Isolating Potential Flow Zones During Well Construction

API STANDARD 65—PART 2
SECOND EDITION, DECEMBER 2010

AMERICAN PETROLEUM INSTITUTE

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Upstream Segment

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Foreword

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A future planned standard, API RP 96, Deepwater Well Design Considerations, will identify considerations for use in deepwater well design. API Std 65-2 has been written to complement the objectives of API RP 90 and API RP 96 and their recommended practices.

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Suggested revisions are invited and should be submitted to the Standards Department, API, 1220 L Street, NW, Washington, DC 20005, standards@api.org.

Contents

Contents

Page

Isolating Potential Flow Zones During Well Construction

1 Scope

1.1 Overview

This standard contains practices for isolating potential flow zones, an integral element in maintaining well integrity. The focus of this standard is the prevention of flow through or past barriers that are installed during well construction. Barriers that seal wellbore and formation pressures or flows may include mechanical barriers such as seals, cement, or hydrostatic head, or operational barriers such as flow detection practices. Operational barriers are practices that result in activation of a physical barrier. Though physical barriers may dominate, the total system reliability of a particular design is dependent on the existence of both types of barriers.

1.2 Objectives

The objectives of this guideline are two-fold. The first is to help prevent and/or control flows just prior to, during, and after primary cementing operations to install or “set” casing and liner pipe strings in wells. Some of these flows have caused loss of well control. They threaten the safety of personnel, the environment, and the drilling rigs themselves. The second objective is to help prevent sustained casing pressure (SCP), also a serious industry problem.

API RP 90, provides guidelines on managing annular casing pressure (ACP) including SCP, thermal casing pressure, and operator-imposed pressure. These guidelines include monitoring, diagnostic testing, establishing the maximum allowable wellhead operating pressure (MAWOP), documenting annular casing pressure, and risk assessment methodologies.

1.3 Background and Technology Review

A detailed background and technology review are in Annex A. Historical data, perspectives, studies, statistics, lessons learned, etc. are included. All this information has been written to help explain how some practices work, have become proven or invalidated, or had performance limitations placed upon their application.

1.4 Conditions of Applicability

The process of barrier element selection and installation (including cement) is governed by the anticipated presence or absence of potential flow zones that require isolation for well integrity or regulatory purposes. This document applies only when it is deemed necessary that a potential flow zone be isolated. The guidance from this document covers recommendations for pressure-containment barrier (cement, packers, etc.) design and well construction practices that affect the zonal isolation process to prevent or mitigate annular fluid flow or pressure. These practices may also help prevent loss of well control (LWC) incidents and minimize the occurrence of SCP during well construction and production.

As presented earlier herein, the content of this document is not all inclusive and not intended to alleviate the need for detailed information found in textbooks, manuals, technical papers, or other documents. Included are those practices (well design, drilling, completion, etc.) that may positively or negatively affect pressure-containment barrier sealing performance along with methods to enhance the positive effects and to minimize any negative ones.

This document does not address shallow water flow zones in deepwater wells which are covered in API RP 65.

1.5 Well Planning and Drilling Plan Considerations

Annex B includes consideration in well planning and drilling plan determinations, such as evaluation for flow potential, site selection, shallow hazards, deeper hazard contingency planning, well control planning for fluid influxes, planning for lost circulation control, regulatory issues and communications plans, planning the well, pore pressure, fracture gradient, drilling fluid weight, casing plan, cementing plan, drilling plan, wellbore hydraulics, wellbore cleaning, barrier design, and contingency planning. These elements factor into the planning of the well to enhance the barrier sealing performance.

In some cases, pre-spud information gathered from offset well(s) and/or from high resolution seismic surveys can be used to indicate flow potential for a particular drilling prospect. Any relevant information should be communicated to the appropriate service provider for incorporation into the design for a particular fluid (drilling fluid or cement) and for preparing engineering and operations procedures.

1.6 Drilling the Well

Annex C gives a general overview of drilling the well and some of the factors that might be considered by the drilling group. Some of those factors may include general practices while drilling, monitoring and maintaining wellbore stability, mitigating lost circulation, and planning and operational considerations. There may be other factors to consider such as type and location of the well being drilled. These factors should be considered during the drilling of the well to enhance the barrier sealing performance. Detailed discussion of these factors is included in Annex C and may be mentioned in other sections.

1.7 Summary of Considerations

Isolating a potential flow zone with cement is an interdependent process. Individual process elements such as slurry design and testing, applied engineering and job execution all impact the ability to successfully install a cement barrier. Superimposed upon these elements are the conditions found in the well at the time of cementing.

Certain cementing process elements contained in Annex D may be individually critical to isolating a potential flow zone or may be of minor consequence until made critical by a separate (sometimes unrelated) event or past well engineering decisions. Conversely, certain elements may not be dominant factors in the success in one cementing operation, yet vitally important in another.

Collectively, the elements described in Annex D produce the design, engineering and operational framework for successfully isolating a potential flow zone.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Recommended Practice 10B-2/ISO 10426-2, *Recommended Practice for Testing Well Cements*

API Recommended Practice 10B-3/ISO 10426-3, *Recommended Practice on Testing of Deepwater Well Cement Formulations*

API Recommended Practice 10B-4/ISO 10426-4, *Recommended Practice on Preparation and Testing of Foamed Cement Slurries at Atmospheric Pressure*

API Recommended Practice 10B-5/ISO 10426-5, *Recommended Practice on Determination of Shrinkage and Expansion of Well Cement Formulations at Atmospheric Pressure*

API Recommended Practice 10B-6/ISO 10426-6, *Recommended Practice on Determining the Static Gel Strength of Cement Formulations*

API Specification 10D/ISO 10427-1, *Specification for Bow-Spring Casing Centralizers*

API Specification 10D-2/ISO 10427-2, *Recommended Practice for Centralizer Placement and Stop Collar Testing*

API Recommended Practice 10F/ISO 10427-3, *Recommended Practice for Performance Testing of Cementing Float Equipment*

API Technical Report 10TR1, *Cement Sheath Evaluation*

API Technical Report 10TR3, *Temperatures for API Cement Operating Thickening Time Tests*

API Technical Report 10TR4, *Technical Report on Considerations Regarding Selection of Centralizers for Primary Cementing Operations*

API Technical Report 10TR5, *Technical Report on Methods for Testing of Solid and Rigid Centralizers*

API Recommended Practice 13B-1/ISO 10414-1, *Recommended Practice for Field Testing Water-Based Drilling Fluids*

API Recommended Practice 13B-2/ISO 10414-2, *Recommended Practice for Field Testing Oil-based Drilling Fluids*

API Recommended Practice 53, *Blowout Prevention Equipment Systems for Drilling Operations*

API Recommended Practice 65, *Cementing Shallow Water Flow Zones in Deep Water Wells*

API Recommended Practice 90, *Annular Casing Pressure Management for Offshore Wells*

3 Definitions, and Abbreviated Terms

3.1 Definitions

For the purposes of this document the following terms and definitions apply. In addition to those listed below other definitions and abbreviations may be found in oilfield glossaries at websites listed in the Bibliography. [47,48,49,50,51]

3.1.1
ambient pressure
Pressure external to the wellhead. In the case of a surface wellhead it would be 0 psig. In the case of a subsea well head, it would be equal to the hydrostatic pressure of seawater at the depth of the subsea wellhead in psig.

3.1.2
annular flow
The flow of formation fluids (liquids and/or gases) from the formation into a space or pathway in an annulus within a well. The annular flow may follow various flow paths inside the annulus to other points including those at shallower or deeper depths.

3.1.3
annular packers and seal rings
Mechanical barrier devices with flexible, elastomeric sealing elements that can be run into a well on casing or liners for application as:

a) annular element installed between an inner and outer pipe or between a casing and openhole formation to seal the annulus,

b) annular seal rings installed on the inner pipe string to seal the micro-annulus and voids formed between the cement sheath and the inner pipe string.

3.1.4
annular pressure buildup
APB
Pressure generated within a sealed annulus by thermal expansion of trapped wellbore fluids typically during production. May also occur during drilling operations when trapped annular fluids at cool shallow depths are exposed to high temperatures from fluids circulating in deep, hot hole sections. This thermally induced pressure is defined and listed in API RP 90 as thermal casing pressure. APB is also referred to as annular fluid expansion (AFE).

3.1.5
annuli
Plural of annulus. A well may contain several annuli formed by multiple casing and liner pipe strings.

3.1.6
annulus
The space between the borehole and tubulars or between tubulars, where fluid can flow. The annulus designation between the production tubing and production casing is the “A” annulus. Outer annuli between other strings are designated B, C, D, etc. as the pipe sizes increase in diameter.

3.1.7
barrier (barrier element)
A component or practice that contributes to the total system reliability by preventing liquid or gas flow if properly installed.

3.1.8
blowout preventer
BOP
A device attached to the casing head that allows the well to be sealed to confine the well fluids in the wellbore. Refer to API RP 53 or other relevant standards for further information.

3.1.9
borehole
Wellbore sections which are not cased with pipe, commonly called open hole.

3.1.10
bottom hole assembly
BHA
Bottom hole assembly is the collection of the bit, drill collars, stabilizers, reamers, hole openers, MWD/LWD/PWD, mud motor, directional steering system and other tools at the base of the drill string that serve special purposes associated with drilling.

3.1.11
cased hole
The wellbore intervals in a well that are cased with casing and/or liner pipe. The diameter of these hole sections is the inside diameter of the pipe contained therein.

3.1.12
completion string
The completion string consists primarily of production tubing, but also includes additional components such as the surface controlled subsurface safety valve (SCSSV), gas lift mandrels, chemical injection and instrument ports, landing nipples, and packer or packer seal assemblies. The completion string is run inside the production casing and used to produce fluids to the surface.

3.1.13
conductor casing
Provides structural support for the well, wellhead and completion equipment, and often provides hole stability for initial drilling operations. This casing string is typically not designed for pressure containment. However, in some cases, the conductor casing may serve to isolate shallow formations, similar to a surface casing.

3.1.14
critical gel strength period
CGSP
The time between the development of the critical static gel strength (CSGS) and a static gel strength of 500 lbf/100 ft^2.

3.1.15
critical static gel strength
CSGS
The static gel strength of the cement that results in the decay of hydrostatic pressure to the point at which pressure is balanced (hydrostatic equals pore pressure) at a point adjacent to the potential flowing formation(s).

3.1.16
diverter
A device connected to the top of the wellhead or marine riser, directing flow away from the rig.

3.1.17
riser
The extension of the wellbore from the subsea BOP stack to the drilling vessel. The riser provides for fluid returns to the drilling vessel, supports the choke, kill, and control lines, guides tools into the well, and serves as a running string for the BOP stack.

3.1.18
drive/jet pipe
Casing which supports unconsolidated sediments providing hole stability for initial drilling operations. This is normally the first string set and provides no pressure containment. This string can also provide structural support to the well system. See also definition for structural pipe (or casing).

3.1.19
equivalent circulating density
ECD
Equivalent circulating density is the effective density of the circulating fluid in the wellbore resulting from the sum of the hydrostatic pressure imposed by the static fluid column and the friction pressure.

3.1.20
external casing packer
ECP
An external casing packer is a mechanical annular barrier that has elastomeric elements that seal the annulus when inflated. Also see the definition in this section for annular packers and the description of an ECP in 4.4.

3.1.21
fixed platform wells
Wells completed with a surface wellhead and a surface tree on a fixed platform. All of the casing strings are tied back to the surface wellhead.

3.1.22
formation fluids
Fluids present within the pores, fractures, faults, vugs, caverns, or any other spaces of formations are called formation fluids whether or not they were naturally formed or injected therein. The physical state of formation fluids

may be liquids or gases and include various types such as hydrocarbons, fresh or saline water, carbon dioxide, hydrogen sulfide, etc.

3.1.23
formation integrity test
FIT
Formation integrity test is similar to a leak-off test (LOT) except that fracture initiation pressure is not exceeded. See definition of leak-off tests.

3.1.24
fracture gradient
FG
A factor, that when multiplied by the true vertical depth, calculates the fracturing initiation pressure.

3.1.25
hybrid wells
Wells drilled with a subsea wellhead and completed with a surface casing head, a surface tubing head, a surface tubing hanger and a surface tree.

3.1.26
intermediate casing
Casing that is set when geological characteristics or wellbore conditions require isolation. These conditions include, but are not limited to, prevention of lost circulation, formation fluid influx or hole instability. Multiple intermediate casing strings can be run in a single well.

3.1.27
leak-off test
LOT
A leak-off test is a procedure used to determine the wellbore pressure required to initiate a fracture in the open or exposed formations.

3.1.28
liner
A liner is a casing string that does not extend to the top of the well or to the wellhead. Liners are anchored or suspended from inside the previous casing string using a liner hanger. The liner can be fitted with special components so that it can be connected or tied back to the surface at a later time.

3.1.29
liner hanger
A device used to attach or hang a liner from the internal wall of a previously set casing string. Conventional liner hangers are “hung” (connected to the last casing) by setting slips that grip against the inner wall of the previously set casing string. Expandable liner hangers are hung by external expansion of the hanger against the inner wall of the previously set casing string.

3.1.30
liner top packer
LTP
A mechanical barrier device typically with flexible, elastomeric sealing elements that can be run into a wellbore with a smaller initial outside diameter that then expands externally to seal the annulus between the liner and the previously installed casing string. Liner top packers are also called liner packers.

3.1.31
loss of well control
LWC
A loss of well control incident is an uncontrolled flow of subterranean formation fluids such as gas, oil, water, etc. and/or well fluids into the environment or into a separate underground formation, in which case it is called an underground blowout.

3.1.32
logging while drilling
LWD
The measurement of formation properties during the drilling of the borehole by logging tools installed in the BHA.

3.1.33
maximum allowable wellhead operating pressure
MAWOP
The maximum allowable operating pressure for a particular annulus, measured at the wellhead relative to ambient pressure. It applies to SCP, thermal casing pressure, pressure from a well control event and operator imposed casing pressure.

3.1.34
mechanical barrier
A subset of physical barriers that features mechanical equipment; not set cement or a hydrostatic fluid column.

3.1.35
mudline
Mudline as referenced in subsea operations refers to the seafloor.

3.1.36
mudline packoff or packer
An upper packer run on the production tubing and set in the production casing below the mudline wellhead to isolate the production riser section from the production casing. These mechanical barrier devices are commonly installed in hybrid wells.

3.1.37
mudline suspension system
A casing suspension system that allows a well to be drilled using a surface BOP and wellhead. The mudline suspension equipment provides for individual casing hangers to be installed with each casing string that interconnect with each other at a preset point below the mudline. The mudline suspension casing hangers do not provide a pressure barrier.

3.1.38
mudline suspension wells
A well drilled using a mudline suspension system and a surface BOP. The mudline suspension well may be completed as either a surface well or as a subsea well.

3.1.39
measurement while drilling
MWD
The measurement of physical properties while drilling, such as pressure, temperature and borehole trajectory, by tools installed in the BHA.

3.1.40
non-aqueous fluid
NAF
Non-aqueous fluid is a non-aqueous drilling fluid or well circulating fluid. Common NAF systems are diesel, mineral oil, or synthetic fluid based invert emulsions, or other non-water based fluids.

3.1.41
nippling down
The process of removing well-control or pressure-control equipment such as a BOP system.

3.1.42
nippling up
The process of installing well-control or pressure-control equipment such as a BOP system.

3.1.43
operator imposed casing pressure
Pressure in a casing that is operator imposed for purposes such as casing pressure integrity tests (prior to drilling out the shoe), gas lift, fluid injection, stimulation treatments, thermal insulation, etc.

3.1.44
overbalance pressure
OBP
Overbalance pressure is the amount by which the hydrostatic pressure exceeds the pore pressure of a formation.

3.1.45
physical barrier element
Physical barrier elements can be classified as hydrostatic, mechanical or solidified chemical materials (usually cement).

3.1.46
polished bore receptacle
PBR
A device with a honed internal diameter (ID) sealing surface for landing a production tubing seal assembly or tie back casing.

3.1.47
pore pressure
PP
Pore pressure is the pressure of the fluid inside the pore spaces of a formation.

3.1.48
potential flow zone
Any zone in a well where flow is possible under when wellbore pressure is less than pore pressure.

3.1.49
production casing
Casing that is set through a productive interval.

3.1.50
production liner
A liner that is set through a productive interval.

3.1.51
production riser
The casing string(s) rising from the seafloor to the wellhead on fixed platforms or the casing string(s) attached to the subsea wellhead rising from the seafloor to the surface wellhead on hybrid wells.

3.1.52
production tubing
Tubing that is run inside the production casing and used to convey produced fluids from the hydrocarbon bearing formation to the surface. Tubing may also be used for injection.

3.1.53
pressure while drilling
PWD
The measurement of downhole pressure while drilling by a tool installed in the BHA.

3.1.54
rate of penetration
ROP
Common term for drilling rate; usually expressed in units of ft/hour or m/hour.

3.1.55
static gel strength
SGS
The yield stress of fluids at rest.

3.1.56
structural pipe (or casing)
Pipe utilized to facilitate the drilling of a well, but not intended for pressure containment after the well has been drilled. Supports unconsolidated sediments and provides hole stability for initial drilling operations, axial support for casing loads and bending loads from the wellhead. See also definition for drive/jet pipe.

3.1.57
subsea wells
Wells drilled and completed with a subsea wellhead located near the seafloor.

3.1.58
subsea wellhead
A wellhead that is located near the seafloor.

3.1.59
surface casing
Casing run to isolate shallow formations.

3.1.60
surface well
A land or offshore well completed on the surface with individual casing heads, tubing head, a surface tubing hanger, and a surface christmas tree, all residing at a designated level above the water line on a fixed platform.

3.1.61
sustained casing pressure
SCP
Pressure in an annulus of casing strings that is measurable at the wellhead that rebuilds to at least the same pressure level after pressure has been bled down. SCP is not due solely to temperature induced fluid expansion or a pressure that has been imposed by the operator. See API RP 90 for further information.

3.1.62
tieback casing
Casing that is run from a liner hanger back to the wellhead after the initial liner and hanger system have been installed.

3.1.63
well barrier system
Well barrier system is one or more barriers that act in series to prevent flow. Well barriers that do not act in series are not considered part of a single well barrier system, as they do not act together to increase total system reliability.

3.1.64
wellbore
The borehole or cased hole sections in a well.

3.1.65
wellhead
A device upon which the BOP and casing hangers are installed during the well construction phase. Also the system of spools, valves and assorted adapters that provide pressure control of a producing well. The wellhead also incorporates a means of hanging the production tubing and installing the christmas tree and surface flow-control facilities in preparation for the production phase of the well.

3.1.66
well integrity
A quality or condition of a well in being structurally sound with competent pressure seals by application of technical, operational and organizational solutions that reduce the risk of uncontrolled release of formation fluids throughout the well life cycle.

3.1.67
waiting on cement
WOC
Waiting on cement, normally expressed in hours, is the period of time after the cement has been placed until the time subsequent drilling or completions operations can resume.

3.2 Abbreviations

ACP	annular casing pressure
API	American Petroleum Institute
APB	annular pressure buildup
BHA	bottom hole assembly
BHCT	bottom hole circulating temperature
BHP	bottom hole pressure
BHST	bottom hole static temperature
BHT	bottom hole temperature
BOEMRE	Bureau of Ocean Energy Management Regulation and Enforcement
BOP	blowout preventer
CGSP	critical gel strength period
CSGS	critical static gel strength
ECD	equivalent circulating density
ECP	external casing packer

EMW	equivalent mud weight
FG	frac gradient
FIT	formation integrity test
HPHT	high pressure, high temperature
LOT	leak-off test
LCM	lost circulation material
LWC	loss of well control
LWD	logging while drilling
LTP	liner top packer
mD	millidarcy
MD	measured depth
MLSH	mud line suspension hanger
MMS	Minerals Management Service
MWD	measurement while drilling
NAF	non-aqueous fluid
ND	nippling down
NU	nippling up
OBP	over balanced pressure
PBR	polished bore receptacle
PIT	pump-in tests
PP	pore pressure
ppge	pounds per gallon equivalent density
psi	pounds per square inch
PWD	pressure while drilling
ROP	rate of penetration
RP	Recommended Practice
SCP	sustained casing pressure
SGS	static gel strength
SPE	Society of Petroleum Engineers
TOC	top of cement
TVD	true vertical depth
WOB	weight on bit
WOC	waiting on cement

4 Barriers

4.1 General

Barrier elements can be classified as either physical or operational. With the exception of operational procedures related to the use of cement as a physical barrier element, operational barriers are not covered in this standard.

Barriers contribute to total system reliability; total system reliability is the probability of barrier success, or one minus the probability that all barriers to uncontrolled flow along a particular path will fail simultaneously. The principles, processes and procedures for planning and implementing barriers are necessary to ensure operations integrity during all life cycle phases of the well. This barrier philosophy should be applied to each potential flow path, considering the consequences of a loss of control.

4.2 Physical Barrier Elements

Physical barrier elements can be classified as hydrostatic, mechanical or solidified chemical materials (usually cement).

4.3 Hydrostatic Barrier Elements

Hydrostatic barrier elements are those in which a column of fluid(s) imposes a hydrostatic pressure which exceeds the pore pressure of the potential flow zone. These fluids may include drilling fluids, cement spacers, cement slurries, water and completion fluids. It is important to understand the hydrostatic contribution of any of these fluids can change with time. Solids settling in drilling fluids or spacers could reduce the hydrostatic pressure at the flow zone. Static gel strength development of cement during hydration will also reduce the transmission of pressure (see 5.7.8). Drilling fluids and spacers also develop static gel strength, although to a lesser extent than cement, and their contribution to loss of hydrostatic pressure should be considered. Some fluids such as NAF may exhibit compressible behavior so downhole temperature and pressure should be considered when calculating the hydrostatic contribution of those fluids. A decrease in the height of the fluid column due to downhole losses may compromise the hydrostatic barrier element and should be taken into account in the planning stages of the operation.

4.4 Annular Mechanical Barrier Elements

4.4.1 General

A mechanical barrier is a seal achieved by mechanical means between casing strings, a casing string and a liner, a casing string and the borehole, a casing string and a wellhead housing, or a liner and the borehole that isolates a potential flowing zone(s). When both cement and mechanical barriers are used in series, it is not possible to physically test them independently to know which is holding pressure. Consequently, both should be designed to be effective and contain the maximum anticipated load. As with all engineering processes, the application of mechanical barriers should be chosen with care. Such barriers may not be necessary or advisable. It is up to the user to exercise due diligence in understanding the variables involved and make the correct decisions.

NOTE When cement cannot be used as a barrier during well construction, mechanical barriers become the primary barriers for isolating annular flow.

Mechanical barriers can be divided into two basic classifications.

1) Mechanical barrier elements designed for preventing loss of well control (LWC).

2) Mechanical barrier elements designed for preventing sustained casing pressure (SCP).

4.4.2 Mechanical Barrier Elements for Preventing LWC

4.4.2.1 General

Mechanical barriers can significantly reduce the risk of annular flow past them. Annular flows may occur while temporary mechanical barriers such as BOPs or diverters are nippled down or a hydrostatic barrier is removed following cementing operations. These flows may result from:

— loss of hydrostatic pressure as the unset cement column develops static gel strength and supports its own weight;

— cement fluid loss;

— internal cement shrinkage;

— reduced fluid density in the annulus during cement washout operations;

— lost circulation during cementing causing:

  — reduced hydrostatic pressure due to shorter fluid columns,

  — lower than planned top of cement columns leaving potential flow zones un-cemented;

— or combination of the above.

While mechanical barriers are designed to prevent the flow of annular fluids past the barrier element or seal, setting of the barrier may actually increase the chance of fluids entering the cement slurry if the cement slurry is not properly designed. Setting the barrier isolates all potential flow zones below the barrier from all of the hydrostatic pressure above the barrier. This reduction in overbalance pressure (OBP) on any potential flow zones effectively decreases the CSGS as defined in 5.7.8. The pressure in the annulus therefore drops to the pore pressure of the flow zones at an earlier time after the cement is in place, increasing the window of opportunity for fluid to enter the cement slurry. Because of this increased chance of fluid entering the cement, it is very important that the slurry placed across potential flow zones is designed with fluid migration control properties (see 5.7.14). Properly designed cement slurries should be considered to help prevent the fluid from migrating through the annulus once it has entered the cement. If migration is not controlled there is potential for either a cross-flow into a lower pressure zone or a collection of fluid directly below the mechanical barrier.

4.4.2.2 Liner Top Packers

Liner top packers (LTP) are typically run in the well with the liner and set immediately after cementing; however, they may be run and set on a separate trip after the liner has been cemented. LTPs seal the annulus between the liner and the host casing string. Once set, they prevent upward or downward flow. If they are tested after they are set, they may allow select operations to safely proceed without having to wait on cement (WOC). Local regulations may supersede this provision.

The industry has successfully used liner top packers for many years to eliminate/reduce flow after cementing as well as to reduce squeeze work on liner tops. The liner top packer is a proven product when properly designed, installed, and verified for the specific application. Expandable liner hangers with elastomer pack-off elements function both as liner hangers and liner top packers.

4.4.2.3 Expandable Tubulars

Expandable tubular liners or expandable liner hangers provide a mechanical barrier while preserving the maximum interior diameter of the liner. A cone or other device expands the pipe to a larger diameter forming either a metal-to-metal or elastomeric seal with the host pipe. When an expandable liner is installed below a host pipe, the liner is placed on the bottom of the hole and cement is (optionally) circulated around the pipe. Expandable tubulars have reduced burst and collapse ratings, which **shall** be taken into account in the well design.

4.4.2.4 Multiple Seals in a Single High Pressure Wellhead Housing

Some wellhead systems provide several casing suspension and sealing positions in one high pressure wellhead housing. The casing hanger is landed, the pipe is cemented in place and then the seal assembly is energized. In some situations the weight of the casing string may hold the seal in place, while in others it is necessary to engage a locking mechanism.

4.4.2.5 Sub Wellhead Liner Hanger Profiles

Landing profiles can be pre-installed in a host casing to allow installation of liners without using the wellhead hanger profiles. The liners are run with a mating profile and the mechanical seals are subsequently engaged to provide a mechanical barrier in the annulus between the liner and host casing, usually following cementing operations. The liner is an extension or deepening of the host casing. This allows for more casing size flexibility in the well design.

4.4.2.6 Inflatable External Casing Packers

Inflatable external casing packers have inflatable elements mounted on mandrels that are equivalent in strength to the liner or casing string. The advantages of these packers include the ability to run through reduced IDs and seal in larger ID sections of casing or open hole. Some open holes may not be suitable for sealing by an inflatable packer. These include holes with irregularities such as fractures, faults, and unconsolidated formations or with drilling induced hole enlargements or key seats. The mechanical barrier is installed by inflating the packer with cement, drilling fluid, or completion fluid. Sealing elements or elastomers can be designed for specific applications.

4.4.2.7 Hydraulic Set External Casing Packers

Hydraulic set external packers differ from inflatable packers in that the external elastomer element is expanded by compressing it, rather than inflating it. Hydraulic-set external casing packers can be used in situations in which pressure can be applied to the casing string to set the packer. The mechanical barrier is energized by applied pressure that activates hydraulic cylinders within the tool to generate pack-off forces. This generally requires bumping the plug that follows the cement slurry; however, pressure can be applied through alternate means. This mechanical barrier can be installed on the inner casing string anywhere within the casing/casing annulus and does not require that casing be set off bottom. This type packer does not require a load shoulder or other setting device. Packers are available with or without slips and are selected for the diameters of the tubulars involved and anticipated differential pressure across the sealing area.

4.4.3 Mechanical Barrier Elements for Preventing SCP

4.4.3.1 General

Some of the barrier elements designed for preventing loss of well control (see 4.4.2) may also act to minimize the potential for SCP. The barrier elements discussed in this section may prevent SCP but they are not effective for preventing LWC events, either because they do not isolate the entire annular area or because a full seal from the set cement will not have developed while the slurry is in the critical gel strength period (CGSP).

4.4.3.2 Annular Seal Rings

Annular seal rings are mechanical barrier devices with flexible, elastomeric sealing elements that can be run in a well on casing or liners for applications to seal the micro-annulus and voids formed between the cement sheath and the inner pipe string. The sealing element has an outside diameter designed to seal the size of a micro-annulus and should not excessively restrict flow during the hole conditioning and cementing process. The sealing element may or may not be designed to chemically swell and may only deform to seal a micro-annulus or void at the interface between the cement sheath and inner pipe string.

4.4.3.3 Swellable Packers

Swellable packers are mechanical barrier devices with flexible, swellable elastomers that are run in a well on casing or liners. The sealing element is designed to chemically swell when it comes into contact with an appropriate activating fluid such as hydrocarbons or produced water. Due to the limited expansion ratios, swellable packers may not be appropriate for some applications. Swellable packers may be used alone or in conjunction with cement.

4.5 Mechanical Wellbore Barrier Elements

4.5.1 General

A mechanical wellbore barrier is a seal achieved by mechanical means inside casing or the borehole that isolates a potential flowing zone. When cement is used in conjunction with a mechanical barrier, there are two potential barriers and it is not possible to know if one or both is preventing flow. When cement is used as a barrier during well construction, mechanical barriers are complementary to a properly executed cementing operation and both may contribute to the total system reliability.

4.5.2 Downhole Tools

4.5.2.1 General

During well construction operations, downhole tools such as packers, retainers and bridge plugs are typically utilized as temporary mechanical barriers to facilitate rig operations. These tools can be classified as retrievable, permanent or drillable and can be used separately, or sometimes in combination.

Downhole tools have various pressure and temperature ratings and tool selection should consider the pressure and temperature of the application for which the tool will be utilized. Care should be exercised when removing the barriers as there could be a differential pressure across the tools.

4.5.2.2 Cased Hole Retrievable Tools

Packers and retrievable bridge plugs are tools that consist of a sealing device, a holding or setting device and an inside passage for fluids. These tools commonly contain mechanical slips to hold the packer in place and elastomeric sealing elements either mechanically or hydraulically set to provide a seal against the casing. Retrievable tools can be set and released many times in a single trip into the wellbore and can perform multiple functions including providing temporary barriers, testing casing, remedial cementing, etc.

Storm packers can provide a temporary barrier and are typically utilized when a rig is required to evacuate. These packers support the total of the drill pipe and drilling assembly to be hung off below the packer. Storm packers utilize a valve and back-off assembly above the packer, allowing the drill pipe above the packer to be pulled from the wellbore, leaving the packer and drill pipe isolation valve in place with the drill string hanging below.

4.5.2.3 Drillable Bridge Plugs

Drillable bridge plugs can be run in the wellbore, set and then drilled after other operations. The slip system on the tools outer body anchors the plug to the wellbore while a packing element provides a pressure seal. Drillable bridge plugs are constructed of drillable metals such as cast iron or composite materials.

One aspect in which composite and conventional cast iron drillable bridge plugs differ is their life expectancies. Cast iron plugs have a long life and can be left in the wellbore for an extended period of time, depending on the downhole environment. Composite plugs, on the other hand, have a short life expectancy and the tool must be selected with the longevity required for the given application. When utilizing composite bridge plugs, the working life of the plug in the planned downhole setting environment should be considered.

4.5.2.4 Retainers

Drillable squeeze packers are commonly referred to as cement retainers. A retainer is a mechanical barrier that can be set on drill pipe or wireline. The retainer provides isolation both above and below where set, but communication through the retainer can be achieved though a sliding sleeve check valve. The check valve is typically operated by a stinger seal assembly. When the stinger is removed from the retainer, the valve closes and isolates the wellbore below the retainer.

4.5.2.5 Cementing Head

Cementing plug containers and head assemblies provide the means by which conventional casing wiper plugs, or darts to launch subsea plugs, can be launched from the surface without significant interruption of pumping operations. If other wellbore barriers are not in place and the float equipment fails, surface cementing plug containers may function as a temporary wellbore mechanical barrier. Prior to removing the cementing head, ensure adequate wellbore barriers are in place.

Cementing heads **shall** be pressure tested by the supplier to the maximum working pressure rating of the head as part of a regular maintenance program. The cementing head selected **shall** have a working pressure in excess of the maximum anticipated surface pressure for the job. Cementing heads are discussed further in 5.4.5.

4.6 Set Cement as a Barrier Element

4.6.1 General

Regulators require that if the operator plans to remove a barrier element, such as a diverter or BOP stack, the operator **shall** determine when it will be safe to do so.

Determination of the safe WOC time should take into account several factors including whether or not a potential flow zone is exposed in the wellbore or if there is the possibility that one is exposed (if it is unknown). There may be other downhole conditions that could impact the guideline. It is extremely important that any plan for removing a barrier element be modified toward a conservative approach to avoid loss of well control or risk to personnel or equipment. Observations prior, during and after the cementing operation that could impact the plan for removing a barrier element include but are not limited to:

— substantial loss of returns while pumping cement;

— significant deviation from the cementing plan such as inability to maintain the desired density of the slurry, use of less than designed volume of slurry, etc.;

— premature returns of cement slurry to surface;

— measured lift pressure of the cement just prior to bumping the plug indicates the top of cement (TOC) is not high enough in the annulus to isolate the uppermost potential flow zone;

— indications of fluid influx prior to, during or after cementing.

In these cases, confidence in the cement job would decrease and further assessment is needed before removing a barrier element.

4.6.2 Special Operational Requirements

The following are special operational requirements.

— Operators and all involved contractors **shall** perform a risk assessment prior to utilizing foamed cement (see 5.6.5.9 and 5.7.13 for more information on foamed cement), and make sure that the results of this assessment are incorporated in the cementing plan. The risk assessment should address safety, health and environmental risks as well as design and operational risks;

— Operators and contractors **shall** not run tubing in the annulus between the casing and the diverter, or BOP, after completion of the cementing operation and prior to determining the well has no potential for flow.

— Hydrostatic pressure calculations **shall** be performed and results considered prior to commencing any operation that will result in a change in hydrostatic pressure in the wellbore.

4.6.3 WOC Guidelines Prior to Removing a Temporary Barrier Element

If no potential flow zone(s) exist or if alternate physical barrier elements are in place, subsequent operations may commence without WOC, if regulations allow.

If design and operational parameters indicate isolation of potential flow zones, cement **shall** be considered a physical barrier element only when it has attained a minimum of 50 psi compressive or sonic strength. The 50 psi compressive or sonic strength threshold exceeds the minimum static gel strength value needed to prevent fluid influx. Local regulations **shall** be adhered to with regards to WOC. However, caution should be exercised when the specified WOC time is less than the time required for the cement to reach a strength of 50 psi.

Laboratory tests, conducted under simulated downhole temperature and pressure conditions (within the limits of the laboratory equipment) with representative cement, additives and mix water **shall** indicate the sustained development of 50 psi compressive or sonic strength. Care should be taken that sonic strength continues to develop following the cement slurry's initial set and that the first "Time to 50 psi" reading is not an artifact of the initial temperature and pressure ramp used in the testing. See the example below (Figure 1) in which an initial "Time to 50 psi" is recorded in 29 minutes 30 seconds while the sustained development of 50 psi occurs in approximately 3 hrs 30 minutes.

Contingency plans to address a flow should be in place prior to initiating the removal of a temporary barrier element after completing a cement job. This planning should include key parties involved in performing the associated operations and specifically should include the operator, drilling contractor, and cementing contractor. The time from the start of removing a barrier element to securing the exposed annulus **shall** be minimized. Waiting time can be reduced if the operator has the required number of tested or verified barrier elements remaining in place prior to removing the barrier element (such as a BOP), subject to local regulatory requirements.

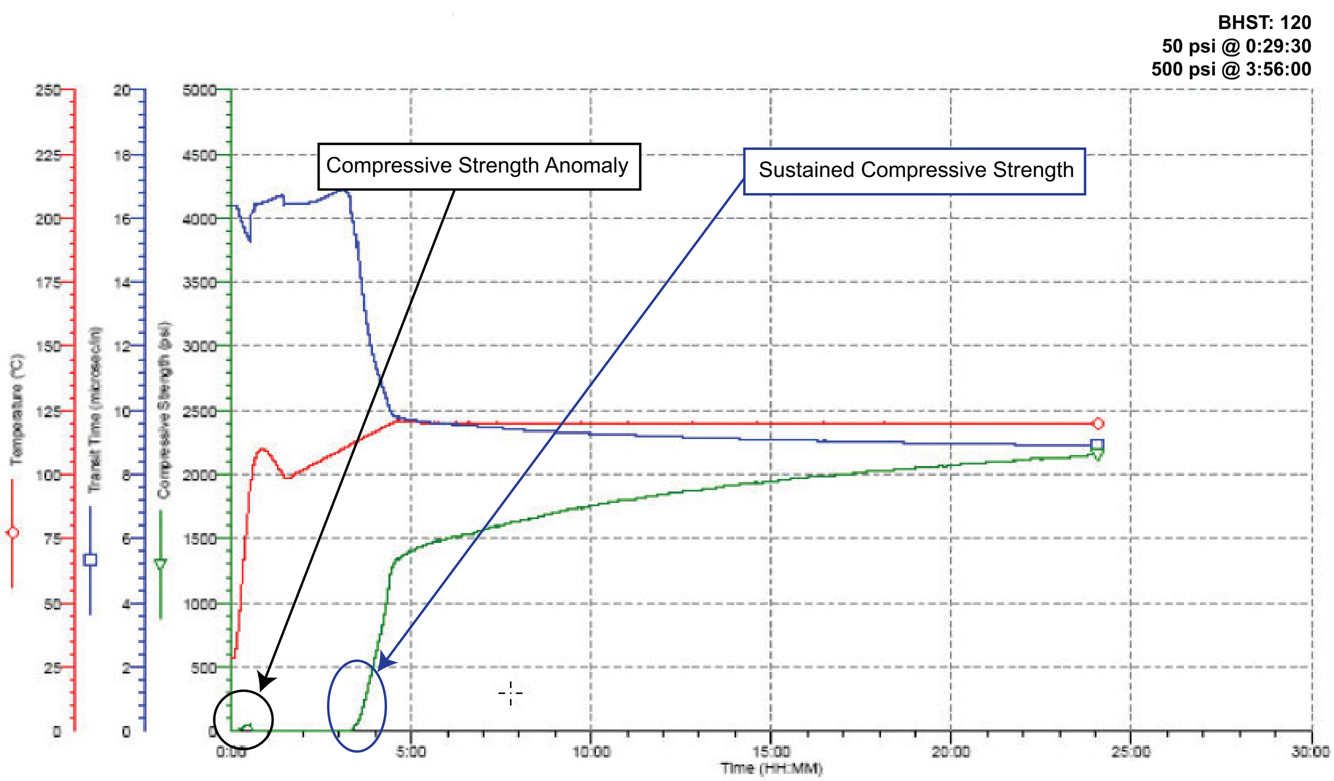

Figure 1—Sonic Strength Anomaly

4.6.4 Cement Wellbore Barriers

4.6.4.1 Shoe Track Barrier Element

A shoe track barrier element is a combination of the two independent float valves and a shoe track of set cement. Under special circumstances (inner-string, reverse cementing, etc.), the use of float valves may not be possible.

Float valves should be rated for the anticipated flow rates and volumes of the fluids pumped during circulation and cementing of the casing string. Float valves **shall** be rated for the differential pressure between the minimum anticipated hydrostatic column above the shoe track and the hydrostatic column in the casing annulus with cement in place. Ensure the float collar is rated for the load imposed when a top cementing plug is landed on it and pressure is applied to verify landing and test the casing. Float valves are typically designed for liquid service (e.g. drilling fluid, cement, etc.). Refer to API RP 10F/ISO 10427-3 for determining service class corresponding to anticipated service requirements.

Float valves may be configured to allow the casing to fill automatically while run into the hole, thereby reducing the surge pressure exerted on the wellbore. These auto-fill devices should be deactivated prior to beginning cementing operations. The impact of auto-fill tools on well control while running casing and procedures for auto-fill conversion should be considered and operational response plans should be in place if flow occurs through the auto-fill float system and up the inside of the casing.

4.6.4.2 Cement Plugs

Cement plugs are set cement located in open hole or inside casing / liner to prevent formation fluid flow between zones or flow up the wellbore. The placement and design of the cement plug should consider specific well conditions such as; pore and fracture pressure gradients, estimated hole volumes, drilling fluid density, presence of hydrocarbons, etc. Slurry properties **shall** be consistent with any regulatory requirements. Cement plugs **shall** be installed and verified as required by regulations.

5 Cementing Practices and Factors Affecting Cementing Success

5.1 Introduction

A well-designed cement job optimizes cement placement through considerations such as laboratory-tested slurry design, honoring pore pressure/ fracture gradient window, use of spacers/pre-flushes, proper density and rheological hierarchy, fluid compatibility and adequate centralization. This section summarizes many of the key drilling issues that affect the quality of a primary cementing operation. This section is not exhaustive, nor does it provide the reader with a comprehensive set of detailed recommendations for well construction. The intent is to highlight the salient aspects that should be considered and summarize the interrelationship between drilling operations and cementing success. All topics discussed are covered in detail in various API, ISO, and other industry publications.

5.2 Hole Quality

Hole quality affects many aspects of the cementing operation. In situations where hole quality could compromise cementing quality, practices exist that may minimize the impact of hole quality. Avoidance of severe doglegs, hole enlargement and spiral patterns in the wellbore will improve the efficiency of drilling fluid displacement during cementing. Use of directional survey data, including azimuth, when modeling centralization and drilling fluid displacement will improve the quality of the results of the simulation.

A caliper log can be a useful tool to confirm the volume of cement slurry required to fill the annulus to the designed TOC. Knowledge of actual hole sizes provides better friction pressure estimations, both for the cementing operation and for running casing. Caliper data of sufficient quality can be used to calculate the centralizer requirements and from centralizer calculations, to calculate flow regimes and rates recommended for effective drilling fluid removal. Sonic and fluid calipers may also be used.

5.3 Drilling Fluid

5.3.1 Drilling Fluid Selection

Drilling fluid (mud) selection and maintenance play a key role in cementing success. Drilling fluid performance affects hole condition (enlargements, etc.), drilling fluid filter cake thickness and gel strength (measured as described in API RP 13B-1/ISO 10414-1 or API RP 13B-2/ISO 10414-2), drilling fluid mobility, fluid and formation compatibility, and bonding of cement to formation.

Drilling fluid performance is controlled by many factors. Drilling with fluids that provide a thin, low permeability filter cake and low non-progressive gel strengths sufficient for transport of drill cuttings and barite support can be more effectively displaced when cementing. Achieving good cementing success through effective drilling fluid displacement requires proper planning. Computer modeling of cement placement or drilling fluid displacement requires careful evaluation of fluid properties and placement processes.

5.3.2 Drilling Fluid Rheology

Drilling fluid rheology has a significant impact on cement placement. Samples representative of the drilling fluid at the time of cementing should be tested for rheological properties prior to cementing operations. This data should be used in displacement simulations.

5.4 Casing Hardware

5.4.1 General

Casing hardware and auxiliary downhole equipment may be used to enhance the cementing operation. Examples include: centralizers, float equipment, stage collars, external casing packers, liner hangers and liner top packers and expandable casing (mechanical barriers are discussed in Section 4).

5.4.2 Centralizers

Appropriate casing centralization is important to successful cement placement and zonal isolation. Casing centralizers exist in many models and designs and are generally categorized as either rigid, solid or bow-spring models. Auxiliary functionalities such as flow diversion and mechanical friction-reduction are also available. Custom-built centralizers are available for either slimhole or extremely large annular clearances. In order for centralization calculations to be done for bowspring centralizers, performance data as measured according to API Spec 10D/ISO 10427-1 should be used. See discussion of installation under 5.6.5.7. Also, see, API RP 10D-2/ISO 10427-2, API 10TR4 and API 10TR5.

5.4.3 Float Equipment

Float equipment is used to prevent the cement from flowing back into the casing when pumping is stopped and/or pressure released. Test procedures for various classes of float equipment and associated mechanical components are provided in API RP 10F/ISO 10427-3.

Float equipment choice should be matched to anticipated bottom hole temperatures and the pressure differentials expected at the end of the cement job. Specialized float equipment including auto-fill, side-ported, and custom-profiled is also available to address the functionalities of surge-reduction and collapse protection, improved hole cleaning, and ease of running casing, respectively. When utilizing auto-fill float equipment, recognize there will be well control implications while the casing is run in the hole.

A float collar and a float shoe can be used together to provide redundant flow-back control as well as a receptacle for contaminated cement slurry. Some lost-circulation materials (LCM) in the drilling fluid and/or cementing fluids may preclude or hamper the use of certain float equipment valve designs. Standard float equipment is not designed to provide a gas-tight seal.

5.4.4 Wiper Plugs

Casing and liner wiper plugs, whether conventional surface release or subsea release, provide the function of mechanically separating cementing fluids from the drilling fluid, wiping the internal diameter of the tubulars, and providing a positive indication of the end of displacement. Wiper plugs should be matched to the anticipated bottom hole temperatures, pressures, depths and drilling fluid type. Not all wiper plugs and associated operating systems (releasing darts) are compatible with all types and manufacturers of float equipment and/or stage tools, liner hanger tools, and liner top packers. Tapered diameter casing strings may require customized wiper plug systems. Wiper plugs and associated operating systems should be designed for the specific size and weight of the casing and all other casing hardware components.

5.4.5 Cementing Plug Containers and Heads

Cementing plug containers and head assemblies provide the means by which wiping devices (casing wiper plugs, drill pipe darts, balls, etc) can be launched from the surface without significant interruption of pumping operations. Cementing heads (plug containers) also allow control of cement U-tubing should the float equipment fail. Each type of cementing head has its own specific capabilities in terms of pressure ratings, mechanical operation, load-carrying capacity, and auxiliary capabilities such as allowing rotation or remote operation. These characteristics are published by the manufacturer. Not all casing wiper plugs are compatible with every model of cementing head and float equipment. Cementing heads and plug sets should be checked for compatibility. Plug containers equipped with remotely-operated plug releasing mechanisms reduce risk to personnel and may minimize shut-down time.

Cementing heads should be in good working order and be pressure-tested as per the service provider's requirements. Various components such as the plug releasing mechanism, plug release indicators, valves, threads and o-rings should be examined prior to each use. Thickness testing should be performed as per the service provider's requirements or if a component is suspect. Type-certification is available from the service provider in many instances. A type-certified plug container is one that has fully traceable components with material mechanical properties verified by laboratory tests.

5.5 Close-tolerance and Other Flow Restriction Considerations

Close tolerances may restrict the flow of drilling and cementing fluids during well circulation and cause lost circulation. Close tolerances are often encountered in pipe-to-pipe annuli, liner tops, expandable casings, and between the inner diameter of outer tubulars and some tools such as liner hangers, liner top packers, polished bore receptacles (PBR), stage tools, external casing packers (ECPs), and expandable tubulars. Conventional types of liner hangers also have reduced flow cross-sectional area called “bypass area” from the flow restrictions formed by the unset slips protruding from the hanger body. The bypass area is further reduced after these slips are set against the inner casing wall to “hang” or connect to and suspend the liner from the casing. Equivalent circulating density (ECD) pressure calculations **shall** include any flow restrictions, particularly those of significant length and small cross-sectional area, such as liner overlaps, liner top packers, liner hangers, tieback sleeves, casing connections and drill pipe tool joints.

5.6 Engineering Design

5.6.1 General

Well construction objectives and local regulations determine the extent of cement coverage and cement performance requirements for each well section. Performance requirements include (but are not limited to) gas control, static gel strength development, fluid loss, free fluid, slurry stability, thickening time, and compressive or sonic strength. Mechanical parameters such as, tensile strength, Young’s Modulus and Poisson’s ratio may also be taken into account in the cement design.

5.6.2 Zonal Coverage Determination

It is important to evaluate which zone(s) have potential for flow in order to plan the cement job to achieve suitable zonal isolation. Such zones should be covered with cement slurries designed to prevent flow after cementing, and the cement placement mechanics should be designed to maximize drilling fluid removal. Zones left uncemented may not flow in the short term if pore pressure is balanced by drilling fluid hydrostatic pressure. However, phenomena such as barite sag and drilling fluid dehydration may lead to SCP.

Cement top selection is influenced by the location of the potential flow zones, regulatory requirements and pore pressure/fracture gradient consideration. Higher density tail slurries may be more easily designed to be “gas tight” (gas controlling) than some lower density lead cements. However, some types of gas controlling cement slurries may be more easily designed based on solids to liquid content rather than density.

5.6.3 Pore Pressure/Frac Gradient

Accurate knowledge of pore pressure and fracture gradient profiles is necessary for successful primary cementing and helps design jobs that prevent lost circulation and annular flows. Pore pressure is a crucial piece of information needed to assess flow potential. The pore pressure and fracture gradient profiles are two of many input values used in computer simulation programs used to evaluate static and dynamic well security.

5.6.4 Temperature

Temperature has the single greatest influence on cement slurry performance. Accurate estimates of cementing temperatures (both static and circulating) are essential to the success of the cement job. These may be available through thermal modeling and or measurement in offset wells. For many wells, API temperature schedules provide adequate estimates of circulating temperatures. However, these schedules are based on data collected in wells in shallow water with little deviation (see API TR 10TR3 on Cementing Temperature Schedules). The API schedules should not be used for wells that vary greatly from these conditions (e.g. deepwater offshore wells or wells with significant deviation). The heat up rate used for a thickening time test can significantly impact the testing result. The heat up rate used for thickening time testing should be based on the anticipated time to bottom for the cement as described in API RP10B-2/ISO 10426-2.

Computer-based thermal modeling programs may be used to develop cementing testing temperatures. Such programs require input information such as static temperature, formation and well fluid thermal characteristics, rheologies, estimated job volumes, planned pump rates and well geometry. The predictions generated by thermal modeling programs may vary significantly; operators may consider employing more than one thermal model to arrive at a cement test temperature schedule. In most circumstances the highest annular temperature found during a cementing operation occurs some distance above the casing/liner shoe.

Temperature information may be obtained from measurement while drilling (MWD) or logging while drilling (LWD) tools as the hole is drilled. Temperatures from MWD or LWD devices tend to be somewhat higher than those derived from models or sensors used on cleanup trips, therefore caution should be applied in using these temperature measurements as the basis for cement testing. Several factors account for this including an elevated drilling fluid suction temperature while drilling compared to initial slurry temperature while cementing. Some bottomhole assemblies and formation types have been demonstrated to give highly elevated MWD readings.

In summary, there are many sources of temperature information. All temperature information should be considered. Sound engineering judgment should be applied to select the best temperature or range of temperatures and the cement should be designed to perform acceptably at that temperature or range of temperatures.

5.6.5 Drilling Fluid Removal

5.6.5.1 Design

Proper slurry design is only part of a successful cementing operation. The other part involves effectively removing the drilling fluid from the well and replacing it with cement slurry. Computer based placement simulators allow the engineer to tailor the cement job to a particular well's conditions rather than relying on arbitrary "rules of thumb." Factors to be considered in planning for efficient drilling fluid removal are discussed in 5.6.5.2 through 5.6.5.9.

5.6.5.2 Annular Fluid Velocity

Higher fluid velocities introduce more energy into the system allowing more efficient removal of gelled drilling fluid. However, tight annular clearances in some wellbore configurations limit how fast the job can be pumped without causing lost returns. Depending on the differentials between fluid rheology and density of the displacing and displaced fluids, and the degree of centralization and hole angle, specific pump rates may promote uneven flow between the narrow and wide sides of the annulus. Fluid simulation modeling is used to determine the best annular velocity, given the parameters and hydraulic limits of the wellbore and surface equipment.

5.6.5.3 Rheology and Density

As a general statement, barring chemical interactions and turbulent dilution effects, drilling fluid removal is more efficient when the displacing fluid displays a higher frictional pressure drop and is of higher density than the fluid being displaced. Various guidelines have been used to decide how to design the density and rheological hierarchy in the displacement design. Narrow pore pressure/fracture gradient windows in some wells may limit application of density/ rheology hierarchies.

5.6.5.4 Drilling Fluid Compressibility

Depending on the temperature and pressure, the density and rheology of compressible fluids can vary. Downhole pressure measurements provide static density and ECD information which can be used for modeling drilling fluid removal.

5.6.5.5 Cement Preflush (Wash) and Spacer Design

The purpose of preflushes and spacers is to aid in bulk drilling fluid removal by avoiding incompatible mixtures of the cement slurry and drilling fluid. When non-aqueous drilling fluids are used, preflushes and spacers are used to remove the oily drilling fluid film and water-wet the downhole surfaces. Procedures for testing spacer compatibility are found in API RP 10B-2/ISO 10426-2. Compatibility testing between the cement and spacer or mixtures of cement, spacer and drilling fluid may be required if well conditions warrant. Some computer programs may be used to determine the type and volume of spacers to be pumped for drilling fluid removal and predict the degree of fluid (cement, spacer, drilling fluid) intermixing that may occur during placement. The use of unweighted preflushes or base oil may worsen channeling in some cases and computer simulators may be used to predict this.

5.6.5.6 Pipe Movement

One of the best aids to achieving effective bulk drilling fluid removal is pipe movement. Pipe movement improves the probability of flow on all sides of the annulus. While reciprocating pipe aids in drilling fluid removal it also imparts swab and surge pressures in the well which could lead to fluid influx or losses respectively. Computer simulators can be used to predict surge and swab pressures. The results of these simulations can provide guidance on maximum reciprocation rates that will prevent losses or influx.

Studies have shown that pipe rotation provides better fluid displacement than reciprocation. Depending on well conditions, rotational rates of 10 rpm to 40 rpm have proven effective. Both reciprocation and rotation present operational challenges. When reciprocating pipe it is important that the pipe does not become stuck in a position that prevents it from properly landing out in the wellhead at the end of the cement job. Pipe reciprocation is not possible on subsea wells. The ability to rotate pipe may be limited by the amount of torque that can be applied. Torque limitations may be casing connections, running tools or rig equipment. For full casing strings a rotating cement head is required. Liners are often suitable candidates for rotation if a rotating liner hanger is used.

5.6.5.7 Centralization

If casing is not centralized, it may lay near or against the borehole wall. Drilling fluid, washes, spacers and cement slurry flow most easily on the wide, less restricted side of the annulus. It is difficult, if not impossible, to displace drilling fluid efficiently from the narrow side of the annulus if the casing is poorly centralized. This results in bypassed mud channels, contaminated fluids and the inability to achieve zonal isolation. Centralization is necessary to improve flow all around the pipe and aid in drilling fluid removal. Other devices in the flow path of the cement, such as liner hanger assemblies, PBR, etc. will also impact fluid flow due to eccentricity.

Computer software is available to design centralizer placement to achieve optimum standoff for drilling fluid removal. The effectiveness of centralization is dependent on a number of factors, including the hole size and deviation, casing size and weight, internal diameter of previously set casing/liner, fluid densities, and centralizer placement and properties. Centralizer properties to be considered in calculating the standoff include centralizer type (e.g. rigid, solid or bow spring), minimum and maximum OD, restoring force, starting force and running force. The actual standoff performance properties provided by the manufacturer should be used in these calculations. Caliper logs (preferably giving two or more diameters) and directional surveys are necessary to correctly calculate standoff.

5.6.5.8 Engineering Software

Engineering programs allow the user to tailor the cementing process to account for an individual well's unique conditions. Engineering programs eliminate the need for users to follow arbitrary "rules of thumb." Numerous programs are available but significant variation in the computational complexity and functional capability exists in current well engineering software. These programs are engineering tools; users are encouraged to recognize the capabilities and limitations of the programs and apply sound engineering judgment in their application. Typical program capabilities include the following:

— swab and surge pressures;

— ECD simulations to predict whether the cement job can be performed within the pore pressure/fracture gradient window;

— centralization/standoff calculations;

— displacement effectiveness;

— circulating and post cementing temperature profiles;

— surface pressure predictions;

— foamed cementing calculations (see 5.6.5.9).

As with any engineering program, the quality of a cementing simulator's output depends on the degree to which the input variables are known. It is not likely an engineering program can provide a single correct answer. However, by bracketing variables, the engineer can gain insight that will assist in achieving zonal isolation.

In order to best facilitate the installation of a cement barrier element, centralizer placement, ECD and fluid displacement simulations **shall** be performed. Within the constraints imposed by hydraulic, operational, logistical or well architecture limitations, these results **shall** be considered during the cementing design and execution.

The information entered into the computer simulation should be as accurate as possible. This information should include drilling fluid, spacer, and slurry rheologies, anticipated pump rates, temperature, caliper log information (if available), survey data (if available), well architecture, fracture and pore pressures and hardware configuration.

5.6.5.9 Foamed Cement Modeling

Engineering software should be used in the design and placement of foamed cement. Foamed cement design software is normally incorporated into the cementing service providers' ECD engineering programs. There are two foamed cement placement methods that are commonly used: (1) constant nitrogen injection rate and (2) constant foam density. Regardless of which method is selected, variances in hole size across the foamed cement column may change the density and the downhole nitrogen volume (foam quality) from that which was designed. This density variance is more pronounced when using the constant density method.

The constant nitrogen injection rate method calls for a single nitrogen injection rate (in volume of nitrogen per volume of base cement) to be added to the base cement at surface. This produces a variable foamed cement density downhole owing to the effects of temperature and pressure. The target foamed cement density used for the design will normally be found at the midpoint of the foamed cement column in the annulus.

When using the constant nitrogen injection rate technique there are two points to be considered.

1) When the foamed cement is placed, the leading edge of the foamed cement, will have a density lower than the target density used for the design. This is due to the lower hydrostatic pressure and lower temperature found at the top of the foamed cement column compared to the pressure and temperature found at the mid-point of the foamed cement column (which was used to calculate the average nitrogen injection rate at surface). When using the constant nitrogen injection rate method the foamed cement density at the top of the foamed cement column should not cause a loss of overbalance pressure.

2) When the leading edge of the foamed cement exits the casing/liner shoe and enters the annulus it will contain a volume of nitrogen designed for a location higher in the annulus (which has a lower hydrostatic pressure and a lower temperature). As such, the density of the leading edge volume of foamed cement, will be greater than the density reduction of that same volume of foamed cement once in place. This produces a higher effective foamed cement density as it exits the casing/liner shoe.

A second placement technique, constant foam density, calls for the nitrogen injection rate at surface to be varied as a function of the temperature and pressure conditions found at expected placement point of the foamed cement in the annulus. This produces a pseudo-constant foamed cement density once the cement is in place. This technique is performed either by constantly ramping or incrementally stepping up the nitrogen injection rate at surface.

When using the constant density technique there are two points to be considered.

1) The density of the foamed cement column should be examined to ensure that it does not cause a loss of overbalance pressure.

2) The density of the leading edge of the foamed cement when exiting the casing/liner shoe should be examined to ensure that ECD does not exceed the fracture gradient.

An accurate cementing temperature profile for the column of foamed cement is necessary to calculate the volume of nitrogen gas injected at surface to produce a foamed cement of desired in-situ density. Temperature simulators should be used to characterize the circulating temperature profile of the well for use in the nitrogen injection rate calculation.

A foamed cement will generally exhibit a higher viscosity than the base fluid from which it was generated. The higher the nitrogen content of the foamed cement (foam quality), the greater the viscosity increase of the foamed cement compared to the base cement from which it was generated. ECD models should account for this increase in foamed fluid viscosity. The process of foaming cement also produces a higher effective fluid rate in the wellbore compared to the base cement fluid rate that will affect ECD.

5.7 Slurry Design and Testing

5.7.1 General

The primary goal of cementing is to maintain the required hydraulic isolation for the life of the well. This may include placing competent cement between pipe and openhole or between pipe and pipe. Cement also serves to protect the casing from corrosive fluids and provides mechanical support of the casing. Cement slurries are designed to function under the expected downhole conditions while meeting the well construction objectives. Various performance parameters are considered in the design process, these include the following:

— rheological properties,

— hydrostatic pressure control,

— fluid loss control,

— free fluid and sedimentation control,

— static gel strength development,

— resistance to invasion of gas or fluid,

— compressive or sonic strength development,

— shrinkage/expansion,

— long-term cement sheath integrity.

The relative importance of each of these factors to cement performance over the life of the well will vary with the application. In some cases they are even competing priorities. There may also be specific well conditions that require other attributes to be prioritized in the cement design. While computer modeling may aid the designer in conducting sensitivity analysis across a range of possible designs, it will still be necessary to use judgment and compromise between competing priorities.

The specific slurry performance properties required to isolate flow zones will vary depending upon the severity of the flow potential and the formation fluids contained in the potential flow zone.

Test methods for determining the performance of cement are described in API RP 10B-2/ISO 10426-2, API RP 10B-3/ISO 10426-3, API RP 10B-4/ISO 10426-4, API RP 10B-5/ISO 10426-5 and API RP 10B-6/ISO 10426-6. These test methods should be adapted, as closely as possible, to simulate the conditions to which the cement will be exposed during placement across any potential flowing zones requiring isolation. The conditioning schedule and test conditions of the slurry will typically reflect the temperature and pressure found at the potential flow zone.

5.7.2 Lead and Tail Cement

Lead and tail cements are routinely placed in the annulus during primary casing cementing. Lead cements can be formulated to meet various requirements ranging from economical filler systems to high performance designs. Low density lead cements are used to lower the hydrostatic pressures to avoid or minimize losses of the cement to the formations. Tail cements are typically mixed without extending components and thus have a higher density.

Carefully consider the design of the cement which will cover the potential flowing formations. Lead cements, although not normally designed to cover formations which might flow, can be designed to control flows. Doing so may require special formulations. Design criteria for lead slurries which are placed across non-productive formations having the potential to flow are the same as for slurries placed across the hydrocarbon bearing zones.

It is important to note that if the potential flow zone is to be covered by tail cement with a lead cement above the zone, the static gel strength development of the lead slurry may reduce the hydrostatic pressure exerted on the potential flow zone before the tail slurry reaches 500 lbf/100 ft^2. These situations may require additional assessment and adjustments of the design parameters and/or operational procedures.

5.7.3 Density

Density plays a key role in the design of cement slurries. In cases with potential for flow, there are two primary considerations for selecting the density: (1) preventing losses to the formation and (2) preventing flow from permeable formations. This implies the density falls between that necessary to provide enough hydrostatic pressure to control flow from the permeable formations (well security) and that which will fracture the weak formations causing lost or partial lost circulation (see previous discussion of pore pressure/frac gradient under engineering design). Other considerations related to the density of the slurry are the performance related to strength development, mechanical properties and slurry stability.

The density under placement conditions (temperature and pressure) should be considered in the design. Some slurries are compressed by pressure while others have components which are deformed by pressure. Either of these can lead to higher densities after placement downhole than the density at which the slurry was mixed at surface.

5.7.4 Thickening Time

The thickening time is the time the cement slurry is judged to be pumpable under conditions simulating those found downhole during placement. Slurries are designed for the specific set of conditions found in the well and for the designed pumping schedule (rates) to be employed during the cementing operation. Wellbore temperature simulators are commonly used to develop schedules for conducting tests while API schedules are not appropriate (see 5.6.4).

Avoid using excessive safety factors in thickening time design. Excessive safety factors can cause delayed strength development, long periods of gelation and increased likelihood of solids segregation. These factors may present a higher potential for flow from the formation before the cement has adequate strength to prevent it.

5.7.5 Fluid Loss

Control of fluid loss plays a key role in preventing flow. Loss of fluid from the slurry is a contributing factor in the loss of the overbalance pressure controlling flow. The rate of fluid loss is dependent on the overbalance pressure, the permeability of the formation, the condition of the drilling fluid cake (including its permeability), and the fluid loss characteristics of the cement. There are numerous fluid loss additives available, such as synthetic and natural polymers, copolymers, latex, and blends thereof.

Fluid loss testing should be conducted according to API RP 10B-2/ISO 10426-2. It is not possible to make a specific recommendation on the fluid loss rate as it depends on many factors, however a low fluid loss rate is generally preferred where there is potential for flow.

5.7.6 Slurry Stability, Sedimentation, and Free Fluid

Stability of the slurry is an important property in preventing annular flow. Free fluid and sedimentation may occur simultaneously or one may occur without the other.

Free fluid can result in a channel or a void in the cement into and through which formation fluid or gas can easily flow. It may also result in a severely underbalanced condition (through the water channel) initiating the flow. Control of free fluid is imperative in situations where there is the potential for flow.

Not only is the presence of a free fluid channel and the resulting underbalanced condition critical, but the condition of the remaining slurry is key as well. When water is lost from the slurry (by free fluid separation), the solids concentration is increased. This can result in uncontrolled gelation, changing other properties of the cement (such as ability to transmit hydrostatic pressure).

Additionally, sedimentation (which results in concentration of solid particles in lower sections and reduced concentrations in upper sections of the well) should be controlled to the extent that the slurry properties both at the top and the bottom of the column are sufficient for controlling flow zones in the well. The properties of the slurry will be changed by sedimentation, leading to greater gelation where the solids are concentrated and low strength and high permeability where they are reduced.

5.7.7 Rheology

Rheology affects fluid displacement and friction pressure generated during placement. The temperatures to which a fluid is exposed, and to a lesser extent the pressure, will alter its rheological properties. In some cases, slurry stability may be dependent on rheology. Gel strength development may also be affected by components of the cement which are used to control rheology. The design of the fluids used in cementing should take these parameters into account.

5.7.8 Static Gel Strength

Static Gel Strength (SGS) development is one of many factors that contribute to decay of hydrostatic pressure. As gelled fluid interacts with the casing and the borehole wall it loses its ability to transmit hydrostatic pressure. It also contributes to the ability of slurries to suspend solids under static conditions. One method to evaluate the impact of gel strength development on wellbore fluid influx is to calculate the CSGS and then to measure the CGSP.

CSGS is defined as the static gel strength of the cement that results in the decay of hydrostatic pressure to the point that pressure is balanced (hydrostatic equals pore pressure) across the potential flowing formation(s).

The CSGS is calculated by:

$$CSGS = (OBP)(300) \div (L/D_{\mathrm{eff}})$$

where

OBP is the initial calculated overbalance pressure, i.e. hydrostatic pressure minus the pore pressure, (psi);

300 is a conversion factor;

L is the length of the cement column above the flow zone (ft);

D_{eff} is the effective diameter (in.) = $D_{\mathrm{OH}} - D_{\mathrm{c}}$;

D_{c} is the outside diameter of the casing (in.);

D_{OH} is the diameter of the open hole (in.).

Wellbores have variable hole diameters and contain multiple fluids (drilling fluid, spacer, lead cement, tail cement) in the annulus. Many wellbore sections have more than one potential flow zone to be evaluated. For these reasons, it is recommended that a computer program be used to accurately calculate CSGS for all potential flow zones.

Experimental data has shown that gas cannot freely percolate through cement that has a static gel strength ranging from 250 to 500 lbf/100 ft^2 or more [21]. The industry has conservatively adopted the upper end of the range as the accepted limit. A CSGS that is considerably lower than the 500 lbf/100 ft^2 limit indicates a situation with a relatively high potential for formation fluid to enter the wellbore during cement hydration. A CSGS value that approaches 500 lbf/100 ft^2 indicates a situation where there is a relatively low probability of fluid influx during cement hydration. It is important to note that, with the exception of density, slurry properties do not affect the CSGS. The CSGS can only be increased by increasing the hydrostatic overbalance on the potential flow zone (e.g. increase the density of the drilling fluid, spacer or cement), decreasing the length of the cement column above the top of the flow zone, increasing the open hole size or decreasing the casing size.

The CGSP is the time period starting when laboratory measurements indicate the slurry has developed CSGS and ending when they show it has developed 500 lbf/100 ft^2. If insufficient information is available to confidently calculate the CSGS, a value of 100 lbf/ft^2 can be substituted as the starting point for determining the CGSP.

When flow potential is deemed severe, the cement slurry should be designed with the CGSP minimized to the extent possible. A CGSP of 45 minutes or less (measured at the temperature of the potential flow zone) has proven effective but for less severe flow potentials a longer period is acceptable.

Static gel strength development is a function of the hydration kinetics of the cement. Gel strength development is highly dependent on temperature, the chemical and physical nature of the cement being used and any additives in the slurry. Static gel strength can be controlled by the use of special additives designed to shorten the CSGP.

Additives for controlling other properties of the cement may also impact gel strength.

5.7.9 Compressive and Sonic Strength

Compressive strength is the force per unit area required to mechanically fail the cement. While not identical, for the purposes of this standard, the sonic strength; (the extent of strength development based on specific mathematical correlations and calculated by measuring the velocity of sound through the sample) and the compressive strength are considered synonymous. As discussed in 4.6, development of a minimum of 50 psi compressive or sonic strength is required to consider cement a barrier element. The compressive or sonic strength also impacts the WOC requirements for drill out and can also be important when considering long term well integrity. The use of highly retarding surfactant spacers may require the compressive or sonic strength testing take into account contamination of the cement which may have occurred during placement.

5.7.10 Compatibility

All fluids expected to come into direct contact with each other during the cementing operation should be compatible. Compatible fluids are capable of forming a mixture that does not undergo undesirable chemical and/or physical reactions. When intermixing occurs at a fluid interface the rheologies of the mixture will be altered. If the fluids are incompatible the mixture may become viscous resulting in poor displacement efficiency and/or lost circulation due to excessive friction pressure. Combining incompatible fluids may also thin the mixture which could lead to fluid bypass and/or instability. If non-aqueous fluids (NAFs) are used, a spacer containing surfactants that water-wet downhole surfaces will be necessary. Compatibility and wettability test procedures for NAF and spacers are found in API RP 10B-2/ISO 10426-2.

Cement slurries are usually compatible, but certain types of cement additives may be incompatible with one another. If additives that are suspected to be incompatible are in slurries that will be in contact with each other then the compatibility should be tested to ensure that rheological behavior, thickening time, fluid loss, slurry stability and compressive strength are not compromised. Procedures described in API RP 10B-2/ISO 10426-2 can be adapted to test cement slurries for which there is concern about compatibility between the slurries.

5.7.11 Mechanical Parameters

The mechanical parameters of set cement such as compressive or sonic strength, tensile strength, Young's modulus, Poisson's ratio, cohesive strength, internal angle of friction, etc. play a key role in the integrity of the cement during the life of the well. The in-situ behavior of the casing and cement system is complex, as is the range of potential loading conditions the cement may be exposed to over the life of the well. Stresses placed on the cement such as changing wellbore temperatures, applying casing pressure or declining reservoir pressure can cause de-bonding between the cement and the casing or formation, tensile failure of the cement sheath, compressive failure of the cement sheath or a combination of the above. These failures can lead to annular fluid leakage resulting in SCP and/or communication between two formations and/or environmental release.

Cements designed to have a low Young's Modulus, high tensile strength and high Poisson's Ratio are considered to be less susceptible to failure. Computer models are available to qualitatively predict the impact of cement design, however, due to assumptions made by the models and the difficulty attaining quality input data, the models alone should not be used to determine the necessity for special slurry designs.

Testing methods adapted from other disciplines may be used for testing mechanical parameters of well cement formulations until fit-for-purpose test protocols are developed. The results derived from these different test protocols can vary widely for a given cement formulation.

5.7.12 Expansion/Shrinkage

When Portland cement reacts with water, the volume of products produced by the reaction is less than the initial volume of reactants. Without access to external water, cement may shrink under certain conditions encountered in the wellbore, such as tieback casing or liner over-laps. Cement shrinkage can be considered in terms of dimensional (external boundary) shrinkage and internal shrinkage. Internal shrinkage causes no dimensional change, but does result in an increase in porosity of the cement matrix. Internal cement shrinkage can reduce the pore pressure within the cement matrix which may contribute to gas influx during cement hydration. Dimensional cement shrinkage may lead to loss of seal resulting in leakage through or around the cement sheath and/or SCP. Expansive agents may be employed to counteract the effects of this shrinkage; however, excessive expansion can also be detrimental to cement integrity. Expansion against an incompetent or "soft" formation can lead to a microannulus at the cement/casing interface or the formation of radial cracks in the cement sheath.

Test methods for determination of shrinkage or expansion of well cement are found in API RP 10B-5/ISO 10426-5.

5.7.13 Foamed Cement Slurry Design

A properly designed foamed cement is a stable dispersion of an inert gas, usually nitrogen, in a base cement slurry. A combination of special surfactants and stabilizing additives are used to create discrete gas bubbles in the slurry and inhibit their coalescence. The ratio of the volume of gas to the volume of base cement slurry (also referred to as foam quality) controls the density and porosity of the foamed cement. As the gas ratio increases, the compressive strength decreases and the permeability increases. Studies have shown that when the gas volume exceeds approximately 35 % of the slurry volume the strength reduction and permeability increase may exceed acceptable levels and the stability of the foam can become compromised. Unless testing of the foamed slurry and the set cement indicate that the foamed cement properties are acceptable, a 35 % in-situ gas volume should not be exceeded.

The compressible nature of foamed cement improves its ability to prevent influx and migration of gas from a potential flow zone. Immediately after placement the pressure in the gas bubbles in the foam are at the hydrostatic pressure of the fluid column. This trapped pressure delays the loss of overbalance pressure to the flow zone while the cement is developing static gel strength.

Procedures for the preparation and testing of foamed cement under atmospheric pressure can be found in API RP 10B-4/ISO 10426-4. It is important to note that when foamed cement is prepared with field mixing equipment, the gas is introduced into the base slurry under pressure and the bubble size and uniformity therefore will not be the same as it will be with foamed cement prepared under atmospheric pressure in the laboratory. Foamed cement prepared under atmospheric pressure cannot be tested in pressurized laboratory equipment. This is because the volume of slurry prepared at atmospheric pressure will significantly decrease when pressurized in lab equipment. For example, a foamed cement with 20 % by volume nitrogen prepared at atmospheric pressure will undergo an approximately 75 fold decrease in nitrogen volume when placed under 1000 psi of pressure.

Since the gas used in foamed cement is inert the rate of cement hydration does not change. This means that the thickening time is not affected and thickening time tests should be performed in a standard HTHP consistometer on the base slurry. The surfactants and stabilizers as well as any other additives should be added to the base slurry because they will affect the thickening time.

The time required for foamed cement to begin to develop strength is also unaffected by the addition of an inert gas but the magnitude of the strength will be lower. Compressive strength of foamed cement is normally performed by crushing specimens of the cement after they have been cured in a sealed curing vessel submerged in a water bath at atmospheric pressure. Studies with specialized equipment have shown that the compressive strength of foamed cement generated and cured under pressure is generally higher than the compressive strength of samples generated and cured under atmospheric pressure.

Even though the chemistry of the base slurry remains unchanged, many slurry properties such as fluid loss and rheology will be altered due to the compressible nature of a multi-phase fluid. Compressible fluids like foamed cement have a lower inherent rate of fluid loss than the base slurry from which they were prepared because as differential pressure is applied across a porous media the gas bubbles will compress more readily than the water can be forced from the base cement slurry. Specialized test equipment can be built to measure the fluid loss of foamed cement slurries but generally the fluid loss of the base slurry is used as the design criteria.

The rheology of foamed cement is difficult to characterize but in general it can be considered to be higher than the rheology of the base slurry. Measuring the rheology of foamed cement on a rotational viscometer will give erroneous results. The rheology of the base slurry can be measured and correlations can be applied to estimate the rheology of the foam.

The stability of foamed cement is one of the most important parameters to evaluate. If the foam is not stable, the bubbles will begin to coalesce and migrate through the slurry. This will result in a decrease in the density of the column as the bubbles rise. It will also cause the set cement to have an unacceptably high permeability and a very low compressive strength. If the gas completely breaks out of the foamed slurry and migrates upwards it will likely result in a loss of overbalance pressure. The loss of the gas from the foamed cement will also result in a loss of volume and thus a lower TOC. The methods for evaluating the stability of both the foamed cement slurry and the set foamed cement described in API RP 10B-4/ISO 10426-4 should be followed to evaluate stability. If there is a possibility that the foamed cement could come into contact with other fluids in the well that could potentially destabilize it, such as NAF, additional stability tests simulating the contact should be performed.

5.7.14 Cement Slurry Techniques for Controlling Annular Flow

A number of slurry design methods have been developed to control annular gas flow. These methods differ fundamentally in their mechanisms of control and it is up to the designer to determine that the selected method is likely to perform well in the specific application. These methods include compressible slurries, such as foamed cement and cement with in-situ gas generating materials, latex of certain types, systems containing microsilica, slurries with surfactants or polymer dispersions and static gel strength controlled slurries. Certain of these require special laboratory testing techniques.

Some of these slurries and techniques are proprietary and service company design criteria should be considered for their use. Simple mathematical expressions are sometimes used to gauge the potential for gas flow within a cemented annulus. Care should be exercised when evaluating the potential for gas flow using this type of generalized expression. Variations in wellbore diameter, the undefined hydrostatic contribution of by-passed drilling fluid, uncertainty in the location of the top of cement and unknown degree of annular hydrostatic pressure reduction owing to the setting of liner top packer or annular wellhead seals can lead to predictions which overestimate or underestimate the actual potential for gas flow.

5.8 Wellbore preparation and conditioning

5.8.1 General

Well preparation, particularly circulating and conditioning fluids in the wellbore, enhances cementing success. Many primary cementing failures are the result of fluids that are difficult to displace and/or of inadequate wellbore conditioning. Drilling fluid with low fluid loss (thin, tough filter cake) and rheological properties that provide low, flat gel strengths are generally more conducive to proper displacement.

Even when good well preparation is planned, contingencies in the cementing operation should be provided in case well conditions prevent the planned well conditioning program from being performed.

Well preparation may include the following:

— adjusting drilling fluid rheological properties to aid in its removal during cementing;

— ensuring the well is static;

— curing losses;

— conditioning of fluids prior to cementing to ensure that static gel strength is broken, that cuttings and gas are removed and that the well is cooled for cementing.

The pre-cementing considerations that are included in this summary are based on sound cementing best practices that are known to enhance the probability of success. Primary cement job failures are predominately due to a breakdown in the “displacement process” which leads to channeling of the cement through the drilling fluid. These guidelines, when applied in conjunction with a simulation software program will enhance the displacement process and improve the probability of successful primary cementing. It is not possible to predict the exact behavior of a fluid in a complex wellbore, but simulation software can be used to gain a qualitative understanding of the impact of design and displacement options.

5.8.2 Lost Circulation Control

If losses have occurred or are expected, impact of the loss on the well objectives should be assessed. In some cases, it may not be necessary to treat the loss, such as when the loss zone is shallower than the potential flow zone which will be covered regardless of losses. When treatment is necessary there are a plethora of options. These include: maintaining the downhole circulating pressures below the pressure at which losses occur by reducing the density of the cement slurry, minimizing the height of the cement column and/or limiting friction pressure during the cementing operation, using lost circulation materials, running a liner rather than a long string, using stage tools, using diverter tools, etc.

5.8.3 Conditioning the Drilling Fluid

The condition of the drilling fluid is one of the most important variables in achieving good displacement during a cement job. Regaining and maintaining good mobility of the drilling fluid is a key parameter. The drilling fluid should be conditioned in preparation for cementing.

Drilling fluids with low gel strength, low rheology and low fluid loss are more easily displaced. Pockets of gelled fluid, which commonly exist following drilling, make displacement difficult. Drilling fluid is conditioned by adjusting properties to those which will be favorable for drilling fluid removal during cementing.

To condition the drilling fluid in preparation for a cement job, the following should be considered.

a) Drilling fluid displacement is generally more effective if yield point and gel strength are minimized. However, other competing priorities may prevent this, such as hole cleaning requirements. The manner in which cuttings are transported, and the ideal rheological properties, vary between low, intermediate and high angles. Hydraulic and hole cleaning software may be used to conduct sensitivity analysis to aid the rheological design of the drilling fluid in balancing hole cleaning and cement placement.

b) The gel strength profile of the drilling fluid should be determined as per methods defined in the following publications:

   1) API RP 13B-1/ISO 10414-1, for water-based drilling fluids,

   2) API RP 13B-2/ISO 10414-2, for oil-based drilling fluids.

   Gel strength should be as low as possible within the constraints of cuttings transport. The gel strength profile should be non-progressive. The API standard time periods for measuring gel strength are at 10 seconds and 10 minutes. Longer time periods are allowed by the API procedures such as measurements at 30 minutes or longer. For the purpose of conditioning the drilling fluid prior to cementing, a minimum of three measurements (10 seconds, 10 and 30 minutes) are recommended to plot a gel strength profile showing whether or not a flat profile exists.

c) Maintain filtrate loss control. Filtrate loss into a permeable zone enhances the creation of a filter cake. A high fluid loss creates a thick or high viscosity, drilling fluid layer immediately adjacent to the formation wall that is difficult to displace prior to or during cementing. The fluid loss recommended is dependent on the hole section being drilled. Fluid loss control should be maintained while conditioning the hole and running casing and cementing. Note that a thick, gelled filter cake deposited while drilling using high fluid loss drilling fluid cannot easily be removed by later lowering the fluid loss of the drilling fluid.

5.8.4 Rathole

Rathole beneath the casing shoe can lead to contamination of cement during placement, or drilling fluid can swap with the cement after placement. These can result in poor strength development, pockets of drilling fluid, or a wet shoe. Rathole length should be minimized or filled with densified drilling fluid.

5.8.5 Surge Pressures while Running Casing

Surge pressures while running casing may cause lost returns if the pressure exceeds formation integrity, or in some situations, loss of well control. When casing is run into the hole, the drilling fluid flow rate (and the friction pressure) is proportional to the casing running speed. Running casing with conventional float equipment causes the drilling fluid to flow at a higher rate up the annulus. Since the well has been static for a prolonged period, the drilling fluid will be gelled, also increasing the surge pressure. Surge pressures can be reduced by decreasing running speed, using auto-fill float equipment, lowering the rheology and gel strength of the drilling fluid and/or staging in hole and breaking circulation while running casing.

Surge prediction software may be used for job planning to predict running speeds that maintain wellbore pressure below formation integrity. However, the lowest integrity in the open hole is often unknown and the surge calculation itself is affected by many other factors that are not precisely known. If losses occur at the planned running speeds, it may be possible to regain circulation by lowering the running speed.

5.8.6 Centralizer Program

Centralizing the casing across the intervals to be isolated helps optimize drilling fluid displacement. In poorly centralized casing, cement will follow the path of least resistance; as a result, the cement flows on the wide side of the annulus, leaving drilling fluid in the narrow side. In a deviated wellbore, standoff is even more critical to prevent a solids bed from accumulating on the low side of the annulus. Computer models may be used to assess the impact of centralizer placement and other conditions on drilling fluid removal (see discussion in 5.6.5.8).

Centralizers can be installed such that they are allowed to slide between casing collars or be held in place with either stop collars or set screws on the centralizer itself. Such holding devices may be exposed to significant forces while running casing and while moving pipe during cementing and may not hold the centralizers in place. Stop collars are necessary to hold centralizers in place when installed on flush joint casing. The practice of holding centralizers in place with set screws may prevent casing rotation.

The preferred method of installation of bow string centralizers is so that the centralizer is pulled into the hole, rather than pushed. An example of pulling a centralizer is when it is placed around a casing or stop collar; an example of pushing a centralizer is when it is allowed to travel freely between stop or casing collars.

5.8.7 Circulating and Conditioning after Casing is Landed

When the casing is on bottom and before cementing, circulating the drilling fluid will break its gel strength, decrease its viscosity and increase its mobility. The volume of the circulatable hole can be estimated by using a fluid caliper. Good fluid returns at the surface do not reliably indicate the mobility of fluid in the annular space.

A fluid caliper is a small volume of fluid which is easily identifiable when it appears on the shale shaker or returns to the pits after circulation. Knowing the time between injection and recovery, and the pump rate, the volume of fluid which is flowing in the well can be calculated. A fluid caliper pumped through the well in a full hole or “trip” volume circulation helps perform several functions:

— measure the openhole circulating volume by subtracting casing capacity and pipe-in-pipe annular volume from the trip volume,

— measure hole cleaning performance (gelled drilling fluid/cake/cuttings removal) of various methods/materials mentioned below,

— validate cement volumes predicted by wireline caliper logs.

Hole cleaning methods include higher circulating rates, pipe movement, and the use of high/low viscosity “sweep” pills to remove any partially dehydrated “gelled” drilling fluid, wall cake, and cuttings that can impair drilling fluid displacement during cementing. More information can be found in the literature (see the Bibliography for papers SPE 18617 [4] and 29470 [5]).

Once the drilling fluid has been conditioned (i.e. drilling fluid properties going in equal to properties at the flowline outlet), stopping circulation may allow the gel strength to rebuild. Shutdown time between circulation and cementing should be minimized by installing the cementing head and pressure testing lines before pre-cementing circulation. The time to drop the plug should be minimized by proper planning. It is best to land casing close to the floor to allow easy access to pins and valves on the cementing head necessary to drop the plug (and to minimize hazards).

5.9 Cement Job Execution

5.9.1 Bulk Plant QA/QC

Accurate cement blends are extremely important to the success of any cement job. Cement blends should be blended in accordance with the written procedures established by the service company providing the cement blend. In addition, the personnel blending and/or loading the cement should be properly trained and competent. The cement blenders and all associated equipment should be regularly maintained and inspected to ensure there are no leaking valves or other equipment malfunction that could cause improper additive introduction, erroneous cement concentrations, or contamination.

Bulk plant scales should be accurate and in proper working order. These scales should be part of a regularly scheduled calibration program. Copies of the calibration certification should be retained at the bulk plant. A certified calibration technician should perform all calibrations.

Bulk plants should be equipped with proper sampling devices to ensure that multiple representative samples are taken throughout each blend. The sampling device should be located in an area on the discharge line that ensures that excess moisture cannot enter the sample containers.

Certain cement blends require specific loading best practices. Service company-specific best practices should be used as appropriate.

5.9.2 Cement and Additive Lot Numbers

The service company providing the cement and/or cement blend should follow all established, documented company procedures to ensure that all received neat cement is within acceptable specifications upon arrival at the bulk plant. In addition, the lot numbers of all additives used should be documented for each cement blend. This information should be contained in the paperwork associated with the particular job for which the blend is loaded. A minimum of two samples of at least one gallon each of neat cement or blend should be documented, labeled, and retained. One of these samples should be retained at the bulk plant and the other sent to the lab for verification testing (if recommended). If verification testing is recommended, testing should be conducted with representative samples of location water.

5.9.3 Transportation and Storage of Cementing Materials

All cement blends should be stored and transported in properly maintained bulk storage tanks. This includes physical inspection of the pads and interior surfaces of the tanks prior to loading/bulk transfer and tank clean-out if weather conditions allow. Allowing moisture into tanks during inspection will lead to possible degradation of cement properties and difficulty unloading the bulk storage tank. Inspection and cleaning will ensure that no contamination is present in the storage tank(s). In addition, discharge, fill, inspection port, and vent valves should be checked to determine that no valves are malfunctioning. Rock catchers should be installed at key points throughout the bulk transport and storage process. Rock catchers should be inspected and cleaned as needed prior to transfer.

Cement volumes to be loaded should take into account any bulk transfer losses that may occur. This is particularly important in an offshore environment where losses in the bulk tanks of a boat and in transfer to the rig may be significant.

5.9.4 Mixing and Pumping

Slurry density fluctuations can have adverse effects on slurry properties including: reduced or extended thickening times, free fluid, retarded compressive strength development, extended slurry transition time, and reduced fluid loss control. Additionally, density fluctuations can result in increased ECD, fracturing of weak formations, and the potential loss of well control.

The cement spacer(s) and slurries should be mixed as closely as possible to the planned densities. Some variance in density will occur with field mixing equipment but acceptable performance properties of the fluids should not be compromised. Computer-aided density control mixing systems normally improve density control. Batch mixing may be necessary if mixing on-the-fly methods are not acceptable.

Low density slurries, such as those containing hollow spheres, have a dry blend density very close to the density of the mix water. A very small change in slurry density with these systems could result in a large variation in the solids content and possibly unacceptable slurry performance. A system that controls the solid/liquid ratio of the slurry (and not the density) should be used when mixing low density systems that will not perform acceptably if density is not controlled within an achievable tolerance.

5.9.5 Executing as Designed

Deviations from the planned job design can result in failure to meet the objectives of the cement job. It is recommended that the job design is communicated with all key personnel prior to job execution. Contingency plans that address surface and downhole equipment malfunctions, bulk delivery problems, losses etc. should also be prepared and disseminated.

Pumping the cement job with the designed pump rates is important but density control should not be sacrificed to obtain a planned rate. From a drilling fluid removal standpoint, flow rate only becomes critical once the spacer/pre-flush has entered the annulus which often occurs during displacement, after mixing of cement has been completed. A computer simulation can be used to determine a range of pump rates to optimize placement efficiency (see 5.6.5.8).

5.9.6 Pipe Movement

Pipe reciprocation and rotation can assist in effective drilling fluid removal. Pipe movement assists in drilling fluid removal by altering the flow path of the drilling fluid, spacer(s), and cement slurry. Pipe movement can also help to break the gel strengths of drilling fluid that may otherwise be bypassed by the spacer and slurry. Reciprocation should be done slowly to ensure that surge pressures are minimized and losses are not induced due to fracturing of formations. Computer surge programs can supply the maximum reciprocation rate during a cement job.

Proper equipment should be utilized anytime pipe movement is planned. When reciprocating, ensure that enough treating iron has been installed from the rig floor to the cementing plug container. Pipe rotation necessitates the use of equipment designed to rotate without creating stress on the plug container and treating iron.

5.9.7 Data Acquisition

All pertinent job data should be monitored and recorded by computerized data acquisition equipment. The data to be recorded should include density of all fluids pumped, rate at which they were pumped, and surface treating pressure. Pressure and rate should be recorded during the entire displacement, regardless of whether cement pumps or rig drilling fluid pumps are used to displace the plug. If possible, return rates should also be recorded.

The recorded job data discussed in this section is necessary as a quality control record and for post job analysis and reporting. It can also supply valuable information in the event that the job cannot be pumped as planned.

5.9.8 Lost Circulation Contingency Plans

Lost circulation contingency plans should be discussed prior to job execution (see A.10). These plans can include increasing or decreasing cement volumes, altering cement thickening times, altering fluid loss control of the slurry, and increasing or decreasing slurry pumping and displacement rates. Computer aids such as surge analysis programs and ECD programs can minimize the risk of lost circulation. In addition, there are several float equipment designs that can be used to help reduce the risk of fracturing formations while running the casing into the wellbore.

5.9.9 Spacers and Pre-flushes

Spacers and pre-flushes play a key role in proper cement placement so it is very important that they are mixed and pumped as designed.

Pre-flushes are not densified and usually contain only a low concentration of a few additives so they can be easily mixed on-the-fly. This means that the volumes pumped are not limited by mix tank capacities and the risk of contamination is low.

The major components of most spacers are a viscosifying agent and a weighting agent (e.g. barite, calcium carbonate, etc.). Small concentrations of other materials such as drilling fluid thinners and fluid loss additives may also be included. The viscosifier and other additives are generally provided by the cementing company as a single mixture which may be either liquid or solid.

Spacers can either be mixed on-the-fly or pre-mixed in a tank. Both the viscosity and the density of the spacer need to be very close to the original design for effective cement placement and fluid stability to prevent sedimentation of the weighting agent. Some amount of time is required for the viscosifying agents to fully hydrate and attain the required viscosity. The density and viscosity of the spacer should be verified to be within acceptable variance of the design parameters. If this cannot be achieved when mixing on-the-fly the spacer should be pre-mixed in a clean tank. Some volume of spacer may be left in the mixing tank so extra spacer should be prepared so that the designed volume will be pumped downhole.

If surfactants are included in the pre-flush or spacer recipe there is a possibility of foaming when mixing which could cause the cement pump to lose prime. If this is an issue, the surfactants may need to be metered into the spacer in the suction manifold of the high pressure pump. An anti-foam agent can also be added before the surfactant.

5.9.10 Displacement

Cement slurries should be displaced at rates required for drilling fluid removal as determined from computer modeling unless lost circulation is encountered and contingency plans are initiated. Cement jobs with small displacement volumes or those that are pumped through drill pipe such as squeezes, plugs, liners, stab-ins and inner-strings may benefit from displacement by the cementing unit for improved volume accuracy. The rig drilling fluid pumps can be used to displace large casing jobs, although the cement unit should monitor and record the displacement pressures. Displacement rates should also be recorded if possible, and methodically documented if recording is not possible.

Over-displacing if the plug does not bump should be discussed prior to job execution. In most instances, volumes in excess of 50 % of the capacity of the shoe track should not be exceeded when pumping additional fluid over calculated displacement volume. When compressible fluids such as NAF are used for displacement, the volume required for bumping the plug will be greater than the volume measured in the displacement tanks on the cementing unit. If there is a technical or operational need to bump the plug (e.g. pressure test casing, operate hydraulic hardware, etc.) then either a measured or calculated compressibility factor can be taken into consideration when determining the surface volume to be pumped.

5.9.11 Multiple Plugs

Top and bottom wiper plugs are recommended for all casing jobs, with the exception of stab-in casing jobs. On stab-in casing jobs, a drill pipe wiper dart or ball should be dropped behind the cement slurry.

A bottom plug may be placed either at the interface between the spacer and the cement or the interface between the spacer and the drilling fluid. Choice of plug location depends upon fluid properties and casing size. Normally, it is preferred to place the plug between the spacer and cement to prevent contamination of the cement by the spacer. The use of two bottom plugs is preferable but not always operationally feasible. This ensures that the cement is uncontaminated in the casing. In addition, double plug containers are recommended where possible. The wiper plug container should have a system to indicate the launch of the wiper plug. The wiper plug departure should be carefully noted, due to the potential for fluid bypass in some plug containers prior to plug launch.

The length of shoe track required may be affected by the amount of mud film removed from the inside of the casing and the number/type of cementing plugs used (cement contamination).

5.9.12 Holding Pressure Inside Casing

The casing floats should be tested after the displacement is complete. Once it has been determined that the floats are holding properly, pressure should be bled off the casing completely. Care should be taken to ensure that no pressure is trapped inside the casing due to closed valves on the cement head. Valves on the cement head should remain open as the fluid inside the casing will undergo heating and thermal expansion. If the valves on the cement head are closed, the casing will expand as pressure increases. Then, when the pressure is released, a micro-annulus may be created as the casing contracts, which could result in poor zonal isolation and SCP.

It is typically not advisable to trap pressure inside the cemented casing unless the float valves have malfunctioned and are not holding pressure.

5.10 Post Cementing Operations

5.10.1 Maintaining a Full Hole and Cases for Applying Surface Pressure

In order to maintain maximum overbalance pressure, the fluid level should be maintained in the annulus. In addition to maintaining the overbalance pressure, keeping the hole full will give an early warning if the well begins to flow. It also provides a means for tracking fluid losses in the annulus.

If wellbore ballooning is occurring, the annulus should be closed and monitored until the cement has gained 50 psi of compressive strength at the loss zone in order to prevent fluids lost to the formation from flowing back and contaminating the unset cement.

Under some circumstances (see A.13), the controlled application, via pumping, of a constant pressure to the annulus can be used to mitigate well control events such as kicks and reduce the risk of a LWC incident. This surface pressure application increases pressure down the annulus to the source of the flow and helps create an overbalance across the flowing zone to mitigate or stop the flow.

Some specialized applications such as foamed cementing or under-balanced operations may require that pressure be held on the annulus during WOC time. Job-specific procedures should be consulted to determine a pressure and time schedule for the annulus.

The characteristics of the well, including depth, fracture gradient and geometry can play a role in the success of the above techniques. They are intended only to supplement other techniques used for control of flow. To be effective, the well should be rigged up and the technique started within a few minutes after bumping the top wiper plug which ends pumping for the primary cementing job.

Care should be taken in washing out a riser, as this can reduce the hydrostatic pressure, leading to flow.

5.10.2 WOC

Operations on the well following cementing should be done in such a way that they will not disturb the cement and damage the seal or cause the cement to set improperly.

Normally pipe movement to complete hanging the casing and activating seals should be finished before significant gel strength has developed. If done after the cement has developed significant gel strength, such pipe movement could cause a micro-annulus. There is also danger of initiating flow if the pipe movement swabs the well in. In some instances the pipe may be moved at a low-rate as a means to break gels until hydration starts.

If the casing is to be hung after cement strength is developed, as when intentionally increasing or decreasing the landed tension in the casing, consideration should be given to the imposed forces on the cement and the cement strength.

Regulations may require casing to be pressure tested. Preferably, pressure testing casing should be done before significant gel strength has developed. However, such pressure testing will be limited by the pressure ratings of plugs, floats, cementing heads and other equipment. Pressure testing can be done after the cement has set but this can result in micro-annulus formation or damage to the cement sheath. The pressure should be held on the casing for the shortest length of time required to accomplish the test. The effect of pressure testing will depend on the properties of the cement, the pressure at which the casing is tested (and consequently the amount of enlargement of the casing) and the properties of the formation around the cement. Mechanical stress modeling can assist in determining the best time to conduct the pressure tests.

In the absence of regulatory guidelines on compressive strength requirements before drilling out, usually a minimum compressive strength of 500 psi is recommended before drilling out the shoe of the cemented casing.

When cement is considered a barrier, refer to the WOC Guidelines Prior to Removing a Temporary Barrier Element (see 4.6.3).

5.10.3 Top Job

A top cement job (that is, one conducted to fill in the annulus when cement did not reach the desired depth for the top of cement) can be conducted immediately after bumping the top wiper plug or it can be done after the cement has set. Consideration should be given to the probable poor displacement when a top job is performed. Every effort should be made to ensure that the primary job circulates cement to surface, when recommended, and a top job be done only as a last resort.

If done immediately after bumping the wiper plug, formations deeper in the well may be broken down. The formations which might be broken down and the impact on the integrity of the well and the annular seal should be considered when using this method.

If the top job is done after the cement has set, consideration should be given to the method of placement, whether it is to be bullheaded or grouted. Bullheading requires breaking down a weak formation somewhere in the wellbore. If the cement has set and there is not a channel in the cemented annulus, the formation will break down between the top of the set cement and the shoe of the previous casing. If the top of set cement is above the shoe of the previous casing, this method cannot be used. In such a case, the cement will have to be placed by grouting with a small diameter pipe run inside the annulus. If the top job is done by grouting comply with requirements in 4.6.3.

6 Casing Shoe Testing

Casing shoe tests including formation integrity tests (FIT), Leak-Off Tests (LOT), and pressure-integrity tests or pump-in tests (PIT) are carried out during the drilling phase after a string of casing has been cemented and a short section of new hole, typically10 ft to 20 ft, has been drilled.

Casing shoe tests serve the following purposes.

— To confirm the pressure containment integrity to ensure that no flow path exists to formations above the casing shoe or to the previous annulus. If such a flow path exists, and it extends to a formation without adequate integrity, the seal around the casing shoe may have to be repaired (e.g. by cement squeeze).

— To investigate the capability of the wellbore to withstand additional pressure below the shoe such that the well is competent to handle an influx of formation fluid or gas without the formation breaking down.

— To collect in-situ stress data that can be used for geo-mechanical analyses and modeling (e.g. wellbore stability and lost circulation prediction).

Most governmental regulatory organizations maintain criteria regarding verification of casing shoe integrity. Formation integrity tests are normally carried out in accordance with the operator’s policy and procedure.

7 Post-cement Job Analysis and Evaluation

7.1 Material Inventory

One important aspect of the post job analysis is material inventory after cementing operations are complete. A final inventory of material should be completed and compared to the pre-job inventory as described in the cementing execution section. A material mass balance, comparing the job plan to the actual final inventory, will determine if the correct amount of cement and additives were used during job execution.

7.2 Job Data

To further evaluate the cementing operations, the real time data can confirm fluid volumes, densities and rates in accordance with the initial design. Using computer software, the acquired versus predicted data can be compared to obtain pressure matching, equivalent circulating densities and confirm well security. When problems occur during the cementing operations, this information can be useful when investigating job failures.

Comparison of the predicted and actual job data may provide verification of placement, or insight into other issues. Prior to the cementing operation, a checklist can be prepared from the job design to ensure all requirements have been achieved after execution is complete. The checklist should include all critical job information such as rates, volumes, densities, pressures, fluid rheologies etc.

Job data collected for a complete analysis can serve as a reference for future wells drilled in the same or similar areas. The knowledge may also be shared with other operators to better understand the reasons why wells flow after cement.

7.3 Cement Evaluation

Formation integrity and cement placement and strength are important parameters to be evaluated before drilling the next hole section. Failure to achieve a positive test may be due to inadequate seal by the cement in the annulus or failure of weak formations near the shoe. When the LOT or the FIT results are inadequate, the operator can perform a cement squeeze or other treatment to enhance the formation's pressure containment integrity or to seal a leaking cement sheath in the annulus. A repeat LOT or FIT may then confirm the squeeze or treatment results in increasing the interval's wellbore pressure containment.

In order to effectively evaluate a cement job, one should determine whether the objectives of the operation have been achieved. The objectives will vary depending on the cement job. Field evidence of a properly executed job may include records of spacer density and rheology, slurry density control, pump rates, pump pressures and observed returns which conform to the cementing plan. Based on the job objectives, multiple techniques are available which include temperature, noise, acoustic and ultrasonic cement logs.

Caution should be exercised when using cement evaluation logs as the primary means of establishing the hydraulic competency of a cement barrier. The interpretations of cement evaluation logs are opinions based on inferences from downhole measurements. As such, the interpretation of cement evaluation logs can be highly subjective. Refer to API TR 10TR1 for an overview of the attenuation physics, features and limitations of the various types of cement evaluation logs.

Annex A
(informative)

Background and Technology

A.1 Background

A.1.1 General

In 2010, the Minerals Management Service was reorganized into the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE). The BOEMRE in 2010 referenced API RP 90 and API RP 65-2 (first edition), in addition to API RP 65, in the *Code of Federal Regulations* (*CFR*).

A.1.2 Historical Background

On August 16, 2000, the MMS of the U.S. Department of the Interior presented safety concerns on uncontrolled annular flows to a new API Work Group. This group included government and industry representatives from several organizations including API Washington staff, API Executive Committee on Drilling and Production Operations, API Subcommittee 10 on Well Cements, International Standards Organization, International Association of Drilling Contractors, Drilling Engineering Association, the MMS, and other interested parties. Issues related to annular casing pressure (ACP) were also discussed. This new group called “API Work Group on Annular Flow Prevention and Remediation” agreed to document industry “best practices” to improve zonal isolation, reduce the occurrence of SCP, and help prevent annular flow incidents prior to, during, and after cementing operations. Studies of available information on flow event causes and prevention helped the Work Group write “best practice” documents for publication as API Recommended Practices. The API Work Group is responsible for the following API Recommended Practice publications:

1) API RP 65 entitled *Cementing Shallow Water Flow Zones in Deep Water Wells*,

2) API Std 65-2 entitled *Isolating Potential Flow Zones During Well Construction* (this document).

Another group has prepared API RP 90 providing guidance on managing ACP, if encountered. API RP 90 covers procedures such as ACP monitoring, diagnostic testing, establishing maximum allowable wellhead operating pressures (MAWOP), documenting ACP, and assessing risk to help determine the need for mitigation measures. API RP 90 refers to API RP 65 for more information on ACP prevention and remediation methods and materials.

A comprehensive overview of API RP 65 and its API Task Group is available in SPE paper 97168 [3]. The following section summarizes some of the key issues studied by this API Group and addressed herein.

A.2 Historical Data and Perspectives

Historical data and verbal communications obtained from many countries strongly suggests that annular flows, gas migration, vent flows, ACP (both sustained and thermal annular casing pressure), pressure zone kicks, and LWC incidents, particularly prior to, during or after cementing pipe strings, can have grave consequences. Some of them have caused loss of human life and/or severe injuries, environmental pollution, loss of expensive facilities, and negative effects on the operator’s future ability to obtain leases. Historical data also suggests that this is a common problem and presents an opportunity for governments, industry, and other contributing parties to work together on solutions. The API is committed to this task and continually works on relevant standard practices that help industry work safely and protect the environment.

API’s publication of a series of API RP 65 documents is a key part of the solution by documenting proven technology that can mitigate and prevent annular flows linked to the well’s casing installation and cementing process. Unforeseen events can happen on any cement job, even when it has been properly designed, so relevant well design parameters, drilling practices, redundant equipment systems, gas control cements, and/or other means of preventing these LWC incidents should be employed when the risk of hydrocarbon flow exists. The current trend to drill deeper HPHT wells heightens the concern for the risk of severe kicks and LWC incidents. Published annular flow study data from some countries is available from government and industry sources with examples from four countries listed below.

A.3 Studies of Annular Flows Primarily in the USA

In 1964, Bearden et al [17] reported on an investigation of inter-zonal flows of formation fluids through the cemented annulus and methods to prevent them. This study concluded that the hydraulic seal of cements can fail when exposed to certain conditions. This type of failure is often due to low "bond" strengths or, in the worst case, a "micro-annulus" formed between the pipe and cement creating pathways for annular flows between high-/low-pore-pressure, high-/low-permeability formations.

For example, cement is placed in the annulus across a potential flow zone and initially it has an internal pressure of 8000 psi caused by the hydrostatic head pressure of the column of cement or cement and drilling fluid above it. At the same depth and time, the hydrostatic head pressure inside the casing or liner pipe has a lower pressure of 6000 psi (called "casing pressure") from the lower density displacement drilling fluid or "mud." This gives a 2000 psi force pushing against the outside wall of the pipe which allows a hydraulic seal or "bond" to form between the cement and the pipe once the cement is set. Figure A.1 (Figure 3 from SPE 903) shows that this example cement seal can withstand over 1400 psi differential pressure between a nearby low pore pressure, permeable zone and the high pore pressure, permeable formation (potential flow zone) in the same annulus.

NOTE The data curve in Figure A.1 should not be used to predict bond or hydraulic seal integrity as it only represents the data for one particular operator's cement slurry tested in one unique device that it not standardized. It serves here only to show how it helped one operator identify his specific zone isolation issues and solutions at a given time in history. For example, today the cements and additives together with the relevant slurry designs may now have different properties that would provide different "bond failure" data curves.

On the other hand, if the initial 8000 psi hydrostatic head (HH) pressure within the cement is prematurely reduced before the cement has set hard and gained enough structural integrity, the hydraulic seal ("bond") can be substantially reduced or totally lost. For example, if the initial 8000 psi annular hydrostatic pressure is reduced to 4000 psi, the force against the outer pipe wall will be totally lost and a 2000 psi force (6000 psi HH csg. pressure to 4000 psi HH annular pressure) will then push against the inter pipe wall causing it to expand slightly in diameter. Figure A.1 shows that this change in direction of force (+2000 to –2000 psi) may reduce the potential hydraulic seal ("bond") strength from 1400 psi to less than 600 psi with the example cement. If this 600 psi is less than the inter-zonal differential pressure, an annular flow may initiate between the zones and also migrate further up the annulus via a micro-annulus. Also, if the 6000 psi internal casing pressure is sufficiently reduced after the cement is set hard, the pipe diameter may shrink enough to break the cement/pipe "bond" leaving an unsealed annular flow path or "micro-annulus" between the set cement and the casing's outer pipe wall.

The more the hole/casing annular HH pressure is reduced during the cement curing phase, the greater chance for an annular flow. The risk of an annular flow also increases as the casing's internal HH pressure decreases after the cement's initial set. However, highly-gelled, unset cement may not deform and fail to maintain contact with the outer pipe wall when the casing diameter shrinks as internal HH pressure is reduced. Thermal effects may also create and/or increase the size of a micro-annulus formed by the loss of annular or internal HH pressure. For example, casing and liners may have a micro-annulus formed or a larger one when:

1) holding pressure inside casing as cement cures (see 5.9.12);

2) the hole fluid level is not kept full (see 5.10.1);

3) moving the casing during WOC (see 5.10.2);

4) the cement displacement fluid is replaced by a lighter density fluid;

5) the replacement fluid inside the casing is much cooler than the displacement fluid;

6) casing pressure tests or other imposed pressure applications are performed:

a) after the cement starts to gain SGS during WOC,

b) after the cement sets at a test pressure above the cement's tensile strength,

c) repeatedly during the life of the well that exceed the cement's fatigue limits;

7) mechanical seals are activated before the cement has gained enough structural integrity to resist pipe expansion from the loss of hydrostatic head pressure in the annulus.

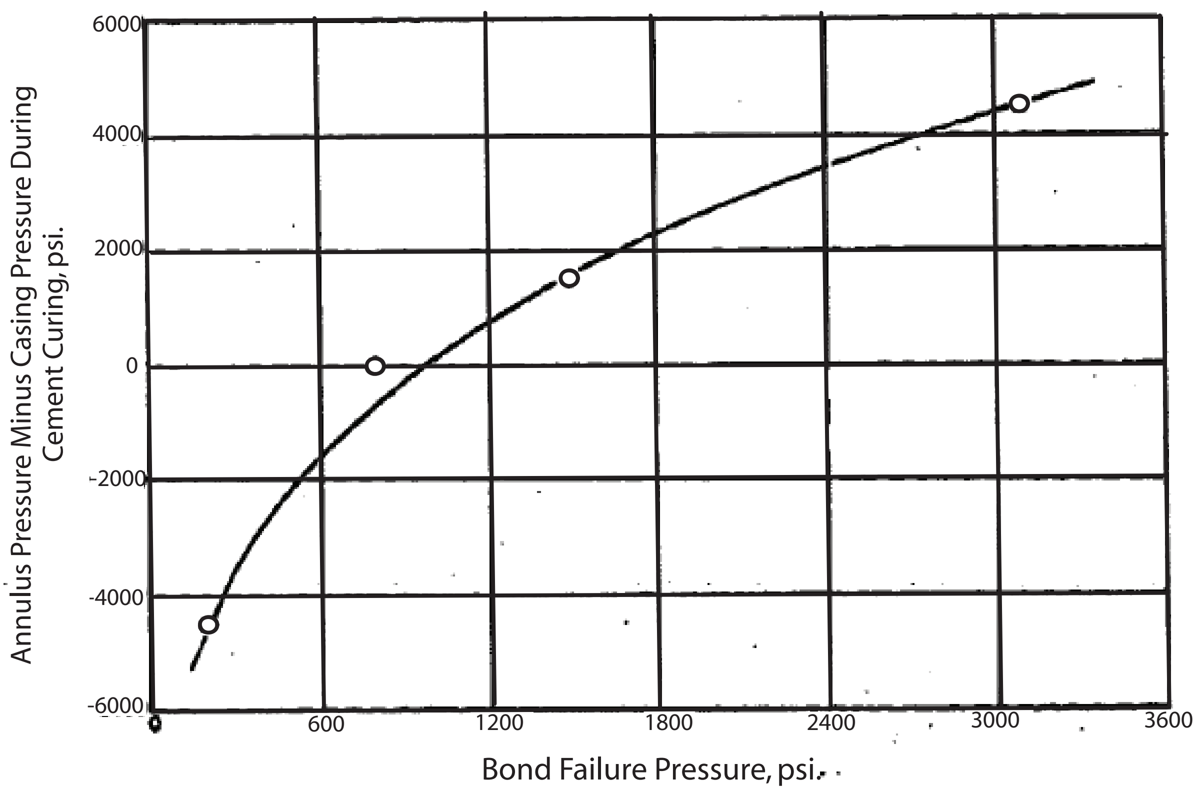

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Figure A.1—Effect of Curing Pressure on Bond Failure

Some of the preventive measures mentioned by Bearden [6] included the use of float equipment, displacing with lighter density fluids, and, in some cases, attaching annular seal rings (type of mechanical barrier) to the casing. The latter method was proven successful in 25 out of 27 well applications. More preventive measures such as new types of annular mechanical barriers have been developed since then and are described in Section 4.

Garcia and Clark [18] disclosed the results of a seven year (1968 to 1975) lab and field study of annular gas flows in numerous wells to better define the issues, challenges, and recommend preventive practices. The significance of this study is the identification of annular flows in the 1960's by various investigators and postulating of the hypothesis or theory that of the loss of hydrostatic head pressure on top of and within the annular column of unset cement slurry was the root cause. A new cause for this loss of hydrostatic pressure was discovered and reported to be premature setting or dehydrated “bridges” of a portion of the cement in the upper parts of the cement column. Another way to visualize this phenomenon is to think of these early set or bridging points as “artificial annular packers” made from cement or “annular cement packers.” Included in the field study were cases where logs were used to identify and measure annular flows between zones after casing and liners were cemented.

Also during the 1960 to 1980 time period other investigators, Carter and Slagle [19] and Christian et al [20] presented substantial evidence of the cement packer effect also called “hydrostatic-pressure bridging” above potential flow zones that resulted in costly annular flows. In 1979, Tinsley et al [21] identified continuing annular gas flow problems and associated costs from several tens to many hundreds of thousands of U.S. dollars per wells. Several years of research efforts to find solutions with associated field applications were summarized by Tinsley. One major finding was that compressible cement systems had positive results in reducing the occurrence of annular gas flow. Included in the field study were several offshore wells in the High Island area of the Gulf of Mexico where annular gas flow events after cementing surface and intermediate casing strings had caused uncontrolled releases of gas to the surface and to the atmosphere (called blowouts in the paper). Also land wells in South Texas were studied that had a history of annular gas flows after cementing production casing and liners causing communications between zones. Other areas with annular gas flows were identified that in low to moderate flow rate cases cause loss of production to thief zones above and/or below the production interval and in severe cases (also called underground blowouts) result in high risk conditions for safe well operations. Tinsley cited the researcher’s consensus of opinion on the “annular cement packer” phenomenon mentioned above that “once pressure in the annulus has decreased by as little as 0.5 psi less than the formation pressure, gas flow can occur” and “this gas entry tends to form a gas channel in the cement column.” Lab studies were presented that better defined how cement slurries can develop SGS which prevents transmission of hydrostatic pressure in cement columns. In addition to having “fluid-loss-controlled” cement slurry properties, Tinsley said that “free water” control in cement slurries, as identified by Webster [22], was needed for compressible cement systems to provide more comprehensive solutions to annular gas flow problems. This combination of cement performance properties was 90 % successful in preventing annular gas flows in over 200 well applications.

Martinez et al [23] studied the causes of annular gas flow and LWC incidents in Outer Continental Shelf (OCS) wells for the U.S. Department of Energy (DOE) and published a report on their work in 1980. This report is available at http://www.mms.gov/tarprojects/027.htm This DOE study report includes case history reports on annular flows after cementing including “USGS” federal agency (pre-MMS) reports on LWC incidents that had similar causes to those disclosed herein API Std 65—Part 2. Also contained within API Std 65—Part 2 is more information on annular flow causes and up to date solutions to this challenge. The benefits of developing and/or implementing solutions to these issues were outlined on pp.6-7 in the DOE report and are still applicable today as follows:

1) safety improved by reduced risk from:

   a) underground blowouts,

   b) pressurized shallow sands,

   c) blowout adjacent conductor and potential loss of platform;

2) environmental protection enhanced by reduced potential for leaks to the seafloor or shallow formations;

3) economics:

   a) expensive blowout risk is reduced (as well as public loss of confidence in industry and agencies),

   b) reduced well control problems save drilling time and cost,

   c) remedial squeeze jobs are reduced.

Martinez et al [23] also called for more research on why cement failed to control annular flows. As mentioned above, significant progress has been made since then to understand the relevant issues and to formulate solutions. Although most of the information in this DOE report is still relevant today, some parts may be updated as follows.

1) Page 4, no.4—Many laboratory and field studies have been published since 1980 that adequately describe cement hydration mechanics. Information from these studies helped developers make significant improvements in cementing technology which are incorporated in the practices recommended in API RP 65 and API Std 65 Part 2. However, methods to measure set cement's mechanical properties are currently being studied by the API and others in order to standardize laboratory test procedures.

2) Page 10, C. on Unreliable Cement Slurry Mixtures—Same update as above no.1 and much more predictable and reliable cement slurries are available today including those designed to prevent annular flows.

3) Page 11, no.2 a.—Research on gas control cement properties in long columns of cement has been performed and reported in several studies cited herein. Laboratory tests to predict these properties and design gas control cements have been developed from these studies. Field cementing practices and materials have also been substantially improved by these studies.

4) Pages 19 to 20—SPE paper 8255 was cited as having good practices to design cementing compositions and field cementing practices. The above mentioned studies, many of which are described herein API Std 65—Part 2, have proven that the following cementing compositions and field cementing practices advised in SPE 8255 are not always technically valid. This uncertainty should be considered accordingly:

   a) Limiting the reduction in loss of unset-cement column hydrostatic pressure to no more than the cement mixwater density gradient and enhancing this gradient by additions of salt to the cement and/or cement mixwater is not valid (see A.13) based on downhole pressure sensor measurements by Cooke et al [24,25] and others that show gradients can decrease below the cement mixwater density gradient.

   b) Applying pump pressure to the annulus during WOC to replace some or all of the loss of unset cement column hydrostatic pressure is not reliable in some cases (see A.13) based on downhole sensor measurements by Cooke et al [24,25] showing surface applied pressures that fail to reach the downhole pressure sensors.

Cement permeability was also evaluated as a potential factor in gas migration incidents by various investigators in the period from 1960 to the early 1980's. Cement permeability is a concern, but risks due to permeability can be mitigated by the use of additives. These slurries formed hard set, very low permeability cements which resisted adverse downhole conditions. Example cement slurries, lab tested under downhole conditions, have properties such as low fluid loss, no free fluid, no-settling, and short transition times for SGS development. Other design methods and associated additives are well known to those skilled in the art. Sutton, Sabins and Faul [26] in 1984 reported that maximum cement permeability of 12 mD found in several test measurements that could be substantially reduced by adding polymer type fluid loss control additives. Even without these additives, the reported 12 mD cement permeability calculates, with Darcy's equation, a migration time period that is too long vs those encountered in field operations. This case can be explained by calculating migration travel times.

The total travel time period (at 0.038 in./hr) for gas to migrate thru cement with high (12 mD) permeability in a 2000 ft long, annular cement column (p.3 of Sutton, Sabins and Faul [26] article) is calculated as follows:

(2000 linear ft × 12 in./ft) ÷ 0.038 in./hr = 24,000 in. ÷ 0.038in./hr = 631,579 hours for gas to displace the cement's uncombined or free water in the pore throats of the cement's matrix permeability (12 mD).

631,579 hours ÷ (24 hr/day × 365 days/yr) = 631,579 hr ÷ 8760 hr/yr = 72.1 years total time period for gas migration through 2000 linear ft of 12 mD cement.

The above 72 year gas migration time period removes cement permeability as a factor or cause for many gas migration occurrences. MMS statistics on well ages for SCP initiation (see graph in A.15) show that the vast majority of cases occur in less than 10 years instead of several decades like the 72 year example calculation above.

When cements contain materials that resist unfavorable downhole conditions and allow very low permeabilities to be achieved, gas migration travel time periods calculated with fractions of a millidarcy (mD) may be several hundreds or thousands of years depending on cement column lengths and differential pressures. Calculation of time to flow through permeability does not eliminate permeability as a concern, especially as permeability may act in concert with other wellbore or cement performance factors, such as communication with channels, high permeability pathways, etc. Additionally, filtrate water does not have to flow all the way to the surface; it can flow into shallow or shallower formations. Other factors may restrict annular gas flow and increase gas migration travel times such as a sealed and fluid filled annulus above the TOC that does not provide a vent for the cement filtrate water pushed out of the cement top by gas migration.

A.4 Barrier Failure Study

A study of LWC incidents in U.S. areas of the Gulf of Mexico OCS and some of the coastal states from 1960 to 1996 is reported in SPE/IADC 39354 by Skalle and Podio [27]. The many types of barrier element failures listed below in Table A.1 (from Table 6 of SPE/IADC 39354) may be prevented with the updated and proven practices described within this API publication. Note the higher total of failures for mechanical vs cement types of barrier elements.

Table A.1—Most frequent Primary and Secondary Barriers that Failed in all Phases (Louisiana + Tx + OCS; 1960 to 1996)

Primary Barrier	BO	Secondary Barrier	BO
Swabbing	158	Failed to close BOP	78
Too low drilling fluid weight	50	Rams not seated	14
Drilling break/unexpectedly high pressure	45	Unloaded too quickly	13
Formation breakdown/lost circulation	43	DC/Kelly/TJ/WL in BOP	5
Wellhead failure	40	BOP failed after closure	66
Trapped/expanding gas	40	BOP not in place	43
Gas cut drilling fluid	33	Fracture at casing shoe	38
Christmas tree failure	23	Failed at stab valve/Kelly/TIW	34
While cement setting	20	Casing leakage	23
Unknown why	19	Diverter—no problem	21
Poor cement	16	String safety valve failed	19
Tubing leak	15	Diverter failed after closures	17
Improper fill up	13	Formation breakdown/ lost circulation	15
Tubing burst	10	String failure	13
Tubing plug failure	9	Casing valve failed	11
Packer leakage	6	Wellhead seal failed	10
Annular losses	6	Failed to operate diverter	7
Uncertain reservoir depth/ pressure	6	Christmas tree failed	7

The high number of BOP failures, such as the “BOP not in place” and other types of BOP failures, was a key focus area for the API Work Group and is addressed accordingly within 3.7. For example, MMS regulation 30 *CFR* 250.422 (b) requires that if the operator plans to nipple down the diverter or BOP stack during the 8-hour or 12-hour WOC time period, the operator should determine when it will be “safe” to do so. The decision should be based on the operator’s knowledge of the formation, cement composition, effects of nippling down, potential drilling hazards, well conditions, and past experience. Even though this regulation is currently in force, the API Work Group determined that more specific guidance (see 3.7) is needed since well control incidents, with this category (BOP failures) involved, are still occurring.

A.5 Studies of Annular Flows in the United Kingdom

Hinton [28] with the Offshore Safety Division of United Kingdom’s Heath and Safety Executive reported in SPE 56921 that 11 % of all wells drilled in the U.K. continental shelf from 1988 to 1998 have experienced reportable kicks during well construction operations. Of these 22 % were in HPHT wells (>10,000 psi and 300 °F). Other U.K. sources cited by Gao et al [29] in SPE 50581 claim that HPHT wells have much higher reportable kick incident rates (1 to 2 kicks per 1 well) compared to non-HPHT wells (1 kick per 20 to 25 wells). Some of the most frequent causes of kicks in drilling U.K. wells were also found in the U.S. wells such as lost circulation in the same hole section with potential flow zones, drilling fluid weight too low, and uncertainty in flow zone existence, flow potential, location, or other important characteristics.

The following quote (SPE 56921, p.3, 1st paragraph) on other types of barrier failures during casing installation operations is significant. “Exactly half the kicks associated with casing operations occurred when liner overlaps or casing shoes leaked when drilling fluid weight was reduced.” The liner overlap failures mentioned in SPE 56921 included one case history of a well with a 7,500 psi shut in drill pipe pressure caused by a leaking liner top packer. These two types of barrier failures (liner overlaps and casing shoes) present opportunities to help prevent future incidents by implementing the updated guidance on proven practices contained herein.

A.6 Studies of Annular Flows in Canada

Gas migration is reported by the Canadian government authorities to exist in many wells in Canada. A recent article by Lang [30] reported on annular flows in Canada’s shallow to moderate depth wells in the areas of Alberta and Saskatchewan “historically have had problems with gas migration developed leaks after primary cementing in 57 % of the cases, on average.” In 2003, Getzlaf and Watson [31] stated that a database that registers gas migration in Alberta “currently has over 5000 recorded vent flows, some serious, but most recorded as non-serious.” A vent flow is the local name for an annular gas flow.

In the time period from April 1998 to March 1999, the Alberta Energy and Utilities Board [32] cites the following LWC statistics for 7094 new wells drilled and included in the new total of over 129,000 active wells.

Table A.2—Drilling and Service Well Control Occurrences, 1998/1999

	Drilling	Servicing
Blowouts	9	1
Blows	1	
Kicks	101	N/A

The latest AEUB [33] report posted on their website is for 17,108 new wells drilled in 2003.

Table A.3—Drilling and Service Well Control Occurrences, 2003

	Drilling	Servicing
Blowouts	1	4
Blows	3	7
Kicks	106	N/A

The 2003 statistics compared to those in 1998 and earlier periods continues the favorable trend in recent years showing substantial decreases in the occurrence of blowouts (also called LWC) and kick incidents (a type of annular flow) during the drilling of new wells.

The AEUB [32] reported gas migration and surface casing vent flows (also called casing pressure) of gas as follows in Table A.4 and Table A.5.

Table A.4—Surface Casing Vent Flows

Year	Serious	Non-serious	Total
1995	393	3121	3514
1996	75	3103	3178
1997/1998	76	3537	3613
1998/1999	139	3671	3810

Table A.5—Gas Migration Problems

Year	Serious	Non-serious	Total
1995	4	596	600
1996	6	809	815
1997/1998	6	801	807
1998/1999	1	813	814

Of the 7667 wells that applied packers to maintain well integrity, relatively low numbers of leaking packers were identified in the mandatory packer isolation testing and reporting program [32] as follows in Table A.6.

Table A.6—Packer Isolation Testing and Reporting Program Results

Year	Notice of suspension letters issued		Closure orders issued		Repeat companies for closures	Abandonment orders issued	
	Companies (no.)	Wells (no.)	Companies (no.)	Wells (no.)	Companies (no.)	Companies (no.)	Wells (no.)
1995	N/A	N/A	51	172	N/A	20	34
1996	N/A	N/A	137	446	24	11	
1997/1998	90	180	15	23	3	1	1
1998/1999	128	443	22	34	6	2	2

A.7 Studies of Annular Flows in Russia

A study by Krylov [34] reports an analysis of data on monitoring annulus pressures (AP) of wells at the Karachaganak gas condensate field. Development drilling began in 1985. The analysis showed that AP is found in wells regardless of their category—operating or shut-in. The percentage ratio of wells with AP to the total stock was calculated for both well categories for the purpose of studying the dynamics of wells with AP. The data show an increase of the percentage of operating and shut-in wells with AP from 45 % and 1 % in 1993 to 56 % and 33 % in 2000, respectively. Assumptions about the causes for the increase of wells with AP are given in the study report.

A.8 LWC Insurance Database Studies

Studies by Adams [35], Adams and Young [36], and Jackson [37] (Willis Ltd.) provide information that helps explain some of the causes, cause effects, and costs of LWC incidents. Adams states that "about 65 % of all blowouts are UGBOs (underground blowouts)." and "Flows originating behind casing after cementing are perhaps the second most common UGBO cause." Adams and Young report the following.

— "UGBOs occur about 1.5 to 2 times more frequently than surface blowouts. Cumulative costs are believed to far exceed that for surface blowouts."

— "A common flowpath is a poorly cemented casing-openhole annulus."

— "The danger associated with this flowpath (poorly cemented annulus) is the circumvention of the primary well-control hydraulic system of the hole, casing and BOPs."

Adams and Young cited Willis Energy Loss Database [37] analytical reports for the costs of 1,224 LWC incidents all with financial loss claims greater than one million U.S. dollars. The well loss incidents include blowouts (~90 % of total), mechanical failure, stuck drill pipe, fire/lighting/explosion, heavy weather, design/workmanship, collisions and others.

Table A.7 from Adams and Young's *World Oil* article [36] shows LWC incident costs by the status of the wells. OEE in the table means operator's extra expense. The intent of the table is to identify where more focus should be placed relative to blowout prevention measures in the future. Drilling operations (includes cementing) has the highest number of incidents at 668 out of the total of 1,224.

Table A.7—Well Status at Time of the Incident

Status of well	Incidents	OEE actual US$	Average OEE actual US$
Abandoned	3	45,383,105	15,127,702
Completion	17	106,722,607	6,277,800
Drilling	668	4,396,562,496	6,581,680
Plugging	3	11,165,400	3,721,800
Producing	82	1,045,737,073	12,752,891
Shut In	14	134,887,062	9,634,790
Workover	42	319,808,465	7,614,487
(Unknown)	393	2,029,815,203	5,164,924
Other	2	8,100,000	4,050,000
Total	**1224**	**8,098,181,411**	**6,616,161**

More LWC incidents are caused by natural gas formations based on the data shown in Adams and Young's [36] Table A.8. The type of blowout fluid was not known for the 500 incidents listed under unclassified well types. This is often the case for underground blowouts.

Table A.8—Blowouts by Well Type

Well type	Incidents	OEE actual US$	Average OEE actual US$
Gas	536	3,732,864,691	6,964,300
Oil	86	560,968,996	6,522,895
Oil & gas	86	1,069,809,755	12,439,648
Sulphur	3	14,443,297	4,814,432
Sulphur	1	3,330,000	3,330,000
Water	9	39,643,956	4,404,884
Other	3	23,100,000	7,700,000
Unclassified	500	2,654,020,716	5,308,041
Total	**1,224**	**8,098,181,411**	**6,616,161**

The highest frequency of LWC incidents occurred in wells between 7500 ft. and 14,999 ft. deep according to the data that Adams and Young [36] present in Table A.9.

Table A.9—Blowouts by Depth Category

Depth (ft)	Incidents	Total actual OEE US$
0 to 4,999	95	795,786,456
5,000 to 7,499	69	558,347,594
7,500 to 9,999	126	567,598,068
10,000 to 14,999	345	1,555,519,961
15,000 to 19,999	183	1,838,981,875
20,000+	28	397,994,687
Unclassified	378	2,382,952,770
Total	**1224**	**8,098,181,411**

Discussions in April 2006 with Andrew Jackson at Willis Limited provided an updated well population in the Willis Energy Loss Database, i.e. includes 1381 well loss incident claims of which 1237 wells are LWC incidents or blowouts (501 underground blowouts, 308 surface blowouts, and 428 unknown). Jackson said that certain types of data needed to pin-point the root cause of incidents are not captured in the database and may only be available from the well owner/operator and/or the insurance claims adjuster for the specific case.

A.9 Summary of API 65 Work Group's Study of 14 LWC Incidents

In API 65 Work Group [3] meetings, annular flow statistics on offshore wells in U.S. federal waters were presented including MMS records on the occurrence of SCP and on 34 LWC incidents that occurred during drilling operations and reported in the years 1992 through 2002. Of the 34 LWC incidents, 19 (56 %) were caused by annular flows associated with the cementing process.

The API Work Group [3] studied 14 of the 19 LWC incidents linked to cementing that occurred from 1996 to 2001 on the U.S. outer continental shelf (OCS), i.e. annular flow events during or after cementing operations. Conclusions of the study of the 14 incidents are listed below.

1) Most of the LWC incidents studied took place during or just after cementing surface casing.

2) In more recent years (2003 to 2004), these events involved deep casing strings with no occurrence of LWC incidents in surface casing cementing operations.

3) Most wells used a mudline hanger/suspension system.

4) Frequently the annulus between surface and conductor casings at the surface was washed out to a point 30 ft to 50 ft below the mudline after cementing. Washing out this annulus resulted in a small but possibly very significant reduction in hydrostatic pressure while also impairing the operation of the BOP and diverter (wash pipes in the annulus prevents sealing).

5) Often, cement slurries were not designed to prevent flows.

6) Effective drilling fluid removal and zonal isolation practices were not followed.

The study included reviews of detailed information on the incidents including "lessons learned" presentations by many of the operators involved. Public documents were available for some of the incidents that reported causes and proposed preventive measures. The studied incident information and the membership's knowledge of annular flow events in other areas allowed the Work Group to prepare proven practices contained herein to help prevent future annular flow incidents and also help reduce the occurrence of SCP.

A.10 Lost Circulation Increases Risk for LWC Incidents

Lost circulation before, during, or just after primary cementing.

a) Can cause a failure to maintain an overbalance across potential flow zones exposed in the wellbore whereby:

   1) an inadequately designed cement slurry (density too heavy, etc.) fails to reach the designed depth for the TOC column;

   2) or the drilling fluid column is reduced or "falls back" or "goes on vacuum;"

   3) and either one of these shortened columns results in an insufficient hydrostatic head pressure to overbalance formation(s) pore pressures.

b) Has often been found by investigators as the root cause for many of the LWC incidents experienced in offshore drilling operations.

c) Can induce LWC incidents at any depth in the well construction process from soon after "spudding" (starting to drill) the well to drilling the well at total depth when conditions occur such as:

   1) structurally weak zones are exposed in the wellbore;

   2) naturally occurring leak off flow paths are encountered such as fractures, faults, vugs, caverns, etc.

As mentioned above, lost circulation during primary cementing operations may cause reduced hydrostatic pressure and underbalanced conditions when losses cause the drilling fluid column to fall to create an underbalance. For example when heavier density (than the drilling fluid) cement slurries are removed from the annulus by total or partial lost circulation (cement flows into weak zones), the TOC can be much lower than the designed top of cement depth.

This substantially decreases the annular column hydrostatic pressure across potential flow zones within the cemented annulus. This decreased hydrostatic pressure allows formation fluids to influx into the wellbore which starts annular flows that can lead to LWC incidents.

Another way for lost circulation during cementing operations to lead to LWC incidents is when the actual TOC does not reach the planned depth to cover potential flow zones and, instead, places drilling fluid across these formations. If the drilling fluid hydrostatic pressure is below the formation's pore pressure, annular flows may start immediately. If the drilling fluid hydrostatic pressure is above the formation's pore pressure, an annular flow may not start until drilling fluid gellation (also called SGS development), solids settling, etc. decreases the hydrostatic pressure enough to create an underbalanced pressure condition. See A.14, 4) for more information on this phenomenon.

Cement channeling may cause total or partial lost circulation during primary cementing by initially raising the cement column to longer than planned heights (shallower depths) which results in pressures greater than fracture initiation/ propagation pressures. Relevant formations exposed to these pressures then "breakdown" or fracture and start taking volumes of the cement slurry out of the annulus. When this occurs, the annular fluid level drops (called "fallback" or the annular fluid flow rate out of the well decreases to less than the rate pumped into the well. In either case, the risk of an LWC incident increases when these losses result in underbalanced pressure conditions across potential flow zones. Applying adequate measures to prevent cement channeling and associated losses are described herein including methods to optimize drilling fluid and cuttings removal/displacement by operational procedures and cementing job designs such as measuring drilling fluid conditioning and hole cleaning performance with fluid calipers (see 5.2), pipe movement, installing centralizers, and pumping relevant cement flushes and spacers at engineered rates.

An API cementing book [38] published in 1991 includes data (see Table A.10) indicating that up to 45 % of all wells require an intermediate casing to prevent severe lost circulation while drilling to total depth (TD). With these extra pipe strings in well designs, lost circulation events still occurred in 18 % to 26 % of all hole sections. Some areas reported many more occurrences of lost circulation events ranging from 40 % to 80 % of wells. In recent years, these percentages have likely increased as the number of shallow, easy-to-find reservoirs has steadily declined and well operators have intensified their search for deeper reservoirs and drilled through depleted or partially depleted formations. Conventional LCM including pills, squeezes, and pre-treatments, and drilling procedures such as ECD management often reach their limit in effectiveness and become unsuccessful in the deeper hole conditions where some formations are depleted, structurally weak, or naturally fractured and faulted.

In some cases, operators perform FIT or LOT measurements after the initial casing shoe test while drilling critical hole intervals or after drilling the entire hole section. This practice helps confirm that lost circulation can be prevented by the integrity of the open hole to contain pressures generated from deeper drilling and/or from operations to set casing/ liner pipes (higher ECD in running pipe and primary cementing). Successful cases over the last 50 years have proven that this practice can successfully predict cementing placement without losses. In other cases when cement losses are predicted by the hole section FIT or LOT, the operator may decide to apply alternative measures such as LCM pills, tack and squeeze, etc. Some technical papers describe these practices including the lessons learned procedure reported by Rederon et al [39] in SPE 149 (p. 5, rt. Column, step no.1) published in the late 1950's.

Table A.10—1991 API Survey Data on Lost Circulation

	United States	North America	Global
Producing fields in survey	204	218	339
Wells needing intermediate casing and/or drilling liner	31 %	33 %	45 %
	Lost Circulation Encountered		
Surface casing	24 %	24 %	21 %
Intermediate casing	24 %	25 %	23 %
Production casing	24 %	24 %	24 %
Liners	18 %	26 %	19 %

A.11 Example LWC Incident Case After Primary Cementing Operations

A drilling rig had completed cementing surface casing. Shortly after the surface/conductor casing annulus was washed out, the annulus began flowing. Rather than release the flow into the diverter system, the crew attempted use the diverter to hold pressure to allow time for the cement to heal. To hold pressure, the diverter was placed in the "test" mode, which allowed both the diverter packer element and vent-line valves to be closed simultaneously and immediately.

The diverter in use featured a telescopic riser with seals bracketing the vent-line housing. When the diverter was closed, the pressure rapidly increased until the seals began leaking, forcing abandonment of the rig floor. It was then discovered that the "test" mode disabled the ability to control the diverter system from the remote location. Seal pressure could not be increased to contain the surface leak; the diverter valves could not be opened to relieve the pressure. With gas on the rig and pressure rising on the untested conductor casing shoe, the rig and adjacent platform were evacuated.

Several factors contributed to the potential severity of the event, including an erroneous chain of decisions, inadequate training of personnel, minimal knowledge of diverter system, and poor planning.

There were 20 diverter incidents in the Gulf of Mexico from 1973 to 1995 related to well kicks after cementing surface casing. Another 13 similar incidents have occurred since 1995, with the most serious consequences being gas broaching to the surface, cratering, well loss, and rig and platform destruction by fire. Annular flow related to cementing surface casing has been identified as one of the most frequent causes of loss of control incidents in the Gulf of Mexico. Additional examples of such well control incidents can be found at http://www.mms.gov/incidents/blowouts.htm.

A.12 General Review of Key Technologies

Achieving zonal isolation in the presence of a potential annular flow requires not only the modification of the cement properties to facilitate control of migrating formation fluids but also several other features including:

— a stable wellbore—no losses or gains,

— adequate annular circulating flow clearances,

— proper drilling fluid conditioning and hole cleaning prior to cementing,

— spacer design,

— casing centralization,

— proper fluid dynamics during circulation and placement of cement to achieve drilling fluid removal,

— tripping requirements,

— drilling techniques,

— well monitoring,

— proper WOC time and associated rig operations,

— sustained hydrostatic pressure during cement curing,

— no wash pipes in the annulus that negates BOP function,

— use of mechanical barriers when appropriate.

This document is a compilation of best practices, engineering considerations and cement property requirements to assist in the prevention of annular flows and to establish zonal isolation within the wellbore. This task entails, at its most fundamental level, the removal of drilling fluid from the wellbore and replacement of drilling fluid with cement capable of achieving and maintaining annular isolation.

During the API Work Group's study and draft RP preparation process, the relevant technology and practices contained herein generated prolonged discussions and comprehensive work in writing the relevant text in this and other parts of API Std 65—Part 2. Numerous literature searches were conducted to find, discuss, and cite the information that helps document whether or not a practice is field proven, technically valid, and reliable in preventing annular flows.

A.13 Loss of Hydrostatic Pressure After Cement Placement

The failure of an annular cement column to control and isolate zones exposed in the wellbore is the root cause for many of the LWC incidents experienced in offshore drilling operations. LWC incidents can occur at any point in the well construction process from soon after spudding the well to drilling the well at total depth.

A number of factors are common to LWC incidents experienced while drilling the top-hole sections. From a pressure maintenance standpoint, many wells are drilled in a near-balanced condition. Often only a minimal pressure margin exists between formation pore pressure and circulating hydrostatic pressure of the drilling fluid. Typically, the well is drilled with simple spud muds with minimal fluid loss control. The cement designs employ lightweight, extended lead cement systems with a tail cement of higher density placed in the lower section of the cemented interval. In common practice, both lead and tail cement slurries are designed without any gas control capabilities. Further, certain lightweight and other cement systems are prone to gel before setting, thereby causing and accelerating the loss of hydrostatic pressure exerted on the column of tail cement below. A detailed discussion of this phenomenon is included in A.13 and A.14 where the "loss of hydrostatic pressure" effect can be caused by pre-mature gellation, also called early static gel strength development of the "critical gel strength period" (see 5.7.8) [18].

Annular flows have been caused by hydrostatic pressure losses that occur before the cement cures into a hard, impermeable barrier. This has happened in both top-hole sections and bottom-hole sections of the well. Several factors or combinations may cause annular flows in the deeper sections of the well including the cementing process, cement design, and the immediate setting of mechanical barriers that can reduce hydrostatic pressures.

While mechanical barriers are designed to prevent the flow of annular fluids past the barrier element or seal, setting of the barrier may actually increase the chance of gas entering the cement slurry. This is because setting the barrier isolates all potential flow zones below the barrier from all of the hydrostatic pressure above the barrier. This reduction in OBP on any potential flow zones effectively decreases the CSGS as defined in 5.7.8. The pressure in the annulus therefore drops to the pore pressure of the flow zones at an earlier time after the cement is in place, increasing the window of opportunity for gas to enter the cement slurry. Because of this increased chance of gas entering the cement, it is very important that the slurry placed across potential flow zones is designed with gas migration control properties (see 5.7.13). Properly designed cement slurries should be used to help prevent the gas from migrating through the annulus once it has entered the cement. If migration is not controlled there is potential for either a cross-flow into a lower pressure zone or the collection of a gas pocket directly below the mechanical barrier.

In other cases (no mechanical barrier), annular hydrostatic pressure losses may fall below permeable formation pore pressures resulting in underbalanced conditions that cause higher pressure formation liquids and gases to flow into the cemented annulus. This can lead to annular flows of formation liquids and gases which may induce cross-flows into permeable formations with lower pore pressures, paths that flow up to the wellhead, or a combination of both.

Cooke et al [24,25] investigated the loss of hydrostatic pressure in columns of drilling fluid and cement slurries and reported the results in SPE papers 11206 and 11416 and in JPT articles dated August 1983 and December 1984. Cooke studied hydrostatic pressure losses by measuring annular pressures vs time at various depths with sensors installed on the casing and hard wired to surface recorders. Measurements were recorded prior to, during, and after primary cementing operations in several wells. Measurements were recorded for several months in some wells that showed long term reductions in drilling fluid column hydrostatic pressures.

Cooke's study [24,25] discovered fundamental mechanisms and explanations supporting some theories on loss of hydrostatic pressure and invalidating others. These discoveries were verified by others such as a similar separate downhole sensor study (SPE 19552) by Morgan [40] while running and cementing casing in the North Sea. Morgan also reported how these downhole measurements indicated the failure to set an ECP.

An analysis of downhole annular pressure measurements can explain other difficult to find or complex root causes for other cause effects such as high ECD pressures when cementing liners. Brehme et al [41] et al found that downhole pressure sensor measurements are a reliable method to help diagnose and evaluate liner running and liner cementing operations. Cementing simulation computer model results were favorably compared to the actual downhole pressures. Brehme et al [41] proposed this process to help predict and evaluate results in future cementing operations by downhole gauge diagnosis of conditions not included in software models such as annular restrictions by cuttings, hole cleaning performance, and liner hanger equipment functions. For example, this data can help operators find answers for some annular flows linked to lost circulation events such as those caused by complete or partial flow restrictions in liner overlaps or liner hanger bypass or cross-sectional areas plugged by cuttings not removed during hole cleaning operations.

A.14 Some Key Results from Cooke's Study [24,25]

Some of the key results from Cooke's study [24,25] are as follows.

1) Downhole sensor measurements proved that the loss of hydrostatic pressure in columns of unset cement may be reduced to values below those found in cement mixwater (fresh, sea or saltwater) density gradients [see A.3, no.4.a)]. See Figure A.2 (Figure 9 in SPE 11206) showing that the cement hydrostatic head from the sensor at 1900 ft. in well G decreased from 13.4 lb/gal to 2.5 lb/gal equivalent density in ca. 420 minutes. This measurement is 6.0 lb/gal equivalent density below the average seawater gradient of 8.5 ppge. Cooke concluded that SGS development caused the cement hydrostatic head to regress to 2.5 ppge based on hole conditions such as formations with little or no permeability across and above the sensor at 1900 ft. This invalidates the idea claimed in SPE 8255 [42] that the loss of hydrostatic head in the cement column never falls below the cement's mixwater density gradient. It also invalidates the associated practice [38] of adding salt in cement slurries to increase the gradient and reduce the loss of hydrostatic head.

2) Surface pressure applied to the annulus may not reach the desired depth depending on drilling fluid and cement properties such as gel strength development (A.3, no.4.b. and 5.7.8). See Figure A.3 (Figure 4 in SPE 11206) that illustrates the lack of pressure response in 3 sensors at 4430 ft, 5454 ft, and 7412 ft in well B when surface pressure is applied. Also notice the large amount of pressure applied after 2100 minutes was high enough to break the cement SGS and allow hydrostatic pressure to be measured at 2 of the 3 sensors. Figure A.3 (Figure 2 in SPE 11206) also shows no pressure response from all sensors in well A by the applications of surface pressure designed to test the validity of said practice described in SPE 8255 [42]. The surface pressure was applied 24 minutes after the cement job ended. This uncertainty in transmitting hydrostatic pressure through unset cement slurry at various times during a cement's curing phase makes it unreliable to carry out the practice of applying and maintaining an annular surface pressure to compensate for hydrostatic head pressure losses as claimed in SPE 8255[42]. Therefore, applying surface pressure by pumping into the top of the annulus should be considered only for well control purposes such as controlling a kick in the annulus. However, in some recent cases applying small amounts of surface pressure in the form of controlled pressure pulses has worked in some wells to help prevent annular flows when the entire process, including the cement system, is properly engineered, understood by all involved, and validated by relevant means such as the lab testing described in 5.7.8.

3) Prior to Cooke's study [24,25] our industry did not have relevant field data to fully understand and confirm the theoretical mechanisms accounting for the rapid losses of designed overbalances after cementing jobs. Cooke's measurement of this rapid decrease in cement column hydrostatic pressures to underbalanced conditions across potential flow zones helped explain the cause of many LWC incidents. It also helped explain how other annular flows such as cross-flows and underground blowouts were initiated. The understanding of how SCP may initiate via different types of annular pathways was also improved. Figure A.4 (Figure 2 in SPE11206) presents annular pressure and temperature measurements in well A that illustrate how the hydrostatic head

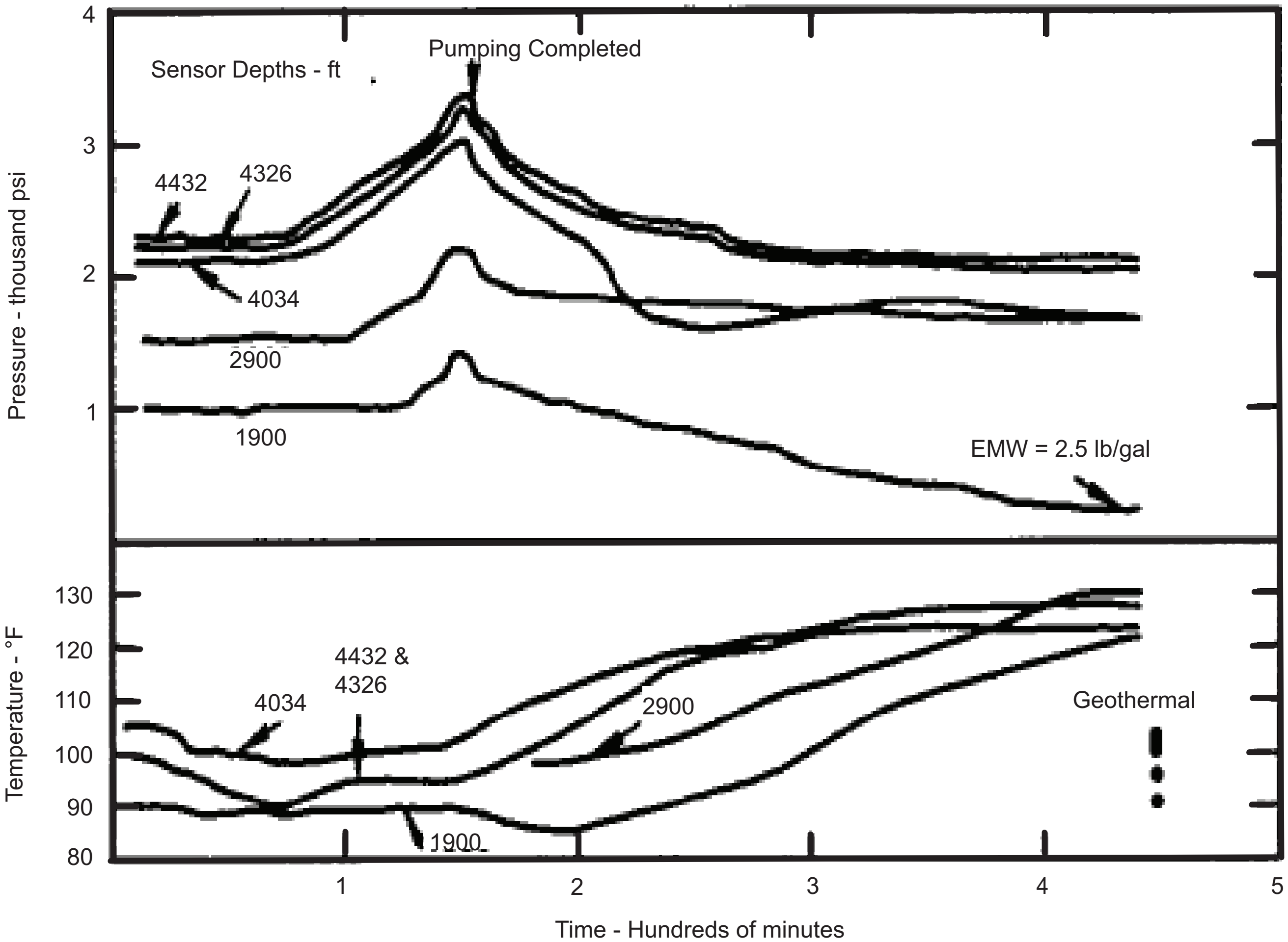

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Figure A.2—Annular Pressure and Temperature—Well G

decreased vs time. Note that the hydrostatic head loss in all sensors started immediately after pumping of the cement slurry ended and the temperature at each sensor indicated that the cement was not set until inflection points in each temperature curve was recorded. These inflection points represent the principal exotherm of the cement that occurs when the cement achieves initial set. In 1983 all the information from Cooke's study was an industry revelation that helped accelerate the implementation of cement practices and materials that were already developed to help control annular flows. It also helped R&D funding by various companies for even better solutions.

4) Many other interesting facts and data analysis results are presented in SPE 11206 and the follow-up paper SPE 11416. The latter one focused on temperature effects, lost circulation during cementing diagnostics, and the hydrostatic pressure decline in columns of "mud" or drilling fluids. Figure A.5 (Figure 7 in SPE 11416) indicates the drilling fluid hydrostatic pressure loss recorded by sensors above the TOC during many days after the cementing jobs in wells B and D.

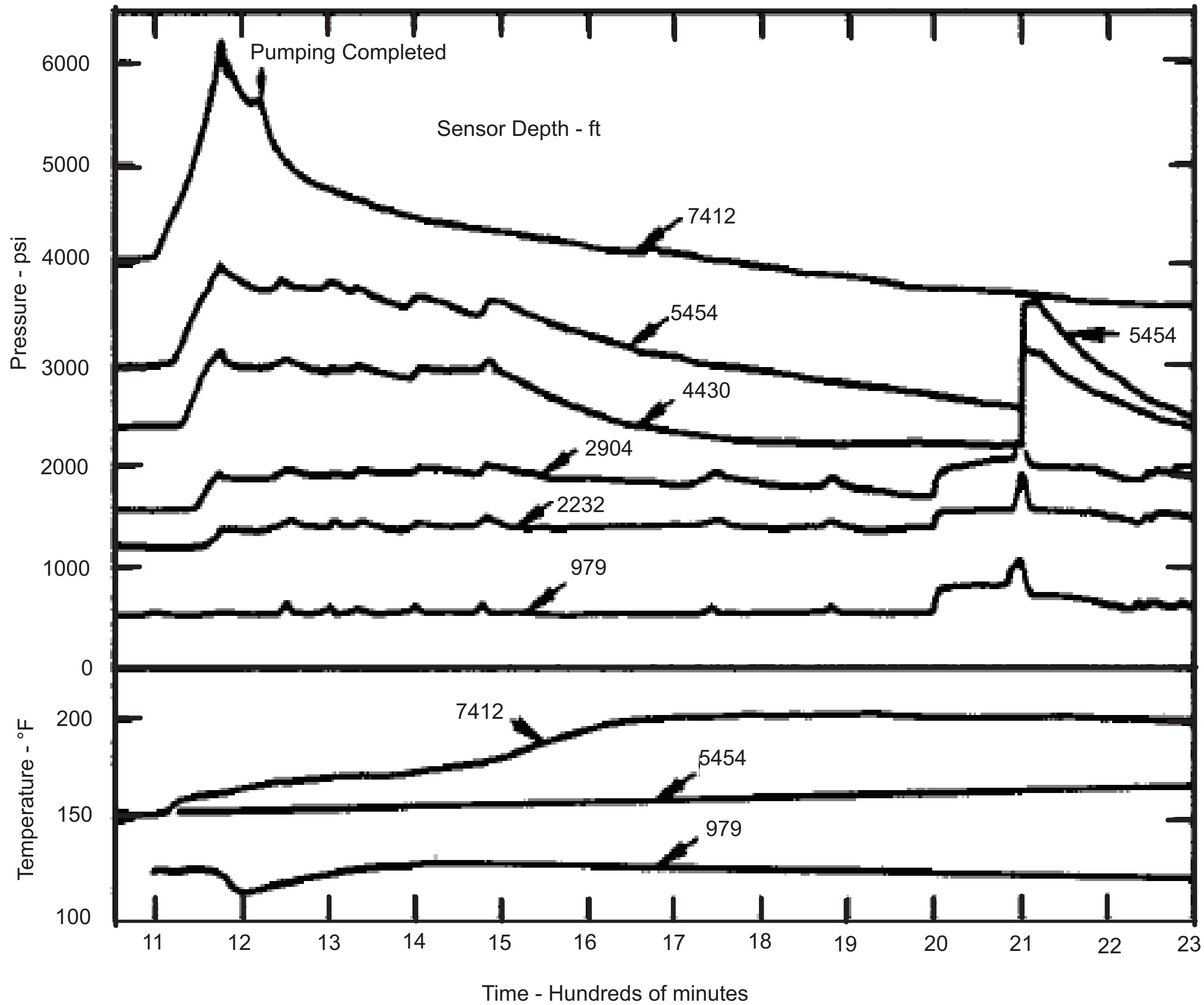

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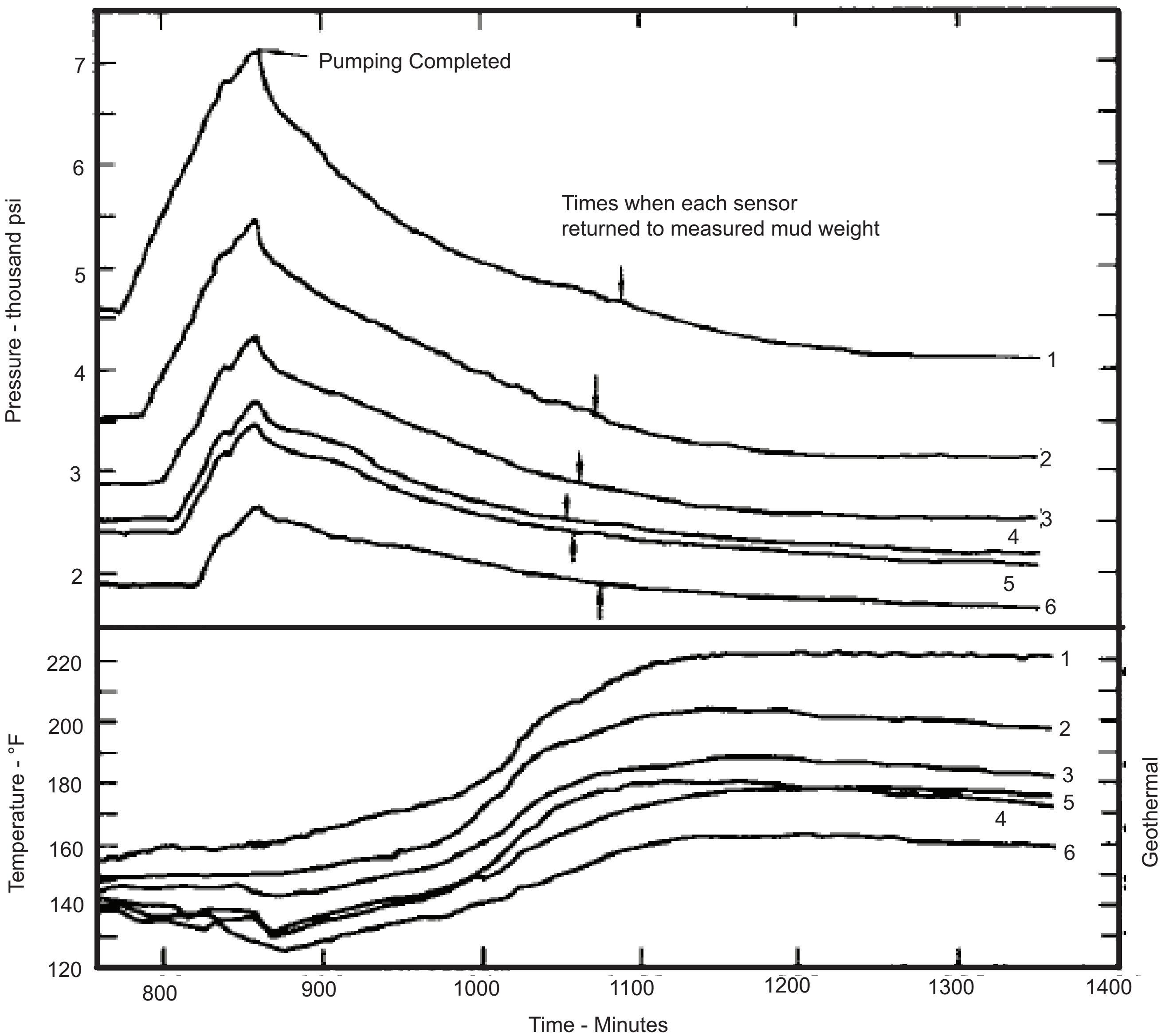
Figure A.3—Annular Pressure and Temperature—Well B

This unexpected loss of drilling fluid hydrostatic head has two major impacts on well design practices:

a) the "initial density of the drilling fluid in the annulus should not be used as the backup pressure in casing burst design,"

b) the drilling fluid hydrostatic pressure based on the original drilling fluid density should not be counted on to overbalance potential flow zones during the life of the well.

During the late 1980's, Cooke's study [24,25] was favorably peer reviewed by API's Subcommittee 10 on Cementing and recognized as one of industry's most important publications for the advancement of cementing technology. Accordingly, its significant findings and data measurements were published in API's book [38] on cementing practices in 1991.



Sensor No.	1	2	3	4	5	6
Depth (ft) (RKB)	8754	6909	5488	4787	4632	3636

Figure A.4—Annular Pressure and Temperature—Well A

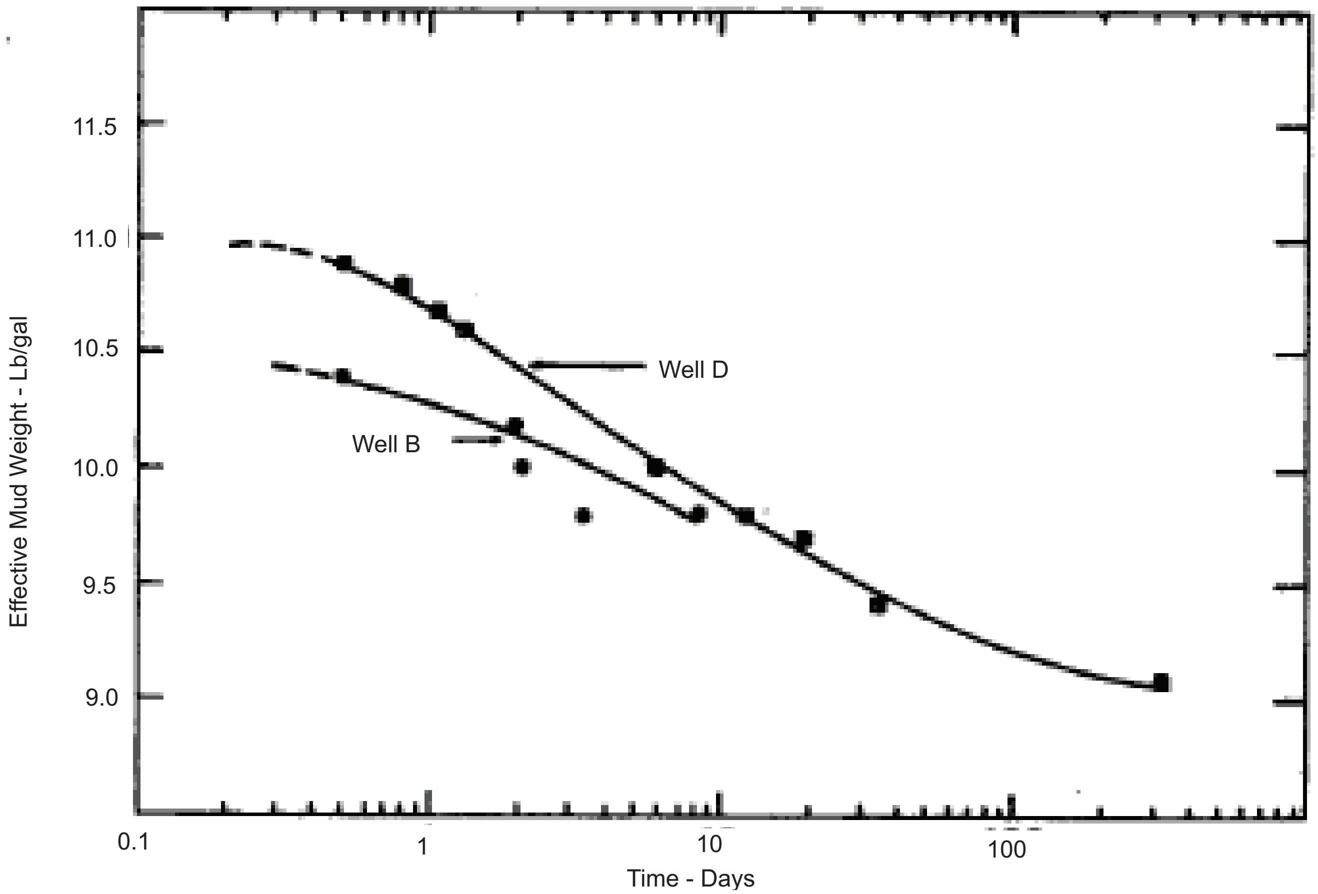


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Figure A.5—Mud Densities Measured By Pressure Sensors in Annulus

Annex B
(informative)

Well Planning and Drilling Plan Considerations

B.1 Evaluation of Well for Flow Potential

B.1.1 General

Before drilling a well, the operator should attempt to identify and analyze potential flow zones. A variety of techniques are available to do this, three of which are discussed below. The success of these techniques in identifying and successfully dealing with flow zones is related to the quality of the available data, a company's experience in a specific geographical area, and the capabilities of the personnel involved in the analysis.

B.1.2 Site Selection

Prior to drilling, the operator can minimize encounters with potential flow zones by carefully selecting a site that achieves target depth while minimizing the risk of encountering a flow. This is accomplished primarily through accurate review and analysis of available shallow and deep hazards data, proper interpretation of this information, and assimilation of this information into the drilling program.

Offset well information (when available) can be evaluated to determine if flow zones were encountered, the magnitude of any flow events, and the methods used to mitigate the effects of these flows. This information should be incorporated into the current drilling program.

API RP 65, Section 4, addresses site selection for minimizing shallow flows in deepwater wells. Many of the same principles apply to operations for all water depths and well depths and are discussed below in this Annex.

B.1.3 Shallow Hazards

Identification and evaluation of hazards through the use of shallow seismic surveys obtained over potential wellsites can aid the operator in proper site selection. If available, shallow seismic data from offset wells or adjacent fields where shallow flows occurred should be used to verify the analysis. If hazards are identified, the risk should be evaluated and mitigation measures taken as appropriate. The operator is cautioned that a shallow hazards analysis is not a conclusive method of prediction, so precautions to minimize the probability of a flow should still be implemented when drilling the shallow portions of the well. If the decision is made to drill a well in an area that is likely to encounter shallow hazards, drilling the shallow portions of the well with a small diameter pilot hole will make killing the well easier to achieve.

B.1.4 Deeper Hazards

Potential sources of deeper drilling hazards include abnormal pressure, pressure depleted zones, faults, tectonic stresses, salt flows, and lost circulation. Such hazards can often be identified through seismic interpretation and/or analysis of offset wells or fields. Identification of hazards that could be encountered during drilling operations will aid in proper well planning and in minimizing risk. If available, deep seismic data from offset wells or adjacent fields should also be analyzed to aid in the prediction of flow zones.

B.2 Planning the Well

B.2.1 Well Conditions

After evaluating the well for flow potential and determining the location that minimizes this potential, detailed well planning can begin. An optimum well plan for these conditions incorporates the following features, which are not all inclusive:

— an understanding of pore pressures, fracture gradients, and required drilling fluid densities;

— a casing plan that addresses limitations imposed by pore pressure, fracture gradient, wellbore stability, and other operational concerns;

— a cementing plan that provides for short- and long-term isolation of potential flow zones;

— evaluation of the impact of potential thermal pressure (APB) in subsea wells;

— selection of drilling fluid(s) that will best control wellbore pressures and enhance cementing success;

— a hydraulics plan that provides for adequate wellbore cleaning and control of static and dynamic wellbore pressures;

— a barrier design that provides for control of all pressures that may be encountered during the life of the well;

— a contingency plan that addresses wellbore instability and unintended gains and losses of fluids;

— adherence to regulations;

— a means to thoroughly and effectively communicate the plan to the personnel that will execute it.

B.2.2 Pore Pressure/Fracture Gradient/Drilling Fluid Weight

The well planner should understand and/or model the anticipated pore pressures, fracture gradients, and drilling fluid densities that will be encountered while drilling the well. Exploration wells will not provide the same level of certainty of pore and fracture gradients as will development wells. This information is generally presented in a graph, as shown in Figure B.1.

General guidelines for the construction of this graph are as follows.

— Plot the predicted pore pressure vs depth, expressed as an equivalent mud weight (EMW). It may also be helpful to note lithological information, if it is available.

— Similarly, plot the predicted fracture gradient (as an EMW) vs depth. Draw a design fracture gradient profile that is offset to the left of the predicted curve by a prescribed amount to roughly account for kick tolerance and the increased ECD during drilling and cementing operations. Typical offset values range from 0.2 ppg to 0.5 ppg.

— Draw the planned drilling fluid weight profile based on the pore pressure and fracture gradient data. In general, the drilling fluid weight profile is offset to the right of the pore pressure curve to provide sufficient overbalance for trips (i.e. a trip margin). Typical trip margin values range from 0.3 ppg to 0.5 ppg.

— Include planned casing diameters and setting depths to clarify wellbore construction features. If drilling fluid weight and LOT information is available from offset wells, include it on the graph for reference.

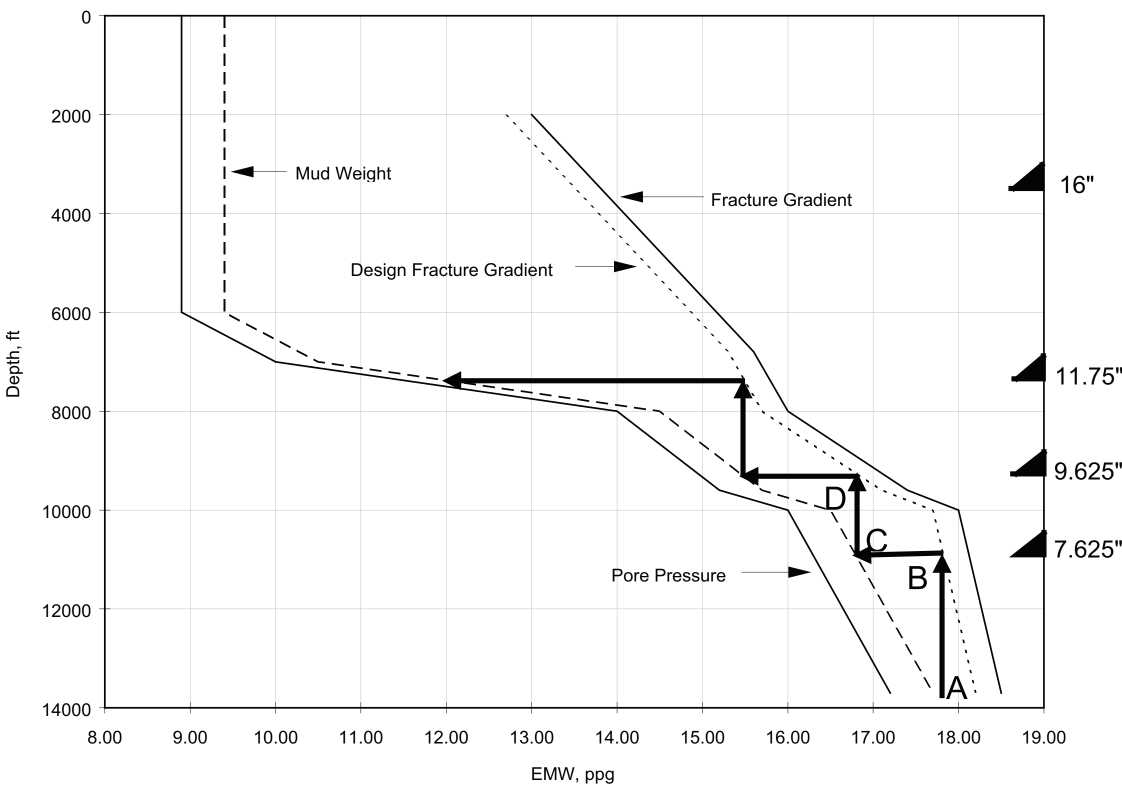

Figure B.1—Casing Shoe Depths with Pore Pressure/Fracture Gradient Graph

If large disparities exist between the offset well information and the predicted values, further investigation may be warranted. This graph will become the design basis for the well.

B.2.3 Casing Plan

The appropriate selection of shoe depths and consequently, the required number of strings is critical to the well design. General guidelines are given here for the selection of shoe depths. Local practices, regulatory requirements and experience should also be used to fine-tune this process.

Initial shoe depth determinations are made as follows (see Figure B.1).

— Starting at the drilling fluid weight at the well's TD (point A), draw a vertical line upwards until it intersects the design fracture gradient curve (point B). This is the approximate shoe depth of an intermediate casing.

— Draw a horizontal line from point B leftwards until it intersects the drilling fluid weight curve (point C) and then upward until it intersects the design fracture gradient curve (point D). This represents the approximate shoe depth of the next casing string.

— Repeat this process until all shoe depths dictated by drilling fluid weight and fracture gradient constraints have been established.

After the preliminary shoe depths have been established, an additional check should be made based on kick tolerance. The kick tolerance is the maximum size kick of a specified intensity that can be circulated out of the hole without causing the formation to fracture in the open hole section (often near the shoe). It may be necessary to adjust casing shoe depths to conform to kick tolerance limits.

In some higher pressure wells with a small margin between the drilling fluid weight and the fracture pressure, the recommended kick tolerance is nearly impossible to achieve. This is particularly true for many wells drilled in the Gulf of Mexico.

There are numerous other factors that affect the design of shoe depths. These factors include the following.

— Regulatory Requirements—Applicable local regulations should be obtained before beginning the design.

— Hole Stability—This can be a function of drilling fluid weight, deviation and stress at the wellbore wall, or it can be chemical. Hole stability problems often exhibit time-dependent behavior, making shoe selection a function of penetration rate. The plastic flowing behavior of salt zones should also be considered.

— Differential Sticking—The probability of becoming differentially stuck increases with increasing differential pressure between the wellbore and formation, increasing permeability of the formation, and increasing fluid loss of the drilling fluid (i.e. thicker drilling fluid cake).

— Shallow Zones with Potential for Flow—Any potential flow zone should be isolated.

— Zonal Isolation—Shallow fresh water sands need to be isolated to prevent contamination. Lost circulation zones should be isolated before a higher-pressure formation is penetrated to avoid downhole cross flow.

— Directional Drilling Concerns—A casing string is often run after an angle-building section has been drilled. This avoids drillstring key seating problems in the curved portion of the wellbore due to the increased normal force between the wall and the drill pipe while drilling deeper sections of the well.

— Uncertainty in Predicted Formation Properties—Exploration wells often require additional strings to compensate for the uncertainty in the pore pressure and fracture gradient predictions.

— Hole and Pipe Diameters—The selection of pipe diameters has the largest impact on well costs in both design base and detailed casing design. In general, hole and pipe diameters should be designed to be the smallest possible, which meet all design requirements, well objectives, safety, and environmental requirements. In exploratory wells, hole diameters may be larger to allow for contingency casing string(s). The final hole or casing diameter is generally determined by evaluation, completion, and production requirements. Because of this, casing sizes should be determined from the inside outward.

Hole and casing diameters are based on the following requirements.

— Drilling—Bit diameter (hole size) should be minimized to aid in maintaining the required “reflection point” when directionally drilling, available downhole equipment, rig specifications, and available BOP equipment.

— Cementing—See B.2.4 for more information.

— Production—Production equipment requirements including tubing, subsurface safety valve, submersible pump and gas lift mandrel size, completion requirements (e.g. gravel packing), and weighing the benefits of increased performance of larger tubing against the higher cost of larger casing over the life of the well.

— Evaluation-logging requirements and tool diameters.

B.2.4 Cementing Plan

Short- and long-term isolation of potential flow zones requires proper cementing planning and execution. Listed below are several aspects of well planning that may affect the success of primary cementing operations. These items are covered in more detail in Section 5:

— hole size and shape (enlargement and annular dimension),

— selection of drilling fluid for filter cake and rheological properties,

— drilling fluid conditioning,

— spacers,

— cement slurry design,

— pump rates,

— centralization,

— testing/evaluation plan.

B.2.5 Drilling Fluids Plan

The drilling fluid is a key factor in the isolation of potential flow zones because of its pressure-control function and because it can affect the success of any cementing operation. Key drilling fluid considerations that relate to cementing success include:

— drilling fluid density or mud weight (MW),

— drilling fluid type,

— filter cake properties,

— rheology and gel strength properties,

— fluid stability,

— effects of drilling fluid on wellbore stability.

These items are covered in more detail in Section 7.

B.2.6 Wellbore Hydraulics

B.2.6.1 (ECD) Management

A plan should be developed to monitor and control static and dynamic fluid pressures of the drilling fluid column such that ECD is maintained within appropriate limits. Static fluid pressure should be sufficient to contain maximum open hole formation pressure and minimize wellbore stability problems, while dynamic fluid pressure should be controlled to minimize fracturing of any exposed formation unless required for wellbore strengthening. Hole size, casing size, BHA and drill pipe size selection should be balanced with the fluid properties and surface equipment ratings to ensure ECD can be maintained within the desired range. Offset well files should be reviewed for indications of lost circulation, stuck pipe, significant borehole enlargement, etc., and the ECD management plan should be modified to mitigate these problems. ECD increase in high-angle and horizontal wellbore sections should be addressed in the plan, as the formation fracture gradient will remain constant in the horizontal section of the well while fluid friction pressure will increase.

Numerous well design parameters can impact ECD including the use of casing strings with increased annular clearances, use of liners rather than full casing strings, selecting fluids that reduce frictional losses, expandable tubulars to preserve hole size, and controlling ROP to avoid overloading the annulus with cuttings. Critical circulating and swab pressures should be documented in the plan. A wellbore hydraulics simulator should be used on each well.

B.2.6.2 Wellbore Cleaning

Cuttings transport to the surface is primarily controlled by annular velocity and fluid rheology, so care should be taken when selecting components that impact these parameters. Surface drilling equipment (drilling fluid pumps, flow lines, and shakers) should be sized to accommodate the maximum rate of cuttings generated. Hole deviation should be considered when designing higher annular velocities for proper hole cleaning. Ensure chemical compatibility of the formation and the drilling fluid system to avoid swelling problems. The bit nozzle selection should be based on optimizing ROP, bit cleaning, and annular velocity for transport of solids to the surface. It is recommended that a wellbore hydraulics/hole cleaning simulation model be run on each well to determine minimum and maximum flow rates. Maximum pipe-tripping speed should be controlled to avoid creation of excess swab/surge pressure during hole cleaning operations. Wells drilled from floating vessels should consider the use of a booster line when high solids loading is expected in the riser.

Conventional hole cleaning tactics may have to be supplemented with hole cleaning pills under certain conditions. Viscous pills and high weight pills can be effective at removing cuttings. However, the use of some pills can contaminate the drilling fluid system.

B.2.7 Barrier Design

The operational goal of any well design is to provide sufficient barriers between formations and between those formations and the surface. A well's barrier plan should include maintaining well control via hydrostatic pressure from fluids, selection and use of well control equipment, and the placement of cement or other mechanical barriers in the well. The well design (i.e. wellhead, BOP equipment, riser, etc.) should consider including a minimum of two barriers available during any operation to prevent uncontrolled flow from the well to the environment. If an operation is performed with fewer than two physical barriers in place, then operational barriers become critical. See industry well design documents for more information. The barrier design should consider incorporating the following elements:

— ability to withstand the maximum anticipated wellbore pressure,

— ability to be tested for function or leaks,

— failure of a single barrier will not result in uncontrolled flow from the well,

— the operating environment is within the design specifications of the barrier element.

In addition, at least one of the barriers should have the capability to do the following.

— Shear any device that passes through the barrier and seal the wellbore after shearing. If this is not possible, an alternative pressure control plan should be considered.

— Seal the wellbore with any size device penetrating the barrier element. If this is not possible, an alternative pressure control plan should be considered.

Evaluation of the viability of each barrier should be considered in the planning process. Plans should address well control issues each time a barrier is removed or replaced. For example, after a cement job, the BOP system is typically removed to install wellhead components. At these times, the barriers in the well have changed from fluids and the BOP stack to fluids and cement. The plan should address when the cement properties are adequate to make that change.

Plans for testing of barrier elements should be part of each well design. Barrier plans should address pressure integrity through pressure testing, but may also require negative testing of a liner top prior to changing out the wellbore fluid. If drilling is planned for an extended period of time (> 30 days), potential casing wear issues should be reviewed, and casing size/tool joint facing material should be selected such that wear will not impair the casing's ability to withstand all potential loads.

B.2.8 Deepwater Barrier Planning

The column of fluid in the riser does not act as a barrier element when the marine riser has been disconnected. Planned or accidental disconnect of the marine riser should be addressed in the well plan. Operators may be able to maintain a drilling fluid density that will provide an overbalance condition with the marine riser disconnected. If this is not possible, a weighted fluid may be displaced into a portion of the wellbore, so that zones with flow potential remain under control in the absence of the hydrostatic pressure from fluid in the marine riser.

Deepwater operating plans should also address the following issues:

— detailed riser analysis should be performed to verify that the riser can withstand all anticipated environmental (weather, current, and sea state) and operating loads;

— the riser disconnect system should be analyzed to verify the ability to safely disconnect under all anticipated loads;

— riser stress should be measured or calculated to determine an optimum rig position to minimize the effects of static and dynamic loads.

B.2.9 Contingency Planning

B.2.9.1 General

The potential for instability caused by unintended transfers of fluids or solids between the wellbore and the formation should be identified in pre-drill analyses. Contingency plans should be developed to specify the procedures, equipment, and personnel needed to avoid adverse situations or to suppress incipient dangers before they become unmanageable. Contingency plans should consider events that fall into three categories: fluid influxes, lost circulation, and formation failures such as breakouts and packoffs.

B.2.9.2 Well Control Planning for Fluid Influxes

Kicks—The following equipment and supplies for contending with kicks should be available at the rig site:

— adequate supplies of heavy drilling fluid—these should be kept ready for mixing in the reserve pit;

— a diverter when shallow formation flow hazards exist such as high pressure shallow gas or water zones; or

— properly selected and well-maintained well control equipment such as blowout preventers (BOPs), chokes, and degassers.

Well control procedures vary depending upon whether surface or subsea BOPs are employed and whether a kick occurs while tripping, drilling, or the bit is out of the hole; however, in general, such procedures include:

— the use of kill drilling fluid and circulating out the kick,

— bullheading the kick back into the formation,

— diverting shallow gas,

— temporarily shutting in the well,

— plugging the borehole with barite or cement plugs leading to partial or complete abandonment of the well.

B.2.9.3 Shallow Water Flows

Shallow water flows are best managed by drilling the interval with weighted fluid. For cementing of shallow flow zones, specialized cements are recommended as detailed in 5.7 and in API RP 65. More information on controlling and cementing shallow water flow zones can be found in API RP 65.

B.2.9.4 Planning for Lost Circulation Control

Methods for avoiding or curing lost circulation during drilling can be found in C.2 and C.3, while those for handling lost circulation during casing and cementing operations are described in 5.8.1. Procedures for managing wellbore breathing or ballooning should also be considered. Wellbore breathing can be an indication of imminent lost circulation. If breathing is observed, the following responses should be considered.

— Review system hydraulics to determine if it is possible to reduce ECD. Consider reducing the drilling fluid weight, if possible.

— Monitor flowback while making connections. Record the volume and duration of flow.

— Do not weight up and risk loss of returns.

— Apply LCM pill.

— When a kick and breathing both occur, consider setting casing.

B.2.9.5 Formation Failure

Procedures for avoiding or managing formation failure vary depending upon the type of formation, the nature of the instability, and the availability of resources. In general, the following practices should be considered:

— maintain the ECD within planned boundaries (see B.2.6);

— use an appropriate drilling fluid type that provides adequate filter cake and cuttings transport, and inhibits chemical reactions with the formation;

— avoid surging or swabbing the formation and reduce tripping speeds when the BHA is opposite problem formations;

— minimize the exposure time in areas where rock deformation or failure is time-dependent (e.g. in salt);

— ensure good hole cleaning (see B.2.6).

In the event of a packoff, the following measures should be considered in the order listed:

— turn off the pumps and bleed down the standpipe pressure;

— apply maximum make-up torque;

— work the drillstring up and down;

— increase the standpipe pressure and continue to apply torque and work the pipe;

— as a last resort, commence jarring in the direction opposite to the last pipe movement.

B.2.10 Regulatory Issues

One component of proper well planning includes appropriate regulatory review. Typically, the regulatory agency with jurisdiction for the well will need to review the well plan before operations begin.

Well plan submittal documents tend to have the following features in common:

— a description of drilling objectives,

— planned casing and cementing programs,

— drilling fluid program,

— equipment testing policies and procedures,

— borehole evaluation and directional survey programs,

— estimates of pore pressures and fracture gradient.

Depending on the type of regulatory system in effect, the agency may or may not approve the well plan in its entirety, or it may require certain changes to the plan to meet regulatory requirements.

B.2.11 Communications Plan

A key feature of good well design is effective communication of the plan to the personnel that will execute that plan. The well design should be communicated through a written plan and through personnel meetings.

For complicated wells, holding a meeting to "drill the well on paper" can often highlight areas of risk and concern, and gives an opportunity for all parties to understand their role in executing the well program. A discussion of human factors, required training and experience of personnel should be highlighted.

Pre-spud meetings are often used to review the relevant topics contained in the well plans, highlight and review safety issues with the personnel, and address topics related to annular flow prevention. The prevention of annular flow does not rest solely with the cementing operation and well control equipment. It is a process that involves wellhead equipment, directional control, wellbore quality, drilling fluid management and cementing operations.

Annex C
(informative)

Drilling the Well

C.1 General Practices While Drilling

The following practices help maintain efficient drilling results and provide hole quality conditions suitable for primary cementing:

— using a drilling fluid of sufficient density to contain formation fluids;

— use of high viscosity sweeps to reduce potential for annular pack off or excessive gumbo deposition;

— controlling drilling fluid losses using LCM as needed;

— minimizing static gelled drilling fluid with flat gel strength drilling fluid rheology;

— preventing excessive drilling fluid filter cake buildup with low fluid loss drilling fluids;

— preventing balling on the BHA due to gumbo;

— rotating pipe while breaking circulation to reduce lost circulation potential on connections;

— while on diverter, the rig should pump out of the open hole and assess trip fill by monitoring each stand while circulating through the trip tank;

— controlling rate of penetration (ROP) to prevent overloading the wellbore with cuttings and minimizing the opportunity for gumbo accumulation;

— monitoring drilling fluid gas content and volume to verify flow potential.

C.2 Monitoring and Maintaining Wellbore Stability

Having a stable wellbore prior to, during, and after the cement job is crucial to cement job success. If losses or gains occur during a cementing operation the possibility of obtaining a successful cement job is greatly diminished. Corrective action should be considered to stabilize the wellbore prior to the cementing operation. Certain corrective measures are best applied prior to running the casing or liner string into the well. The following indicators are used to identify potential flows and losses, contributing to wellbore instability:

— changes in pit volume—monitor trend;

— changes in flow rate—monitor trend;

— changes in pump pressure;

— ROP—monitor trend;

— torque and drag;

— changes in weight on bit (WOB)—monitor trend;

— pressure while drilling (PWD) data;

— ECD variations;

— fracture gradient via shoe and open hole LOT data;

— cuttings size and shape;

— variation in “d” and dxc” exponent;

— abrupt lithology changes;

— returned drilling fluid gas (background, connection, and trip);

— flowline temperature;

— drilling fluid properties-look for drilling fluid cut density, change in salinity, oil in retort, etc.;

— shale density;

— formation changes from LWD/MWD data;

— presence of geologic hazards:

  — fractures,

  — faults,

  — unconformities.

Many of these indicators are precursors to wellbore losses or kicks which can result in an unstable wellbore.

C.3 Lost Circulation

C.3.1 General

Detailed well planning and accurate hydraulic modeling is extremely important in minimizing lost circulation. Lost circulation is one of the most common and expensive problems that are encountered while drilling or while running casing. Loss of circulation can lead to loss of well control and a multitude of associated problems. The financial consideration is of concern with any type of drilling fluid but the importance is the greatest when using NAF. Loss of circulation can lead to well bore instability and well control problems that can drastically affect the outcome of drilling and cementing of the well. See A.10 for more information.

Loss of circulation occurs when either one of the following conditions is met:

— the static or dynamic pressure exerted by the drilling fluid column exceeds the fracture pressure of one or more of the formations exposed in the borehole;

— the porosity and permeability of the formation or space within the fissure or pre-existing “natural” fracture is large enough to permit the passage of whole drilling fluid thus preventing the sealing effect of the filter cake.

Drilling fluid losses can be categorized as two types: natural and induced.

C.3.2 Natural Losses

Examples of natural losses include the following.

— Loss Through Rock Permeability—For whole drilling fluid to be lost, the formation openings are larger than the largest particles contained in the drilling fluid. These types of formations are usually characterized by seepage losses occurring in highly porous intervals usually encountered at shallow depths. Typically these formations are sands and gravels.

— Formations containing natural fractures and leaking faults.

— Cavernous and Vugular Porosity—Formations such as limestone or dolomites in which voids have been dissolved by ground water.

C.3.3 Induced Losses

Losses due to a mechanical disturbance of the wellbore can create fractures in the formation. The hydrostatic pressure thus created in the wellbore exceeds the formation break-down pressure and mechanically fractures the rock. These types of losses are different than what is seen in natural fractures since the fracture network is not interconnected. Some of the causes of induced fractures are affected by the following:

— fluid density and/or ECD,

— additional hydrostatic pressure due to length of riser,

— insufficient hole cleaning,

— excessive ROP with solids loading of drilling fluid column increasing MW,

— high pump rates,

— drilling fluid rheological properties,

— tripping speed,

— wellbore geometry,

— restricted annulus from packoffs or BHA balling.

C.3.4 Loss Rate Categories

Losses of drilling fluid to the formation have been arbitrarily defined in the following categories:

— seepage losses from 1 to 20 bbl/hr;

— partial losses from 20 to 50 bbl/hr;

— severe losses greater than 50 bbl/hr but the hole will remain full with the pumps off;

— complete losses, no returns while pumping or the hole will not remain full with the pumps off.

C.3.5 Preventing Losses

C.3.5.1 Drilling Fluid Properties

Drilling fluid properties can be optimized to prevent losses using the following:

— proper solids control management,

— keeping the fluid density as low as possible,

— maintaining gel strengths and yield point at the lowest levels that will effectively clean the hole and effectively suspend barite and cuttings,

— preventing excessive filter cake build-up by controlling fluid loss,

— using hydraulic prediction software to predict ECD and determine optimum fluid properties.

C.3.5.2 Minimize Surge Pressures

Surge pressures can be minimized by:

— staging in the hole to prevent excessive circulating pressures;

— rotating the pipe to mechanically shear the drilling fluid reducing gel strength before turning on the pumps, and bringing the pumps up slowly;

— monitoring and controlling pipe running speeds;

— using available hydraulics modeling software for predicting surge pressures;

— calculating annular flow and running casing slowly enough to avoid high pressure (speed of lowering each joint, not the average speed).

C.3.5.3 Downhole Equipment

The following downhole equipment practices will help reduce ECD to limit losses:

— using downhole pressure measurements to monitor and manage ECDs in real time;

— using BHA components with maximum annular flow paths across the tools;

— installing auto-fill and various enhanced flow by-pass equipment to minimize surges while running casing, note well control implications while running casing;

— using downhole tools that allow for high concentrations of LCM.

C.3.6 Identifying the Loss Zone

Quickly identifying where the loss zone is located will greatly enhance the performance of the treatment used to counter the lost circulation. Temperature logs, spinner surveys, noise logs, LWD data analysis and stress modeling, connection flow monitoring analysis, lost circulation computer model simulations, and offset well drilling fluid loss data are a few of the techniques used to identify where the suspected loss zone may be located. If a NAF is used, the suspected loss zone could be identified during a short trip by very high resistivity readings in an otherwise non-productive zone.

C.3.7 Lost Circulation Materials and Systems

C.3.7.1 General

There are a wide variety of lost circulation materials available to deal with the most severe types of lost circulation. There is no universal treatment available to cure all types of lost circulation. LCM can range from fine to coarse particulate materials, fibers, cements, reactant pills and acid soluble particulates. The type of material should be matched with the severity of the lost circulation encountered.

C.3.7.2 Seepage Losses

The most common type of lost circulation materials for seepage losses are the fine cellulosic fibers and fine granular types of additives. The most commonly used granular material is calcium carbonate. Another widely used technique is to pump the fine seepage loss additives as a sweep while drilling the seepage loss zone.

C.3.7.3 Partial Losses

The most commonly used materials for this type of loss circulation are granular- and flake-type products that have particles sizes larger than those used to deal with seepage losses. These can include mica, nut shells, and medium to coarse calcium carbonate, graphitic materials and coarse cellulosic fibers. These additives can be added to the drilling fluid system as a continuous treatment or can be spotted as a sweep across the suspected loss zone.

C.3.7.4 Severe Losses

Materials commonly used for severe losses are granular and flake type products that have larger particle sizes than those used to deal with partial losses. As the severity of the loss becomes greater than the preceding two types of losses, coarser sizes of the same additives should be used for bridging, but some of the finer particles can be included. These additives can be added to the drilling fluid system as a continuous treatment or they can be spotted as a sweep across the suspected loss zone.

C.3.7.5 Complete Losses

The types of additives and procedures used to deal with complete losses are generally different than those required for the preceding types of lost circulation. These types of losses generally occur in formations with leakoff flow paths larger than the diameter of most bridging particles. Large fracture openings and vugs usually account for these massive losses. These openings are not effectively sealed with the cellulosic and granular type of products described above. Reactive pills and agglomerating-type LCM materials are used under these circumstances. Some of these include:

— high filtration squeezes allowing for rapid loss of the carrier fluid resulting in a solid plug forming in the formation opening;

— hydration type systems where a very active material such as powdered clay or mixtures of clays and polymers in an inert carrier reacts with the drilling fluid to form a rubbery type of plug;

— chemical systems where special resins or polymers and catalysts react to form a semi-solid plug;

— mixtures of the above systems with cement to create highly viscous and hard setting plugs;

— special, highly thixotropic cement slurries squeezed into the zone or left in the wellbore as a plug;

— large volumes of these materials for cavernous loss zones or special squeeze cements such as foamed cement;

— silicate-base gels with and without cement;

— fibrous cement systems that form a bridge across the thief zone.

C.3.8 Planning and Operations Considerations

The following outline summarizes, in general terms, the data requirements and steps involved to plan a well in which lost circulation is a possibility.

a) Pre-well planning for all phases.

1) Drilling:

i) pore pressures and fracture gradients;

ii) fluid selection—NAF vs water based mud (WBM);

iii) optimizing flow properties;

iv) ECD control, annular pressure measurements;

v) controlled ROP and hole cleaning;

vi) caliper logs;

vii) lost circulation, near-wellbore stress, and ECD computer modeling;

viii) treatment plan to prevent or mitigate losses.

2) Running casing and liners:

i) swab and surge pressure modeling;

ii) insure the hole is clean and free of cuttings;

iii) reduced drilling fluid weight and rheology;

iv) casing hardware selection;

v) pre-treat the drilling fluids to reduce pressures;

vi) breaking circulation.

3) Cementing:

i) ECD modeling;

ii) ensure losses are cured before cementing;

iii) utilize good cementing practices

iv) cement slurry design;

v) LCM in the cement slurries;

vi) spacer considerations—flushes, spacer design (hydraulics);

vii) use proper cement densities and cement volumes.

b) Operational considerations.

1) Drilling:

i) pre-treat drilling fluid with various particle size distribution materials;

ii) modify pre-treatment as required depending on wellbore reaction;

iii) apply planned treatments as needed to control losses.

2) Running casing:

i) if possible cure the lost circulation prior to running casing;

ii) spot LCM in the open hole prior to running casing.

3) Lost circulation and near-wellbore stress computer modeling:

i) optimize planned treatments based on actual conditions.

Annex D[1]
(normative)

Process Summary: Isolating Potential Flow Zones During Well Construction

Isolating a potential flow zone with cement is an interdependent process. Individual process elements such as slurry design and testing, applied engineering and job execution all impact the ability to successfully install a cement barrier. Superimposed upon these elements are the conditions found in the well at the time of cementing.

Certain cementing process elements contained in this annex may be individually critical to isolating a potential flow zone or may be of minor consequence until made critical by a separate (sometimes unrelated) event or past well engineering decisions. Conversely, certain elements may not be dominant factors in the success in one cementing operation, yet vitally important in another.

Collectively, the elements described below produce the design, engineering and operational framework for successfully isolating a potential flow zone.

Flow Potential Risk Assessment	
The results from any pre-spud hazard assessment of the proposed drill site should be provided to the cementing service provider to be used as a basis of design for the cementing program or used in the slurry design guidelines provided by the operator. Typically the information provided will include location of possible hydrocarbon bearing, water bearing and lost circulation intervals as well as over-pressured or under-pressured zones.	
Site Evaluation	Was a pre-spud hazard assessment conducted for the proposed well site?
Assess Flow Potential	Are there any potential flow zones within the well section to be cemented?
Communication	Has the information concerning the type, location, and likelihood of potential flow zones been communicated to key parties (cementing service provider, rig contractor, or 3rd parties)?

Critical Drilling Fluid Parameters	
The drilling fluid design should be appropriate for parameters such as formation type, wellbore stability, formation damage potential, cuttings removal and proper management of ECD, etc. The drilling fluid used to drill a hole section containing a potential flow zone may not be ideal for cementing operations. Within the limitations imposed by the drilling fluid used, computer modeling **shall** be conducted to assess the impact of the drilling fluid circulation and cement placement on the pore and fracturing pressure limits and on drilling fluid removal across any hole section with a potential flow zone. This analysis will allow the cementing service provider and operator to consider alternate means of meeting the objective of isolating potential flow zones should drilling fluid circulation or cementing placement be ECD constrained limits.	
Rheology	Are rheological properties and static gel strength value conducive to cuttings removal, solids suspension and proper management of ECD?
Density	Are fluid densities sufficient to maintain well control without inducing lost circulation?
Fluid Loss	Is filtration control appropriate for formation type and well conditions?

[1] Users of these forms should not rely exclusively on the information contained in this document. Sound business, scientific, engineering, and safety judgment should be used in employing the information contained herein.

Critical Well Design Parameters	
The condition of the wellbore affects the ability to successfully isolate a potential flow zone. These well conditions, whether induced or naturally occurring, should be considered in the cement design and placement.	
Pore/Fracture Pressure	Wellbore fluid hydraulics (ECD) modeling **shall** be performed in well sections containing a potential flow zone in order to assess pore pressure and fracture gradient limits.
Simulations	In order to best facilitate the installation of a cement barrier element, centralizer placement, ECD and fluid displacement simulations **shall** be performed. Within the constraints imposed by hydraulic, operational, logistical or well architecture limitations, the results of these simulations **shall** be considered during the cementing design and execution.
Close-tolerance and Other Flow Restriction Considerations	ECD pressure calculations **shall** include any flow restrictions, particularly those of significant length and small cross-sectional area, such as liner overlaps, liner top packers, liner hangers, tieback sleeves, casing connections and drill pipe tool joints.
TOC	The planned TOC **shall** cover the shallowest potential flow zone.
Hole Diameter	Is hole enlargement minimized sufficiently to allow for adequate centralization?
Deviation, Dogleg Severity	Is the wellbore trajectory sufficiently smooth to allow for running casing and adequate centralization?
Trapped Annular Pressure	Has the risk of trapped annular pressure in designing the TOC been assessed and mitigated for subsea wellheads?
Lost Circulation	Is there a plan for mitigating lost circulation?
Mechanical Barrier	Has the use of mechanical barriers (e.g. liner top packers, ECPs) been evaluated and included in the well design if warranted?
Rathole	Has the rathole length been minimized or filled with drilling fluid with a density greater than the cement density?

Critical Operational Parameters	
There are a number of operational parameters, prior to and during the cementing operation, which can affect the ability to successfully isolate a potential flow zone.	
Float Equipment	Are the float valves rated for the anticipated flow rates and volumes of the fluids pumped during circulation and cementing of the casing string? Float valves **shall** be rated for the anticipated differential pressure between the minimum anticipated hydrostatic column above the shoe track and the hydrostatic column in the casing annulus with cement in place. Have two independent float valves been installed in the shoe track?
Cementing Heads	Cementing heads **shall** be pressure tested by the supplier to the maximum working pressure rating of the head as part of a regular maintenance program. The cementing head selected **shall** have a working pressure in excess of the maximum anticipated surface pressure for the job.
Contingency Plans	As a minimum, are contingency plans in place for the following? — Lost circulation. — Unplanned shut-down. — Unplanned rate change. — Float equipment does not hold differential pressure. — Surface equipment issues.
Running Casing	Has the maximum casing running speed been determined to minimize swab and surge effects?
Well Control	Is the well stable (no volume gain or losses, drilling fluid density equal in vs out) before commencing cementing operations?
Surface Systems	As a minimum, were the following surface systems checked for operability? — Cement mixing and pumping equipment. — Additive proportioning equipment. — Bulk delivery system. — Plug launching systems. — Treating iron. — Mix water/drilling fluid deliverability. — Monitoring and recording systems.
Annular Returns Monitoring	Is there a plan to monitor the annulus during cementing and WOC time?
Static Time	Has the time between drilling fluid circulation/conditioning and commencing cementing operations been minimized?
WOC	Has the appropriate WOC time been determined?
Barrier Removal	The time from the start of removing the barrier element to securing the exposed annulus **shall** be minimized.
Risk Assessment	If foamed cement is used, operators and all involved contractors **shall** perform a risk assessment prior to utilizing foamed cement, and make sure that the results of this assessment are incorporated in the cementing plan

Critical Drilling fluid Removal Parameters	
Displacing the drilling fluid during the cementing operation is one of the most important factors in isolating a potential flow zone. Poor drilling fluid displacement will jeopardize the ability to isolate potential flow zones.	
Centralization	Centralizer placement simulations **shall** be performed in order to best facilitate the installation of a cement barrier element. Have the centralizer simulator results been considered during the cementing design and execution within the constraints imposed by hydraulic, operational, logistical or well architecture limitations?
Mixing and Placement Rate	Have placement rates during cementing been modeled and designed to achieve the best possible drilling fluid removal?
Spacer	Has the spacer been modeled and designed to achieve the best possible drilling fluid removal?
Fluid Compatibility	Has the spacer been tested for compatibility with drilling fluid and cement according to API RP 10B-2/ISO 10426-2? When using NAF, has the spacer composition been optimized for wettability according to API RP 10B-2/ ISO 10426-2?
Circulation Volume	As a minimum, does the pre-cementing circulating plan account for actual well conditions? — Drilling fluid conditioning and mobility. — Gas in excess of background levels. — Wellbore cooling. — Lost circulation/ballooning. — Confirm float equipment is free of obstruction. — Hole stability.
Rheology	Has altering the drilling fluid's static and dynamic properties after drilling the section containing the potential flow zone been considered to improve drilling fluid displacement efficiency and/or ECD management? Do the fluids' rheological profiles provide a friction pressure hierarchy appropriate for effective drilling fluid removal?
Wiper Plugs	If possible, are top and bottom wiper plugs used?
Pipe Movement	Has pipe movement been considered?
Annular Volume Determination	Has consideration been given for how the open hole volume will be determined?

Critical Cement Slurry Parameters	
Cement serves as an isolation medium during well construction. The design of the cement slurry, taking into account the anticipated well conditions, is central to successfully isolating potential flow zones. Lead and tail cement slurries designed to isolate potential flow zones should be fit for their intended purpose.	
Cement Compressive or Sonic Strength	Cement **shall** be considered a physical barrier element only when it has attained a minimum of 50 psi compressive or sonic strength as measured at simulated pressure and temperature conditions (within the limits of the laboratory equipment) at the uppermost flow zone. Once the time to reach a minimum of 50 psi compressive or sonic strength has been determined by lab tests for the specific cement slurry, the operator **shall** wait on the cement to set for that amount of time prior to removing or disabling a barrier element.
Wellbore Barriers: Cement Plugs	Slurry properties **shall** be consistent with any regulatory requirements. Testing **shall** comply with accepted industry standard practices.
Temperature for Cement Testing	Have temperature schedules been established based on methods contained in API RP 10B-2/ISO 10426-2, direct measurements, computer modeling and/or offset well data?
Slurry Design (lead vs tail slurry)	Has the lead slurry been designed so that the static gel strength development and thickening time are longer than for the tail slurry, including applicable (batch) mixing and placement times?
Slurry Design (static gel strength)	Have the cement slurries, placed across potential flow zones, been designed to have as short a CGSP as possible, preferably less than 45 minutes, at the temperature and pressure conditions found at the potential flow zone?
Slurry Design (rheology)	Are the rheological properties of the slurries conducive to surface mixability, drilling fluid removal and ECD management with respect to fracture pressure?
Slurry Design (fluid loss)	Does the fluid loss of the slurry placed across potential flow zones have appropriate control for the flow potential?
Slurry Design (density)	Does the slurry density meet requirements for maintaining well control?
Slurry Design (stability)	Are free fluid control, sedimentation and foam stability (when cement is foamed) appropriate for the conditions found at the potential flow zone?
Slurry Design (compatibility)	Are lead and tail slurries compatible?
Slurry Design (mechanical properties)	Is the cement designed with mechanical properties suitable for long-term sheath integrity for anticipated well operations?
Slurry Design (field blend verification)	Have representative field blended samples been tested?
Slurry Design (mechanical barriers)	Has the presence of mechanical barriers been taken into account in the slurry design and testing?
Slurry Design (formation type and fluids)	Is the cement designed for specific formation (such as salt) and for expected formation fluids (such as gas)?
Slurry Design (regulatory)	Slurry properties **shall** be consistent with any regulatory requirements.

Job Execution	
A well executed cement job is critical to isolating potential flow zones.	
Circulation and Conditioning	Was the well circulated and the drilling fluid conditioned prior to cementing
Density Control	Was the cement placed across potential flow zones mixed within a density range or solid to liquid ratio range that did not compromise the slurry performance (static gel strength, thickening time, etc.) required for flow prevention?
Pre-flushes and Spacers	Were spacers mixed and pumped as designed including rheology, density and volume?
Placement Rates	Were the placement rates adequate for effective drilling fluid removal?
Centralizers	Were centralizers properly installed as designed?
Special Blending Mixing	If used, were specialty blended cements prepared, transported and stored in accordance with the suppliers established guidelines?
Liquid Additive System	If used, was the liquid additive system calibrated before the cement job and was an inventory check performed after the job to verify actual usage?
Post Job Monitoring	During WOC was the annulus monitored and kept full?

Special Operational Considerations	
Barrier Acceptance	If the criteria for verification of a mechanical barrier or cement cannot be met the operator **shall** establish an appropriate course of action with the regulator or permitting authority.
Diverter or BOP Obstruction	Operators or rig contractors **shall** not run tubing in the annulus between the casing and the diverter, or BOP, after completion of the cementing operation and prior to determining the well has no potential for flow.
Hydrostatic Overbalance	The operator **shall** perform hydrostatic pressure calculations to verify sufficient hydrostatic overbalance pressure throughout the well prior to washing out to the mudline suspension hanger.
Foamed Cement	Operators and cementing service providers **shall** perform a risk assessment prior to utilizing foamed cement to isolate a potential flow zone. The results of this assessment **shall** be incorporated into the cementing plan.
Foamer, Stabilizer and Nitrogen Injection (foamed cement)	Will the foamer, stabilizer and nitrogen injection be controlled by an automated process system? Were the foamer, stabilizer and nitrogen ratios within design tolerances?
Cement Plugs	Cement plugs **shall** be installed and verified as required by regulations.

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