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Analysis of Current Cementing Procedures Employed in the US Outer Continental Shelf: Optimized Methods

REN0146

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Definitions

Term	Definition
AADE	American Association of Drilling Engineers
APB	Annular Pressure build-up
API	American Petroleum Institute
BHA	Bottom Hole Assembly
BHCT	Bottom Hole Circulating Temperature
BHST	Bottom Hole Static Temperature
BOEM	Bureau of Ocean Energy Management
BOEMRE	Bureau of Ocean Energy Management, Regulation and Enforcement
BOP	Blow Out Preventer
BSEE	Bureau of Safety and Environmental Enforcement
BWOW	By Weight of Water
CFR	Code of Federal Regulations
CUP	Condition Under Pressure
E&P	Exploration and Production
ECD	Equivalent Circulating Density
FIT	Formation Integrity Test
GOM	Gulf of Mexico
HP/HT	High Pressure / High Temperature
IADC	International Association of Drilling Contractors
ISO	International Organization for Standardization
LCM	Lost Circulation Material
LOT	Leak-Off Test
LWD	Logging while Drilling
MD	Measured Depth
MWD	Measurement while Drilling
N_2	Nitrogen
O&G	Oil and Gas
OBM	Oil-Based Mud
OCS	Outer Continental Shelf
OTC	Offshore Technology Conference
PBR	Polished Bore Receptacle
QA	Quality Assurance
QC	Quality Control
R&D	Research and Development

ROP	*Rate of Penetration*
ROV	*Remote Operated Vehicle*
RP	*Recommended Practice*
SBM	*Synthetic-Based Mud*
SCP	*Sustained Casing Pressure*
SPE	*Society of Petroleum Engineers*
STD	*Standard*
SWF	*Shallow Water Flow*
TD	*Total Depth*
TOC	*Top of Cement*
TVD	*True Vertical Depth*
WBM	*Water-Based Mud*
WOC	*Wait on Cement*

Table 1 Definitions

Objective

- Identify and analyze current cementing practices in the OCS with accompanying technical justification.
- Identify specific current cementing practices or environments that result in a safety risk and propose safer alternatives.
- Develop a relational database for efficient access to the current cementing operational guidelines.
- Identify required research and development (R&D) areas to address cementing operations for which no acceptably safe method exists.

Conclusions

- Very few cementing best practices are applicable across all cementing environments in the Outer Continental Shelf. There are five global best practices which encompass cementing operations worldwide.
    1. Perform sound Pre-Job engineering design and simulation for cementing operations based on clearly defined job objectives
    2. Use defined job objectives to tailor the pre-job work into a final placement design fit to be executed in the as-drilled well
    3. Blend cement as the design dictates
    4. Mix and place cement as the design dictates
    5. Incorporate case specific cementing operational guidelines and lessons learned which have been developed from highly experienced and knowledgeable individuals and historical offset well data into all cement designs
- While this document does not address lessons learned for any particular fields or blocks, it does provide a situational guide for cementing across several common OCS environments. When cementing a well, there is no substitute for the knowledge gained from wells that are similar in design or close in proximity. Data acquired and lessons learned from these wells will provide the best template for cementing success.
- There are many areas within the OCS where additional R&D study can be implemented for better fundamental understanding of technical issues facing the GOM. Two areas were focused on as part of this project which includes mixing energy vs. total mixing time and fluid loss measurement procedures and variances in their results.

Summary of Results

Discussed below are summaries of the main conclusions derived from the literature review, analysis of general and case specific guidelines, operational improvements, and technology deficits.

Identification of Candidate Wells

A total of five generalized candidate wells were developed to represent the complete range from easy and straightforward to complex and technically challenging. Each cemented casing string was analyzed to provide an accurate assessment of current state of the art for cementing in the GOM.

Literature Review

Upon review of technical literature sources it was found that appropriate attention has been given to cement design and formulation for short-term isolation in most cases, but investigators have paid relatively little attention to long-term zonal isolation. Multiple factors affect the outcome of all cementing operations and several case specific operational guidelines are already in place to address some of these factors. There are novel solutions on the horizon of cementing but several have not been fully field tested.

General Operational Guidelines

The general cementing operational guidelines have been categorized into four major subsections. These subsections relate to: drilling, casing, dry cement/additive considerations, and cement placement. Current cementing practices and recommended cementing operational guidelines are proposed and discussed further in each of these sections

Case Specific Operational Guidelines

The five generalized well-bore schematics which covered the majority of drilling and primary cementing environments in the OCS were used as tools to cover case specific cementing operational guidelines. These well-bore schematics are shown within section 2 below. Case specific cementing guidelines covered within this section include: initial casing strings, intermediate casing strings, production strings, tieback liners, case specific formation considerations, and remedial cementing.

Case Specific Operational Improvements

Case specific operational practices vary from operator to operator. Each has their own inherent case specific technical difficulties which must be overcome by sound engineering design and lessons learned from offset historical well data.

Areas in Need of Additional Research and Development

From the mixing energy study, it was found that variances in slurry performance characteristics were dependent on both applied mixing energy and total mixing time. Variance was negligible for mixing energies at or above API mixing schedule. From the fluid loss study, it was found that any of the three fluid loss testing methods generally give comparable results for test temperatures below 190°F. As a safety factor, the stirred method should be used for systems above 190°F since the largest fluid loss measurements were observed from this test method.

Detailed Discussion of Results

1 Formation of Industry Steering committee

Representatives from a broad spectrum of operating companies (large and small, operating shallow and deep) have formed a broad, balanced point of view. Each participating company has provided input relating to general cementing operational guidelines for representative wells that have formed the basis for safety analysis and established guidelines for cementing practices and identification of deficient areas. We will cover a broad geological cross section and varied conditions in the OCS, including challenging cementing conditions in deep water such as the predominately oil reservoirs like the lower tertiary trend, primarily gas reservoirs in the eastern GOM like the Miocene trend and some of the deep HP/HT wells drilled on the shelf.

2 Identification of Candidate Wells

The study utilized 5 general GOM well types. These are: Generic Well #1: deep-water well through salt zone; Generic Well #2: shelf well through salt zone; Generic Well #3: deep-water well with no salt zone; Generic Well #4: deviated shelf well; and Generic Well #5: HP/HT shelf well. These wells are purely examples based on wells drilled within the OCS, actual well designs in the OCS will vary. Schematics are presented below along with representative hole sizes, casing sizes, depths, drilling fluid types, temperature gradients, and pressure gradients. For each of these general well types, specific recommendations for cementing each casing string were developed and are presented here. Any cementing practices posing a safety risk are highlighted along with possible approaches for mitigating the risk. Additionally, any general cementing guidelines discussed in this report that apply specifically to a casing string will be cited for more in depth reference located in the later sections of this report.

CSI TECHNOLOGIES
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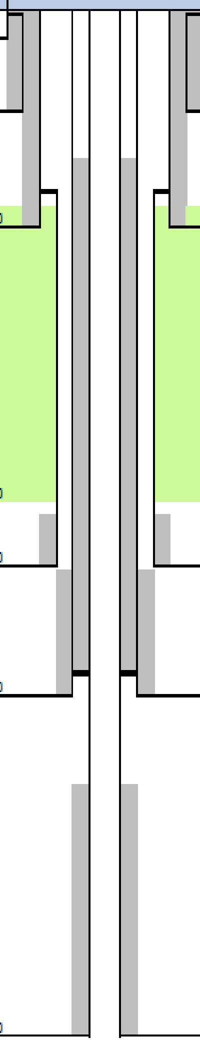
2.1 Well #1: Deep-Water Well through Salt Zone

Generic Well #1



Formation/Directional	TVD	MD	Casing Size	Weight	Cement Information	Mud Type	Mud Weight	Frac Gradient
	75	75						
	6000	6000						
	6300	6300	36"					
	7900	7900	28"	218	TOC @ ML	WBM	9.4	
Top of Salt	9800	9800						
	10400	10400	22"	227	TOC @ ML	WBM	9.5	10
Bottom of Salt	17500	17500						
	19000	19000	16"	97	TOC @ 18000'	SOBM	13	13.8
			Tieback 10 1/8"	79.29	Tieback TOC @ 8000'			
	21500	21600	13 5/8"	88.2	TOC @ 19300'	SOBM	14	14.6
	29000	30400	10 1/8"	79.29	TOC @ 24000'	SOBM	14.6	15.7

Figure 1 Well #1 – Deep-water Well through Salt Zone

2.1.1 Casing #1 – 28" Conductor Casing

Table 2 below discusses the casing hardware and common cementing risks for this casing string.

28" Conductor Casing Summary			
Casing Inner Diameter	26.5"	Previous Casing Inner Diameter	Drive Pipe
Open Hole Diameter	Drill with 26" Bit, Under ream to 32"	Previous Casing Outer Diameter	36"
Measured Depth	7900'	Previous Casing Measured Depth	6300'
True Vertical Depth	7900'	Previous Casing True Vertical Depth	6300'
Placement Technique	Inner String	Notable Formations	Unconsolidated Sands
Common Cementing Risks and Considerations	• Shallow Hazards (gas or water flow zones) • Lost Circulation • Hole Stability • Riserless (fluid returns to seafloor) • Narrow pore/frac windows • Large annular volumes • Volume ratio of shoe track and rathole • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.1.1, and 3.2.5 below		

Table 2 Well #1 – 28" Conductor Casing Summary

2.1.2 Casing #2 – 22" Surface Casing

Table 3 below discusses the casing hardware and common cementing risks for this casing string.

22" Surface Casing Summary			
Casing Inner Diameter	20"	Previous Casing Inner Diameter	26.5"
Open Hole Diameter	26"	Previous Casing Outer Diameter	28"
Measured Depth	10400'	Previous Casing Measured Depth	7900'
True Vertical Depth	10400'	Previous Casing True Vertical Depth	7900'
Placement Technique	Inner String	Notable Formations	Salt Zone, Possible Rubble Zone above Salt Zone
Common Cementing Risks and Considerations	• Shallow Hazards (gas or water flow zones) • Lost Circulation • Salt formation considerations • Hole Stability • Riserless (fluid returns to seafloor) • Narrow pore/frac windows • Large annular volumes • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.1.1, and 3.2.5 below		

Table 3 Well #1 – 22" Surface Casing Summary

2.1.3 Casing #3 – 16” Intermediate Liner

Table 4 below discusses the casing hardware and common cementing risks for this casing string.

16" Intermediate Liner Summary			
Casing Inner Diameter	14.85”	Previous Casing Inner Diameter	20”
Open Hole Diameter	18.125”	Previous Casing Outer Diameter	22”
Measured Depth	19000’	Previous Casing Measured Depth	10400’
True Vertical Depth	19000’	Previous Casing True Vertical Depth	10400’
Placement Technique	Liner (Through Tubing)	Notable Formations	Salt Zone, Possible Rubble Zone below Salt Zone
Common Cementing Risks and Considerations	• Salt formation considerations • SBM displacement • Lost Circulation, usually at the base of salt • Riser margin • Large cement volumes • APB potential • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.2, and 3.2.5 below		

Table 4 Well #1 – 16" Intermediate Liner Summary

2.1.4 Casing #4 – 13 5/8" Intermediate Casing

Table 5 below discusses the casing hardware and common cementing risks for this casing string.

13 5/8" Intermediate Casing Summary			
Casing Inner Diameter	12.375"	Previous Casing Inner Diameter	14.85"
Open Hole Diameter	Drill with 14" Bit, Under ream to 17"	Previous Casing Outer Diameter	16"
Measured Depth	21600'	Previous Casing Measured Depth	19000'
True Vertical Depth	21500'	Previous Casing True Vertical Depth	19000'
Placement Technique	Casing Displacement	Notable Formations	NA
Common Cementing Risks and Considerations	• Large displacement volume • Volume ratio of shoe track and rathole • Mud compressibility • SBM Displacement • Potential flow zones present • CFR may dictate TOC • Potential trapped annulus and subsequent APB • Potential lost circulation • Considerations and operational guidelines can be viewed within sections 3.1 and 3.2.2 below		

Table 5 Well #1 – 13 5/8" Intermediate Casing Summary

2.1.5 Casing #5 – 10 1/8" Production Liner

Table 6 below discusses the casing hardware and common cementing risks for this casing string.

10 1/8" Production Liner Summary			
Casing Inner Diameter	8.5"	Previous Casing Inner Diameter	12.375"
Open Hole Diameter	Drill with 12.25" Bit, Under ream to 14"	Previous Casing Outer Diameter	13.625"
Measured Depth	30400'	Previous Casing Measured Depth	21600'
True Vertical Depth	29000'	Previous Casing True Vertical Depth	21500'
Placement Technique	Liner (Through Tubing)	Notable Formations	Production Interval
Common Cementing Risks and Considerations	• Fluid Migration • SBM displacement • Volume ratio of shoe track and rathole • TOC will be dictated by CFR requirements • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.3.1, 3.2.3.2, and 3.2.5.1 below		

Table 6 Well #1 – 10 1/8" Production Liner Summary

2.1.6 Casing #6 – 10 1/8" Tieback

Table 7 below discusses the casing hardware and common cementing risks for this casing string.

10 1/8" Tieback Summary			
Casing Inner Diameter	8.5"	Previous Casing Inner Diameter	12.375"
Open Hole Diameter	NA	Previous Casing Outer Diameter	13.375"
Measured Depth	21100'	Previous Casing Measured Depth	21600'
True Vertical Depth	21000'	Previous Casing True Vertical Depth	21500'
Placement Technique	Through Casing	Notable Formations	Extra coverage of salt zone
Common Cementing Risks and Considerations	• Casing collapse from salt creep • Pressure limitations of casing equipment • SBM displacement • Cementing unit HHP • Cement shrinkage due to casing/casing annulus • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.4, and 3.2.5.2 below		

Table 7 Well #1 – 10 1/8" Tieback Summary

2.2 Well #2: Shelf Well Through Salt Zone

Generic Well #2

Formation/Directional	TVD	MD	Casing Size	Weight	Cement Information	Mud Type	Mud Weight	Frac Gradient
	150	150						
	520	520						
	850	850	36"					
	1500	1500	24"		TOC @ ML	WBM	9.2	
	4000	4000	18 5/8"	94.5	TOC @ ML	WBM	10	12
KOP	6000	6000						
Top of Salt Zone	7700	7800						
	8000	8100	13 5/8"	88.2	TOC @ 5500'	WBM	13.5	14.5
			7 3/4"	46.1	TieBack String TOC @ 7800'			
Bottom of Salt Zone	11500	11900						
	13200	13700	9 7/8	62.8	TOC @ TOL (8000')	WBM	16.8	17.8
	14800	15500	7"	35	TOC @ TOL (13600')	WBM	16.5	17.5

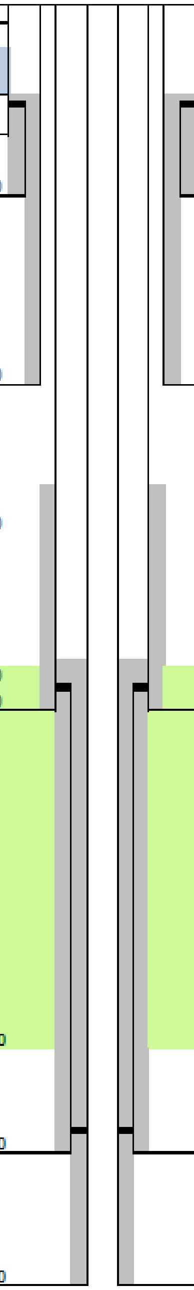


Figure 2 Well #2 - Shelf Well Through Salt Zone

2.2.1 Casing #1 – 24" Conductor Liner

Table 8 below discusses the casing hardware and common cementing risks for this casing string.

24" Conductor Liner Summary			
Casing Inner Diameter	20.525"	Previous Casing Inner Diameter	Drive Pipe
Open Hole Diameter	Drill with 26" Bit, Under ream to 32"	Previous Casing Outer Diameter	36"
Measured Depth	1500'	Previous Casing Measured Depth	850'
True Vertical Depth	1500'	Previous Casing True Vertical Depth	850'
Placement Technique	Liner (through tubing)	Notable Formations	Unconsolidated Sands
Common Cementing Risks and Considerations	• Shallow Hazards (gas or water flow zones) • Lost Circulation • Hole Stability • Liner hanger pressure restrictions • Narrow pore/frac windows • Large annular volumes • Volume ratio of shoe track and rathole • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.1.2, 3.2.5.1, 3.2.5.3, and 3.2.5.4 below		

Table 8 Well #2 – 24" Conductor Casing Summary

2.2.2 Casing #2 – 18 5/8" Intermediate Casing

Table 9 below discusses the casing hardware and common cementing risks for this casing string.

18 5/8" Intermediate Casing Summary			
Casing Inner Diameter	17.689"	Previous Casing Inner Diameter	20.525"
Open Hole Diameter	Drill with 18" Bit, Under ream to 21.5"	Previous Casing Outer Diameter	24"
Measured Depth	4000'	Previous Casing Measured Depth	1500'
True Vertical Depth	4000'	Previous Casing True Vertical Depth	1500'
Placement Technique	Inner String	Notable Formations	Possibility of Unconsolidated Sands
Common Cementing Risks and Considerations	• Cement column temperature differential • Large cement volume to be pumped • ECD considerations • Potential shallow hazards • Volume ratio of shoe track and rathole • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.1.2, 3.2.2, 3.2.5.1, 3.2.5.3, and 3.2.5.4 below		

Table 9 Well #2 – 18 5/8" Intermediate Casing Summary

2.2.3 Casing #3 – 13 5/8" Intermediate Casing

Table 10 below discusses the casing hardware and common cementing risks for this casing string.

13 5/8" Intermediate Casing Summary			
Casing Inner Diameter	12.375"	Previous Casing Inner Diameter	17.689"
Open Hole Diameter	Drill with 14" Bit, Under ream to 17"	Previous Casing Outer Diameter	18.625"
Measured Depth	8100'	Previous Casing Measured Depth	4000'
True Vertical Depth	8000'	Previous Casing True Vertical Depth	4000'
Placement Technique	Casing Displacement	Notable Formations	Entering salt zone, possible rubble zone above salt
Common Cementing Risks and Considerations	• Salt formation considerations • Lost circulation • Large cement volumes • Volume ratio of shoe track and rathole • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.1.1, 3.2.2, and 3.2.5 below		

Table 10 Well #2 – 13 5/8" Intermediate Casing Summary

2.2.4 Casing #4 – 9 7/8" Intermediate Liner

Table 11 below discusses the casing hardware and common cementing risks for this casing string.

9 7/8" Intermediate Liner Summary			
Casing Inner Diameter	8.625"	Previous Casing Inner Diameter	12.375"
Open Hole Diameter	12.25"	Previous Casing Outer Diameter	13.375"
Measured Depth	13700'	Previous Casing Measured Depth	8100'
True Vertical Depth	13200'	Previous Casing True Vertical Depth	8000'
Placement Technique	Liner (through tubing)	Notable Formations	Salt zone, possible rubble zone below salt zone
Common Cementing Risks and Considerations	• Salt formation considerations • SBM displacement • Lost Circulation • Large cement volumes • APB potential • Recommended improved practice to hang liner above salt zone • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.2, and 3.2.5 below		

Table 11 Well #2 – 9 7/8" Intermediate Liner Summary

2.2.5 Casing #5 – 7” Production Liner

Table 12 below discusses the casing hardware and common cementing risks for this casing string.

7" Production Liner Summary			
Casing Inner Diameter	6.004”	Previous Casing Inner Diameter	8.625”
Open Hole Diameter	8.5”	Previous Casing Outer Diameter	9.875”
Measured Depth	15500’	Previous Casing Measured Depth	13700’
True Vertical Depth	14800’	Previous Casing True Vertical Depth	13200’
Placement Technique	Liner (through tubing)	Notable Formations	Production Interval
Common Cementing Risks and Considerations	• Fluid Migration • TOC will be dictated by CFR requirements • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.3, and 3.2.5.1		

Table 12 Well #2 – 7" Production Liner Summary

2.2.6 Casing #6 – 7 3/4” Tieback

Table 13 below discusses the casing hardware and common cementing risks for this casing string.

7 3/4" Tieback Summary			
Casing Inner Diameter	6.56”	Previous Casing Inner Diameter	8.625”
Open Hole Diameter	NA	Previous Casing Outer Diameter	9.875”
Measured Depth	13200’	Previous Casing Measured Depth	13700’
True Vertical Depth	12700’	Previous Casing True Vertical Depth	13200’
Placement Technique	Casing Displacement	Notable Formations	Extra coverage of salt zone
Common Cementing Risks and Considerations	• Casing collapse from salt creep • Pressure limitations of casing equipment • SBM displacement • Cementing unit HHP • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.4, and 3.2.5.2 below		

Table 13 Well #2 – 7 3/4" Tieback Summary

2.3 Well #3: Deep-water Well with no Salt Zone

Generic Well #3

Formation/Directional	TVD	MD	Casing Size	Weight	Cement Information	Mud Type	Mud Weight	Frac Gradient
	100	100						
	6500	6500						
	6800	6800	36"					
	9000	9000	22"	227	TOC @ ML	WBM	9.2	
	11500	11500	16"	97	TOC @ 9500	SOBM	10	12.5
	13500	14000	14	90	TOC @ 12000	SOBM	10.5	13
155 F	16500	17500	11 7/8"	71.8	TOC @ 15500	SOBM	11.5	13.5
180F	19000	21000	9 7/8"	62.8	TOC @ 19000	SOBM	13	14

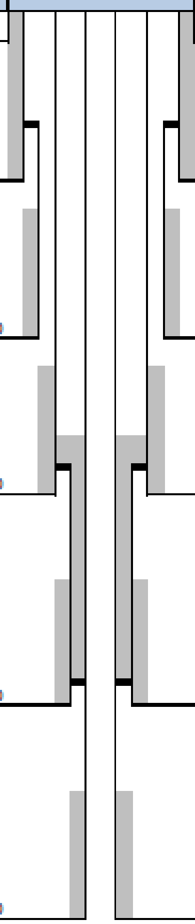


Figure 3 Well #3 - Deep-water Well with no Salt Zone

2.3.1 Casing #1 – 22” Surface Casing

Table 14 below discusses the casing hardware and common cementing risks for this casing string.

22” Surface Casing Summary			
Casing Inner Diameter	19.975”	Previous Casing Inner Diameter	Drive Pipe
Open Hole Diameter	26”	Previous Casing Outer Diameter	36”
Measured Depth	9000’	Previous Casing Measured Depth	6800’
True Vertical Depth	9000’	Previous Casing True Vertical Depth	6800’
Placement Technique	Inner String	Notable Formations	Unconsolidated Sands
Common Cementing Risks and Considerations	• Shallow Hazards (gas or water flow zones) • Lost Circulation • Hole Stability • Riserless (fluid returns to seafloor) • Narrow pore/frac windows • Large annular volumes • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.1.1, and 3.2.5 below		

Table 14 Well #3 – 22” Surface Casing Summary

2.3.2 Casing #2 – 16" Intermediate Liner

Table 15 below discusses the casing hardware and common cementing risks for this casing string.

16" Intermediate Liner Summary			
Casing Inner Diameter	14.85"	Previous Casing Inner Diameter	19.975"
Open Hole Diameter	18.125"	Previous Casing Outer Diameter	22"
Measured Depth	11500'	Previous Casing Measured Depth	9000'
True Vertical Depth	11500'	Previous Casing True Vertical Depth	9000'
Placement Technique	Liner (through tubing)	Notable Formations	Possible loss zones due to riser margin
Common Cementing Risks and Considerations	• SBM displacement • Lost Circulation • Riser margin • Large cement volumes • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.2, and 3.2.5.3		

Table 15 Well #3 – 16" Intermediate Liner Summary

2.3.3 Casing #3 – 14" Intermediate Casing

Table 16 below discusses the casing hardware and common cementing risks for this casing string.

14" Intermediate Casing Summary			
Casing Inner Diameter	12.7397"	Previous Casing Inner Diameter	14.85"
Open Hole Diameter	Drill with 14" Bit, Under ream to 17"	Previous Casing Outer Diameter	16"
Measured Depth	14000'	Previous Casing Measured Depth	11500'
True Vertical Depth	13500'	Previous Casing True Vertical Depth	11500'
Placement Technique	Casing Displacement	Notable Formations	NA
Common Cementing Risks and Considerations	• Large displacement volume • Mud compressibility • SBM Displacement • Volume ratio of shoe track and rathole • Considerations and operational guidelines can be viewed within sections 3.1 and 3.2.2 below		

Table 16 Well #3 – 14" Intermediate Casing Summary

2.3.4 Casing #4 – 11 7/8" Intermediate Liner

Table 17 below discusses the casing hardware and common cementing risks for this casing string.

11 7/8" Intermediate Liner Summary			
Casing Inner Diameter	10.711"	Previous Casing Inner Diameter	12.7397"
Open Hole Diameter	Drill with 12.25" Bit, Under ream to 14"	Previous Casing Outer Diameter	14"
Measured Depth	17500'	Previous Casing Measured Depth	14000'
True Vertical Depth	16500'	Previous Casing True Vertical Depth	13500'
Placement Technique	Liner (through tubing)	Notable Formations	NA
Common Cementing Risks and Considerations	• SBM displacement • Large displacement volumes • Potential flow zones present • CFR may dictate TOC • Volume ratio of shoe track and rathole • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.2, and 3.2.5.3		

Table 17 Well #3 – 11 7/8" Intermediate Liner Summary

2.3.5 Casing #5 – 9 7/8" Production Liner

Table 18 below discusses the casing hardware and common cementing risks for this casing string.

9 7/8" Production Liner Summary			
Casing Inner Diameter	8.625"	Previous Casing Inner Diameter	10.711"
Open Hole Diameter	12.25"	Previous Casing Outer Diameter	11.875"
Measured Depth	21000'	Previous Casing Measured Depth	17500'
True Vertical Depth	19000'	Previous Casing True Vertical Depth	16500'
Placement Technique	Liner (through tubing)	Notable Formations	Production Interval
Common Cementing Risks and Considerations	• Potential flow zones present • Potential for short annular lengths of cement • SBM Displacement • TOC will be dictated by CFR requirements • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.3.1, 3.2.3.2, and 3.2.5.1 below		

Table 18 Well #3 – 9 7/8" Production Liner Summary

2.3.6 Casing #6 – 9 7/8" Tieback

Table 19 below discusses the casing hardware and common cementing risks for this casing string.

9 7/8" Tieback Summary			
Casing Inner Diameter	8.625"	Previous Casing Inner Diameter	10.711"
Open Hole Diameter	NA	Previous Casing Outer Diameter	11.875"
Measured Depth	17000'	Previous Casing Measured Depth	17500'
True Vertical Depth	16000'	Previous Casing True Vertical Depth	16500"
Placement Technique	Casing Displacement	Notable Formations	NA
Common Cementing Risks and Considerations	• Pressure limitations of casing equipment • SBM displacement • Cementing unit HHP • Considerations and operational guidelines can be viewed within sections 3.1 and 3.2.4		

Table 19 Well #3 – 9 7/8" Tieback Summary

2.4 Well #4: Deviated Shelf Well

Figure 4 Well #4 - Deviated Shelf Well

2.4.1 Casing #1 – 13 3/8" Conductor Casing

Table 20 below discusses the casing hardware and common cementing risks for this casing string.

13 3/8" Conductor Casing Summary			
Casing Inner Diameter	12.615"	Previous Casing Inner Diameter	Drive Pipe
Open Hole Diameter	Drill with 14" Bit, Under ream to 17"	Previous Casing Outer Diameter	30"
Measured Depth	1500'	Previous Casing Measured Depth	500'
True Vertical Depth	1500'	Previous Casing True Vertical Depth	500'
Placement Technique	Casing Displacement	Notable Formations	Unconsolidated Sands
Common Cementing Risks and Considerations	• Shallow Hazards (gas or water flow zones) • Lost Circulation • Hole Stability • Volume ratio of shoe track and rathole • Narrow pore/frac windows • Large annular volumes • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.1.2, 3.2.5.1, 3.2.5.3, and 3.2.5.4 below		

Table 20 Well #4 – 13 3/8" Conductor Casing Summary

2.4.2 Casing #2 – 9 5/8" Intermediate Casing

Table 21 below discusses the casing hardware and common cementing risks for this casing string.

9 5/8" Intermediate Casing Summary			
Casing Inner Diameter	8.681"	Previous Casing Inner Diameter	12.615"
Open Hole Diameter	12.25"	Previous Casing Outer Diameter	13.325"
Measured Depth	3000	Previous Casing Measured Depth	1500'
True Vertical Depth	2500	Previous Casing True Vertical Depth	1500'
Placement Technique	Casing Displacement	Notable Formations	NA
Common Cementing Risks and Considerations	• Casing shoe highly deviated • Cement column temperature differential • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.1.2, 3.2.2,3.2.5.1 and 3.2.5.4 below		

Table 21 Well #4 – 9 5/8" Intermediate Casing Summary

2.4.3 Casing #3 – 5 1/2” Production Casing

Table 22 below discusses the casing hardware and common cementing risks for this casing string.

5 1/2" Production Casing Summary			
Casing Inner Diameter	4.95”	Previous Casing Inner Diameter	8.681”
Open Hole Diameter	7”	Previous Casing Outer Diameter	9.625”
Measured Depth	4000’	Previous Casing Measured Depth	3000’
True Vertical Depth	2600’	Previous Casing True Vertical Depth	2500’
Placement Technique	Casing Displacement	Notable Formations	Production Interval
Common Cementing Risks and Considerations	• Horizontal wellbore • Poor zonal isolation potential • Potential flow zones present • APB potential • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.3.2, and 3.2.5.1		

Table 22 Well #4 – 5 1/2" Production Casing Summary

2.5 Well #5: HT/HP Shelf Well

Generic Well #5

BHT	TVD	MD	Casing Size	Weight	Cement Information	Mud Type	Mud Weight	Frac Gradient
	75	75						
	250	250						
	550	550	36"					
	1000	1000	24"	156.03		WBM		12.2
	5000	5000	18 5/8"	101		WBM	9.5	15.2
			7 5/8" Tieback		Tieback TOC @ 8900'			
260F	12900	12900	11 7/8"	71.8	TOC @ 8900'	WBM	12.5	17.8
275F	14000	14000	9 5/8"	53.5	TOC @ TOL (12800')	OBM	17.5	19
355F	19500	19500	7 5/8"	55.12	TOC @ 14500'	OBM	18	19.6

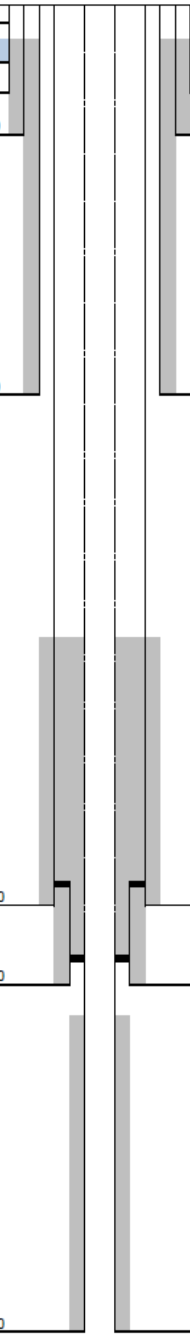


Figure 5 Well #5 - HT/HP Shelf Well

2.5.1 Casing #1 – 24" Conductor Casing

Table 23 below discusses the casing hardware and common cementing risks for this casing string.

24" Conductor Casing Summary			
Casing Inner Diameter	22.75"	Previous Casing Inner Diameter	Drive Pipe
Open Hole Diameter	28"	Previous Casing Outer Diameter	36"
Measured Depth	1000'	Previous Casing Measured Depth	550'
True Vertical Depth	1000'	Previous Casing True Vertical Depth	550'
Placement Technique	Inner String	Notable Formations	Unconsolidated Sands
Common Cementing Risks and Considerations	• Shallow Hazards (gas or water flow zones) • Lost Circulation • Hole Stability • Volume ratio of shoe track and rathole • Narrow pore/frac windows • Large annular volumes • Possibility of temperature cycling effects • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.1.2, 3.2.5.1, and 3.2.5.3 below		

Table 23 Well #5 – 24" Conductor Casing Summary

2.5.2 Casing #2 – 18 5/8" Intermediate Casing

Table 24 below discusses the casing hardware and common cementing risks for this casing string.

18 5/8" Intermediate Casing Summary			
Casing Inner Diameter	17.58"	Previous Casing Inner Diameter	22.75"
Open Hole Diameter	Drill with 18" Bit, Under ream to 21.5"	Previous Casing Outer Diameter	24"
Measured Depth	5000'	Previous Casing Measured Depth	1000'
True Vertical Depth	5000'	Previous Casing True Vertical Depth	1000'
Placement Technique	Casing Displacement	Notable Formations	NA
Common Cementing Risks and Considerations	• Possibility of shallow hazards (gas or water flow zones) • Lost Circulation • Hole Stability • Volume ratio of shoe track and rathole • Large annular volumes • Possibility of temperature cycling effects • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.2, and 3.2.3.3 below		

Table 24 Well #5 – 18 5/8" Intermediate Casing Summary

2.5.3 Casing #3 – 11 7/8" Intermediate Casing

Table 25 below discusses the casing hardware and common cementing risks for this casing string.

11 7/8" Intermediate Casing Summary			
Casing Inner Diameter	10.711"	Previous Casing Inner Diameter	17.58"
Open Hole Diameter	Drill with 12.25" Bit, Under ream to 14"	Previous Casing Outer Diameter	18.625"
Measured Depth	12900'	Previous Casing Measured Depth	5000'
True Vertical Depth	12900'	Previous Casing True Vertical Depth	5000'
Placement Technique	Casing Displacement	Notable Formations	Entering abnormal pressure zone
Common Cementing Risks and Considerations	• Strength retrogression • Volume ratio of shoe track and rathole • Fluid stabilities at elevated temperature • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.2, and 3.2.3.3 below		

Table 25 Well #5 – 11 7/8" Intermediate Casing Summary

2.5.4 Casing #4 – 9 5/8" Intermediate Liner

Table 26 below discusses the casing hardware and common cementing risks for this casing string.

9 5/8" Intermediate Liner Summary			
Casing Inner Diameter	8.535"	Previous Casing Inner Diameter	10.711"
Open Hole Diameter	12.25"	Previous Casing Outer Diameter	11.875"
Measured Depth	14000'	Previous Casing Measured Depth	12900'
True Vertical Depth	14000'	Previous Casing True Vertical Depth	12900'
Placement Technique	Liner (through tubing)	Notable Formations	HT/HP Zone
Common Cementing Risks and Considerations	• Strength retrogression • Liner hanger restrictions • High density slurry – possible mixing issues • OBM displacement • Mud compressibility • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.2, and 3.2.3.3 below		

Table 26 Well #5 – 9 5/8" Intermediate Liner Summary

2.5.5 Casing #5 – 7 5/8" Production Liner

Table 27 below discusses the casing hardware and common cementing risks for this casing string.

7 5/8" Production Liner Summary			
Casing Inner Diameter	6.125"	Previous Casing Inner Diameter	8.535"
Open Hole Diameter	Drill with 8.5" Bit, Under ream to 10"	Previous Casing Outer Diameter	9.625"
Measured Depth	19500'	Previous Casing Measured Depth	14000'
True Vertical Depth	19500'	Previous Casing True Vertical Depth	14000'
Placement Technique	Liner (through tubing)	Notable Formations	Production Interval, HT/HP Zone
Common Cementing Risks and Considerations	• Strength retrogression • Liner hanger restrictions • OBM displacement • Mud compressibility • Volume ratio of shoe track and rathole • Fluid stability at temperature • High density slurry – possible mixing issues • TOC will be dictated by CFR requirements • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.3.3, and 3.2.5.1		

Table 27 Well #5 – 7 5/8" Production Liner Summary

2.5.6 Casing #6 – 7 5/8” Tieback

Table 28 below discusses the casing hardware and common cementing risks for this casing string.

7 5/8" Tieback Summary			
Casing Inner Diameter	6.125”	Previous Casing Inner Diameter	8.535”
Open Hole Diameter	NA	Previous Casing Outer Diameter	9.625”
Measured Depth	13500’	Previous Casing Measured Depth	14000’
True Vertical Depth	13500’	Previous Casing True Vertical Depth	14000’
Placement Technique	Casing Displacement	Notable Formations	NA
Common Cementing Risks and Considerations	• Strength retrogression • Pressure limitations of casing equipment • OBM displacement • Cementing unit HHP • APB potential • Considerations and operational guidelines can be viewed within sections 3.1, 3.2.3.3, and 3.2.4 below		

Table 28 Well #5 – 7 5/8" Tieback Summary

3 Analysis of Cementing Processes and Associated Safety Issues and Specification of Best OCS Cementing Practices

Several factors go into every cement job. Some are within the operator or Service Company's control; others are not. The guidelines outlined in this document are for cementing in the OCS; however, specific well conditions and local guidelines will exist where going against standard practices produces the safest cementing operation which is most likely to meet its defined objectives. In these instances, it is advisable to use said non-standard practices.

Comprehensive data sets from candidate wells have been pulled from well records by CSI engineering and operations staff. This data has been organized into general and specific cementing procedures and operational guidelines. General cementing guidelines are operational guidelines which can be, or already are applied to the majority of cementing operations being performed in the GOM. Specific cementing guidelines relate more to case specific scenarios where additional considerations are necessary.

3.1 General Cementing Procedures and Guidelines

The general cementing procedures and guidelines have been categorized into four major subsections. These subsections relate to: drilling, casing, dry cement/additive considerations, and cement placement. These topics are discussed further below.

3.1.1 Drilling

Typically, drilling is designed and engineered around efficiency, safety and control of the well. Cementing designs and procedures are tailored around how the well was drilled. Contrary to conventional logic, in certain circumstances it may be beneficial to let the cement designs dictate drilling practices instead of letting drilling practices dictate cement design.

Some drilling operational considerations, rathole considerations and mud considerations will help with zonal isolation success. In a perfect design environment, cement is considered as part of the drilling process and is incorporated into a successfully designed drill program. These points are discussed below.

3.1.1.1 Drilling Operational Considerations

Several operational drilling procedures need to be focused on when considering cementing guidelines. Two of the main considerations relate to hole condition and lost circulation. These main points are discussed further below in the accompanying subsections.

3.1.1.1.1 Hole Condition

Wells need to be drilled in a manner of minimizing tortuosity, unwanted doglegs, spiral boreholes, borehole enlargement, and cuttings left in the hole. There are many variables including drilling ROP, weight on bit, and downhole vibrations which directly affect borehole conditions. As a guideline, the objectives of drilling design and operational practices should be to provide the highest quality borehole when and if possible. Hole condition is one of the major drilling aspects related to cementing which needs to be taken into consideration. Certain drilling practices as well as formations encountered can lead to variances in hole condition such as borehole enlargement, tight spots, excessive rat hole, spiral boreholes and doglegs. Some of the mentioned adverse hole conditions are unavoidable because of the zonal circumstances, but many can be remedied through operational guidelines. Borehole enlargement is considered detrimental to displacement efficiencies creating ineffective laminar flow regimes and a potential for incomplete casing to formation coverage of the section. These areas of low fluid velocity make mud removal and cement coverage very difficult leading to lower zonal isolation. Operators should have a very good understanding of annular hole volumes prior to cementing. Wireline calipers, where needed for engineering purposes, are considered a good tool for hole volume estimation, but can be very costly and time inefficient. Other options for performing calipers on open hole sections are with LWD or by performing a fluid caliper. Another operational guideline should be to re-drill any tight spots encountered in the bore-hole. Tight spots reduce efficiency when running casing as well as reduce cement sheath thickness.

During all drilling operations, it should be an operational guideline to keep the bore-hole as stable as possible to minimize any losses, influxes, or formation collapse. Hole stability can be influenced from swab and surge pressures during pipe tripping operations. Necessary calculations of maximum swab and surge pressures should be completed prior to any pipe tripping such that there are not any adverse effects to the bore-hole.

Under-reaming is a practice performed to enlarge a wellbore past its original drilled size. Generally, under-reaming equipment is located further up the BHA allowing 30-100ft of rathole once reaching TD. Although certain situations necessitate under-reaming to lower ECD's and provide adequate cement sheath thickness, the practice has the potential to lead to larger unconsolidated rathole volumes as an end result. At present, virtually every well in the GOM is drilled using undreamed hole sections. As a guideline, when hole sections are under-reamed, special consideration should be taken as to the ratio of the casing shoe track volume to the rathole volume.

3.1.1.1.2 Lost Circulation

Lost circulation can be one of the more serious problems that can arise during drilling operations. The consequences of lost circulation can be as little as loss of drilling fluid to the formation or as serious as loss of hydrostatic pressure leading to potential riser collapse or formation influx and loss of the well. It should be considered an operational guideline to reduce losses as much as possible during drilling operations. Losses should be controlled prior to running casing when possible. Unfortunately, there are few options for curing losses once the casing is in the hole. If curing the lost circulation is not possible, LCM should be added to the spacer and cement to reduce the loss risks. There are certain scenarios, such as narrow annular flow areas, where LCM can increase risks associated with bridging off. Proper analysis of flow paths and all potential risks must be taken into account before utilizing LCM. Offset historical well data may assist in predicting loss zones such that casing and cement programs can be designed in which losses do not affect cement coverage. In other words, known loss zones are above calculated TOC. As a guideline, BHA's which have the ability to tolerate different types and sizes of LCM should be considered if there is any anticipation of encountering zones where losses could be a factor.

3.1.1.1.3 Summary

When reviewing the operational guidelines above relating to drilling, some decisions need to be made as to priority. Not all the operational guidelines discussed above can be performed simultaneously. In summary, proper risk-based engineering analysis should be performed on each special scenario to balance the various operational practices.

3.1.1.2 Rathole Considerations

When drilling oil and gas wells, generally the hole is drilled out a little deeper than the designed casing point. This open hole section is called the rathole. API STD 65-2 quickly mentions rathole considerations recommending that the rathole length be minimized and filled with a high density mud or other appropriate barrier. As a clarification to this recommended practice, it should be considered an operational guideline to spot a higher density viscous mud pill in the rathole to minimize the likelihood of fluid swapping during placement.

3.1.1.3 Mud

The mud used while drilling plays a large role in cementing procedures in relation to mud removal. Careful planning must be performed on the mud service company level, cementing service company level and the operator's level when considering mud designs and mud removal designs prior to cementing. Good communication between the mud service company, and cement service company is required for effective job planning and design. The main discussion of mud and its effects on cementing have been broken up into three categories: mud types, mud properties and additional considerations which are discussed further below.

3.1.1.3.1 Mud Types

Mud types are generally identified by the base fluids used in the mud. Water based muds (WBM), oil based muds (OBM) and synthetic based muds (SBM) are the three main mud types. Mud systems usually become more complex as the deeper the well becomes and the higher the bottom hole temperature and pressure increases. Regardless of the mud type used, there are common design and operational parameters in terms of cementing that need to be followed, mostly focusing on proper removal prior to cementing. Each mud type has inherent advantages and disadvantages discussed below.

3.1.1.3.1.1 Water Based Mud

The major advantages of water based muds are less environmental impact, cost, and usually less design complication. Generally, the initial casing string depths are drilled with sea water which is considered a type of water based mud. Another advantage of drilling with sea water or a mud design that is primarily sea water is that the mud returns don't have to be brought back to surface and can be sacrificed to the sea floor with no negative environmental impact. Deep water wells rely on this advantage on their initial casing strings since the increased hydrostatic pressure of a riser margin would lead to fracturing of the weak formations. A disadvantage of water based muds as compared to the more technically advanced oil and synthetic based muds is lower cooling and lubricating of the drill bit. In addition, they may provide less control of shale swelling. Water based muds typically have rheology profiles that experience variability across the temperature and pressure profiles of the well.

3.1.1.3.1.2 Oil and Synthetic Based Mud

The typical advantages of oil and synthetic based muds when compared to water based mud include higher effective drilling rates, lower required torque due to less friction, and reductions in the likelihood of differential sticking due to thinner mud filter cakes and hole stability. Although reductions in friction when drilling has it inherent advantages, oil and synthetic based muds require much more sophisticated spacer packages prior to cementation. Since the mud is non-aqueous, a film can easily be left behind which must be removed for quality bonding of the cement to the casing and formation. Synthetic based muds (SBM) can increase drilling efficiency and minimize environmental impact. One inherent disadvantage of SBM is cost. In cases where all job objectives can be achieved, a less expensive mud system, rather than SBM may be more advantageous when drilling takes place in zones where total loss is inevitable.

3.1.1.3.2 Mud Properties

The objectives of the mud design during drilling operations are to suspend, release and remove cuttings from the well. Other design considerations relating to mud are controlling formation pore pressures through fluid density, reducing lost circulation risks through density control as well as suspension of LCM, minimizing formation damage through thin impermeable filter cakes, transmitting hydraulic energy to the bit and cooling/lubricating the bit/BHA. Although mud systems are designed around the above mentioned parameters, generally mud is not designed for cementing. Mud conditioning performed prior to cement jobs should remove all residual cuttings from the mud system and begin to remove the erodible mud filter cake from the walls of the formation. It should be considered a guideline to pay close attention to the rheological parameters of the mud system during and after conditioning operations. Moderate plastic viscosities and low yield points are considered a guideline to assist the removal of mud during cementation. The more viscous the mud system is when cementing, the more difficult it is for the cement to effectively displace the mud.

The mud system also serves to cool and clean the bit, deliver hydraulic horsepower to the bit, powering downhole motors and turbines, and it also serves as a communications medium for mud pulse telemetry systems. Its condition and properties are also critical to formation measurements (wireline and LWD), directional survey measurements, and the traversing of wireline tools through the wellbore.

3.1.1.3.3 Additional Considerations

As described above in the various different mud types, one of the most important attributes of the mud in regards to cementing is the effective removal of the mud, gelled mud, and if possible the mud filter cake prior to cementation. If it is not possible to completely remove the filter cake, it is possible that a sufficiently thin and tight filter cake can provide adequate isolation. Mud conditioning and spacer design are very important to achieve effective mud removal. Turbulent flow should be considered the preferred flow regime for effective mud removal; however, turbulent flow often is not achievable and laminar flow or transition flows are often accepted as a best case. Fluid flow at velocities not capable of overcoming the wall shear stress on the narrow side of the annulus should be avoided. If the laminar flow rate is too high, the differential velocity between the wide and narrow sides will be too large creating a potential for channeling. The proper velocity range falls between these two limiters. One other consideration which needs to be taken into account when designing a spacer package is the fluid contact time. Contact time is the period that a fluid flows past a particular point in the annular space during displacement. Typically contact time is calculated when fluids are in turbulent flow. Calculation based on spacer annular length can also be used when in laminar flow. Proper engineering simulation of fluid placement is necessary to determine the best criteria for the designed spacer volume.

Mud sweeps are used to aid in cuttings removal prior to cementing. Unfortunately, sweeps or pills may not be effective all the time on removing cuttings and in some cases can be detrimental to hole stability or interfere with the transmission of data from MWD/LWD systems causing failure of their turbines and pulsars. Proper engineering design and simulation must be performed for the most efficient method to properly remove cuttings and condition the hole. Viscous mud pills can be used for effective coverage of the rathole to reduce fluid swapping tendencies during cementing. Where possible, a pill heavier than the cement is preferred. If this cannot be achieved, adequate testing should be performed to ensure fluid swapping will not occur. Excess pill volume left in static conditions can lead to initial increases in circulating pressure profiles. As a guideline, computer simulation programs should be used for anticipation of ECD during hole conditioning operations. It should be considered a guideline to break circulation very slowly as to not unintentionally fracture the formation. Once circulation has been achieved, any excess pill volume should be removed by circulating bottoms up.

It should be further noted that additives must be properly mixed and applied to the mud system to mitigate risks of clogging the bit or causing damage to the MWD/LWD tools.

3.1.2 Casing

Casing is utilized during oil well drilling operations for isolation of zones with different formation pressures allowing drilling to deeper depths. Casing hardware and casing surface condition are two major points discussed below as to how they affect cementing properties. A third sub-section relating to additional considerations is also discussed.

3.1.2.1 Casing Hardware

Centralizers and casing connections are the main casing hardware relating to cementing operational guidelines. Some additional casing hardware considerations are discussed below as well.

3.1.2.1.1 Centralizers

The centralizer program is known to assist in allowing effective placement of cement in the annulus. From the literature review, some have recommended a minimum standoff of 75 percent; however, it should be considered a guideline to use proper simulation software to properly design the centralizer type, number, and placement to achieve zonal isolation across the target zones. Several different styles of centralizers are on the market including: bow type, rigid, spiral, and many other variations of these styles. It should be considered a guideline to utilize the right type of centralizer for the task at hand. Considerations such as hole-size, well-bore deviation, annular wall configuration, and whether or not the casing will be rotated/reciprocated during the cement job are major aspects related to choosing the correct centralizer for the situation.

3.1.2.1.2 Casing Connections

The casing connection paradigm in the oil industry is to have casing configured as pipe with exterior threads on each end. The joints of casing are then made up together with couplings. This is the most cost effective and efficient means of building casing from a manufacturing standpoint. Generally the couplings have an annular clearance reduction and may be accounted for when cementing calculations are performed. Smooth bore casing is more expensive than generic casing, the smooth-bore lowers ECD’s by eliminating annular restrictions. It should also be considered a guideline to take any other annular restrictions into account when performing cementing calculations such as the anticipated top of cement (TOC) or ECD simulations. These calculations are important for long columns of cement which cover several casing joints and for tight annulus cement jobs. Pin and box casing connections are often utilized and the same calculation guidelines should be performed. If wellbore configuration does not allow you to run centralizers, collared casing may assist with casing centralization.

3.1.2.1.3 Casing Hardware Additional Considerations

Some additional considerations relating to casing hardware need to be discussed. Prior to running any casing, it should be considered a guideline to measure the length and inner diameter of each casing joint. This practice acts as a quality check of the casing condition prior to the cement job as well as a more reliable means of calculating displacement volume instead of relying on tabulated data found in handbooks. Calculations should be performed on the casing total stretch prior to tripping in to avoid the risk nosing the casing into the rathole leading to poor quality shoe cementation. The use of auto-fill tubes on float equipment is recommended on casing strings to minimize the risks associated with buoyant forces acting on the casing while tripping into the hole. In addition, auto-fill is normally only advised to prevent excessive mud losses due to surge pressures while running casing. Some risks associated with auto-fill equipment can include taking a kick while running casing and failure to properly convert. Buoyant forces can easily be overcome simply by stopping to fill the casing occasionally or by specialized casing running tools which allow the pipe to be continuously filled. Certain scenarios where high well control risks are present may call for conversion of float equipment prior to reaching TD.

Although multistage cementing is not a typical offshore cementing practice, some additional special considerations must be made when performing one of these cement jobs. Operators must have a detailed knowledge of the pressure ratings for the plug launchers and shear pins that are involved within the stage tools. Knowing these parameters helps with estimating the total displacement volume during the cement job as well as additional hydraulic horsepower which may be necessary.

Although cable wall cleaners are not generally utilized in the offshore industry, implementation may be recommended as a guideline if there have been higher than normal risks of formation micro-annuli from historical offset well data. For best performance, casing reciprocation should be increased.

3.1.2.2 Casing Surface Condition

The casing outer wall surface condition plays a very large role in the sealing effectiveness of a cement sheath. Previous research and case studies have shown that mill varnish or any other oily residue left on the casing walls inhibits the cement from properly bonding to the surface, which leads to micro-annuli. One of the studies has shown that cement will have better bonding attributes on slightly rusted surfaces when compared to smooth wall surfaces. It should be considered an operational guideline to remove any traces of mill varnish from the casing wall surfaces prior to running casing. There are many ways of removing mill varnish including power-washing with soap water or even sand-blasting. It is up to the operator as to which method should be used before shipping offshore.

3.1.2.3 Additional Considerations

Although there are many other additional considerations relating to casing, two topics are focused on below. These topics are shoe track considerations and engineering simulations.

3.1.2.3.1 Shoe Track

Non-stab-in primary cement jobs generally utilize two independent check valves run at the bottom of the casing which are separated by one to three joints. Another method includes two float valves being installed at the collar with a guide shoe separated by 2-4 joints. This area, which is known as the shoe track, acts primarily as a cement coverage safety factor for the well-bore to reduce the likelihood of a "wet shoe" caused by over displacement, or cement contamination during displacement. Quality cement within the shoe track may be an indicator of quality shoe coverage increasing the likelihood of a quality LOT/FIT test. As an added safety factor, it should be considered a guideline to have a shoe track volume which is in excess of the mud compressibility volume. Shoe track volumes can be easily modified by adding or subtracting casing joints between the landing collar and the shoe joint. Shoe track lengths should be increased as the displacement volume increases from string to string. For cement jobs with no bottom plug, the shoe track volume should be even larger to account for residual mud film on the inner casing walls.

The volume associated with the rathole must be considered as well. An operational guideline when considering fluid swapping risks with ratholes would be to pump a weighted viscous pill into the rathole prior to pulling drill pipe. As a guideline, the pill density should be greater than the tail cement density. This helps reduce the chances of the cement swapping with the fluid left in the rathole which could lead to a wet shoe. This is a generally accepted current operational practice in the OCS.

3.1.2.3.2 Engineering Simulations

The ability to simulate actual well conditions increases safety and operational efficiency. Current engineering simulations on the market allow for almost all aspects of drilling, cementing, and completion to be simulated prior to job execution. Previous research studies have shown that casing rotation and/or reciprocation helps increase displacement efficiencies. As a guideline, engineering simulations can help model the most efficient rotation/reciprocation speeds and stroke lengths if planning on moving casing during placement. The engineering simulations also can take the casing collars into consideration and what effect they have on fluid flow in the annulus. Although input of collar restrictions can be somewhat tedious, the collars can affect the simulated friction pressures and should be modeled if possible.

Hook load calculations are also a recommended guideline to perform prior to any cement job which these engineering simulations can easily and readily perform. Although hook load calculations generally are not needed during the actual placement in a primary cement job, the knowledge of what these values are can be very helpful for operational contingencies which may need to be performed. Some instances exist where the hook load will end up exceeding the rated pulling capacity of the rig's draw works while running casing. This is known as a one way trip. Proper calculation of the one way trip point should be made such that all necessary operations and contingency plans are completed prior to the casing reaching that point.

3.1.3 Dry Cement and Additive Considerations

Several major considerations relating to dry cement and additives where operational guidelines must be followed are needed for quality cementing outcomes. These considerations are broken up into three separate sections: general considerations, bulk plant considerations, and in-transit considerations. All three of these topics are discussed below.

3.1.3.1 General Considerations

One of the main considerations when discussing the operational guidelines associated with dry cement and additives is documentation and document control. The quantities and batch/lot numbers of the cement and additives should be documented and these documents should be kept with the materials at all times (storage, in-transit, and on-site). Lab pilot slurry designs should accompany this documentation for completeness and both should be cross-referenced to field designs prior to cementing operations. An operational guideline would have a documented chain of custody for all cementing materials arriving on location to easily track lot/batch numbers, chemical manufacture dates, cement QAQC/grind reports, and previous owners/storage locations of the cement and additives. Record tallies of bulk storage tanks showing a history of cement blends and cleaning operations should also be considered a guideline. There always is minor variability in cements and additives from batch to batch which is generally mended through laboratory pilot and confirmation testing, but contamination from storage tanks can easily be overlooked leading to major operational failures.

3.1.3.2 Bulk Plant Considerations

Bulk plants should have documented operating procedures and maintenance schedules. Although the majority of cementing operations in the OCS utilize liquid additives, some cases exist where dry additives are blended into the cement prior to the job. Silica Flour is a prime example of a dry additive which needs to be dry blended. It should be considered a guideline to record the lot numbers of each additive that is dry blended. Each additive should be blended from a single lot number such that there is less chance of variability throughout the blend. In cases where this is not possible due to large job volumes, field blend tests should be performed using all lot numbers being pumped. Any substandard or suspect material in the bulk plant should not be used. Dryers, vacuum systems, rock catchers, scales, and compressors should be in place and in good working order. All weight indicators, pressure vessels, and pressure gauges should be maintained and certified on a regular basis. All valves should be inspected and maintained on a regular basis. The bulk plant data recording system should be able to print out weight tickets for additives and bulk. When blending the cement, care should be taken to avoid product loss through the vent line by overfilling the bulk tank. Product loss may occur well before a bulk tank is considered "full". Prior to bulk plant operations, all of the transfer lines should be purged to remove any cement/additive residue from previous operations. It is recommended to transfer the blended cement system as many times as necessary for proper blend homogeneity. QA/QC checks on cement blend samples can help determine if blending operations have sufficiently dispersed system components. All bulk storage tanks should be emptied, cleaned, and inspected regularly. At a minimum, these procedures should be carried out before a new cement blend is placed into the storage tanks. The final quantity and storage tank number should be documented for the blended cement system as well.

3.1.3.3 In Transit Considerations

Open communication is very important prior to performing any bulk transfer operations to storage tanks on the Offshore Supply Vessels. Prior to loading or inspecting, the service company should present copies of load tickets to the boat captain and discuss which tanks are to be loaded. Storage tank capacities and hose connections should be verified. Loading operations should conform to the same guidelines discussed above. After loading, it is recommended to open the tank hatches to verify the amount of cement in each tank. During transport, bulk storage tanks should be isolated from the environment to reduce the cement’s natural hygroscopic tendencies. It is not recommended to leave residual pressure on the storage tanks as the cement will tend to pack off in the discharge lines during transport. All of the cement discharge hoses should be capped and stowed to reduce the moisture contact with the cement. Blend samples should be collected prior to loading the transport vessel and during loading of the rig from the vessel. Where possible, final laboratory confirmation testing should be performed with the sample taken from supply vessel to rig bulk tank.

3.1.4 Placement

Poor quality cement in the annulus may lead to future problems that develop over time. These issues may prove to be far more expensive and damaging than the initial primary cement job. Prior experience in the area assists in determining the procedures necessary to overcome these problems. It can be agreed upon that the cement design and the placement operations work hand-in-hand to obtain a quality cement job. The cementing guidelines relating to placement have been broken up into nine separate sections: cementing hardware consideration, bulk and liquid delivery systems, QC and sample collection considerations, mixing, fluid contamination, job recording and engineering simulations, placement techniques, cement placement contingency planning and post job considerations. All sections are further discussed below.

3.1.4.1 Cementing Hardware Considerations

Cementing hardware is designed to increase the quality of the cement in the annulus. Cementing hardware such as wiper darts, plug launchers, cement heads, float equipment, mixing equipment, bulk delivery equipment, and centralizers (discussed within section 3.1.2.1.1) are all standard items used to increase cementing success rates. Considerations for cementing hardware are discussed below.

API STD 65-2 recommends the use of both top and bottom plugs for all casing cement jobs other than sting-in or inner string jobs. The bottom plugs are used as a mechanical separator between fluids while in the casing. Using only two plugs should be considered a minimum guideline. To get the best chances of cementing success, fluid intermixing should be minimized by all means and at all times. This is accomplished partially by the rheological parameter modification discussed as part of mud removal, but fluid contamination through intermixing still occurs. It should be considered a guideline to mechanically separate consecutive fluids in the landing string and casing during cementing operations when it will not increase operational complexity. The reduction of intermixing that can take place in the casing will increase the effective mud removal in the annulus allowing for higher cement sheath quality and bonding.

Special attention is needed when loading bottom plugs into cement heads. The diaphragms must be left intact for the bottom plugs to perform as expected. It is also a guideline to reduce the displacement pumping rate prior to the bottom plug reaching any known restrictions within the casing or the float collar. The rate reduction decreases the pressure spike applied to the diaphragm, decreasing the likelihood of premature rupture. It is preferential to have the plug launching equipment pre-loaded with all of the plugs for the job. Pre-loading the plugs into the cement head or darts into the dart launcher reduces additional shut-down time that could lead to cement failure through gel strength development tendencies. As a cautionary note, plugs which sit in a head for an extended period of time may be subject to permanent deformations. While discussing cement heads, it should be considered a guideline to incorporate rotating cement heads when possible such that casing rotation can be achieved during the cement job. Casing rotation helps increase annular flow velocity profiles allowing for higher quality mud removal.

3.1.4.2 Bulk and Liquid Delivery Systems

The bulk capacities of the rig's dry storage tanks and dry product travel distances should be taken into account prior to designing for cementing operations. More often than not, the travel distance from the dry cement storage bins to the mixing equipment can be in excess of 100ft leading to issues with dry product delivery rates. Maximum dry product delivery rates should be accounted for when designing cementing operations such that the placement will not be cut short by the set time of the cement. It should also be considered a guideline to install dry product storage bins as close to the mixing equipment, or vice versa, on new rig builds to mitigate the reduction in dry product transfer rates. Dry product delivery plumbing should have a minimum amount of vertical rise, bends, and elbows as well to assist in delivery quality. The rig bulk system should have documented operating procedures and maintenance schedule for key components. Prior to job execution, functionality should be checked. Rock catchers that are already built into the bulk delivery system should be checked and maintained before and after each cementing operation and whenever there are reductions in dry product delivery rates which are suspect. The cementing service company should have knowledge of the locations of all screens within the bulk and liquid delivery systems prior to delivering any materials to the cement unit; such that, if the screens need to be removed in a timely manner, they can. Cement delivery is a primary component of a successful cement job. In the deep water OCS, the first cement job performed is usually of large volume and may be foamed. It is important to make sure the cement mixing system is operational and works correctly before the job. One way of doing this is to mix a practice volume overboard. Test mix rates should match anticipated job rates when possible. If non-cementing personnel have assigned tasks during the job, their competency needs to be evaluated pre-job. Most rigs have procedures for transferring product, developed by experience. In these cases, pre-job review can act as a surrogate to bulk delivery practice runs.

3.1.4.3 QC and Sample Collection Considerations

Adherence to the sample collection procedures within API STD 65-2 should be considered an operational guideline. Cement sample collection should be performed during each dry product transfer, whether it is from the bulk plant to the transport vessel or from the rig storage bins to the mixing equipment. These additional samples can be used for random spot QA/QC testing for assurance of blend quality and dramatically help towards pinpointing any issues when performing post-job investigations. The majority of drilling rigs in the OCS currently do not have the capability of collecting representative dry cement samples during the transfer from the rig storage bins to the mixing equipment. Generally, if a sample needs to be caught during this transfer, residual cement is left in the surge can at the end of the job and then collected as the blend sample.

Some liquid additives used for cement systems lose their effectiveness from long term storage. Other liquid additives lose their effectiveness over time when pre-mixed as a mix fluid to be used later on. It should be considered a guideline to have manufacture and expiration dates documented for all cementing liquid additives which are on location. Laboratory testing can be done to re-qualify additives that are beyond their expiration date in some cases. If the mix fluid is planned to be pre-mixed for a cement job, aging tests should be performed on the mix fluid to observe and document any changes in slurry performance parameters over time. This allows for real-time decision making in the field should any delays occur. Although mix water quality is not as critical of a parameter when comparing to fracturing fluids, several solutes detrimentally impact slurry characteristics. As a guideline, the mix water on location should be tested to ensure it is representative of what was used during pre-job laboratory design testing. Differences may result in performance variations from the design.

3.1.4.4 Mixing

Planned slurry properties are achieved in the field by mixing the slurry at the required density and minimizing contamination. Density variations of more than (+-) 0.2 ppg over extended periods during the mixing process, can have adverse effects on slurry properties and meeting job objectives. The guideline to be followed is to have a recirculating mixer with automatic density control. The mix tub volume should be kept at a maximum level to homogenize momentary density fluctuations. Proper pre-job simulations should account for reasonable density variations which may occur during job execution. Many offshore cement units have a relatively small capacity mixing tub, usually between 6 to 8 barrels of volume. Mix tubs do generally spill over into 14 to 18 barrel averaging tubs for better downhole density control, but cement service companies should not rely on these averaging tubs to replace standard mix density control practices when on location. If auxiliary equipment, such as an averaging tub, is available to increase the volume of slurry being mixed on the fly, it will not only increase the homogeneity of the slurry, but provide a means to pump the slurry with the most consistent density at the designed rate. Minor problems associated with the mixing process such as momentary line plugs or similar mixing issues will have a lesser impact on the cement quality and mixing rate. When a larger or more time consuming problem occurs, the downhole pumping rate can be adjusted downward in smaller increments over a longer time period and hopefully the problem will be resolved prior to full shut down.

When using liquid additives for cementing operations on location, it should be considered a guideline to document the storage tank volumes of the additives prior to the cement job for comparison with post job tank volumes. This comparison works as an additional quality assurance check that the correct volumes of liquid additives were injected into the slurry. During the cementing operations, service company representatives should periodically check additive injection rates for quality control. Lot numbers for all liquid additives on location should be tracked as well to help reduce issues with individual additives.

The flow regime and chemical constituents of the spacers and cement is designed so that mud removal and cement placement do not fracture the weakest formation or initiate injection into zones of high permeability. The surface pumping rate is fixed by the design criteria and is easily controlled by the cement equipment operator. The actual flow velocity in the well may be higher if the density differential of the spacers and cement against the fluid in the annulus allows gravitational forces to exceed the designed flow rate. Simulation software can assist with placement designs where this occurs.

3.1.4.5 Fluid Contamination Considerations

The less fluid intermixing that is allowed to occur, the better chances of quality cement placement. It should be considered a guideline to control fluid rheological parameters to assist displacement efficiencies. The yield points of sequential fluids should be successively increased to reduce risks associated with fluid swapping in static conditions. Dynamically, successive fluids should impart a higher annular friction pressure such that the viscosity of the displacing fluid will tend to overcome the viscosity of the displaced fluid. Fluid compatibility should be tested for each fluid being pumped to assure there aren't any incompatibilities as discussed in section 3.1.1.3. The mud-spacer compatibility is most important, but the spacer-cement compatibility should be analyzed as well.

While discussing the importance of laboratory fluid compatibility testing, it should also be considered a guideline to run cement-spacer contaminated testing to observe how contamination will vary the slurry and set cement performance parameters; the most common would be to determine its effect on thickening time and compressive strength. Thickening time graphs should be attached to cement lab reports as the graphical data helps field personnel easily make real-time contingency planning if and when needed. Laboratory reports should also include the cement slurry departure time for quick reference during placement operations.

3.1.4.6 Job Recording and Engineering Simulations

It should be considered a guideline to record the cementing operations which occur on location. As a minimum, the downhole pumping rate, pump pressure and fluid density should be monitored and recorded for all cementing operations. There are some additional operational parameters which when recorded can assist with post job analysis for QA/QC and help with incident investigation. Both the pump and well head pressures can be recorded as a redundancy check on pressure as well as can be implemented into post job simulations. The mix density and downhole density help visualize where bulk delivery or mixing issues may have occurred. Generally, the mix density will fluctuate more than the downhole density, but it still should be a guideline to minimize the mix density fluctuation as much as possible. Downhole densometers do not have to be installed within the high pressure line but can be out of an averaging tub or some other location that isn't part of the recirculation system. A guideline is to record the fluid returns through flow-meters during the cement job. Certain scenarios exist where this may not be possible. In instances where the rig will displace the cement job instead of the cementing unit, it should be a guideline for the cementing unit to record the pressure and if possible the displacement rate from the rig pumps. Some of the newer offshore rigs in the GOM have the cement recording equipment integrated into the central rig recording equipment. Although offshore installments like these are considered the best case scenario, other methods of recording can be more than sufficient. The central data collection area for all operations on the rig organizationally helps all operational practices, but integration can be very costly to implement, especially on older drilling rigs.

When discussing cement placement simulation software, it should be considered a guideline to have competent cementing engineers perform the cementing simulations. Cementing simulation software is a powerful tool when used correctly. Unfortunately, the quality of the simulation's results is directly proportional to the quality of the input parameters. Competent cementing engineers will be able to tell which input parameters can be assumed and which parameters cannot. Certain assumed parameters will have negligible change to the simulation end result and others will have a detrimental effect. It is important for the design engineer be aware of the software's limitations, and assumptions. It is recommended that the design engineer clearly document what assumptions went into the simulation output. As a guideline, simulations such as ECD, surface pressure, calculated casing/annular rate, temperature, friction pressure, rheological hierarchy, and effectiveness of mud removal should be performed and analyzed for all cement jobs when and if possible.

Prior to any cement job, it should be considered a guideline to calculate the hydraulic horsepower needed to accomplish the operation and compare it to the equipment which will be used on location. Slight changes in cement placement designs can help reduce the required hydraulic horsepower if the pumping equipment is insufficient, but placement designs should never be dramatically changed, especially at the risk of not satisfying job objectives. Cementing simulation software programs provide great assistance in estimating the required hydraulic horsepower for cementing operations.

Special consideration needs be taken into account when performing cement placement simulations for foam cementing. Additional simulations, based on common contingency plans, should be run so if these situations arise during foam cement jobs, proper placement simulations are available. Equivalent circulating density is one of the more significant parameters for cement jobs whether they are foamed or un-foamed. It should be considered a guideline to perform ECD placement simulations assuming gauge hole and hole with excess, assuming average nitrogen injection rate and varied injection rate, taking into account, changes in slurry rheology, foam quality, temperature and pressure during the foam job. No industry consensus currently exists on the best method to address the rheology of a foamed slurry into these simulations. This issue has been identified as an area in need of additional R&D work which has been mentioned within section 6 of this document.

3.1.4.7 Placement Techniques

Some considerations related to placement techniques are discussed in this section. Several cement jobs in the GOM have been run as an inner string to help decrease total pump time and displacement volume. A technical analysis should be performed to identify whether or not running an inner string will better meet job objectives. All cement jobs should be pumped at the highest allowable rates while keeping ECD's below the fracture gradient to allow for better hole cleaning efficiency.

Prior to cementing operations it should be considered a guideline to have the pipe capacity from the cementing equipment to the rig floor documented. This is generally a fixed volume, but should be a known and used volume for simulation software and for friction pressure calculations. When using the mud pumps for displacement, it should be a guideline to know ahead of time the pump efficiencies for calculation purposes. As a redundancy, flow meters can be installed on the rig pumps for quality assurance. During displacement of the cement slurry, it should be considered a guideline to recalculate the displacement volume from anticipated bumps or release encountered during displacement. Displacement recalculation is very beneficial in deep-water situations or where the mud compressibility is a factor. It should also be considered a guideline to slow the displacement rate prior to bumping the plug as to not over pressure any of the equipment.

Reverse circulation cementing is a technique which is currently not used often in the GOM. It may be possible to achieve lower ECD's during placement through reverse circulation cementing, but additional special equipment is required for the operation to be successful. Additional research and development is needed to assess the viability of this option, especially in deep-water scenarios.

3.1.4.8 Cement Placement Contingency Planning

Contingency planning is an important part of any cementing placement design. Although it is best to perform cementing operations exactly as planned, there are multiple scenarios that require the placement operations to be changed real-time. The best placement design has a contingency plan which encompasses foreseeable operational difficulties that could be encountered during placement. Some examples of operational difficulties can include: slurry gelation, dry product delivery issues, data acquisition failure, high pressure pump issues, mix density issues, and many others. Having a contingency plan set for each scenario prior to the job helps operators make real-time decisions which are in line with meeting job objectives. By following simple contingencies, major operational failures can be prevented and/or mitigated. There are different procedures related to “circulating out” a poorly executed cement operation. When cementing riserless, the slurry can be easily circulated out onto the seafloor. In certain deep-water condition, a much higher probability exists that the pump time needed to circulate the slurry out is much greater than the set time of the cement. In this case, placement is the only option followed by remedial work to meet job objectives.

The cement placed at the casing shoe is the most critical for continuation of deeper drilling operations. After the cement has developed sufficient compressive strength, the shoe is drilled out and a FIT or LOT is performed. The FIT is a quantitative test where hydraulic pressure is applied to observe if the formation will be able to withstand anticipated ECDs during future drilling operations. It should be considered a guideline to compare the pumped volumes and measured pressures from the FIT to the volumes and pressures from the casing test. This step is a starting point in anticipating required pump volume to reach a specified bottom hole pressure. In most situations, the drilling engineers designed the drilling operations under anticipated FIT results. If the measured FIT is lower than expected, it should be considered a guideline to modify drilling rates and ECD's to reduce the likelihood of lost circulation during drilling. Poor FIT results may also require the need to set extra casing strings in certain situations. Poor mud displacement and/or hole cleaning can lead to bad FIT results from fluid migration in the cement sheath either through mud channels or micro-annulus paths. In this case, it should be considered a guideline to perform remedial operations on the shoe for better zonal isolation. When performing shoe squeeze operations, it should be considered a guideline to use the Bradenhead squeeze method, described further within the squeeze cementing subsection. In certain situations where special casing hardware is attached, a Bradenhead method may need to be avoided and the squeeze operation may require additional tools such as a cement retainer or a retrievable packer. The cement slurry should have sufficient fluid loss control such that it will plug off flow paths by depositing a filter cake and sufficient set time such that multiple hesitations can be performed.

It is virtually impossible to plan and have equipment and/or material on stand-by, for every imaginable scenario, and it is certainly not cost effective. Certain scenarios which have higher probabilities of occurring should be planned for ahead of time to help mitigate their effects. One common contingency is to have enough material on the rig to redo the job should cement have to be circulated out of the hole. This isn't always feasible due to rig capacity limitations but at least plans should be in place to have materials for a repeat job available at the shore base. Prior to performing any primary cementing operations, it should be considered a guideline to have a shoe squeeze contingency plan in place with sufficient materials on location to perform this operation. Currently, shoe squeeze contingency plans are formulated if there are sufficient risks associated with lost circulation, but generally, the shoe squeeze contingency slurry can be designed around the tail slurry being pumped for that operation. Special slurry parameter considerations need to be focused on such as the necessity of sufficient fluid loss control or longer set times for hesitations.

The ability to deal with problem scenarios in a timely manner can mitigate the severity of a given situation, and help to contain the cost of the operation. The guideline is a formal plan that has listings for specialty equipment or material, particularly for exotic or rare items such as unusually large packers, cement retainers, or chemicals. The well designs will be the guide for specialty equipment possibilities, and the knowledge gained by in house and area histories, can give indications of what other material may be needed or useful.

3.1.4.9 Post Job

Post job analysis is used to evaluate the end quality of the cement being placed. There are several methods used to qualitatively determine the quality of the cement. These methods include: performing

FIT/LOT tests, comparing design parameters to execution parameters, lift pressure analysis, completion of job objectives, and running bond logs on the cement in the annulus. Some additional considerations need to be taken into account when discussing bond logs. As cement begins to develop compressive strength, the acoustic impedance inherently increases. Special consideration needs to be taken into account in regards to the timing of running bond logs on cement. If the bond log is run before the cement has developed sufficient compressive strength, the cement in the annulus may not be visible on the logs. The acoustic impedance of set cement can vary depending on multiple factors including, but not limited to: density, porosity, additives in the system, and slurry contamination. It should be considered a guideline to measure or calculate the acoustic impedance and compressive strength of the cement under laboratory conditions prior to the cement job such that wireline technicians are able to properly interpret their logs. Acoustic impedance is used for ultrasonic logs. For sonic logs, the measurement is amplitude or attenuation of the sonic signal as it travels through the casing. For sonic logs, the user needs to know the strength of the cement so that the anticipated amplitude/impedance can be estimated for cemented pipe. It should also be considered a guideline to not run a bond log until the calculated top of cement (TOC) slurry has reached an acoustic impedance of at least ½ MRayl above the mud's measured acoustic impedance.

3.2 Specific Cementing Procedures and Operational Guidelines

Practical minimum standards outlined by API are required for each type of cement. All of the scenarios discussed in the following paragraphs assume the cement meets the requirements of the situation where it is being used. The cement system, along with the cement spacer system, must be designed for a specific environment and job objective. Cement slurry laboratory testing and cement spacer testing should be performed under simulated downhole conditions.

3.2.1 Initial Casing Strings

For initial casing strings it should be considered a guideline to perform laboratory testing on the cement slurry at bottom-hole conditions and additional tests should be performed on systems designed for coverage at the mud line. This is especially important for deep water cementing operations as the mud line temperature begins to dramatically decrease for water depth greater than 300 feet. More time is required for Portland cement to develop compressive strength at lower temperatures. In addition to providing zonal isolation, the cement used in top hole sections must also provide the axial support for the installation of the BOP and other equipment.

Surface cement jobs are normally high volume, ranging from 2000 to 5000 sacks or more. The majority of cement jobs require nitrogen or low density solids to be added to control hydrostatic and expected ECD pressures, to prevent fracture or ingress to a particular zone. As with all cement systems, proper design and field implementation must be performed for quality post-job results. Additional foam cementing considerations are outlined within section 3.2.5.4 of this document.

Other case specific guidelines relating to initial casing strings have been broken into two specific categories: cementing operations where returns are to the seafloor and cementing operations where returns are to surface. Both are discussed further below.

3.2.1.1 Fluid Returns to Seafloor

Subsea surface strings where the BOP has not been landed are drilled with returns to the sea bed. Pore Pressure and Fracture Gradient limitations will be the critical factor to be considered on all cementing operations. Shallow water flows are common in many areas and some are of great enough magnitude to cause concern when cementing over these sections.

Generally, the initial open hole sections are drilled with seawater, then the seawater is replaced with pad mud. As a general guideline, the pad mud should have a somewhat low yield point such that the cement slurry does not have to be designed with a higher than normal yield for proper displacement efficiency. It should be considered a guideline to install a dart catcher sub on the drill pipe to assist with cleaning during the cement job. The density, viscosity, and long term gel strength of the fluid to be displaced needs to be taken into consideration to prevent naturally occurring forces that will exceed the design parameters. The fluid added after the drilling process has completed is generally a low solid high gel consistency, and little thought is given to the long term gel strength and the effects of low temperature. A relatively high pump pressure may be needed to initiate fluid movement creating an unwanted stress on the formation. The falling velocity due to density differential cannot be controlled as returns are to the sea bed and the annulus is completely open. The guideline is to engineer the fluid resident in the well bore to be consistent with the design criteria of the cement job thus avoiding or minimizing undesirable characteristics. Pad fluids that have non-progressive gelation tendencies tend to be suitable choices.

It is very critical to have good cement coverage at the shoe for all cemented casing strings, but it is especially important on the initial casing strings and in deep water conditions where the next hole section could potentially be drilled with the riser in place. It should be considered a guideline to pump excess cement slurry on initial casing strings to reduce the risk of not having proper cement coverage at the mud line. One method is a fixed slurry excess, generally 100 to 200 percent depending on external factors and historical well data. A second option is to monitor the fluid returns at the mud line while pumping lead slurry either visual or through a pH meter. When cement has reached the mud line, mixing of tail cement should be initiated. The positive aspect of this method is confirmation of cement to the mud line while not pumping large amounts of slurry excess. In most cases, a larger volume of lead cement circulated to the seafloor will not affect the cemented annulus end result; however, care should be taken to ensure that cement returns will not affect any subsea equipment.

3.2.1.2 Fluid Returns to Surface

Cementing initial casing strings where fluid returns to surface are more prevalent in shallow water shelf conditions. Hole gauge is a very critical factor when cementing these initial casing strings as the cement needs to be circulated to the mud line but the casing may be cut at or near the mud line during future operations. Excess cement can't be pumped as it will be placed in unwanted areas. Another aspect which needs to be taken into account is the possibility of having two separate flow regimes which the fluids may pass through while in the annulus. The annular clearance of the drive pipe section is much larger than the annular clearance from the open hole section. It should be considered a guideline to incorporate these geometries into placement simulations to anticipate their displacement efficiencies.

3.2.2 Intermediate Strings

Intermediate strings are used to break the well up into workable sections or isolating potential problem areas. Examples are high permeability and/or low pressure sands, pressured aquifers, salt or mobile formations, rubble zones, sloughing shale's, etc. Running intermediate strings as liners can eliminate long sections of narrow annuli which can reduce ECD's.

When a possibility for flow or losses exists in this zone, the guideline is to ensure isolation of the area either by mechanical or chemical (e.g. cement) means, and test to validate the seal. The top of the liner should be tested prior to drilling out the shoe. Once the shoe has been drilled out, testing the integrity of the liner top seal becomes more difficult. Upon drilling out the shoe a LOT or FIT is typically performed to verify the subsequent section can be drilled.

Other intermediate strings are brought to the wellhead to isolate previous casing strings. If the string will have a significant amount of unsupported pipe, a guideline should include calculations encompassing the expected temperature and pressure changes during the production cycle. If a failure should occur, the total damage may not be localized, and can extend to adjacent casing strings. It may be possible to predict areas where failure could occur; particularly if there are recurring cycles where changes in the pressure and stress dynamics are anticipated or programmed. Some additional support can be placed on the string at calculated strategic points to minimize the chance of catastrophic stress accumulation.

Intermediate casing strings are generally the first jobs where mechanical separation of all fluids can be achieved. Generally, displacement volumes are much larger than mixed cement volumes. It should be considered a guideline to have mechanical separation of fluids to reduce the likelihood of fluid contamination during placement. During displacement, it should be considered a guideline to have displacement pump rates as high as possible for better hole cleaning efficiency while keeping dynamic pressure below the fracture gradient. High displacement rates help to keep up with the cement's tendency to free fall in the casing from the U-tube effect. Although measurement of mud compressibility should be considered a guideline prior to any cementing operation, the larger the displacement volume, the more important it is to perform these measurements. Entrained air can give incorrect final displacement volumes leading to higher risks of cement left in pipe. It should also be considered a guideline to keep track of the mud return volume as an additional quality assurance check during displacement. Mud displacement volumes should be physically measured by tank straps where possible.

3.2.3 Production Strings

3.2.3.1 Vertical

Production strings can be set as a liner or as a single string of casing to the well head. Liners will normally be tied back to the well head if conditions warrant such an action. The majority of production strings will be of relatively small diameter (7 5/8" casing or smaller) and the annuli will normally be less than two inches greater than the casing size. The only characteristic the producing formations will have in common is that they contain hydrocarbons in some form. Of all cementations, this one can be considered the most critical. Selecting the best design and technique that will meet job objectives can be challenging. Once a design is selected, procedures are written to implement the process in the field. Very critical aspects merit more attention to detail when writing the field procedure. As with all jobs, a step by step program is necessary to ensure field implementation will be carried out in the manner prescribed. When a special sequence must be followed, those instructions need to be clear and the importance of the sequence should be explained. When an ordering of events is very critical, a description of the consequences when the order is breached will add emphasis.

Batch mixing in the field will produce the closest match to the laboratory results. Batch mixing ensures homogeneity in the slurry, chemicals are in the exact proportion required, density is uniform, and eliminates potential bulk delivery issues which may be encountered during the cement job. While batch mixing will provide the most uniform slurry, it does come with its own set of operational challenges which must be addressed if slurries will be batch mixed. Among these operational challenges are the need for additional equipment on location, volume limitations, and surface retention time considerations.

The displacement flow regime also is critical. Adhering to the programmed rate will maximize mud removal and create the environment necessary for the cement to effectively seal the annulus. Generally, cement and spacer designs are based on the mud properties at bottom hole conditions. Parameters such as density and rheology of the mud can be very different when comparing to atmospheric conditions. Additional consideration should be performed to check the compatibility of the mud and cement at surface conditions as well as bottom hole conditions. Where bottom hole conditions cannot be met in the laboratory, compatibility testing should be conducted as close as reasonably practical. When running casing within vertical production zones, it should be considered a minimum guideline to centralize the casing to the calculated top of cement. As an additional recommendation, centralization to the calculated top of spacer would help increase the likelihood of cement coverage to TOC by reducing eccentric annuli where mud removal is taking place.

3.2.3.2 Horizontal

The same practices as described in vertical production casing cementing apply equally when cementing high angle or horizontal casing strings. The major difference is that the force vector applied by gravity is now nearly or exactly perpendicular to the direction of flow. Inside of the casing, fluids of different densities can be separated by gravity moving a heavier fluid to the bottom of the casing and any lighter fluid will tend to float on the denser fluid. Mud, spacers, and cement normally have a density hierarchy where the spacer is heavier than the mud, and the cement is heavier than the spacer. If they can all be separated by cement plugs, this method can still be useable in high angle scenarios, but it should be considered a guideline to have all fluids very close in density and have displacement efficiency built around the rheological hierarchy where successive fluids have greater viscosity. When competent cement through the deviated and vertical section is a primary job objective, density hierarchy for the fluids which cover this section will aid in displacement efficiency. Alternatively, to avoid unnecessarily pumping fluids through a horizontal section, a stage tool may be considered whenever isolation is needed in the vertical section of the wellbore.

Production strings run as liners may have only a top plug. When wiper plugs are not available, it may be beneficial to have the cement and spacer at the same density to maintain a more defined interface. If the density differential between the spacer and the mud is more than two pounds per gallon, consideration should be given to increasing the volume of spacer if it is felt that the spacer/mud interface may suffer excessive contamination. The guideline should be to have a physical barrier between different fluids. When that is not possible or practical, increase the volume(s) to allow for some sacrificial losses.

Centralization is very important when cementing horizontal trajectories. Certain bow type centralizers should not be used in horizontal sections as the weight of the casing will flatten out the centralizers on the lower portion, where the restoring forces of the centralizers are not enough to support the weight of the casing. Running rigid type centralizers should be considered a guideline in horizontal sections as annular clearance is more likely to occur. Cement slurry designs are recommended to have no free water or settling tendencies when placed in horizontal sections. Small amounts of free water within a cement system can lead to flow channels in horizontal sections.

3.2.3.3 HP/HT

High pressure and high temperature wells pose additional technical issues relating to cementing. Higher temperature wells require the addition of silica to cement systems to combat strength retrogression which can occur above temperatures of 230°F. When bottom hole temperatures are above this temperature, special consideration should be performed on the temperatures experienced by cement on previous strings. It should be considered a guideline to add silica to all cement designs which have the possibility of encountering temperature profiles above 230°F throughout the life of the well.

Higher density cement systems are required in abnormally pressured zones to adequately hold back the possibilities of formation influx. Cement systems become more difficult to design as the density is modified outside of its "neat" formulation. The addition of weighting materials to slurry designs may change the slurry performance parameters. It is important to design slurries which are not only dense enough to hold back formation pressure but also meets all job objectives.

3.2.4 Tiebacks

As an offshore well is drilled, several liners end up being hung inside each other making the casing profile go from narrow at the bottom of the well to much wider up near the mud line. As a final step, generally a tieback string is run for many reasons which include increased well integrity during production operations and additional support of the cased well during flow-tests or fracturing treatments. Two additional pieces of hardware need to be considered when designing for a tieback string. The polished bore receptacle (PBR) has a rated differential pressure which must not be exceeded during cementing operations or while stinging into. The cement column must not exert more hydrostatic pressure than the collapse pressure rating of the PBR as well. The hydrostatic and dynamic pressure of the cement column must not exceed the differential pressure rating of the liner top packer. Since the cement slurry does not contact open hole sections during placement, fluid loss control is not needed. As an introduction into special formation considerations, it should also be considered a guideline to have the top of cement generally 500ft above salt formations when tiebacks overlap salt zones. It should also be considered a guideline to centralize the tieback string very well throughout salt zones in anticipation of point loading from salt creep.

3.2.5 Case Specific Formation Considerations

Case specific formation considerations have defined parameters to minimize problems and provide the stability required for effective isolation. Cementing in potential annular flow zones, salt zones, lost circulation zones, and foam cementing considerations are all discussed further in the below subsections.

3.2.5.1 Potential Annular Flow Zone Cementing

Special design considerations need to be taken into account when cementing across potential annular flow zones. Currently, operators are required to follow to the recommended practices stated within API STD 65-2 as part of the revised Code of Federal Regulations. As an additional guideline, the transition time of the cement (also known as the critical hydration period) should be minimized as much as possible such that there is minimal time between the loss of hydrostatic pressure due to gel strength development and initial compressive strength within the system occurs.

3.2.5.2 Salt Zone Cementing

Salt zone cementing has its inherent difficulties and associated operational guidelines which are discussed further below. When cementing across salt there are three general philosophies for salt dissolution mitigation: no salt; low salt; and salt saturated. All three of these techniques have advantages and disadvantages to them. For example, salt saturated cement systems will decrease the amount of salt dissolution, but can diminish the fluid loss control of a cement system. Regardless of which approach is taken in the slurry design phase, a full technical analysis of the final slurry and how contact with a salt formation will affect it should be conducted.

Just above salt is a rubble zone which has been known to cause operational difficulties due to lost circulation. Having a liner hanger contingency plan allows operators to case and cement off this lost circulation zone without the need to redesign the remainder of the casing program if losses are more than expected. It should also be considered a guideline to avoid hanging liners within any salt zones if possible. Liner hangers create annular clearance restrictions which should be avoided due to the salt creep point load considerations.

3.2.5.3 Lost Circulation Zone Cementing

As discussed above, rubble zones generally occur above and below salt zones where higher risks of lost circulation are present. This is one example of lost circulation cementing which operators can experience during drilling and/or cementing. As discussed in the general cementing guidelines subsection, it should be considered a guideline to use BHA's that are able to pass LCM through if losses are anticipated. It should also be considered a guideline when cementing across known lost circulation zones to have LCM built into the cement design. It should be considered a guideline to cure any losses prior to cement placement when possible. If it is not possible to cure losses prior to cementing and the cement is anticipated to reach the loss zone, the cement slurry should be designed so that lost formation will not cause annular bridging or other issues that could be detrimental to zonal isolation. As a cement placement consideration guideline, pump rates should be increased if losses are encountered during the cement job. Although this statement is counterintuitive, the faster pump rates will ensure better hole cleaning at the shoe. If pump rates are slowed down, there are more risks associated with improper hole cleaning leading to potential communication through the cement matrix after placement.

3.2.5.4 Foam Cementing

Foam cementing is used often in offshore situations where low ECD's are needed due to formation fracture gradients. There are many recommended guidelines derived from foam cementing case studies which are discussed within the literature review along with documented testing methods discussed within API 10B-4. When nitrogen is incorporated into the mix, the use of a process controller to inject the nitrogen will keep the Nitrogen (N_2) volume consistent with the rate cement is mixed and pumped. The process controller measures the incoming cement rate and adjusts the volume of N_2 injected to keep the ratio of N_2 to cement within the designed parameters. Several additives should be avoided if possible when designing a foam cement system. These additives are: antifoams, dispersants, and potassium chloride. These additives have been known to decrease foam quality and stability within cement slurries. If one of these additives does need be used in the base slurry for various reasons, careful measurement of foam stability and resulting foam quality should be performed to see what affect it will have on the system. It should be considered a guideline to have the yield point of the base slurry greater than $10lb_f/100ft^2$. Base slurries with low yield points can also affect the foam quality and foam stability. It should also be considered a guideline to adjust the mixing density of the cement slurry to account for any additives that will be injected downstream of the mixing unit, such as foaming agents and stabilizers.

3.2.6 Remedial Cementing

The main guideline for remedial cementing should be to reduce the likelihood of needing to perform remedial cementing through sound placement of previous primary jobs. Sometimes remedial work can't be avoided and must be performed which is the case in well plug and abandonment operations. The remedial cementing subsection has been broken into several categories of guidelines which include: rig equipment considerations, cement kick-off plugs, plug cementing, squeeze cementing, and special considerations when cementing through perforations. Operational guidelines for each of the categories are discussed below.

3.2.6.1 Rig Equipment Considerations

Specific pieces of equipment are needed on location for remedial operations. Most are case specific to the operation that is being performed. Items such as packers, stingers, wireline retainers, tong sizes and diverter subs need to be taken into special consideration for a successful remedial operation. When planning on using packers, it should be considered a guideline to take into account the manufactured size restrictions of current packers on the market. Certain scenarios, generally in large diameter casing strings, are possible where there is no packer on the market which will fit within the wellbore. If cement is to be placed using a stinger attached to drill pipe, it should be considered a guideline to have the length of the stinger be twice the calculated length of the longest cement plug which is being set. Separation of fluids during placement is still considered a guideline. If possible, a foam ball launching manifold should be used to assist with fluid separation. When performing squeeze operations, it should be considered a guideline to have a squeeze manifold rigged up for the cement job, even if the squeeze procedure does not require one to be rigged up. The squeeze manifold assists with any contingency operations which may need to be performed. It should be considered a guideline to perform abandonment operations with a derrick. From a cost standpoint, abandonment operations are less expensive when performed rig-less, but can end up being more operationally difficult in certain scenarios. A cost/benefit analysis should be performed when planning whether or not to perform abandonment operations with a rig in place. It should be considered a guideline to attach diverter subs onto tubing for placement of any cement plug including: balanced plugs, kick-off plugs, Bradenhead squeeze plugs, etc.

3.2.6.2 Cement Kick-Off Plugs

When the hole being drilled cannot be continued for any reason, a decision is made to plug back and move in a different direction. A cement plug is placed and drilling continues by-passing the original hole. A cement plug is set to isolate the hole below and may be used to provide the platform to kick-off and drill in another direction. The guideline would be to set the plug across the softest formation when that is possible. Generally the plug needs to be in a strategic position so that the original target depth can be reached with as little disruption to the well plan as possible. Kick-off plugs are generally reduced water slurries designed to be harder than the surrounding formation. There are two criteria necessary for a kick-off plug to be effective. The first is to put the cement in place with no contamination, and the second is time to gain compressive strength.

The majority of drilling fluids are not compatible with cement. Oil or synthetic based muds may damage the quality of the cement so that it will not gain compressive strength or completely retard the chemical process. It is imperative to use the correct type and volume of spacer to remove as much of the mud as is possible. Placement simulations may be used to calculate the effective spacer volume needed for these operations if available. If placement simulators are not available and the spacer is assumed to be in laminar flow, a common practice is to base spacer volume on 10 minutes of contact time. The larger the open hole the greater the volume of spacer required. Some muds are so reactive that even a small amount of contamination will inhibit or destroy the properties of the cement. Cement contamination will account for the majority of failed attempts to side track. Plugs and Kick-off plug setting operations should be treated with the same importance as production string jobs in regards to simulations for mud removal.

The second part is time to gain compressive strength. Until the cement acquires enough compressive strength to equal or exceed the formation strength, it is more likely the plug will be drilled up before the kick-off is achieved. If the placement time and the temperature of the hole will support the use of a cement accelerator, WOC time can be reduced as accelerators produce high early strength.

Large diameter holes combined with light low viscosity and low yield point muds, may allow the plug to slump and fall through the mud until it reaches a point where it can be supported or it begins to be self-supporting. The guideline in this situation is to spot a high viscosity mud pill below the plug to help hold the cement in place.

Whenever possible, batch mixing the cement is the preferred method for mixing. If the formation where the cement will be placed is permeable, the addition of a fluid loss agent may be a further consideration. Usually pipe rotation and reciprocation can be achieved on these plugs and can contribute to successful operations. Hole size should be determined to the best of the operators ability in order to set a successful plug, using previously mentioned methods. Additional considerations which may increase the chances of successfully setting a kick-off plug include using a centralized placement string, using a slick-wall stinger, using drill pipe wiper balls and a ball catcher sub, using a diverter tool, or using a disconnect tool.

To be able to balance the plug if using open ended pipe the fluid in the annulus and drill pipe has to be of the same density. Any mud pill or heavier density fluid in the annulus or drill pipe will make accurate placement difficult or impossible as the fluid will u-tube in the pipe until equilibrium is established. The guideline is to circulate and condition the mud until a stable density is achieved.

3.2.6.3 Plug Cementing

A cement plug is used to isolate or abandon a section of hole either temporarily or permanently. The specific procedures for putting a plug in place are: a.) balancing a plug through open ended pipe, b.) pumping through a cement retainer, c.) bull heading the cement to a desired position. All of these methods will produce isolation. Individual well conditions will determine the best or most practical method of placement, or conditions dictate a particular method. The cement plug plug requirements outlined within the code of federal regulations must be followed unless an exemption is granted.

A balanced plug through open ended pipe is normally used when there are no adverse well conditions. The well is stable and the fluid level is static. A work string is run in the hole to a required depth and cement is pumped around and up into the annulus until the cement is of equal height in both the work string and the annulus. If a spacer is needed, it also must be calculated so the top of the spacer will be equal inside and outside the work string. The work string is then removed and the plug is in place. Points to consider are the density of the cement against the in-situ fluid. If the fluid in the hole is Newtonian or near Newtonian, especially with a large density differential, the cement may slump and fall down the hole until finding a platform that will stop the process. This is particularly true in large diameter holes (over 8 inches in diameter). The guideline to prevent this from occurring is a high viscosity gel pill immediately below the proposed bottom of the cement to prevent the gravity slump of the cement.

When well conditions are unstable and/or a mechanical barrier is needed or required, a plug can be put in place using a cement retainer. The retainer may be the bottom of the cement plug or if there is an exit for fluid flow below the retainer, cement can be pumped through the retainer to form the plug. The cement retainer is run in the hole and set at the required depth. The running tool for the retainer can be stung in and out of the tool permitting cementing above and below the retainer. When the fluid in the hole is reactive with the cement, spacers need to be used above and below the retainer. An example is where a given volume of cement is needed below the retainer, and a further volume is desired above the retainer. Spacer and cement will be pumped down to the bottom of the work string that is immediately above the retainer top, a volume of spacer will be spotted on top of the retainer.

The running tool is then stung into the retainer; the remaining spacer and the required volume of cement are pumped below the tool. The running tool or “stinger” is then pulled out of the tool and the final volume of cement is pumped across the top of the tool. The spacer initially placed above the retainer is equal in height to the spacer that was pumped behind the cement so essentially a balanced plug exists on top of the retainer when pumping ceases.

The final case is where a balanced plug or a cement retainer is impractical or unable to be used. An example is where a tool is hopelessly stuck and there is no circulation above the tool. The decision is made to abandon the tool and the section of hole below the tool. The conditions dictate that there must be cement below the tool to isolate the formation as well. In this case there are perforations below the tool, so fluid can be injected through the string and exit to the formation.

Spacer and cement in the required volume are mixed and pumped and essentially bull headed down the string past the tool and into the perforations. The cement is displaced to the proposed depth above the tool and pumping is stopped. The pipe can then be safely cut and recovered, and if necessary, another abandonment plug can be run if required.

Performing remedial cementing operations through coil tubing has its own special considerations. The friction pressure drop caused by long lengths of tubing must be calculated prior to the cementing operation such that there is sufficient hydraulic horsepower for placement. It should be considered a guideline to design cement systems under specific performance parameters for coil tubing operations. The viscosity and gel strengths should be minimized to assist with reducing any unnecessary friction pressure during placement. There should not be any free water or sedimentation in the slurry. Settled solids can bridge off inside the coiled portion of the tubing leading to job failure. When pump and pull operations will be performed, pre-calculation of pump/pull rates should be performed such that placement modifications can be made real-time if needed.

3.2.6.4 Squeeze Cementing

Many reasons will dictate the need to squeeze cement. They include zonal isolation; water shut-off, shoe repair, and abandonment to name a few. Choosing a placement technique will be dependent on the task to be accomplished. In general squeezing is filling a void space with cement to prevent flow, provide support for a structure, or to prevent movement. The cement should have a permeable medium in order to achieve a squeeze. This information is used to determine perforation placement when necessary. Volumes to be used in a squeeze are dependent on several factors. It could be a known volume needed to fill a space between casing strings, or a volume estimated from an injection rate. For the safety and integrity of the well, the burst and collapse pressures of all casing, drill pipe, or tubing should not be exceeded during the squeeze operation. The three prevalent placement techniques are Bradenhead, running, and hesitation squeezes. The specific procedures are described below.

All squeezes are classified as either high or low pressure. During high pressure squeezing operations, the fracture gradient will be exceeded and induced fracturing will occur. In low pressure squeezes, the fracture gradient is never exceeded allowing cement to remain within the wellbore and travel only into preexisting flow paths within the wellbore. Generally, low pressure squeezing is preferable if possible. However, there are certain instances where high pressure squeezing is the only way to effectively place cement where it is desired.

A Bradenhead squeeze is most commonly used when squeezing a shoe to gain pressure integrity for continued drilling. Bradenhead squeezing is most often performed as a low pressure squeeze. Cement is placed as a plug at the bottom of the casing string and the placement pipe is pulled out of the cement to some point above the top of cement. The annulus is closed in and pump pressure is applied forcing the cement into the void space to be filled. A given volume of the cement is pumped to the void and usually some percentage is left in the casing. The well may be shut in during the curing process if conditions warrant. After curing, the cement is drilled out and pressure is re-applied to see if the void or channel has been eliminated.

A running squeeze is normally done through a packer or cement retainer but can be conducted by closing in the BOP stack. The work string is placed near to the injection point of the cement. Cement is then circulated down the string preceded and followed by an appropriate spacer. The annulus is isolated either by closing the BOP stack or setting a packer. The cement is then pumped into the injection point to perform the remedial action. Depending on the operation, pressure may be expected to build to a point where pumping is stopped, or a predetermined volume or height is reached and the operation is halted.

The same operation can be performed using a cement retainer. The operation is the same but annular isolation is performed by stinging into the retainer. Retainers are normally used for abandonment purposes, but are frequently used when well control is an issue. As good example is lost returns during the drilling operation.

A hesitation squeeze is performed using the same isolation techniques used for the running squeeze. The main reason to perform the squeeze in this manner is to inject given volumes of cement with waiting periods between injections to build pressure on each successive pump operation. The interval between injections can be predetermined, or by letting the pressure profile dictate the frequency. This technique is normally used to seal off a formation by destroying the permeability behind the casing.

The guideline for all squeeze scenarios is clearing any contamination that may affect the quality of the cement. In the case of formations containing hydrocarbons the surfaces must also be water wet for the squeeze to be effective. It should also be considered a guideline to avoid performing squeeze operations below inflatable packers.

3.2.6.5 Perforation Considerations

The size, number, and phase of perforations play a large role in placement designs for squeeze and plug operations. In a perfect scenario, the larger and more frequent the perforations, the higher likelihood of having quality remedial operations. Phasing that perforates the casing along several azimuths increases the likelihood of providing a flow path to channels and provides more uniform coverage behind blank pipe. Generally, perforations built into remedial operations are either pre-existing or under special design constraints creating scenarios where the slurry and placement design is catered to the downhole conditions. As previously mentioned, cementing operations should be designed hand-in-hand with the well design. This is especially true for squeeze jobs through perforations. Perforations need to be placed so that connectivity to a permeable medium is established or no “low pressure” squeeze can occur and a "high pressure" squeeze will be necessary. This dramatically reduces the chance of a successful squeezing operation. Good fluid loss control should be built into slurry designs that will be flowing through perforations. The fluid loss control decreases the risks associated with the cement dehydrating and bridging off perforations prematurely.

4 Development of Relational Database Containing the Operational Guidelines

A searchable database has been developed which contains all cementing operational guidelines discussed above. The database contains information covering various contingencies which may be encountered during cementing operations and addresses procedures with identification of problem areas in the current state-of-the-art of cementing success.

5 Identification of OCS Cementing Issues Requiring Improved Practices

The vast majority of proposed cementing guidelines outlined in the previous sections are case specific depending on wellbore environments and conditions. Although most cementing guidelines discussed above are already current practices for most operators, some improved operational procedures are discussed below. A total of three sections below outline some additional improvements. These sections are cement design/operational improvements, service company improvements, and operator improvements. The goal of these new methods is to improve cementing and cement sheath quality success rates.

5.1 Cement Design/Operational Immediate Improvements

Centralization has always been important for cementing success. Good centralization is needed, and in most situations required, for the entire cement sheath. As an improved practice, the average casing standoff through the column of spacer in the annulus should mimic the average casing standoff through the cement. In other words, centralization is as important to the spacer for effective mud removal as it is to the cement for proper coverage. Effective spacer volume calculation and spacer contamination testing should be performed pre-job as well for all cementing operations. When centralization is unsuccessful, it is often because centralizers are based on gauge hole, when ample evidence exists that the potential for borehole enlargement is high. In areas and formations prone to borehole enlargement, gauge hole should not be used as the baseline for centralizer size selection.

The majority of drilling rigs in the OCS currently do not have the capability of collecting representative dry cement samples during the transfer from the rig storage bins to the mixing equipment. Generally, if a sample needs to be caught during this transfer, residual cement is left in the surge can at the end of the job and then collected as the blend sample. As an immediate improvement, cement dry sample collection valves should be installed in the bulk systems on rigs to allow for higher quality representative samples to be collected during cement jobs.

Another recommended immediate operational improvement is directly related to salt formation cementing. If and when at all possible, operators should attempt to avoid hanging liners in salt formations such that there are minimal annular restrictions within the salt zone.

5.2 Service Company Immediate Improvements

The main cementing issue identified as requiring immediate improvement is operational service delivery. Cementing service companies have highly advanced cementing design simulation software programs and are very knowledgeable of the operational guidelines and procedures needed for successful placement operations, but more focus needs to be placed on executing cementing operations as designed. Certain situations require operations to deviate from original placement design, but the majority of these are because of improper initial assumptions made during the design process. Cementing service companies generally have similar sets of standards and best practices for their operations. Well thought out contingency planning, if not currently performed, must be performed such that there is a planned contingency for any and all design deviations that could occur.

5.3 Operator Immediate Improvements

For operators, there are two immediate improvements which work hand-in-hand. The first immediate improvement is operators need to develop internal cementing standards and requirements for operational best practices if they don't currently have standards in effect. The content in this report will assist as a starting point for operators who currently do not have internal cementing standards and requirements. The second immediate improvement for operators is to monitor and validate that their internal cementing standards and requirements are being followed at all times.

6 Identification of OCS Cementing Issues Requiring Fundamental R&D and Outline Steps to Develop Fundamental Understanding

During analysis of current cementing practices primarily being used within the OCS, several issues were identified as needing additional fundamental research and development which are discussed further below. These issues should not be considered an all-encompassing list as further research and development can be performed on virtually all aspects of offshore E&P design and operational practices.

6.1 Identified Technical Deficits

6.1.1 Cement Simulation Software

As discussed within section 3.1.2.1, it should be considered a guideline to take all annular restrictions into account when performing cement placement simulations. More specifically, section 3.1.2.3.2

outlines the importance of performing placement simulations with the casing collars implemented into the simulator. Generally, casing collar annular restrictions are either overlooked or annular restriction is made from assumptions due to the tedious nature of manually inputting the data in for each joint of casing. Very few commercially available cement simulation software programs have the ability to automatically place casing collars.

An outline of steps to develop a fundamental understanding of this issue would begin by conducting a survey of current operators and service companies working within the OCS on cementing simulation software and how it is implemented for their individual scenarios. All parties would discuss their inherent difficulties with currently available simulation software such that the software companies have a solid foundation of current issues in need of investigation and future development modifications.

6.1.2 Foam ECD

As discussed within section 3.1.4.6, there presently is not an industry consensus on the best method to address the rheology of foamed slurries for cement placement simulations. Generally, rheology measurements are performed on the base slurry before it is foamed, but foamed cement rheology, especially under downhole conditions still remains unknown.

An outline of steps to develop a fundamental understanding of this issue would begin by development of a laboratory scale foam rheological measuring device based upon a flow loop concept. Base slurry would be foamed to required foam quality to meet job objectives. The foamed slurry would then be transported under temperature and pressure through a fluid rheometer flow loop developed for measurement techniques. Data acquired through this new testing method would be used to better simulate anticipated foam ECD’s in the field.

6.1.3 Mixing Energy

Currently, cement lab report should document any additional time needed to adequately wet cement at low shear, but how much effect does this additional time change field mixing operations or cement slurry properties. The main question from this is does total mixing time affect cement slurry properties or is mixing energy the only determining factor.

An outline of steps to develop a fundamental understanding of this issue would be to perform a mixing energy study where first the cement performance parameters of a control cement system were measured under API conditions. The shear rates and mixing times would then be modified such that mixing was performed throughout a matrix of conditions including low mixing energy, low total mix time, high mixing energy, and high total mix time. Slurry performance parameters would then be compared to observe any trends.

6.1.4 Laboratory Measurement of Fluid Loss

Currently, there are three separate API recognized test methods for fluid loss testing which include: atmospheric conditioning of slurry to BHCT followed by performing fluid loss measurement in a static cell, pressurized conditioning of slurry followed by performing fluid loss measurement in a static cell, and utilizing a stirred fluid loss cell for pressurized conditioning and fluid loss measurement. One question brought up is do the measured fluid loss results differ depending on the test method used and is one method more recommended under certain conditions when compared to the other methods.

An outline of steps to develop a fundamental understanding of this issue would be to perform a fluid loss study where several cement systems with fluid loss control additives are tested using all three fluid loss test methods and compare the results. The testing matrix for this study would have to include slurries with both moderate fluid loss control and high fluid loss control. Different temperature ranges also would have to be analyzed for completeness.

6.1.5 Gas Cut Prior to Cementing

More occurrences of gas cut mud being used prior to cementing on the shelf exist than in deep water conditions. Certain offshore scenarios are virtually impossible to completely remove all gas units from the mud prior to cementing. Currently, there is no standard procedure or means of identifying what are considered reasonable gas units within the mud where it will have negligible effect on the cementing operation.

An outline of steps to develop a fundamental understanding of this issue would best be handled through scaled down laboratory testing. First an annular configuration would be built for a simulated primary placement job. Mud would be gas cut at different quantities and a gas differential pressure would be held on the cement after placement, loosely simulating a fluid migration analyzer testing operation. As the cement transitioned through the critical hydration period, differential pressure measurement would be conducted and measurements of seal effectiveness would then be conducted on the cement sheath after it developed compressive strength.

6.1.6 Fluid Contamination

Fluid cross-contamination is inevitable during cementing operations. Many current operational recommended practices are used to help reduce overall contamination, but prevention is virtually impossible. This leads to the question of how much contamination is considered reasonable and what methods can be used to accurately measure fluid contamination within offshore cemented annuli.

An outline of steps to develop a fundamental understanding of this issue would best be handled through scaled down laboratory testing. First an annular configuration would be built for a simulated primary placement job. Different fluid sequences which simulate offshore placement techniques would be simulated. The set cement would be analyzed for seal effectiveness, column length, and ultimate compressive strength for comparison.

6.1.7 Slugs and their Effects

Prior to virtually every cementing operation, a slug is pumped downhole before initiation of tripping out drill pipe. Currently, there is no real standard for preparation of these high viscosity muds. Limited studies have been performed on what effect the slugs may have on mud removal or how much they may affect cementing success if they aren't completely removed prior to cementing.

An outline of steps to develop a fundamental understanding of this issue would best be handled through initial formation of an offshore steering committee with an equal balance of members with cementing background, mud engineering background, and drilling background. Members would provide generic slug preparation procedures used for most field operations. Laboratory scale volumes would be prepared for additional testing relating to rheological parameters, gel strength development, and contact time required for effective removal. Large scale testing would be performed simulating offshore environments of various conditions to analyze the various effects of these viscous pills and whether or not additional contact time may be necessary for proper cleaning of the hole prior to cementing.

6.1.8 Reverse Circulation Cementing

While RCPC has been used on land and on a few shallow water offshore wells, it has not yet been fully evaluated for use in a challenging deepwater environment. The application of reverse circulation cementing to deepwater wells is expected to reduce bottom-hole circulating pressures and prevent lost circulation during cementing as well as increase safety, environmental sustainability, zonal isolation and improve cement seals. One major challenge in deepwater cementing is the narrow formation fracture gradient, so the potential application of reverse circulation cementing has clear benefits.

An outline of steps to develop a fundamental understanding of this issue is already underway. The Research Partnership to Secure Energy for America is funding a 2-year investigation to evaluate the viability and applicability of reverse circulation cementing in deepwater wells. The current state of reverse circulation cementing technology and practices is being documented and assessed as part of this project. Analysis includes numerical models and simulations, mechanical placement controls and cementing materials. The results of this analysis are being used to determine whether or not reverse circulation cementing is a viable technique for deepwater cementing and if it is, what technical issues that need to be addressed before deepwater reverse circulation cementing applications can occur.

6.2 Physical Demonstration of Issues and R&D Approach

Of the multiple topics discussed above, the first two topics were chosen for additional laboratory R&D as part of this project. The results are discussed further below.

6.2.1 Mixing Energy Study

It has been shown that the applied mixing energy will affect slurry properties and that lab scale mixing conditions are not the same as field mixing conditions. Unfortunately, there is not conclusive evidence whether the applied mixing energy has a standalone effect on slurry properties or if the total mix time contributes to the variability. It was specified within the recommended guidelines above to document additional time needed for sufficient wetting under low shear in the lab. This additional time not only slightly increases the applied mixing energy, but total mixing time is increased as well. CSI performed a study to compare cement slurry properties under variable mixing energy and total mix time. Neat Class H cement was mixed using a Waring blender while varying rotational blender velocity and running time. Details as to mixing conditions and raw data are shown within the Mixing Energy Study inside Appendix B – R&D Laboratory Investigation section 7.2.1. Several contour plots were generated showing variances for the following slurry characteristics: atmospheric plastic viscosity, atmospheric yield point, BHCT conditioned plastic viscosity, BHCT conditioned yield point, measured free water, thickening time to 40Bc, and thickening time to 70Bc. These surface plots are Figure 7 through Figure 13 below respectfully. Applied mixing energy was calculated from the equation in Figure 6 below (Orban, et al., 1986).

$$Mixing\ Energy\ (kJ/kg) = \frac{k\omega^2 t}{V}$$

$Where$:

$k = 6.4X10^{-9}\ Nm/kgm^{-3}/rpm\ \ Note: Experimentally\ measured\ constant$

$\omega = Blender\ Rotational\ Speed\ (rpm)$

$t = Mixing\ Time$ (seconds)

$V = Slurry\ Volume/100\ (mL)$

Figure 6 Mixing Energy Calculation Equation

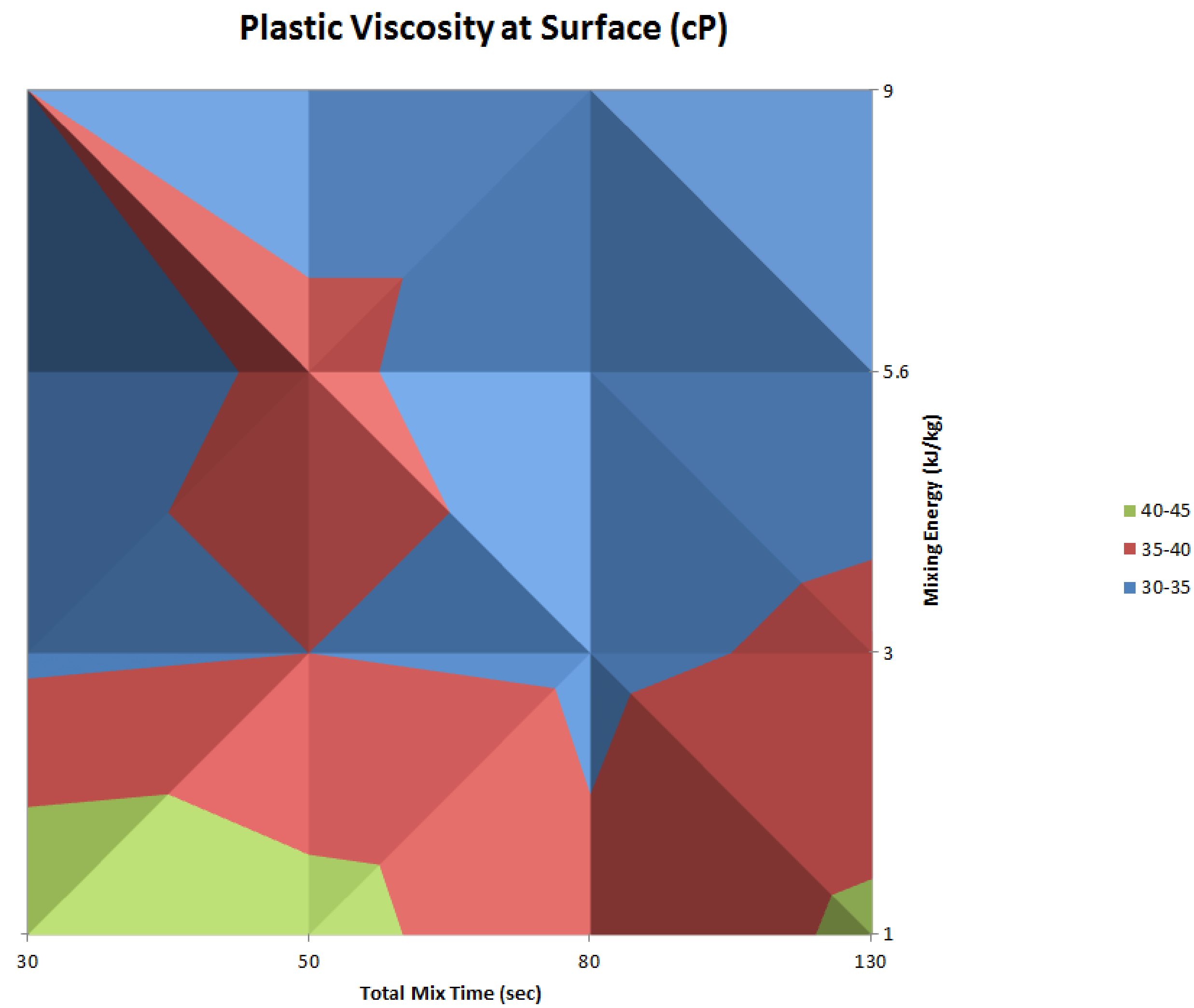


Figure 7 Mixing Energy Study - Plastic Viscosity at Surface Conditions

Figure 7 above shows the calculated plastic viscosity of the neat cement at atmospheric conditions. It can be seen from this plot that when mixed API, plastic viscosity was in the range of 35-40 cP. Higher total mix times at higher mixing energy reduce the measured plastic viscosity and there was an inherent increase as lower mixing energy was applied. It also should be noticed from this plot that the overall variance in plastic viscosity is somewhat small across the regime of testing conditions.

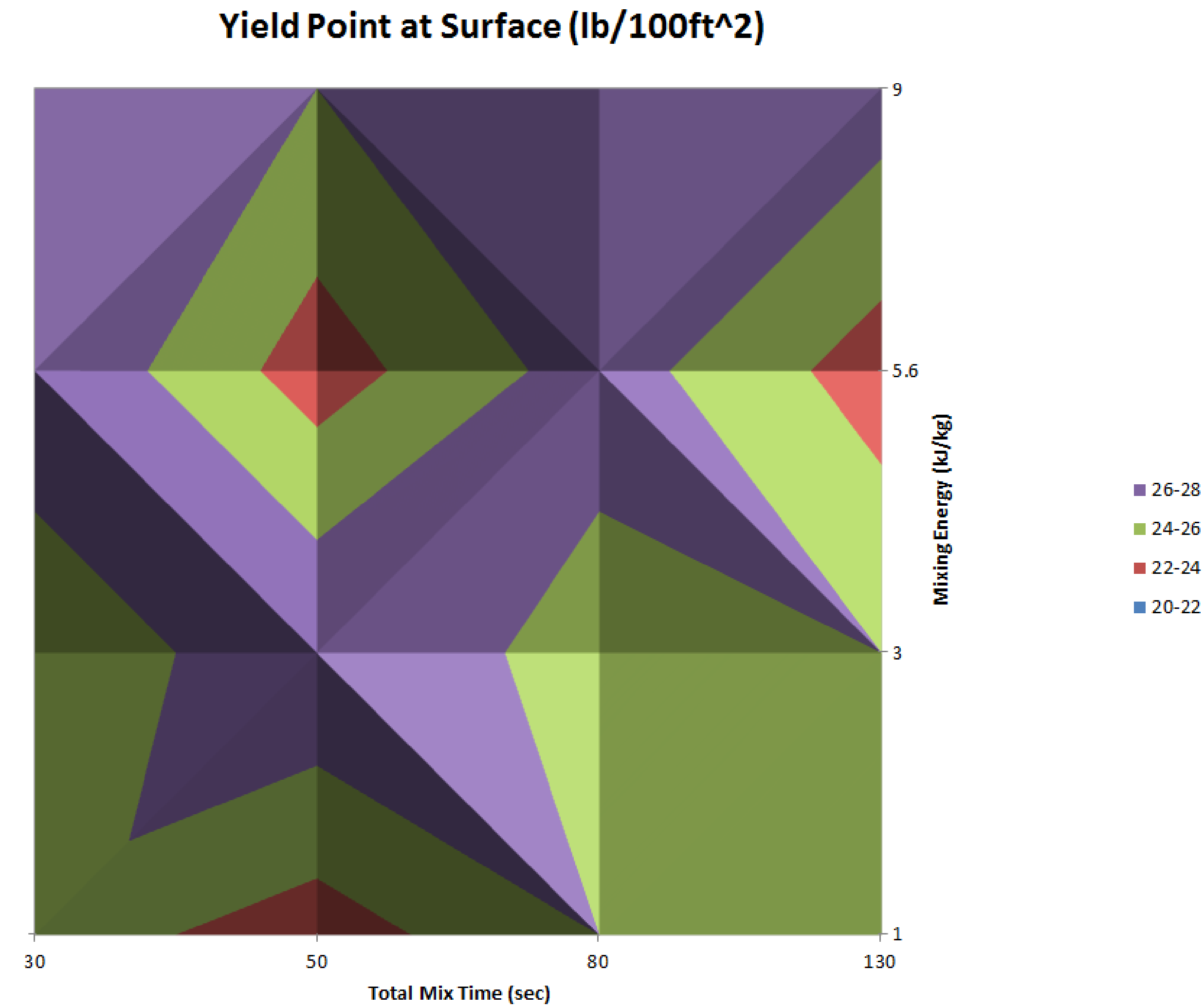


Figure 8 Mixing Energy Study - Yield Point at Surface Conditions

Figure 8 above shows the calculated yield point of the neat cement at atmospheric conditions. It can be seen from this plot that when mixed API, the yield point was in the range of 22-24 lb/100ft^2. Both slight changes in mix time and applied mixing energy increased the calculated yield point of the slurry. It also should be noticed from this plot that the overall variance in plastic viscosity is somewhat small across the regime of testing conditions.

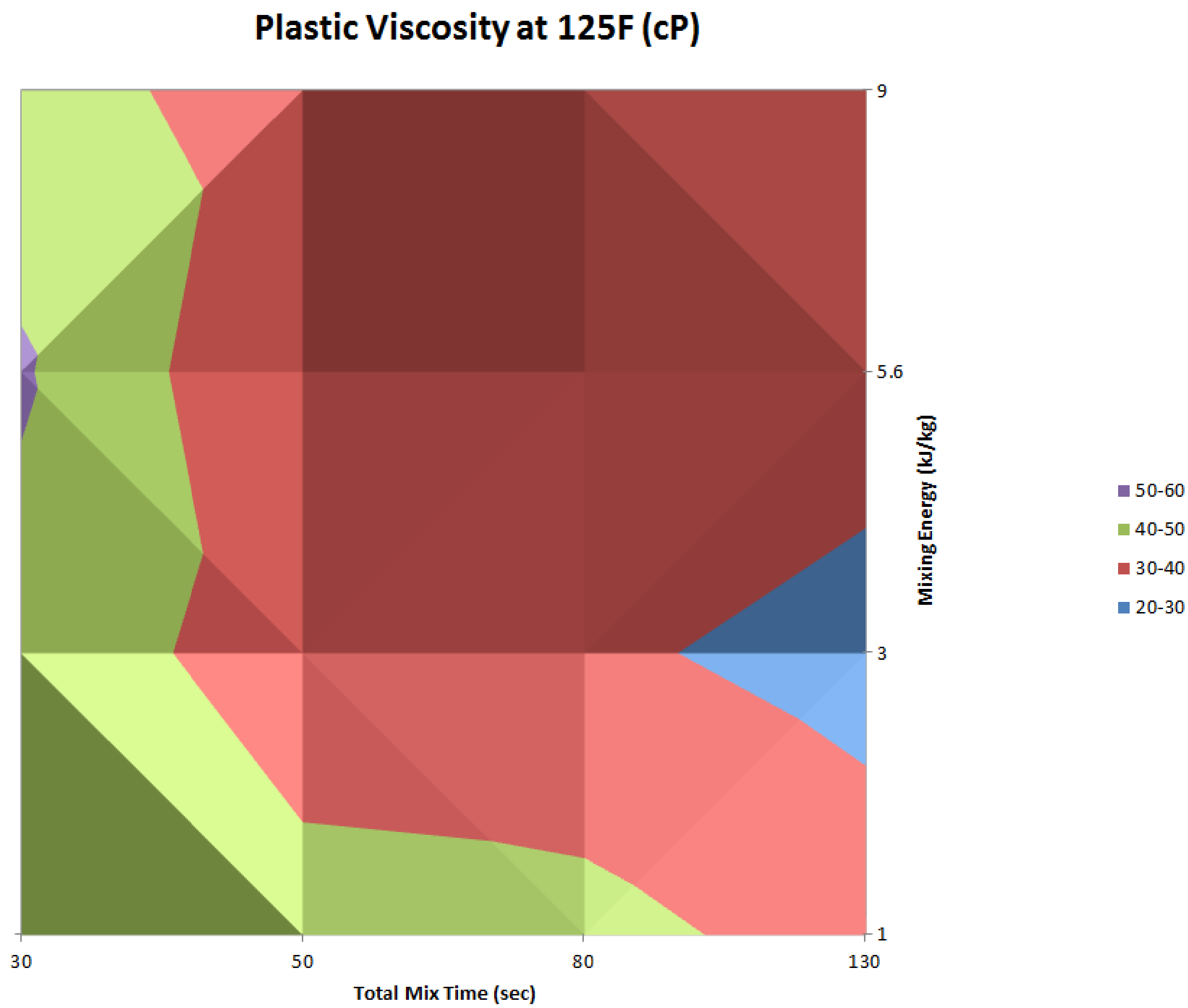


Figure 9 Mixing Energy Study - Plastic Viscosity at 125° F

Figure 9 above shows the calculated plastic viscosity of the neat cement after conditioning at 125°F and atmospheric pressure. It can be seen from this plot that when mixed API, plastic viscosity was in the range of 30-40 cP. Applying the same mixing energy in a shorter amount of time increased the calculated plastic viscosity, but longer total mix time had a negligible effect on plastic viscosity when the minimum applied mixing energy was API. It also should be noticed from this plot that the overall variance in plastic viscosity at temperature is larger than at surface conditions shown in Figure 7.

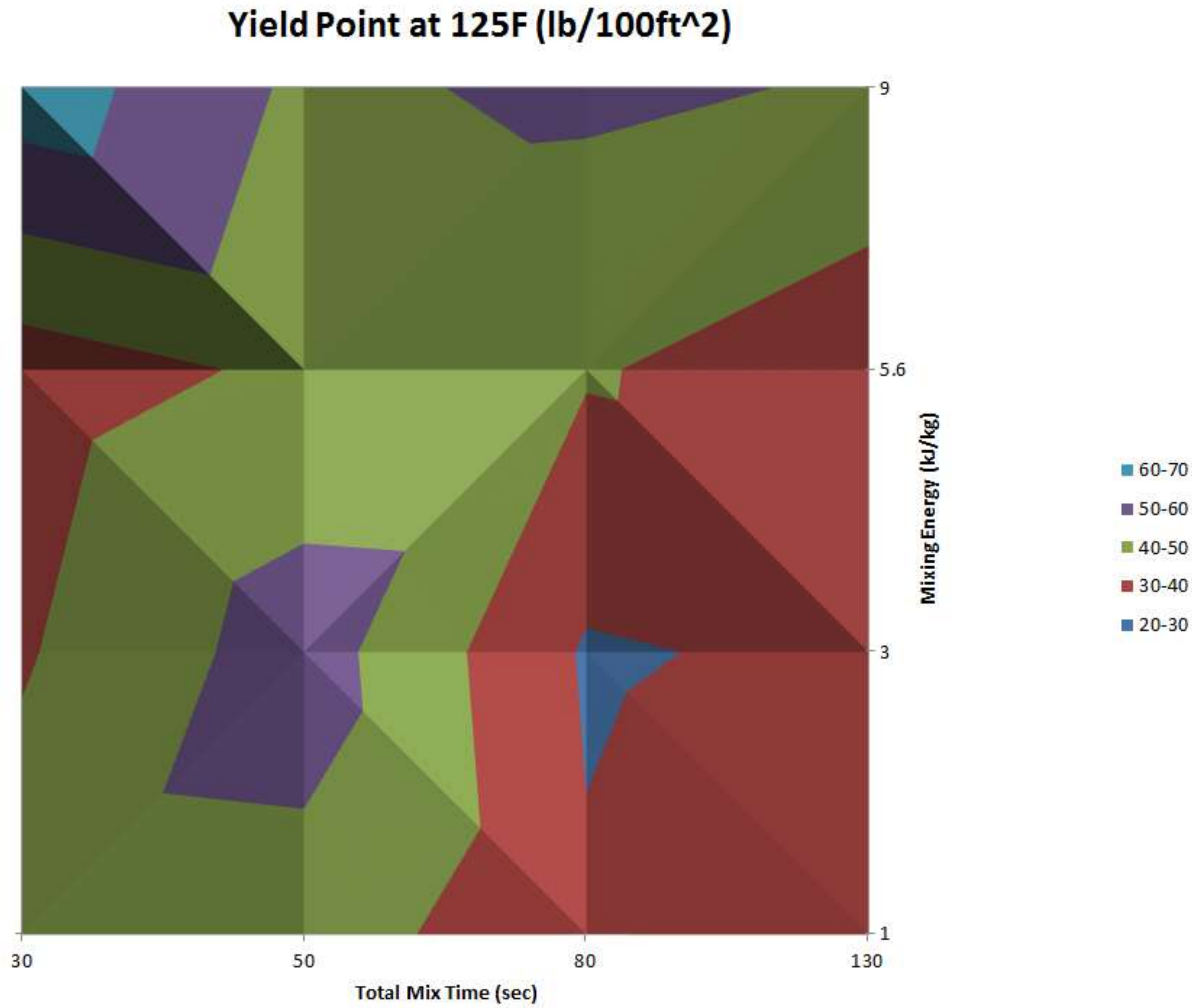


Figure 10 Mixing Energy Study - Yield Point at 125° F

Figure 10 above shows the calculated yield point of the neat cement after conditioning at 125°F and atmospheric pressure. It can be seen from this plot that when mixed API, yield point was in the range of 40-50 lb/100ft^2. Increases in applied mixing energy or total mix time had negligible effect on the yield point. It should be noticed that increases in total mix time with lower applied mixing energy decreased the calculated yield of the slurry. It also should be noticed from this plot that the overall variance in yield point at temperature is larger than at surface conditions shown in Figure 8.

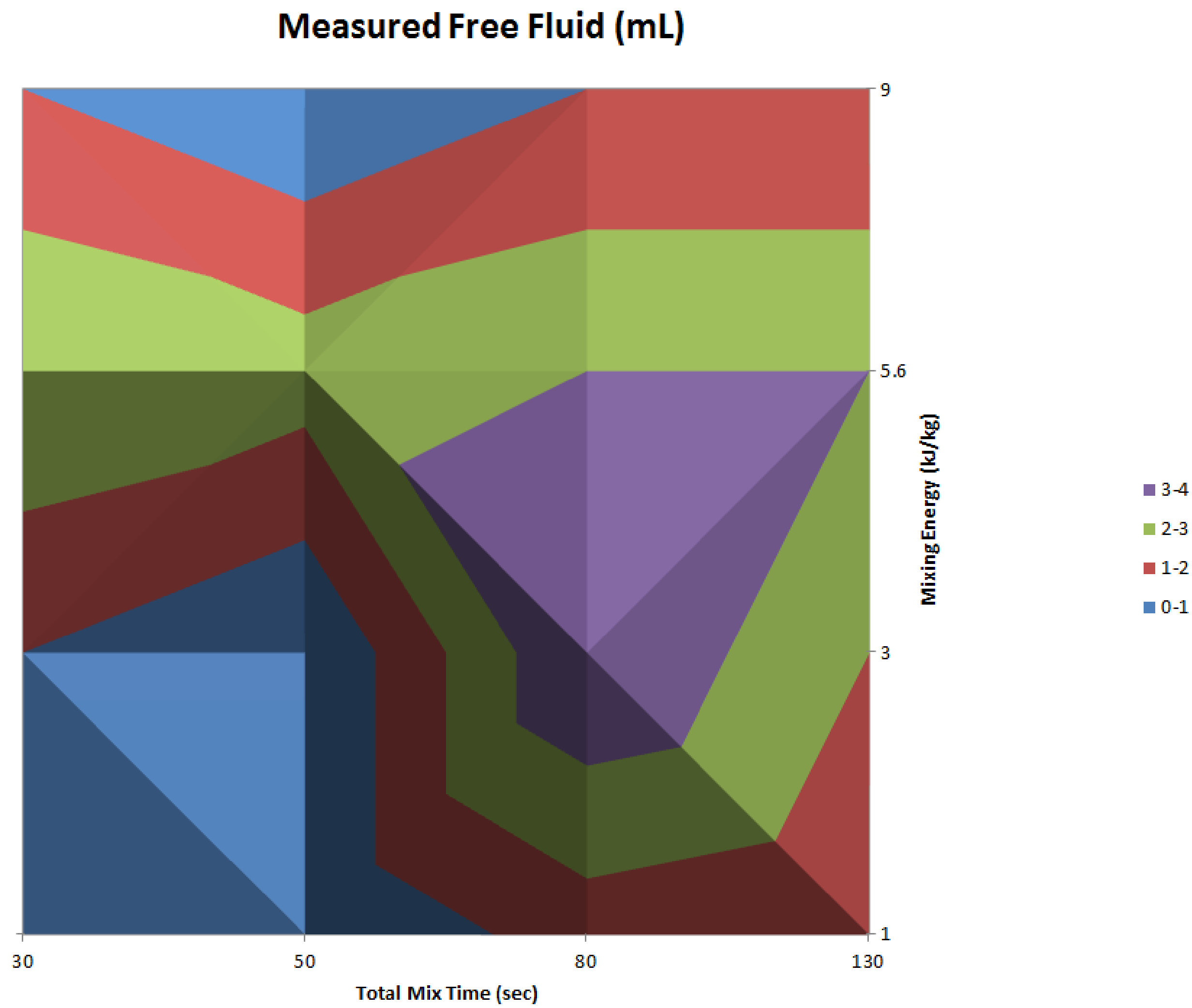


Figure 11 Mixing Energy Study - Measured Free Fluid

Figure 11 above shows the measured free fluid of the neat cement after conditioning at 125°F and atmospheric pressure. It can be seen from this plot that when mixed API, the measured free fluid was in the range of 2-3 mL. Increases in total mix time had negligible effect on the measured free fluid, but higher measured free fluid was observed through increasing total mix time at lower applied mixing energy. It also should be noticed from this plot that the overall variance in measured free fluid was somewhat small across the regime of testing conditions.

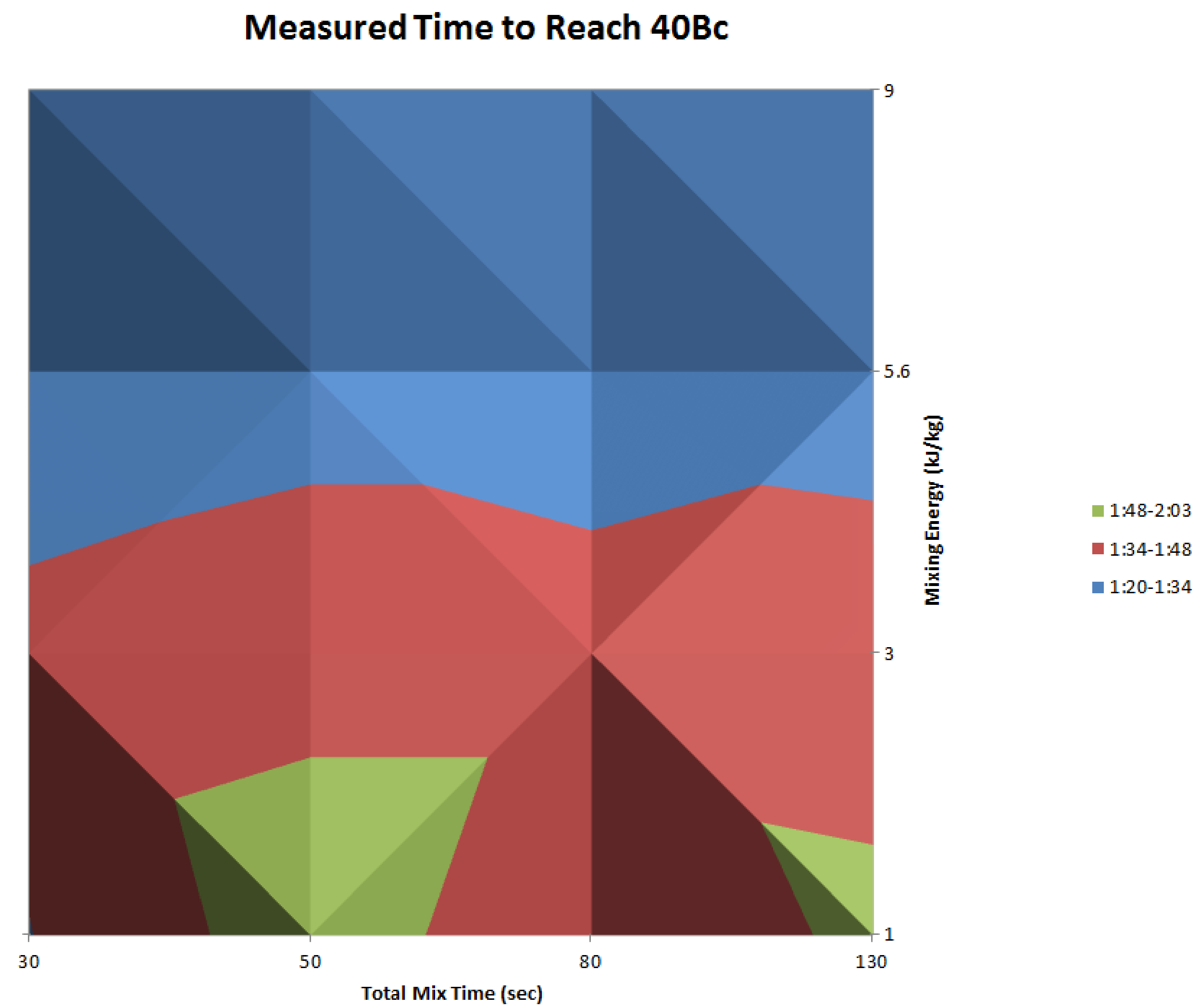


Figure 12 Mixing Energy Study - Measured Time to Reach 40Bc

Figure 12 above shows the measured time for the cement to reach 40 Bc during a pressurized consistometer test. It can be seen from this plot that when mixed API, the measured time to reach 40 Bc was in the range of 1:20-1:34 HH:MM. Increases in total mix time had negligible effect on the measured thickening time, but longer thickening time was observed at lower applied mixing energy for all total mix times. It also should be noticed from this plot that the overall variance in time was somewhat small across the regime of testing conditions.

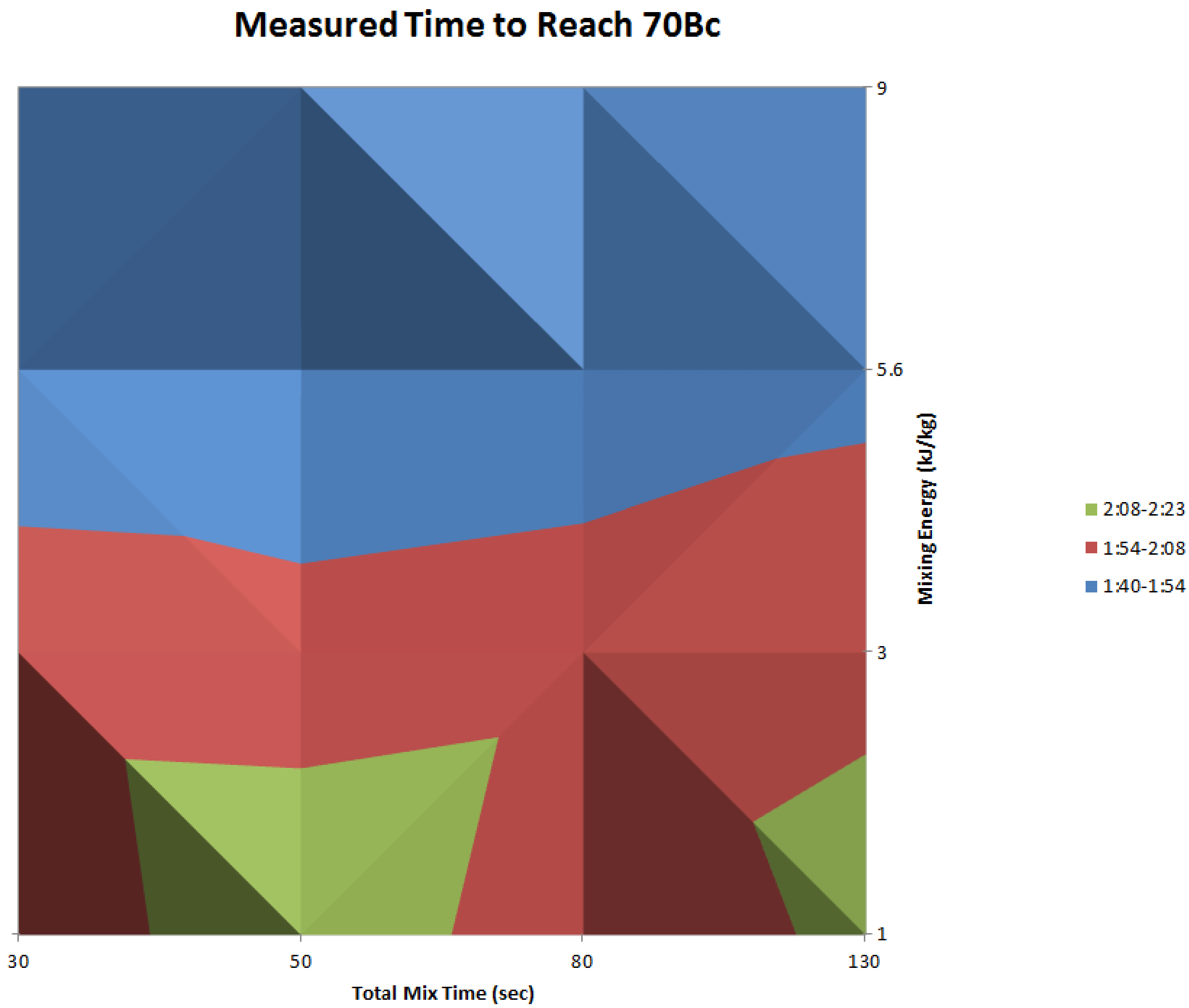


Figure 13 Mixing Energy Study - Measured Time to Reach 70Bc

Figure 13 above shows the measured time for the cement to reach 70 Bc during a pressurized consistometer test. It can be seen from this plot that when mixed API, the measured time to reach 70 Bc was in the range of 1:40-1:54 HH:MM. Increases in total mix time had negligible effect on the measured thickening time, but longer thickening time was observed at lower applied mixing energy for all total mix times. It also should be noticed from this plot that the overall variance in time was somewhat small across the regime of testing conditions which was to be expected from previous observation of Figure 12.

6.2.2 Fluid Loss Study

Currently, three separate API recognized test methods for fluid loss testing exist which include: atmospheric conditioning of slurry to BHCT followed by performing fluid loss measurement in a static cell, pressurized conditioning of slurry followed by performing fluid loss measurement in a static cell, and utilizing a stirred fluid loss cell for pressurized conditioning and fluid loss measurement. A fluid loss study was conducted to analyze whether or not the three separate fluid loss testing methods have variable results depending on bottom-hole conditions or designed fluid loss control within the system. A total of four separate cement systems were tested as part of this study. Two of the slurries were at 170°F BHCT and the other two were tested at 300°F BHCT. For completeness of the range of fluid loss control, one of the slurries was designed for fluid loss control in the 100-350 API range while the other was designed to be under 50 API. Full data sets for slurry performance parameters are shown in section 7.2.2 of Appendix B – R&D Laboratory Investigation. The results of this study are shown in Figure 14 and Figure 15 below.

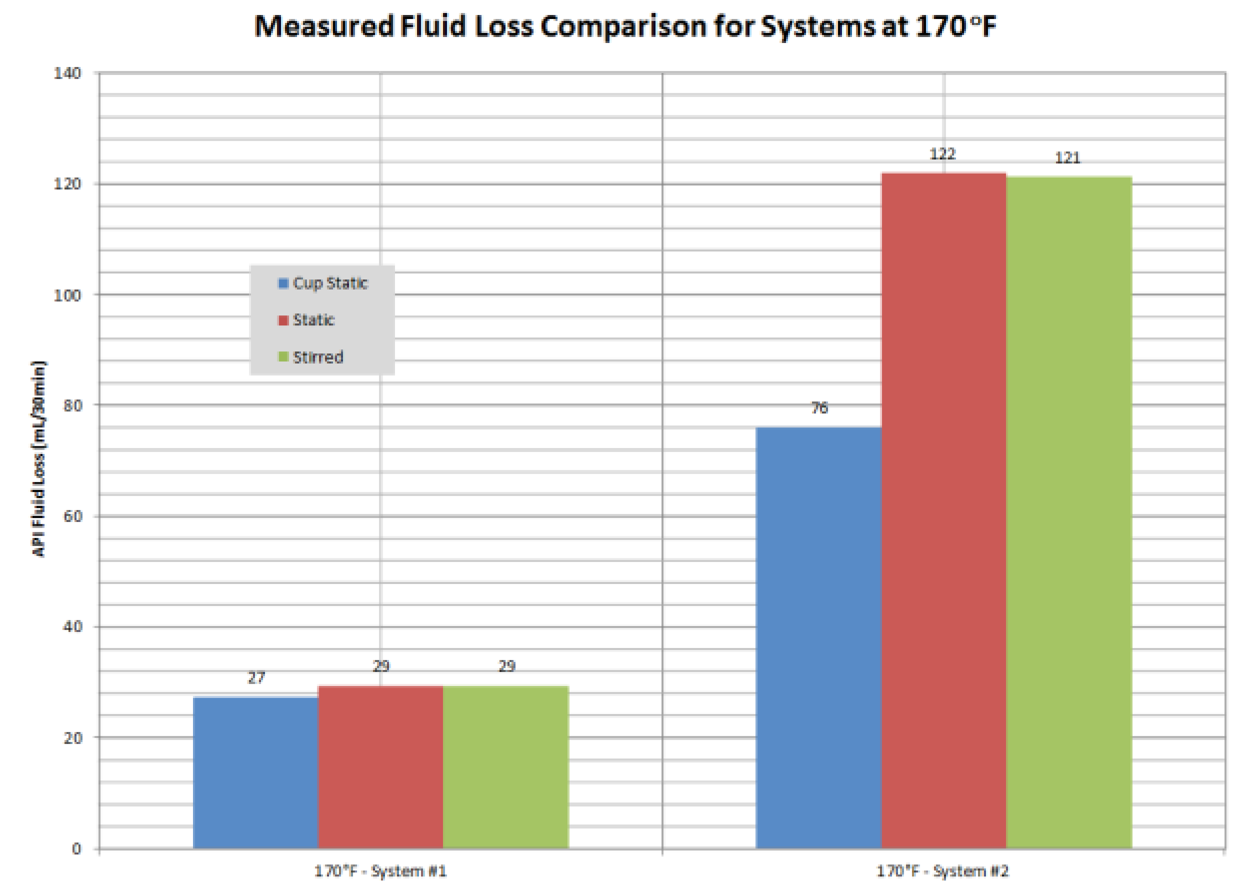


Figure 14 Fluid Loss Study - Measured Fluid Loss Comparison for Systems at 170°F

As can be seen from Figure 14, very little difference in measured fluid loss was observed within system #1. Slight variance in measured fluid loss was observed from the CUP static in system #2. Generally for low temperature applications, most cementing service companies perform the static fluid loss test method. Initial conclusions from this fluid loss study are that lower fluid loss values are measured from the CUP Static method as compared to the static and stirred methods, but overall variance in test method is negligible allowing any of the three methods outputting a trustworthy result. Figure 15 below shows the measured fluid loss comparison for systems tested at 300°F.

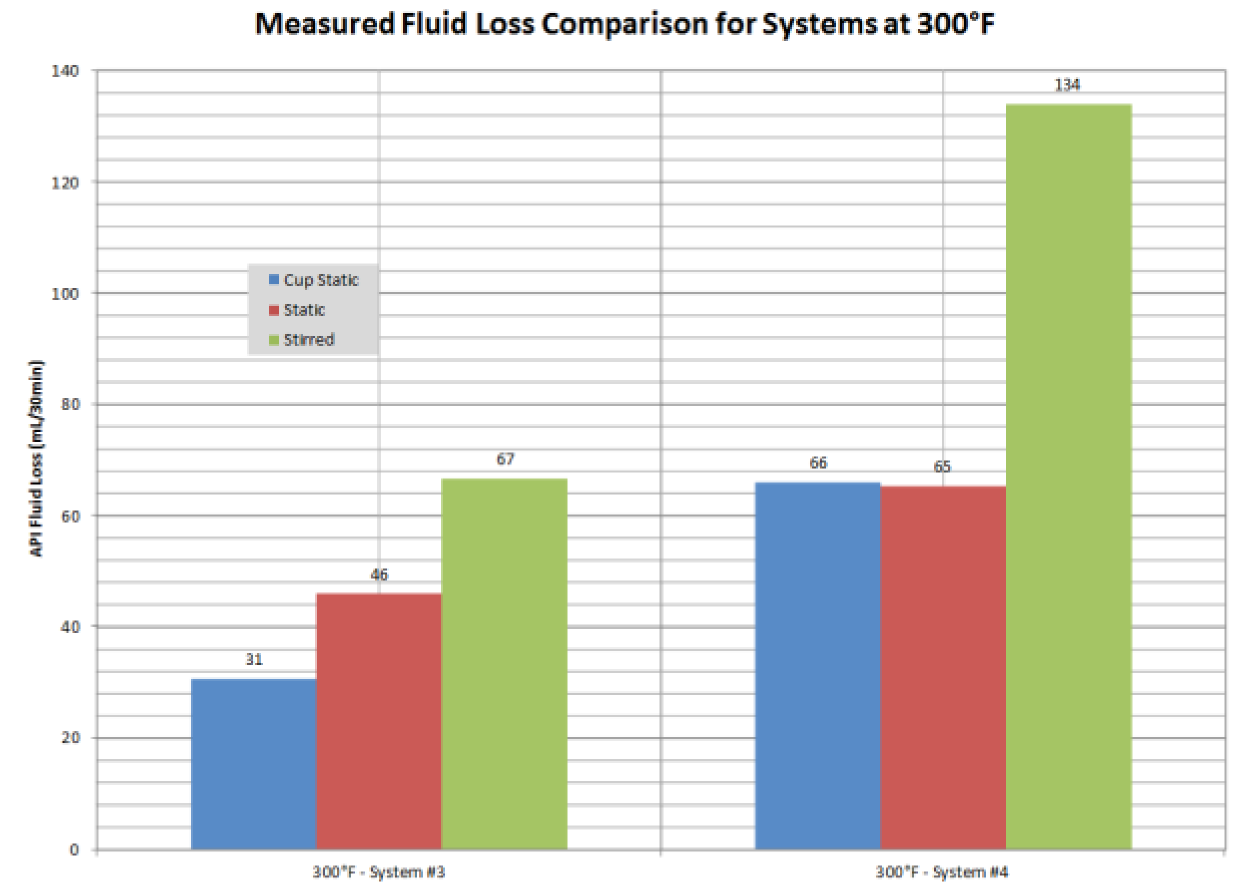


Figure 15 Fluid Loss Study - Measured Fluid Loss for Systems at 300°F

As can be seen upon initial observation in Figure 15, there is much more variability in the three test methods when comparing to Figure 14. The highest measured fluid loss values were with the stirred method for both systems. Generally, cementing service companies utilize the stirred method for testing systems above 190°F. The results from this initial study are somewhat alarming in regards to testing for designed fluid loss control. As can be seen from system #3, running a CUP static on a system may result in an under 50 API fluid loss when the system may not actually have sufficient control needed for coverage of potential flow zones. As an initial conclusion from this study, at testing temperatures below 190°F, any of the three methods will generally give comparable results. As a safety factor, the stirred method should be used for systems above 190°F since the largest fluid loss measurements were observed from this test method.

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7 Appendices

7.1 Appendix A – Literature Review Summaries

7.1.1 Appendix A.1 Well Design and Planning

(Reeves, et al., 1994) A new computer program optimizes centralizer spacing by using new API fixed-end condition beam equations to model casing centralizers. Previously, centralizer spacing was based on hinged end equations. The new equations result in more accurate solutions, and typically fewer centralizers to achieve desired standoff in directional wells. Fewer centralizers = fewer stop collars, less rig time, lower drag force. Using this program has resulted in bond index values of 80-91%. These wells had a maximum inclination angle of 46-50°. The lower amount of centralizers and stop collars required resulted in a savings of 52-57%

(Ravi, et al., 2002) Zonal isolation is critical to long term success of a well. Without it, safety and environmental concerns can arise, it is also costly and difficult to fix. Typically, compressive strength, and cement placement technique is the only consideration when determining zonal isolation. Other mechanical properties such as Young's modulus need to be considered. One study indicates a technique based on finite element analysis combined with methods to improve sealant placement can increase the likelihood the sealant will last the life of the well. This model takes into account: Rock properties, cement slurry and sheath properties, casing properties, and operational details for completion, stimulation, production, and injection. When using this analysis it is important to consider the borehole condition, sealant hydration characteristics, and resultant in-situ stresses in the sealant. Sealant failure occurs in three ways: Micro annulus at casing/cement interface, micro annulus at cement/rock interface, and sheath cracks due to changes in temperature or pressure. With results from finite element analysis, engineers and technicians can formulate sealants to meet operational requirements. Rather than traditional formulations, sealants can employ rubber, foam or be a hybrid.

(Sauer, et al., 1985) Process design chart: Indicates maximum additive allowances, casing hardware, informs user of more inexpensive options. Case histories have shown savings of up to $35K due to elimination of certain additives or processes. Such as: Maximizing synergy between attapulgite clay and a small amount of polymeric fluid loss agent vs. using large amounts of the polymeric fluid loss agent. Another example: Eliminating salt from a system has saved money in both eliminating the salt and reducing the amount of other chemicals necessary to combat the salt's negative effects. More emphasis has been placed on solving cementing problems with additives instead of using good placement techniques. As of late, more importance has been placed on lowering drilling and completion costs. Cementing operations can be lowered by eliminating unnecessary and expensive additives by improving placement technique. Combining new cementing technology with the logic of the process design chart using can result in lower cost and squeeze free jobs.

(Winker, et al., 2007) The Ursa field is in the GOM and characterized by high overpressures close to the seafloor resulting in narrow drilling margins. Two strategies used for drilling thru the SWF zone (1) Overbalanced drilling with a riser – tends to fracture (2)Underbalanced riserless drilling with seawater followed by killing with heavy mud – allows water flow from sands during drilling which tends to wash out sands and contaminate cement. This can result in foundation failure and ultimately casing failure. To control SWF they employed additional casing strings, improved drilling practices and technology, and relocation to an area of thicker overburden and less sand. Best practices Include: Proper hole cleaning, through controlled drilling and gel sweeps, specs for casing running speed, keeping an ROV on bottom at all times, always LWD, avoid setting a casing shoe in sand. New technologies include: new casing systems, low temperature foam cement, pressure while drilling tools useful while drilling near surface section, geotechnical boreholes, 3D high resolution seismic survey to better define sand bearing intervals and improve sand prediction. Success factors include: improved drilling practices due to careful study of each well by a multidisciplinary team of engineers and geoscientists with both operational and research backgrounds, technology advanced markedly during the eight years of Ursa drilling operations with innovations such as low temp foam cement, PWD logging, Piezometric measurements in geotechnical boreholes. Number of shallow casing points increased several times during the project. Second batch set was sited in an area of more favorable geological conditions than the previous sites, including greater overburden over the sands and thinner Blue unit. Modes of foundation failure included: uncontrolled flow from a sand during underbalanced drilling – large washouts, contaminated/compromised cement around conductor casing, fracturing induced at casing shoe by inadvertently exceeding the fracture gradient during overbalanced operations, closely spaced wells = large sand washouts from where adjacent wells interact or coalesce. Main conclusions of the paper were: requirements of a properly constructed deep-water well can be divided into: excavation, foundation, and plumbing. SWF associated with narrow margin drilling thru the near surface over pressured sands can degrade the wells integrity in all areas.

7.1.2 Appendix A.2 Cement Slurry Properties

(Bittleston, et al., 1990) Developed a numerical simulator for predicting downhole temperatures during cementing. His simulator takes into account heat transfer at the casing/fluid interface as well as the fluid/formation interface and in turn calculates heat transfer coefficients instead of assuming they are constant as is the case with the API correlations. His experiments showed that after circulating a 3000 meter well for 11 hours the bottom of the well had cooled and the upper regions had warmed, proving that the hottest fluid temperature is not at the shoe, but some distance up the annulus. He recommended not using the shoe temperature when designing the cement slurry.

(Calvert, et al., 1998) Studied well temperatures in deep water (>1500 ft) and determined that standard API circulating temperature correlations should not be used in these instances. They compared API correlations and newer computer simulations to actual downhole data and found that the computer simulations were much more accurate. Both the API and computer simulators use the static bottom hole temperature as a starting point, but the computer simulators are capable of using multiple temperature gradients, whereas the API correlation only uses one, along with true vertical depth. The API correlation also assumes a surface temperature of 80°F, which is not always the case. The computer simulators on the other hand, take into account other factors such as circulation rate and time, fluid inlet temperature, sea temperatures and currents, fluid rheologies and thermal properties, as well as wellbore geometry such as the pipe, hole dimensions, well deviation, and presence of a riser. While actual measurements of downhole temperatures offer the most accurate temperature determination for slurry design, the authors recommend using computer simulators in conjunction with actual data in order to validate measurements. They also recommend a cooling schedule in laboratory tests instead of a heating schedule (as recommended by API) because their data showed that in deep-water wells the cement actually cools down below the mixing temperature during placement and that bottom hole circulating temperatures are actually cooler than circulating temperatures further up the hole.

(Ravi, et al., 1999) Looked at factors previously studied such as the sea temperature and depth, but also took into account the heat of hydration of the cement and how it is affected by these factors, and how this in turn affects cement properties such as WOC, gel strengths and CS development. They conducted lab-scale experiments that mimicked deep-water conditions and developed a model that determined a Simulated Slurry Temperature (SST) profile which was validated by their experiments. The SST is a temperature profile of the slurry during placement and WOC. They recommend using this profile when determining cement properties such as Thickening Time and Compressive Strength. They also succeeded in shortening the onset of cement hydration by two hours with the addition of calcium chloride, which in turn shortened the gel strength development.

(Romero, et al., 2000) Also studied the effects of deep-water on cement heat of hydration. The model they developed took heat of hydration into account, along with heat exchange with the formation and casing fluid. Their approach varied from previous studies in that they focused on the cement seal and compressive strength development in the conductor and surface casings since they are subjected to unique hazards, such as shallow water flows, making cement integrity critical for well stability. They developed a model that calculates the heat production rate of any cement slurry as a function of the actual temperature and the degree of hydration. They recommend using a simulator that takes the hydration heat into account to determine an accurate temperature schedule for CS testing. They do not recommend using the API test schedule for CS testing when the BHST is lower than the BHCT.

(Ward, et al., 2001) Conducted a joint industry project to assess circulating temperatures in deep-water wells, specifically monitoring the cooling effects of the sea by measuring the fluid temperature at the mud depth. Their primary focus was the differences in the cooling effects with or without a riser present. As was expected, their data showed that circulating temperatures are higher when a riser is present due to the insulating effects of the riser. Actual field temperature data and computer simulations were comparable.

(Tahmourpour, et al., 2009) Studied intermediate casing strings in deep-water. In addition to the cooling effects of the water, shallow water flow, and compressive strength development, considerations for intermediate casing strings include higher formation temperatures, adequate pumping time, cement slurry stability, gas migration, lost circulation, narrow fracture windows, and long-term chemical and mechanical endurance of cement. Since temperature and pressure play a role in all of the above issues to some extent, they stress the importance of testing cement slurries at the correct bottom hole temperatures and pressures, which can be determined with simulation software before designing the slurry. Their studies reinforce previous conclusions that

- simulation software is better than API correlations for temperatures in deep-water
- seawater can have a dramatic cooling effect on slurry temperature
- once the cement crosses the mud line the formation will have a warming effect
- CS and PT lab test schedules should mimic the modeled temperature curves

7.1.3 Appendix A.3 Spacer Optimization

(Maserati, et al., 2010) A novel spacer design has been proposed used nano-emultions. The nano-emulsion provides an extremely large surface area of the internal phase while maintaining low interfacial tension. This lends itself to a very high cleaning efficiency. This novel spacer was compared to three existing spacers, all using 10% solvent concentration for OBM removal. In laboratory testing, the spacer showed to maintain stability at temperature and pressure (tested to 130 degF and 1,000 psi). The spacer showed to be better than traditional spacers in grid, wettability, contact angle and shear bond tests. In contamination testing, the spacer exhibits no adverse effects on rheology of cement or mud. In additional contamination testing, 5% contamination into cement doubled the thickening time while 25% showed a 10-fold lengthening of the thickening time. Further stability testing would be required at greater pressures to ensure offshore feasibility. A dual-spacer package would have to be used in order to ensure that the nano-emultion spacer was not mixing with slurry. Other options include a modification of the surfactant / solvent package in an attempt to reduce the effects of small amount of contamination.

(Berry, et al., 2005) New emulsifiers added to OBM / SMB have resulted in more difficult displacement of these fluids. A new emulsion based spacer has been implemented to more easily displace these muds. This water-in-oil spacer has not been designed for cementing application and is used to displace the mud when swapping out to completion brine. Cleaning the wellbore prior to swapping to completions brine is as important as before cementing as any OBM / SMB sheath left on the casing can be detrimental to the completions process. The space is considered an unstable emulsion, which for the purpose of displacing to brine, is advantageous in its ability to recover a major portion of the base hydrocarbon for reuse. The system has shown signed of “soft” settling after 12 static hours which allows for the reuse of 50-60% of spacer. The spacer has been field tested in the North Sea. If this system is to be adapted for cementing use, it would require a minimum of an additional water based spacer between this spacer and the slurry.

(Zanten, et al., 2010) Microemulsion forming surfactants can solubilize large volumes of oil like a solvent while simultaneously water-wetting the casing with its external water phase. Environmentally friendlier spacers can be developed by eliminating solvents from spacers and turning to micro emulsion forming surfactant-based spacers. In addition to being less harsh on the environment, these spacers have shown better water wetting properties than their surfactant/solvent counterparts. Surfactant nanotechnology has been used to develop packages which will self-assemble into nanostructures. In the presence of smaller amounts of oil, micelles will form. In the presence of larger amounts of oil beyond what the micelles can incorporate, a secondary oil-based phase will be emulsified in the system. This emulsification is unstable and will settle out into layers over time, without vigorous mixing. The micro emulsion forming spacer also showed less variability in performance across a spectrum of different muds than solvent/surfactant spacers, simplifying the design aspect of spacers. No contamination testing was performed between the spacer and cement.

(Heathman, et al., 2000) An experimental method is developed to allow for objective testing of water-wettability. The test measures the electrical activity of the fluid in question and measures the "apparent" wettability in a dimensionless unit called Hogans (Hn). This test takes away subjectivity in determining if a surfactant / surfactant package in a spacer is suitable for the mud it is meant to remove. Through case studies, it has been determined that proper surfactant packages vary heavily based on several parameters. A few of significant notes from this are: temperature, mud type / sub-type, mud manufacturer, and surfactant selection / concentration / ratio. Through titrations, surfactant packages are able to be optimized to fully water-wet a specific mud and do so with smaller volumes. The paper also shows that contrary to common belief, addition of more surfactant is not also a viable solution. Adding too much of any one surfactant, may have no effect at all (saturation) or cause deterioration of the system (instability). As such, it is suggested that all muds must be tested for proper surfactant package based on the above variables.

(Schumacher, et al., 1996) A novel spacer solution is implemented in the Gulf of Mexico and Gulf Coast Land Region. The spacer uses a copolymer dispersant to allow for miscibility of cement and WBM, and uses additional surfactant packages (sugar lipids and linear alkyl ethoxylated alcohol) when dealing with OBM / SBM. The surfactant packages have been designed to form a Windsor "Type III" micro emulsion in the presences of OBM / SBM. Moreover, the paper presents an overall approach to good cementing practices: "…cleanout technology, together with pipe centralization and proper job execution, has resulted in good downhole placement of the cement slurry with minimal mud contamination." It also outlines details of a good cement design.

7.1.4 Appendix A.4 Mud Displacement

(Singamshetty, et al., 2004) Describes how synthetic base oil is affected by pressure and temperature which dictate the compressibility and expansivity of the entire synthetic based mud. Accurate displacement of a cement job will avoid costly remedial work as well as costly drilling operations. Knowing the compressibility of a mud will aid in avoiding those situations. The technique of downhole density calculation based on the effects of pressure and temperature is not new. The abundance of different synthetic base oils necessitates measurement of PVT data for each fluid. A key factor is the reference density at a known temperature and pressure. The compressibility calculator takes into account: Fluid density at surface, Surface temperature, Percentage of Synthetic oil in the mud, Mud volume for a section, Mud temperature for a section, and Pressure experienced in a section. This calculator is used in conjunction with a good temperature simulator and a cement displacement program. To analyze the fluid compression inside the running string and casing, this must be run several times for each section. For each section or grid, the hydrostatic pressure and local temperature must be input. Investigating several case studies has led to the following conclusions. Theoretical mud compression during cement displacement is as follows: 1.7% or lower for 16" casing, 1.8-2.14% for the 13 3/8". Results were inconclusive for the liner due to smaller volumes and greater error. Most operators pump ½ the casing shoe when a plug does not bump. This is insufficient in 13 3/8" casing. Compressibility calculations are very sensitive to pressure and temperature. Compressibility of SBM must be accounted for in cement displacement calculations, this is most critical for large intermediate sections.

7.1.5 Appendix A.5 Mixing and Placement

(Padgett, et al., 2008) Discusses that shear rates produced in cement slurries by a mixing system exerts a more substantial influence on slurry properties than that exerted by total mixing energy. Through field and laboratory testing, it was found that mixing energy can influence, but not always these properties: rheology, free water, settling, fluid loss, and gelation time. Gelation time wasn't affected often but generally decreased with higher mixing energies. It was also found that field data and laboratory data never yielded identical results and that 24hour compressive strength development was never judged to be a function of mixing energy. Studies found also that batch size influences gelation, even when a constant total mixing energy is maintained. It was also concluded that higher shear-mixing environments produce less free water in neat cements because of an increase in surface area resulting from aggregate and agglomerate breakdown, but in cement containing fluid loss additives, higher shear rates produced more free fluid because of structural damage to the additive. It was also found that laboratory mixing of cement is at much higher shear rates than mixing cement in the field and that field mixing systems should be compared by the range of slurries that can be mixed successfully and on how well the system controls density, not on the total mixing energy delivered to the slurry.

(MacEachern, et al., 2003) Provides an overview of the first reverse-circulation foam tieback string in an offshore environment. The well was drilled in the Mobile Bay region to a TD of 23,320ft where a tieback liner was placed for added structural support during the production phase. Several pros and cons were discussed such as: Pros: reduce placement time, reduce WOC time, reduction in ECD. Cons: unconventional rig-up, unconventional float equipment, difficult to accurately track cement height inside casing, and may need to hold back pressure on the tieback casing. A reduction of retarder concentration was used throughout the cement placement to help facilitate uniform compressive strength development of the foam cement. The outcome of the job was successful with top of cement measured to within 381ft from predicted. He also states that it is imperative to design slurries with low, non-progressive gel strengths for the time period of landing the tieback.

(Landrum, et al., 1985) Discusses the attractive attributes of rotating liners during cementing operations. From previous studies it was shown that casing rotation has more favorable results than reciprocation in terms of fluid velocities. Average liner rotations during this case study of over a year were at 16 rev/min. Generic cement blends with minimal additives including: dispersant, fluid loss, retarder, antifoam, and silica when applicable. Proper spacer design was discussed and its importance to cement placement. A comparison between previous wells where liners were not rotated and current jobs where liners are now rotated resulted in many findings. These findings were: approximately 50% of rotated liners still required liner-top squeezes but only 17% required isolation squeezes, approximately 50% of non-rotated liners required isolation squeezes and each well averaged 2 liner top squeezes prior to liner rotation. Landrum stresses in the conclusions that the cementing basics cannot be neglected when liner rotation is incorporated into a procedure.

(Brady, et al., 1992) Begins by discussing current cement placement best practices including: wellbore geometry, cement design, casing centralization, mud conditioning, casing movement, chemical washes/spacer design, and wiper plugs. The paper then goes into discussing a computer aided cement design program used in calculation of mud circulation efficiency, flow regimes, and hole eccentricity. The main flow regimes best for displacement efficiency are turbulent and effective laminar flow as shown by computer simulation. It was found: mud displacement by the spacer and cement is as critical as the cement slurry properties in cement job success, all phases of the cement job must be planned/simulated and controlled for high job success rates, and mud removal is the most critical factor in cement job success.

(Hitt, et al., 1991) Describes the design and operation of a computerized vortex cement mixing system. The system is an impeller pump in a circular housing. Water is suction fed into the system at a constant flow rate and varying the dry cement injection rate automatically varies water suction for constant volume discharge. The mixer is fed by a surge can and works off of high shear rate. Density is measured with radioactive densometers in an averaging tank. General outlet pressures are around 60psi. When this mixing system is coupled with a computerized process control system, the density accuracy of the vortex mixer system is better than 0.2ppg accuracy.

(Harris, et al., 2001) Describes the use of a database containing more than 4000 shoe-cementing operations to find correlations between the success/failure rates of industry-accepted best practices. It was found that these factors are the most important for shoe test success: pipe movement, maintenance of circulation during cementing, accurate displacement volumes, centralization and the application of foam cementing. The cementing parameters which had less effect on shoe test outcomes were: mud properties, displacement rates, spacer volumes, and application of a hesitation squeeze at the end of the primary cement job. It was also found that shoe test failure rates were much higher on intermediate casings and liners as opposed to conductor and surface casings. This is partially attributed to casings and liners often being set incorrectly within pressure transition zones as well as shale zones leading to washouts and channeling.

7.1.6 Appendix A.6 Foam Cementing

(Taiwo, et al., 2011) Talks about the advantages of foam cement utilization in deep-water operations. Foam cement slurries offer a comparative advantage of enhanced mud removal, good ductility, fluid loss and gas migration control, insulation properties, and excellent compressive strength development at low slurry density. The disadvantages of foam cement are the need for specialized equipment for both field application and laboratory analysis. Foam cement's tensile strength, ductility, and displacement properties have made it useful in severe zonal isolation scenarios (main purpose of primary cementing is to provide effective zonal isolation during the entire life span of the well). Foam cement is made by properly combining 3 elements: cement slurry, foaming agents, and a gas (usually nitrogen). A term commonly used in foam cementing is the "foam quality" which refers to the amount of nitrogen entrained in the cement slurry. Example: if the slurry is a 30% quality, the cement is entrained with 30 % nitrogen by volume. In foam cementing nitrogen is the preferred gas due to its neutral effects, but compressed air can also be utilized. In some instances compressed air may be cheaper than nitrogen and related pumping equipment. Recent experience has shown that cement sheath failure is often caused by pressure and temperature-induced stresses inherent in the well operations.

(Weisinger, et al., 2004) There are three sides to the debate of foam vs. non-foam slurries for controlling SWF: Logistical, Operations, and Technical. Logistically, foamed slurries are simpler. To use a non-foam slurry when SWF mitigation measures are required, specialized blended cements must be used to achieve the desired slurry properties. The blends must be pre-mixed onshore 7-10 days prior to the cementing operation and blended uniquely for each application. If major changes between plan and actual drilling occur (e.g. new MW, unexpected overpressure sands, significant change in TD criterion), the entire blend may be rendered useless and re-blending is required. That may cause significant rig delays / last minute operations wherein errors are more likely. Foamed slurries can be significantly modified "on the fly" to account for many of those changes. Operationally, non-foam jobs are much simpler once the blend is on location. With foam jobs, there are several additional steps. Additional iron rig up, foamer/stabilizer rig up, N_2 tanks and pumps, hazards of energized fluids, specialty gas dispersion equipment, etc. All of these together lead a significant increase in operational complexity which can lend itself to HSE and Service Quality events. Technically, there is a great debate between the two. Papers have been published on both sides of the fence as to which method is "better" as a SWF mitigation measure.

(Cook, et al., 1999) Foam cement has ductile properties which allow it to flex and absorb stresses which may damage conventional cement systems. Some of the advantages associated with foam are:

modifiable density which allows for last minute changes; stronger than conventional extended systems and lighter than 'neat' conventional systems; provides a lightweight, low permeability, low density, high compressive strength system.

(Rozieres, et al., 1991) Provides an in-depth look at laboratory testing of foamed slurries as well as best practices in operation. There are two groups of properties to focus on when designing a foamed cement. The first is parameters which will affect bubble size distribution (BSD). These include the foam quality, stability, mixing procedure and pressure. The second group is the composition of the base slurry, including cement type, additive selection and density. These parameters affect TT, FL, and durability among others. In choosing surfactants and stabilizers, a test should be run by mixing 100 ml of mix fluid and ensuring that it creates at least 600 ml of foam and that the half-life of this foam is no less than 6 minutes. This test should be re-run using the slurry @ 70% foam quality and no destabilization should be evident until set. Traditional TT tests do not work on foamed systems as they impart a high shear part to certain parts of the slurry and little to no shear to others. This creates some sections of the foam slurry which are under-sheared and others which are over-sheared which can cause N_2 destabilization. However, ultrasonic imaging and calorimetry both show consistent set times regardless of foam quality up to 70%. Slurries over 70% foam quality were not tested. If good foam stability is not achieved, the pore structure of the bubbles will become highly inter connected (permeable) by adjacent bubbles rupturing and creating larger bubbles / gas pockets. In order to ensure that the foam is stable, it is first recommended to use anionic surfactants as a stabilizer. They are primarily preferred due to their lack of interaction with other cementing chemicals. When the ionic strength of the MF is too strong for anionic surfactants, the use of cationic surfactants is suggested; however, these may inhibit the effectiveness of dispersants. The paper does note that amphoteric surfactants have also been used successfully but does not mention any drawbacks or advantages. All surfactants must be coupled with a foam stabilizer to ensure the bubbles will not coalesce prior to cement set. In addition to chemicals, the cement particles also play a strong role in foam stability. It has been shown that when a solid particle is attached to a foam bubble, the bubble becomes more stable. When foam quality is high, the bubbles will interface with each other; in these situations, it is most important that the bubbles do not have a tendency to rupture and join. Higher Pressure exerted on the foamed slurry will affect both the bubble size and BSD. In regards to size, higher pressure will lead to smaller bubbles and a tighter BSD. At constant pressure, bubble size increases with quality. At constant quality, bubble size will decrease as pressure increases. All of these conclusions agree with the hypothesis that foamed cements made in large volume field applications, with high shear and pressure are more stable than foams in laboratory conditions. Slurries with broader BSD show very low permeability to a threshold point around 35% foam quality, and then permeability increases rapidly.

Slurries with narrow BSD show a more progressive trend, increasing constantly with foam quality. Foamed slurries of varying quality were prepared for fluid loss testing. The tests show that increased quality leads to less fluid loss. It's also noted that the fluid escaping the chamber was thick and "shaving-cream like". If foam is used about 230°, X-ray diffraction was used to show that the xonotlite crystalline structures will completely fill in the bubbles while setting. This decreased the permeability of the cement but has the potential to inhibit some of the other advantages which foam brings. There are four key parameters to consider when designing the placement of a foamed slurry: # of stages; N_2 rate per stage; backpressure; cap slurry length. These considerations should all be taken into account to ensure through the course of placement, the hydrostatic pressure is never lower than the pore pressure or above the fracture gradient. With regard to stages, unless an exact caliper is known for the hole section, one more N_2 rate should be used as a variable rate placement depends on a very good understanding of hole size. In short, a foamed cement design should be based around making the operation as simple as possible to avoid unnecessary risk and placing as much cement and as little N_2 as possible to ensure that all above criteria are met. If these design considerations are all taken into account, the jobs has been designed as well as possible.

(Kopp, et al., 2000) Six deep gas well were pumped in Wyoming. Two of them used a conventional cement system and four used foam cement. The two using conventional cement experienced outer-zone communication after stimulation; the foamed systems showed good zonal isolation after perforation and stimulation. The added ductility from the foam cement allowed the cement sheath to endure greater stresses without cracking. Tracers in the stimulation showed communication between high and low pressure zones in the conventional jobs whereas no such communication was seen when foam cement was used. Additionally, the foam cement develops greater shear stress in dynamic flow conditions, increasing its hole cleaning ability. The gas used to foam the cement will continue to expand as the cement begins to set and shrink during its transition period. This allows the cement column to exert more pressure towards formation while it is experiences pressure decay as well as prevent micro debonding from shrinkage. An acceptable quality range is from 20-35%; less than 20 will lead to brittle cement, which will behave similar to conventional cement; more than 35 will lead to overly porous cement which will not provide the necessary isolation. Depleted sands may cause formation compaction which in turn can cause casing damage. Foam cementing is one option to reduce this. Some concern is raise about the ultimate compressive strength of foamed cement for use in production zones do to the hydraulic fracturing which follows cementing. However, these concerns are unfounded as the principle stresses placed on cement sheath during these treatments are tensile in nature and governed less by compressive strength and more by Poisson's Ratio and Young's modulus. It is noted that flexible cement systems offer longer term solution and can endure more cycles of stress regimes than foam cement. Foam cement can endure hundreds of cycles whereas flexible cements can endure tens of thousands of cycles before failing. "Flexible cement provides the ultimate resistance to stress-relaxation cycles of a flexible compaction. However, the initial investment of a flexible cement job is at least two magnitudes higher than a foamed cement job."

(White, et al., 2000) Describes how foam cement is used to help prevent compaction damage. The focal point of the paper is on the planning and preparation stages of foaming cement for production liners. In conjunction with foam cement, important aspects of production liner design are proper casing design, effective cement placement and mechanical properties of cement which will sustain in dynamic wellbore conditions. If the cement system cannot mitigate compact damage, early casing damage at relatively low levels of compaction can create significant production challenges. In order to design compaction resistant cement, a finite element analysis (FEA) must be conducted to fully understand the forces acting on the cement sheath over time. If left unchecked, compaction damage will lead to: column buckling over unsupported intervals, crushing of cross connections, connection failures, local buckling, and bending of the pipe. Compaction strains as low as 0.5% has shown to buckle 10ft sections of unsupported casing. This can be prevented with good cement coverage. In addition to cementing, casing selection is paramount. Grade and D/T ratio must be considered. With the proper casing in place, a competent cement sheath is required to minimize buckling, parting and elongation due to wellbore stresses. Foam cement is an ideal candidate for these issues as provides good mud removal, gas migration control and long-term sealing ability through resistance to cracking in the cement sheath. Good mud removal is achieved through higher dynamic shear stresses than conventional systems, created by the entrained gas. Gas migration control is achieved through gas expansion to combat cement shrinkage and loss of hydrostatic overburden through the transition time. Slurries with a foam quality of 20-35% have shown resistance to temperature and pressure induced sheath stresses. The cement provides enough ductility to yield as the casing expands and has less potential for cracking. In logging, it is imperative to note that amplitudes will come back significantly lower for foam cement than conventional cement. The use of multi-transducer tools should be considered as they can distinguish between the cement and fluid even if they have the same acoustic impedance.

(Fuller, et al., 2010) Describes how foam cement and specialized lightweight blends tend to have about the same heat of hydration. Foam cement provides a compressibility which the lightweight blends do not which allow for maximum hydrostatic transmission during the transition period. It also allows for on-the-spot density changes to account for changing / unforeseen wellbore conditions; specialized blends may have the capability to changes ± 0.2 ppg but rarely any more than that. The uncertainty of riserless drilling demands a flexible system to allow for significant deviations from plan. SWFs can lead to unforeseen mud weight changes which in turn can require changes in cement density. Liquid additives should be used to obtain an optimized thickening time, free fluid control, minimal free water, acceptable rheology, and short transition times. As a general practice, 100-150% excess should be pumped for top-hole jobs. The foamed lead system can be cut short if returns to the mud line are seen with the ROV. To facilitate seeing returns, a tracer can be added to the spacer. Common tracers are dyes, mica, and rubber but anything that the ROV can visually detect and is environmentally friendly, can be used. It is important to plan the end of the inner string drill pipe to allow for an acceptable shoe track length, and a diverter sub should be used on the drill pipe.

(Ravi, et al., 2004) Describes that when subjected to cyclic loading, a cement sheath undergoes stresses. The degree to which these stresses affect the set cement are a function of its mechanical properties. The extreme environments into which the oil field is expanding (deep-water, HPHT, shallow gas) is putting greater demands on the cement jobs to provide long term zonal isolation through in these environments. If isolation is not achieved, SCP or damaged casing will result and ultimately a well will have to shut down production or incur high remedial costs. Because of the critical mature of these jobs, the cement sheath integrity must be considered during the planning phase. First, an engineering analysis must be conducted on the principle stresses to which the cement sheath will be exposed. This analysis can determine how much "remaining capacity" or useful life is left in the sheath after it undergoes the first stress cycle. Then, based on the stresses which the sheath will see, a slurry which can cope with the stresses must be selected. Finally, the slurry must be mixed and pumped as designed. The testing of mechanical properties discussed by the paper leads to the conclusion that no single mechanical parameter can be measured to determine which slurry should be used. Only through engineering analysis of all of the parameters, and testing in a fit-for-purpose manner can determine if a slurry will be able to cope with an environment. Some cements show brittle failure in unconfirmed testing, but show plastic deformation in confined testing; some show significant deviation from a linear stress-strain model; others act as linear elastic solids for certain ranges of compressive strength but not the entire range. Foam cement shows reasonable linear elastic behavior with a ductile failure mechanism. All other slurries tested (note: flexible cement was not tested) showed permanent plastic deformation after one load cycle @ 50% of its compressive strength. Foam cement after 1,000 cycles showed lower plastic deformation levels than all other slurries did after the first cycles. Conventional cement systems have poor resistance to repeated stress cycles.

7.1.7 Appendix A.7 Shallow Hazards

(O'Leary, et al., 2004) Discuss the desired properties for mitigation of shallow water flow hazards. It is stated that operators and service companies agree on the following properties are instrumental in addressing shallow flow zones: Strict slurry density control at surface and downhole conditions, Adequate rheology for optimal mud displacement, Fast gel and compressive strength development, Minimal shrinkage and low permeability, and Engineered set cement mechanical properties to ensure long term hydraulic isolation. It is also stated more than 60% of deep-water wells experience shallow water flows. Slurry properties that are desirable for shallow water flow hazards are discussed as follows: Free Fluid – none desirable, Stability – any settling is undesirable, may cause density differentials, Fluid Loss Control – API fluid loss values between 20 and 50 mL per 30 min recommended, Rheology – should be specifically designed for effective annular displacement, Thickening Time – computer modeling should be utilized for temperature and job simulations, TTs should follow these simulations closely, Gel-Strength Development – the shorter the critical hydration period the better the chances for controlling fluid migration, Mechanical Properties – cement properties should be simulated in a Set Cement Stress Analyzer simulator. In dealing with foam cements, a key factor is to keep the density constant throughout the cement column. This is complex and it is accepted to split the cement columns into shorter sections in order to inject nitrogen at different rates to keep density within an acceptable range. With foam cement specialized equipment and personnel are needed to run the job. With PSD (particle size distribution) systems the mechanical properties of the set cement can be optimized for long-term zonal isolation. These are the advantageous properties of PSD systems: Slurry and set properties are independent of solids/liquids ratio, A wide range of densities can be achieved with minor changes in the blend, Fluid loss control is provided by the characteristics of the blend, Fast gelling and compressive strength development, Low slurry and set cement permeability and porosity, Elastic properties can be controlled and engineered, Density variations have minimal effect on stability and set properties, Minimal additional training is needed for cementing personnel, nor is additional personnel needed, and No additional safety precautions required, no energized fluids are used.

(Alberty, et al., 1997) Describes four mechanisms have been identified as causes of shallow water flows. Induced fractures: The pressure generated at the casing shoe exceeds the formation strength resulting in the generation of a fracture which provides a flow path for wellbore fluids back to the surface. Pressure may be the result of friction, well pack off, suspended cuttings, or increased base mud weight. Induced Storage: A condition that is produced when the pressure generated in the mud column charge permeable and porous sands or silts that were previously normally pressured. When circulation stops, the charged formation is at higher pressure than the borehole resulting in flow back into the wellbore which can be observed at the wellhead. Geopressured Sands: The drilling out of geopressured sands without the riser or BOP is the most common cause of SWF and also one of the most damaging mechanisms. When a geopressure sand is left uncontained the formation water will flow to the ocean transporting formation solids creating potentially significant washout. And will contaminate cement and mud if flow is present during running casing and cementing. Flow from a geopressuresd sand will tend to increase in time. Transmission of Geopressure through Cement Channels: Caused by poor cementing of either the conductor or surface strings. Can be hard to diagnose due to the time delay of the flow through a channel. Some detection methods are also talked about in the paper. The general principle will involve these steps: 1) identify shallow sands from MWD data in the nearest offset wells in multiple directions, 2) pull a seismic line from the offset wells through the planned location from a 3D volume or suedo 3D from 2D lines, 3) identify the seismic attributes of the sands in the offset wells. It can be difficult to decipher if a sand is pressurized or not, when in doubt treat it as pressurized.

(Mueller, 2002) Describes lessons learned and mitigation involving shallow water flows. Some of the collective experience is as follows. It is important to note that shallow lithology is markedly different from deeper rock lithology. SWF sands are water-saturated with high permeability and low shear strength. If SWF occurs, kill the well. The longer the well remains underbalance, the more likely the flow will increase. If SWF occurs kill the well. The more formation material mined from the wellbore, the larger the wellbore and the more difficult it is to obtain a quality cement sheath. Accumulation of solids in the diverter valve can be a mud line expression of poor mud displacement in the wellbore. Success in SWF mitigation is not always readily apparent after the cementing operation. Casing failure due to buckling/shearing can occur quickly after cementing or could take months. SWF cannot be mechanically controlled with pack-off devises. Specialty foamed cements or cements containing light weight spheres afford the best opportunity to control SWF. A cement design with excessive TTT may still be poorly suited for SWF mitigation; the situation can be made worse when mud displacement conditions are not ideal. Successful drilling and casing of the top hole section require pre-drill assessment, planning the drilling program with contingencies for SWF and communication with relevant service providers.

(Weisinger, et al., 2004) Describes disadvantages of using a variety of cement types and blends in offshore applications can be that unused materials designed for special applications must be discarded or offloaded and new cement loaded for subsequent operations. A special blend composed of Portland cement, ultra-fine cement, and microspheres can be designed with short transition times and rapid development of compressive strengths in low temperatures and pressures. Although, studies showed that foam cement was superior to non-foamed slurries for dealing with SWF. Special light weight blends designed to deal with SWF tend to be expensive and there is relatively no flexibility in the density of the design.

(Furlow, 1998) Discusses how a cement job is only as good as the sweeps that go before it. If the casing is not properly centralized before cementing, then a channel could develop where cement is thin. SWF generally occur within 2000 ft of the mud line. It is essential that the well be killed and in a static state when a SWF occurs before cementing. The service company has to find a base cementing system that is aggressive enough to set up at very low temperatures. Foam cements are compressible and dynamic, and by altering the amount of N_2 in the system, an operator can vary the cement density at will. As cement reaches a gel strength of 100 lbs/sqft, it losses the ability to transmit hydrostatic pressure. At 500 lbs/sqft, the cement reaches a gel strength enough to prevent fluid influx. Foam imparts thixotropic properties to cement, as well as increased viscosity, and a compressible phase that makes the cement more resilient. Foams are good at displacing fluids, a foamed lead slurry can assist in removal of residual mud in the open hole. Temperature gradients in the GOM may deviate from the standard, simulators should be run to predict temperature profiles.

(Ostermier, et al., 2000) Discusses how drilling shallow over pressure sands may cause large and long lasting uncontrolled flows, well damage and foundation failure, formation compaction, damaged casing, and re-entry and control problems. This problem is compounded by the difficulty in seismically imaging these sands. If pore pressures are not controlled the shallow sand formation will flow. This can lead to washout, ineffective cementing, sand compaction, damaged casing and re-entry problems. Excessive pressures can fracture the formation causing communication to shallower zones, adjacent wells, etc.

7.1.8 Appendix A.8 Annular Pressure Build-up

7.1.8.1 APB Mitigation:

(Vargo, et al., 2003) Discusses the aftermath of a casing collapse upon starting production in the Marlin field, BP investigated the possible causes. The root-cause analysis led to APB, from fluid in a trapped annulus heating, as the primary cause. In order to mitigate this in the future, the operator used N_2 foamed spacers in front of the cement slurries designed to remain stable for 72 hours, prior to the N_2 becoming unstable and dissociating. Once the N_2 has dissociated, the bulk gas is able to absorb pressure changes due to liquid's thermal expansion. Laboratory testing was done to ensure enough N_2 was placed in the annulus to adsorb the modeled temperature swings.

(Williamson, et al., 2003) Discusses trapped annular fluids, during production and how they can lead to APB. The heating of these fluids over time through production causes the pressure in closed annuli to rise, possibly to the point of failure. Outlined below are some of the common mitigation methods and their potential advantages / disadvantages. Cement Shortfall: By leaving TOC below the previous shoe, a bleed path is created to formation where over-pressured liquids can invade / fracture the formation at pressures below the collapse of casing. Advantages: With a known formation pressures (LOT at previous shoe for example), a clear understanding of the max pressure which an annulus will see can be easily estimated. Disadvantages: Some formations have unknown fracture gradients; environmental risks of allowing drilling fluids into formation; unidentified sands above TOC may still cause problems; barite sag can still create a trapped annulus. Full-height cementing: By filling the entire annulus with cement, there is no liquid to be subjected to temperature and pressure increased. Advantages: If all drilling fluid is properly removed and the pumping operation is performed as designed, there is no fluid to expand. Disadvantages: Long casing strings can result in high lift pressures / high ECDs; inaccurate hole gauge / displacement efficiency can bring cement across the BOP stack and into the riser, both of which have significant complications; any associated complications involving long cement columns. Preferred leak path of bleed port installation in previous casing string: Allow the trapped fluids from one annulus move to another annulus to alleviate the pressure buildup. Advantages: In casing strings which have no close but to create a trapped annular, this allows a solution. Disadvantages: the solution is only as good as the care taken to create a leak off path in the previous annulus. Syntactic crushable foam wrap: Wrap the casing string in a foam material to allow some "crushability". Advantages: Alleviates initial APB. Disadvantages: If APB is sever, it may not be enough; creates additional annular restriction resulting in higher ECDs during placement. Enhanced casing design: Use casings with light burst / collapse ratings. Advantages: In cases where the expected APB is relative low, this solution will prevent casing failure. Disadvantages: Does nothing to address APB other than provide an additional safety factor in its presence. Compressible fluids placed in the trapped annulus to absorb volume: A compressible fluid will decrease the pressure buildup by compressing. Advantages: Mitigates pressure buildup through compression. Disadvantages: Placement techniques of some compressible fluids, if not properly executed, can lead to kicks.

7.1.8.2 APB Prevention:

(Badalamenti, et al., 2009) Describes how the only prevention method for APB leading to SCP is cement sheaths designed to cope with the long-term stresses associated with well production. A synergistic approach is suggested for creating these long-term barriers. Unless all aspects are examined as contributing to the goal, a proper solution cannot be reached. These aspects include: mud removal, centralization, ECDs, annular flow patterns, and tailored cement systems—all of which must be considered on a case by case basis to ensure that appropriate parameters for each variable are considered.

(Tellisi, et al., 2005) Discusses the properties of a 'curing' and a 'cured' cement system are analyzed. It is noted that 'cured' properties of the cement including its endurance limit, shrinkage and Young's Modulus and Poisson's ratio are often neglected as part of slurry design. These factors all affect the set properties of a system. They are important when considering the purpose of the cement slurry over the life of a well. The paper breaks down slurry properties into two categories, short term characteristics and long term characteristics. Short Term: Mixable at surface, settling and FF, TT and density, FL and compressive strength development, resistant to fluid influx, environmentally friendly, 100% placement in the annulus. Long Term: Thermally stable under downhole conditions of pressure and temperature, mechanical properties to withstand stresses from various downhole operations and provide zonal isolation for the life of the well.

(Ravi, et al., 2007) Describes that in order to achieve full and long term zonal isolation, the steps outlined below must be followed. Drilling Fluid must be removed from all sides of the annulus (wide and narrow, casing and formation). The entire annulus must be filled with cement. The cement sheath must be capable of withstanding the loads which the well operation through time will place on it.

(Kulakofsky, et al., 2010) Describes how there are several long term detriments which are caused by lack of lasting zonal isolation ranging from SCP, less effective stimulation treatments, loss on hydrocarbon, and water influx among others. In order to prevent the long term failure of cement sheaths, there are a few solutions put forth. First, the use of “react-and-respond” cement systems which contains particles which, in the presence of hydrocarbons, will swell. This technology can eliminate leaking micro-annuli and seal small cracks. These systems provide the capability to swell between 1 and 2%. In addition to this, swell packers can be run on casing strings as a form on back-up annular seal. These packers can swell over 100% in volume and provide a full seal. These packers can be designed to swell in either the presence of oil or water.

(Abbas, et al., 2002) Discussed how the first prerequisite to good zonal isolation is effective drilling fluid removal. If the drilling fluid is not removed, it may lead to the lack of an effect annular seal, which can in turn lead to production of unwanted fluids, loss of hydrocarbons, SCP, casing corrosion, and underground blowouts. To assist with this removal, a software program (WELLCLEAN II) has been developed to help engineers optimize spacer density and rheology. Several case studies in which the WELLCLEAN module was used in conjunction with good cementing practices and the use of specialized low porosity / low permeability cements show vast improvements in cementing compared to previous efforts made without these advances. Casing sections were logged and shown to have significantly better bond than seen previously. In fields where oil-water contacts exist in the pay zone, this extended zonal isolation is especially important to ensure there is no water influx or loss of potential hydrocarbon pay. Advanced cementing technology, including cement systems with flexibility, expansion and impact resistance, can be used to isolate zone which are planned for significant pressure / temperature changes over the life of the well. These systems are easily mixed and pumped by incorporating a particle size distribution of solids. By tailoring these variables to the long term expected conditions of the well, the threat of APB is greatly reduced. To fully optimize this process, the mechanical properties of the formations surrounding the wellbore must be known as well.

7.1.8.3 APB Alleviation:

(Sorter, et al., 2003) Focuses on techniques to alleviate casing pressure on a work-over well. Casing pressure can occur from expansion of annular fluid, however once the flow has reached steady state, the pressure can be bled through a needle valve to remain at atmospheric conditions. The objective of this program was to alleviate SCP in a field with a consistent and effective method. All 4 wells studied in this process have SCP and previous attempts to perforate and squeeze and cut casing to circulate were unsuccessful at alleviating SCP. The preferred method in this program was to attempt isolation at the greatest depth first, allowing for farther remedial processes if needed. The First Method: Termination of Inner Casing, Cut and Pull, Casing Cleanout: Preparation for Pressure Isolation of Inner Casing Stub and Annulus, Pressure Isolation of Inner Casing Stub and Annulus (Cementing Operations). Latex cement was utilized for cementing operations in the cementing system. Second Method: Window Milling Operation, Casing Cleanout: Pressure Isolation of Lower Casing, Pressure Isolation of Lower Casing (Cementing Operation). Latex Cement was again utilized in this method.

(Eaton, et al., 2006) Outlines how SCP was dealt with in the magnolia field on the GOM. It does not involve cementing. It does, however, detail the difficulty of finding an acceptable / economic solution of SCP presents itself.

7.1.9 Appendix A.9 Salt Zone Cementing

(Griffin Jr., et al.) Discuss the practices and procedures in designing cementing and drilling operations through salt. The paper discusses the movement of salt be it creep or geological stresses causing flow, and the authors also discuss cementing properties and testing procedures to combat this salt phenomenon. Hole-size, spacer design, and mud properties are also discussed and recommendations on the properties are presented in the paper. The authors also include multiple case histories to support their document.

(Heathman, et al., 2006) Present the differences between salt and non-salt slurries used in salt formation cementing. The types of questions to be raised, presented by the authors are: the formation type, composition of the mud system, the wellbore temperature profile, the intended purpose of the casing string, and what the set cement is to accomplish. The authors also talk of the importance of identification of the salt zones and the processes in place for dealing with water sensitive zones. The topic of dissolution is discussed and the laboratory result vs. actual reality of the process.

(Simmons, et al., 2008) Discusses cementing across salt formations and states that the US GOM contains the largest known deposits of salt in the world. The article goes on to discuss the important parameters to look at during cementing in salt formations such as mud composition, temperatures, pressures, etc. The author also discusses the importance of selecting the correct system due to salt dissolution into the cementing system which can cause detrimental effects. It is stated that cementing properties such as TT and compressive strengths are crucial to a good cementing operation in salt formation.

(Redden) Discusses the ongoing challenges of drilling in salt despite new technology available to the oil field. The author discusses the effects of creep, high shock while drilling in salt and ROP when entering and exiting salt. These are discussed and the mitigation of processes to alleviate these issues are talked about in the paper. The mud weight is also talked about due to the issue of choosing a mud weight for exiting salt as too high a mud weight can cause losses and a low mud weight can cause control issues.

(Willson, et al., 2002) Discuss salt loading on well casings. The authors discuss the casing design adjacent to salt and go on to talk about experimental casing designs, the incorporation of non-uniform loading effects into the design, field proven, heuristic solutions to salt loading problems, and numerical analysis based on advanced constitutive modeling of salt. The authors also discuss what happens during the occurrence of creep and steps to mitigate the occurrence. It is concluded that: Salt encompasses many different types of formations, In the GOM ~94% of salt is halite, Many Rules of Thumb do not conform to the known deformation mechanics of salt, Where hole quality can be assured it is considered necessary to cement the casing through the salt.

(Garzon, et al., 2008, May 19) Discusses the problem of creep in salt and the cement properties needed for mitigation of salt creep.

7.1.10 Appendix A.10 Remedial Cementing

(Verret, et al., 2002) Talks about plague of lost circulation in the oil and gas industry. It is stated that as the industry has evolved, the best remedy for lost circulation has become waiting on the hole to heal. In deep-water this is not an option due to the cost of drilling in deep-water fields and other remedies are utilized. Once a remedy is found, the next highest priority becomes: How long will it last? Will it fail or breakdown or erode before the interval can be completed? What about the BHA? The remainder of the paper presents the procedures and processes used to pump E Z Squeeze.

(Whanger, et al., 2010) Speaks of the procedures and processes involved in DwL (drilling with liner). It is discuss that tight-tolerance, extended reach deep-water drilling poses multiple hazards. In utilizing DwL operations, cuttings and debris from the wellbore can be an issue in circulating the well while drilling. DwL advantages: Reduces personnel needed on the rig floor, Holes are straighter due to the liner diameter; reducing drag and torque, Circulation is uninterrupted until cementing begins, and Fewer tripping runs.

(Reeves, et al., 1994) Discusses that centralization is crucial to obtain competent, uniform cement sheaths around pipe. API Spec 10-D for bow spring centralizers was the main directive of the paper and the equation used in the calculation required for number and placement of centralizers. It was first presented by calculating using a Hinged-end condition and changes to a fixed-end condition as of 1995. The hinged-end equation was conservative calling for more centralizers, but could also cause problems trying to run casing in the hole with the extra drag.

(El-Hassan, et al., 2003) Discuss the application and basis behind advanced-fiber cement system (AFCS) and high-performance lightweight cement slurry (HPLW). The majority of the paper is discussing Case Studies that can be referred to for operational practices.

(Schultz, et al., 2008) Speaks of the job planning and execution of running and cementing an expandable liner; discussing the job planning, the working of expandable tubulars, cementing considerations, slurry design and volumes, spacer design, lab testing, job execution, and post-job results. The conclusions and recommendations from the execution are as follows: Proper window preparation and hole cleaning before running the expandable liner is recommended, Determine placement time needed based on liner length and expansion cycles needed, Perform temperature simulations to determine BHCT and heat up rates, Prepare a TT schedule based on cycles required for motor shut off, Perform proper lab testing based on the modified schedule for TT and compressive strength, Perform simulations using cementing software for proper ECD management, Deliver these designs to the well site with a plan for placement using offshore equipment capabilities.

(Faul, et al., 1999) Discusses the advantages of fine-grind cement systems for use in cement plugging operations. It is stated that proper plugging is the operator's responsibility and the main objectives in well abandonment include: Protecting remaining geothermal resource reserves, Controlling fluid movement within the well bore to minimize risks of surface pollution or contamination of fresh water, Limiting fluid movement until nature can restore the static balance that existed before the well was drilled. It states the conventional method of plugging a gravel packed well involves establishing an injection rate, squeezing the perforations, and setting plugs into the gravel pack assembly. Fine Grind Cement (FGC) technology combines the enhanced penetration of tiny cement particles and proper dispersion techniques to help solve P&A issues when using conventional slurries. FGC has the following qualities over conventional cements: Can penetrate 2-darcy permeability, Plugging can be achieved in a single stage, Gravel pack can be squeezed without perforating, Old casings can be perforated and removed from the well. The paper also presents 4 case histories with FGC systems being utilized.

(Syed, 2008) Discusses the best practices in designing and testing HPHT cement plug systems. It is discussed that the boundaries for HPHT have been accepted as mud density above 15 lbs/gal and BHT exceeding 250 degree F. The author also discusses the cement system design process including: Formulation of job objectives, Assessing the extreme conditions, Assess the risks involved in the extreme conditions and possible solutions and precautions, Monitor the well closely, gathering and collecting all the required well/job data, Validating the data collected considering the various methods or measuring/logging, Determine the bottom hole working temperature for laboratory testing, Assessing the appropriate resources, Collect samples of the relevant products/cements and water using specially prepared procedure for HPHT sampling, Perform lab testing with representative samples, Compare the properties of the slurry system with desired results, and Recommend additional/alternate products. Another important topic discussed is the properties of the additives to be able to combat the effects of HPHT, as well as requirements for the spacers and lab testing for the cementing system.

7.1.11 Appendix A.11 Novel Technologies

(Myers, 2008) Discusses Riserless Mud Recovery systems (RMRs) and how they allow for drilling sections of the well using dual-gradient techniques. A riser narrows the window between pore and fracture pressures of the formation. By increasing this window with dual gradient technology, the drilling, cuttings removal and cementing processes all become simpler and less prone to error. It replaces the commonplace pump-and-dump method used widely across the gulf and allows for mud coming out of the wellbore to be recovered back to the rig floor while enjoying the advantages of riserless drilling.

7.2 Appendix B – R&D Laboratory Investigation

7.2.1 Mixing Energy Study

Laboratory Data Summary

Test Date:	February 15, 2013	Depth MD (ft):	NA	Job Size / Type:	10 (in) Casing
Project No:	REN0146 - A-1	Depth TVD (ft):	NA	Well Fluid Density (lb/gal):	NA
Company:	NA	BHST (°F):	140	Well Fluid Type:	Na
Requestor:	Eric Evans	BHCT (°F):	125	Test Schedule	#5
Operator:	BSEE	Temp. Grad. (°F/100ft):	NA	Spacer Type:	NA
Well Name:	NA	Test Pressure (PSI):	5,160	Spacer density (lb/gal):	NA
Rig Name:	NA				

Cement Slurry Design

Slurry Density (lb/gal):	16.2	Slurry Yield (ft^3/sk):	1.09	Total Mixing Fluid (gal/sk):	4.55

Cement Blend	Sack Weight, lb	% of Total Sack Weight	Prod Weight, lb/sk	CSI Log #
Cement - Class H (CSI)	94	100	94.00	Lab Stock

Mix Water	Concentration	Units	CSI Log #
Deionized Water	4.553	gal/sk	Lab Stock

Test Results

	Low Shear		High Shear		Mixing Energy	Total Mix Time
	RPM	Time (sec)	RPM	Time (sec)	kJ/kg	Seconds
Test # 1	4000	14.65	6767	15.35	1	30
Test # 2	4000	24.65	4628	25.35	1	50
Test # 3	4000	39.65	2740	40.35	1	80
Test # 4	2685	130	0	0	1	130
Test # 5	4023	14.04	12732	15.95	3	30
Test # 6	4000	23.95	9656	26.05	3	50
Test # 7	4000	38.95	7302	41.05	3	80
Test # 8	4000	63.95	5204	66.05	3	130
Test # 9	4000	7	14785	23	5.632	30
Test # 10	4000	15	12000	35	5.632	50
Test # 11	5717	21.56	8848	58	5.632	80
Test # 12	5661	21.56	6505	108	5.632	130
Test # 13	6000	7	14000	23	6.549	30
Test # 14	11500	19.8	14000	30.1	9	50
Test # 15	5850	30.5	12229	49.41	9	80
Test # 16	5747	30.5	8643	99.4	9	130

	80 F Rheology		125 F Rheology		Free Water	Thickening Time			
	PV	YP	PV	YP	mls	Initial Bc	40 Bc	70 Bc	100 Bc
Test # 1	45	25	42	45	Trace	18	1:34	1:59	2:17
Test # 2	42	23	44	46	Trace	8	1:57	2:20	2:34
Test # 3	36	26	43	31	1.5	16	1:37	1:59	2:13
Test # 4	41	25	36	36	1.0	14	1:52	2:12	2:25
Test # 5	34	24	47	39	1.0	12	1:40	2:02	2:15
Test # 6	35	28	34	55	Trace	15	1:44	2:01	2:13
Test # 7	34	25	32	29	4.0	10	1:44	2:04	2:13
Test # 8	36	26	26	32	2.0	6	1:42	2:07	2:24
Test # 9	32	28	51	35	3.0	19	1:22	1:45	1:54
Test # 10	36	23	30	42	2.5	10	1:28	1:40	1:54
Test # 11	32	27	35	41	3.0	10	1:22	1:43	1:58
Test # 12	33	23	35	33	3.0	11	1:28	1:50	2:02
Test # 13	35	28	45	66	1.0	8	1:33	1:49	2:05
Test # 14	33	26	34	48	Trace	12	1:34	1:51	2:00
Test # 15	33	28	40	52	1.0	13	1:24	1:40	1:51
Test # 16	31	27	36	49	1.0	11	1:24	1:33	1:50

7.2.2 Fluid Loss Study

7.2.2.1 Low Temp

SLURRY 1

Density: 16.4 ppg
BHCT: 170 F

Rheological properties

Surface Rheology	R300	R200	R100	R60	R30	R6	R3	Gel 10s	Gel 10min	PV	YP
	226	164	90	56	30	8	5	5	11	218	14

Rheology @ 170 F	R300	R200	R100	R60	R30	R6	R3	Gel 10s	Gel 10min	PV	YP
	192	142	85	57	33	10	6	5	10	175	23

Cup Rheology	R300	R200	R100	R60	R30	R6	R3	Gel 10s	Gel 10min	PV	YP
	158	117	57	41	25	8	5	5	10	151	11

Free Water 0 mls

Thickening Time

Consistency	40 Bc	70 Bc	100 Bc
Time	5:28	5:39	5:42

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SLURRY 2

Density: 16.4 ppg
BHCT: 170 F

Rheological properties

Surface Rheology	R300	R200	R100	R60	R30	R6	R3	Gel 10s	Gel 10min	PV	YP
	132	91	52	34	21	11	6	6	18	123	10

Rheology @ 170 F	R300	R200	R100	R60	R30	R6	R3	Gel 10s	Gel 10min	PV	YP
	102	75	47	35	23	8	5	6	12	86	16

Cup Rheology	R300	R200	R100	R60	R30	R6	R3	Gel 10s	Gel 10min	PV	YP
	156	121	80	62	43	25	21	22	24	123	38

Free Water Traces

Thickening Time

Consistency	40 Bc	70 Bc	100 Bc
Time	5:21	5:25	5:26

7.2.2.2 High Temp

SLURRY 3

Density: 16.4 ppg
BHCT: 300 F

Rheological Properties

Surface Rheology	R300	R200	R100	R60	R30	R6	R3	Gel 10s	Gel 10min	PV	YP
	190	136	78	52	31	11	9	10	28	176	18

Rheology @ 190 F	R300	R200	R100	R60	R30	R6	R3	Gel 10s	Gel 10min	PV	YP
	146	115	85	73	60	45	36	26	40	94	56

Cup Rheology	R300	R200	R100	R60	R30	R6	R3	Gel 10s	Gel 10min	PV	YP
	134	105	68	50	35	21	19	20	22	109	30

Free Water 0 mls

Thickening Time

Consistency	40 Bc	70 Bc	100 Bc
Time	3:17	3:29	3:32

SLURRY 4

Density: 16.4 ppg
BHCT: 300 F

Rheological Properties

SurfaceRheology	R300	R200	R100	R60	R30	R6	R3	Gel 10s	Gel 10min	PV	YP
	394	293	176	122	74	23	11	10	20	352	53

Rheology @ 190 F	R300	R200	R100	R60	R30	R6	R3	Gel 10s	Gel 10min	PV	YP
	144	112	65	43	25	8	5	6	10	132	18

Cup Rheology	R300	R200	R100	R60	R30	R6	R3	Gel 10s	Gel 10min	PV	YP
	90	66	37	26	15	5	4	6	30	83	9

Free Water Traces

Thickening Time

Consistency	40 Bc	70 Bc	100 Bc
Time	6:15	6:23	6:26

7.3 Appendix C – Steering Committee Member Comments and Revisions

Sub-Section Heading Number	Referenced Statement	Proposed Comments, Clarification, Revision to Statement	New Paragraph Statement	Accepted	Additional Info Relating to comment
1	• There are many areas within the OCS where additional R&D study can be implemented for better fundamental understanding of technical issues facing the GOM. Two areas were focused on as part of this project; mixing energy vs. total mixing time and fluid loss measurement procedures and variances in their results.	Out of all the challenges in deepwater we are concerned about R&D for mixing energy and fluid loss?		FALSE	Based on time and financial constraints of project, these two topics were focused on

1	Discussed below are summaries of the main conclusions derived from the literature review, analysis of general and case specific guidelines, operational improvements, and technology deficits.	Would it be better to break this section up so that you clearly distinguish between the summary of results form the literature review, and the other things you looked at?		FALSE	
1	Each participating company has provided input relating to general cementing operational guidelines for representative wells that have formed the basis for safety analysis and established guidelines for cementing practices and identification of deficient areas.	I do not see any kind of safety analysis that took place in this document? Please remove this sentence.		FALSE	Statement from contracted scope of work

1	Representatives from a broad spectrum of operating companies (large and small, operating shallow and deep) have formed a broad, balanced point of view .	Not sure about the wording here. Why not just leave it as; A number of operating companies provided input into this document. The focus area was cementing in the OCS. Then delete the rest of the paragraph, it all sounds like filler material which is not required.		FALSE	statement from contract scope of work.

1	From the mixing energy study, it was found that variances in slurry performance characteristics were dependent on both applied mixing energy and total mixing time. Variance was negligible for mixing energies at or above API mixing schedule. From the fluid loss study, it was found that any of the three fluid loss testing methods generally give comparable results for test temperatures below 190°F. As a safety factor, the stirred method should be used for systems above 190°F since the largest fluid loss measurements were observed from this test method.	Out of all the challenges in deepwater cementing, I am not sure how these two items are the only needed R&D cases? I can't say I have had any major issues with mixing energy, or fluid loss control.		FALSE	Based on time and financial constraints of project, these two topics were focused on

1	Case specific operational practices do vary from operator to operator which leads to immediate operational improvements following suit	This sentence makes no sense, I am not sure what you are trying to say here? I am not sure how varying practices between companies lead to "immediate" improvements?Might be better just to say; currently each operator and service providers have their own set of operational best practices. Each company will have specific challenges for the fields in which they operate.		TRUE	Sentence has been removed from document
1	...basis for safety analysis and establishment of optimized cementing practices and identification of deficient areas.	Standard practices already exist. In what way is this committee doing a safety analysis? Is there a purpose to this sentence?		FALSE	Statement directly from contract

1	Upon review of technical literature sources it was found that appropriate attention has been given to cement design and formulation for short-term isolation in most cases, but investigators have paid relatively little attention to long-term zonal isolation .	Not sure if I completely agree with this statement. I think a lot of study has gone into long term isolation; but perhaps further R&D is required to fully understand what the initial state of the cement sheath is, and how forces affect its ability to maintain isolation throughout the life of the well and permanent abandonment		FALSE	cement sheath and how forces affect its ability to maintain isolation are part of long term zonal isolation.
1	Each participating company has committed to provide procedural information for representative wells that will form the basis for safety analysis and establishment of optimized cementing practices and identification of deficient areas.	Remove this sentence. I have not provided any procedural information for representative wells, nor to my knowledge have any of the other operating companies.	Each participating company has provided input relating to general cementing operational guidelines for representative wells that have formed the basis for safety analysis and establishment guidelines for cementing practices and identification of deficient areas.	TRUE	

1	General	I would argue with much of the wording here. I do not believe any members provided procedural information for example, and not involved in the initial writing of this document	Each participating company has provided input relating to general cementing operational guidelines for representative wells that have formed the basis for safety analysis and establishment guidelines for cementing practices and identification of deficient areas.	TRUE	

1	We will cover a broad geological cross section and varied conditions in the OCS, including challenging cementing conditions in deep water such as the deep low per predominately oil reservoirs like the lower Tertiary tertiary trend, high per primarily gas reservoirs in the eastern GOM like the Miocene trend and some of the deep HPHT well drilled on the shelf	We will cover a broad geological cross section and varied conditions in the OCS, including challenging cementing conditions in deep water such as the predominately oil reservoirs like the lower tertiary trend, primarily gas reservoirs in the eastern GOM like the Miocene trend and some of the deep HPHT well drilled on the shelf	We will cover a broad geological cross section and varied conditions in the OCS, including challenging cementing conditions in deep water such as the predominately oil reservoirs like the lower tertiary trend, primarily gas reservoirs in the eastern GOM like the Miocene trend and some of the deep HPHT well drilled on the shelf	TRUE	

1	...the deep low per predominately oil reservoirs like the lower tertiary trend, high per primarily gas...	Typos	We will cover a broad geological cross section and varied conditions in the OCS, including challenging cementing conditions in deep water such as the predominately oil reservoirs like the lower tertiary trend, primarily gas reservoirs in the eastern GOM like the Miocene trend and some of the deep HPHT well drilled on the shelf	TRUE	
1	There are novel solutions on the horizon of cementing but several have yet to be fully field tested.	This seems like an empty statement?		FALSE	this is a main conclusion from the literature review. More supporting detail can be found within the literature review.

2	The investigators and the steering committee developed 5 general GOM well types to serve as the basis for this study.	Were these well types developed by Steering Committee Members or just by CSI?It should very clearly state that these are just examples and that the size and number of casing strings may vary significantly in actual OCS wells.	The investigators and the steering committee developed five general GOM well types to serve as the basis for this study. These are: Generic Well #1: deep-water well through salt zone; Generic Well #2: shelf well through salt zone; Generic Well #3: deep-water well with no salt zone; Generic Well #4: deviated shelf well; and Generic Well #5: HP/HT shelf well. These wells are purely examples based on wells drilled within the OCS, actual well designs in the OCS will vary.	TRUE	
2	The investigators and the steering committee developed 5 general GOM well types to serve as the basis for this study	Did any operatory give well types? I would say; The study utilized 5 general GOM well types.	The study utilized 5 general GOM well types.	TRUE	

2.1.1	• Shallow Hazards (gas or water flow zones)	If a 28" casing is being set, it is most likely top setting any shallow hazard zone that will be then cemented with the next surface casing string.		FALSE	agreed that that is often the intention
2.1.1	Common Cementing Risks and Considerations	What about; low temperatures, pad mud rheology and static gel strength development.These two apply for the 22" casing below as well		FALSE	these are design considerations rather than operational risks and considerations
2.1.3	• Lost Circulation	Add; Particularly at the base of salt	• Lost Circulation, usually at the base of salt	TRUE	
2.1.4		Add; lost circulation	potential lost circulation	TRUE	
2.1.4	Common cementing risks and considerations	Potential trapped annulus and subsequent APB should be listed as a common cement risk and consideration.	• CFR may dictate TOC • Potential trapped annulus and subsequent APB	TRUE	

2.1.5	10-1/8" liner	I've never heard of 10-1/8" casing. It certainly isn't a standard size and I don't think it's commonly used in the GOM. Normally, 9-5/8" or 10-3/4" or maybe even in a few cases 10" would be run below 13-5/8".		FALSE	leave 10 1/8 in casing for this well, Casing exists within tabulated field data
2.1.6	10-1/8" tieback	See previous comment regarding 10-1/8" liner.		FALSE	leave 10 1/8 in casing for this well
2.1.6		What about cement shrinkage due no availability of water (casing/casing annulus)	• Cement shrinkage due to casing/casing annulus	TRUE	
2.3.1		Surface Casing?		TRUE	changed to surface

2.3.4	• Large cement volumes • Potential gas migration issues • CFR may dictate TOC	-Is this supposed to be large displacement volumes?-You could keep this consistent with API documentation and just state potential flow zones present.-This is true in any case really depoendign on what you run across. TOC is dictated by many factors, and CFR is only one of them; think we coudl take this out.	• Large displacement volumes• Potential flow zones present • CFR may dictate TOC	TRUE	All instances of potential gas migration have been changed to potential flow zones present. This casing has a high likelihood to cover a flow zone requiring a minimum coverage dictated by CFR
2.3.5	• Fluid Migration • SBM Displacement • TOC will be dictated by CFR requirements	again I woudl try to keep consistency and just state potential flow zones. Do not think we need to add this. The TOC may be dictated by many factors, and CFR woudl only be one consideration. Add; small cement slurry volume in annulus.		TRUE	all instances of fluid migration have been changed to potential flow zones present. Potential for short annluar lengths of cement

2.4		Is thsi really representative; only 1000 ft of MD below the 9 5/8" shoe? I am not familiar with shelf wells, so this may be correct.		FALSE	yes
3	The guidelines outlined in this document are meant to be a guide to cementing in the OCS; however, specific well conditions and local guidlines will exist where going against standard practices produces the safest cementing operation which is most likely to meet its defined objectives. In these instances, it is advisable to use said non-standard practices.	Seems liek a long winded sentence her. Would it be better to say "This document offers guidance to cementing in the OCS. Specific well conditions can require deviation from said guidance to meet cement job objectives."		FALSE	no change in content

3	This data has been organized into general and specific cementing procedures and operational guidelines.	Suggest to change; "This data has been organized into general guidance on cementing procedures and guidelines."		FALSE	
3.1.1	Typically, drilling is designed and engineered around efficiency, safety and control of the well. Cementing designs and procedures are then tailored around how the well was drilled. Contrary to conventional logic, there are certain circumstances where it may be beneficial to let the cement designs dictate drilling practices instead of letting drilling practices dictate cement design. There are some drilling operational considerations, rathole considerations and mud considerations which when taken into account, will help with zonal isolation success.	the sentence structure in this paragraph do not make sense. Can we chang eit to; "It is recommended that the cementing objectives be taken into consideration when planning and executing the drilling of a hole section. For example, during the planning phase of the well consiuderation can be given to casing size, hole size, mud properties, flow restrictions, fluid displacement, etc. Some points are discussed in more detail below."	Typically, drilling is designed and engineered around efficiency, safety and control of the well. Cementing designs and procedures are tailored around how the well was drilled. Contrary to conventional logic, in certain circumstances it may be beneficial to let the cement designs dictate drilling practices instead of letting drilling practices dictate cement design. Some drilling operational considerations, rathole considerations and mud considerations will help with zonal isolation success. In a perfect design environment, cement is considered as part	TRUE	

	In a perfect design environment, cement is considered as part of the drilling process and is incorporated into a successfully designed drill program. These points are discussed below.		of the drilling process and is incorporated into a successfully designed drill program. These points are discussed below.		

3.1.1.1	There are several drilling operational procedures which need to be focused on when considering cementing guidelines. Some of the main considerations relate to: drilling rate of penetration (ROP), hole condition, and lost circulation.	does it sound better to say; "operational drilling procedures" or just leave it at "drilling procedures"?change to "can" and delete the "to" just after it.can we remove rete of penetration reference here? Waht we are concerned with is hole condition (stability), hole tortuosity (low dog leg severity, no key seatrs, no spiraling), hole size (no wash-outs), mud condition.	Several operational drilling procedures need to be focused on when considering cementing guidelines. Two of the main considerations relate to hole condition and lost circulation. These main points are discussed further below in the accompanying subsections.	TRUE	ROP section has been removed

3.1.1.1	The weight on the drilling bit needs to be carefully monitored throughout the drilling of a well. Higher ROP allows for the well to be drilled faster, but the induced weight on the bit affects hole conditions which may hurt future drilling and cementing success. More weight on a drill bit increases risks of unwanted doglegs, a spiral borehole, and increased tortuosity.	This statement is not necessarily correct. There is not a direct correlation between borehole quality and ROP. Limiting downhole vibrations is the key to minimizing spiraling, tortuosity, etc. In many cases, when WOB is too low the borehole quality will worsen. I suggest you don't try to tell people how to drill. Instead make the point that spiraling, tortuosity and dogleg severity will negatively affect cement placement and they should be minimized as much as practically possible.If you do wish to tell the reader how to drill a better quality hole then a literature search should be undertaken to get a proper understanding of the issue.	Several drilling operational procedures need to be focused on when considering cementing guidelines. Two of the main considerations relate to hole condition and lost circulation. These main points are discussed further below in the accompanying subsections.3.1.1.1.1 Hole ConditionWells need to be drilled in a manner of minimizing tortuosity, unwanted doglegs, spiral boreholes, borehole enlargement, and cuttings left in the hole. There are many variables including drilling ROP, weight on bit, and downhole vibrations which directly affect borehole conditions. As a guideline, drilling design and operational practices should be optimized to	TRUE	

			provide the highest quality borehole when and if possible. Hole condition is one of the major drilling aspects related to cementing which needs to be taken into consideration.		

3.1.1.1.1		I do not like the reference here to Drilling ROP, as below you try to tie that with weight on bit. At the end of the day we want a good hole to cement in; if they can give us that with a ROP then so be it. Hole stability is dependent on many factors (mud type, formation type, geomechanical stresses, etc), and the only one noted here specifically is surge and swab. I do not see why there seems to be so much focus here in this paper on the "ratio of the casing shoe track volume to the rat hole volume". Granted I agree the rat hole should be kept to a minimum but we have established practices to deal with rat holes in normally under-reamed holes (spotting a dense viscous pill on bottom before POOH with BHA). I can't remember		TRUE	ROP section has been removed

		having a job issue blamed on excessive rat hole in a long-long time. I think a onetime general statement here about minimizing rat hole length would suffice. I would suggest we combine the section called Drilling ROP and Hole Condition into one. Combine section on Drilling ROP and Hole Condition – call it "Hole Condition", then include the below:"Hole condition can impact the ability to effectively place cement into the casing by formation annulus. It is recommended that drilling practices minimize wash-outs, tight spots, ledges, spiral bore holes, severe doglegs, cuttings, hole instability, and excessive rat holes. Wash-outs and spiral bore holes can impact displacement efficiency;			

		potentially creating pockets of immovable drilling fluid. Incomplete annulus cement coverage can occur, potentially leading to ineffective zonal isolation (if zonal isolation was a cement job objective fir that hole section).It is recommended that an estimate of hole size be obtained prior to cement job execution. This can be accomplished by the use of mechanical caliper, sonic caliper, or fluid caliper.It is recommended that the hole be conditioned prior to running casing."			

3.1.1.1.1		I am not sure about the wording here. What we want as cementers is a stable wellbore, with limited washouts, minimal dog leg severity, minimal spiral effects, and be free of cuttings. If the drillers can produce that with a high ROP then that should be fine. I think for this and the section just below you should simply state what you want in a wellbore for cementing, and then say that drilling practices should be optimized to provide what is needed where possible	More weight on a drill bit increases risks of unwanted doglegs, a spiral borehole, and increased tortuosity. From a cementing point of view, stable wellbores with limited washouts, minimal dogleg severity, minimal spiral effects, and no cuttings left in the hole are the best case scenario. As a guideline, drilling design and operational practices should be optimized to provide these outcomes when and if possible. One method of doing this is to drill on torque measurements as opposed to ROP. As the bit is introduced to different formations with higher or lower hardness, the torque required will change. The weight on the drill bit should be varied to keep a constant application of	TRUE	

			torque that is transmitted to the formation.		

3.1.1.1.2	"washouts"	A more technically correct term is borehole enlargement. The key to minimizing borehole enlargement is carrying sufficient MW and having properly sized blocking solids in the mud. It has little to do with other drilling practices.	Certain drilling practices as well as formations encountered can lead to variances in hole condition such as borehole enlargement, tight spots, excessive rat hole, spiral boreholes and doglegs. Some of the mentioned adverse hole conditions are unavoidable because of the zonal circumstances, but many can be remedied through operational guidelines. Borehole enlargement is considered detrimental to displacement efficiencies creating ineffective laminar flow regimes and a potential for incomplete casing to formation coverage of the section.	TRUE	all instances of the term washout have been changed to borehole enlargement

3.1.1.1.2	Wireline calipers are considered the best practice, but can be very costly and time inefficient	Wireline calipers, where needed for engineering purposes, are considered the best practice, but can be very costly and time inefficient	Wireline calipers, where needed for engineering purposes, are considered the best operational guideline to follow, but can be very costly and time inefficient	TRUE	
3.1.1.1.2	A caliper should be run prior to every primary cement job covering an open-hole section.	Remove Statement	A caliper should be run prior to every primary cement job covering an open-hole section. Wireline calipers, where needed for engineering purposes, are considered the best operational guideline to follow, but can be very costly and time inefficient. Other options for performing calipers on open hole sections are with MWD or by performing a fluid caliper.	FALSE	Statement modifications were made

3.1.1.1.2	Under-reaming is a practice performed to enlarge a wellbore past its original drilled size. Although certain situations necessitate under-reaming to have a large enough annulus for lower ECD's and adequate cement sheath thickness, the practice should be avoided if possible. Under-reaming generally leads to larger unconsolidated rathole volumes	Virtually every well in the GoM is drilled using undreamed hole sections. To say that it should be avoided where possible is not realistic. This document should be pointing out operational best practices to deal with the challenges we have. The rat hole is the least of my worries when we have an under-reamed hole section	Under-reaming is a practice performed to enlarge a wellbore past its original drilled size. Generally, under-reaming equipment is located further up the BHA allowing 30-50ft of rathole once reaching TD. Some bits, such as Bi-center bits have the under-reamer built into the bit. Although certain situations necessitate under-reaming to have a large enough annulus for lower ECD's and adequate cement sheath thickness, the practice generally leads to larger unconsolidated rathole volumes as an end result. At present, virtually every well in the GOM is drilled using undreamed hole sections. As a guideline, when hole sections are under-reamed, special consideration should be taken as	TRUE	

			to the ratio of the casing shoe track volume to the rathole volume.		

3.1.1.1.2	Under-reaming is a practice performed to enlarge a wellbore past its original drilled size. Although certain situations necessitate under-reaming to have a large enough annulus for lower ECD's and adequate cement sheath thickness, the practice should be avoided if possible. Under-reaming generally leads to larger unconsolidated rathole volumes	Remove Statement	Under-reaming is a practice performed to enlarge a wellbore past its original drilled size. Generally, under-reaming equipment is located further up the BHA allowing 30-100ft of rathole once reaching TD. Some bits, such as Bi-center bits have the under-reamer built into the bit. Although certain situations necessitate under-reaming to lower ECD's and provide adequate cement sheath thickness, the practice has the potential to lead to larger unconsolidated rathole volumes as an end result. At present, virtually every well in the GOM is drilled using undreamed hole sections. As a guideline, when hole sections are under-reamed, special consideration should be taken as to the ratio of the casing shoe track	TRUE	

			volume to the rathole volume.		

3.1.1.1.3	The consequences of lost circulation can be as little as loss of expensive drilling fluid to the formation or as disastrous as loss of hydrostatic pressure leading to potential riser collapse or formation influx and a major well control situation	Change disasterous to serious and change to loss of the well.	The consequences of lost circulation can be as little as loss of drilling fluid to the formation or as serious as loss of hydrostatic pressure leading to potential riser collapse or formation influx and loss of the well.	TRUE	
3.1.1.1.3	The consequences of lost circulation can be as little as loss of expensive drilling fluid to the formation or as disastrous as loss of hydrostatic pressure leading to potential riser collapse or formation influx and a major well control situation	Remove expensive	The consequences of lost circulation can be as little as loss of drilling fluid to the formation or as serious as loss of hydrostatic pressure leading to potential riser collapse or formation influx and loss of the well.	TRUE	

3.1.1.1.3	Another option would be to induce attempt to induce losses above the calculated TOC…..	This needs to be re-written, losses would not be induced but may be already occuring above the intended TOC - therefore the cementing operation could continue if the mud loss is acceptable to the operator	Offset historical well data may assist in predicting loss zones such that casing and cement programs can be designed where losses do not affect cement coverage. In other words, known loss zones are above calculated TOC.	TRUE	
3.1.1.1.3	It should be a best practice to cure all losses prior to cementing if casing is on bottom and there is no circulation when possible	This makes no sense the way it is written. Losses should be controlled prior to running casing in the wellbore when possible; once casing is in the hole you have very few options	It should be considered an operational guideline to reduce losses as much as possible during drilling operations. Losses should be controlled prior to running casing when possible. Unfortunately, there are few options for curing losses once the casing is in the hole.	TRUE	

3.1.1.1.3	If curing the lost circulation is not possible, LCM should be added to the spacer and cement to reduce the loss risks. Another option would be to attempt to induce losses above the calculated TOC such that the losses will not affect the cement sheath end result	You may not want to add LCM to spacer and cement in all cases; think about LCM passing through a liner hanger with limited flow area; may not be a good option in that case. I would be very reluctant to state that you wanted to intentionally induce losses in a wellbore	If curing the lost circulation is not possible, LCM should be added to the spacer and cement to reduce the loss risks. There are certain scenarios, such as narrow annular flow areas, where LCM can increase risks associated with bridging off. Proper analysis of flow paths and all potential risks must be taken into account before utilizing LCM. Offset historical well data may assist in predicting loss zones such that casing and cement programs can be designed where losses do not affect cement coverage. In other words, known loss zones are above calculated TOC.	TRUE	

3.1.1.1.3	it should be a best practice to utilize bottom hole assemblies……	Change to - since lost circulation can occur in nearly any wellbore, as a best practice consider BHA's that tolerate different types and sizes of LCM	As a guideline, BHA's which have the ability to tolerate different types and sizes of LCM should be considered if there is any anticipation of encountering zones where losses could be a factor.	TRUE	

3.1.1.1.4	When reviewing the operational guidelines above relating to drilling, one may notice several key operations which contradict other operations mentioned. One example of this is recommending the guideline to drill as smooth and straight as possible, but still utilize a bit which is able to pass LCM through it. Another example is the contradiction between maximizing drilling ROP while recommending to not under-ream.	I don't understand. Why is drilling a smooth straight hole contradictory with using a bit which can pass LCM? What does maximizing ROP have to do with not underreaming?	When reviewing the operational guidelines above relating to drilling, some decisions need to be made as to priority. Not all the operational guidelines discussed above can be performed simultaneously. In summary, proper risk-based engineering analysis should be performed on each special scenario to balance the various operational practices.	TRUE	
3.1.1.2	API RP 65-2	The correct reference is API STD 65-2		TRUE	all instances have been changed to API STD 65-2

3.1.1.2	A caliper should be run prior to every primary cement job covering an open-hole section.	A caliper may be useful when hole enlargement is suspected but I don't like using such a definitive statement that says it should be run on every job.	Operators should have a very good understanding of annular hole volumes prior to cementing. Wireline calipers, where needed for engineering purposes, are considered a good tool for hole volume estimation, but can be very costly and time inefficient. Other options for performing calipers on open hole sections are with MWD or by performing a fluid caliper.	TRUE	
3.1.1.2	During all drilling operations, it should be an operational guideline to keep the bore-hole as stable as possible.	When you say borehole stability do you mean losses and influxes orr do you mean formation breakout? This should be clarified.	During all drilling operations, it should be an operational guideline to keep the bore-hole as stable as possible to minimize any losses, influxes, or formation collapse.	TRUE	

3.1.1.2	Some bits, such as Bi-center bits have the under-reamer built into the bit.	Bi-center bits and under reamers are two totally different things. Bi-center bits do not have a built-in under reamer.		TRUE	Statement Removed
3.1.1.3	Careful planning must be performed on the mud service company level , cementing service company level and the operator's level when considering mud designs and mud removal designs prior to cementing.	This does not seem to read correctly. Do you mean to say "Communication between the mud service company, and cement service company is required for effective job planning and design."	Careful planning must be performed on the mud service company level, cementing service company level and the operator's level when considering mud designs and mud removal designs prior to cementing. Good communication between the mud service company, and cement service company is required for effective job planning and design.	TRUE	

3.1.1.3.1.1	Some disadvantages of water based muds as compared to the more technically advanced oil and synthetic based muds is lower cooling and lubricating of the drill bit resulting in lower rates of penetration and hole/formation stability difficulties	Woudl it be better to say; "A typical disadvantage of WBM is their interaction with the formation and controlling hole stability."	A disadvantage of water based muds as compared to the more technically advanced oil and synthetic based muds is lower cooling and lubricating of the drill bit. In addition, they may provide less control of shale swelling.	TRUE	
3.1.1.3.1.1	Water based muds are considered one of the more simple mud types and are the most historically used in the oil and gas industry	Remove		TRUE	

3.1.1.3.1.1	Some disadvantages of water based muds as compared to the more technically advanced oil and synthetic based muds is lower cooling and lubricating of the drill bit resulting in lower rates of penetration	What about hole/formation stability; this is one of the main reasons for using NAF fluids over WBM	Some disadvantages of water based muds as compared to the more technically advanced oil and synthetic based muds is lower cooling and lubricating of the drill bit resulting in lower rates of penetration and hole/formation stability difficulties.	TRUE	
3.1.1.3.1.1	sacrificed to the sea floor….	Add statement highlighting "no negative environmental impact"	Another advantage of drilling with sea water or a mud design that is primarily sea water is that the mud returns don't have to be brought back to surface and can be sacrificed to the sea floor with no negative environmental impact.	TRUE	

3.1.1.3.1.1	Some disadvantages of water based muds as compared to the more technically advanced oil and synthetic based muds is lower cooling and lubricating of the drill bit resulting in lower rates of penetration and hole/formation stability difficulties.	Cooling and lubricating of the bit have little to do with hole/formation stability difficulties. The fact that WBMs are less inhibitive to clays is a much bigger factor.	A disadvantage of water based muds as compared to the more technically advanced oil and synthetic based muds is lower cooling and lubricating of the drill bit. In addition, they may provide less control of shale swelling.	TRUE	

3.1.1.3.1.1		I do not agree with how the entire mud section is put together here. We are talking about cementing, so regardless of the mud type there are common things we need from the mud in terms of cementing and that is what should be stated here. Many factors go into the selection of a mud system that you do not cover, and you should not cover in this kind of document	3.1.1.3.1 Mud TypesMud types are generally identified by the base fluids used in the mud. Water based muds (WBM), oil based muds (OBM) and synthetic based muds (SBM) are the main three mud types. Mud systems usually become more complex as the deeper the well becomes and the higher the bottom hole temperature and pressure increases. Regardless of the mud type being used, there are common design and operational parameters in terms of cementing that need to be followed, mostly focusing on proper removal prior to cementing. Each mud type has its inherent advantages and disadvantages discussed below.	TRUE	

3.1.1.3.1.1	Another advantage of drilling with sea water or a mud design that is primarily sea water is that the mud returns don't have to be brought back to surface and can be sacrificed to the sea floor with no negative environmental impact. Deep water wells rely on this advantage on their initial casing strings since the increased hydrostatic pressure of a riser margin would lead to fracturing of the weak formations.	Woudl it be better to say; "Seawater or WBM are utilized when drillign riserless to allow returns to the mud line."		FALSE	comment does not change content
3.1.1.3.1.1	The major advantages of water based muds are cost and design simplicity	Not sure if I totally agree here, some WBM desings can be pretty complex and challenging. I think one major advantage is the environmental impact.	The major advantages of water based muds are less environmental impact, cost, and usually less design complication.	TRUE	

3.1.1.3.1.2	The large advantages of oil based muds	change to; "Typical advantages"	The typical advantages of oil and synthetic based muds when compared to water based mud include higher effective drilling rates, lower required torque due to less friction, and reductions in the likelihood of differential sticking due to thinner mud filter cakes.	TRUE	
3.1.1.3.1.2	and reductions in the likelihood of differential sticking due to thinner mud filter cakes .	coudl we just say here; "and hole stability"	The typical advantages of oil and synthetic based muds when compared to water based mud include higher effective drilling rates, lower required torque due to less friction, and reductions in the likelihood of differential sticking due to thinner mud filter cakes and hole stability.	TRUE	

3.1.1.3.1.2	General	Mention should be made of the improved clay inhibition of OBM and SBM and the resultant improved hole quality.Also, since there is very little difference between the discussion on OBM and SBM, I would suggest that you combine the two under the heading Non-Aqueous Drilling Fluids (NADF)		TRUE	OBM and SBM sections combined
3.1.1.3.1.2	Although reductions in friction when drilling has it inherent advantages, oil – based muds require much more sophisticated spacer packages prior to cementation .	WOULD IT BETTER TO JUST SAY; "Cement spacer design is dependant on the type of mud being used."		FALSE	

3.1.1.3.1.3	Synthetic based muds (SBM) should be considered the best option for drilling efficiency while minimizing environmental impact	Would it be better to say; " Synthetic based muds (SBM) can increase drilling efficiency and minimize environmental impact."	Synthetic based muds (SBM) can increase drilling efficiency and minimize environmental impact.	TRUE	
3.1.1.3.1.3	One inherent disadvantage of SBM is cost. When drilling takes place in zones where total loss is inevitable, a less expensive mud system, rather than SBM may be more advantageous.	Remove	In cases where all job objectives can be achieved, a less expensive mud system, rather than SBM may be more advantageous when drilling takes place in zones where total loss is inevitable.	TRUE	

3.1.1.3.1.3	SBM, like OBM require complex spacer and surfactant packages to reverse the emulsion to water wet casing and formation to allow for good cement bonding characteristics	replace with; "spacer designs which are abel to"	Although reductions in friction when drilling has it inherent advantages, oil and synthetic based muds require much more sophisticated spacer packages prior to cementation. Since the mud is non-aqueous, a film can easily be left behind which must be removed for quality bonding of the cement to the casing and formation	TRUE	
3.1.1.3.2	Mud conditioning performed prior to cement jobs should remove all residual cuttings from the mud system and begin to erode the mud filter cake from the walls of the formation	Mud conditioning performed prior to cement jobs should remove all residual cuttings from the mud system and begin to remove the erodible mud filter cake from the walls of the formation	Mud conditioning performed prior to cement jobs should remove all residual cuttings from the mud system and begin to remove the erodible mud filter cake from the walls of the formation.	TRUE	

3.1.1.3.2	The mud design criterion during drilling operations is optimized to suspend, release and remove cuttings from the well. Other design considerations relating to mud are controlling formation pore pressures through fluid density, reducing lost circulation risks through density control as well as suspension of LCM, minimizing formation damage through thin impermeable filter cakes, transmitting hydraulic energy to the bit and cooling/lubricating the bit/BHA	for this document can we just delete all of this.	Other design considerations relating to mud are controlling formation pore pressures through fluid density, reducing lost circulation risks through density control as well as suspension of LCM, minimizing formation damage through thin impermeable filter cakes, transmitting hydraulic energy to the bit and cooling/lubricating the bit/BHA. Although mud systems are designed around the above mentioned parameters, generally mud is not designed for cementing. Mud conditioning performed prior to cement jobs should remove all residual cuttings from the mud system and begin to remove the erodible mud filter cake from the walls of the formation.	TRUE	Statement modifications were made

3.1.1.3.3	Turbulent flow is often not achievable and high laminar flow or transition flows are often accepted as a best case.	change to; "However, turbulent flow" remove the word high and stick to laminar.	Turbulent flow should be considered the preferred flow regime for effective mud removal; however, Turbulent flow often is not achievable and laminar flow or transition flows are often accepted as a best case.	TRUE	
3.1.1.3.3	Low velocity laminar flow should be avoided when possible. One other consideration which needs to be taken into account when designing a spacer package is the fluid contact time	How do you define low velocity here?		FALSE	low velocity laminar flow is any flow where fluid is not reaching transiton phase laminar flow

3.1.1.3.3	One other consideration which needs to be taken into account when designing a spacer package is the fluid contact time. Contact time is the period of time that a fluid flows past a particular point in the annular space during displacement. It should be considered a guideline to adhere to spacer volume calculations based on the contact time needed for proper mud removal.	It is true that contact time is the accepted design factor for turbulent flow but for laminar flow many studies have suggested that the annular length is more important than the contact time.	Contact time is the period that a fluid flows past a particular point in the annular space during displacement. Typically contact time is calculated when fluids are in turbulent flow. Calculation based on spacer annular length can also be used when in laminar flow. Proper engineering simulation of fluid placement is necessary to determine the best criteria for the designed spacer volume.	TRUE	

3.1.1.3.3	Low velocity laminar flow should be avoided when possible.	What should be avoided is flow at velocities not capable of overcoming wall shear stress on the narrow side of the annulus. If the laminar flow rate is too high then the differential velocity between the wide and narrow sides will become effective. The proper velocity range falls between these two limiters.	Turbulent flow often is not achievable and high laminar flow or transition flows are often accepted as a best case. Fluid flow at velocities not capable of overcoming the wall shear stress on the narrow side of the annulus should be avoided. If the laminar flow rate is too high, the differential velocity between the wide and narrow sides will be too large creating a potential for channeling. The proper velocity range falls between these two limiters.	TRUE	

3.1.1.3.3	As described above in the various different mud types, the most important attribute of the mud in regards to cementing is the effective removal of the mud and mud filter cake prior to cementation.	There is not industry consensus on the need to remove mud filter cake or whether it is even possible. A sufficiently thin and tight filter cake will probably provide adequate isolation.	As described above in the various different mud types, one of the most important attributes of the mud in regards to cementing is the effective removal of the mud, gelled mud, and if possible the mud filter cake prior to cementation. If it Is not possible to completely remove the filter cake, it is possible that a sufficiently thin and tight filter cake can provide adequate isolation.	TRUE	
3.1.1.3.3	The modified rotor test can be used….	Use industry accepted methods to determine optimum contact time		TRUE	Statement Removed
3.1.1.3.3	Spacer packages used and special considerations into spacer design are very important to achieve mud removal	replace with; "Mud conditioning and cement spacer design are" chage to; "effective mud removal."	Mud conditioning and spacer design are very important to achieve effective mud removal.	TRUE	

3.1.1.3.3	Slugs are volumes of mud that are more viscous and generally heavier than the mud that is currently in the well-bore. Slugs are generally used to aid with cuttings removal, especially in deviated well bores, and to create a viscous base for a cement job to prevent fluid swapping	This does not make sense. You are combining two different things here; sweeps used to aid in cuttings removal, and plug setting operations. Additionally, sweeps or pills may not be effective all the time on removing cuttings and in some cases can be detrimental to hole stability. I do not see why you need to mention sweeps here. All we need to state is that the hole should be clean and free of cuttings prior to the casing being run into the hole. Drilling optimization would seem to be far outside the scope of this document	Mud sweeps are used to aid in cuttings removal prior to cementing. Unfortunately, sweeps may not be effective all the time on removing cuttings and in some cases can be detrimental to hole stability. Proper engineering design and simulation must be performed for the most efficient method to properly remove cuttings and condition the hole. Viscous mud pills can be used for effective coverage of the rathole to reduce fluid swapping tendencies during cementing. Excess pill volume left in static conditions can lead to initial increases in circulating pressure profiles. As a guideline, computer simulation programs should be used for anticipation of ECD during hole conditioning	TRUE	

			operations. It should be considered a guideline to break circulation very slowly as to not unintentionally fracture the formation. Once circulation has been achieved, any excess pill volume should be removed by circulating bottoms up.		

3.1.1.3.3	Viscous mud pills can be used for effective coverage of the rathole to reduce fluid swapping tendencies during cementing.	Viscous mud pills are not effective for preventing rathole swapping unless they have a density equal to or, preferably greater than, the cement density.	Viscous mud pills can be used for effective coverage of the rathole to reduce fluid swapping tendencies during cementing. Where possible, a pill heavier than the cement is preferred. If this cannot be achieved, adequate testing should be performed to ensure fluid swapping will not occur.	TRUE	

3.1.2.1.1	From the literature review, it should be considered a guideline to have a minimum standoff of 75% throughout the well-bore during cementing which is accomplished with the use of centralizers .	Do not agree here with this statement. It shoudl read more like; Computer simulation of fluid displacement can determine the casing standoff required for effective cement placement."	The centralizer program is known to assist in allowing effective placement of cement in the annulus. From the literature review, some have recommended a minimum standoff of 75 percent; however, it should be considered a guideline to use proper simulation software to properly design the centralizer type, number, and placement to achieve zonal isolation across the target zones.	TRUE	

3.1.2.1.1	The centralizer program is well known to assist in concentric casing allowing placement of higher quality cement sheaths	Does not really make sense; if you say concentric casing it implies casing inside casing to me, and would not cover casing by formation annulus. Why not just keep it simple and say; it is well know that casing centralization can allow for the effective placement of cement in the annulus	The centralizer program is well known to assist in allowing effective placement of higher quality cement in the annulus	TRUE	

3.1.2.1.1	There are several different styles of centralizers on the market including: bow type, rigid, spiral, and many other variations of these styles. It should be considered a guideline to utilize the right type of centralizer for the task at hand. Considerations such as hole-size, well-bore deviation, annular wall configuration, and whether or not the casing will be rotated/reciprocated during the cement job are major aspects related to choosing the correct centralizer for the situation.	This does not seem to add any value, I woudl delete these senteces here.		FALSE	
3.1.2.1.1	The centralizer program is well known to assist in allowing effective placement of higher quality cement in the annulus	Delete higher quality	The centralizer program is known to assist in allowing effective placement of cement in the annulus.	TRUE	

3.1.2.1.1	The centralizer program is well known to assist in concentric casing allowing placement of higher quality cement sheaths	The centralizer program is well known to assist in allowing placement of higher quality cement sheaths	The centralizer program is well known to assist in allowing effective placement of higher quality cement in the annulus	TRUE	
3.1.2.1.2	Generally the couplings have a negligible annular clearance reduction and are not accounted for when cementing calculations are performed.	Generally the couplings have an annular clearance reduction and may be accounted for when cementing calculations are performed	Generally the couplings have an annular clearance reduction and may be accounted for when cementing calculations are performed	TRUE	
3.1.2.1.2	It should also be considered a best practice to take drill collars and any other annular restrictions into account when performing cementing calculations such as the anticipated top of cement (TOC)	It should also be considered a best practice to take any other annular restrictions into account when performing cementing calculations such as the anticipated top of cement (TOC)	It should also be considered a guideline to take any other annular restrictions into account when performing cementing calculations such as the anticipated top of cement (TOC) or ECD simulations	TRUE	

3.1.2.1.2	It should also be considered a best practice to take drill collars and any other annular restrictions into account when performing cementing calculations such as the anticipated top of cement (TOC)	Do you not mean ECD simulations here?	It should also be considered a guideline to take any other annular restrictions into account when performing cementing calculations such as the anticipated top of cement (TOC) or ECD simulations	TRUE	
3.1.2.1.2	concentricity	Is this a word? Would it be better to say assist with casing centralization?	If the casing or wellbore configuration does not allow you to run centralizers, casing made up with collars will slightly assist with casing centralization as compared to nothing at all.	TRUE	
3.1.2.1.2	It should be considered a best practice to use smooth bore casing if at all possible.	Remove Statement	Smooth bore casing is more expensive than generic casing, the smooth-bore lowers ECD’s by eliminating annular restrictions	TRUE	

3.1.2.1.2	If the casing or wellbore configuration does not allow you to run centralizers,……	Suggest - remove this entire reference	If wellbore configuration does not allow you to run centralizers, collared casing may assist with casing centralization	TRUE	
3.1.2.1.2	The casing connection paradigm in the oil industry is to have casing configured as pipe with exterior threads on each end. The joints of casing are then made up together with couplings. This is the most cost effective and efficient means of building casing from a manufacturing standpoint. Generally the couplings have an annular clearance reduction and may be accounted for when cementing calculations are performed. Smooth bore casing is more expensive than generic casing, the smooth-bore lowers ECD's by eliminating annular	This paragraph just does nto sound correct or fit togethere well. Suggest changing to; "Typically a casing collar, or coupling, is used to join sections of casing. This coupling has an OD larger than the casing OD. In tight tolerance cases this can impact ECD simulations, and shloud be accounted for when possible. Additionally, other restrictions in the annulus impact ECD simualtions can be included; an example woudl be liner top packers and PBR's."		FALSE	no content changed

	restrictions. It should also be considered a guideline to take any other annular restrictions into account when performing cementing calculations such as the anticipated top of cement (TOC) or ECD simulations. These calculations are especially important for long columns of cement which cover several casing joints and for tight annulus cement jobs. Pin and box casing connections are often utilized and the same calculation guidelines should be performed. If wellbore configuration does not allow you to run centralizers, collared casing may assist with casing centralization.				

3.1.2.1.3	The use of auto-fill tubes on float equipment is recommended on all casing strings to minimize the risks associated with buoyant forces acting on the casing while tripping into the hole.	In some cases you need to think about well control scenarios when using autofill equipment. You may want to convert this equipment at some point prior to reach TD; so I disagree with making statements like this outright	The use of auto-fill tubes on float equipment is recommended on casing strings to minimize the risks associated with buoyant forces acting on the casing while tripping into the hole. Certain scenarios where higher well control risks are present may call for early conversion of float equipment prior to reaching TD.	TRUE	

3.1.2.1.3	The use of auto-fill tubes on float equipment is recommended on casing strings to minimize the risks associated with buoyant forces acting on the casing while tripping into the hole.	Auto-fill is normally only advised to prevent excessive mud losses due to surge pressures while running casing. Risks associated with auto-fill are high including taking a kick while running casing and failure to properly convert. Buoyant forces can easily be overcome simply by stopping to fill the casing occassionally. In fact, the casing running tools commonly used today allow the pipe to be continuously filled.	The use of auto-fill tubes on float equipment is recommended on casing strings to minimize the risks associated with buoyant forces acting on the casing while tripping into the hole. In addition, auto-fill is normally only advised to prevent excessive mud losses due to surge pressures while running casing. Some risks associated with auto-fill equipment can include taking a kick while running casing and failure to properly convert. Buoyant forces can easily be overcome simply by stopping to fill the casing occasionally or by specialized casing running tools which allow the pipe to be continuously filled. Certain scenarios where high well control risks are present may call for conversion of float equipment prior to	TRUE	

			reaching TD.		

3.1.2.1.3	Prior to running any casing, it should be considered a guideline to measure the length of each joint of casing as well as the inner diameter associated	highlighted - associated … delete.	Some additional considerations relating to casing hardware need to be discussed. Prior to running any casing, it should be considered a guideline to measure the length and inner diameter of each casing joint.	TRUE	
3.1.2.1.3	the risks associated with buoyant forces acting on the casing while tripping into the hole	Do you mean minimize surge and swab forces?		FALSE	

3.1.2.1.3	Although multistage cementing is not a typical offshore cementing practice, some additional special considerations must be made when performing one of these cement jobs. Operators must have a detailed knowledge of the pressure ratings for the plug launchers and shear pins that are involved within the stage tools. Knowing these parameters helps with estimating the total displacement volume during the cement job as well as additional hydraulic horsepower which may be necessary.	If this is all that will be said about stage cementing I woudl just delete this paragraph.		FALSE	

3.1.2.1.3	Although cable wall cleaners are not generally utilized in the offshore industry, implementation may be recommended as a guideline if there have been higher than normal risks of formation micro-annuli from historical offset well data.	Don't agree with this. To have cable wall cleaners work you need to reciprocate the casing a considerable amount. In deepwater this is not typically done as you need to ensure you land out casing properly in the well head or suplimental adapters etc.	Although cable wall cleaners are not generally utilized in the offshore industry, implementation may be recommended as a guideline if there have been higher than normal risks of formation micro-annuli from historical offset well data. For best performance, casing reciprocation should be increased.	TRUE	
3.1.2.1.3	Although cable wall cleaners are not generally utilized in the offshore industry, implementation may be recommended as a guideline if there have been higher than normal risks of formation micro-annuli from historical offset well data.	I've never heard of "formation micro-annuli"	Although cable wall cleaners are not generally utilized in the offshore industry, implementation may be recommended as a guideline if there have been higher than normal risk of sustained casing pressure from historical offset well data.	TRUE	

3.1.2.11	From the literature review, it should be considered a guideline to have a minimum standoff of 75% throughout the well-bore during cementing which is accomplished with the use of centralizers.	Do not use an arbitrary number such as 75%. Depending on several factors such as annular gap size, fluid density hierarchy, friction pressure hierarchy and hole angle a higher standoff may be required or a lower standoff may be sufficient. Computer mud removal modeling is the best indicator of how much standoff is required.	From the literature review, some have recommended a minimum standoff of 75 percent; however, it should be considered a guideline to use proper simulation software to optimize centralizer type, number, and placement to achieve zonal isolation across the target zones.	TRUE	

3.1.2.11	General	Discussion on using centralizer placement software to determine where centralizers should be placed should be included in this section.	From the literature review, some have recommended a minimum standoff of 75 percent; however, it should be considered a guideline to use proper simulation software to optimize centralizer type, number, and placement to achieve zonal isolation across the target zones.	TRUE	
3.1.2.2	Although cable wall cleaners are not generally utilized in the offshore industry……..	Cable wall cleaners are not used for cleaning the casing walls but the formation walls…this should be moved to casing hardware	Moved to Casing Hardware	TRUE	

3.1.2.2	Mill varnish removal can be easily achieved by jet washing the casing with a soap water solution followed by rinsing off the soap residue. Sandblasting is another option which can be used, but is a more expensive option.	While pressure washing with soapy water may wash off oily residue I don't think it will remove mill varnish.Sand blasting has HSE implications.	It should be considered an operational guideline to remove any traces of mill varnish from the casing wall surfaces prior to running casing. There are many ways of removing mill varnish including power-washing with soap water or even sand-blasting. It is up to the operator as to which method should be used on location.	TRUE	
3.1.2.2	Although cable wall cleaners are not generally utilized in the offshore industry, they should be considered an above and beyond best practice if there have been higher than normal risks of micro-annuli.	Remove Statement	Although cable wall cleaners are not generally utilized in the offshore industry, implementation may be recommended as a guideline if there have been higher than normal risks of micro-annuli from historical offset well data.	TRUE	modifications have been made

3.1.2.3.1	The volume associated with the rathole must be considered as well. An operational best practice when considering fluid swapping risks with ratholes would be to pump a weighted viscous pill. This helps reduce the chances of the cement swapping with the fluid left in the rathole which could lead to a wet shoe	You might want to explain here that the weighted pill is placed in the rathole	The volume associated with the rathole must be considered as well. An operational guideline when considering fluid swapping risks with ratholes would be to pump a weighted viscous pill into the rathole prior to pulling drill pipe. As a guideline, the pill density should be greater than the tail cement density. This helps reduce the chances of the cement swapping with the fluid left in the rathole which could lead to a wet shoe. This is a generally accepted current operational practice in the OCS.	TRUE	

3.1.2.3.1	It is generally assumed that quality cement in the shoe track works as an indicator that the cement providing zonal isolation is also robust	Do not agree with this at all. Cement in the shoe track would tell you nothing of cement in the annulus which is covering a potential flow zone. It may indicate whether you might get a good LOT/FIT, but nothing at all about overall zonal isolation	Quality cement within the shoe track may be an indicator of quality shoe coverage increasing the likelihood of a quality LOT/FIT test.	TRUE	
3.1.2.3.1	First Sentence	Another method - two float valves at the collar with a guide shoe only, seperated by 2-4 joints	Non-stab-in primary cement jobs generally utilize two independent check valves run at the bottom of the casing which are separated by one to three joints. Another method includes two float valves being installed at the collar with a guide shoe separated by 2-4 joints.	TRUE	

3.1.2.3.2	Previous research studies have shown that casing rotation and/or ….It should be considered a best practice to utilize the engineering simulations prior to the cemetn job to estimate the most efficient rotation/reciprocation speeds	Not all service companies software include this option - remove the should statement	Previous research studies have shown that casing rotation and/or reciprocation helps increase displacement efficiencies. As a guideline, engineering simulations can help model the most efficient rotation/reciprocation speeds and stroke lengths if planning on moving casing during placement.	TRUE	
3.1.2.3.2	As a guideline, engineering simulations can help model the most efficient rotation/reciprocation speeds and stroke lengths if planning on moving casing during placement.	To my knowledge only one commercially available simulator takes pipe movement into account with regards to mud removal simulations.		FALSE	we arent saying must but can help. And software is comercially availible.

3.1.2.3.2	The engineering simulations also take the casing collars into consideration and what effect they have on fluid flow in the annulus.	To my knowledge this requires tedious input of casing collars as none of the simulators have the capability to automatically place them.	The engineering simulations also can take the casing collars into consideration and what effect they have on fluid flow in the annulus. Although input of collar restrictions can be somewhat tedious, the collars can affect the simulated friction pressures and should be modeled if possible.	FALSE	Task 6 -> simulators don't account for collars workaround is time consuming or over assume parameters
3.1.2.3.2	The ability to simulate offshore operations increases	woudl change to; "actual well conditions"	The ability to simulate actual well conditions increases safety and operational efficiency.	TRUE	
3.1.2.3.2	simulated prior to the actual task at hand taking place .	change to; "job execution."	Current engineering simulations on the market allow for almost all aspects of drilling, cementing, and completion to be simulated prior to job execution.	TRUE	

3.1.2.3.2	As a guideline, engineering simulations can help model the most efficient rotation/reciprocation speeds and stroke lengths if planning on moving casing during placement. The engineering simulations also take the casing collars into consideration and what effect they have on fluid flow in the annulus.	Not all simulation software can do this currently; so I am not sure if I agree with it being put in here like this. Can we just leave it with the sentence above saying that casing movement, rotation or reciprocation, can aid in mud removal.		FALSE	
3.1.2.3.2	weighted viscous pill	Pill should be of a higher density than the tail cement	An operational guideline when considering fluid swapping risks with ratholes would be to pump a weighted viscous pill into the rathole prior to pulling drill pipe. As a guideline, the pill density should be greater than the tail cement density.	TRUE	

3.1.3.1	but intermixing from storage tanks can easily……	not sure what this statement is referring to - contamination?	There is always minor variability in cements and additives from batch to batch which is generally mended through laboratory pilot and confirmation testing, but contamination from storage tanks can easily be overlooked leading to major operational failures	TRUE	
3.1.3.1	Lab slurry designs should accompany this documentation for completeness and both should be referenced prior to cementing operations	In many cases the bulk and additives may be sent to the rig in advance of a laboratory report being ready such that a lab report is not available to send at the same time of the bulk. Not sure if lab report needs to follow the blend/additives from the bulk plant all the way to the rig.	Lab pilot slurry designs should accompany this documentation for completeness and both should be cross-referenced to field designs prior to cementing operations.	TRUE	

3.1.3.2	Bulk Plant Considerations	Would add wording around; All weight indicators, pressure vessels, and pressure guages should be maintained and certified on a regular basis. All valves should be inspected adn maintained on a regular basis. The bulk plant data recording system should be abel to print out weight tickets for additives and bulk.	Dryers, vacuum systems, rock catchers, scales, and compressors should be in place and in good working order. All weight indicators, pressure vessels, and pressure gauges should be maintained and certified on a regular basis. All valves should be inspected and maintained on a regular basis. The bulk plant data recording system should be able to print out weight tickets for additives and bulk. When blending the cement, care should be taken	TRUE	

3.1.3.2	It is recommended to transfer the blended cement system five separate times for homogeneity	Remove Statement	It is recommended to transfer the blended cement system as many times as necessary for proper blend homogeneity. QA/QC checks on cement samples can help determine if blending operations have sufficiently dispersed system components.	TRUE	
3.1.3.2	When blending the cement, operators should not exceed 60% of the scale tank's capacity to reduce product loss through the vent lines.	Some scale tanks are capable of holding considerably more without loss, especially vacuum systems.I suggest removing a specific capacity value.	When blending the cement, care should be taken to avoid product loss through the vent line by overfilling the bulk tank. Product loss may occur well before a bulk tank is considered "full".	TRUE	
3.1.3.2	Any substandard or suspect material in the bulk plant should not be used when dry blending	delete these words and just end the sentence after "... not be used."	Any substandard or suspect material in the bulk plant should not be used	TRUE	

3.1.3.2	60% of the scale tank's capacity to reduce product loss through the vent lines	This number may vary greatly between bulk plants and how they are set up. Not sure if you should note a hard and fast number here. I woudl suggest to leave it more broad; " Operators shoudl take care not to over fill the scale tank. Overfilling will result in loss of product through the vent lines, and potentially alter the blend."		TRUE	previously changed
3.1.3.2	QA/QC checks on cement samples can help determine if blending operations have sufficiently dispersed system components	change samples to batches	QA/QC checks on blend samples can help determine if blending operations have sufficiently dispersed system components	TRUE	

3.1.3.2	All bulk storage tanks should be emptied, cleaned, and inspected regularly .	I woudl make this a more overall statement, maybe at the start of this paragraph; "The bulk plant should have documented operating procedures, and maintenace schedules."	Bulk plants should have documented operating procedures and maintenance schedules. Although the majority	TRUE	
3.1.3.2	Each additive should be blended from a single lot number such that there is less chance of variability throughout the blend.	This is true but for large jobs it is not always possible to have sufficient quantity of some additives from a single batch. In those cases field blend tests should be performed using all lot numbers to be pumped.	Each additive should be blended from a single lot number such that there is less chance of variability throughout the blend. In cases where this is not possible due to large job volumes, field blend tests should be performed using all lot numbers being pumped.	TRUE	

3.1.3.2	It should be considered a best practice to clean and inspect the bulk storage tanks after……	This could be a "must" statement when referring to loading cement of two different types or blends.	All bulk storage tanks should be emptied, cleaned, and inspected regularly. At a minimum, these procedures should be carried out before a new cement blend is placed into the storage tanks.	TRUE	
3.1.3.2	Each additive should be blended from a single lot number such that there is less chance of variability throughout the blend .	woudl add a clarifier; when possible …		TRUE	previously changed
3.1.3.3	Ships	Offshore Supply Vessels	Open communication is very important prior to performing any bulk transfer operations to storage tanks on the Offshore Supply Vessels	TRUE	

3.1.3.3	After loading, it is recommended to open the tank hatches to verify the amount of cement in each tank.	It is not recommended to open hatches in inclement weather as this will introduce moisture into the tanks.		FALSE	Although this statement is true, the document cannot go over all precautionary aspects related to field conditions.
3.1.3.3		What about a section on loading the rig, or sampling. There are certain sampling points we would want to ensure checks are done; bulk leaving the bulk plant to a transpot truck or supply vessel, transport truck to the supply vessel, supply vessel to the rig bulk tank. Where possible the final confirmation test should be done with the sample taken from supply vessel to rig bulk tank.	All of the cement discharge hoses should be capped and stowed to reduce the moisture contact with the cement. Blend samples should be collected prior to loading the transport vessel and during loading of the rig from the vessel. Where possible, final laboratory confirmation testing should be performed with the sample taken from supply vessel to rig bulk tank.	TRUE	

3.1.4	It has been said that a quality cement job requires 10% design and 90% placement. Although the weights of each facet of cementing design and operations can be argued, it can be agreed upon that the cement design and the placement operations work hand-in-hand to obtain a quality cement job.	Remove Statement	It can be agreed upon that the cement design and the placement operations work hand-in-hand to obtain a quality cement job.	TRUE	
3.1.4.1	Changes in cement placement designs can help reduce the required hydraulic horsepower if the pumping equipment is insufficient	You can only do so much here in this regard, and you would not want to sacrifice meeting job objectives in doing so. Would you want to put some kind of qualifying statement here? In some cases you may just need to get more horsepower to meet job objectives.	Slight changes in cement placement designs can help reduce the required hydraulic horsepower if the pumping equipment is insufficient, but placement designs should never be dramatically changed, especially at the risk of not satisfying job objectives.	TRUE	

3.1.4.1	Cementing hardware such as wiper darts, plug launchers, cement heads and float equipment, mixing equipment, and bulk delivery equipment are all standard items used to increase cementing success rates	Cementing hardware such as wiper darts, plug launchers, cement heads and float equipment are all standard items used to increase cementing success rates	Cementing hardware such as wiper darts, plug launchers, cement heads, float equipment, mixing equipment, and bulk delivery equipment are all standard items used to increase cementing success rates	TRUE	
3.1.4.1	hardware is designed to increase the quality of the cemented annulus	"aids in the the placement of cement into the annulus." Cement hardware is also used for reasons other than getting cement in the annulus. Centralizers are often run to aid in casing running, etc in sections of the annulus where you do not plan to put cement.	hardware is designed to increase the quality of the cement in the annulus	TRUE	

3.1.4.1	Cementing hardware such as wiper darts, plug launchers, cement heads, float equipment, mixing equipment, and bulk delivery equipment are all standard items used to increase cementing success rates.	you are missing a key one here in your example list; I woudl start out with "casing centralizers"	Cementing hardware such as wiper darts, plug launchers, cement heads, float equipment, mixing equipment, bulk delivery equipment, and centralizers (discussed within section 3.1.2.1.1) are all standard items used to increase cementing success rates.	TRUE	
3.1.4.1	Pre-loading the plugs into the cement head reduces additional shut-down time that could lead to cement failure through gel strength development tendencies	Are you talking about cement plugs here or cement darts? Your plug will have been loaded in the subsurface release tool well before you woudl be worrying about having to shut down in the middle of a cement job.	Pre-loading the plugs into the cement head or darts into the dart launcher reduces additional shut-down time that could lead to cement failure through gel strength development tendencies.	TRUE	

3.1.4.1	It is preferential to have the plug launching equipment pre-loaded with all of the plugs for the job	Would you want to put any kind of statement in here that you would not want to have a plug set pre-loaded for an extended period of time; which may increase the risk of permanently deforming the fins?	It is preferential to have the plug launching equipment pre-loaded with all of the plugs for the job. Pre-loading the plugs into the cement head reduces additional shut-down time that could lead to cement failure through gel strength development tendencies. As a cautionary note, plugs which sit in a head for an extended period of time may be subject to permanent deformations.	TRUE	

3.1.4.1	It should be considered a best practice to mechanically separate each consecutive fluid in the casing during cementing operations	Remove Statement	It should be considered a guideline to mechanically separate consecutive fluids in the landing string and casing during cementing operations when it will not increase operational complexity.	TRUE	modifications have been made

3.1.4.1	As a cautionary note, plugs which sit in a head for an extended period of time may be subject to permanent deformations. While discussing cement heads, it should be considered a guideline to incorporate rotating cement heads when possible such that casing rotation can be achieved during the cement job. Casing rotation helps increase annular flow velocity profiles allowing for higher quality mud removal.	this goes witht he above comment; wording here sounds more like when you use a surface cement head. Think you need to clarify when you are talkign about the darts loaded int he surface release head, and the plugs loaded int he subsurface release tool.		FALSE	this is for surface cement heads
3.1.4.1	API RP65	Should be "API STD 65-2"		TRUE	All instances have been changed to API STD 65-2

3.1.4.1	. It should be considered a guideline to mechanically separate consecutive fluids in the landing string and casing during cementing operations when it will not increase operational complexity .	this is a repeat of the above statment; get rid of one of them.	To get the best chances of cementing success, fluid intermixing should be minimized by all means and at all times. This is accomplished partially by the rheological parameter modification discussed as part of mud removal, but fluid contamination through intermixing still occurs. It should be considered a guideline to mechanically separate consecutive fluids in the landing string and casing during cementing operations when it will not increase operational complexity. The reduction of intermixing that can take place in the casing will increase the effective mud removal in the annulus allowing for higher cement sheath quality and bonding.	TRUE	

3.1.4.1	This is accomplished partially by the density and rheological parameter modification discussed as part of mud removal, but fluid contamination through intermixing still occurs	Are you talking about inside the casing here or in the annulus, it is not clear here where you are talking about.		FALSE	for rheology its both, for density it's the annulus
3.1.4.1	To get the best chances of cementing success, fluid intermixing should be minimized by all means and at all times .	delete this and just end it after "...be minimized."		FALSE	no change in content
3.1.4.1	Using only two plugs should be considered a minimum guideline	This sounds too strong, especially where many system can not support two bottom plugs. I woudl change it to; "Where applicatbel two bottom plugs can be used", or just delete it.		FALSE	one of the two is the top plug

3.1.4.1	API RP 65 recommends the use of both top and bottom plugs for all casing cement jobs other than sting-in jobs .	Inner-string instead	API STD 65-2 recommends the use of both top and bottom plugs for all casing cement jobs other than sting-in or inner string jobs.	TRUE	
3.1.4.1	mutiple places - it "should" be considered a minimum best practice	Change to - this is a reccomended best practice and eliminate "should"		TRUE	Eliminated best practice from document. The word should still exists in some places

3.1.4.1	Prior to any cement jobs, it should be considered a guideline to calculate the hydraulic horsepower needed to accomplish the operation and compare it to the equipment which will be used on location. Slight changes in cement placement designs can help reduce the required hydraulic horsepower if the pumping equipment is insufficient, but placement designs should never be dramatically changed, especially at the risk of not satisfying job objectives. Cementing simulation software programs provide great assistance in estimating the required hydraulic horsepower for cementing operations.	What does this paragraph have to do with cementing hardware? Are you considering the cement pump hardware? The rest of this section is solely about plugs and heads.		TRUE	Entire paragraph has been moved into Job Reording and Engineering Simulation section

3.1.4.1	The cementing service company should have knowledge of the locations of all screens within the liquid delivery systems prior to delivering any liquids such that if the screens need to be removed, they can in a timely manner.	Misplaced - Talking about liquids	The cementing service company should have knowledge of the locations of all screens within the bulk and liquid delivery systems prior to delivering any materials to the cement unit; such that, if the screens need to be removed in a timely manner, they can.	TRUE	
3.1.4.1	Missing language	50% of a successful job is cement delivery. In DW OCS the first cement job performed is usually a large foamed cement job. Rig crews should have practiced moving bulk cement to the unit before the first job. Practice volume should match 2000-5000sx volume mentioned earlier.	Cement delivery is a primary component of a successful cement job. In the deep water OCS, the first cement job performed is usually a large foamed cement job. Rig crews should have practiced moving bulk cement to the unit before the first job. Practice volume should match anticipated job volumes.	TRUE	

3.1.4.2	As a minimum best practice, the mix water on location should be tested for chloride content, hardness, and pH	Nice that this is mentioned but you do not give any guidance as to what to do with the measured values or what kind of impact they would have on the slurry. At a minimum I would think you would want to say measured values should be compared to those measured in the laboratory when the confirmation test was performed	As a guideline, the mix water on location should be tested for chloride content, hardness, and ph. These measured values should then be compared to the mix water used in the lab when confirmation testing was performed. Variances in mix water quality can have detrimental effects on cement slurry properties and performance parameters.	TRUE	
3.1.4.2	It should also be considered a guideline to install dry product storage bins as close to the mixing equipment, or vice versa, on new rig builds to mitigate the reduction in dry product travel rates	transfer rates	It should also be considered a guideline to install dry product storage bins as close to the mixing equipment, or vice versa, on new rig builds to mitigate the reduction in dry product transfer rates.	TRUE	

3.1.4.2	It should also be considered a guideline to install dry product storage bins as close to the mixing equipment, or vice versa, on new rig builds to mitigate the reduction in dry product travel rates.	The number of bends, elbows, etc. as well as the amount of vertical rise in the bulk transfer lines is far more critical than the overall distance.	It should also be considered a guideline to install dry product storage bins as close to the mixing equipment, or vice versa, on new rig builds to mitigate the reduction in dry product travel rates. Dry product delivery plumbing should have a minimum amount of vertical rise, bends, and elbows as well to assist in delivery quality.	TRUE	

3.1.4.2	Rig crews should have practiced moving bulk cement to the unit before the first job. Practice volume should match anticipated job volumes.	Exactly how do you propose accomplishing this? Mixing overboard? Some top hole jobs use more than 1500 bbls of cement.	It is important to make sure the cement mixing system is operational and works correctly before the job. One way of doing this is to mix a practice volume overboard. If non-cementing personnel have assigned tasks during the job, their competency needs to be evaluated pre-job. Most rigs have procedures for transferring product, developed by experience. In these cases, pre-job review can act as a surrogate to bulk delivery practice runs.	TRUE	

3.1.4.2	Rig crews should have practiced moving bulk cement to the unit before the first job. Practice volume should match anticipated job volumes .	In some cases doign test mixes can be difficult due to disposal. Woudl change to; "In some cases a test mix can be performed to check the bulk delivery and cement unit readiness. Test mix rates shoudl match anticipated job rates when possible."	One way of doing this is to mix a practice volume overboard. Test mix rates should match anticipated job rates when possible. If non-cementing personnel have assigned tasks during the job, their competency needs to be evaluated pre-job.	TRUE	previously addressed
3.1.4.2	Cement delivery is a primary component of a successful cement job. In the deep water OCS, the first cement job performed is usually a large foamed cement job	delete and replace with; "of large volume."	In the deep water OCS, the first cement job performed is usually of large volume and may be foamed.	TRUE	

3.1.4.2	Rock catchers that are already built into the bulk delivery system should be checked and maintained before and after each cementing operation and whenever there are reductions in dry product delivery rates which are suspect.	more than just the rock catchers shoudl be checked. "The rig bulk system should have documented operating procedures and maintenace schedule for key components. Prior to job execution functionality shoudl be checked."	The rig bulk system should have documented operating procedures and maintenance schedule for key components. Prior to job execution, functionality should be checked. Rock catchers that are already built into the bulk delivery system should be checked and maintained before and after each cementing operation and whenever there are reductions in dry product delivery rates which are suspect.	TRUE	

3.1.4.2	The bulk capacities of the rig's dry storage tanks and dry product travel distances should be taken into account prior to designing for cementing operations. More often than not, the travel distance from the dry cement storage bins to the mixing equipment can be in excess of 100ft leading to issues with dry product delivery rates. Maximum dry product delivery rates should be accounted for when designing cementing operations such that the placement will not be cut short by the set time of the cement .	You can accomplish all you wantto say here in one sentence; "It is recommended to establish maximum bulk delivery rates to the cement unit prior to job execution. Differnet cement blends may have different delivery rates."		FALSE	pertains to design and not only execution

3.1.4.2	Missing language	Most rigs have procedures for transferring product, developed by experience. Should mention the pre-job review of rigs transfer procedures	Practice volume should match anticipated job volumes. Most rigs have procedures for transferring product, developed by experience. In these cases, pre-job review can act as a surrogate to bulk delivery practice runs.	TRUE	
3.1.4.2	Struggling with the placement of this entire paragraph, should be cement mixing systems		3.1.4.2 Bulk and Liquid Delivery Systems	TRUE	Section moved

3.1.4.3	The majority of drilling rigs in the OCS currently do not have the capability of collecting representative dry cement samples during the transfer from the rig storage bins to the mixing equipment. Generally, if a sample needs to be caught during this transfer, residual cement is left in the surge can at the end of the job and then collected as the blend sample.	This does not seem like a best practice. It is not impossible to collect samples during the loadign of rig tanks. "It is recommended to collect representative sampels of cement blend during the loading of rig bulk tanks fromthe supply vessel; during dynamic bulk movement." Scooping out sample from teh top of tanks or the surge can rarely provides a good representative sample		FALSE	sample collection during execution
3.1.4.3	The majority of drilling rigs in the OCS currently do not have the capability of collecting representative dry cement samples during the transfer from the rig storage bins to the mixing equipment.	I believe it would be a good recommendation from this report that sample valves should be installed in the bulk systems on rigs to allow representative sample collection.		TRUE	Implemented into Task 6: immediate improvemen t

3.1.4.3	RP 65	Should be "API STD 65-2"		TRUE	All Instances have been changed to API STD 65-2
3.1.4.3	These additional samples can be used for random spot QA/QC testing for assurance of blend quality and dramatically help towards pinpointing any equipment issues when performing post-job investigations.	How do samples help pinpoint equipment issues?	These additional samples can be used for random spot QA/QC testing for assurance of blend quality and dramatically help towards pinpointing any issues when performing post-job investigations.	TRUE	
3.1.4.3	. For above and beyond cementing guidelines ,	Delete		TRUE	
3.1.4.3	cement sample collection should be performed during each dry product transfer, whether it is from the bulk plant to the transport vessel or from the rig storage bins to the mixing equipment.	"Cement samples can be collected at each transfer point; bulk plant to transport truck or supply vessle, transport truck to supply vessel, supply vessel to rig."		FALSE	more sample collection is always better than less.

3.1.4.3	Some liquid additives used for cement systems lose their effectiveness from long term storage. Other liquid additives lose their effectiveness over time when pre-mixed as a mix fluid to be used later on. It should be considered a guideline to have manufacture and expiration dates documented for all cementing liquid additives which are on location	Suggest to change wording:"Liquid additives should not be used if past their expiration date. Laboratory testing can be done to re-qualify additives that are beyond their expiration date in some cases."	Some liquid additives used for cement systems lose their effectiveness from long term storage. Other liquid additives lose their effectiveness over time when pre-mixed as a mix fluid to be used later on. It should be considered a guideline to have manufacture and expiration dates documented for all cementing liquid additives which are on location. Laboratory testing can be done to re-qualify additives that are beyond their expiration date in some cases.	TRUE	

3.1.4.3	If the mix fluid is pre-mixed for a cement job, aging tests should be performed on the mix fluid to observe and document any changes in slurry performance parameters.	You never catch up with this cycle, say you take a smaple after 8 hr of mix fluid being prepared and send it to shore for testing; its goign to be roughly 24 hr later before you get a result of a lab test. Now your mix fluid is 32 hr old, is it still good? Any mix fluid agign tests woudl need to be done during the planning stages of a well to determine sensitivity to ageing."It is recommended to prepare mix fluid (additives + mix water) just prior to job execution to limit mix fluid ageing effects. Mix fluid ageing tests can be performed prior to the job to evaluate effects on slurry performance."	If the mix fluid is planned to be pre-mixed for a cement job, aging tests should be performed on the mix fluid to observe and document any changes in slurry performance parameters over time. This allows for real-time decision making in the field should any delays occur.	TRUE	

3.1.4.3	As a guideline, the mix water on location should be tested for chloride content, hardness, and ph.	How does hardness affect cement slurry performance? It should be pH, not ph.	As a guideline, the mix water on location should be tested to ensure it is representative of what was used during pre-job laboratory design testing. Differences may result in performance variations from the design.	TRUE	

3.1.4.4	An above and beyond best practice	I would recommend to avoid this kind of wording	Some of the newer offshore rigs in the GOM have the cement recording equipment integrated into the central rig recording equipment. Although offshore installments like these are considered the best case scenario, other methods of recording can be more than sufficient. The central data collection area for all operations on the rig organizationally helps all operational practices, but integration can be very costly to implement, especially on older drilling rigs.	TRUE	

3.1.4.4	It should be considered a best practice to perform ECD placement simulations: assuming gage hole and hole with excess, assuming average nitrogen injection rate and varied injection rate, taking into account changes in slurry rheology and foam quality, and taking into account temperature and pressure changes during the foam job	So how should one go about accounting for foam rheology when it is not measured directly	It should be considered a guideline to perform ECD placement simulations assuming gauge hole and hole with excess, assuming average nitrogen injection rate and varied injection rate, taking into account, changes in slurry rheology, foam quality, temperature and pressure during the foam job. There presently is not an industry consensus on the best method to address the rheology of a foamed slurry into these simulations. This issue has been identified as an area in need of additional R&D work which has been mentioned within section 6 of this document.	FALSE	Section has been placed within task 7 additional R&D

3.1.4.4	During the cementing operations, service company representatives should periodically check additive injection rates for quality control .	Some systems may not allow you to easily check injection rates durign the job. I think it might be better to say that additive injection rates shoudl be verified prior to job execution.		FALSE	addtitive injection system which don't have real-time injection rate or volume monitoring should not be used.
3.1.4.4	Lot numbers for all liquid additives on location should be tracked as well to help reduce issues with individual additives.	You have already mentioned LOT numbers a coupel times above, think we can delete this here.		FALSE	
3.1.4.4	The mud-spacer compatibility is most important, but the spacer-cement compatibility should be analyzed as well.	What is the user supposed to do when they find that the mud and cement are incompatible, as they always will be? That's why we run spacer.		FALSE	Although this statement is true, the spacer must be compatable with both fluids, otherwise there will be risks of premature shutdown during cement job.

3.1.4.4	The yield points of sequential fluids should be successively increased such that the viscosity of the displacing fluid tends to overcome the viscosity of the displaced fluid.	This is not technically correct. The key link to viscosity is that each successive fluid should impart a higher annular friction pressure than the fluid before it. A hierarchy in YP does not ensure this.	The yield points of sequential fluids should be successively increased to reduce risks associated with fluid swapping in static conditions. Dynamically, successive fluids should impart a higher annular friction pressure such that the viscosity of the displacing fluid will tend to overcome the viscosity of the displaced fluid.	TRUE	

3.1.4.4	It should be considered a guideline to keep very close observation of fluid rheology to assist displacement efficiencies. The yield points of sequential fluids should be successively increased such that the viscosity of the displacing fluid tends to overcome the viscosity of the displaced fluid.	what does close obeservation mean? Woudl suggest to change this;"Rheological hierarchy between fluids can aide in minimizing fluid intermixing. The friction pressure of successive fluids shoudl increase; displacing fluid greater than displaced fluid. Density hierarchy between successive fluids can also aide in fluid displacement; this becomes more effective the more vertical the well trajectory is."	It should be considered a guideline to control fluid rheological parameters to assist displacement efficiencies.	TRUE	
3.1.4.4	As a common sense rule of thumb, the less fluid intermixing that is allowed to occur, the better chances of quality cement placement	would re-word this; " Minimizing fluid intermixing can result in cement slurry placed in the annulus meeting desing parameters."	The less fluid intermixing that is allowed to occur, the better chances of quality cement placement.	FALSE	no change in content

3.1.4.4	As a common sense rule of thumb	delete this wording please	The less fluid intermixing that is allowed to occur, the better chances of quality cement placement.	TRUE	
3.1.4.4	While discussing the importance of laboratory fluid compatibility testing, it should also be considered a guideline to run contaminated thickening time tests to observe how the contamination will vary the cement system's set time.	What is the user supposed to do when they find that the mud contaminated cement has an altered TT, as it always will? That's why we run spacer.	While discussing the importance of laboratory fluid compatibility testing, it should also be considered a guideline to run spacer contaminated thickening time tests to observe how the spacer contamination will vary the cement system's set time.	TRUE	

3.1.4.4	While discussing the importance of laboratory fluid compatibility testing, it should also be considered a guideline to run contaminated thickening time tests to observe how the contamination will vary the cement system's set time. Thickening time graphs should be attached to cement lab reports as the graphical data helps field personnel easily make real-time contingency planning if and when needed. Laboratory reports should also include the cement slurry departure time for quick reference during placement operations.	Contamination does not only effect thickenign time but otehr slurry properties as well, I woudl change wording; "Cement slurry contamiantion by spacer or mud can impact the desinged slurry properties. Laboratory testing of contaminated cement slurry can be performed to determine its sensitivity to contamiantion; the most common woudl be to determine its effects on thickenign time and compressive strength."	While discussing the importance of laboratory fluid compatibility testing, it should also be considered a guideline to run spacer contaminated testing to observe how contamination will vary the slurry and set cement performance parameters; the most common would be to determine its effect on thickening time and compressive strength.	TRUE	

3.1.4.4	observe how the contamination	delete the	While discussing the importance of laboratory fluid compatibility testing, it should also be considered a guideline to run spacer contaminated thickening time tests to observe how contamination will vary the cement system's set time.	TRUE	

3.1.4.5	It should be considered a best practice to minimize the displacement volume when and if at all possible	Do you want to qualify this statement somehow. Its written in such a way that it makes it sound like all jobs should be done via inner string or something?	There are some considerations related to placement techniques which are discussed in this section. Several cement jobs in the GOM are run as an inner string to help decrease total pump time and displacement volume. A technical analysis should be performed to identify whether or not running an inner string will better meet job objectives. If it is found that either method will better meet job objectives, that placement method should be used. If both methods meet all objectives of the cement job, a cost analysis should be performed, keeping in mind that any remedial cement work will likely cost a minimum of 24 hours of down time. All cement jobs should be	TRUE	

			pumped at the highest allowable rates while keeping ECD's below the fracture gradient to allow for better hole cleaning efficiency.		

3.1.4.5	A cost benefit analysis should be performed to identify whether or not running an inner string should be performed	Cost benefit is not why I would run an inner string; if it makes technical sense to run an inner string on a cement job then it should be done	There are some considerations related to placement techniques which are discussed in this section. Several cement jobs in the GOM are run as an inner string to help decrease total pump time and displacement volume. A technical analysis should be performed to identify whether or not running an inner string will better meet job objectives. If it is found that either method will better meet job objectives, that placement method should be used. If both methods meet all objectives of the cement job, a cost analysis should be performed, keeping in mind that any remedial cement work will likely cost a minimum of 24 hours of down time. All cement jobs should be	TRUE	

			pumped at the highest allowable rates while keeping ECD's below the fracture gradient to allow for better hole cleaning efficiency.		

3.1.4.5	Some of the newer offshore rigs in the GOM have the cement recording equipment integrated into the central rig recording equipment. Although offshore installments like these are considered the best case scenario, other methods of recording can be more than sufficient. The central data collection area for all operations on the rig organizationally helps all operational practices, but integration can be very costly to implement, especially on older drilling rigs.	Woudl suggest just to delete this section here, do not see it addign any real value.		FALSE	disagree, the more data collected from previous jobs helps increase continuous improvemen t on future jobs
3.1.4.5	Pump and downhole pressures	do you mean pump pressure and wellhead pressure? Not sure what you are getting at with "downhole" pressure?		TRUE	previously implemented

3.1.4.5	There are some additional operational parameters which when recorded can dramatically assist with post job analysis for QA/QC and help with incident investigation.	Remove emotional wording out	There are some additional operational parameters which when recorded can assist with post job analysis for QA/QC and help with incident investigation.	TRUE	

3.1.4.5	The mix density and downhole density help visualize areas where slightly insufficient dry product delivery may have occurred	what do you mean by downhole density? Not all companies are able to measure density in the high pressure line. Would be careful with wordin' here so as not to isolate some service providers.	The mix density and downhole density help visualize where bulk delivery or mixing issues may have occurred. Generally, the mix density will fluctuate more than the downhole density, but it still should be a guideline to minimize the mix density fluctuation as much as possible. Downhole densometers do not have to be installed within the high pressure line but can be out of an averaging tub or some other location that isn't part of the recirculation system.	TRUE	

3.1.4.5	General	Add a comment that says if the rig displaces the displacement pressure should still be recorded by the cement unit.	Certain scenarios exist where this may not be possible. In instances where the rig will displace the cement job instead of the cementing unit, it should be a guideline for the cementing unit to record the pressure and if possible the displacement rate from the rig pumps. Some of the newer offshore rigs in the GOM have the cement recording equipment integrated into the central rig recording equipment.	TRUE	
3.1.4.5	Both the pump and downhole pressures can be recorded as a redundancy check on pressure as well as can be implemented into post job simulations.	What is the difference between pump pressures and downhole pressures?	Both the pump and well head pressures can be recorded as a redundancy check on pressure as well as can be implemented into post job simulations.	TRUE	

3.1.4.5	slightly insufficient dry product delivery may have occurred	Not sure hwat you mean here? It coudl be that the mixing system is not wroking properly, not only insufficient dry bulk delivery? This seems to be filler material, woudl delete.	The mix density and downhole density help visualize where bulk delivery or mixing issues may have occurred.	TRUE	
3.1.4.5	There are certain scenarios where this may not be possible, but the larger amount of data collected from each cementing operation, the easier it is to make changes to the placement operations for higher quality on future wells.	I woudl delete this sentence; do not see it adding any value over what has already been stated.		FALSE	disagree, the more data collected from previous jobs helps increase continuous improvemen t on future jobs

3.1.4.5	The mix density and downhole density help visualize areas where slightly insufficient dry product delivery may have occurred . Generally, the mix density will fluctuate more than the downhole density, but it still should be a guideline to minimize the mix density fluctuation as much as possible	This whole littel section here is confusing,and potentially isolating some service providers. Can you just say;"Cement unit mixing density can vary slightly from design during execution. Most cement units are fitted with larger averaging tanks which mitigate against large density variations. It is recommended to check mixed slurry density with a pressuried mud balance periodically throughout job execution."		TRUE	
3.1.4.5	An guideline is to record the fluid returns through flow-meters during the cement job .	"Fluid returns are monitored closely throughout the job. This can be done by observation or through the use of flow meters on the return line."		FALSE	quantitiative data is better than qualitative

3.1.4.5	Cementing simulation software is a very powerful tool	delte word very.	Cementing simulation software is a powerful tool when used correctly.	TRUE	
3.1.4.5	General	It might be appropriate to list what things should be simulated (e.g. ECD, Surface Pressure, Flow-in/Flow-out, Temperature, Centralization and Mud Removal Effectiveness).	As a guideline, simulations such as ECD, surface pressure, calculated casing/annular rate, temperature, friction pressure, rheological hierarchy, and effectiveness of mud removal should be performed and analyzed for all cement jobs when and if possible.	TRUE	

3.1.4.5	Certain assumed parameters will have negligible change to the simulation end result and others will have a detrimental effect.	"It is important for the desing engineer be aware of the softawares limitations, and assumptions. It is recommended tha the desingn engineer clearly document what assumptions went into the simulation output."	Certain assumed parameters will have negligible change to the simulation end result and others will have a detrimental effect. It is important for the design engineer be aware of the software's limitations, and assumptions. It is recommended that the design engineer clearly document what assumptions went into the simulation output.	TRUE	
3.1.4.5	Qualified cementing engineers will be able	Competent		TRUE	all instances of qualified have been changed to competent
3.1.4.5	guideline to have qualified cementing engineers	suggest to change to "competent"		TRUE	all instances of qualified have been changed to competent

3.1.4.5	Qualified cementing engineers will be able to tell which input parameters can be assumed and which parameters cannot.	woudl delete this sentence, you already noted you want competent cementing engineers to run the software		FALSE	
3.1.4.5	This issue has been identified as an area in need of additional R&D work which has been mentioned within section 6 of this document.	This isn't mentioned in your conclusions on Page 1.		TRUE	Section added into additional R&D on Foam Cementing.
3.1.4.5	Equivalent circulating density is one of the more significant parameters during foam cement jobs. It should be considered a guideline to perform ECD placement simulations assuming gauge hole and hole with excess	This can be bennificial for non-foamed jobs as well.	Equivalent circulating density is one of the more significant parameters for cement jobs whether they are foamed or un-foamed.	TRUE	

3.1.4.5	Special consideration needs be taken into account when performing cement placement simulations for foam cementing. Various situations can arise during foam cement jobs where proper initial placement simulations will be able to address these on location	This makes little sense to me.	Special consideration needs be taken into account when performing cement placement simulations for foam cementing. Additional simulations, based on common contingency plans, should be run so if these situations arise during foam cement jobs, proper placement simulations are available.	TRUE	

3.1.4.5	Equivalent circulating density is one of the more significant parameters during foam cement jobs. It should be considered a guideline to perform ECD placement simulations assuming gauge hole and hole with excess , assuming average nitrogen injection rate and varied injection rate, taking into account, changes in slurry rheology, foam quality, temperature and pressure during the foam job. There presently is not an industry consensus on the best method to address the rheology of a foamed slurry into these simulations. This issue has been identified as an area in need of additional R&D work which has been mentioned within section 6 of this document.	This section is not worded very effectively. Woudl change to: "The most common simulations performed during pre-job planning are; ECD, temperature, casing centralization, and mud removal." If you are goign to mention foam in here you woudl need to go into a lot more detail I think to make it bennificial.		FALSE	no change in content

3.1.4.6	If the measured FIT is lower than expected, it should be considered a best practice to modify drilling rates and ECD's to reduce the likelihood of lost circulation during drilling	A poor FIT may result in more than just modified drilling parameters, it may result in the need to set an extra casing string as you will not be able to drill the next open hole section safely	If the measured FIT is lower than expected, it should be considered a guideline to modify drilling rates and ECD's to reduce the likelihood of lost circulation during drilling. Poor FIT results may also require the need to set extra casing strings in certain situations.	TRUE	
3.1.4.6	The formation integrity test is a qualitative test which estimates the fracture pressure of the formation at the shoe	An FIT may not give you any idea what the actual fracture initiation pressure is of a formation; an FIT is generally taken to a fixed value and the test stopped without initiating fracture.	The FIT is a qualitative test where hydraulic pressure is applied to observe if the formation will be able to withstand anticipated ECDs during future drilling operations.	TRUE	
3.1.4.6	If it is found that either method will better meet job objectives, that placement method should be used.	delete		TRUE	

3.1.4.6	. If both methods meet all objectives of the cement job, a cost analysis should be performed, keeping in mind that any remedial cement work will likely cost a minimum of 24 hours of down time.	woudl delete, don't think you need ot bring cost analysis into this docuemtn.		TRUE	statement removed
3.1.4.6	All cement jobs should be pumped at the highest allowable rates while keeping ECD's below the fracture gradient to allow for better hole cleaning efficiency.	I don't agree with the pump as fast as you can philosophy. This can lead to situations where the differential velocity difference between the wide and narrow sides of the annulus becomes too high, promoting channeling.		FALSE	
3.1.4.6	or where the mud is known to be aerated .	"mud compressibility is a question."	Displacement recalculation is very beneficial in deep-water situations or where the mud compressibility is a factor.	TRUE	

3.1.4.6	anticipated bumps or shears encountered	"...anticipated plug bumps or release.	During displacement of the cement slurry, it should be considered a guideline to recalculate the displacement volume from anticipated bumps or release encountered during displacement.	TRUE	
3.1.4.6	recalculation is very necessary in deep	"benificial"	Displacement recalculation is very beneficial in deep-water situations or where the mud is known to be aerated.	TRUE	

3.1.4.6	Although operators are able to achieve much lower ECD’s during placement, special equipment is necessary to perform reverse circulation cementing operations.	I am not aware there is a simulation software out there right now that can verify that much lower ECD's are reached. I woudl change to;"It may be possible to achieve lower ECD's..."	Reverse circulation cementing is a technique which is currently not used often in the GOM. It may be possible to achieve lower ECD's during placement through reverse circulation cementing, but additional special equipment is required for the operation to be successful.	TRUE	

3.1.4.6	Reverse circulation cementing is a technique which is currently not used often in the GOM. Although operators are able to achieve much lower ECD's during placement, special equipment is necessary to perform reverse circulation cementing operations. Additional research and development is needed to assess the viability of this option, especially in deep-water scenarios.	Recommend deleting this entire paragraph.		FALSE	

3.1.4.7	The two main methods are performing an FIT test on the shoe and running bond logs on the cemented annulus	What about monitoring execution job parameters and comparing to planned, and utilizing lift pressure analysis as another option?	There are several methods used to qualitatively determine the quality of the cement. These methods include: performing FIT tests, comparing design parameters to execution parameters, lift pressure analysis, and running bond logs on the cemented annulus. There are some additional considerations to be taken into account when discussing bond logs.	TRUE	
3.1.4.7	If the bond log is run before the cement has developed sufficient compressive strength, the CBL will not show only liquid behind the casing	Why would you only chose to mention CBL here. I have very rarely seen only a CBL run (normally at a minimum it is CBL/VDL in combination), and more and more circumferential logs are utilized for cement bond logging	If the bond log is run before the cement has developed sufficient compressive strength, the cemented annulus may not show up on the logs	TRUE	all instances of CBL have been changed to bond log

3.1.4.7	The acoustic impedance of set cement is dependent on the system's density and porosity	This is not always the case; some cement additives can also lower acoustic impedance for slurries of similar density. What about the effects of mud or spacer contamination on the set cement acoustic impedance?	The acoustic impedance of set cement is can vary depending on multiple factors including, but not limited to: density, porosity, certain additives in the system, and any mud/spacer contamination within the system.	TRUE	
3.1.4.7	remedial work to patch zones with insufficient coverage	to meet job objectives	In this case, placement is the only option followed by remedial work to meet job objectives.	TRUE	
3.1.4.7		paragraph is switching back and forth between sonic and ultra-sonic tools		FALSE	All instances of specific bond logging tools have been generalized to bond log

3.1.4.7	make real-time quick decisions	remove quick	Having a contingency plan set for each scenario prior to the job helps operators make real-time decisions which are in line with meeting job objectives.	TRUE	
3.1.4.7	allowing for the highest quality end result .	"which are in line with meeting job objectoves."	Having a contingency plan set for each scenario prior to the job helps operators make real-time decisions which are in line with meeting job objectives.	TRUE	
3.1.4.7	the CBL will not show only liquid behind the casing.	reword	If the bond log is run before the cement has developed sufficient compressive strength, the cemented annulus may not be visible on the logs	TRUE	

3.1.4.7	which encompasses any and all operational difficulties	woudl change this all encompasing wording; "foreseable"	The best placement design has a contingency plan which encompasses foreseeable operational difficulties that could be encountered during placement.	TRUE	
3.1.4.7	The cement slurry should have very good fluid loss control such that it will plug off flow paths by depositing a filter cake and sufficient set time such that multiple hesitations can be performed.	Slurries with no fluid loss control are more effective for squeezing shoes. It is desirable for the cement to gel and dehydrate in the channels during the hesitations. FL control will have the opposite effect.	The cement slurry should have very good fluid loss control such that it will plug off flow paths by depositing a filter cake and sufficient set time such that multiple hesitations can be performed.	FALSE	Disagree

3.1.4.7	When performing shoe squeeze operations, it should be considered a guideline to use the Bradenhead squeeze method, described further within the squeeze cementing subsection.	While a Bradenhead method may be the best choice for some shoe squeezes there are situations where it is preferable to squeeze shoes through a cement retainer or retreivable packer.	When performing shoe squeeze operations, it should be considered a guideline to use the Bradenhead squeeze method, described further within the squeeze cementing subsection. In certain situations where special casing hardware is attached, a bradenhead method may need to be avoided and squeeze operations may require additional tools such as a cement retainer or a retreivable packer.	TRUE	
3.1.4.7	formation integrity test (FIT) is performed.	woudl you want to add; "or LOT (Leak Off Test)"	After the cement has developed sufficient compressive strength, the shoe is drilled out and a FIT or LOT is performed.	TRUE	

3.1.4.7	The cement slurry should have very good fluid loss control such that it will plug off flow paths by depositing a filter cake and sufficient set time such that multiple hesitations can be performed.	I think the desing of the slurry FL is dependent on what is considered to be causing the poor FIT. I woudln't make a blaket statemtn that you need very good fluid loss control.	The cement slurry should have sufficient fluid loss control such that it will plug off flow paths by depositing a filter cake and sufficient set time such that multiple hesitations can be performed.	TRUE	
3.1.4.7	second paragraph	I struggle with sections liek this that are pretty broad with little detail; in the end they do not add very much value to the docuemnt?		FALSE	
3.1.4.7	The FIT is a qualitative test where hydraulic pressure is applied to observe if the formation will be able to withstand anticipated ECDs during future drilling operations.	A properly performed FIT is quantitative, not qualitative.	The FIT is a quantitative test where hydraulic pressure is applied to observe if the formation will be able to withstand anticipated ECDs during future drilling operations.	TRUE	

3.1.4.7	but generally, the shoe squeeze contingency slurry can be designed around the tail slurry being pumped for that operation. Special slurry parameter considerations need to be focused on such as the necessity of higher fluid loss control or longer set times for hesitations.	higher fluid loss control meaning a lower fluid loss value, or higher fluid loss value. how does this line up with your above statement that shoe squeeze slurries needed very good fluid loss control?	but generally, the shoe squeeze contingency slurry can be designed around the tail slurry being pumped for that operation. Special slurry parameter considerations need to be focused on such as the necessity of sufficient fluid loss control or longer set times for hesitations.	TRUE	
3.1.4.7	generally, the shoe squeeze contingency slurry can be designed around the tail slurry being pumped for that operation. Special slurry parameter considerations need to be focused on such as the necessity of higher fluid loss control or longer set times for hesitations.	Tail slurries usually contain FL control additives. A slurry with no FL control is prefered for shoe squeezes.Also, the slurry must be tested on a hesitation squeeze schedule in the lab.	generally, the shoe squeeze contingency slurry can be designed around the tail slurry being pumped for that operation. Special slurry parameter considerations include high fluid loss control and long set times able to withstand multiple hesitations.	TRUE	

3.1.4.8	performing FIT tests , comparing	or LOT	Post job analysis is used evaluate the end quality of the cement being placed. There are several methods used to qualitatively determine the quality of the cement. These methods include: performing FIT/LOT tests, comparing design parameters to execution parameters, lift pressure analysis, completion of job objectives, and running bond logs on the cemented annulus	TRUE	
3.1.4.8	running bond logs on the cemented annulus.	cement bond log		FALSE	bond log is more generic term to reference all bond measurement devices

3.1.4.8	If the bond log is run before the cement has developed sufficient compressive strength ,	You mention compressive strength here, but just above you were talkign about acoustic impedence. You need to explain the link between the two before you can use them interchangably.	As cement begins to develop compressive strength, the acoustic impedance inherently increases. Special consideration needs to be taken into account in regards to the timing of running bond logs on cement. If the bond log is run before the cement has developed sufficient compressive strength, the cemented annulus may not be visible on the logs. The acoustic impedance of set cement is can vary depending on multiple factors including, but not limited to: density, porosity, additives in the system, and any mud/spacer contamination within the system	TRUE	

3.1.4.8	It should be considered a guideline to measure or calculate the acoustic impedance of the cement under laboratory conditions prior to the cement job such that wire-line technicians are able to properly calibrate their tools for best results.	Acoustic impedance is only used for ultrasonic logs. For sonic logs the measurement is amplitude or attenuation of the sonic signal as it travels through the casing. For sonic logs the user needs to know the strength of the cement so that the anticipated amplitude/impedance can be estimated for "perfectly" cemented pipe.In either case there is no calibration of the tools with regards to cement properties. Knowledge of the cement properties is useful for proper presentation and interpretation of the log.Suggest you reference API 10TR1.	It should be considered a guideline to measure or calculate the acoustic impedance and compressive strength of the cement under laboratory conditions prior to the cement job such that wire-line technicians are able to properly interpret their logs. Acoustic impedance is used for ultrasonic logs. For sonic logs, the measurement is amplitude or attenuation of the sonic signal as it travels through the casing. For sonic logs, the user needs to know the strength of the cement so that the anticipated amplitude/impedance can be estimated for cemented pipe.	TRUE	

3.1.4.8	cement is can vary	remove 'is'	The acoustic impedance of set cement can vary depending on multiple factors including, but not limited to:	TRUE	
3.1.4.8	and any mud/spacer contamination within the system .	just say ...and slurry contamination.	The acoustic impedance of set cement can vary depending on multiple factors including, but not limited to: density, porosity, additives in the system, and slurry contamination.	TRUE	
3.1.4.8	slurry has reached an acoustic impedance of at least ½ MRayl above the mud's measured acoustic impedance.	NA		FALSE	
3.1.4.8	the cemented annulus may not be visible on the logs	...the cement in the annulus...	If the bond log is run before the cement has developed sufficient compressive strength, the cement in the annulus may not be visible on the logs.	TRUE	

3.1.4.8	One of the major concerns regarding post job analysis is the actual quality of the cement being placed.	Isn't the post job analysis trying to evaluate the quality of the cement placed? I would reword this; "Post job analysis of planned (simulated) versus actual execution data can be done to evaluate whether cement job objectives were met."	Post job analysis is used evaluate the end quality of the cement being placed. There are several methods used to qualitatively determine the quality of the cement. These methods include: performing FIT/LOT tests, comparing design parameters to execution parameters, lift pressure analysis, completion of job objectives, and running bond logs on the cemented annulus	TRUE	
3.2	Where special treatment of the cement is necessary to gain the desired results, the slurry has the properties to conform to those specifications.	this sentence does not make sense to me?		TRUE	statement previously modified

3.2	Where special treatment of the cement is necessary to gain the desired results the slurry has the properties to conform to those specifications. The same applies to compatibility relationships between the cement and spacer, and the spacer and the mud. The mud also is assumed to be within the standards required to drill the well effectively.	This entire paragraph makes no practical sense to me the way it is written. Not sure what you are trying to get across. Do you mean; "The cement system, along with the cemetn spacer system, are designed for a specific environment and job objective. Cemetn slurry laboratory testing, and cemetn spacer testing, is performed under downhole conditions where possible."	The cement system, along with the cement spacer system, must be designed for a specific environment and job objective. Cement slurry laboratory testing and cement spacer testing should be performed under simulated down hole conditions.	TRUE	

3.2.1	NA	This whole paragraph does not make sense. So you are saying a tail slurry pumped on a surface string should also be tested at mud line conditions? I believe you are trying to also say that good cement coverage is necessary for well structural integrity, but it is not coming across clearly the way it is worded	For initial casing strings it should be considered a guideline to perform laboratory testing on the cement slurry at bottom-hole conditions and additional tests should be performed on systems designed for coverage at the mud line. This is especially important for deep water cementing operations as the mud line temperature begins to dramatically decrease for water depth greater than 300 feet. More time is required for Portland cement to develop compressive strength at lower temperatures. It is very critical to have good cement coverage at the shoe for all cemented casing strings, but it is especially important on the initial casing strings and in deep water conditions where	TRUE	

			the next hole section could potentially be drilled with the riser in place.		

3.2.1	best practice to perform laboratory testing on the cement slurry at bottom hole conditions and at the mudline	If I could only run two tests it would be at bottom hole and at the corresponding depth of the highest potential flow zone	For initial casing strings it should be considered a guideline to perform laboratory testing on the cement slurry at bottom-hole conditions and additional tests should be performed on systems designed for coverage at the mud line.	FALSE	For the sake of this paper, there is not a limit of two tests. Only two tests were recommended. Operators can perform laboratory testing at as many depth as they see fit.
3.2.1	It is very critical to have good cement coverage at the shoe for all cemented casing strings, but it is especially important on the initial casing strings and in deep water conditions where the next hole section could potentially be drilled with the riser in place.	could potentially be drileld with riser? We would know which string will have the BOP and riser installed on it. Maybe; "Cement used in top hoel sections provides axial support for the instillation of the BOP and other equipment which will be installed."I don't know if that is exactly good either, but the existing wordign does not sound correct.	In addition to providing zonal isolation, the cement used in top hole sections must also provide the axial support for the installation of the BOP and other equipment.	TRUE	

3.2.1	For initial casing strings it should be considered a guideline to perform laboratory testing on the cement slurry at bottom-hole conditions and additional tests should be performed on systems designed for coverage at the mud line .	With the modified statement suggested above you could now delete this. Maybe say "It is recommended to consider the low mud line temperatures when testing cemetn slurry which will be circulated back to mud line."		TRUE	
3.2.1.1	It should be considered a best practice to install a dart catcher sub on the casing to assist with cleaning during the cement job	Do you mean installed on the DP?	It should be considered a guideline to install a dart catcher sub on the drill pipe to assist with cleaning during the cement job	TRUE	

3.2.1.1	Density variations of more than (+-) 0.1 ppg over extended periods during the mixing process, can have deleterious effects on the hydrostatic control of the section being cemented	I would hope that the slurry design used was robust enough to handle a o.1 ppg variation, and proper pre-job simulations account for reasonable density variations during execution	Density variations of more than (+-) 0.2 ppg over extended periods during the mixing process, can have deleterious effects on the hydrostatic control of the section being cemented. Proper pre-job simulations should account for reasonable density variations which may occur during job execution.	TRUE	

3.2.1.1	The density, viscosity, and long term gel strength of the fluid to be displaced needs to be taken into consideration to prevent naturally occurring forces that will exceed the design parameters. The fluid added after the drilling process has completed is generally a low solid high gel consistency, and little thought is given to the long term gel strength and the effects of low temperature. A relatively high pump pressure may be needed to initiate fluid movement creating an unwanted stress on the formation. The falling velocity due to density differential cannot be controlled as returns are to the sea bed and the annulus is completely open. The best practice is to engineer the fluid resident in the well bore to be	This seems like a long way to say that it is recommended to place a pad fluid in the wellbore that has non-progressive gelation tendencies; if that is what you were trying to get at with this paragraph?	The density, viscosity, and long term gel strength of the fluid to be displaced needs to be taken into consideration to prevent naturally occurring forces that will exceed the design parameters. The fluid added after the drilling process has completed is generally a low solid high gel consistency, and little thought is given to the long term gel strength and the effects of low temperature. A relatively high pump pressure may be needed to initiate fluid movement creating an unwanted stress on the formation. The falling velocity due to density differential cannot be controlled as returns are to the sea bed and the annulus is completely open. The guideline is to engineer the fluid resident in the well bore to be	TRUE	

	consistent with the design criteria of the cement job thus avoiding or minimizing undesirable characteristics		consistent with the design criteria of the cement job thus avoiding or minimizing undesirable characteristics. Pad fluids that have non-progressive gelation tendencies tend to be suitable choices.		
3.2.1.1	Rotation and/or reciprocation is not an allowable option on these initial casing strings as drill pipe is generally stung into the casing shoe	In the majority of cases the DP may not be stung into the casing shoe, but done as an inner string, not a stab-in configuration		TRUE	Statement Removed

3.2.1.1	The density, viscosity, and long term gel strength of the fluid to be displaced needs to be taken into consideration to prevent naturally occurring forces that will exceed the design parameters. The fluid added after the drilling process has completed is generally a low solid high gel consistency, and little thought is given to the long term gel strength and the effects of low temperature. A relatively high pump pressure may be needed to initiate fluid movement creating an unwanted stress on the formation. The falling velocity due to density differential cannot be controlled as returns are to the sea bed and the annulus is completely open. The guideline is to engineer the fluid resident in the well bore to be	"it is recommended that the mud left in the hole after drilling have non progressive gels. High gel strength can increase the pressure required to initiate circulation once casing is on bottom, increasing the chance of lost circulation."		TRUE	previously implemented

	consistent with the design criteria of the cement job thus avoiding or minimizing undesirable characteristics. Pad fluids that have non-progressive gelation tendencies tend to be suitable choices.				

3.2.1.1	API RP 65-2 recommends hole caliper logs for primary cementing operations. Although wireline calipers are considered the best way of measuring open hole volumes, there are other more cost effective means which can be used such as dye fluid markers, adding polypropylene beads to the mud system to be viewed by the ROV, or using pH meters. Generally, the initial open hole sections are drilled with seawater for cost effectiveness , then the mud is swapped out with pad mud to hold back the formation while tripping in casing . As a general guideline, the pad mud should have a somewhat low yield point such that the cement slurry does not have to be designed with a higher than normal	this paragraph is all over the place; you start out by talkign about hole size estimation, transition to pad mud desing, and finish with a ball catched sub on the DP. This creates a document that just does not flow smoothly and makes it difficult to follow what point you are trying to get across. I would suggest to be more clear and precise, and not mix themes in the same paragraph		TRUE	already addressed

	yield for proper displacement efficiency. It should be considered a guideline to install a dart catcher sub on the drill pipe to assist with cleaning during the cement job.				

3.2.1.1	All discussion on density control	Why is this discussion only included in this section for returns to seafloor as it is just important for all jobs? It seems that density control might better be discussed in 3.1.4.6 or even as its own section.		TRUE	Moved into new section.
3.2.1.1	to hold back the formation while tripping in casing .	delete	Generally, the initial open hole sections are drilled with seawater for cost effectiveness, then the mud is swapped out with pad mud	TRUE	
3.2.1.1	mud is swapped out with pad	replaced	Generally, the initial open hole sections are drilled with seawater, then the seawater is replaced with pad mud.	TRUE	
3.2.1.1	effectiveness , then the mud is swapped out with	seawater	Generally, the initial open hole sections are drilled with seawater, then the seawater is replaced with pad mud.	TRUE	

3.2.1.1	with seawater for cost effectiveness ,	delete cost	Generally, the initial open hole sections are drilled with seawater, then the seawater is replaced with pad mud.	TRUE	
3.2.1.1	Cement in the well bore of poor quality may be more detrimental than no cement at all. Problems that develop over a period of time, and especially those that escalate with the passage of time, may prove to be far more expensive and damaging than an initial higher cost on the primary cement job. Prior experience in the area generally determines the procedures necessary to overcome these problems. It is virtually impossible to plan and have equipment and/or material on stand-by, for every imaginable scenario, and it is certainly not cost effective. Certain	I read this and get no value, it seems to run on. I think there is one point you are trying to get across? ; "Ineffective placement of cement in the annulus can in some instnaces be more detrimental than no cement at all. Contingency plans for when to circulate out a primary job should be in place prior to job executioin."		FALSE	previously addressed

	scenarios which have higher probabilities of occurring should be planned for ahead of time to help mitigate their effects.				
3.2.1.1	Cement in the well bore of poor quality	annulus	Poor quality cement in the annulus may lead to future problems that develop over time	TRUE	

3.2.1.1	Many offshore cement units have a relatively small capacity mixing tub, usually between 6 to 8 barrels of volume	I would argue that the majority of units used today offshore have a 6 or 8 bbl mixing tubs that then spill over into 14 or 18 bbl averaging tubs for better density control.	Many offshore cement units have a relatively small capacity mixing tub, usually between 6 to 8 barrels of volume. Mix tubs do generally spill over into 14 to 18 barrel averaging tubs for better downhole density control, but cement service companies should not rely on these averaging tubs to replace better mixing practices when on location.	TRUE	
3.2.1.1	To achieve proper shut-off within these problem areas, density control will be a priority.	remove		TRUE	Removed
3.2.1.1	As required in the code of federal regulations, the cement must conform to the parameters outlined in API RP-65 and RP-65-2	As required in the code of federal regulations, the cement must conform to the parameters outlined in API RP-65 and STD 65-2	As required in the code of federal regulations, the cement must conform to the parameters outlined in API RP-65 and STD 65-2	TRUE	

3.2.1.1	As required in the code of federal regulations, the cement must conform to the parameters outlined in API RP-65 and STD 65-2.	Untrue. The CFR does not specify cement conformance. The CFR states: "A written description of how you evaluated the best practices included in API Standard 65—Part 2, Isolating Potential Flow Zones During Well Construction, Second Edition (as incorporated by reference in § 250.198). Your written description must identify the mechanical barriers and cementing practices you will use for each casing string (reference API Standard 65—Part 2, Sections 4 and 5)."Also, STD 65-2 specifically states that it is not applicable for top hole cementing so its reference should be removed from this section.		TRUE	statement removed

3.2.1.1	In most cases, a larger volume of lead cement circulated to the seafloor will not affect the cemented annulus end result.	It should be noted that pumping large volumes of cement returns to the seafloor results in covering the wellhead.	In most cases, a larger volume of lead cement circulated to the seafloor will not affect the cemented annulus end result; however, care should be taken to ensure that cement returns will not affect any subsea equipment.	TRUE	
3.2.1.1	The majority of cement jobs require nitrogen or low density solids to be added to control hydrostatic and expected ECD pressures, to prevent fracture or ingress to a particular zone.	wording is more complicated than it needs to be; "Due to the narrow margin between formation fracture pressure and formation pore pressures it is typical to cement top hole casings with low density systems."		FALSE	no content change

3.2.1.1	but cement service companies should not rely on these averaging tubs to replace better mixing practices when on location .	what does this mean, what are better mixing practices on location?	Mix tubs do generally spill over into 14 to 18 barrel averaging tubs for better downhole density control, but cement service companies should not rely on these averaging tubs to replace standard mix density control practices when on location.	TRUE	
3.2.1.1	Density variations of more than (+-) 0.1 ppg over extended periods during the mixing process, can have deleterious effects on the hydrostatic control of the section being cemented	Density variations of more than (+-) 0.2 ppg over extended periods during the mixing process, can have deleterious effects on the hydrostatic control of the section being cemented	Density variations of more than (+-) 0.2 ppg over extended periods during the mixing process, can have deleterious effects on the hydrostatic control of the section being cemented. Proper pre-job simulations should account for reasonable density variations which may occur during job execution.	TRUE	

3.2.1.1	the hydrostatic control of the section being cemented	.." on slurry properties and meeting job objectives."	Density variations of more than (+-) 0.2 ppg over extended periods during the mixing process, can have adverse effects on slurry properties and meeting job objectives.	TRUE	
3.2.1.1	mixing process, can have deleterious effects on the hydrostatic	I had to look up what this meant. Can you keep it simple; "adverse	Density variations of more than (+-) 0.2 ppg over extended periods during the mixing process, can have adverse effects on slurry properties and meeting job objectives.	TRUE	
3.2.1.1	The cement design will only be effective if the mixing of the cement on surface is rigidly controlled	"Planned slurry properties are achieved in the field by mixing the slurry at the required density and minimizing contamination."	Planned slurry properties are achieved in the field by mixing the slurry at the required density and minimizing contamination.	TRUE	

3.2.1.1	The guideline to be followed for these types of slurries is to have a recirculating mixer with automatic density control. The mix tub volume should be kept at a maximum level to homogenize momentary density fluctuations. When nitrogen is incorporated into the mix, the use of a process controller to inject the nitrogen will keep the N_2 volume consistent with the rate cement is mixed and pumped. The process controller measures the incoming cement rate and adjusts the volume of N_2 injected to keep the ratio of N_2 to cement within the designed parameters.	When foam cement slurries are planned, it is recommended to use process control during job execution. This will help adjust the nitrogen rate based on the cement slurry rate, maintaining designed foam sluryr density."		TRUE	Statement previously modified

3.2.1.1	If auxiliary equipment, such as a recirculating skid, is available to increase the volume of slurry being mixed on the fly, it will not only optimize the homogeneity of the slurry, it will provide the means to pump the slurry with the most consistent and optimal (designed) rate	Remove Statement	If auxiliary equipment, such as an averaging tub, is available to increase the volume of slurry being mixed on the fly, it will not only optimize the homogeneity of the slurry, it will provide the means to pump the slurry with the most consistent and optimal (designed) rate	FALSE	Revisions to statement were made
3.2.1.1	The surface pumping rate is fixed by the design criteria and is easily controlled by the pumping crew	The surface pumping rate is fixed by the design criteria and is easily controlled by the cement equipment operator	The surface pumping rate is fixed by the design criteria and is easily controlled by the cement equipment operator	TRUE	

3.2.1.1	All discussion on placement and mud removal.	Why is this discussion only included in this section for returns to seafloor as it is just important for all jobs? It seems that placement/mud removal might better be discussed in 3.1.4.6 or even as its own section.		TRUE	previously modified
3.2.1.1	Cement in the well bore of poor quality may be more detrimental than no cement at all.	What does this statement mean. It doesn't seem to be supported by the remainder of the paragraph.		FALSE	previously addressed

3.2.1.1	It is virtually impossible to plan and have equipment and/or material on stand-by, for every imaginable scenario, and it is certainly not cost effective.	One common contingency is to have enough material on the rig to redo the job should cement have to be circulated out of the hole. This isn't always feasible due to rig capacity limitations but at least plans should be in place to have materials for a repeat job available at the shore base.	It is virtually impossible to plan and have equipment and/or material on stand-by, for every imaginable scenario, and it is certainly not cost effective. Certain scenarios which have higher probabilities of occurring should be planned for ahead of time to help mitigate their effects. One common contingency is to have enough material on the rig to redo the job should cement have to be circulated out of the hole. This isn't always feasible due to rig capacity limitations but at least plans should be in place to have materials for a repeat job available at the shore base.	TRUE	

3.2.1.1	Every hour saved can reduce the cost and severity of a particular operation by a significant amount.	Remove Statement		TRUE	Removed
3.2.1.1	API RP 65-2 reference	Remove the reference to 65-2. API STD 65-2 specifically states in the Conditions of Applicability that "This document does not address shallow water flow zones in deepwater wells which are covered in API RP 65."		TRUE	anything with returns to seafloor - RP65 not -2
3.2.11		should mention pH meter - has been successful for detecting slurry	A second option is to monitor the fluid returns at the mud line while pumping lead slurry either visual or through a pH meter. When cement has reached the mud line, mixing of tail cement should be initiated.	TRUE	

3.2.2	Intermediate Casing Strings (Title)	The title of the section is casing strings, but you go right into talking about intermediate drilling liners?	Intermediate Strings	TRUE	
3.2.2	There are instances where an intermediate string will be run as a liner to isolate a known or possible problem zone, or to span a section of hole at the lowest cost while still preserving well bore integrity. Examples are high permeability and/or low pressure sands, pressured aquifers, salt or mobile formations, rubble zones, sloughing shale's, etc. When there is no hydrocarbon bearing formation in that section, the shoe will be tacked in with a predetermined volume of cement, and the liner hanger will be set in the previous casing string	What about reducing ECD by limiting a long section of narrow annuli; which can be done in some cases	There are instances where an intermediate string will be run as a liner to isolate a known or possible problem zone, or to span a section of hole at the lowest cost while still preserving well bore integrity. Examples are high permeability and/or low pressure sands, pressured aquifers, salt or mobile formations, rubble zones, sloughing shale's, etc. Additionally, running intermediate strings as liners can eliminate long sections of narrow annuli which can reduce ECD's. When there is no hydrocarbon bearing formation in that section, the shoe will be tacked	TRUE	

			in with a predetermined volume of cement, and the liner hanger will be set in the previous casing string		

3.2.2	When there is no hydrocarbon bearing formation in that section, the shoe will be tacked in with a predetermined volume of cement, and the liner hanger will be set in the previous casing string.	delete	Removed	TRUE	
3.2.2	etc. Additionally, running intermediate	remove 'additionally'	Intermediate strings are used to break the well up into workable sections or isolating potential problem areas. Examples are high permeability and/or low pressure sands, pressured aquifers, salt or mobile formations, rubble zones, sloughing shale's, etc. Running intermediate strings as liners can eliminate long sections of narrow annuli which can reduce ECD's.	TRUE	

3.2.2	There are instances where an intermediate string will be run as a liner to isolate a known or possible problem zone, or to span a section of hole at the lowest cost while still preserving well bore integrity	why specify liner? Woudl it be better to say; "Intermediate casing strings are used to break the well up into workable sections or isolating potential problem areas."	Intermediate strings are used to break the well up into workable sections or isolating potential problem areas. Examples are high permeability and/or low pressure sands, pressured aquifers, salt or mobile formations, rubble zones, sloughing shale's, etc. Running intermediate strings as liners can eliminate long sections of narrow annuli which can reduce ECD's.	TRUE	

3.2.2	After drill out of the shoe track, the formation integrity test will verify there is a seal for continued drilling with increasing mud weights.	What about a LOT, and you may not alwyas be increasing the mud weight, in some cases the mud weight will be lowered. "Upon drilling out the shoe a LOT or FIT is typically performed to verisy the subsequent section can be drilled."	Upon drilling out the shoe a LOT or FIT is typically performed to verify the subsequent section can be drilled.	TRUE	
3.2.2	either by mechanical or chemical means	what do you mean by chemical means?	When a possibility for flow or losses exists in this zone, the guideline is to ensure isolation of the area either by mechanical or chemical (e.g. cement) means, and test to validate the seal.	TRUE	

3.2.2	The top of the liner needs to be tested prior to drilling out the shoe according to standards that meet the minimum requirements to control the well.	whos standards are you talkiing about here?	The top of the liner should be tested prior to drilling out the shoe. Once the shoe has been drilled out, testing the integrity of the liner top seal becomes more difficult.	TRUE	
3.2.2	When there is a possibility for flow or losses in this zone, the guideline is to ensure isolation of the area either by mechanical or chemical means , and test to validate the seal	so if you are using cement to isolate a flow zone are you saying here you always want to log? Not sure if this statement is clear, as it coudl be interprited in different ways		FALSE	

3.2.2	Other intermediate strings are brought to the wellhead to isolate previous casing strings. If the string will have a significant amount of unsupported pipe, a guideline should include calculations encompassing the expected temperature and pressure changes during the production cycle.	I think you lost the scope of this document in many palces; it was supposed to be an operational guide for cementing; operational, not engineering design and deffinately not casing design. Woudl delete this entire paragraph.		FALSE	
3.2.2	It should also be considered a guideline to keep track of the mud return volume as an additional quality assurance check during displacement.	I think before we look at mud return volumes which tend to go into a larger mud system, you shoudl say to suggest that the mud used for displacement be physically measured by tank straps where possible.	It should also be considered a guideline to keep track of the mud return volume as an additional quality assurance check during displacement. Mud displacement volumes should be physically measured by tank straps where possible.	TRUE	

3.2.3.1	In the field, it should be considered a best practice to batch mix the slurry when possible	Keep in mind that batch mixing comes with its own challenges and may not be the best option all the time, even when the option is available	Batch mixing in the field will produce the closest match to the laboratory results. Batch mixing ensures homogeneity in the slurry, chemicals are in the exact proportion required, density is uniform, and eliminates potential bulk delivery issues which may be encountered during the cement job. While batch mixing will provide the most uniform slurry, it does come with its own set of operational challenges which must be addressed if slurries will be batch mixed. Among these operational challenges are the need for additional equipment on location, volume limitations, and surface retention time considerations.	TRUE	

3.2.3.1	Permeability can vary from a millidarcy to several Darcy's. Each production zone is a unique entity, and each will have their own peculiarities and special characteristics.	delete unless you are going to somehow link this to an operational cemetn issue.	removed	TRUE	
3.2.3.1	common is that they contain hydrocarbons in some form and hopefully, in a commercially viable quantity.	Delete ' and hopefully, in a commercially viable quantity.'	statement removed	TRUE	
3.2.3.1	Permeability can vary from a Millidarcy to several Darcy's	Permeability can vary from a millidarcy to several Darcy's	Permeability can vary from a millidarcy to several Darcy's	TRUE	
3.2.3.1	Selecting the best technique that will	design not technique	Selecting the best design and technique that will meet job objectives can be challenging.	TRUE	
3.2.3.1	that will produce acceptable results can be challenging	"... will meet job objectives."	Selecting the best design and technique that will meet job objectives can be challenging.	TRUE	

3.2.3.1	There may be small sections within the matrix that have more demanding attributes	what matrix are you talking about; cement matrix, formation? What demading attributes? This sentence does not give any information the way it stands right now. I woudl delete this.	removed	TRUE	
3.2.3.1	The system finally chosen is expected to meet or exceed the critical parameters of zonal isolation and provide adequate support for the productive life of the well.	delete		TRUE	
3.2.3.1	The guideline to follow is usually becomes a compromise	Sentence does not make sense the way it is written. What are you compromisign between? I woudl just delete this.		TRUE	
3.2.3.1	This is particularly needed if catastrophic and/or fatal events could be the expected outcome.	Remove Statement		TRUE	Removed

3.2.3.1	A step by step program may be necessary to ensure field implementation	A step by step procedure is written for every cement job, not just the one performed on the production casing?		TRUE	
3.2.3.1	The guideline to follow is usually becomes a compromise . The producing formation may not have the same integrity throughout the zone, so it becomes a balancing act to design a system that will meet at least the minimum criteria. Once a design is selected, procedures are written to implement the process in the field. Very critical aspects merit more attention to detail when writing the field procedure. A step by step program may be necessary to ensure field implementation is carried out in the manner prescribed. When a special sequence must be	I get no value out of this paragraph, I woudl delete the entire thing.		FALSE	modifications have been made

	followed, those instructions need to be clear and the importance of the sequence should be explained. When an ordering of events is very critical, a description of the consequences when the order is breached will add emphasis.				

3.2.3.1	In the field, the best practice will always be batch mixing the slurry. That method ensures homogeneity in the slurry, chemicals are in the exact proportion required, and density is uniform. That method will produce the closest match to the laboratory sample that can be performed on a location	Remove Statement	Batch mixing in the field will produce the closest match to the laboratory results. Batch mixing ensures homogeneity in the slurry, chemicals are in the exact proportion required, density is uniform, and eliminates potential bulk delivery issues which may be encountered during the cement job. While batch mixing will provide the most uniform slurry, it does come with its own set of operational challenges which must be addressed if slurries will be batch mixed. Among these operational challenges are the need for additional equipment on location, volume limitations, and surface retention time considerations.	FALSE	Statement Revised

3.2.3.1	Generally, cement designs are based on the mud properties at bottom hole conditions.	cement designs or spacer designs? or better cement and spacer designs?	Generally, cement and spacer designs are based on the mud properties at bottom hole conditions	TRUE	
3.2.3.1	The displacement pumping regime is also critical .	do you mean displacemetn flow regime?	The displacement flow regime also is critical	TRUE	
3.2.3.1	When running casing within vertical production zones, it should be considered a minimum guideline to centralize the casing to the calculated top of cement	this makes it sound like you woudl only centralize the production casing if it were in a vertical conditioni. Suggest to clear up wording.		FALSE	

3.2.3.1	Additional consideration should be performed to check the compatibility of the mud and cement at surface conditions as well as bottom hole conditions	you can't really check all compatability at true bottom hole conditinos; you can condition fluids at pressure and temperature but you then need to cool them down to run rheological compatability in most cases currently	Additional consideration should be performed to check the compatibility of the mud and cement at surface conditions as well as bottom hole conditions. Where bottom hole conditions cannot be met in the laboratory, compatibility testing should be conducted as close as reasonably practical.	TRUE	
3.2.3.2	Running ridged type centralizers should be considered a best practice in horizontal sections as annular clearance is guaranteed	I would avoid wording such as “guaranteed” in this document.	Running ridged type centralizers should be considered a guideline in horizontal sections as annular clearance is more likely to occur.	TRUE	

3.2.3.2	If they can all be separated by cement plugs, this method can still be useable in high angle scenarios, but it should be considered a best practice to have all fluids very close in density and have displacement efficiency built around the rheological hierarchy where successive fluids have greater viscosity	In some cases the main objective of a cement job done in a horizontal configuration may be to obtain a hydraulic seal in the heal and vertical portion of the wellbore (after passing through the horizontal section), and in this case you would still want some density differential preferably. May of the statements being made throughout the document really depend on the job objectives and it is very hard to make general "best practice" statements about the operation	If they can all be separated by cement plugs, this method can still be useable in high angle scenarios, but it should be considered a guideline to have all fluids very close in density and have displacement efficiency built around the rheological hierarchy where successive fluids have greater viscosity. When competent cement through the heel and vertical section is a primary job objective, density hierarchy for the fluids which cover this section will aid in displacement efficiency. Alternatively, to avoid unnecessarily pumping fluids through a horizontal section, a stage tool may be considered whenever isolation is needed in the vertical section of the wellbore.	TRUE	

3.2.3.2	Production strings run as liners generally only have a top plug with no wiper plugs	Production strings run as liners generally only have a top plug.	Production strings run as liners generally only have a top plug.	TRUE	
3.2.3.2	Production strings run as liners generally only have a top plug .	is this still true? More and mor esystems utilize dual plugs.	Production strings run as liners may have only a top plug.	TRUE	
3.2.3.2	Cement slurry designs need to have excellent properties for cementing in horizontal section.	what does excellent mean? I woudl leave out wording like this and just lead intot he nex sentence by sayin; " Cement slurry desings are recommended to have the followign properties in horizontal sections:."	Cement slurry designs are recommended to have no free water or settling tendencies when placed in horizontal sections. Small amounts of free water within a cement system can lead to flow channels in horizontal sections.	TRUE	

3.2.3.2	Centralization is very important when cementing horizontal trajectories. Certain bow type centralizers should not be used in horizontal sections as the weight of the casing will flatten out the centralizer on the lower portion. Running ridged type centralizers should be considered a guideline in horizontal sections as annular clearance is more likely to occur. Cement slurry designs need to have excellent properties for cementing in horizontal section. It should be considered a guideline to have no free water or settling tendencies within the slurry design. Small amounts of free water within a cement system can lead to flow channels in horizontal sections.	Add wording regarding restoring force	Centralization is very important when cementing horizontal trajectories. Certain bow type centralizers should not be used in horizontal sections as the weight of the casing will flatten out the centralizers on the lower portion, where the restoring forces of the centralizers are not enough to support the weight of the casing. Running rigid type centralizers should be considered a guideline in horizontal sections as annular clearance is more likely to occur	TRUE	

3.2.3.3	Higher density cement systems are required in abnormally pressured zones to adequately hold back the possibilities of formation influx.	You need higher cement slurry density becasue the mud weight required to control formation pressures are high. "High mud weights are required to control formation pore pressures adn subsequently high cemetn slurry densities are required for fluid displacement and hydrostatic control during cemetn placement."		FALSE	
3.2.3.3	Addition of weighting materials to slurry designs end up changing the slurry performance parameters creating a balancing act between having a system heavy enough for formation pressure but robust enough to develop strength.	delete	The addition of weighting materials to slurry designs may change the slurry performance parameters. It is important to design a slurry which is not only dense enough to hold back formation pressure but also meets all job objectives.	TRUE	

3.2.4	Several cementing considerations relating to other primary cement jobs don't apply to tieback strings, but several other operational considerations need to be taken into account	I would argue that a lot of the cementing considerations relating primary cementing also apply to tie-back cementing. It would be nice to list what is not to be considered if that kind of statement is made	As a final step, generally a tieback liner is run for many reasons which include increased well integrity during production operations and additional support of the cased well during flow-tests or fracturing treatments. There are two additional pieces of hardware which need to be considered when designing for a tieback string.	TRUE	Statement removed and revised
3.2.4	As a final step, generally a tieback liner is run for additional support of the cased well during flow-tests or fracturing treatments	There seem to be many more reasons to run tieback liners that would come before mentioning their use in flow tests or fracture treatments; one being well integrity during production operations	As a final step, generally a tieback liner is run for many reasons which include increased well integrity during production operations and additional support of the cased well during flow-tests or fracturing treatments	TRUE	

3.2.4	As an offshore well is drilled, several liners end up being hanged inside each other making the casing profile go from narrow at the bottom of the well to much wider up near the mud line.	change to hung then delete sentence	As an offshore well is drilled, several liners end up being hung inside each other making the casing profile go from narrow at the bottom of the well to much wider up near the mud line.	TRUE	
3.2.5		makes no sense at all		TRUE	Revisions made

3.2.5.2	It should be considered a guideline to use the same salt type for saturating well fluids as the salt type within the formation. Utilization of different salts may create unexpected issues such as formation damage. When discussing cement excess, it should be considered a guideline to calculate the tail excess for total coverage of the salt zone. The lead cement excess should be calculated upon the open hole volume. It should also be considered a guideline for all fluids being circulated through or near salt zones to be salt saturated if possible to reduce the likelihood of formation damage.	This paragraph does not have enough detail to fully convey the concept		TRUE	Removed Statement

3.2.5.4	It should also be considered a best practice to adjust the mixing density of the cement slurry when foaming	This does not really make sense as a statement all alone; what are you trying to say here?	It should also be considered a guideline to adjust the mixing density of the cement slurry to account for any additives that will be injected downstream of the mixing unit, such as foaming agents and stabilizers.	TRUE	
3.2.5.4	ISO 10426-4	I believe you should be referencing API documents and not API here in this document	There are many recommended guidelines derived from foam cementing case studies which are discussed within the literature review along with documented testing methods discussed within API 10B-4	TRUE	

3.2.6.2	The best practice is to use computer simulations for the volume of spacer to be used	Should use other criteria here since not all computer software will determine spacer length.	Placement simulations may be used to calculate the effective spacer volume needed for these operations if available. If placement simulators are not available and the spacer is assumed to be in laminar flow, a common practice is to base spacer volume on 10 minutes of contact time.	TRUE	

3.2.6.2	The best practice is to use computer simulations for the volume of spacer to be used	Remove Statement	Placement simulations may be used to calculate the effective spacer volume needed for these operations if available. If placement simulators are not available and the spacer is assumed to be in laminar flow, a common practice is to base spacer volume on 10 minutes of contact time.	FALSE	Modified Statement
3.2.6.2	The best practice in this situation is to spot a high viscostiy mud pill……	Pill should meet specific criteria, SPE 30514 should be included in the references any time viscous pill is suggested		FALSE	This paper is being written without any specific reference to SPE/IADC technical documents other than API or CFR. Specific criteria vary from operator to operator.

3.2.6.2	Missing language	Hole size should be determined to the best of the operators ability in order to set a successful plug, use previously mentioned methods	Whenever possible, batch mixing the cement is the preferred method for mixing. If the formation where the cement will be placed is permeable, the addition of a fluid loss agent may be a further consideration. Usually pipe rotation and reciprocation can be achieved on these plugs and can contribute to successful operations. Hole size should be determined to the best of the operators ability in order to set a successful plug, using previously mentioned methods. Additional considerations which may increase the chances of successfully setting a kick-off plug include using a centralized placement string, using a slick-wall stinger, using drill pipe wiper balls	TRUE	

			and a ball catcher sub, using a diverter tool, or using a disconnect tool.		

3.2.6.2	Missing language	Usually pipe rotation and recriprocation can be achieved here, this operator has had much success with rotation at rigs maximum rate with open ended drill pipe - no stinger	Whenever possible, batch mixing the cement is the preferred method for mixing. If the formation where the cement will be placed is permeable, the addition of a fluid loss agent may be a further consideration. Usually pipe rotation and reciprocation can be achieved on these plugs and can contribute to successful operations.	TRUE	
3.2.6.2	Missing language	Plugs and Kick-off plug setting opertions should be treated in importance the same as a production casing job with regards to simulations for mud removal	Cement contamination will account for the majority of failed attempts to side track. Plugs and Kick-off plug setting opertions should be treated with the same importance as production string jobs in regards to simulations for mud removal.	TRUE	

3.2.6.2	Missing language	What about centralization or utilizing slick wall pipe. Additionally the use of a Disconnect tool has been very successful in the GOM	Additional considerations which may increase the chances of successfully setting a kick-off plug include using a centralized placement string, using a slick-wall stinger, using drill pipe wiper balls and a ball catcher sub, using a diverter tool, or using a disconnect tool.	TRUE	
3.2.6.3		Many issues with wording in this entire plug cementing section …		FALSE	Not descriptive enough comment to make sufficient concise revisions
3.2.6.3	The retainer is then pulled out of the tool….	This should be…..The running tool or "stinger" is then pulled…….	The running tool or “stinger” is then pulled out of the tool and the final volume of cement is pumped across the top of the tool	TRUE	

3.2.6.3	Missing language	Once again need reference to viscous pill preparation - This is the most frequent piece of information that I provide to my customers		FALSE	This paper is being written without any specific reference to SPE/IADC technical documents other than API or CFR. Specific criteria vary from operator to operator.
3.2.6.3		Add language that references adherence to all BSEE regulations regarding plug spotting. In paragraph 6 cement may not need to be spotted below the tool if hydrocarbon zones do not exist	Individual well conditions will determine the best or most practical method of placement, or conditions dictate a particular method. Plug cementing must adhere to CFR-30.250.1715. The plugging requirements outlined within the code of federal regulations must be followed unless an exemption is granted.	TRUE	

3.2.6.4		The definition of a squeeze needs a little work both here and in other sections. Reference should be made to the fact that the cement should have a permeable medium in order to achieve a squeeze. This information is used to determine perf placement when necessary	In general squeezing is filling a void space with cement to prevent flow, provide support for a structure, or to prevent movement. The cement should have a permeable medium in order to achieve a squeeze. This information is used to determine perforation placement when necessary. Volumes to be used in a squeeze are dependent on several factors.	TRUE	

3.2.6.4	Missing language	Should add details discussing the differences between high pressure squeezes and low pressure squeezes. This operator resorts to high pressures squeezes only when no other option exists.	All squeezes are classified as either high or low pressure. During high pressure squeezing operations, the fracture gradient will be exceeded and induced fracturing will occur. In low pressure squeezes, the fracture gradient is never exceeded allowing cement to remain within the wellbore and travel only into preexisting flow paths within the wellbore. Generally, low pressure squeezing is preferable if possible. However, there are certain instances where high pressure squeezing is the only way to effectively place cement where it is desired.	TRUE	

3.2.6.4	Missing language	The majority of bradenhead squeezes need to be applied "below formation fracture pressure" . Additionally language needs to be added regarding burst pressure and ratings of the casing and the age of the casing.	For the safety and integrity of the well, the burst and collapse pressures of all casing, drill pipe, or tubing should not be exceeded during the squeeze operation. The three prevalent placement techniques are Bradenhead, running, and hesitation squeezes. The specific procedures are described below.Bradenhead squeezing is most often performed as a low pressure squeeze	TRUE	

3.2.6.5	Missing language	When trying to hit a channel behind pipe consideration must not only be givin to the number of perforations but to the "phasing" this operator uses 60 degree phasing any time a channel is trying to be intersected. This has been successful nearly 100 percent of the time	Phasing that perforates the casing along several azimuths increases the likelihood of providing a flow path to channels and provides more uniform coverage behind blank pipe.	TRUE	

3.2.6.5	Missing language	Once again need to reference that perforations need to be placed so that connectivity to a permeable medium is established or no squeeze will occur and a risky "high pressure" squeeze will be necessary - Success rates for high pressure squeezes are low	As previously mentioned, cementing operations should be designed hand-in-hand with the well design. This is especially true for squeeze jobs through perforations. Perforations need to be placed so that connectivity to a permeable medium is established or no "low pressure" squeeze can occur and a "high pressure" squeeze will be necessary. This dramatically reduces the chance of a successful squeezing operation.	TRUE	

5	Missing language	Centralization is often unsuccessful because centralizers are based on gauge hole, yet some operators pump very large amounts of excess acknowledging that they are aware of the potential for washout. In areas and formations prone to washout gauge hole should not be used as the baseline for centralizer size selection	When centralization is unsuccessful, it is often because centralizers are based on gauge hole, when ample evidence exists that the potential for washout is high. In areas and formations prone to washout, gauge hole should not be used as the baseline for centralizer size selection.	TRUE	
NA	The terms "best practices," "risks," as well as others are used repeatedly in this document with no clarity.	You are reviewing "practices," not necessarily "best." Suggest "normal" or "standard" as the wording. If you are going to state that an action or practice poses a risk you define why in clear and concise language, else you do not state it as a risk.		TRUE	All instances of Best Practice have been changed to operational guideline.

NA	· Identify specific current best cementing practices that result in a safety risk and propose safer alternatives.	How can a "best practice" result in a safety risk? This is an oxymoron.		FALSE	
NA	...but Investigators have paid relatively little attention to long-tern zonal isolation.	Delete, this is a vague, outdated, and too encompassing statement. Literature review cites references that are largely +15 years old, a lot of which is now out of date within operator practices.		TRUE	Literature Review section has been removed
NA	...and technology deficits.	What technology deficits? Document is not specific on anything. Delete unless specifics are stated.		FALSE	
NA	· R&D Improvements are to be determined based on ongoing laboratory investigation	Delete, this committee is not carrying out any laboratory investigations.		FALSE	Although it is true the steering committee is not carrying out any laboratory investigation, CSI is performing a laboratory investigation

					as part of this project.
NA	The terms "optimal" and "optimize"	Are misguided phrasology. Remove and replace with "design" or other more appropriate terms.		TRUE	all have been changed.
NA	· Identify areas of required R&D to address cementing operations for which no acceptably safe method exists.	Delete, vague and undefined statement as it is never addressed in the body of the document.		FALSE	statement is identified and addressed within the body of document
NA	· Develop a relational database for efficient access to the current cementing best practices.	Delete, this is very unlikely to ever happen and if something is developed it is very unlikely to ever be used so why promise it.		FALSE	Database part of contract requirement s

NA	but investigators have paid relatively little attention to long term zonal isolation	Strong statement, should be restated		FALSE	
NA	#1-#4	o Point 1: I would suggest adding wording in here to address the fact that sound pre-job engineering design and simulations are based on clearly defined job objectives. Without well-defined job objectives you cannot effectively engineer your job correctly. I would suggest adding an additional item here in this list; Final job design and execution is based on as drilled well conditions. We may plan and design very well in advance but the actual as drilled conditions will dictate the final placement design. o Point 4: I would suggest removing the wording around “highly experienced and knowledge		TRUE	parts added to conclusions.

		individuals”.			

NA	Identify specific current best cementing practices that result in a safety risk and propose safer alternatives	In terms of the second bullet point about safety risk: was a risk matrix or assessment tool used to evaluate alternative options you are mentioning here? In reading the document I did not get a feel that many risk based comparisons were done		FALSE	statement part of contract.
NA	Multiple factors affect the outcome of all cementing operations and several case specific best practices are already in place to address these factors. There are novel solutions on the horizon of cementing but several have yet to be fully field tested	not sure what you are trying to say here. I do not really take much of anything from these two sentences?		FALSE	Literature review has been removed from document.

NA	NA	o Would it be prudent here to mention that some of the literature reviewed was old? I think it is important to note some place that a lot of what was reviewed was relatively old in nature, and might not be up to date with the latest technologies		FALSE	Literature review has been removed from document.
NA	3	o Why would R&D improvements be limited to laboratory investigation? If you think about CSI's other project with reverse cementing it is clear that some R&D would be equipment based and outside a "laboratory" investigation perhaps		FALSE	Reverse Circulation cementing section

NA	NA	Spell out OCS or provide a definition table in the beginning of the document, also definitions of Task Names and Numbers		TRUE	Table of Definitions implemented
NA	NA	Need to make sure that your definitions are consistent with API documents		TRUE	
NA	NA	This document would be better constructed if API RP 65, Standard 65-2 second edition and Standard 96 were used as guiding templates for current topics that should be in the document. The current document reads like it has a high percentage of filler material in it and some of the filler material came from older reference documents		FALSE	Due to time constraints we could not re-structure entire document

NA	NA	I recommend that you stay away from calling this document "Optimized Methods" or "Best Practices". It should be written in the format of like a guide that states that individual operators may have slight variations in the way they conduct cementing operations based on well conditions. There is also the concern that if it is labeled "Best Practice" it could become regulatory		TRUE	Implemented , all instances of best practice have been modified to read operational guideline
NA	R&D Improvements are to be determined based on ongoing laboratory investigation	This statement means nothing. If no detail or guidance is given I would suggest to just leave these statement out, or change them to mean something.		TRUE	data added

NA	Case specific operational best practices do vary from operator to operator which leads to immediate operational improvements following suit	Again here I do not know what you are trying to get at. Does not make much sense this sentence or the one which follows it	Case specific operational practices vary from operator to operator. Each has their own inherent case specific technical difficulties which must be overcome by sound engineering design and lessons learned from offset historical well data.	TRUE	
NA	NA	Overall, the document skips around with and is stuffed with "filler" material that serves no purpose. Field jargon and casual wording is used repeatedly, which is inappropriate in such a document.		FALSE	

Page 3	From the mixing energy study, it was found that variances in slurry performance characteristics were dependent on both applied mixing energy and total mixing time. Variance was negligible for mixing energies at or above API mixing schedule. From the fluid loss study, it was found that any of the three fluid loss testing methods generally give comparable results for test temperatures below 190°F. As a safety factor, the stirred method should be used for systems above 190°F since the largest fluid loss measurements were observed from this test method.	What evidence is there that mixing energy or changing FL test procedures have a significant impact on the quality of cement jobs?These don't sound much like R&D Projects to me. Surely there must be other areas that would have a much larger impact.		FALSE	due to time and money constraints, different research will not be conducted.
Page ix		Remove my name and company. My legal department will not agree to this being in the report.		TRUE	All committee members names have been removed from document as

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					requested