BSEE Public Forum on Well Control and Blowout Preventer Rule

Mickey Leland Federal Building

Houston, TX

September 20, 2017

Topics

- Overview
- Drilling Margins
- Remote Real Time Monitoring
- Casing and Cementing
- Containment
- API 53
- BAVOs
- Shearing Requirements
- Accumulators
- Codifying Interpretations
- Summary

Overview

Holly Hopkins, API

COMMITMENT TO SAFETY

- Government and industry have made a continuous effort to enhance safety offshore.
- The incident in the GOM seven years ago provoked the largest gatherings of subject matter experts in history to come together to debate, and implement, improvements to safety in the offshore industry.
- Together, we have improved regulations and consensus standards on safety and environmental management systems, offshore equipment and operations, including well control and well design to protect workers and the environment and ensure designs are robust and equipment operates as expected.
- API has published over 100 new and revised exploration and production standards
- In addition, the Center for Offshore Safety was established to foster safety culture and share lessons learned amongst industry.
- Industry’s goal is zero accidents and zero spills.
- We are working every day to improve standards, research technologies and tools, and learn lessons from incidents that do occur.

JOINT INDUSTRY EFFORT

- 7 Trade Associations
  - API
  - IADC
  - IPAA
  - NOIA
  - OOC
  - PESA
  - USOGA
- Over 70 Companies
- Over 300 Individuals
- Tens of Thousands of Person Hours

8 Subject Matter Expert Workgroups

1. Drilling Margin
2. API Standards IBR
3. Real Time Monitoring
4. Casing/Cementing
5. BOP Equipment
6. Containment
7. Inspection/Mechanical Integrity
8. Economic Analysis

Industry Work to Date

- OMB Meeting January 2015
- BSEE/DOI Meeting July 13, 2015
- July 16, 2015 Comment Letter to BSEE on Proposed Rule
- BSEE Meeting September 14, 2015
- BSEE Meeting December 7, 2015
- May 27, 2016 29 page letter to BSEE asking for clarification and/or interpretation
- BSEE clarification and/or interpretation website: http://www.bsee.gov/Regulations-and-Guidance/Well-Control-Rule/
- May 17, 2017 53 page letter to DOI recommending changes to the WCR based on Executive Order 13795 & Secretarial Order 3350

Industry Commitment to Safety

- We share BSEE's and the public's expectation that offshore oil and gas development should be done safely and in an environmentally sound manner
- We would like more collaborative engagement with the Agency to address issues with the Final Well Control Rule so that the outcome is aligned with the stated intent
- The final rule does not fully consider the significant progress made since 2010 by both BSEE and Industry to improve safety

MAJOR CONCERNS

- Unintended Consequences may increase risk and decrease safety
- Unachievable and Unrealistic Implementation Period
- Additional Administrative Burden for BSEE
- Drilling Margin
- Remote Real Time Monitoring
- Casing and Cementing
- Containment
- BOP requirements beyond API Standard 53
- BAVOs

Drilling Margins

Joe Leimkuhler, LLOG

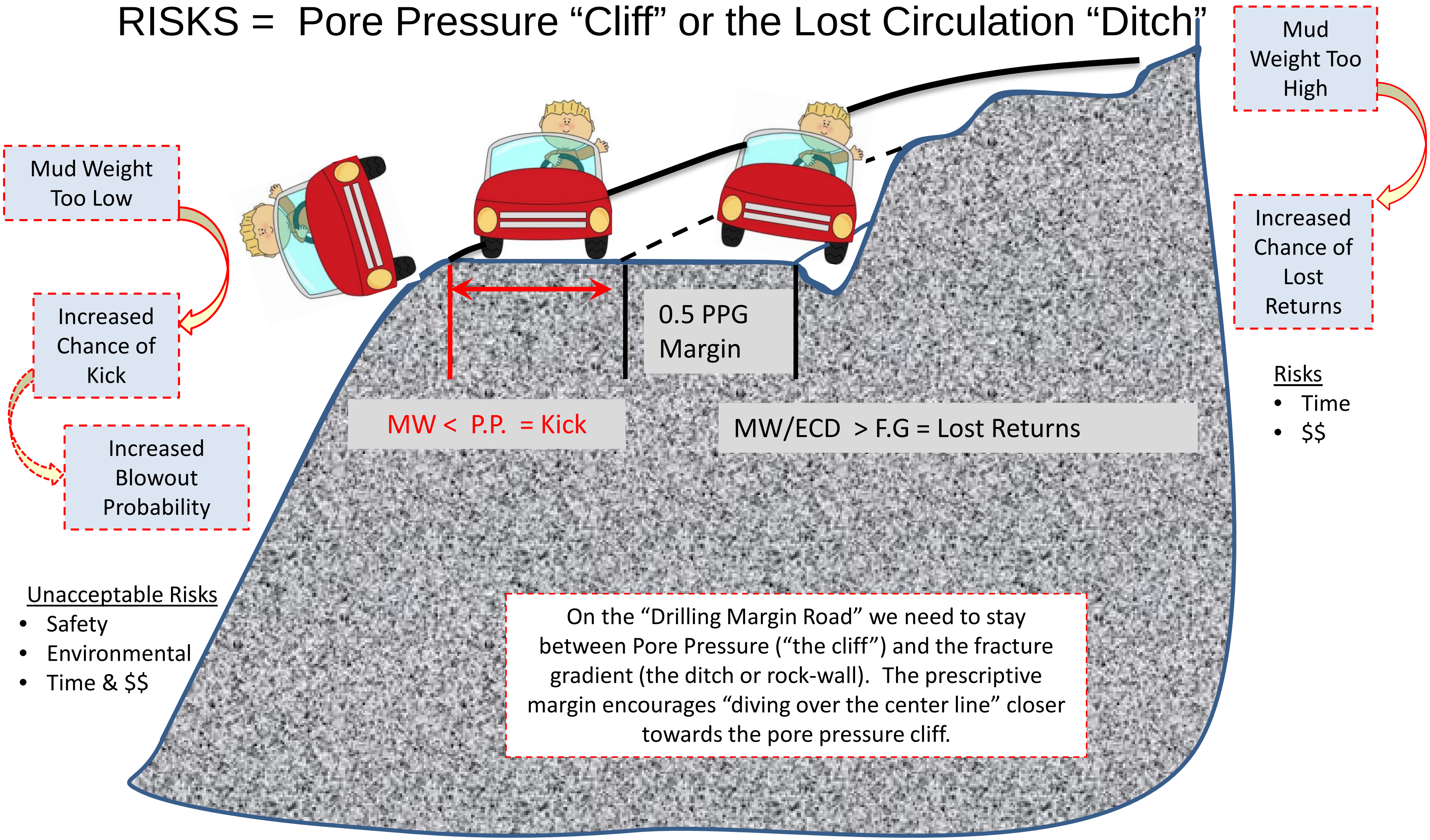
Drilling Margin Summary – Pre WCR Release

- Drilling of deepwater and shelf wells will be severely impacted by a potentially hard line interpretation/implementation of the 0.5 ppg drilling margin
  - Many wells drilled safely to total depth in previous years could not be drilled
  - Development of significant future reserves would be cancelled. Operators may be unable to sanction a project when unable to meet a hard line 0.5 ppg drilling margin. (not a prior requirement and operators are getting approvals with less than 0.5 ppg to proceed, based on current well conditions and risk analysis)

- No technical basis for the change
  - To date drilling margin has been safely managed by operators in conjunction with BSEE
  - A less prescriptive rule provides flexibility enabling engineered solutions for safer operations
  - Review of BSEE Well Control Database indicates no justification for a prescriptive margin.

- Unintended consequences created by the proposed rule
  - Potential DECREASE in safety and INCREASE in risk exposure
  - Increased risk of well control events due to decreased overbalance between formation pressure and mud pressure to accommodate BSEE margin

The Drilling Margin Road:
RISKS = Pore Pressure "Cliff" or the Lost Circulation "Ditch"



The BSEE Justification for increased drilling regulations to lower the Loss of Well Control (LWC) Incidents is not supported by the LWC data.

"The need for the Well Control Rule is demonstrated by the fact that loss of well control (LWC) incidents are happening at the same rate five years after the Macondo blowout as they were before. In 2013 and 2014, there were eight and seven LWC incidents per year, respectively – a rate on par with pre-Macondo losses of well control. [5]"

STATEMENT OF BRIAN SALERNO, DIRECTOR, BUREAU OF SAFETY AND ENVIRONMENTAL ENFORCEMENT
UNITED STATES DEPARTMENT OF THE INTERIOR
BEFORE THE COMMITTEE ON ENERGY AND NATURAL RESOURCES, UNITED STATES SENATE

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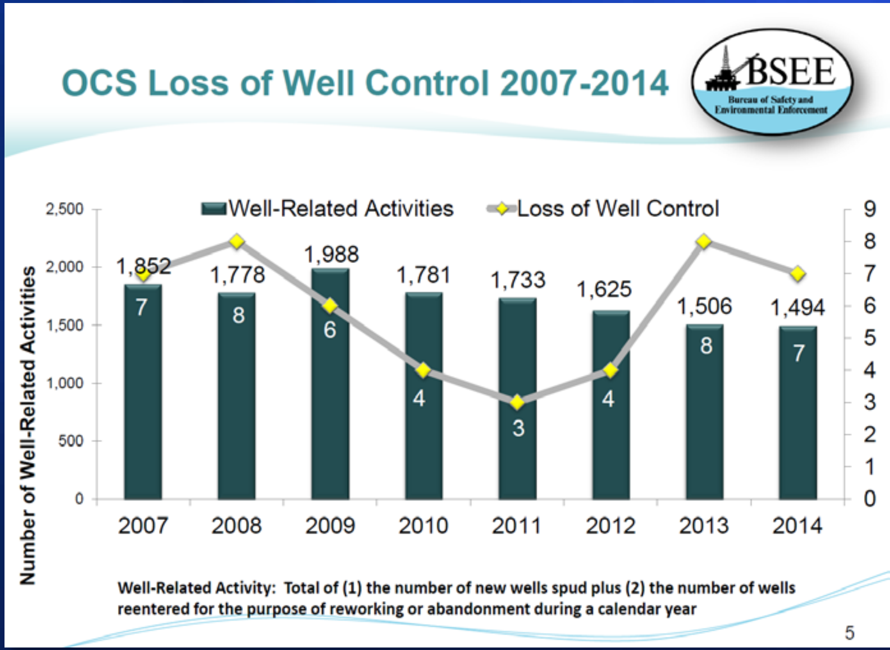

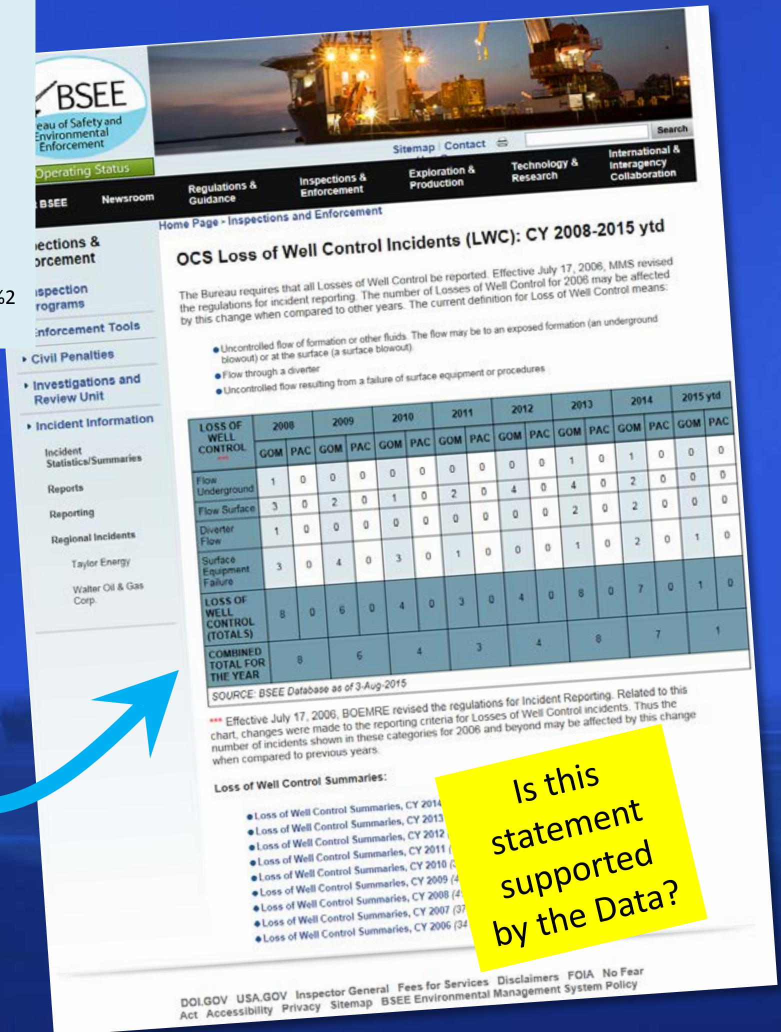

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- Inspection Programs
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- Civil Penalties
- Investigations and Review Unit
- Incident Information
  - Incident Statistics/Summaries
  - Reports
  - Reporting
  - Regional Incidents
    - Taylor Energy
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OCS Loss of Well Control Incidents (LWC): CY 2008-2015 ytd

The Bureau requires that all Losses of Well Control be reported. Effective July 17, 2006, MMS revised the regulations for incident reporting. The number of Losses of Well Control for 2006 may be affected by this change when compared to other years. The current definition for Loss of Well Control means:

- Uncontrolled flow of formation or other fluids. The flow may be to an exposed formation (an underground blowout) or at the surface (a surface blowout).
- Flow through a diverter
- Uncontrolled flow resulting from a failure of surface equipment or procedures

LOSS OF WELL CONTROL ***	2008		2009		2010		2011		2012		2013		2014		2015 ytd	
	GOM	PAC	GOM	PAC	GOM	PAC	GOM	PAC	GOM	PAC	GOM	PAC	GOM	PAC	GOM	PAC
Flow Underground	1	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0
Flow Surface	3	0	2	0	1	0	2	0	4	0	4	0	2	0	0	0
Diverter Flow	1	0	0	0	0	0	0	0	0	0	2	0	2	0	0	0
Surface Equipment Failure	3	0	4	0	3	0	1	0	0	0	1	0	2	0	1	0
LOSS OF WELL CONTROL (TOTALS)	8	0	6	0	4	0	3	0	4	0	8	0	7	0	1	0
COMBINED TOTAL FOR THE YEAR	8		6		4		3		4		8		7		1	

SOURCE: BSEE Database as of 3-Aug-2015

*** Effective July 17, 2006, BOEMRE revised the regulations for Incident Reporting. Related to this chart, changes were made to the reporting criteria for Losses of Well Control incidents. Thus the number of incidents shown in these categories for 2006 and beyond may be affected by this change when compared to previous years.

Loss of Well Control Summaries:

- Loss of Well Control Summaries, CY 2014
- Loss of Well Control Summaries, CY 2013
- Loss of Well Control Summaries, CY 2012
- Loss of Well Control Summaries, CY 2011
- Loss of Well Control Summaries, CY 2010
- Loss of Well Control Summaries, CY 2009
- Loss of Well Control Summaries, CY 2008
- Loss of Well Control Summaries, CY 2007
- Loss of Well Control Summaries, CY 2006

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Is this statement supported by the Data?

How does the "Drilling Margin" Prescriptive Rule… apply to the drilling events in the BSEE data base?

Of the 49 events in the database, only 19 are drilling related.

Poor 20" cement job

1 -Flow Post Cmt Job W/Nipplig up BOPs
2 -Pressure below Gumbo Attack - MW Poss too low.

Diverter, both events.

Underground B/O - little to no details in database

Diverter

Casing Grouting Operation

Operation	YEAR 2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Totals	
Drilling	**1**	**1**	**4**	**1**	**0**	**0**	**1**	**6**	**5**		**19**	**39%**
Shelf - Top Hole - No BOPs		1	2					2	1		6	
Shelf - Lower Hole - With BOPs	1		1					1	1		4	
Deepwater - Top Hole No BOPs							1	1	2		4	
Deepwater Lower Hole - With BOPs			1	1				2	1		5	10%

SWF

SWF 2X

Post Cementing Issues

Likely not LWC, flow on Conn, SI - stick Pipe. Underground Flow Indeterminate

LWC not clear - gas bubble in riser - expanding gas bubble in riser led to a 2 BBl. SBM mud spill at Surface.

Drilled into Overpressuresd Salt Inclusion - Shut In - Incr MW 0.2 PPG hole stable.

SWF

Csg on Btm but stuck R/T, Lost Returns, Cemented Well, 16" Conn leaks, Underground Flow, broach mud to seafloor.

1 - Balooning
2 - Casing Hole

Answer – After reviewing all drilling LWC events in the BSEE database – the Prescriptive Margin clearly does not apply to any DW Drilling Events. In addition any tie to Shelf events is limited to 5 events – 4 while drilling with a diverter (no BOPs in place) and 1 with inadequate info to make a determination.

Conclusion – The BSEE DW LWC data /information shows the 0.5 PPG prescriptive drilling margin will have no positive impact in reducing LWC events. Conversely, the prescriptive rule is likely to decrease safety by encouraging operators to drill with lighter mud weights, thus increasing the frequency of well control events and thus subsequently increase the risk of a loss of secondary well control…..i.e. a blowout.

Drilling Margin – Final WCR

- <u>Drilling margin exceptions have been approved through both Conditions of Approval as well as real-time waivers</u>.
  - Operations impacted waiting on real-time approval.
  - Inconsistent application across districts for preapproval in APD vs afterhours or real-time approval.
  - Regulation does not tie to risk reduction and improved safety in OCS. Why include a regulation that requires frequent exceptions to enable safe drilling?
  - Future well control regulatory revisions should require a safe drilling margin approved as per the APD submittal and approval protocol with no prescriptive specified margin.

- <u>Drilling margin exceptions approvals are policy dependent and subject to change between project investment and execution</u>.
  - High operator risk to rely on these approvals at an APD level or real-time when sanctioning development

- <u>If a prescriptive drilling margin remains in the regulations, a mechanism for approval prior to project investment decision is required.</u>

Drilling Margin – Current Practical Improvements

*“ **§ 250.427** (b) While drilling, you must maintain the safe drilling margins identified in § 250.414. When you cannot maintain the safe margins, you must suspend drilling operations and remedy the situation.”*

- What constitutes a loss of safe drilling margin? Needs to be better defined.
  - Normal Background seepage.
  - Excessive seepage cured with time (filter-cake deposition) or a PSD sweep.
  - Ballooning – Temporary loss of whole mud, that flows back on connections.
  - Partial loss of returns, no ballooning back on connections.
  - Full loss of returns – hole stays full.
  - No returns – hole does not stay full.

No Loss of drilling margin.

Loss of drilling margin, suspend operations

- Once the drilling margin is clearly lost, operators must suspend drilling, but may proceed with operations to restore a safe drilling margin such as well bore treatments to plug or repair thief zones. District approval is needed on any subsequent drilling. Such approval should not be withheld provided the operator’s operational forward plan is backed by a comprehensive risk based analysis/protocol.

Remote Real Time Monitoring

Remote Real Time Monitoring

- Implementation of the proposed prescriptive real time monitoring requirements has the potential to shift decision-making authority away from Operators’ wellsite personnel.
- The increased engagement of BSEE in ongoing operations could distort the lines of responsibility and accountability, and create confusion that could decrease overall operations integrity.
- Requires onshore real time data feeds and monitoring systems which can create digital security issues.
- May decrease wellsite personnel authority and potentially compromise long term effectiveness of wellsite supervision.
- Remote monitoring stations onshore have reduced situational awareness that wellsite personnel have.
- While some operators currently use RRTM technology today in support of offshore operations, it is typically not in the manner proposed by BSEE.

Casing and Cementing

Alan Parlipiano, Hess

Casing and Cementing

- API Standard 65-2 provides sufficient direction for planning and evaluating the cementing operation

- 250.420(a)(6) - "Provide adequate centralization to ensure proper cementation." Industry requests codification of BSEE's interpretation that evaluation of adequacy per API 65-2 is sufficient.

- 250.428(c)&(d) – Indications of an inadequate cement job. Industry requests revision of the language to allow for technological advances to help analysis and determine whether an operation is successful . Allow adequacy of cement jobs to be evaluated based on well specific objectives.

- 250.518(e)(1) & 250.619(e)(1) & 250.1703(b) – BSEE should codify clarification that if a packer or bridge plug is not being used or qualified as a mechanical barrier (e.g. sump packer), it is not required to comply with API Spec 11D1.

Containment

Mike Drieu, Anadarko

Containment Comments

- Recommended retaining 250 462 (d) with revisions
- BSEE interpretation stated “recognized equipment owned by the SCEE consortiums” as the focus for the inspections
- No response to the Joint Trade Letter clarifying inspections are limited to “uniquely” designated equipment which is not used for other commercial uses/purposes.
- Should industry assume that BSEE concurs with industry interpretation or does BSEE have a different view?

Recommendation

Revised regulatory text to add “uniquely designed equipment not used for other commercial use (e.g. capping stacks, subsea dispersant wands and manifolds) owned by SCEE consortiums as scope for inspections.”

Containment

- Industry has provided comments to 250.462(a) supporting well containment analysis by factoring well control for designing subsea wells.
- 250.462(b) should be updated to set a performance standard on well containment and not specific equipment requirements as it prevents technology advancements.
- Any specific equipment requirements should be based on the well containment analysis outlined in 250.462.(a) (i.e. cap and flow equipment not required for well designed for full shut-in)

Recommendation

- Remove prescriptive regulatory text in 250.462(b) and update equipment requirements to tie to the BSEE defined well containment analysis in 250.462(a).

Containment – Capping Stack Testing

- The current practice with BSEE working with HWCG and MWCC and their OEMs has worked well for several years with no set backs

Recommendation:

- Eliminate the need for BAVOs for witnessing Capping Stack testing in addition to BSEE
- If BSEE needs to designate Third Party witnessed testing in lieu of BSEE witnessing, recommend working with HWCG, MWCC and OEMs for establishing capping stack pressure testing requirements

API 53

Ricky Cummings

After April 20, 2010

- Immediately Industry recognized the need establish a new baseline for operating BOPE
- Industry SME's joined together and provided direction to strengthen API *Recommended Practice* 53
- Published the now API *Standard* 53 (API 53) in 2012
- During the development, when challenges were met, two priorities were established over all others:
  - **HUMAN LIFE** then **ENVIRONMENT**
  - All else was deemed tertiary
- Priority aligned well with then MMS (BSEE) and US Coast Guard

API RP 53 Transition to Standard

- Need for Standardization – everyone operate identically
- Operators, Drilling Contractors, Equipment Manufacturers, 3rd Party Inspectors and Regulatory Bodies participated in the Standard Revision
- Industry worked diligently for two years to accelerate the development of the document.

Standardization

- Standardization – continues to be the most important contribution to the industry for the 4th Edition of API Standard 53
- Accepted globally as a recognized petroleum and natural gas industry standard
- All of industry operates on the same level 'SAFE' playing field
- Incremental requirements above API 53 increase cost, complexity, risk and may reduce reliability

API Standard 53 Progress

- Published Addendum 1 in July 2016, to address FAQ's and clarifications on the intent contained within API 53
  - Addressed Subsea BOP "well hop" testing criteria
  - Clarified that equipment be maintained in accordance with the requirements of the edition of the applicable specification used for its manufacture
    - Newer editions should be used for mods, remanufactured or replacement equipment
  - Clarified start criteria for 5 year major inspection periods

API 53 – 5th Edition Proposals

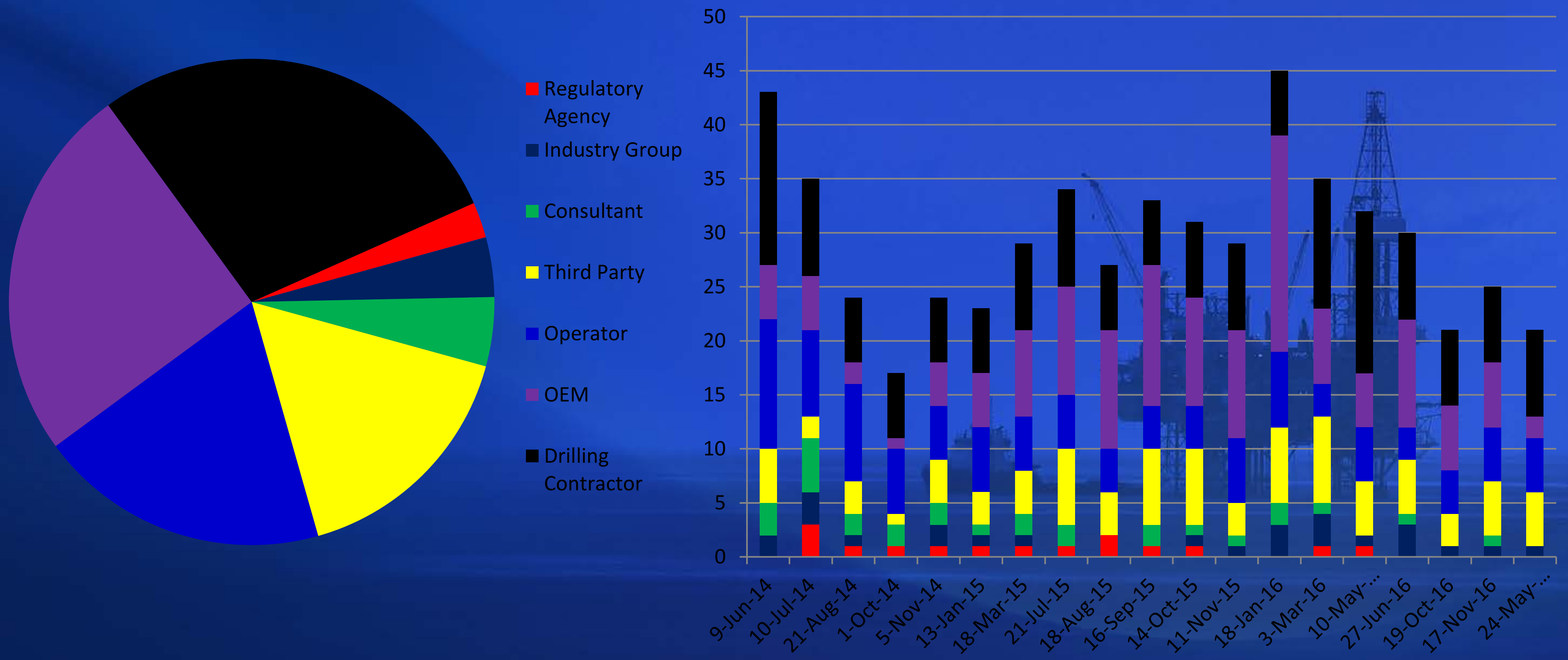
- Removed “informative” language in lieu of more “normative” language – Standardization
- Transferred equipment design/manufacturing criteria to the applicable product specification
- Incorporated state and other regulatory input in order to facilitate API 53 integration with regulations
    - API 53 Task Group identified a need to develop a land-focus group to address surface BOP requirements

API 53 – 5th Edition Proposals

- Surface BOP Pressure Requirements
  - Originally BOP requirements were dictated by the RWP of the BOPs
  - Shifting to BOP requirements driven by MASP of well and not RWP of available equipment
- N2 Back-up for BOP Controls
- Testing Section improvements/clarifications to text/tables
- Surface Testing requirements for Land BOPs

API 53 Participation

- Steady participation from industry



Examples of Conflicts

- 250.737(d)(5) – “double function testing”
  - **<u>Both</u>** pods/panels weekly instead of alternating as per API 53
  - 90% & 82% Increase over API 53

Testing Increase
Rams & Annulars

API S53- Tests on VBR/Ann		
0	P	F
7	F	
14		F
21	P	
28		F
35	F	
42		P
49	F	
56		F
63	P	
70		F
77	F	
84		P
91	F	
98		F
105	P	
112		F
119	F	
126		P
Closures	20	
P Cycles	7	

Old CFR - Tests on VBR/Ann		
0	P	F
7	F	
14		P
21		F
28	P	
35	F	
42		P
49		F
56	P	
63	F	
70		P
77		F
84	P	
91	F	
98		P
105		F
112	P	
119	F	
126		P
Closures	20	
P Cycles	10	

Old CFR % Increase	
Closures	0%
P Cycles	43%

New CFR - Tests on VBR/Ann		
0	P	F
7	F	F
14	P	F
21	F	F
28	F	P
35	F	F
42	P	F
49	F	F
56	F	P
63	F	F
70	P	F
77	F	F
84	F	P
91	F	F
98	P	F
105	F	F
112	F	P
119	F	F
126	P	F
Closures	38	
P Cycles	10	

New CFR % Increase	
Closures	90%
P Cycles	43%

Comparison of Old & New CFR Testing Requirements versus Standard 53
- Major increase in closures
- Life expectancy of equipment will be reduced

Testing Increase
BSRs

API S53 - Tests on BSR/CSR		
0	P	F
7		
14		
21	F	
28		P
35		
42		
49		F
56	P	
63		
70		
77	F	
84		P
91		
98		
105		F
112	P	
119		
126		P
Closures	11	
P Cycles	6	

Old CFR- Tests on BSR/CSR		
0	P	F
7		
14	F	
21		
28		P
35		
42		F
49		
56	P	
63		
70	F	
77		
84		P
91		
98		F
105		
112	P	
119		
126	P	
Closures	11	
P Cycles	6	

Old CFR % Increase	
Closures	0%
P Cycles	0%

New CFR - Tests on BSR/CSR		
0	P	F
7		
14	F	F
21		
28	F	P
35		
42	F	F
49		
56	P	F
63		
70	F	F
77		
84	F	P
91		
98	F	F
105		
112	P	F
119		
126	F	P
Closures	20	
P Cycles	6	

New CFR % Increase	
Closures	82%
P Cycles	0%

Examples of Conflicts

- 250.737(a)(2)
  - CFR requires 14-day pressure test cycles while globally 21-day testing is utilized per API 53
  - 2009 West Engineering study of almost 90,000 individual pressure tests concluded proper interval as long as 32 days.
  - Operators have approached BSEE on numerous occasions proposing 21-day performance based pilot programs but have been denied without technical justification.
  - In order to obtain new data to validate no additional risk, BSEE must work collaboratively with industry.
  - Additional risk (safety and well success) and cost are not justified. BSEE has provided no technical justification or data to substantiate difference from Industry recommended interval.

Examples of Conflicts

- 250.737(d)(2) – high pressure test value for Blind Shear Ram type BOPs
  - API 53 recommends 'casing test pressure' while BSEE mandated MASP+500 psi despite Industry's warning of increased risk without justification.
  - In October 2016, testing to MAWP+500 resulting in 1 Operator failing a subsea wellhead.
  - BSEE subsequently began to accept casing pressure for subsequent BSR tests in recognition of the increased risk.
  - BSEE should revise the rule to codify the BSR pressure testing requirements as recommended by Industry, in alignment with API 53 and currently accepted alternative compliance.

Short Term Recommendations

- Delay effective dates of any requirements that exceed API 53 that have not gone into effect
- Incorporate by reference the 4th Edition Addendum
- Remove reference to equipment specifications (API 16A, C, and D)

Long Term Recommendations

- Reference API 53 5th Edition
- Eliminate any requirements that exceed API 53

Closing Comments

- Since API 53 4th edition has been published, industry now has one international document for standardized inspections, testing, and maintenance on blowout preventers.
- API 53 4th Edition has been serving the industry for 5 years, industry has recognized improvements to the Standard which will be reflected in the 5th Edition.
- The 5th Edition document continues to improve through collaboration between industry personnel and regulatory bodies.

BSEE Approved Verification Organizations

Tony Hogg, Pacific Drilling

BAVOs

Noticeably absent from the preamble to the WCR, was any explanation of why a BAVO was needed to perform a number of enumerated reporting, verification, and certification requirements related to BOP systems and equipment.

BAVO requirement s create a new redundant level of scrutiny that threatens to dramatically increase compliance and operating costs for OCS operators and equipment owner's, without establishing that it will achieve any measurable enhancement in offshore safety.

On 1 May 2017, Secretary Zinke signed an order that directed BSEE to re-evaluate the WCR, including "prescriptive measures that are not needed to ensure safe and responsible development of our OCS resources."

250.732(d)

- Once every twelve months, you must submit a Mechanical Integrity Assessment Report for a subsea BOP, BOP being used in an HPHT environment as defined in 250.807, or a surface BOP on a floating facility. This report must be compiled by a BAVO.

- This report is a good example of what we believe the Presidential Order is referring to. The APD contains sufficient information to clarify the status of the well control equipment. The MIA Report would duplicate the already submitted information. Costs can be saved by not producing it and BSEE not having to analyze and check it, without there being any meaningful reduction in oversight.

250.739(b)

- A complete breakdown and detailed physical inspection of the BOP and every associated system and component must be performed every five years.
  - A BAVO is required to be present during each inspection and must compile a detailed report documenting the inspection, including descriptions of any problem and how they were corrected.
  - Q&A 27 Jul 2016: Is the BAVO only required to be present during the five-year breakdown and inspection, and not required to be present during any repairs or remanufacturing work at any location?
  - A; In accordance with 250.739(b), a BAVO is only required to be present for the 5-year complete breakdown and detailed physical inspection of the BOP system.
- Recommendation to revert to API 53 requirements for inspection and maintenance requirements. I3P verification of maintenance and inspection required by 250.731(c)

BAVOs

- There are several specific questions/problems related to the BAVO program:
  - Qualifications of BAVO personnel.
  - Oversight of BAVO operations.
  - When, exactly, a BAVO is required to be engaged (or disengaged).
  - How to handle disputes.

Short Term Recommendations

- Do not publish BAVO list; continue utilization of I3Ps for verification
- Formally cancel the MIA requirement (250.732(d))

Long Term Recommendations

- Remove BAVO requirements and 250.732 in their entirety
- Reference API 53 for maintenance and inspection requirements of BOP equipment
- Revert to Interim Safety Rule requirements for I3P verification (previously outlined in 250.416(e), (f), and (g))

Shearing Requirements

250.732 – General Requirements for BOP Systems

- What are the general requirements for BOP systems and system components?
  - (a) Certifications / Verifications / Reports must be compiled by a BSEE Approved Verification Organization (BAVO) or Independent 3rd Party; BAVO list available within 1 yr of WCR release
  - (b) Shear Testing:
    - By April 2018, BOP must shear drill pipe, electric, wire, and slick line
    - Testing must be conducted on outermost edge of Ram shearing blade
    - Post shear pressure test must be 30 minutes minimum
    - Provide calculations for shearing and sealing under MASP conditions
  - (c) HPHT wells require additional review by BSEE / BAVO
  - (d) 12 month Mechanical Integrity Assessment (MIA) required on Subsea BOPs, HPHT, and Surface BOPs on a floating facility

250.733 – Surface BOP Stack requirements

- What are the requirements for a surface BOP Stack?
  - (a) Regardless of rated working pressure, BOP Stack must be minimum Class 4-A1-R3 consisting of: 1x Annular, 1x Blind Shear Ram, and 2x Pipe or VBR Ram
  - (a)(1) Blind Shear Rams must shear/seal tubular body of drill pipe, workstring, & tubing
    - Must shear electric/slickline by April 2018
    - If you cannot shear by date, alternative means must be located on the drill floor of the rig
  - (b) After April 2019, Surface BOPs on floating rigs must conform to 250.734 (a)(1), including Dual Shear Rams

250.734a – Subsea BOP System requirements

- What are the requirements for a subsea BOP system (shearing)?
  - (a)(1) Minimum Class 5-A1-R4 including: 1x Annular, 2x Shear Rams, & 2x Pipe Rams
    - Shear the tubular body of drill pipe, workstring, & tubing
    - At least one shear ram must be capable of sealing the wellbore under MASP
    - Shear Wire/Slickline – April 2018
    - Dual Shear Rams – April 2021
  - (a)(16)(i) Mechanism coupled with each shear ram to position the pipe within the shearing blade by May 2023
    - Planned shear events may use Annular or Ram BOP for positioning prior to shearing
    - Non-planned shears may not use another ram or annular for positioning
  - (a)(16)(ii) BOP must mitigate compression of the pipe between dual shear rams when both are closed

Subsea Accumulator Volume Requirements

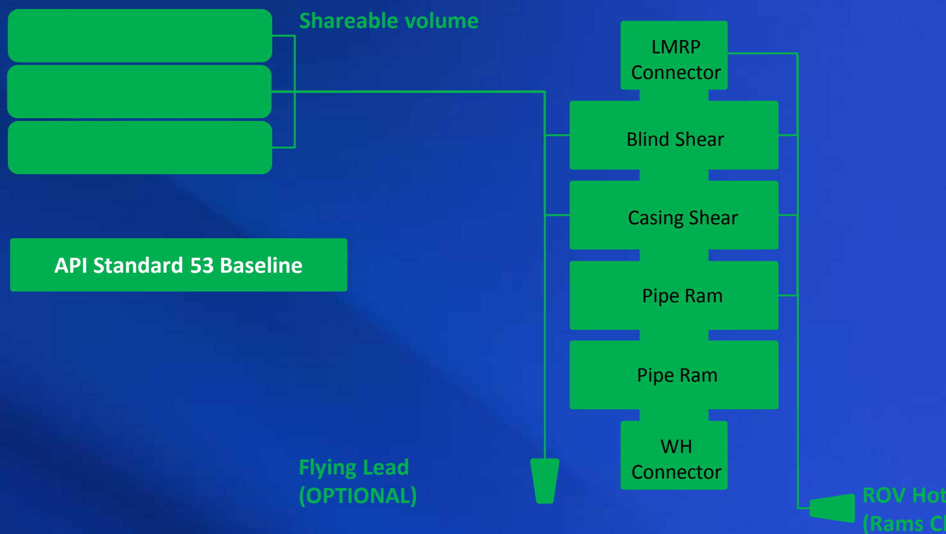
Pete Bennett, Pacific Drilling

Subsea Accumulator Volume Requirements

- Draft BOP Well Control Rule contained numerous problematic accumulator requirements
- Final Rule remedied some issues, generally via greater incorporation of API Standard 53 requirements, now is the time for further incorporation of API 53 requirement
- WCR requirements associated with 5-year implementation for modification to global industry standard for subsea accumulators should be delayed to prevent unintended consequences while the WCR is further reviewed
- Incremental BSEE requirements above API Standard 53 add additional equipment and increase complexity without adequate justification or support
- Industry does not believe there is a need for further accumulator redundancy above those outlined in API 53

Subsea Accumulator Design and Testing

- Consistent with BSEE clarification, accumulator sizing requirements should be aligned with API 53 and the referenced sections of API 16D
- Accumulator drawdown test requirement should be updated to be consistent with API 53 (6.5.6.2; 7.3.9; 7.4.6.4)
- Frequency of accumulator drawdown test requirements should be clarified as outlined in API 53
- Current WCR requirements are ambiguous and not aligned with global standards



	Volume (gals)	Weight (MT)
API S53	W	W

Example Baseline*

API Standard 53 – Minimum Subsea Accumulator Setup

**assumes floater operating in ~6000ft water depth with 15ksi subsea BOP*

- BOP requirements in API Standard 53 establish multiple levels of redundancy which means it is highly unlikely that DMAS or ROV functionality would be needed to mitigate a potential loss of well control event
  - Such a scenario would require multiple low likelihood failure events across a range of systems and specific wellbore conditions
- Subsea accumulators for DMAS circuits secure the well by closing shear rams and ram locks
  - Volume can be shared with other secondary control systems: Acoustic, flying leads / ROV
- ROV functionality is required to enable closing each shear ram, one pipe ram, ram locks and unlatching the LMRP connector
  - API Standard 53 allows three different methods for supplying the necessary power fluid: ROV, stack mounted accumulators (which may be a shared system), or an external hydraulic power source that shall be maintained at the well site
- Industry's position is that pipe ram and LMRP functions are not critical for securing the well
  - Subsea accumulators may be recharged after securing the well or ROV intervention may be utilized in order to function the pipe ram or LMRP connector, if needed

Regulatory Text Proposal – 250.734 (a) (3)

- The following regulatory text is proposed as an update to 250.734 (a) (3) to further clarify the requirements:
- (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;
- *(Current regulation text)*
- 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.

- *(Proposed regulatory text)*

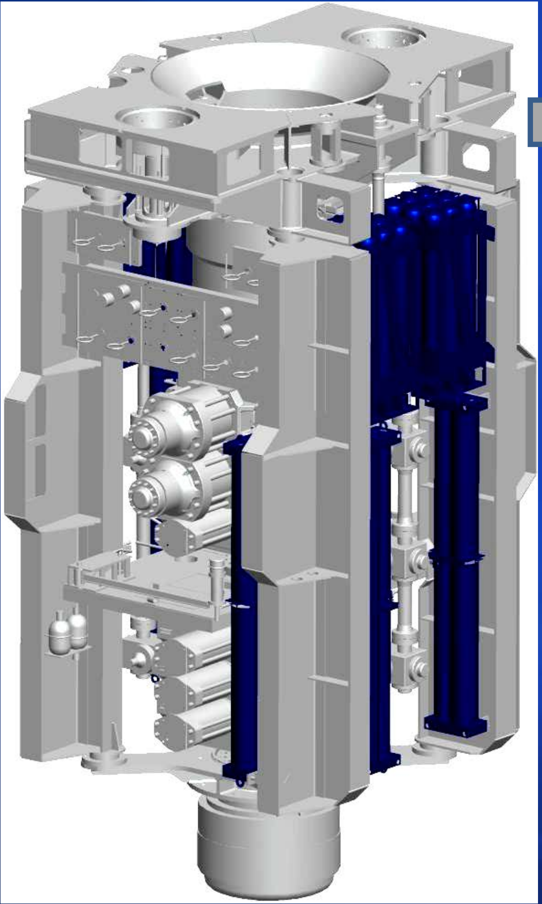
(3) Have the accumulator capacity located subsea, to provide fast closure of the BOP components and to operate all critical functions in case of a loss of the power fluid connection to the surface:

The accumulator system design and sizing calculations must:

(i) No later than April 29, 2021, have bottles for the autoshear / deadman (which can be shared between those two systems) to secure the wellbore, but can also be utilized to perform the ROV secondary critical functions or acoustic functions, if applicable to secure the well (API STD 53 7.3.18, 7.3.19, and 7.3.20; or 7.4.14, 7.4.15, and 7.4.16).

(ii) Include MASP in the Minimum Operation Pressure calculation to secure the well then seal with the autoshear / deadman functions.

Consequences of Incremental Requirements



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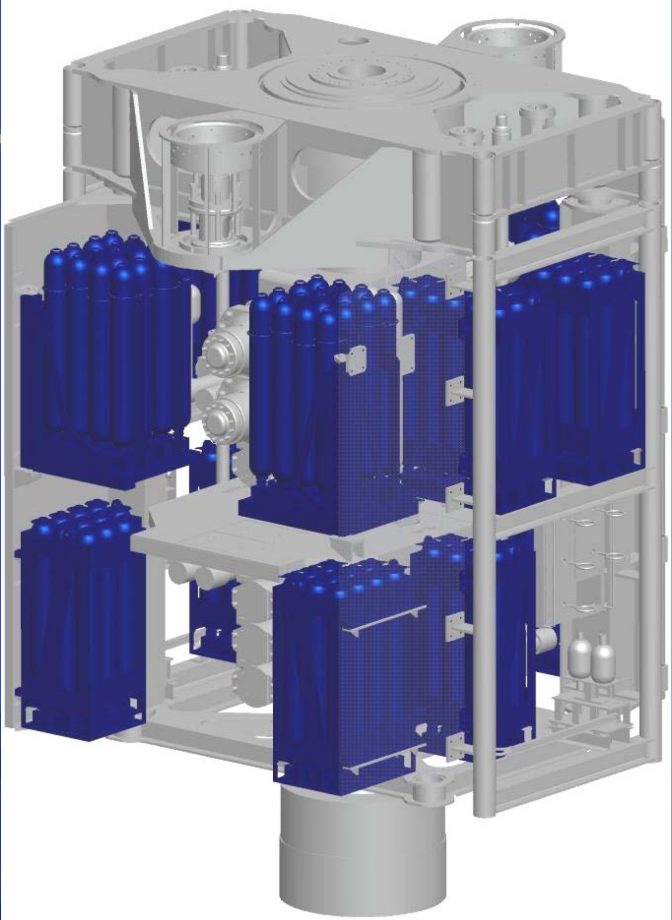

Subsea Accumulator Conclusions

Short Term Recommendations:

- Delay effective dates of any incremental requirements to API 53 that are not currently in effect

Long Term Recommendations:

- Incorporate API 53 and eliminate any incremental requirements
  - Emergency Accumulators have the capacity to close the critical functions under API 53 requirements
  - To add further accumulators adds weight, restrict access for maintenance, restrict ROV view & access, creates further leak paths and adds complexity
  - Wellheads, BOP transport systems and cranes were not designed for the additional BOP weight
  - Incremental requirements will impact competitiveness of OCS projects without enhancing safety

Codifying Interpretations

BSEE Clarification Overview

- BSEE has posted clarifications to the final Well Control Rule online.
- A total of 98 questions have been answered and posted from June 6, 2016 through Dec. 30, 2016. Approximately 70 relating to section Subpart G Well Operations and Equipment (250.7xx). These clarifications have been important in the implementation of the rules by industry.
- Clarifications were the result of collaboration between industry representatives and BSEE personnel and were developed within certain rules/limitations.
- During the next opportunity to revise the current rules, it would be appropriate for BSEE and industry to conduct a specific process of reviewing the clarifications with the goal of identifying:
  - Existing Clarifications that should be codified as is.
  - Clarifications that need to be modified before codification.
  - Additional clarification requests that have not yet been addressed, and codifying those.

SUMMARY

- Safety is a core value of the oil and natural gas industry
- We share the government's goal of enhancing offshore safety while producing more oil and natural gas here at home
- We support effective regulations in the area of blowout preventer systems and well control
- Significant portions of the final rule increase risk and decrease safety
- A number of provisions must be revised
- BSEE and industry must work together to finalize a new rule with our shared safety objectives

BSEE Public Forum on Well Control and Blowout Preventer Rule

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