin acceptable with special case-specific justification.	414																				1400 kPa Mannville		
F4	Alternative Fluid Density Margin	Allows use of an equivalent downhole mud weight as specified in APD, provided adequate documentation.	414																						
F5	Swabbing - Consider Pipe Pulling Speed	You must run and pull drill pipe and downhole tools at controlled rates so you do not swab or surge the well;	456				X																X		
F6	Swabbing - Consider Mud Properties	Specifies that Mud Rheological Properties must minimize potential for pressure surge or swab	N/A		X	X																			
F7	Gas Buster	Fluid-gas separator and degasser required.	457																						
F8	Fluid Monitoring Equipment for Tripping	Volume measuring device to accurately determine fluid volumes required to fill the hole on trips;	457		X	X		X		X								X					X	X	X
F9	Mud Properties Check	Periodic Check of Mud Properties Required (BSEE-once per tour)	456	8 hrs	Daily	Tour		8 hrs		Daily								X				X		X	X
F10	Rig Floor Surveillance	Continuous surveillance on the rig floor unless you have secured the well with blowout preventers (BOPs), bridge plugs, cement plugs, or packers.	703		X	X		X				X											X	X	X
F11	Fill-up Volume Measurement	You must use a mechanical, volumetric, or electronic device to measure the drilling fluid required to fill the hole;	457	X	X	X		X		X								X					X	X	
F12	Posted fill-up Volume	Both sets of numbers (number of stands and corresponding fill-up volume) must be posted near the driller's station.	456			Daily Report																			
F13	Maximum Pressure loss before fill-up	Specified maximum pressure loss before fill up; Show value in column in place of check mark for equivalent comparison, e.g. 75 psi or 100 psi. (BSEE maximum is 75 psi)	456		75 psi	75 psi		100 ft	100 ft	100 ft							100 ft		Keep Full				Keep Full	30 m	
F14	Completions same as Drilling	Completions use same safe fluid practices during tripping as Drilling.	514	X	X	X		X	X	X		X	X					X				X	X	X	X
F15	Trip Sheet	Record of fill-up volume and volume of steel removed when seepage or ballooning occurs	N/A			X		X															X	X	
F16	Drilling Fluid Quantities	Adequate quantities of drilling fluids and drilling fluid materials, including weight materials,for well control to be kept at the site.	418	X	X					X								X					X	X	X
F17	Barite on hand	Minimum acceptable quantity of barite available at well site. (Regulatory Review Practice)	418, 458	X																			X		
F18	Drilling Fluid Safe Practices for Tripping	Circulate at least one annular volume to condition mud before tripping out of hole (with exceptions).	456	X	X	X		X										until equal					X	X	X
F19	Maximum seepage Rate	Regulation regarding maximum seepage rate when tripping out of well	N/A																				zero		
F20	Maximum Hole Ballooning	Regulation regarding maximum mud influx rate due to hole ballooning when tripping out of well	N/A																				zero		
F21	Hole fill-up Frequency	When coming out of the hole with drill pipe, you must fill the annulus with drilling fluid before the hydrostatic pressure decreases by maximum pressure loss before fill-up, or every five stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure. You must calculate the number of stands of drill pipe and drill collars that you may pull before you must fill the hole. You must also calculate the equivalent drilling fluid volume needed to fill the hole.	456		X	X		X	X	X							X		Keep Full at all Times				Keep Well Full	X	Control and correlate fill/trip volume
F22	Corrective Action after Influx	When there is an indication of swabbing or influx of formation fluids, you must take appropriate measures to control the well. You must circulate and condition the well, on or near-bottom, unless well or drilling-fluid conditions prevent running the drill pipe back to the bottom.	456		X			X		X													X		
F23	Drill Stem Test (DST) Fluid Circulation	Before pulling drill-stem test tools from the hole, you must circulate or reverse-circulate the test fluids or otherwise remove test fluids from well with appropriate kill weight fluid;	456	X	X			X															X		
F24	Daylight Only DST Circulation	Tripping operations after open chamber DST during daylight																							

**Table D4 –Regulations in various Jurisdictions Pertaining to Mechanical Containment by the BOPE (Secondary Barrier)**

Shorthand	Description of Essential Elements	BSEE (CFR §250)	BLM	Alabama	Alaska	Arkansas	California	Colorado	Florida	Kansas	Louisiana	Mississippi	Montana	North Dakota	Oklahoma	Pennsylvania	Texas	Utah	West Virginia	Australia	Brazil	Canada	Norway	Russia
M1	Rams for Tapered String	At least one set of pipe rams capable of sealing around each size of drill string or work string. If the expected pressure > 5,000 psi, at least two sets of rams for larger size drill string.	730	X	X		X				X						X				X	X	X	
M2	Shear Rams	Shear rams are always required.	730		X		Marine										Marine				Marine		X	
M3	Upper Kelly Valve	A kelly valve installed below the swivel.	736	X	X	X	X		X		X		X	X			X				X	X		X
M4	Lower Kelly Valve	A lower kelly valve below kelly or top joint that can be stripped thru BOP stack.	736	X	X	X	X				X		X				X				X	X		
M5	Top Drive Safety Valve	A strippable kelly-type valve below the remote-controlled valve on a top-drive system equipped with a remote-controlled valve.	736						X								X				X	X		
M6	Inside BOPs	Inside BOPs in the open position located on the rig floor for each size connection in the drill string.	736	X	X	X	X				X						X				X	X		
M7	DP Safety Valves	Drill-string safety valves in the open position located on the rig floor for each size/ type connection in the drill string	736	X	X	X	X		X		X	X					X				X	X	X	X
M8	Casing Safety Valves	Casing safety valves in the open position located on the rig floor for each size/ type connection in the casing string.	736		X		X		X		X						X				X	X	X	
M9	Full Open Safety Valves	Kelly and Safety Valves must be essentially full opening.	736		X	X	X		X		X		X				X				X	X		
M10	Safety Valve Wrench	Drilling crew must have ready access to a wrench to fit each manual valve.	736	X	X	X	X										X				X	X	X	
M11	API RP 53	Industry Standards and Guidelines incorporated by Reference. Includes API RP 53 with Drill String Safety Valve Recommended Practice for tripping operations.	198		X		X										X	X				X		
M12	API Standard 53	Industry Standard regarding Blowout Prevention Equipment Systems incorporated by Reference (including certification every 5 yrs)	198														X	X						
M13	Pit Drill	The timing of your drills must include tripping. For each drill, you must record performance metrics in the driller's report.	462								X										X	X		
M14	Ordered Pit Drill	Must conduct a well control drill during an inspection if so ordered by inspector.	462																			X		