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DRILLING AND COMPLETION COMMITTEE

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Primary Cementing

An Industry Recommended Practice (IRP)
for the Canadian Oil and Gas Industry

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CAODC
CANADIAN ASSOCIATION OF OILWELL DRILLING CONTRACTORS

CAPP
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The recommendations set out in this IRP are meant to allow flexibility and must be used in conjunction with competent technical judgment. It remains the responsibility of the user of this IRP to judge its suitability for a particular application.

If there is any inconsistency or conflict between any of the recommended practices contained in this IRP and the applicable legislative requirement, the legislative requirement shall prevail.

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Table of Contents

List of Figures

List of Equations

List of Tables

25.0 Preface

25.0.1 Purpose

This document contains a collection of Industry Recommended Practices (IRPs) to ensure that industry supported guidelines for primary cementing are available for all relevant organizations and personnel. It may be used as a reference for the intended audience (see Audience), act as a guideline for operators and service companies during employee training or may be accessed as a guide to support the development of internal procedures for effective cementing operations.

Regulators from Alberta, British Columbia and Saskatchewan regularly attended committee meetings and had opportunity to comment on all drafts and offer agreement in principle. With support of the primary cementing community along with significant representation from the Canadian jurisdictional regulators, the IRP 25 Committee believes these recommended practices represent the approach of a progressive and collaborative industry committed to primary cementing practices that provide the required zonal isolation throughout the life cycle of the well.

It is the reader's responsibility to refer to the most recent edition of this document, regulations and supporting documents.

All operations must adhere to jurisdictional regulations. This publication was produced in Alberta and emphasizes provincial legislation with references to AER Directives for minimum standards and regulatory requirements. When working outside Alberta the regulations for the local jurisdiction must be used as the regulatory standard. A full disclaimer is noted on the inside cover of this document.

25.0.2 Audience

This document is primarily intended for the primary cementing sectors of the oil and gas industry. It assumes the reader has a working knowledge of cementing operations. Organizations involved in primary and/or remedial cementing may find all or some portions of this IRP of interest.

25.0.3 Scope and Limitations

This IRP covers primary cementing. Remedial cementing is addressed in a separate IRP.

> **Note:** At the time of publication of IRP25, the IRP for remedial cementing was planned but not written. Refer to the Enform website for current information about remedial cementing.

IRP 25 focuses on the cementing practices and factors that can impact the success of the primary cement job. It considers all phases of the job from job design through to execution and post-job evaluation. The design and placement of plugs is discussed, highlighting the areas where practices for plugs vary from the wellbore casing cementing. IRP 25 also provides some framework for managing change and establishing a continuous improvement process.

Application of the practices in this document is intended to reduce the risk of issues associated with poor primary cementing operations, including but not limited to, gas migration (GM), surface casing vent flows (SCVF) and ground water contamination.

25.0.4 Revision Process

IRPs are developed by the Drilling and Completions Committee (DACC) with the involvement of both the upstream petroleum industry and relevant regulators. Enform acts as administrator and publisher.

Technical issues brought forward to the DACC, as well as scheduled review dates, can trigger a re-evaluation and review of this IRP in whole or in part. For details on the IRP creation and revisions process, visit the Enform website at www.enform.ca.

Revisions to this document are logged in Appendix A: Revision History.

25.0.5 Sanction

The following organizations have sanctioned this document:

Canadian Association of Oilwell Drilling Contractors (CAODC)

Canadian Association of Petroleum Producers (CAPP)

Petroleum Services Association of Canada (PSAC)

Explorers & Producers Association of Canada (EPAC)

25.0.6 Acknowledgements

The following individuals helped develop this edition of IRP 25 through a subcommittee of DACC.

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25.0.7 Range of Obligations

Throughout this document the terms ‘must’, ‘shall’, ‘should’, ‘may’, and ‘can’ are used as indicated below:

Table 2. Range of Obligation

Term	Usage
Must	A specific or general regulatory and/or legal requirement that must be followed.
Shall	An accepted industry practice or provision that the reader is obliged to satisfy to comply with this IRP
Should	A recommendation or action that is advised
May	An option or action that is permissible within the limits of the IRP
Can	Possibility or capability

25.0.8 Copyright Permissions

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Table 3. Copyright Permissions

Copyrighted Information	Used in	Permission from
Continuous Improvement – Interpretive Evaluation Matrix	Appendix H	Suncor Energy
Halliburton presentation about hole conditioning. Information derived from SPE 30514	Tables 23 and 24 in 25.11.4.1 Hole Conditioning	Halliburton

25.0.9 Background

IRP 25 was originally published in April 1995 as Primary Cementing Guidelines. It was created in response to one of the recommendations set forth by the DACC Surface Casing Vent Flow Subcommittee in based on a study of the problem of uncontrolled gas migration.

Between 2013 and 2016 the IRP was redeveloped with completely new content.

25.0.10 Terminology

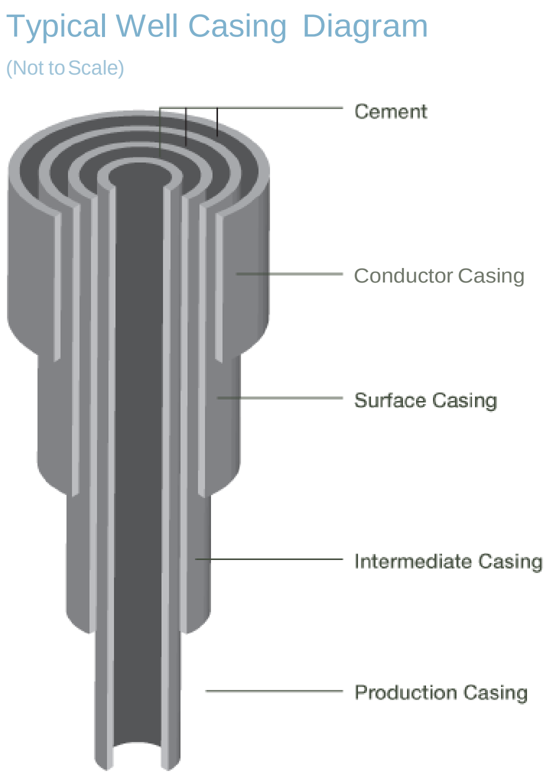
IRP 25 uses several abbreviations and acronyms for standard industry terminology. A complete listing can be found in the Acronyms and Abbreviations section near the end of this document.

IRP 25 uses specific definitions for many of the key industry terms used in this document. A list of definitions can be found in the Glossary.

Surface casing vent flows and gas migration are key concerns for cementing. IRP 25 uses the AER definitions for these terms as per AER Interim Directive: ID 2003-01. These detailed definitions can be found in the Glossary.

Well casing terminology (e.g., conductor pipe, surface casing, intermediate casing, production casing, cement) is commonly used in the industry. Figure 1 is included only to establish a visual identification of these terms. It is not intended as a sole descriptor of well casing design. Refer to the Glossary for definitions of these terms.

Figure 1. Well Casing Diagram



25.1 Overview

The main goal of primary cementing is cement integrity throughout the life cycle of the well. This includes the following objectives:

- All zones of interest (e.g., potential hydrocarbon bearing, water bearing, injection/disposal zones) must be isolated from one another with the primary cement job as per jurisdictional regulations. Surface casing vent flows and gas migration are indicators of a lack of zonal isolation and IRP 25 identifies testing procedures to check for their presence (see 25.10.3.1 Surface Casing Vent Flow Testing and 25.10.3.2 Gas Migration Testing).
- Isolation of upper hole sections from downhole wellbore conditions.
- Support for the casing string and protection from mechanical failure or corrosion.

These objectives can only be achieved with a quality cement job. Although every well may have specific needs and challenges, there are many recommended practices that, if followed, will ensure a high rate of success with the primary cementing process.

A quality cement job requires detailed planning that considers the life cycle of the well, all potential job execution parameters, slurry and spacer design, wellbore construction implications, drilling practices and cement placement. Simulations and lab testing can aid in design and product selection. Effective change management processes and communication between designers and operational teams can help ensure that any operational changes don't jeopardize the integrity of the plan and design. Post-job evaluation is required to ensure the objectives are met. Evaluation results should feed into a continuous improvement process to ensure that mistakes are not repeated and so new or innovative techniques that are successful are fed back into the design process.

There are several challenges to cementing jobs that can be addressed through the job design, spacer design, slurry design, wellbore design, wellbore construction practices or job execution practices. This IRP outlines practices and contingency plans for planning and executing any cement job and includes suggestions for addressing these challenging situations. Refer to Appendix B: Cement Job Challenges for a high level matrix of challenges, potential consequences, possible solutions and the section of the document that discusses the solutions.

Personnel involved in designing and executing a primary cement job need to evaluate the lifecycle wellbore conditions so the risks associated with primary cementing that increase the chance of SCVF and GM are adequately addressed. This IRP can be used to help evaluate the risk for a particular well and develop a design and execution plan that addresses the issues.

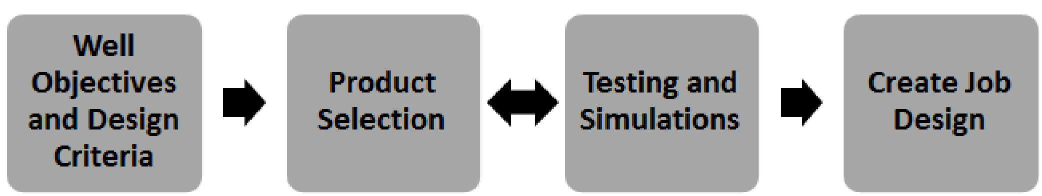
25.2 Cement Job Design

There are few circumstances, even within the same field, where two wells or two cement jobs are identical. Variations in formation properties and drilling practices make it difficult to apply a standard procedure for all jobs. The cement job design needs to minimize integrity issues throughout the life of the well considering pressure cycling (i.e., hydraulic fracturing, production, injection), the corrosive environment (e.g., H_2S, CO_2, salt) and thermal cycling. A quality cement job design that considers all of the unique challenges and risk factors for the well provides the basis for a successful cement job.

25.2.1 Design Process

Figure 2 shows the typical process for designing a cement job. In this process the order of operations can change and there can be multiple iterations of each to reach a solution that meets the objectives and best manages the identified risks.

Figure 2. Cement Job Design Process



25.2.2 Simulations

IRP Cementing job simulators should be considered for optimizing primary cementing design to improve placement and the reliability of the cement job, particularly in complex jobs or jobs with technical uncertainty.

There are cementing simulators that can be used for specific applications (e.g., centralization, bottom hole circulating temperature, casing stresses).

Simulators are typically used in the following situations:

- High temperature wells
- Large job volumes
- Long pump times

- Weak formations
- Narrow annular clearances
- New drilling areas
- Areas prone to gas migration and surface casing vent flows
- Problem drilling areas (e.g., lost circulation, high deviation or over/under pressured)
- New technology is being used (e.g., monobores)

Simulators can calculate the predicted surface pressures, rates and equivalent circulating density (ECD) throughout the job as well as final placement of all fluid pumped into the well during the cementing job. Other outputs from the simulator may include the following:

- Cement and spacer volumes
- Hook load calculations
- Centralizer spacing calculations
- Free fall calculations
- Flow regimes
- Casing collapse/burst calculations
- Foam cement calculations
- Gas flow potential calculations

Well and fluid information are needed to complete a simulation. The accuracy of the simulation is dependent on the quality of the data input. It is important for the operator and cementing service provider to work together to ensure the required data is made available in order to limit assumptions.

The following are typical well data inputs for basic simulations:

- Depths
- Wellbore dimensions
- Formation pressures
- Fracture gradients
- Pipe information
- Directional survey information
- Caliper information
- Temperature gradients
- Lost circulation zones

- Slurry properties (density and rheology)
- Pumping schedule (fluid volumes and rates)
- Pipe movement
- Centralization

Import job data to the simulation software to compare the job design with actual job parameters. This will help verify the success of the cementing operation and feed into a continuous improvement cycle for the cementing process (see 25.13 Continuous Improvement).

25.2.3 Cement Volumes

The initial cement volume will be based on a calculated volume plus an open-hole annular excess factor. The excess factor is often based on previous experience in an area or formation. If losses were incurred during drilling they should be dealt with prior to cementing.

IRP Final cement volumes should be calculated based on actual well data (e.g., a caliper log) and an excess factor should be applied to cover hole size uncertainty.

25.2.4 Displacement Volumes

Consider the effects of aeration and fluid compressibility on the displacement volume if a fluid other than water is planned for displacement. Compressibility is most often seen when pumping drilling fluids (i.e., entrapped air or compressible oil-based drilling fluid).

In certain situations the casing inside diameter (ID) needs to be verified (e.g., large displacement volumes, large pipe, deep wells) because API Tables use a nominal value and may not be precise enough to make accurate calculations.

IRP Pump efficiency factors shall be included in the calculations if rig pumps are used to displace the slurry.

25.2.5 Pump Rates

Pump rates are based on surface equipment capacity, formation integrity and simulations optimizing displacement efficiency. In some cases, an increased pump rate may be required to prevent freefall of the slurry in the casing and limit contamination of fluids.

Any unplanned changes in pump rate may change the time required to place the job, circulating temperatures and displacement efficiency. This could ultimately jeopardize slurry placement and the success of the job.

IRP Changes to the planned pump rate (either from wellbore conditions or surface equipment) should be agreed to by the cementing service provider and operator.

Reduced pump rates on a primary cement job can be considered to minimize ECDs, minimize fallback and mitigate gas migration. At these low pump rates it is important to verify that removal of drilling fluid is not compromised.

25.2.6 Mixing Methods

Job objectives dictate the mixing method.

Table 4. Mixing Methods

Batch Mixing	Slurry Averaging Method	Continuous Mixing
Cement, additives and water are mixed together in a large vessel to uniform density	Slurry is mixed to density and pumped to a larger averaging tank prior to pumping downhole.	Slurry is “mixed on the fly” to density and immediately pumped downhole.
• Best density control • Limited to tank size • “Residence time” needs to be considered • Additional equipment (batch mixer) required	• Allows for good density control for small or large volumes • May or may not require additional equipment	• Least control of density • Can mix large volumes

For example, a typical surface job is low risk and can be mixed continuously while a liner or whipstock plug requires a tighter control of density.

25.2.7 Centralization

The annular velocities around the casing being cemented in an eccentric annulus can vary drastically which can leave channels of drilling fluid or spacer. Casing centralization and annular velocity need to be designed to fully remove drilling fluid from the wellbore when zonal isolation is required.

IRP Centralization should provide minimum standoff for effective removal of drilling fluid and hydraulic isolation throughout the life of the well. Simulations are recommended to determine standoff requirements.

Consider deviation, pipe sag, drilling fluid removal, washout/hole enlargement and fluid properties in centralizer design. Refer to 25.6.1.11 Centralization for more detail.

The designed standoff is typically a balance between the displacement efficiency and the ability to run the casing in the wellbore.

25.2.8 Wiper Plugs

When feasible, use top and bottom plugs to separate slurry from other fluids (e.g., drilling fluid, spacer). This minimizes fluid contamination within the casing. It is preferable to preload the plugs to limit interruptions to the pumping schedule.

Larger spacer volumes or under-displacement are potential mitigations to minimize slurry contamination if wiper plugs are not used.

25.2.9 Pipe Movement

The movement of pipe during the wellbore preparation, cementing and displacement operations will improve cement placement and drilling fluid displacement efficiency by moving stagnant drilling fluid and removing drilling fluid filtercake. This is accomplished by forcing the fluid to travel in changing flow paths. Rotation and reciprocation are the two types of pipe movement typically used. Both methods introduce complexity and challenges to the operation.

IRP Pipe movement during drilling fluid conditioning and cementing should be utilized where practical.

Note: There are other methods, tools and technologies available to improve drilling fluid displacement.

Use caution when reciprocating so the surge and swab effects created during the movement of the pipe do not induce losses, affect wellbore stability or create well control problems. These effects are amplified when annular clearance is small. There is also potential for the casing to get stuck during this process which may cause the casing to be landed incorrectly.

Rotation is more effective than reciprocation under most conditions. Consider the potential for connection fatigue and the use of specialized cement head equipment if rotation is planned.

Pipe movement may be impossible for some applications (e.g., highly deviated wellbores, liners or staged cement jobs). If rotation and/or reciprocation are not possible then other parameters become more critical (e.g., pump rates, centralization, fluid design parameters and/or spacer volumes). Refer to Wellbore Construction section 25.6.2.5 Ability to Rotate/Reciprocate During Cementing for more information.

25.2.10 Drilling Fluid Conditioning

IRP The wellbore should be circulated and conditioned to minimize cuttings build up in the wellbore prior to running casing.

After casing is landed, circulate and condition the drilling fluid to the rheology planned for in the cement design, including thinning to reduce gel strength. Consider the impact thinning the drilling fluid can have on water wettability, particularly for oil-based drilling fluids. If the drilling fluid is chemically treated the ability to achieve good water wettability with the surfactants in the spacer may be compromised. Condition immediately prior to cementing.

IRP The amount of drilling fluid pumped during conditioning should be a volume sufficient for the drilling fluid to reach its designed rheology and density.

It may be possible to increase circulation rates during fluid conditioning to reach the ECDs expected during cementing.

Failure to properly condition the drilling fluid can result in poor friction pressure and/or density hierarchy between the drilling fluid, spacer(s) and cement slurry, resulting in poor displacement efficiency and inability to achieve cementing objectives.

25.2.11 Wait on Cement Time

Wait on cement time should be planned. Refer to 25.9.3 Wait on Cement for more detail about wait on cement time.

25.2.12 Spacers

The fluids between the cement slurry and the drilling fluids can go by a variety of names such as spacer, preflush, wash, etc. For the purposes of this IRP, a spacer is any fluid pumped immediately before the cement that is different from the drilling fluid already in the hole (whether it is weighted, non-weighted, viscosified or non-viscosified).

Spacers can be used as follows:

- To separate the cement slurry from the drilling fluid (to prevent contamination of the cement) and fully displace the drilling fluid.
- To water wet or condition the casing and borehole wall, particularly when using oil-based drilling fluids.
- To remove drilling fluid filtercake from the borehole wall.
- To thin and disperse drilling fluids.
- To maintain stability of various formations.
- To control downhole fluid loss.

25.3 Spacer Design

The various spacer types have many common characteristics and functions as noted below:

- Spacers usually have a suspending agent and optimized rheology.
- Spacers may contain surfactants to reduce or eliminate compatibility problems.
- Spacers should be stable at bottom hole application temperature.
- Spacers should have low fluid loss to the formation.
- Spacers help prevent and break emulsions and water blocks.
- Spacers may have a breaker that helps break up highly gelled drilling fluid and filtercake.
- Spacers should incorporate environmental friendly fluids and additives when possible.

The performance of a spacer depends mainly on the following:

- The rheology of the spacer at the desired temperature.
- The density of the spacer compared to densities of the fluids in front and behind.
- The compatibility of the spacer with the drilling fluid and the cement.
- The volume of spacer necessary to provide sufficient separation of the cement from the drilling fluid to prevent the cement from becoming contaminated.
- The contact time for chemical interactions to occur.
- The pump rate of the spacer to optimize drilling fluid displacement.

Apply engineering principles and area experience when designing spacers. Advanced computer simulation models can assist in predicting displacement efficiency. There may be situations where it is not possible to apply all of the best practices listed in this section. Try to apply as many as possible.

25.3.1 Scavenger Slurries

A scavenger slurry is a spacer consisting of diluted cement that can provide some scouring action on immobile drilling fluid and maintain pressure control. Cement used for a scavenger slurry is not appropriate for isolation or achieving a cement top. Scavenger slurries may not be stable and can separate if pumping is stopped. Use of a scavenger slurry does not preclude the need for a spacer unless the scavenger is compatible with the drilling fluid.

IRP Scavenger slurries should not be included in the calculated cement volume required for isolation.

25.3.2 Annular Velocity and Fluid Flow

There are three flow patterns to consider when designing a spacer for displacement purposes. These are turbulent, laminar and plug flow. Each of these flow patterns may be employed successfully with different fluid types in an effort to balance chemical and physical performance characteristics. Cement is usually pumped in a laminar flow pattern in typical wellbore and casing configurations. Variations in hole diameter and eccentricity may result in unpredictable flow patterns and thus the fluid may go through all three flow patterns in various parts of the hole. Increasing the annular velocity via pumping rates may improve removal of drilling fluid.

The following factors impact annular velocity:

- ECD relative to formation integrity
- Surface equipment capability
- Annular gap/washout

Rely on field experience, computer simulations and logging results to optimize and drive process improvements (see 25.13 Continuous Improvement).

25.3.2.1 **Turbulent Flow**

Turbulent flow placement is recognized as the most effective technique for removing drilling fluid. For turbulent flow to be effective, the spacer needs to be in turbulence around the entire circumference of the annulus across all zones of interest. This may be difficult to achieve in situations where the casing is poorly centralized or the hole has significant ovality. Studies have shown that a contact time of 10 minutes across the zone(s) of interest is recommended for complete drilling fluid displacement. Avoid situations where the column of unweighted turbulent flow spacer causes the well to become hydrostatically underbalanced or induces wellbore instability.

IRP Turbulent flow should be used whenever well conditions allow.

Note: The cement does not need to be pumped in turbulent flow, only the spacer ahead of the cement.

Consider laminar flow methods if the turbulent-flow technique cannot be used.

25.3.2.2 **Laminar Flow**

Laminar flow placement techniques are used when turbulent flow is not practicable. For laminar flow to be effective, a friction pressure hierarchy and density hierarchy are utilized. In laminar flow, fluids will move at a higher velocity on the wide side of the annulus than the narrow side.

Plug flow is a specific laminar flow technique sometimes utilized to minimize the differential velocity. With Plug flow the job is pumped at very low rates. The rate needs to be sufficient to overcome the wall shear stress imposed by the gel strength of the drilling fluid on the narrow side of the annulus.

25.3.2.2.1 **Friction Pressure Hierarchy**

Friction pressure is an important factor in fluid displacement optimization. A thicker fluid will more effectively displace a thinner fluid. If the order is reversed, a thinner fluid will tend to channel through the thicker fluid and take the path of least resistance. There is no defined minimum requirement for friction pressure hierarchy but a common industry practice is to have a 10% increase in friction pressure of the displacing fluid relative to the fluid being displaced.

IRP When using laminar flow techniques, the planned rheology of the conditioned drilling fluid and the cement slurries should be used to optimize friction pressure hierarchy when designing spacers.

25.3.2.2.2 **Density Hierarchy**

The optimal spacer density is dependent on the drilling fluid and cement density. The drilling fluid and cement densities are constrained by the formation pressure and wellbore integrity. Reevaluate the spacer density if unexpected hole conditions are encountered and/or drilling fluid or cement densities change.

IRP When using laminar flow techniques, each fluid should be heavier than the fluid it is displacing. Density hierarchy between each fluid should be maximized within ECD limitations.

There is no defined minimum requirement for density hierarchy but a common industry practice is to have a 10% or 100 kg/m^3 increase in the density of the displacing fluid relative to the fluid being displaced.

25.3.3 Spacer Length and Contact Time

Contact time is how long any given point of the wellbore will be in contact with the spacer fluid. Spacer length is the calculated annular length of the spacer in measured depth (accounting for excess). Contact time is especially important when chemicals are used to perform a function in the wellbore. These functions may include water wetting, breaking up drilling fluid or breaking emulsions. Spacer length may be more important than contact time when using a weighted spacer.

The minimum contact time for an un-weighted spacer should be 10 minutes if practical.

The optimum application of a weighted spacer may not always be measured in contact time but in annular length. A good rule of thumb for vertical wells, where practical, is a minimum spacer length of 150 m in the open hole section but the length should be based on drilling fluid parameters and hole conditions.

Larger volumes or lengths of spacers may be required in horizontal or deviated wellbores.

25.3.4 Compatibility

Fluid compatibility between the various wellbore fluids is important to avoid channels through the cement that result in poor isolation. If two fluids are incompatible then removal of drilling fluid can be disrupted due to the creation of high viscosity mixtures or emulsions which will be easily bypassed by the thinner fluid behind it. Compatibility considerations include settling, alteration of thickening time, delay of compressive strength, etc.

IRP Fluid compatibility should be tested, at minimum, between the drilling fluid and the spacer system.

There are many ways to evaluate fluid compatibility. Two methods are described in Appendix C.

25.3.5 Wettability

If an oil-based or non-aqueous drilling fluid is to be used to drill the well then consider water wetting the wellbore with the spacer system. This can be done by using a two-part system where a hydrocarbon is pumped followed by a water-based spacer or a one-part water-based spacer. In either case, a package of solvents and surfactants should be added to these fluids to remove, clean and water wet the surfaces of the casing and formation. Cement is a water-based fluid and thus requires the formation and pipe to be water wet to achieve a good bond.

IRP When using oil-based drilling fluids, a wettability test should be completed to demonstrate the proposed spacer will work as designed at wellbore temperatures.

25.3.6 Spacer Stability

The stability of the spacer is important so that solids do not settle out of the spacer during pumping or in the event of any planned or unplanned shutdowns. There are two types of stability or sedimentation tests for spacers: static and dynamic. The choice of which test(s) to run is dependent on the job design.

Note: There are API standards for static tests but not for dynamic tests.

IRP The spacer should remain stable at downhole conditions for the calculated job time.

25.4 Slurry Design

Slurry design that utilizes parameters appropriate to the well objectives and conditions is required to achieve primary cement integrity throughout the life cycle of the well. Consider the following:

- Well objectives (e.g., oil, gas, injection, storage, vertical, deviated, horizontal).
- Completions operations (e.g., multi-stage fracturing, matrix treatments, open hole).
- Production conditions (e.g., cycling pressure and temperature).
- Corrosive wellbore fluids (e.g., CO_2, H_2S, brine).
- Future field development or change in well objectives (e.g., producer to injector).
- Future abandonment and/or suspension procedures.
- Contingencies for unexpected wellbore conditions (e.g., geology, lost circulation, hole instability).

Slurry design is an iterative process. The pilot formulation expected to meet the required performance criteria and local regulations is usually based on experience in the area (usually via databases of historical information). Laboratory testing and simulations can be used to verify the predicted results and refine the slurry design to arrive at an optimal formulation for a given set of well conditions.

IRP The same design rigor/considerations that are applied to the reservoir zone shall also be applied to other potential flow zones in the well (e.g., nuisance gas, gas migration, water flows, potential future production zones).

25.4.1 Slurry Density

The primary consideration in slurry density selection is to meet the pore and fracture gradient window requirements. Once the density is selected other requirements for specific well conditions can be addressed to ensure well objectives are met. The cement slurry is typically heavier than the fluid it is displacing. See 25.3.2.2.2 Density Hierarchy for more information.

25.4.2 Cement Type

The type of cement to be utilized on a cement job depends on the job objectives. Class “A”, “C” and “G” cements are common oil and gas well cements. Class “G” cement is the most widely used cement in the oilfield worldwide.

Pozzolan and Portland cement blends offer predictable and reliable performance and can be designed to meet specific temperature, density and depth requirements. The major benefits of these systems are protection against sulphate attack and improvement in the cement’s resistance to the corrosive nature of formation fluids.

Table 5 identifies some typical applications for the most common types of cements.

Table 5. Common Cement Types

Cement Type	Features / Applications

Class A	• Nominal Density: 1878 kg/m^3
	• Mixing Water: 46%, 0.46 m^3/tonne
	• Yield: 0.777 m^3/tonne
	• Usage:
	  ○ Surface casing or shallow well cementing
	  ○ High C_3A content (Ordinary resistance to sulfate attack)
	  ○ Similar to ASTM C-150, Type I (construction), CSA “GU”, T-10 (construction)

NP (Normal Portland) Cement	• CSA “GU” or T-10 construction cement
	• Similar to API Class A
	• Density Range: 1878 - 2000 kg/m^3
	• Usage:
	  ○ Surface casing or shallow well cementing
	  ○ Economical Replacement for API Class A
	  ○ High C_3A content (Ordinary resistance to sulfate attack)
	  ○ No API Quality Checks

Class C	• Nominal Density: 1773 kg/m^3
	• Mixing Water: 56%, 0.56 m^3/tonne
	• Yield: 0.877 m^3/tonne
	• Usage:
	  ○ Surface casing or shallow well cementing
	  ○ Similar to ASTM C-150, Type III (construction)
	  ○ Ordinary to high resistance to sulfate attack

Cement Type	Features / Applications

HE (High Early) Cement	• CSA "HE" or T-30 construction cement
	• Similar to API Class C
	• Nominal Density: 1776 kg/m^3 (dependent on the cement fineness)
	• Usage:
	    ○ Surface casing or shallow well cementing
	    ○ Economical Replacement for API Class C
	    ○ High C_3A content (Ordinary resistance to sulfate attack)
	    ○ No API Quality Checks

Class G	• Nominal Density: 1901 kg/m^3
	• Mixing Water: 44%, 0.44 m^3/tonne
	• Yield: 0.757 m^3/tonne
	• Usage:
	    ○ All-purpose cement
	    ○ Intended use to all depths, with additives
	    ○ Most used cement class, world-wide

Ultra-Fine Cement System	• Fine grind penetrating cement
	• Early strength development
	• Lower density than API cement
	    ○ Nominal density is highly variable depending on PSD and composition
	• Low permeability
	• Provides seal or squeeze in problem areas:
	    ○ Thief zones, water zones, gas zones, casing leaks or gravel packs

Light Weight Cements	• <u>Manufactured</u> light weight cement
	    ○ Made as per Portland cements
	    ○ With added light weight aggregate
	
	• <u>Blended</u> light weight cement (Field Blends)
	    ○ Light weight aggregate blended after manufacture
	    ○ API or Construction cement with Fly Ash, Bentonite, additives, etc.

Pozzolan Mixtures	• Economical extended slurries
	• Densities as low as 1450 kg/m^3
	• Standard blend designation is A**:**B**:**C
	Where:
	    A = number of absolute volumes of fly ash
	    B = number of absolute volumes of cement
	    C = percent bentonite (or Gel) by weight of blend)
	• Cement Type should be specified

Certain conditions during drilling or during the life of a well may require the use of special cements. Examples of special cement systems are shown in Table 6.

Table 6. Special Cement Systems

Special Cement Systems	Features/Applications
Thixotropic	Cement slurry rapidly gains gel strength when slurry is static. The most common additive used is gypsum. Typical applications include: • Primary cement • Lost circulation plugs • Gas migration control
Artic/Permafrost Cements	Permafrost cements have the ability to set at temperatures as low as -10ºC. They have a low heat of hydration which maintains the integrity of the permafrost. These systems typically incorporate salt (NaCl) to suppress the freeze point and gypsum to lower the heat of hydration.
High Temperature Cements (110 – 360ºC)	Portland cements (Class G & Class A) retain their set properties up to a temperature of 110ºC. Above 110ºC, the cement becomes susceptible to strength retrogression (chemical phase changes result in shrinkage within the cement matrix accompanied by the loss of compressive strength). These systems typically have a minimum of 35% silica added to the cement blend to create different mineral phases which are less damaging to the cement matrix ("thermal" cement blend)
Ultra-High Temperature Cements (above 360ºC)	Ceramic and high alumina cements are generally recommended where the cement will be exposed to extreme temperatures of fire flood operations.
Salt Cements	Salt (NaCl or KCl) can be added to cement to: • Preserve the integrity of a salt zone • Act as an expansion aid • Minimize sloughing shales
Foamed Cements	Typical applications include: • Lost circulation (either as a primary cement or as a lost circulation plug) • Thermal wells (foamed cement have a lower thermal conductivity) • Gas migration control
Lightweight Cement	A blend of cement that allows a slurry density to be lightened as low as ±1000 kg/m^3 without the addition of nitrogen. Used to reduce the hydrostatic gradient of the cement column which is useful for wells with lost circulation or low bottom hole pressure. Have lower compressive strengths than their Class "G" or "A" counterparts.
Gas Control Additives	Used to inhibit gas flow into the cement.
Right-Angle Cement	Can be specifically designed to set in as low as 15- 20 minutes Typical used to address lost circulation
Microfine Cement	Ultra-fine cement typically used in squeezing micro-channels and low feed rate situations.

25.4.3 Additives

A common way to achieve specific properties is through the use of chemical additives in the cement blend. Meeting specific slurry objectives may require the use of several additives. Common classes of cement additives are described in Table 7.

Table 7. Cement Additives

Additive Type	Purpose
Extenders	Used to decrease slurry density, increase yield and decrease costs.
Weighting Agents	Used to increase the density of the cement slurry.
Accelerators	Used to decrease the thickening time of cements and increase the rate of compressive strength development to reduce WOC time.
Retarders	Used to extend the thickening time of cement.
Dispersants	Used to reduce the slurry viscosity, decrease the fluid loss of the slurry, improve the pumpability of high density slurries and increase the effectiveness of some fluid loss control agents.
Fluid Loss Control Agents	Reduces the amount of aqueous phase that is lost to a permeable formation from a pressure differential. Minimizes sloughing and formation damage caused by reducing cement filtrate loss. Maintains cement properties (thickening time and rheology). Minimizes gas influx and migration during cement hydration.
Lost Circulation Additive	Used to prevent loss of slurry to high permeability, low pressure or easily fractured formations.
Gas Control Additives	Used to inhibit gas flow into the cement.
Salt Additives	Added to cements for one or more of the following reasons: • To preserve the integrity of salt zones that must be cemented across • As an expansion aid • To minimize sloughing shales (as per “salt cements”) • To decrease wait on cement • To freeze suppression in permafrost applications

25.4.4 Thickening Time

Thickening time (TT) is a measure of consistency of the slurry and is measured in Bearden consistency units (Bc).

TT determines the length of time a cement slurry remains in a pumpable state. Slurry is typically considered pumpable up to 70 Bc.

TT is highly dependent on slurry temperature. Ensure an appropriate temperature ramp is used for TT tests. Consider running a temperature simulation if wells are deviated, horizontal or High Pressure High Temperature (HPHT).

When designing the cement slurry consider the potential for increased thickening time and changes in other slurry properties due to the cooler temperatures seen up-hole at the slurry's highest placement point in the annulus.

IRP The minimum thickening time (working time) should take into account the mixing method, job placement time, planned static periods and an appropriate safety factor.

Note: Working time is often used interchangeably with thickening time in industry. Terminology should be understood between the operator and the cementing service provider.

25.4.5 Compressive Strength

Cement requires compressive strength to support the casing and withstand operational stresses. The minimum required compressive strength is governed by jurisdictional regulations. However, the objectives for the cement job may require a higher compressive strength than the regulated minimum.

Lower temperatures will delay compressive strength onset at top of cement (TOC). Depending on the consequences of this delay, it may be necessary to model first particle temperature and design the slurry accordingly. Drilling out cement before the entire column has gained compressive strength may damage the bond to the pipe.

Wait on cement requirements are discussed in section 25.9.3 Wait on Cement.

25.4.6 Fluid Loss

Fluid loss control is important when slurry is placed across a permeable formation or where the annular gap is small (slim-hole cementing). A common industry guideline is fluid loss of <= 50 ml/30 minutes (as per the API Fluid-loss Test) for liner and slimhole applications and for areas with potential for annular flow. Insufficient fluid loss control allows some of the water to separate from the slurry and some of the aqueous phase of the slurry to penetrate the formation. This can lead to an increase in slurry rheology, increase in density, higher friction pressures, reduction in thickening time, formation damage, inability to maintain hydrostatic head after placement, annular bridging or, in worst case, plugging of the annulus. Any of these conditions can result in cement job failure. Fluid loss control is also essential for all high temperature and high pressure cementing applications.

25.4.7 Free Water

In highly deviated or horizontal wells the free water can coalesce to form a continuous channel on the upper side of the hole. This forms a path that may allow annular flow. Excessive free water can also be detrimental to the achievement of the desired top of cement.

IRP For thermal, high temperature, highly deviated or horizontal cementing the free water should be zero ml. The test is to be performed at a 45° angle.

Failure to eliminate free water can result in casing collapse or burst in thermal applications with casing in casing.

25.4.8 Rheology

To properly design, execute and evaluate a primary cement job it is critical to understand the rheological properties of the cement slurries. Proper rheological characterization is essential to the following:

- Evaluating the slurry's mixability and pumpability.
- Optimizing removal of drilling fluid and slurry placement.
- Determining the friction pressure when the slurry flows in pipes and annuli.
- Evaluating the slurry's ability to transport large particles (e.g., lost circulation materials).
- Predicting annular pressure during slurry placement (ECD).
- Predicting how the wellbore-temperature profile affects slurry placement.

IRP The rheology of the cement slurries and spacer should provide an optimized friction pressure hierarchy within ECD and pumpability constraints.

There is no defined minimum requirement for friction pressure hierarchy but a common industry practice is to have a 10% increase in friction pressure of the displacing fluid relative to the fluid being displaced.

25.4.9 Static Gel Strength

Static Gel Strength (SGS) development may contribute to decay of hydrostatic pressure in the column of cement. As gelled fluid interacts with the casing and the borehole wall it loses its ability to transmit hydrostatic pressure. One method to evaluate the impact of gel strength development on the potential for annular flow is to calculate the critical static gel strength (CSGS) and then to measure the critical gel strength period (CGSP). Wellbores often have variable hole diameters, contain multiple fluids in the annulus after the cement job and have more than one potential flow zone to be evaluated. For these reasons, it is recommended to use a computer program to evaluate the CSGS for all potential flow zones.

CSGS is 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). Density is the only slurry design parameter which can affect CSGS. The CSGS can be increased by increasing the hydrostatic overbalance relative to the potential flow zone, by reducing the length of the cement column above the top of the flow zone or by increasing the annular clearance.

Experiments have shown that gas cannot freely percolate through cement that has a static gel strength ranging from 120 to 240 Pa (250 to 500 lbf/100ft^2) or more. The industry has conservatively adopted the upper end of the range as the accepted limit. CGSP is the time period starting when lab measurements indicate the slurry has developed CSGS and ending when they show it has developed a SGS of 240 Pa (500 lbf/100ft^2). If insufficient information is available to confidently calculate the CSGS, a value of 48 Pa (100 lbf/100ft^2) can be assumed as a starting point.

IRP When annular flow or formation fluids influx is a risk, the CGSP should be minimized. Industry standard is a maximum of 45 minutes but there are situations where a shorter time is recommended.

The slurry CGSP should not be confused with setting time profiles as measured on a consistometer.

25.4.10 Stability

The term stability has various aspects with regard to any cement system.

Slurry Stability: During the liquid stage of cement slurry, stability is defined as the ability of the slurry to maintain a homogeneous density where solids are uniformly distributed without excessive separation of water.

IRP Slurry settling tests should be performed for high risk jobs and jobs with low and high density slurries.

Thermal and Chemical Stability: Once the cement sets, stability refers to the ability of the cement to withstand the wellbore conditions throughout the life of the well. The main wellbore conditions detrimental to cement sheath integrity are bottom-hole temperatures and fluid exposures.

Portland cements are stable under down-hole temperatures of less than 110°C (230°F). Above 110°C the cement goes through strength retrogression resulting in decreased compressive strength and increased permeability.

IRP A minimum of 35% silica (based on the weight of cement) shall be added to stabilize compressive strength and permeability/porosity of the cement when down-hole temperatures are above 110°C. In thermal areas there is a regulatory requirement that cement be stable at 360.5 °C (see AER Directive 09: Casing Cementing Minimum Requirements).

Formation and/or injected fluids can also be detrimental to cement matrix stability. It is important to know the fluid environment to which the cement sheath will be subjected.

For instance, in a corrosive fluid environment the durability of a Portland cement can be improved by adding corrosion resistant materials, lowering the permeability through optimizing particle sizes or adding chemical compounds to the slurry.

25.4.11 Expansion

Cement bulk shrinkage can create microannuli between the formation and the cement sheath which prevents the cement from providing a seal. A microannulus will result in a poor cement bond and, in some wells, a path for gas to flow. An expanding agent can be incorporated into the cement slurry to address the cement bulk shrinkage and reduce the risk of a microannulus forming. This is especially critical in wells with risk of gas or fluid migration.

Minor and controlled expansion is needed to seal off the microannulus and it is recommended that linear expansion not exceed two percent. Any expansion beyond two percent can result in poor cement quality and mechanical performance (see 25.4.13 Mechanical and Thermal Properties).

25.4.12 Solids Volume Fraction

Solids volume fraction (SVF) is the ratio between the volume of solids to the total slurry volume. A conventional neat 1900 kg/m^3 Class G slurry has a SVF of 0.41 whereas conventional extended slurries can have SVF as low as 0.20. Porosity is the ratio of the volume of pores within set cement to the total volume of the cement. While set cement porosity cannot be directly inferred from SVF, slurries with lower SVF will generally result in set cement with higher porosity and vice versa. Lower SVF cement may not have sufficient strength or result in high porosity set cement that cannot adequately combat fluid invasion through the cement matrix. Low SVF is usually associated with extended slurries (i.e., economical systems) where the slurry is placed in the annulus mainly to provide additional support to the pipe and there is no annular flow from the formation. Low porosity slurry is recommended when there is a risk of potential formation influx. Higher solid content slurries provide superior strength and resistance to fluid invasion.

Particular attention needs to be paid to up-hole zones which are covered by lead cement slurries because lead cements often have high porosity as a function of lowering the SVF to achieve a lower density.

25.4.13 Mechanical and Thermal Properties

Cement systems are required to withstand operational loads and provide zonal isolation throughout the life cycle of a well. Traditional cement system selection is based on compressive strength and typically neglects other mechanical and thermal properties of set cement. However, in many extreme service wells (e.g., thermal stimulation, hydraulic fracturing), other properties can provide a more relevant indication of cement performance. Additional properties to consider during design for extreme service wells include the following:

- Elastic modulus
- Tensile strength
- Confined and unconfined compressive strength (i.e., Mohr-Coulomb properties)
- Thermal expansion
- Permanent volumetric shrinkage/expansion
- Thermal diffusivity (i.e., density, thermal conductivity and specific heat)
- Poisson's ratio

Radial expansion/contraction of the casing from internal casing pressure or large temperature changes in extreme-service wells generates substantial deformations in the cement sheath over the life of the well. The mechanical and thermal properties of the cement can be optimized to withstand these deformations. However, optimization relies on a thorough understanding of the governing cement properties and how the cement interacts with the casing and formation under the loads introduced by operations. For example, formation properties like stiffness need to be considered when designing the mechanical and thermal properties for an application.

IRP The cement mechanical and thermal property design should be optimized and fit for purpose.

Understanding and manipulating these properties can produce cement systems capable of withstanding different types of deformations and improve long-term integrity. Computer modelling programs may help evaluate the possible loading conditions on cement, evaluate the effect of those loads on the cement sheath and understand the relative importance of certain cement properties, but should not be relied on exclusively for cement selection. Other evaluation techniques like field experience, experimental testing and fundamental engineering analysis can be used to select an optimal property set.

Consider the downhole curing path and loading conditions when designing the cement thermal and mechanical properties. Cement properties can be affected by downhole conditions (e.g., temperature, pressure).

IRP Cement samples used to measure mechanical and thermal properties for design purposes should be cured under pressure and temperature representative of the downhole environment.

For example, most steam-assisted gravity drainage (SAGD) wells have a low bottomhole static temperature but loading is generated by elevated temperatures. An ideal test path for this application is to cure at low temperature followed by a test at elevated temperature. Conversely, cement in deep wells will be exposed to high geothermal temperatures. An ideal test schedule for this application is to cure and test at high temperature. Simplified cure/test paths can be considered if the simplified cure/test path is confirmed to be representative.

25.4.14 Lost Circulation

It is expected that lost circulation encountered during drilling will be cured prior to the primary cement job if possible. However, even after curing the losses it is possible for lost circulation to re-occur during the cement job due to the removal of the filter cake, increased hydrostatic or additional ECD.

Lost circulation can be addressed either through addition of lost circulation material (LCM) or through specialized blends. Consider the effect of increased cement density and ECDs relative to drilling fluid when managing lost circulation. Some examples of special blends and their purpose are listed in Table 8.

Table 8. Special Blends to Combat Lost Circulation

Type	Situation/Purpose
Conventional lightweight cement and foam systems	Use to minimize hydrostatics
Thixotropic cement systems	Use across shallow formations with low fracture gradients to minimize fallback
Lightweight cements with high solid contents and varied particle sizes in the blend	Use to plug fractures and minimize hydrostatics

IRP Lost circulation below intended top of cement should be addressed prior to commencing the primary cement job.

When LCM is incorporated into the spacer or cement, the fluid needs to exhibit good carrying capability to avoid settling of LCM. Slurry with a yield point (YP) of 7.5 Pa is typically considered adequate for suspension of LCM. Lab testing can confirm system stability and LCM compatibility.

25.5 Lab Testing

Lab testing procedures are designed to replicate downhole conditions for temperature and pressure. Temperature has the strongest effect on slurry properties and typically pressure is a secondary effect. Over or underestimating the temperature can result in premature setup and unpredictable slurry properties which could result in a compromised cement job.

IRP Cement samples tested for design purposes should be cured and tested based on the anticipated placement process and well conditions representative of the downhole environment.

25.5.1 Testing Temperature

Both bottomhole static (BHST) and circulating (BHCT) temperatures are required for cement testing.

When available, use offset information (i.e., wells, logs) to determine the BHST. If no information is available BHST gradients could be used.

Equation 1. BHST Gradients

$$BHST = (D \times TG) + S$$

Where:

- D = Depth (metres)
- TG = Thermal Gradient (°C/m)
- S = Surface Temperature (°C)

IRP Thermal gradients to be used for testing should be based on well data (e.g., offset well logs).

Note: Temperatures obtained from Measurement While Drilling (MWD) tools are not necessarily reflective of circulating temperatures.

BHCT can be calculated or simulated from the BHST and is considered to be the critical design temperature for slurry placement.

When designing slurry consider the potential for change in slurry properties due to the cooler temperatures seen up-hole at the slurry's highest placement point in the annulus. Additional tests at cooler temperatures may be required to model up-hole conditions.

25.5.2 Testing Specifications

IRP All cement testing procedures shall, at minimum, adhere to the latest version of the following standards:

- API RP 10B-2
- API RP 10B-3
- API RP 10B-4
- API RP 10B-5
- API RP 10B-6

Note: There are ISO standards related to cementing however they are not equivalent to API in all cases.

Note: Some cement properties are not fully characterized using standard methods. Deviation from the above standards is acceptable if the planned testing process is more rigorous (i.e., exceeds the standard) or presents a more realistic approach to the planned operations.

Deviation from the API standards would be expected under the following circumstances:

- When batch mixing
- During shut-down periods (liner, two-stage when-cement above stage tool is circulated out of hole)
- When placing Balanced Plugs
- When reverse cementing
- When using materials with unconventional or specific mixing requirements
- When characterizing cements for unconventional applications (i.e. thermal stimulation)
- In highly-deviated or horizontal wells

IRP The operator and the cementing service provider shall agree on the testing procedures to be used.

25.5.3 Testing Requirements

Match testing requirements to the risk and complexity of the job. Pilot and sensitivity testing regimes require more rigour due to the risk of failure. The cementing service provider and the operator should agree on the level of testing.

IRP Pilot testing should commence as the well(s) planning phase is initiated.

Pilot testing defines the slurry design, provides data for modeling and establishes the slurry properties and expected results for stock materials.

IRP More complex jobs should have slurry sensitivity tests performed and demonstrated to the operator.

Sensitivity tests may include variable temperatures, densities and additive loadings.

See section 25.7.1.5 Bulk Plant Sampling and 27.1.6 Bulk Plant Blend Testing for bulk plant sampling and testing requirements.

25.5.4 Testing New Products or Technology

Improvements to cementing equipment, products and services are always being introduced to the industry in an effort to provide high quality cement jobs. Although there can be a risk to trying new technology, these risks are controlled or managed with proper testing through the scale up process.

IRP Due diligence (i.e., risk assessment, performance testing, application quality assurance and operational procedures) should be performed for any new processes or products and demonstrated to local jurisdictional regulator as required.

25.6 Wellbore Construction

Minimum wellbore design may be regulated and local jurisdictional regulations need to be consulted during design. Some of the key design considerations include protection and isolation of groundwater resources, isolation of hydrocarbon-bearing formations and containment of all operational fluids and pressures.

Wellbore design lays the framework for how hydrocarbon reserves will be accessed and recovered through cased wellbores. It is one of the first steps in the rigorous process of providing and assuring well integrity through the full life cycle of the well.

Well objectives and any potential future use of the well have direct effects on cementing. Cement designs need to consider the past, present and future condition of the well in early planning stages. Any potential future use of the well (e.g., oil, gas, water, thermal, observation, disposal, sour, CO_2, exploratory, etc.) needs to be considered in design. Operating conditions for the wellbore can only be modelled after evaluating all potential uses of the well. It is important to include the conditions the wellbore will be exposed to during construction as well (e.g., pressure tests, fracturing, wellbore fluid containment during drilling, dealing with losses or kicks, etc.).

IRP Planners should consider the life cycle of the well (up to and including abandonment) in wellbore design. Changes in scope or use of the well should consider the following:

- The original design parameters.
- Exposure to temperature, pressure, chemicals and reservoir fluids.
- The condition of the casing.
- The state of the completion activities (i.e., are there perforations, scab liners, bridge plugs, etc.).
- The condition of the cement sheath.
- Recompleting for secondary zone.
- Future remediation work on the well.
- Offset wells (i.e., impacts of and to offset wells, offset well condition).

All groups, including on-site personnel, are expected to operate within the parameters of the well design. Keep the necessary records to accurately assess well status for any future project.

25.6.1 Well Design

25.6.1.1 Formations

The potential for SCVF and GM can be minimized through the analysis of reservoir geology and overburden formation properties along with sound casing and cementing designs and installation practices. An understanding or analysis of the area geology and geomechanics can assess the potential gas bearing reservoirs and indicate where isolation is required along the well. There are circumstances where GM and SCVF initiate as a result of wellbore activity (i.e., thermal activity or fracturing). In complex scenarios there could be fluid movement that involves adjacent wells with cross-flow through permeable zones. Mature wells may have used less rigorous cementing practices and operating conditions may have changed which affect zonal isolation. The industry is confronted with a significant challenge to understand and remediate these scenarios.

Potential zonal isolation issues can be identified prior to drilling using data from offset or stratigraphic wells or from formation evaluations.

IRP Offset wells and formation information should be used to aid wellbore design and planning activities to prepare the well for cementing.

Evaluating this information can help improve the potential for zonal isolation, optimize the completion and production processes and identify formation properties.

Formations with potential to cause lost circulation can negatively impact a cement job. This can be due to the following:

- Low strength (i.e., those with a low fracture gradient).
- Natural fractures or high porosity/permeability.
- High matrix permeability with insufficient filter cake can act as a fluid loss site for leak-off for water from the cement resulting in dehydration of the cement slurry.

Some formations may be chemically or mechanically reactive which can affect wellbore conditions and adversely affect cementing. The effects can be mitigated through the following:

- Choice of drilling fluid and drilling fluid weight
- Choice of spacer and spacer weight
- Depth of casing
- Adjustments to hole size
- Additional casing strings
- Wiper trips

- Hole conditioning
- Minimizing the length of time the wellbore is left open
- Optimization of cement job design (see 25.2 Cement Job Design)

25.6.1.2 Hole Size and Annular Spacing

Hole size and annular clearance impact the ability to properly place cement. Consider the following:

- The clearance required to run centralizers and achieve stand-off.
- Increased frictional pressure loss associated with small annuli (ECDs).
- The cost of future wellbore operations versus the cost savings associated with smaller hole and casing sizes.

Annular size will affect the selection of the optimal centralization program (see 25.6.1.11 Centralization).

Cutting beds will increase drag during casing running. Tolerance of running operations to cutting bed size will depend on annular clearance and slack-off weight available. Tight clearance casing programs may encounter the most difficulty in open hole sections with 30° - 60° inclination due to the potential accumulation of cuttings.

Small and large annuli (under-reamed sections) increase cementing challenges.

Table 9 discusses the pros and cons of a larger hole size.

Table 9. Pros and Cons of a Larger Hole Size

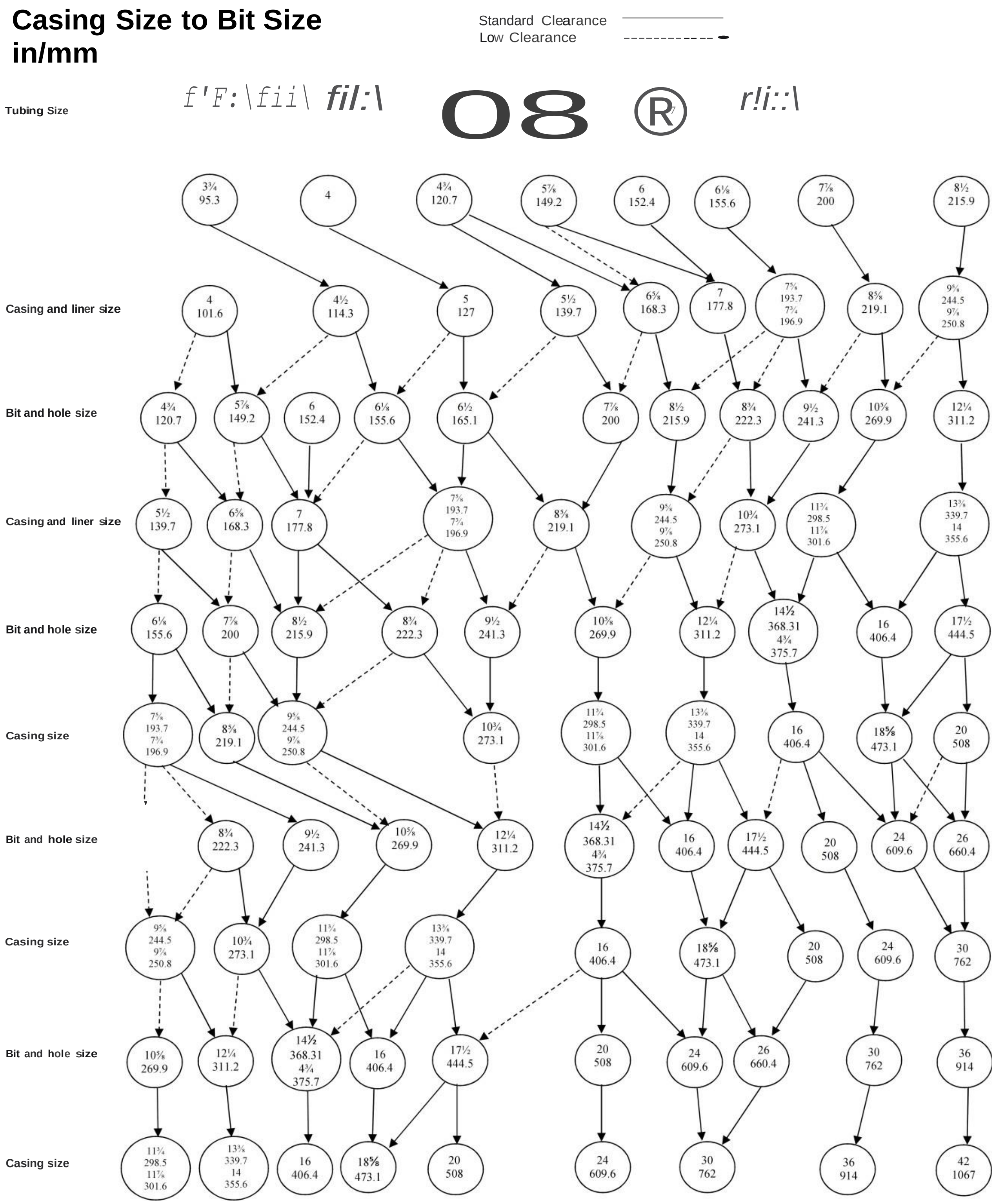
Pros	Cons
Lower ECDs	Lower annular velocities
Easier casing placement	Difficulty centralizing
Thicker cement sheath	Difficult cuttings transport efficiency
Greater tolerance for poor hole conditions (i.e., cuttings beds, wellbore instability)	Potentially higher cementing costs
Easier to rotate and reciprocate during cementing	Difficulty removing drilling fluid/filtercake
Larger tool sizes are more robust	Generally, increased drilling costs and time (to deal with cuttings and make the hole)
Allows for greater array of contingency planning (i.e., the bigger the hole the more options available)	Larger tool sizes may be difficult or unsafe to handle (but they may also be more robust)

Washout can make it more difficult to resolve the issues associated with a larger hole size.

IRP Annular clearance and hole cleaning should be considered when designing hole sizes and casing sizes

Select hole and casing sizes based on well design and objectives. Common hole and casing sizes are shown in Figure 3 below. If the well design deviates from the chart then additional cement job design rigor is required (e.g., additional spacer, centralization, friction pressure hierarchy, etc.).

Figure 3. Hole and Casing Sizes



This chart is to be used for initial casing design.

25.6.1.3 Casing and Connection Selection

Consider formation properties, hole size and all future operations of the wellbore (e.g., production, fracture stimulation, remediation, abandonment, etc.) when designing the casing strings. Consider the most severe environments expected throughout all operations.

Casing configuration is generally dependent on geology, production strategy and completion design. Well objectives and wellbore properties influence the type of casing connection, which may impact cement design due to the following:

- The ability to rotate and/or reciprocate casing
- Standoff
- The type of centralizers that can be used
- Job pressures (casing burst and collapse)

Pipe movement has a significant impact on cement placement.

IRP Casing and connection limitations (fatigue, axial, etc.) should be assessed and used to define rotation limits if casing rotation is employed.

Select casing and connections that have greater torque and axial capacity than loads imposed during rotation or reciprocation. If standard API connections do not provide the required capacity for the expected conditions then use modified API (e.g., with a torque ring), semi-premium or premium connections with suitable capacity (see Glossary for definitions).

Torque and drag analysis can provide useful information to estimate loads during casing movement. Often these estimates can be refined based on measurements taken at the rig during casing running.

Wellbore curvature in deviated wells will impose a stress gradient on casing, tension on the wellbore extrados and compression on the wellbore intrados. The stress gradient increases as dogleg severity (DLS) and the diameter of the casing increases. Casing rotation causes these stresses to alternate (i.e., cyclic loading) thus introducing fatigue damage and, in the worst case, fatigue failure. Fatigue damage is typically highest in connections where thread geometries cause stress concentrations. Cyclic stress limits and subsequent fatigue life (i.e., the number of rotations) need to be considered before utilizing casing rotation.

Refer to API TR 5C3 for information about casing design limits. See also IRP 3: In Situ Heavy Oil Operations for thermal implications and IRP 1: Critical Sour Drilling for H_2S implications.

25.6.1.4 **Stage Tools**

Stage tools are used when specific or unique cement placement is required. Stage tools are typically used to cement a partial length of the string and assist in providing isolation over problem zones that cannot withstand a full hydrostatic column of cement without breaking down. They are often run with a packer below them.

The following are some common reasons for using stage tools:

- To attain desired TOC above a low fracture gradient formation.
- To separate large differentials in temperature gradients.
- To cement the up-hole section of a monobore well with open-hole completions.
- When there are ECD restrictions.
- When multiple formations are still open below the intermediate casing and require isolation.

Confirm that the stage tool has a mechanical strength ratings equal to or greater than the required rating of the casing. If the stage tool is hydraulically activated, the activation pressure needs to be below the ratings of all other well components plus a reasonable safety factor.

There can be additional challenges with stage tools within the build section. It can be difficult to mechanically activate the stage tool and wellbore curvature can impact the performance of stage tools.

Port Collars provide a selective communication path from inside the casing to the annulus and can be utilized as a contingency for stage/remedial cementing operations.

25.6.1.5 **External Casing Packers**

An External Casing Packer (ECP) creates a seal against fluid migration between zones by packing off against the borehole. ECPs can be equipped with three types of rubber elements: inflatable, solid and swellable. The inflatable element is expanded by filling a bladder with wellbore fluid or cement. The solid element is expanded by application of a mechanical force to compress the solid rubber. The swellable element expands when contacted by an aqueous fluid, liquid hydrocarbon or a gas. Swellable packers are not typically used for cementing because the swelling process requires multiple days or weeks and is highly dependent on temperature.

Inflatable or solid ECPs are more typically used when cementing and can be positioned in the casing string directly above a lost circulation zone. The packer prevents the loss of cement slurries to the thief zone.

In a multi-stage cement job an ECP is typically set below the stage collar. This allows the upper stage of a staged cement job to be pumped immediately after inflation. The ECP will also aid in the centralization of the casing at this point.

It is generally not advisable to set an ECP above a gas migration risk zone after placing cement. Doing so removes the hydrostatic pressure off the cement and significantly lowers the CSGS of the cement making it more like to have gas invasion.

Other applications include the following:

- Placement of the packer slightly above an oil-water or a gas-water contact can aid in the prevention of unwanted water production
- Packers can be used to minimize damage to sensitive formations and barefoot completions.

Annular clearances are reduced with the use of ECPs and need to be given due consideration when running in the hole. Potential washout at ECP setting depth may also be a concern. Hole conditions need to be considered prior to running ECPs to confirm surge pressure tolerance and to confirm optimal placement in the event washout is a concern.

25.6.1.6 **Liners**

Liners are used to case off the open hole below a previous casing point. Liners are run in the hole on the end of drill pipe and “hung” off the previous casing with a liner hanger. Key design parameters include whether to cement the liner lap and length of the overlap.

Cement can be the primary barrier for the liner lap. Consider the following when determining the length of liner lap:

- Pressure/ECD
- Whether you have a packer or not
- Production liner vs. intermediate (i.e., how critical is it?)
- Thermal expansion
- Centralization

Liner hangers can be equipped with packers to provide a secondary mechanical seal. The packer will

- help to seal against possible fluid migration,
- serve as a back-up if liner lap is not properly cemented and
- allow for excess cement on top of the liner to be reversed out without applying additional pressure to the cement column below the liner hanger.

A cementing simulation for liners that will be cemented is recommended. Liners are more challenging to cement for the following reasons:

- They use smaller cement volumes (higher chance of contamination)
- Unique cement blends are often used (increased complexity)
- There is stop and start of cement movement when the drill pipe disconnects from the top of the liner
- They use latching wiper plugs
- There are often tighter ECD windows
- There are flow restrictions at the liner hanger
- There are hole cleaning restrictions through horizontal sections
- There is increased difficulty in attaining standoff in horizontal sections

Excess cement is pumped into the drill pipe/casing annulus during placement. This excess cement is usually circulated out of the hole. Use caution if reverse circulating to keep the extra pressure from pushing cement away from the lap.

Centralization is especially important in the liner lap section to avoid a liner top leak. Liners are often designed with smaller annuli or under-reamed hole sections which requires additional focus on the associated cementing and centralization challenges (see 25.6.1.2 Hole Size and Annular Spacing).

25.6.1.7 Directional Planning

The directional profile of the wellbore will affect the objectives of the cement job. Inclination and azimuth may affect wellbore stability and hole cleaning. DLS and profile may affect centralization and the ability to move casing.

Three dimensional fluid hydraulic models can be used to model the cement job to quantify the effects and to run sensitivity analyses on different options.

Wells with high DLS may have casing in contact with the formation which can prevent proper cement placement and increase the risk of poor isolation. DLS can increase the difficulty of hole cleaning as cuttings tend to build up in “sumps”. It also becomes more difficult to reciprocate and rotate casing in a well with high DLS and rotation may result in connection seal/structural failure due to fatigue. Reaming through sections of unplanned high DLS may improve the ability to move casing. See 25.6.2.5 Ability to Rotate/Reciprocate During Cementing for more detail.

IRP Casing and cement job design (i.e., centralization, pipe movement, spacer design) should be re-evaluated based on actual directional surveys and severity of doglegs.

For effective cement placement, minimize fluctuation in DLS and use adequate centralization practices (see 25.2 Cement Job Design section 25.2.7 Centralization).

25.6.1.8 Equivalent Circulating Density

ECD's are a function of annular size, flow rate, density and rheology. Consider ECD when designing the well.

Detailed ECD modelling is recommended in the planning phase to understand the implications of the well design and equipment being used. Sensitivities to key variables should be included (e.g., fluid densities, rheology, flowrate, rpm, drill string, well profile, well length, etc.). Calculate ECDs and compare to the fracture and pore pressure gradients for the entire open hole interval.

IRP ECD limitations should be considered when designing the wellbore to ensure circulation.

ECDs are not necessarily the highest at Total Depth (TD) or the lowest at the previous casing seat (e.g., when backpressure is held at surface).

Consider collapse loads during and after the cement job in the casing design (see 25.6.1.3 Casing and Connection Selection). Collapse loads typically occur during inner-string cementing and bleed-off of float equipment.

Consider the following implications of ECD on the casing configuration if the ECD margins are tight:

- Modify cement slurry and/or spacer design
- Alter job execution (e.g., slurry placement, pump rates, reverse cementing)
- Run casing as a liner
- Increase hole size and/or decrease casing size
- Use stage tools

25.6.1.9 Drilling Fluid Selection

Drilling fluid design is a critical component of the wellbore construction design because of the drilling fluid's impact on the following:

- Well control
- Hole stability
- Washout/hole enlargement
- Cuttings removal
- Filter cake quality
- Wettability

Drilling fluid selection is driven by the ability to successfully drill and case an open hole section. Different types of drilling fluid can impact cement in different ways when they interact.

Proper spacer design is essential to successful cementing operations because it keeps drilling fluid separate from the cement and aids in the removal of the drilling fluids and filtercake. Inability to remove drilling fluid from the wellbore may impact the effectiveness of cement placement. The drilling fluid and cement slurry/spacer have to work together. The type of fluid system needs to be considered when designing spacer. Refer to 25.3.4 Compatibility for more information.

Drilling fluid challenges for cementing are shown in Table10.

Table 10. Drilling Fluid Challenges

Drilling Fluid Type	Example Usage	Typical Challenges
Gel Chem/Polymer Based (Water Based)	Surface casings, shallow wells	• Contamination of drilling fluids can result in the formation of emulsions, increase the difficulty of drilling fluid removal and adversely affect the cement setting times.
Silicate	Reactive formations, minor losses	• Premature or flash setting.
Oil/Synthetic Based	Reactive formations, extended reach, lower density required. Drilling through salt formations.	• OBM contamination of cement significantly retards or prevents cement from developing compressive strength. • Changes wettability of casing and formation. • Often expensive to reduce rheology prior to cementing. • Incompatible with cement, creating viscous interface.
Salt Based (Water Based)	Drilling through salt formations, reactive formations	• Similar to Gel Chem, with additional risk of flash setting.
Air/Mist/Foam	Low density, high lost circulation, shallow holes	• No/minimal filter cake. • Cement fluid loss into formation may affect slurry properties or cause flash set. • May mask hole stability problems.

25.6.1.10 Casing Hardware and Accessories

Float equipment, cementing plugs, stage tools, centralizers and scratchers are mechanical devices commonly used in running pipe and in placing cement around casing.

25.6.1.11 Centralization

Using centralizers improves pipe standoff which will improve cement placement. The pipe standoff enables an even flow profile which improves the displacement of the drilling fluid allowing the cement to surround the casing and create zonal isolation with a channel-free seal. The annular velocities in an eccentric annulus can vary drastically and create channels of drilling fluid or spacer.

Develop the centralization plan during wellbore design. Centralizers can assist running casing in deviated sections by reducing side-loads due to buckling. However, an excessive number of centralizers can increase running loads. Centralization design (frequency, size, placement and type of centralizer) is a balance between achieving optimal running loads, displacement efficiency and standoff.

IRP Centralization should provide minimum standoff for effective removal of drilling fluid and hydraulic isolation throughout the life of the well. Simulations are recommended to determine standoff requirements.

Consider the following:

- Alignment at surface to accept the casing bowl and casing seal assembly.
- Actual borehole trajectory and caliper along the open hole section.
- The restoration force of bow spring centralizers relative to side load.
- The geology (i.e., rock strength) of the formations.
- Adequate standoff in both open hole and cased hole sections.
- Proper centralization of the shoe track.
- Centralizer rib profile and circumferential coverage.
- Method of centralizer attachment (i.e., crimp-on vs. floating).
- Whether rotation or reciprocation is planned.
- Pipe buoyancy.

IRP Centralization design should be revisited if there has been a significant deviation from the original plan.

25.6.1.12 **Spiral Centralizers**

Spiral centralizers can be used in wellbore construction to divert the flow vector azimuthally around the wellbore to disrupt cement channeling. They typically affect the flow for somewhere between two and four metres (seven to twelve feet).

25.6.1.13 **Scratchers**

Scratchers are used to mechanically (i.e., with pipe movement) remove excessive filtercake over specific intervals. Removing the filter cake may improve cement bond to formation thereby improving zonal isolation. Removal of the filter cake may also induce lost circulation across high permeability zones, especially if lost circulation material was used to stop lost circulation during drilling operations.

25.6.1.14 Cement Baskets

Cement baskets may help support the cement column during cementing operations. They may reduce the hydrostatic fluid column above a loss zone or weak formation to reduce losses.

Consider the following in the decision to use cement baskets:

- Cement baskets can limit annular clearance and result in complications in cuttings removal leading to pack off/bridging. Consideration should be given to placement due to bridging off in the baskets.
- There is an increased risk of gas migration from lower formations due to the reduction of hydrostatic pressure below the basket.
- Cement baskets may limit or eliminate the ability to reciprocate or rotate the casing string.
- Cement baskets may impede the ability to do a top-up job with spaghetti string.
- Cement baskets can unknowingly create an uncemented interval below the basket.

25.6.1.15 Floats

Float equipment is typically a float collar and/or float shoe. Floats are essentially a one-way check valve (i.e., cement can be pumped through them but they will prevent backflow up the casing). They can reduce the chance of a microannulus forming as they reduce internal pressure post-placement. Floats need to

- resist plugging and erosion,
- be designed to withstand the impact forces of plug bump,
- form an adequate seal with the wiper plug(s) and
- have a rating greater than the anticipated final differential pressure.

Surge forces need to be considered when running casing if float equipment is used.

Auto-fill float equipment is designed to temporarily disengage the one-way check valve system and allow flow of drilling fluid in either direction while casing is being run into the well. This may aid in reducing losses while running casing by decreasing surge pressures.

Refer to API RP 10F for more information about float selection and performance.

25.6.1.16 Shoe Track

The purpose of the shoe track is to catch any drilling fluid film that is wiped from the casing during displacement by the wiper plug. It also allows a buffer to prevent over-displacement of cement or wet shoe if the plug isn't bumped. This is done to provide a more consistent cement bond around the casing shoe.

IRP When used, the length of the shoe track should consider the following:

- The volume of contaminated fluids.
- The type of drilling fluid to be wiped from the casing and its compatibility with the cement.
- Subsequent operations.
- The efficiency of the wiper plugs.
- Whether a bottom plug was run or not.

The length of the shoe track can be determined by calculating the volume of film expected to be wiped off the casing.

In the absence of a shoe track, consider pumping a defined volume of cement on top of the plug (to be cleaned out later) to act as the buffer and prevent over-displacement.

25.6.1.17 Planning for Alternative Cement Placement

Additional casing design considerations and hardware may be required for reverse or inner string cementing (see 25.8.12 Alternate Placement Techniques).

25.6.2 Drilling Operations

Proper drilling practices and hole preparation, including cuttings removal and hole cleaning/conditioning, are critical for a strong effective bond to both casing and formation.

IRP Drilling problems have the potential to jeopardize the cement job and should be addressed prior to cementing (e.g., lost circulation, high pressure, low pressure, hole sloughing, etc.).

IRP Hole cleaning should be completed prior to running casing.

Note: Hole cleaning is more challenging in deviated wells because they typically accumulate cuttings on the low side of the well.

Consider the following during drilling to optimize the condition of the hole for primary cementing:

- Achieve wellbore geomechanical stability (i.e., maintain effective drilling fluid properties).
- Understand formation fracture gradient (use Formation Integrity Tests (FITs) and Leak-off Tests (LOTs) if required)
- Address losses. Open hole cementing may be required (see 25.4.14 Lost Circulation).

- Avoid primary cementing in uncontrollable situations (e.g., underbalanced, losses).
- Avoid excessive doglegs.
- Compare the field measurements to torque and drag models.
- Consider drill pipe rotational rate and a hydraulics program to optimize pump rates and drilling fluid properties as they relate to hole cleaning.
- Consider hole to pipe size ratio.
- Minimize hole washout/enlargement.
- Examine cuttings returns and monitor the tank volumes to understand hole conditions.
- Optimize rate of penetration (ROP).

25.6.2.1 **Wiper Trips and Backreaming**

IRP Wiper trips and backreaming should be considered in response to field history or hole conditions observed while drilling.

A wiper trip can be used after drilling to identify tight spots, which may indicate high doglegs, ledges or excessive cuttings accumulation.

Pump rate (i.e., circulating at a high enough rate) and RPM are parameters that can be manipulated during wiper trips and/or backreaming to reduce hole drag and smooth out dog legs.

25.6.2.2 **Drilling Tools/Techniques to Remove Cuttings**

There are various drilling tools and technologies for cuttings removal.

Bladed drill pipe can be used to stir up cuttings beds in long tangent sections and increase the rate at which the hole is cleaned. Blades lift cuttings off of the low side of the borehole and auger them into the drilling fluid flow. Bladed drill pipe can also reduce the risk of pack-off while backreaming. Staged blade sizes can reduce the risk further.

Sweeps and pills can also be used during and after drilling to clean the hole.

25.6.2.3 **Running Casing**

Consider the following when running casing:

- Clean the hole prior to running casing
- Follow the centralization program for designed standoff.
- Break circulation to reduce gelation of drilling fluid as required.
- Consider rotating casing within design limits to enhance removal of drilling fluid (see 25.6.2.5 Ability to Rotate/Reciprocate During Cementing).

- Monitor trip-in speeds to prevent surging of the wellbore. If small annular clearance consider utilizing auto-fill float equipment.

25.6.2.4 Circulating/Conditioning Drilling Fluid Prior to Cementing Casing

High viscosity can make the drilling fluid difficult to displace during the cement job. Cement channelling through the drilling fluid can be an issue in both vertical and directional wellbores. The drilling fluid may need to be thinned or conditioned prior to cementing. Refer to 25.4.1 Slurry Density for a discussion on density and rheology hierarchies.

Consider the following techniques:

- Before conditioning the drilling fluid, circulate until the shaker is as clean as practically possible when at planned depth with casing.
- Reduce the drilling fluid viscosity, density and yield point as low as reasonably possible to improve drilling fluid displacement. Consider the implications reducing viscosity and yield point will have on barite sag or other drilling fluid instability. Decreasing density may result in increased risk of borehole instability or well control issues. Transition slowly and circulate enough to ensure displacing drilling fluid is not channeling through the thicker drilling fluid.
- Run a step-rate circulation test to optimize removal of drilling fluid (refer to Appendix J: Step-Rate Circulation Test for more information).
- Utilize fluid caliper and/or displacement marker sweeps (e.g., with dye, grain, coloured beads, etc.) to determine whether the entire hole is being circulated to help analyze hole problems. Early returns could indicate channelling or cuttings build-up.

25.6.2.5 Ability to Rotate/Reciprocate During Cementing

Reciprocation and rotation of casing (casing movement) improves cement placement and displacement efficiency by moving stagnant drilling fluid and removing filter cake. Casing and connection selection should consider the ability to reciprocate and rotate.

IRP Pipe movement during drilling fluid conditioning and cementing should be utilized where practical.

Generally, it is beneficial to maintain casing movement throughout cement circulation. Buoyancy effects may make reciprocation challenging during displacement if the casing is displaced with a fluid with a lower density than the cement.

If casing movement is planned, the limitations of the casing (tensile torque and fatigue) and connection need to be identified in advance so they are not exceeded during operations. Refer to 25.6.1.3 Casing and Connection Selection for more information.

25.7 Pre-Job Preparation

The focus of pre-job preparation is to have the appropriate processes and verification procedures in place to prevent failures.

25.7.1 District Pre-Job

District pre-job is all of the work that must be completed by the cementing service provider from the point of sourcing the material up to the point where the equipment mobilizes for the well site. Procedures put in place at this stage ensure equipment will perform as expected and materials used and blended will meet the design specifications.

25.7.1.1 Vendor QA/QC of Materials

Cementing success begins with quality control for all cementing additives and bulk materials.

IRP Material quality should be verified through vendor quality control processes and be certifiable to the purchaser. All products to be used should be included in a quality control plan.

A thorough process allows all materials to be verified and traced back to their manufacturer. This ensures consistency and provides traceability.

25.7.1.2 Equipment

Cementing success requires the proper equipment for the job and that all equipment functions properly.

IRP The equipment supplied for the job shall be verifiable as being capable of performing, at minimum, to the job design.

IRP Preventative maintenance programs shall be in place for all equipment.

Equipment selection is driven by job design elements such as the following:

- Pump rates
- Pressure
- Pipe movement
- Type of cement head to accommodate pipe movement or number of plugs
- Downhole tools

- Rig configuration (e.g., layout, space requirements, top drive)
- Volumes (surface, contingency or customer requested)
- Batch mixing requirements

Improper equipment can result in jobs not being pumped according to design or complete failure during treatments. The impact of inadequate equipment and/or malfunction ranges from lost time to compromised well integrity.

A cement head is preferred over a swage to minimize HSE concerns, reduce the introduction of air into the casing and increase the efficiency of plug launch. The use of a swage is not permitted in some jurisdictions. Consult local jurisdictional regulations.

IRP Due to the potential operational and HS&E severity of a failure, only high pressure iron and hoses that have undergone proper and regular certification should be used.

25.7.1.3 Bulk Plant QA/QC

A preventative maintenance program for the Bulk Plant helps ensure a quality preparation of the blend.

IRP Bulk plant storage silos are pressure vessels and must comply with applicable regulations regarding the operation of pressure vessels.

In Alberta, the Alberta Boilers Safety Association (ABSA) regulates pressure vessels over 14.9 Psi. Vessels under 14.9 Psi are not subject to provincial regulation but should meet internal standards of the cement service provider. Other provinces have equivalent standards but the Alberta standard is recognized as the most stringent. Refer to www.ABSA.ca for additional information.

IRP The Bulk Plant weights and measures must be recertified annually as per Measurement Canada's Certification Requirements for Measuring Apparatus.

Each bulk plant has a specific blending system which requires its own maintenance program that includes the following:

- Valve and compressor maintenance
- Dust control measures
- Pipe wear monitoring
- Safety relief valve maintenance

IRP QA/QC should include the use of audits (internal and external) to verify adherence to company standards (e.g., cementing service provider, operator requirements) and regulatory compliance.

25.7.1.4 Bulk Plant Dry Blending Procedures

A standardized blending procedure has been shown to improve the consistency of the prepared blends. Cement systems that are dry blended may have many different components in various concentrations and volumes so it can be difficult to achieve a homogenous blend.

The layering method is referred to in industry as the sandwich method. It involves layering the products in the dry blend. The blend is transferred from the bottom of one tank to the top of the preceding tank to ensure mixing of the components.

IRP A layered method should be used for dry blending.

25.7.1.5 Bulk Plant Sampling

The challenge in sampling is to trap a sample that is representative of the total blend. There are multiple methods for sampling (e.g., ball valves, delta Y System, physical sampling, auto sampler). Each system has benefits and drawbacks but both the delta Y system and the auto sampler provide the most consistent results.

IRP A minimum of three transfers should be completed before taking samples for quality testing.

Some blends may require additional transfers to obtain a homogenous mixture.

25.7.1.6 Bulk Plant Blend Testing

Test the final product to verify the blend and ensure the produce meets design requirements prior to going on site. Well parameters and slurry design requirements dictate the number and type of Bulk Blend tests performed.

IRP The Bulk Blend testing plan should be agreed to by the cementing service provider and operator. Suggested minimum testing is outlined in Table 11.

Table 11. Suggested Minimum Bulk Plant Blend Testing

	Rheology	Thickening Time	Fluid Loss	Free Water	Compressive Strength
Surface	x				
Intermediate	x	x			
Production	x	x	x	x	
Liner	x	x	x	x	
Horizontal	x	x	x	x	
Plug	x	x			x, for kickoff
Squeeze	x	x	x		

Additional tests can be completed to verify cement performance meets the job objectives.

25.7.1.7 Transportation/Bulk Storage

Most oilfield transfer of cement product occurs pneumatically. As these silos are pressurized with air, the amount of stored energy in these vessels is substantial and needs to be treated as a potential safety risk.

IRP Transportation and storage silos are pressure vessels and must comply with provincial and national regulations regarding the operation and transport of pressure vessels.

In Alberta, the Alberta Boilers Safety Association (ABSA) regulates storage silos over 14.9 Psi. Vessels under 14.9 Psi are not subject to provincial regulation but should meet internal standards of the cement service provider. Other provinces have equivalent standards but the Alberta standard is recognized as the most stringent. Refer to www.ABSA.ca for additional information.

Tractor trailer units fall under the jurisdiction of Transport Canada.

Consider the following about silos:

- Striking a silo with a hammer, a historical practice thought to enhance flow, can damage the silo.
- For pneumatic silo operation, use the lowest pressure that still ensures good flow and maintain that pressure until the silo is empty. This ensures a steady rate of flow to the mix unit which will help the consistency of the mix and limit the amount of air entrained in the system.
- The back purging of air through the system is commonly used to fluidize the bed of particulate material. This is referred to as “fluffing the tank”. It is a misconception that this process helps mix dry products together. In fact the opposite can occur. A natural separation of particles will take place based on the specific gravity of the individual components as the material becomes fluidized. Since cement blends containing particles of vastly different specific

gravities, a prolonged back purge of air could result in a segregation of the blended materials. Back purging for one to two minutes is usually sufficient to fluidize the materials without causing segregation.

- The best method to ensure a consistent blend when loading a partially full silo is to transfer the product from one silo to another.
- Use dust control equipment when transferring cement and additives between silos to reduce the health and environmental effects of the products. This can be accomplished with a properly designed dust control device or, at minimum, by attaching dust socks to the vent lines.

25.7.2 On-Location Pre-Job

The focus of this section is activities to be performed once the cementing service provider has arrived on location but before starting the job. This includes verification of all job design parameters and equipment readiness. Thorough checks at this stage of the operation often uncover changes from the original design that need to be addressed.

The checklists in the subsections below are suggested minimums. They are not exhaustive and not all items will apply to all strings. The cementing service provider and well operator have to determine what is applicable for the job.

25.7.2.1 Design Verification and Calculations

IRP Upon arrival on location, the cementing service provider and operator should compare the job design with actual well data and agree to any changes to the design.

The original job design may have been formulated months prior to the actual job and updates to the drilling program may have taken place throughout this time. Many changes take place once drilling starts and it is impossible to predict all of these changes prior to drilling. On-site verification at this stage can uncover items that need to be addressed before starting the cement job. Applicable change management processes should be followed if changes are required (see 25.12 Management of Change).

Tables 12 and 13 summarize the checks to perform and calculations to verify.

Table 12. Initial Checks

Parameter	Description
Job objective	Prioritize job objectives (e.g., providing casing support, achieving adequate compressive strength soon after placement, providing zone isolation or a combination of several factors).
Design	Verify that design matches actual well conditions (e.g., depth, hole size, top of cement, depth of previous casing set, lead volume, tail volumes, densities, pore pressure, fracture gradients, mixing and pumping rates, plugs to be used, spacer volumes, temperature).
Drilling Fluid	Verify drilling fluid rheology matches design assumptions and conditioning is as per recommendations.
Hole conditions	Monitor hole conditions. Losses, gains and tight sections can have a significant effect and require changes to the job.
Lab testing	Verify slurries will meet job requirements.

Table 13. Calculations

Parameter	Description
Slurry volume	Calculate the mixed volume of the slurry using yield and delivered volume of dry product (including excess). In areas where lost circulation is likely consider increasing slurry volume accordingly.
Displacement volume	Calculate displacement volume considering pipe dimensions (size and weight) and depth to floats. Determine if the displacing fluid is drilling fluid and whether a compressibility factor should be used.
Annulus volume	Calculate annulus volume based on available data (i.e., bit size or caliper, open hole below the float shoe and shoetrack).
Total pump time	Calculate total pump time Including all pump time needed to complete the job (i.e., scavenger, slurries, shutdown times, displacement and contingency).
Casing Lift pressure	Calculate the pressure needed to overcome the weight of the pipe and cause the pipe to float.
Hydrostatic pressure	Verify hydrostatic pressure based on density of the system and final gradients (fracture and pore) to ensure well control is maintained and so that fracture gradients are not exceeded.
Pressure to land plug	Calculate pressure that will be required to land plug based on hydrostatic pressure in the annulus and in the pipe.
Water volumes	Calculate total water needed on location (i.e., prime up, flushes, slurry, displacement volume and clean up).

25.7.2.2 Material and Equipment Checks

IRP Critical products and equipment delivered to the site shall be checked to confirm they meet the job requirements.

Table 14 summarizes material checks and table 15 summarizes equipment checks.

Table 14. Material Checks

Parameter	Description
Tail cement	Verify composition and volume. Identify appropriate silo(s).
Lead cement	Verify composition and volume. Identify appropriate silo(s).
Spacer	Verify composition and volume. Identify material location.
Mix Water	Verify volume, verify valve operation and identify additional source(s). • Volume must be sufficient to provide the necessary fluid for the spacer(s), mixing cement(s), displacement and wash-up. • Changes in source may require retesting the water. • Environmental changes (e.g., spring run-off, excessive precipitation, lack or precipitation, etc.) may impact the water source and require retesting the water.
Mix water temperature	Verify temperature is within acceptable range: • Under normal conditions acceptable range is 15°C to 25°C • Under abnormal conditions the acceptable range needs to be agreed to between the cement service provider and operator
Mix water quality	Check pH, chlorides, sulfates, lignosulfonates. Ensure water quality and/or source of water is the same or similar to the water utilized in lab testing.
Centralizers	Confirm number, type and installation witness.
Float Equipment	Confirm type, depth and installation witness. Operation of the float can be confirmed while running casing.
Cement Head	Verify pressure rating/testing, certification, size, connection type.
Wiper Plugs	Verify: • Type of plug (top, bottom, latch-in, tapered string design). • Compatibility with cement head and float collar. • Flow-through area on the bottom wiper plug(s).
Samples	Collect samples of dry cement, cement slurry, additives, mix water and, if applicable, water with additives.

Table 15. Equipment Checks

Parameter	Description
Cement Pump	Verify the mixing system is functioning and can provide the rate of flow required for the job. Ensure sufficient fuel and have plans for re-fueling on extended or high horsepower jobs.
Sensors	Verify rate, pressure, densitometer and back-up sensors.
Function test all compressors	Ensure all compressors function and the unloader valve functions correctly.
Pressurized mud balance on location	Verify the mud balance is present and calibrated.
Recording device	Verify unit is correctly functioning and storing information.
Cement Head	Confirm operation of all valves and the plug release mechanism.
Treating Line	Verify certification, pressure rating, proper connections for job and total amount adequate for correct hookup.
Containment for equipment	Ensure drip pans are in use and total unit containment is achieved.
Communication equipment	Ensure there is adequate communication available during the job.
Plug loaded in cement head	Ensure plug loading is witnessed by operator representative.

25.7.2.3 Pre-Job Operational and Safety Meeting

IRP A pre-job safety meeting shall be held with all personnel that will be involved in the cementing process (e.g., cementing personnel, rig crew, water haulers, drilling fluid company, etc.).

Discuss all safety and job parameters to set the stage for a successful treatment. Make all parties aware of the objectives of the cement job. Table 16 summarizes job plan issues to be discussed and Table 17 summarizes personnel issues.

Table 16. Job Plan Issues

Parameter	Description
Pump procedure	Outline sequence of steps to take place
Max pressure	Clearly define maximum pressure permitted.
Lift pressure	Determine if casing will need to be secured.
Casing burst and collapse pressure	Ensure casing burst and collapse pressures are documented and job maximum pressure agreed to between cement service provider and operator.
Pipe movement during job	Outline procedures and personnel involved including rpm or meter/minute.
Job assignments	Designate key personnel (i.e., who will operate valves, monitor returns, operate bulk equipment and release the plug).
Displacement procedure	Define rates and expected pressures/volumes.
Contingency Planning	Create and discuss contingency plans for potential cementing issues and problems. Refer to 25.7.3. Contingency Plans for more information.

Table 17. Safety and Personnel Issues

Parameter	Description
Personal Protective Equipment (PPE)	Ensure PPE is available (i.e., goggles, hard hat, dust mask, fire resistant coveralls, hearing protection, fall protection).
Muster area	Define escape route and location.
First aid area personnel	Identify person, facilities, evacuation procedure.
Well hazards	Identify any well hazards (e.g., pressure, H_2S).
Well-site hazards	Identify well-site hazards (e.g., simultaneous operations, noise, pressure, chemicals).
Head count of all personnel	Document all personnel on location.
Fire extinguishers	Identify location of all fire extinguishers.
H_2S plan	Identify H_2S plans (e.g., alarms, procedures).

25.7.3 Contingency Plans

There is potential for a number of things to go wrong during a cementing operation and prevent the original objectives of the cement job from being met (job failure). These failures may be caused by insufficient planning, equipment malfunctions or unforeseen changes in the condition of the hole.

Proper pre-job contingency planning can minimize the impact of the majority of events that can occur during operations.

IRP The cementing service provider and operator should have contingency plans for anticipated cementing issues and problems.

Prepare contingency plans during job planning and align with change management procedures (see 25.12 Management of Change). Communicate contingency plans to field personnel and discuss during the on-site pre-job safety meeting.

25.7.3.1 Flow Before, During and After Cementing Operations

Flow before, during or after cementing operations can be an indication that the wellbore is experiencing a kick.

IRP If the cement job has finished and the annulus well is flowing, the well should be shut in immediately and well control techniques implemented.

It is more difficult to detect a kick during cementing operations because different fluids are being introduced to the active drilling fluid system and thus pit volumes are often changing. One common indicator is pit gains rising faster than the rate being pumped. Understanding the U-tube effects and proper pre-job planning with rate in and rate out charts can eliminate false indications of a kick. Notify the operator as soon as well flow is identified.

25.7.3.2 Lost Circulation

Lost circulation is a common occurrence in Canadian drilling environments. Most of the time, potential losses are known within a given area. When lost circulation occurs there needs to be a coordinated effort between drilling and cementing operations to resolve the problem. Cure losses prior to the primary cement job if possible.

One course of action to address lost circulation may be to decrease pump rates. This will reduce the ECD of the cement slurry being placed and therefore increase the potential to regain or maintain cement circulation. However, reducing the pump rate could impact the quality of the cement job.

If LCM was not included in the cement design, adding cello flake, fibres or some other LCM to the mixing tub during execution may aid in successful cement placement. Use caution when adding LCM. Too much LCM can cause centrifugal pumps to cavitate and the triplex pump valves to bridge in the open position causing mixing issues. Additionally, high concentrations of LCM can bridge off float equipment. Consider not running a bottom wiper plug in these cases as the burst disc can become plugged which may result in cement being left inside the casing.

If a bottom plug is not utilized, consider pumping additional volumes of spacer and/or slurry to account for intermingling and contamination inside the casing. Make sure compatibilities between the fluids have been thoroughly tested. Refer to 25.3.2.2.2 Density Hierarchy for more information on spacer compatibility and 25.4.1 Slurry Density for slurry compatibility.

Another option to deal with lost circulation may be to increase the cement volume being pumped as cement can help heal loss zones as it is pumped past them. This option is most often considered during pad work where a cement silo may contain enough cement for multiple jobs. Keep a record of how much slurry was mixed to avoid issues on future operations (i.e., less cement in the bin than expected) and discuss during the pre-job meeting.

25.7.3.3 Equipment Malfunction

IRP A contingency plan should be in place to deal with equipment malfunction.

The action may be as mild as continuing with operations or as severe as circulating cement out of the hole. Ensure thickening time of cement is well understood at downhole conditions and that on-site personnel are aware of the maximum time the blend can remain static while diagnosing equipment issues. It is a good practice to have secondary options available for major equipment malfunctions.

Table 18 summarizes some potential equipment issues and suggested contingency plans.

Table 18. Equipment Issues and Contingency Plan(s)

Issue	Contingency Plan(s)
Cementing unit automated system failure	• Most cementing units have a way to override the automated system and mix cement manually. • If operationally possible, mix water should be gauged and manual density readings should be taken to ensure a quality product is being delivered down hole.
Flow/density meter failure	• Flow meters can often become plugged during cementing operations so it is important to maintain accurate tank gauging and density control during the job. • Contingency plans should consider the allowable tolerance for density variation and actions to take if the target density is not achieved at different times within an operation.
Density meter calibration error	• Improper calibration of density measuring devices gives unreliable fluid measurements and can lead to exponentially greater density errors. • There should be a secondary method of density verification available.
Liquid additive system failure or incorrect metering of additives	• The function of the additive and its importance to the cement job should be considered when contingency planning. • The additive will dictate the contingency plan severity. • Actions may range from taking no action to circulating cement out of the hole.
Leaks	• Leaks associated with the treating equipment are addressed during the pressure test portion of the job. • Leaks that occur on the high pressure treating equipment during pumping operations require pumping be stopped and the leak addressed. Care must be taken to remove the pressure from the affected lines and minimize the time cement is not moving. • Leaks that occur on the low pressure treating equipment during pumping operations need to be dealt with based on severity (i.e., type and/or volume of fluid). • The type of leak will dictate the contingency plan severity. Actions may range from containing the leak to suspending operations for repair.
Bulk cement delivery interruptions	• Bulk cement delivery interruptions can cause serious problems during cementing operations. • Understanding how the cement behaves in a static state (i.e., how quickly it gains gel strength) determines how long pumping operations can be suspended to fix an issue before the job has to be terminated and potentially cement circulated out of the hole. The length of time should be communicated to all parties during the safety meeting.
Mix water delivery interruptions	• Mix water delivery issues can cause interruptions to cementing operations. • It is a good practice to always have a minimum of two sources of mix water available. • Alternate sources need to be tested prior to the operation. • Water delivery rates and delivery methods for each source need to be understood prior to the safety meeting to avoid over-pressuring lines.
Radio communication failure	• Communication is a key area that can easily make the difference between a good cement job and a failed one. • Most operations rely on radios to relay information to each other. • The crew must also be aware of the appropriate hand signals to communicate in the event of a radio failure. Since this form of communication requires eye contact, it is appropriate to have secondary tasks assigned to personnel on location to relay information across blind areas (e.g., floor to shaker, etc.).

Issue	Contingency Plan(s)
Pump Failure	• The seriousness of pump failure depends on what stage of the job it occurs in. • If failure occurs during displacement, a second high pressure pump should be rigged in (i.e., an additional cement unit or the rig pumps). • Triplex pump failure during mixing usually means mixing operations can't continue (unless a second cementing unit is on site). The volume of slurry already pumped dictates the correct course of action. Options are: 1. Drop the plug and have the rig displace the cement. 2. Have the rig circulate the cement out of the hole.
Floats Do Not Hold	• Shut in with minimum pressure to prevent u-tubing and to reduce the size of the microannulus.

25.7.3.4 Non-Equipment Issues

Table 19 summarizes some potential non-equipment issues and suggested contingency plans.

Table 19. Non-Equipment Issues and Contingency Plan(s)

Issue	Contingency Plan(s)
Extremely early cement returns	• Extremely early cement returns do not happen often but can occur due to the following: 1. Cement channelling (due to improper casing centralization or improper job design). 2. A part in the casing. 3. Fluid compatibility issues. • If the plug has not been dropped circulate the cement out of the hole with continued bottoms up until it can be verified that all of the cement has been removed from the annulus. • The appropriate management personnel will need to be contacted to help diagnose the problem and formulate a new cementing plan.
Maximum pressure reached during job	• Pressure increases are common during primary cement jobs. • Maximum pressure is the lowest of 1. the pressure test value, 2. 80% of the maximum burst rating of the casing, 3. the maximum pressure rating of the treating lines, plug loading head and pump or 4. frictional pressure drop in the annulus + hydrostatic pressure in the annulus remaining below fracture pressure. • Moving the pipe during operations can help to reduce pressure increases but this may not always be possible or effective. • As the pressure increases the flow rates must be reduced in order to stay under the maximum pressure. • Pumping must stop if maximum pressure is reached. If pressure bleeds off pumping can resume until maximum pressure is reached. Suspend pumping operations if the pressure does not bleed off.

Issue	Contingency Plan(s)
Hole sloughing	• In situations where an unstable wellbore exists, there is a possibility for formations to cave into the annulus, bridging off flow. This is most often observed by a gradual loss of returns at surface coupled with an unexpected steady increase in pressure, or a sudden loss of circulation and a sudden pre-mature pressure increase. Both cases are indications of the annulus sloughing in. A quick analysis of both cementing charts and rig data can aid in identifying this phenomenon. • In these situations there is little that can be done other than trying to move the pipe (if possible). At this time, cementing operations are generally suspended. • If this occurred during a surface or intermediate job, the rig may have to make up a BHA and drill through any cement remaining in the casing (depending on where the cement top reached before the hole packed off and operations were suspended). Remediation may have to take place before drilling ahead. • During production string cementing, there is little a drilling rig can do since in most cases, the drill pipe will not fit inside the production casing. The issue may need to be rectified using a service rig or coil tubing unit. • Hole sloughing may be incorrectly interpreted as a cement flash set when in reality cement flash set is rare.
Loss of pressure while displacing, pumping or mixing	• This problem does not arise often but can be the sign of a large problem. Depending on what stage in the cement job you are at and if circulation to surface still exists, pressure loss during cementing operations is usually an indication that the casing has parted, an over-displacement situation exists, lost circulation has occurred or surface equipment has failed. • The cement truck operator must communicate this situation back to his supervisor or the operator as soon as possible. This is a situation that requires very quick analysis of a situation so the operator can determine what the next course of action is. • Probable causes for this situation are either an over-pressure event on the casing causing it to fail, or if no pressure spikes were observed, the sudden loss of pressure may be due to an incorrectly installed joint of casing separating. • If both a loss of pressure and loss of circulation at surface occur, the situation could be a matter of lost circulation and dealt with accordingly.
Plug did not bump	• This can occur if the displacement volume was not accurately tracked, if the displacement fluid was aerated, if the casing tally was incorrect, if the wrong casing dimensions were used or if the plug failed to launch properly from the cement head. • During the safety meeting, a contingency plan needs be agreed upon as to how much additional fluid is to be pumped after the calculated volume has been pumped.
Floats did not hold	• After the job is complete the floats must be checked to ensure they are holding by bleeding the treating line volume back to the cement unit and monitoring the inside of the casing for flow (the differential pressure between the heavier cement in the annulus and the lighter displacement fluid inside the casing will always create backflow up the casing if the floats are not holding). • The operator must gauge his tanks to ensure he has quantified the correct volume that did flow back. • If the floats are not holding, the operator needs to pump the equivalent gauged volume back into the casing and shut in the cement head with no more than differential pressure until the cement reaches sufficient compressive strength.
Variation in displacement rates	• This commonly occurs when circulating pressures are much higher than predicted, bringing the job to the pressure limitations of either the wellbore, casing or pumping equipment resulting in a reduced pump rate • The impact on the slurry by pumping at a reduced rate must be clearly understood. Do not exceed the placement time of the cement blend.

Issue	Contingency Plan(s)
A low cement top on a surface cement job	• Typically occurs if lost circulation is encountered or insufficient cement volume is pumped. • Evaluate cement top and consult regulatory requirements before drilling ahead or proceeding with top-up or other remedial action.

25.8 Cement Slurry Placement

Careful risk assessment and planning are components of successful slurry placement. Contingency plans for many of the issues raised in this section are discussed in 25.7.3 Contingency Plans.

25.8.1 Pressure Testing

Pressure testing lines from the pump truck to the wellhead verifies all connections are properly tightened and leak free.

IRP Working pressure and connection compatibility of all permanent and temporary piping should be verified before pressure testing.

IRP All high pressure treating lines must have a successful pressure test completed before starting the job (as per OH&S regulations).

IRP The cement service provider and operator shall establish the maximum treating pressure and the testing pressure prior to pumping. Pressure tests shall not exceed the maximum working pressure of treating iron or casing cement head.

IRP The testing pressure, anticipated treating pressure and maximum allowable treating pressure shall be communicated during the pre-job safety meeting.

While testing, ensure the pump is properly primed and all air is removed from the high pressure system.

25.8.2 Mix Water Verification

Mix water is not often viewed as a priority in a cementing operation but it is essential to a successful cement job.

IRP Mix water volume, temperature and quality shall be verified before starting the cement job.

The volume of water on site has to be sufficient to provide the necessary fluid for the spacer(s), mixing cement(s), displacement and wash-up. Mix water samples should be taken for performance verification purposes. Refer to Table 14 Material Checks for specifics.

25.8.3 Bottom Wiper Plug

The bottom wiper plug is the first plug pumped down the casing. It is used to wipe the casing and to separate the spacer from the drilling fluid while inside the casing. This provides a barrier between the fluids to prevent contamination. When the wiper plug lands, a small amount of pressure is required to puncture the membrane on the top of the plug to allow flow through its centre. The pressure required to puncture the plug is minimal and typically not seen on the pressure recording devices.

IRP Plug loading procedures shall be agreed to by the cementing service provider and the operator. Ensure plugs are loaded in the correct order.

The following are situations when a bottom plug may not be recommended:

- During foam cementing operations.
- When high concentrations of LCM are planned or expected.
- When high density preflushes and/or spacers are used and weighting material sag may be an issue.

If a bottom plug is not utilized, consider pumping additional volumes of spacer and/or slurry to account for intermingling and contamination inside the casing. Make sure compatibilities between the fluids have been thoroughly tested. Refer to 25.3.2.2.2 Density Hierarchy for more information on spacer compatibility and 25.4.1 Slurry Density for slurry compatibility.

25.8.4 Spacer(s)

The spacer systems pumped ahead of the cement are one of the more important aspects of the job in order to attain cement bond. They separate the fluids to prevent contamination while displacing the drilling fluid from the wellbore, remove filter cake and leave the well in a water wet state. Cementing success depends on the spacer design matching the hole conditions at the time of cementing. Additional information about spacer design can be found in 25.3 Spacer Design.

Consider the following for spacers prior to job execution:

- Ensure adequate volume to complete the job.
- Follow approved mixing procedure.
- Ensure the required density is achieved.
- Verify rheologies against lab test (for high priority jobs).

25.8.5 Pumping the Cement Slurry

The rate the cement is pumped impacts effective wellbore fluid displacement. The rates which are achievable, as well as ideal, are dependent on wellbore configuration, fluid properties, deviation, centralization and hole stability. The annular velocity is typically targeted as the value to achieve or maintain based on the original job design.

IRP Minimum and maximum pump rates specified in the job design should be followed without sacrificing slurry density requirements.

Use caution when increasing velocity (rate) because increasing velocity will increase the ECD, cause a packoff and may induce losses. Keep cement rate Annular Velocity (AV) below the AV used while drilling the hole section if possible. Follow the same rule for circulating prior to cementing.

Consider the following when pumping the cement:

- The density tolerance of the cement.
- The impact of pressure changes. If pressure is high there could be an impact to the ECD and thickening time. The rate may need to change to accommodate changes in pressure.
- The impact of volume changes. A change from the planned volume may impact the time required to complete the job.
- The impact of pump rate changes. A change in pump rate may impact the time required to complete the job.

25.8.6 Measuring Slurry Density

There are four methods commonly used to measure density: radioactive densometers, coriolis meters, mass balance techniques and mud balances.

IRP All equipment for measuring density shall be properly maintained and calibrated with an approved procedure. Functionality should be verified before the job starts.

IRP A calibrated, pressurized mud balance should be used to verify slurry density throughout the job and to act as a backup in case of any electronic failure.

25.8.7 Collecting Data and Samples

IRP All data for the cement job should be recorded and retained for future reference. The data captured varies by job type but should, at minimum, include the following:

- Fluid density

- Fluid rate
- Pump pressure

Relevant job data needs to be recorded for each unit if there are multiple pumping units. The data recording can be tied into the rig data collection system. This information may be useful in the event that a post job investigation is required as well as for post job analysis, reporting, quality control purposes and continuous improvement.

There are three types of samples that can be taken on location: dry cement, field water and cement slurry samples.

IRP At minimum, dry cement and mix water samples shall be taken during the cement job. All samples shall be properly labelled and stored (see 25.9.4 Sample Storage for more detail).

Use the following procedures for collecting samples:

- Take an appropriate volume of dry sample for testing. Suggested sample size is 10 kg (four litre container).
- Ensure sample is representative of the total blend on location.
- Take a field location water sample so that the lab testing represents the slurry used in the operation.
- Collect samples of the additives, mix water and the final mix fluid (water plus additives) if liquid additives are used. Suggested minimum sample size is eight litres.
- Store samples in clean, airtight containers that are labelled appropriately.

Samples of the cement slurry (cup samples) are often taken during the execution of the job to verify that the cement slurry will develop compressive strength. This sample technique has limited value for measurement as it does not represent the conditions for which the cement slurry was designed.

The cementing service provider is normally responsible for collecting and storing samples because they are providing the equipment and service. Operators may choose to take their own samples.

25.8.8 Pump Out Lines

Once the cement is mixed and pumped, and prior to the displacement of the cement slurry, the surface treating lines may be pumped out. This process is used to prevent cement slurry from being placed on the top plug. This process may not be required on certain strings. Whether or not the process is used will depend on the completion process and/or the next steps for the wellbore.

A pump out tee is required to effectively pump out the lines. Position the pump out tee as close to the cement head (or tool used to connect to the casing) as possible to minimize the slurry volume remaining in the surface treating iron. The effects of the remaining slurry are magnified in smaller casing strings because a small volume can equate to a large height.

IRP The cement service provider and operator should agree on the proper pump out procedures and ensure they are followed.

Cement slurry performance and the allowable time for shutdown while pumping out the lines needs to be carefully considered. Shutting down for too long can allow the cement that was pumped to become immobile in the casing.

25.8.9 Top Wiper Plug

There are two methods to drop the top plug. The common procedure is to stop all pumping, release the plug then recommence pumping once the release is complete. A less common alternative is to release the plug “on the fly” (without stopping pumping). Releasing on the fly can be effective in reducing cement stagnant time in the wellbore and eliminate the time when hole sloughing can occur. There are increased risks associated with releasing the plug on the fly because valves are being operated during pumping.

The top plug is released after the cement slurry has been pumped and prior to pumping the displacement fluid. The top plug is a solid shut-off plug and has no membrane. When it lands on the bottom plug the pressure increases and the plug provides a physical barrier between the cement slurry and the displacement fluid within the casing string**.** Slow down pump rate as the top wiper plug approaches the bottom wiper plug or the float collar.

IRP A positive indicator on the plug loading head should be utilized for confirmation that the plug has been released.

There are many different ways to verify plug launch. These methods may be simple such as including a wire tied to the top of the plug or more complicated methods such as electronic sensors, flag sub or mechanical flapper valves.

25.8.10 Cement Slurry Displacement

Accurate measurement of the volume of fluid displaced is essential for an effective cement operation. Monitor drilling fluid returns from the annulus throughout the cement job.

IRP The displacement volume should be measured manually and electronically.

Give preference to the displacement tank measurement if there is a discrepancy in the two measurements.

The calculated displacement volume may be affected by the fluid compressibility so an additional amount of displacement fluid may be required. The additional volume may be determined by measurement or calculation. When the additional volume is added it is important to ensure that that the plug is not over-displaced.

Displacement is complete when the top wiper plug lands on the float. Normal process is to increase the pressure to 3.5 MPa above the last displacement pressure for a period of time to verify the plug has landed and held and to verify pressure integrity. It is important to record the final displacement pressure at a reduced pump rate so that friction pressures during the high rate displacement do not result in unnecessarily high pressure being applied during the plug bump. Reducing to minimum pump rates prior to pumping can help provide a more accurate final displacement pressure.

The operator needs to have a contingency plan in case the plug is not bumped at the anticipated volume (e.g., a decision to pump additional displacement volume or shut down. See Table 19 in 25.7.3.4 Non-Equipment Issues for more details). The risks associated with the contingency plan need to be understood before taking action.

25.8.11 Float Testing

Float equipment is tested by releasing the surface pressure and watching for fluid flow back. Fluid returns up the casing indicate improper float function and may require an additional plug bump. If required, re-bump the plug and bleed back to check for fluid flow. Check with the operator before re-bumping the plug.

If the floats do not hold, the differential pressure between the cement in the annulus and the displacement fluid has to be held on the casing side to prevent backflow up the casing.

25.8.12 Alternate Placement Techniques

25.8.12.1 Inner String Cementing

It is common practice to use an inner string when using large-diameter casing. The amount of displacement required is reduced by the smaller diameter pipe that is run inside the casing. When dealing with unknown washout or losses, this practice enables the operator to pump cement until cement returns are seen at surface and minimize the amount of excess that is needed. The inner string can be withdrawn from the casing as soon as the plug has landed provided the casing is equipped with a float or latch-down baffle. If inner string is not to be withdrawn from casing as soon as the plug is landed, ensure sufficient spacing between inner string bottom and cement top inside casing.

Note: Casing collapse loads may occur during inner-string cementing. Refer to 25.6.1.8 Equivalent Circulating Density for more information.

25.8.12.2 Reverse Cementing

Reverse cementing involves pumping cement down the annulus instead of down the casing string. It is occasionally necessary under special circumstances (e.g., heavy losses, pack off, etc.) and can be an alternative to using stage tools. Table 20 shows several advantages and disadvantages of reverse cementing.

Table 20. Advantages and Disadvantages of Reverse Cementing

Advantages	Disadvantages
Improves the likelihood of cement to surface when losses are encountered.	High risk of packing off due to cuttings bed disturbances when the flow path is reversed.
Reduction in ECDs.	Potential for contaminated cement around the shoe.
Elimination of displacement (shorter placement time).	Larger cement volumes inside the casing to drill out.
Lower additive loading due to lower circulating temperatures.	Requires additional equipment (e.g., specialized float, cement head design, placement confirmation methods, real-time logging deployment, etc.).
	May require regulatory approval (depending on where operating).
	May require additional over-hole for the float (casing is landed further off bottom).

25.9 Post-Placement Considerations

25.9.1 Pressure Testing

After bumping the plug the operator may request a casing pressure test to verify mechanical integrity of the casing.

IRP If a casing pressure test is required after plug bump, it should be done before the cement has gained significant gel strengths to reduce any disturbance of the bond between the casing and cement. Alternatively, the pressure test can be done after the cement has gained sufficient compressive strength.

Once the pressure test is complete, release the pressure and leave the casing open. This will eliminate any internal casing pressure build-up due to cement heat of hydration.

25.9.2 Post-Job Back Side Pressure

This procedure is performed when cementing operations were completed as an underbalanced treatment or the wellbore has a high Gas Flow Potential (GFP) and backside pressure is used to mitigate the problem.

IRP When backside pressure is used the cement pump unit should be rigged into the backside of the well (casing bowl in the cellar) prior to the start of operations.

Apply backside pressure after cement placement as soon as practically possible, before cement gel strengths begin to develop. If too much time passes the additional pressure applied at surface may have no benefits.

Excessive pressure on the backside may cause damage to producing formations, breakdown of weak zones or casing collapse.

25.9.3 Wait on Cement

Waiting on cement (WOC) is the period of time after the cement has been placed until subsequent operations can resume. Often the end of the WOC time is determined by the cement achieving a certain compressive strength. The WOC time (a fixed number of hours) or a compressive strength requirement may be dictated by jurisdictional regulations. Compressive strength development is typically slower at the top of the cement column than at the shoe due to lower temperatures. Consider these conditions in testing. Perform tests with the most representative location water and cement samples available.

IRP The operator shall wait until cement has developed sufficient compressive strength before resuming well operations.

IRP Casing movement, loading, and/or vibrations should be avoided after cement has started to develop gel strength, until it has developed sufficient compressive strength for the planned operations

25.9.3.1 Wait on Cement as a Barrier

Cement is not considered a barrier until it has gained a minimum of 350 kPa (50 psi) compressive strength. The 350 kPa threshold exceeds the minimum static gel strength value needed to prevent fluid influx. If the cement job is isolating potential flow zone(s), keep alternate barriers such as a BOP in place until 350 kPa compressive strength is achieved. Have contingency plans in place to address a flow during removal of a temporary barrier (e.g., BOP) prior to removing the temporary barrier. Minimize the elapsed time between the start of removing a barrier to securing the exposed annulus.

Further assessment may be required to determine the adequacy of the cement job before removing other barriers (e.g., BOPs) due to unplanned events that include, but are not limited to, the following:

- Significant lost circulation during the cement job
- Inability to mix the desired slurry density, or pump the planned volume of slurry
- Premature cement returns which indicates channeling
- Lift-pressure at the end of the cement job indicates that the top of cement is not high enough to isolate the shallowest potential flow zone
- Indications of influx

25.9.3.2 Wait on Cement to Avoid Damaging Cement

IRP Well operations following cementing should avoid disturbing the cement as disturbances may damage the seal or cause the cement to set improperly.

Typically, pipe movement to hang the casing and activate wellhead seals is finished before cement has developed significant gel strength. Pipe movement after gel strength has developed could cause a micro-annulus or initiate flow if the pipe movement swabs formation fluid into the wellbore. In some instances, steady and slow reciprocation may be used to prevent development of gel strength until the pipe can be landed at the final depth.

In some cases, such as surface casing where a structural conductor is not in use, BOP nipple-up or nipple-down operations may result in movement of the casing, especially when the recently cemented casing is the only string bearing the weight of the BOP.

Before drilling out a casing string that has been cemented, more compressive strength is required to resist damage caused by vibration of the drill string. Usually, a minimum of 3500 kPa (500 psi) is recommended before drilling out the shoe of a cemented casing.

25.9.4 Sample Storage

Aging and contamination will spoil samples. Proper storage helps preserve the material.

IRP All samples taken during the job should be stored in a dry controlled environment for a minimum of 30 days.

Improperly stored samples may give inconsistent test results.

25.9.5 Documentation

Retain a copy of all data recorded and all reference materials used during the cementing operation on site. Include, at minimum, a treatment report and job chart.

25.10 Post-Job Evaluation

There are several methods and tools that can be used for evaluating the cement job. No single method will give all of the necessary answers to form a conclusion about the success or failure of a cement job but a combination of the various tools and methods will contribute to informed decisions that can be used to feed into in a continuous improvement plan (see 25.13 Continuous Improvement).

The evaluation methods rely on the data and samples collected during job execution (see 25.8.7 Collecting Data and Samples). Matching the design parameters and modelling to the actual job data can assist in conformation of the final job effectiveness. Acoustic logging tools can be used for further assessment of the coupling of the cement to the formation and the cement to the pipe.

25.10.1 Operational Data Evaluation

Operational data evaluation is one aspect of evaluating cement job success. The purpose is to measure whether or not the cement job (primary, remedial, plug, etc.) was executed according to the plan (i.e., was the job executed as designed). Without monitoring it is almost impossible to understand what may have contributed to a poor outcome. The samples and measurements collected during job execution are used for operational monitoring (see 25.8.7 Collecting Data and Samples).

25.10.1.1 **Mass Balance Evaluation**

This is the first check that can verify proper execution. The density and volume of the pumped cement slurry can be verified by comparing the calculated and actual volumes of cement slurry pumped, the volume of water and the amount of dry blend cement.

25.10.1.2 **Fluid Returns**

The well returns may provide an indication of fluid displacement efficiency during the cement job. Cement returns are not the only indicator of success.

IRP Timing of the interfaces getting to surface, volume of fluid and volume of cement returned should be gauged and recorded to evaluate effectiveness of cement placement.

The timings and volumes can be interpreted as follows:

- A loss of returns may indicate weak formations, thief zones or formation breakdown.
- Fluid volume discrepancies could indicate hole enlargement or poor displacement.
- Visual observations and the pH and density of fluid returns can be used to identify fluid interfaces and the amount of contamination.
- Early and/or excessive returns are often an indication of channeling and ultimately poor zonal isolation.

25.10.1.3 Set Verification

A common practice is to take a sample of the cement slurry from the job to verify set of the slurry. This type of sample has limited value by itself and can be misleading because the conditions the sample will be exposed to at the surface can be grossly different from downhole conditions.

25.10.1.4 Pressure Matching

Post-job pressures, rates and densities can be compared to planned parameters and can be rerun on simulators to evaluate any abnormalities observed during the cement job. With the input of actual pumped data and actual well data (e.g., caliper, deviation, centralizers, rheology properties, etc.) simulators can confirm the effectiveness of cement slurry placement.

The results of the pressure matching may be interpreted as follows:

- Higher observed pressures may indicate a flow restriction (e.g., reduced hole size due to wellbore instability or a smaller hole size than expected) or higher rheology of the fluids (e.g., due to incompatible fluids mixing or unknown fluid parameters).
- An early increase in pressure may be an indication of channelling during the job.
- Lower observed pressures may indicate there is a washed out/enlarged section, increased hole size, losses due to a weak formation interval, lower rheology or casing failure.

25.10.1.5 Liner Cement Integrity

Pressure testing of the cement job after the cement has set can give indication of proper isolation. If the pressure test indicates that isolation is not achieved then remedial action may be necessary (e.g., a squeeze).

IRP A pressure test should be performed after cementing a liner in place to determine if there is an effective seal around the liner lap.

There are two types of tests that can be performed on the liner lap:

1. A positive test. This involves pressuring up the wellbore before drilling out the shoe to check for leaks at the liner lap.
2. A negative test. This involves reducing the hydrostatic pressure of the wellbore fluids below the formation pressure at the liner section and gauging inflow to the wellbore.

25.10.2 Cement Log Evaluation

Acoustic logging tools are commonly used to evaluate the cement job. No logging tool can directly measure the ability of cement to provide zonal isolation for flow behind the casing but acoustic logs can help confirm cement placement outside the casing and provide insight into the likelihood of zonal isolation.

Cement evaluation logs all work by transmitting an acoustic signal into the casing and then measuring the reflection of that signal at the tool receivers. Casing that is in contact with the cement sheath will have lower amplitude reflections and the signal will die out more quickly than with casing that is not bonded.

Cement evaluation logs are commonly classified in two main groups:

- Sonic (lower frequency – 10's of kHz)
- Ultrasonic (higher frequency – 100's of kHz)

25.10.2.1 **Sonic Bond Logs**

There are four main types of sonic cement evaluation logs available (as per API 10TR1):

- Cement Bond Log (CBL)
- Compensated Cement Bond Log (CBT)
- Segmented Bond Tool (SBT)
- Sector Bond Log (SBL)

Table 21 describes the typical configuration details, outputs, advantages and disadvantages of the four types of sonic cement evaluation logs. Supporting diagrams for Sonic Bond Log configuration and output samples can be found in Appendix D: Sonic Bond Logs.

Table 21. Sonic Bond Log Comparison

	Configuration	Output	Advantages	Disadvantages
CBL	• One transmitter and two receivers. • Standard configuration is one receiver three ft. below the transmitter (the CBL) and another five ft. below (the Variable Density Log (VDL)). • See Figure 5 in Appendix D.	• Log presentation varies depending on logging company but the basic output usually includes a gamma ray, transit time, amplitude from the three ft. receiver and the VDL presentation. • See Figure 6 in Appendix D.	• Easily accessible/readily available. • Technology is understood and accepted by industry. • Provides a measure of contact between casing and cement and a qualitative indicator of contact between cement and formation.	• Interpretation of the data can be complex because the signals received are impacted by borehole fluid, casing thickness, cement thickness and shear strength, along with the acoustic coupling of cement to the casing and formation. • The reflections are averaged around the casing so it is incapable of identifying channels that exist in only one part of the circumference. • Calibration of these tools can be challenging. A ‘free’ section of un-bonded pipe in the well can help calibrate the tool and show the difference that can be expected between bonded and un-bonded casing.
CBT	• Two transmitters and three receivers. • See Figure 7 in Appendix D.	• Presentation is similar to the CBL but in this case there are two transit time tracks and the measured attenuation is plotted in addition to the amplitude response. • See Figure 8 in Appendix D.	Advantages over CBL are: • The attenuation rate measurement is independent of borehole fluids. • The signal strength is better. • Calibration is improved. • Attenuation rate is measured directly rather than being calculated. • It is easier to identify tool eccentering (where tool is off-centre) with this log.	• Availability

	Configuration	Output	Advantages	Disadvantages
SBT	• High frequency (~100 kHz) six arm ultrasonic tool that has a transmitter and receiver on each arm. • A standard VDL is included on the bottom of the tool and a Gamma Ray and CBL are mounted on top of the string. • See Figure 9 in Appendix D.	• Includes the delta time minimum/delta time maximum (DTMN/DTMX) displays along with the six individual attenuation tracks. • The minimum attenuation value (ATMN) is typically plotted with the average value from all six tracks (ATAV). • This display is useful to depict the extent of channeling versus a circumferential change in bond quality. • The VDL display is similar to other logs. • See Figure 10 in Appendix D.	• Minimal sensitivity to centralization (the transmitters and receivers are on pads that ride on the inner casing wall) • Six independent measures of attenuation that can be useful to detect channeling. • A cement map gives a good visual display to help identify sections of varying quality. • The DTMN and DTMX curves that are displayed with this log can clearly identify when debris inside the casing is affecting the tool output	• The results are more impacted by debris left inside the casing than other logs because the pads are designed to contact the casing directly.
SBL	• Multiple directional receivers and, in some cases, multiple directional transmitters. • Each receiver or transmitter/receiver pair covers a portion of the casing. • See Figure 11 in Appendix D.	• Many possible presentations. • Output depends on the number of tracks available. • See Figure 12 in Appendix D for a sample.	Improved ability over the CBL and CBT to detect channeling.	Impacted by similar factors as CBL and CBT.

25.10.2.2 Ultrasonic Bond Logs

Ultrasonic bond logging tools are used for both cement and casing evaluation. A single rotating transducer is used as both an emitter and receiver of ultrasonic signal (see Figure 13 in Appendix E: Ultrasonic Bond Logs). The acoustic impedance (related to the compressive strength) of the material in the annulus is determined by analyzing a portion of the received waveform. The strength of the measurement is in the high spatial resolution which can help in identifying narrow cement channels. A relatively low sensitivity of the ultrasonic tools to wet microannulus can aid in the bond interpretation in the absence of a pressure pass. Characteristic patterns in the cement log image can identify the location of casing centralizers and also yield qualitative indications of casing centralization.

The primary outputs of ultrasonic tools are as follows:

- Inner casing wall condition (qualitatively inferred by the amplitude of the initial echo)
- Inner casing radius (determined by the two-way transit time)
- Wall thickness (derived from the frequency of resonance)
- Acoustic impedance of the material in the annulus (determined by the form of the resonance)

In a typical ultrasonic log display, two-dimensional images of cement coverage around the pipe circumference may be shown as either a raw image without interpretation of material type or with colour coding that differentiates solids from liquid or gas based on acoustic impedance thresholds or cut-offs (see Figures 14, 15 and 16 in Appendix E: Ultrasonic Bond Logs for diagrams). These images can tell you the following:

- Intervals of continuous cement coverage without evidence of channeling suggest possible isolation.
- Low acoustic impedance, de-bonded or contaminated cement can sometimes be detected using variance based techniques that compare the acoustic impedance of each data point with surrounding data. The assumption is that solids typically show greater variability in acoustic properties than do liquids. Individual service companies implement variance based processing in different ways.

Perfect bond logs may not be a guarantee of zonal isolation. Tiny channels within the cement sheath and pathways at the cement formation interface cannot be resolved with current technology.

IRP When running ultrasonic bond logs, they should be run in combination with CBL-VDL logs to provide an independent measure of contact to pipe as well as a qualitative indication of the cement contact with the formation.

25.10.2.3 Flexural Mode

Flexural mode is a variant of ultrasonic bond measurements that incorporates the conventional pulse-echo ultrasonic mode with a second mode that imparts a flexural wave into the casing. Flexural attenuation derived from two additional receivers is paired with the pulse-echo acoustic impedance and compared with a laboratory database to provide an image of the annular material. This technique provides an improved sensitivity to light weight and contaminated cement. In addition, echoes reflecting from the cement-formation interface can often be detected which provide information about the conditions out to the formation or inner wall of a second casing string. These echoes are referred to as third interface echoes (TIE).

Flexural attenuation applications are as follows:

- Low acoustic impedance and contaminated cement logging.
- Channel map to highlight problem areas in cement coverage.

TIE applications are as follows:

- Casing position within the hole.
- Velocity profile of the annular material

Sample outputs are shown in Figures 17 and 18 in Appendix F: Flexural Mode Logging.

25.10.2.4 Recommended Practices for Sonic and Ultrasonic Bond Logging

IRP Cement sheath assessment should not be based solely on bond log output.

Consider the following:

- Use the operational record from cementing (e.g., cementing rates, cement returns, expected cement top), formation assessment (e.g., critical tops) and logging conditions (e.g., logging pressures) to help verify log interpretation.
- Design cement evaluation logging strings using well specific information and objectives.
  - Some tools have difficulty assessing low density (foam) cements and similar products.
  - Proper centralization may be a challenge in some wells.
  - Hole deviation may require tractoring or other conveyance to get the logging tools to target depth.
- Ensure proper logging conditions are provided (i.e., stable borehole fluids, clean hole/casing).

- Include verification of logging parameters (e.g., casing thickness, cement compressive strength or acoustic impedance, logging pressures, etc.) in log assessment. Use tool calibration checks and assess a repeat section to verify results.
- Review quality control curves and images to ensure the logs comply with the measurement standards. Both ultrasonic and sonic measurements are sensitive to eccentering. The transit time curve is a good indicator of CBL eccentricity. Ultrasonic logs typically include a measurement of tool eccentricity estimated from the radius measurements.
- Plots of bond index along a wellbore can be used to highlight potential areas of concern however they are not be used as the sole indicator of zonal isolation. Refer to API 10TR1 for more information about bond index.

IRP Where zero pressure passes indicate poor cement contact, pressure passes should be used to identify whether a microannulus is present.

Consider the following:

- Where microannuli are present the logs may indicate lower quality cement placement when in fact the placement may be fine and there is just a tiny gap between the casing and cement at time of logging.
- Micro annuli can be formed by previous pressured operations after cement has started to set, heating/cooling of the casing and the reduction of hydrostatic pressure on the inside of the casing.
- Thermal operations on wellbores (i.e., Cyclic Steam Stimulation (CSS) and SAGD) raise casing temperature to 250 – 330 °C and can form larger microannuli from temperature expansion in some cases.
- Operators commonly run pressure passes with internal surface pressure at 7 MPa (or higher as dictated by the pressure history) to demonstrate microannular effects.
- In some thermal operations, a microannulus formed by thermal expansion of the casing and permanent deformation of the cement may be greater than the radial deflection achievable by pressure alone during logging.
- Ultrasonic and sonic log measurements respond to a microannulus. Ultrasonic measurements are relatively insensitive to a liquid filled microannulus (<200 um) but they are more sensitive than CBL tools to dry microannulus conditions.
- Dry microannulus is common in dual casing situations or after cured cement has been exposed to elevated temperature or pressure.

IRP Cement shall be allowed enough time to develop compressive strength before logging.

Consider the following:

- Cement set up times can be slower than expected, especially near the surface where formation temperatures are lower. The cementing service provider can provide compressive strength and acoustic impedance vs time curves (Ultrasonic Cement Analyzer plots) to help confirm the appropriate waiting time before logging and the appropriate compressive strength to use in logging correlations.
- Use cement top, lead-tail cement transitions and measured impedances to confirm the planned cement placement. The acoustic impedance of solids measured by ultrasonic tools can be 30-40% higher than the compressional acoustic impedance determined in the lab due to additional shear losses but gas and liquids in the annulus should read close to their true impedance. This is an important free pipe check.
- Where cement top is not known (e.g., sheath not designed to come to surface, lost returns, etc.) and knowledge of cement top is critical, operators can consider running a temperature log while cement is hydrating to identify the top of cement. The curing of cement is an exothermic reaction, with maximum heat evolution occurring 8-10 hours after hydration. A temperature log run 8-24 hours after hydration may enable cement top to be evaluated. This information can be used on its own or to help verify cement top indicated on the bond log. This technique is only viable in lower temperature formations.
- Ultra-light cement systems will affect log response. To help determine the quality of the cement, ensure the appropriate correlations/acoustic impedance are used to calibrate the logging.
- Very heavy weight and highly attenuating drilling fluids may prevent the transmission of sufficient ultrasonic energy to acquire quality data. There is no general rule for weight limits. Good logs have been recorded in fluid densities of 2000 kg/m^3 drilling fluid or more. Oil-based and synthetic oil-based drilling fluids tend to be more attenuating than water-based drilling fluids. Pre-job planning is needed to insure the logging operations are possible in extreme conditions.
- Casing corrosion can impact the ultrasonic cement map. Areas of extensive pitting corrosion will disperse the ultrasonic energy resulting in a noisy cement image. Casing radius and thickness data, also recorded by the tool, will confirm this. The lower frequency sonic CBL is less influenced by corrosion.
- Configure cement impedance maps with thresholds to properly discriminate between gases, liquids and solids. There needs to be some contrast between the acoustic properties of the drilling fluid, the spacer and the cement to reliably discriminate the solids. Include information about the acoustic impedance or compressive strength for each stage of the cement job in the pre-job planning.

25.10.3 Evaluation of Zonal Isolation

There are several techniques available to assess the level of zonal isolation provided by a cement sheath.

25.10.3.1 Surface Casing Vent Flow Testing

Presence of a SCVF typically indicates that gas from a formation below the surface casing is able to flow to surface inside the surface casing.

IRP Surface casing vent flow testing procedures and timing must adhere to jurisdictional regulations.

Refer to the Surface Casing Vent Flow Testing section of Appendix I: Additional Resources and References for more information about regulations that are in place for Alberta.

25.10.3.2 Gas Migration Testing

The presence of gas migration typically indicates that gas from a formation within the surface interval or below the surface casing shoe is able to flow to surface outside the casing. This can sometimes be observed as bubbles in the cellar or wider area surrounding the wellhead.

GM testing is typically done by drilling holes in a defined pattern around the wellbore and testing for gas inside the holes. It is the Operator's responsibility to provide the test methodology to the appropriate jurisdictional regulatory body upon request. A testing or repair program will be required if testing shows methane above background levels.

Refer to the Gas Migration Testing section of Appendix I: Additional Resources and References for more information about regulations that are in place for Alberta.

25.10.3.3 Nuclear Logging

Movement of fluid behind casing typically indicates a lack of zonal isolation. Nuclear logging can be used to detect issues below surface and most commonly near a completion interval. There are two main techniques to accomplish this: Tracer Surveys and Pulsed Neutron Tools

Additional information about Nuclear Logging can be found in Appendix G: Nuclear Logging.

25.10.3.4 Temperature Logging

Temperature logs can be run to detect fluid movement behind the pipe downhole. Some applications of temperature logging for the purpose of confirming isolation include the following:

- The "log-inject-log" technique can be used to determine the location of channeling behind the pipe. It is commonly applied when converting a producing well to an injector. This is done by running a baseline log, injecting fluid and logging again to evaluate movement behind the pipe.
- Detecting steam migration out of a zone. Temperature fall-off after steaming is suspended and can reveal hot spots related to steam injection.
- Detecting gas flow due to the cooling effect of expanding gas. This can help detect the presence, and potentially the source, of GM and SCVF on larger flows.

Other sensors may be required to determine whether the temperature effects are due to flow inside or behind the casing. Temperature tools are commonly combined with production logging suites.

Distributed Temperature Sensing (DTS) systems can provide long term well performance information and leak detection that cannot be practically achieved with wireline conveyed tools.

25.10.3.5 Noise Logging

Noise logs are commonly used to detect the source of GM and SCVF. They are particularly useful to help detect low rate gas flow sources outside the casing because this type of flow creates a characteristic "bubbling" sound in the liquid environments that are common downhole.

IRP Noise logs should be considered to identify the source of SCVF and GM if surface testing cannot provide adequate certainty. Audio files should be recorded when logging for this purpose.

Due to the high noise levels generated during tool movement, noise logs are recorded with the tool stationary at depth increments of five to ten metres. Audio files are recorded over a period of ten seconds to one minute or more.

Note: Some noise events can be intermittent and may be missed with short duration recording.

A temperature log is run during the initial down pass in combination with the noise tool to help identify potential flow. Bond logs can identify restrictions and channels that tend to increase flow velocity and therefore noise levels.

Fibre optic technology is also available that allows for distributed acoustic profiling in addition to temperature profiling.

25.11 Abandonment Plugs

Abandonment plugs are often utilized to cure lost circulation, seal off a weak formation, side track around a fish, kick off directionally, to abandon zones and to abandon wells without casing. This section deals only with plugs relating to abandonment. Other plugs (e.g., kick off plugs) are mentioned only if they are part of an abandonment.

Each plug job is unique and the placement of open hole plugs requires the same level of engineering design and operational due diligence as a primary cement. The plug design process can be iterative until a solution is achieved that meets the objectives and best manages the identified risks.

25.11.1 Plug Design

Abandonment plugs are required to provide permanent zonal isolation of the well. Any design needs to consider the offset well activities that may impact the plug.

Most of the design principles for a primary cementing job apply to the design of cement plugs. This section contains only the differences between the primary cement job and the plug job. Reference the following sections in 25.2 Cement Job Design for design principles and IRP statements that apply to both the primary cement job and plugs:

- 25.2.2 Simulations
- 25.2.3 Cement Volumes
- 25.2.5 Pump Rates
- 25.2.6 Mixing Methods
- 25.2.10 Drilling Fluid Conditioning
- 25.2.11 Wait on Cement Time
- 25.2.12 Spacers

25.11.1.1 Simulations

Cementing job simulators can be used to help design plug jobs when there is some technical uncertainty in the job design.

Simulators are typically used in the following situations:

- Kick-off plug for abandonment
- High or low temperature wells
- Long plug lengths

- Long pump times
- Deviated/Horizontal wellbore
- Fluid interface stability
- To determine what is required to remove drilling fluids and filter cake
- To determine pumping pressures through small ID pipe and slim annuli

It is important for the operator and cementing service provider to work together to ensure the required data is made available in order to limit assumptions.

Refer to 25.2.2 Simulations for more information.

25.11.1.2 Drilling Fluid/Hole Conditioning

Plug job design needs to consider spacers, whether centralization is required and other methods to improve displacement of drilling fluid and filter cake with cement within the intended placement area of the cement plug.

IRP Where practical, pipe movement (i.e., rotation, reciprocation) should be used while circulating before pumping the cement plug. Once the pipe is at depth the wellbore should be circulated and conditioned to make the hole as clean as practically possible, drilling fluid density uniform, and gel strengths e as low as practically possible. Conditioning should be done immediately prior to balancing the plug.

One option to aid in filter cake removal is the step rate process for removal of drilling fluid.

Refer to 25.2.10 Drilling Fluid Conditioning for more information.

25.11.1.3 Plug Stability

Slurry stability (or lack of stability) has greater consequences for plugs in horizontal wells because it results in a long section of cement that could have undesirable set properties. In deviated or horizontal wells, free fluid may rise to the high-side forming a channel. Refer to section 25.4.10 Stability for more information.

Interface instability (plug slumping) is an issue when setting plugs off bottom. Higher density cement plugs may swap out with lower density fluids below them. Slumping of the placed plug will occur but the amount or length of slumping varies depending on wellbore conditions (e.g., hole size, deviation, cement slurry properties, wellbore fluid properties).

IRP Plug instability should be minimized.

Slurry rheological properties (e.g., yield point and gel strength development) and wellbore fluid/spacer properties (e.g., density, yield point, gel strength) impact the amount of slumping. Typically, wellbore fluids and spacers with higher yield points will minimize the interface profile. Lowering the density differences between the drilling fluid/spacer/cement may also improve interface stability. A longer plug may be required to achieve the objective.

25.11.1.4 **Chemical Support Plugs**

Viscosified polymers, reactive pills, diesel gel or bentonite slurries can be spotted below cement plug depth to serve as support and prevent fluid swapping. Slurry/drilling fluid incompatibility and downhole fluid swap can, potentially, cause sufficient gelation to provide some support for a balanced plug. A lower-density “sacrificial” plug could be spotted and allowed to set to provide this base.

25.11.1.5 **Mechanical Support**

Mechanical supports are an alternative to chemical support plugs.

Bridge plugs can be set at the bottom of the intended cement plug to prevent heavier slurry from falling through wellbore fluids when placing a cement plug off bottom. Sand or calcium carbonate can be spotted on top of a retrievable bridge plug to allow access to the (un)setting mechanism if cement is ever drilled out. Alternatively, pump down mechanical systems can be used (e.g., foam poly plugs) to prevent the cement from unintentionally mixing at interfaces with other wellbore fluids.

Alternative mechanical supports include umbrella-type tools and inflatable packers.

25.11.1.6 **Fluid Separation**

Wiper plugs, neoprene balls or foam balls can be pumped to help isolate slurry from spacer. If plugs or balls are not run then consider other steps to prevent slurry contamination by drilling fluid and/or spacer.

Foam balls can be used to segregate fluid systems by providing a mechanical barrier between fluids. Solid plugs can also be used to separate the fluids. The use of solid plugs requires the use of a plug catcher tool at the bottom of the drill string to ensure the plugs do not become lodged in the annulus section.

Diverter tools or subs can be run to help prevent downward jetting action of slurry, reducing the chance of contamination and stringing out the cement plug.

25.11.1.7 **Tail Pipe**

Tailpipe (often referred to as a cement stinger) is often utilized when the regular work string results in a small annular clearance to minimize swab pressure and cement disturbance while pulling out of the plug.

IRP Tailpipe should be appropriately sized to minimize cement disturbance but still facilitate placement.

IRP Tailpipe should be of sufficient length to accommodate height of the plug, including excess, prior to pulling pipe.

Tailpipe can be used sacrificially to eliminate any disturbance that may be encountered from pulling out of the plug and can serve as reinforcement for the cement plug. Sacrificial tailpipe can be advantageous when long plug intervals are required or for future access to the wellbore.

If sacrificial tailpipe is left in the cement plug the following should be considered:

- How to disconnect from the tailpipe.
- Contingencies for risks that may result in a low cement top such as lost circulation or packoff.

25.11.1.8 Cement Volumes and Plug Length

The initial cement volume is based on the length requirement of the plug and should include an excess factor to account for washout and slurry contamination. As slurry contamination is one of the primary failure mechanisms for cement plugs, it may be advantageous to pump excess slurry and circulate off the cement top to desired depth than risk multiple job failures due to insufficient slurry volume. Refer to AER Directive 020: Well Abandonment for more information.

Minimum volumes are often dictated by regulations but wellbore factors need to be taken into account because sometimes the minimum volumes are insufficient and/or operationally impractical.

Slurry volumes, especially in small hole sizes, can be small and subject to contamination from spacer and wellbore fluids both ahead and behind the slurry. Resulting contamination may prevent compressive strength development and provide ineffective isolation in abandonment situations.

Consider larger excess volumes when there is a higher risk of contamination (e.g., deeper or longer plugs).

Be cautious when pumping extended plug lengths because of the risks associated with swabbing and stuck pipe. Discuss plug length best practices with the cementing service provider.

Refer to 25.2.3 Cement Volumes for more information.

25.11.1.9 Mixing Methods

The volume of cement required for a plug is much smaller than a primary casing cementing job. Batch mixing or slurry averaging will improve control of slurry density.

Refer to 25.2.6 Mixing Methods for more information.

25.11.1.10 Pump Rates and Displacement

Ideally, when pumping a balanced plug, the height of each fluid pumped (i.e., drilling fluid, spacer, cement) is equal inside the pipe and in the annulus. Calculate displacement volumes based on actual pipe tally data. Common practices are to under-displace slurry by a set volume or to rely on surface pressure to determine when to stop displacement. Both methods are used to allow the heavier fluid in the pipe to "fall out" and balance itself, but have limitations when high friction pressure is encountered (e.g., deep or horizontal wells, high viscosity fluids). The amount of under-displacement that is required to reduce the amount of interfacial mixing that will take place as pipe is pulled out of the cement plug needs to be calculated.

Refer to 25.2.4 Displacement Volumes and 25.2.5 Pump Rates for more information.

25.11.1.11 Pipe Movement

Pipe movement can improve the chances of a successful plug job. Consider the following:

- Rotation of pipe is recommended to improve slurry placement by moving stagnant drilling fluid and removing drilling fluid filter cake. Rotation may be impossible for some highly deviated wellbores.
- Layering, or pulling pipe during placement, can be considered. This is most common when placing plugs with coil tubing or with top drives.
- Reciprocation is not recommended while spotting slurry when balancing plugs.

Refer to 25.2.9 Pipe Movement for more information.

25.11.1.12 Post Displacement

Tailpipe may be pulled out of the plug after slurry has been balanced.

IRP Pipe should be pulled out of the plug slow enough to prevent swabbing and contamination. A good rule of thumb is 5-10 m/minute but that should be adjusted based on conditions (i.e., hole size, annulus size, slurry viscosity, temperature, depth).

IRP Static time after placement should be minimized before pulling out.

Pull above anticipated TOC (a good rule of thumb is 20 m) and circulate out excess cement. Depending on the situation (e.g., geometry, plug design, ECDs, hole conditions, etc.), consider the advantages and disadvantages of direct or reverse circulation. Avoid jetting or washing away the top of the plug.

IRP Verification of plugs should be done in a manner that does not affect the integrity of the plugs and use a method that accurately records the plug intervals.

25.11.2 Plug Spacer Design

The plug slurry volumes are often significantly smaller than primary cementing therefore it is critical that contamination is minimized by using appropriate spacer volumes and rheological properties.

The general guidelines and recommendations for spacer design for primary cementing outlined in 25.3 Spacer Design also apply to the design of the spacers used for setting plugs.

Refer to the following sections in Spacer Design for more information:

- 25.3.2 Annular Velocity and Fluid Flow
- 25.3.3 Spacer Length and Contact Time
- 25.3.4 Compatibility
- 25.3.5 Wettability
- 25.3.6 Spacer Stability

25.11.3 Plug Slurry Design

Plug slurry design is a process that is often overlooked, resulting in additional time and costly failures. The slurry formulation can vary greatly depending on the objective of the plug. Permanent abandonment plugs should be designed for long-term zonal isolation. Temporary plugs such as lost circulation or kick-off plugs may only require initial set properties. Laboratory testing and simulations can be used to verify the predicted results and refine the slurry design to arrive at optimal formulation for a given set of well conditions.

The general guidelines and recommendations for slurry design for primary cementing outlined in 25.4 Slurry Design also apply to the design of the slurry used for plugs.

Refer to the following sections in Slurry Design for more information:

- 25.4.1 Slurry Density
- 25.4.2 Cement Type
- 25.4.3 Additives
- 25.4.4 Thickening Time
- 25.4.5 Compressive Strength
- 25.4.6 Fluid Loss
- 25.4.7 Free Water
- 25.4.8 Rheology
- 25.4.9 Static Gel Strength

- 25.4.10 Stability
- 25.4.11 Expansion
- 25.4.12 Solids Volume Fraction
- 25.4.13 Mechanical and Thermal Properties
- 25.4.14 Lost Circulation

25.11.3.1 Hole Conditions

The following information provided by Halliburton is derived from SPE 30514 data about cement slurry design based on specific hole conditions.

> **Note:** Original SPE data was in imperial units. It has been converted to metric for this document.

Table 22. Angle and Hole Size

	Hole Size				
Angle	**4.5" (114.3 mm)**	**6" (152.4 mm)**	**8.5" (215.9 mm)**	**12" (304.8 mm)**	**16" (406.4 mm)**
Horizontal	H/L/L	H/L/L	H/M/M	H/L/M	H/M/M
76°	H/M/M	M/L/L	M/L/L	M/L/L	M/L/L
60°	H/M/M	M/L/L	L/H/H	VL/M/M	VL/M/M
45°	L/L/L	L/L/L	L/M/M	VL/M/M	VL/M/M
30°	L/L/L	L/M/M	VL/M/M	VL/M/M	VL/M/M
Vertical	L/H/H	L/H/H	L/H/H	L/H/H	L/H/H

Table entries are as follows:

- 1st Letter: Density Difference (value given in table below or smaller)
- 2nd Letter: Mud's Yield Point (value given in table below or larger)
- 3rd Letter: API's 10 Minute Gel Strength (value given in table below or larger)

Table 23. Density Difference, Mud Yield Point and 10 Minute Gel Strength

	Density Difference		Mud's YP		10 Minute Gel Strength	
	lb/gal	**kg/m^3**	**lbf/ 100 sq. ft.**	**Pa**	**lbf/ 100 sq.ft.**	**Pa**
VL	1	120				
L	1.8 – 2.6	215 – 312	15 – 60	7.2 – 28.7	5 – 15	2.4 – 7.2
M	3.7 – 4.7	443 – 563	60 – 150	28.7 – 71.8	20 – 65	9.6 – 31.1
H	6.7 – 7.9	803 – 947	>150	>71.8	105 - 160	50.3 – 76.6

25.11.3.2 Slurry Density

As with primary cementing, slurry density selection needs to be sufficient to maintain hydrostatics within the pore pressure and fracture gradient window. Once the density is selected other requirements for specific well conditions can be addressed to ensure job objectives are met.

If there is not a base for the plug it may be optimal to have a minimal density differential between drilling fluid and slurry to prevent slumping. If this is not possible consider mechanical aids, increased slurry volume or additional plugs.

For plugs placed in horizontal or deviated wellbores, density differential will not have a significant impact on the stability of the plug so the rheological parameters need to be optimized to aid in placement and prevention of contamination.

Reduced water (densified) slurries are less susceptible to drilling fluid contamination. Consider a reduced water slurry when wellbore conditions allow and if there is a suitable base for the plug.

Refer to 25.4.1 Slurry Density for more information.

25.11.3.3 Thickening Time

IRP Thickening time should take into account the mixing method, plug placement time, planned static periods (i.e., pulling out of plug), time to reverse/forward circulate pipe and an appropriate safety factor.

IRP When possible, temperature simulations should be used to calculate the appropriate placement (dynamic) temperature so cement testing can be performed under representative wellbore conditions.

Use the recommendations in API RP 10B-2: Squeeze and Plugs if temperature simulations are not available.

Refer to 25.4.4 Thickening Time for more information.

25.11.3.4 Compressive Strength

The minimum required compressive strength is governed by jurisdictional regulations for abandonment plugs. Depending on the objectives of the cement plug, there may be requirement for higher compressive strength (e.g., kick off plugs). Higher compressive strengths do not necessarily contribute to improved zonal isolation.

IRP Slurry should remain undisturbed until it has developed sufficient compressive strength for the application.

Plug logging that requires logging through the slurry should be done in a manner that minimizes disturbance of the plug. Tagging the plug before it has gained compressive strength may jeopardize the plug integrity.

IRP When possible, temperature simulations should be used to calculate the appropriate curing temperatures (i.e., how long it takes for the rock to go from BHCT to BHST) so cement testing can be performed under representative wellbore conditions.

Lower temperatures will delay compressive strength onset at top of cement (TOC).

Refer to 25.4.5 Compressive Strength for more information.

25.11.3.5 **Rheology**

In order to set balanced plugs it is critical that slurry rheology be such that pipe can easily be pulled out of the plug and slurry is not swabbed while doing so. Consider yield point, gel strength, hole size and pipe size to prevent swabbing and/or stuck pipe.

Refer to 25.4.8 Rheology for more information.

25.11.3.6 **Transition Time**

Transition time has to be accounted for in plugs set across a porous interval in order to prevent formation influx.

Refer to 25.4.9 Static Gel Strength for more information.

25.11.4 Plug Failure

The following may indicate plug failure:

- Inability to verify the plug (either by tagging or logging) or tag on depth.
- Inability to pressure test or pressure at surface post job.
- Insufficient strength to perform kick off operations if kick off is planned off of an abandonment.
- Flow observed at surface.
- Lost circulation while placing the plug.

The following are common causes of plug failure:

- Incorrect assessment of downhole conditions (i.e., temperature, pressure and hole size).
- Cement excess (i.e., inaccurately assume excess by not understanding the hole size).

- Slurry contamination due to channeling, poor fluid separation and/or removal of gelled drilling fluid or filtercake.

  Note: It is more difficult to remove filter cake in old or abandoned wells.

- Fluid swap.
- Inability to stop downward momentum of slurry.
- Downhole cross-flow.
- Inability to achieve contact or bond with the formation because the formation is “oil wet” after drilling with oil-based drilling fluid.
- Incorrect plug length (too long or too short).
- Incorrect operations (e.g., pulling out of the plug too quickly creating swab effect, not balancing the cement plug).

25.11.5 Alternative Abandonment

In some instances, casing may be run and cemented as an alternative to setting plugs in the open hole. In these situations, the casing is either cemented in its entirety (inside and annulus) or conventionally as a primary cement job. Cement plugs can then be spotted within the casing if required.

25.12 Management of Change

Management of change (MOC) is a process to recognize and mitigate risk associated with changes.

IRP A management of change process should be in place for all cement jobs and all employees should be trained in the process.

The success and usefulness of any management of change process is dependent on management, technical support and operations support.

The components of a management of change process are as follows:

- Identification of variances
- Analysis of associated risk
- Approval
- Implementation
- Documentation

25.12.1 Identifying Variances

Sections 25.7.2.1 Design Verification and Calculations and 25.7.2.2 Material and Equipment Checks define the checks that need to take place to identify when there is a change in the plan.

The following are some examples of changes that may trigger a management of change process:

- Wellbore: Temperature, depth, pressures, hole conditions/stability, geology, downhole equipment, casing, deviation, stand-off, change of well objective
- Surface: water quality, surface equipment condition, capacity and ratings, environment, personnel
- Job Design: Change of job objective, change in additives or blends

25.12.2 Analysis of Risk

Once a variation has been identified, consult with personnel familiar with the technical and operational aspects of the work to determine the likelihood and severity of potential risks. An action plan may be required to mitigate the risk (see 25.7.3 Contingency Plans).

25.12.3 Approval

Depending on the risks and actions determined from the previous step, an appropriate level of management and/or technical approval may be required. Approval from the local jurisdictional regulator may also be required.

25.12.4 Implementation

Assign responsibility for the action plan's implementation. Inform all effected personnel in a timely manner.

25.12.5 Documentation

Documentation of the changes and the reasons for the changes helps build a robust management of change process and assist with the post job evaluation.

25.13 Continuous Improvement

Cement job evaluations can be used to measure the success or failure of a cement job and feed into the continuous improvement of cementing practices. A detailed review of the planned job compared to the actual job parameters and results can indicate where design or execution practices could be modified to achieve a better result. To complete the continuous improvement loop it is critical to feed the identified modifications back into the job planning and execution processes.

Continuous improvement is an iterative process that requires management support throughout an organization in order to be successful. Management support is more easily obtained when direct measurements of success are readily available. This can be challenging in the cementing process where only indirect measures can be used to evaluate success. Using measured data for several important predictive elements of success and an objective approach to the evaluation can make the continuous improvement process more effective.

IRP Operators and cementing service providers should implement measurement and review processes to facilitate continuous improvement of cementing practices.

25.13.1 Cement Job Evaluation

A cement job evaluation includes the following:

- A review of the job plan and whether the job was pumped as planned.
- A review of the treatment parameters.
- An evaluation of the cement annular sheath or plug.
- An evaluation of the cement integrity and its ability to provide zonal isolation on an ongoing basis.

Critical job data (e.g., pump rates, pressures, cement densities, etc.) and job results (e.g., returns, cement slump, cement evaluation log results, SCVF and GM monitoring, etc.) have to be captured in order to evaluate the job.

25.13.2 Continuous Improvement Process

The basic approach for continuous improvement is to plan the job, execute the job, check or evaluate the result of the job and then implement any modifications to the planning or execution that could improve the result. This is more commonly referred to as the PDCA loop (Plan, Do, Check, Act).

25.13.2.1 Plan

The plan step of a cementing operation starts with the definition of the primary objective (or objectives) of the treatment. It is best not to look at the final outcome of the well but to define the objectives one casing string at a time. These objectives need to be clear to those involved in the design and operation(s) of the well. An objective could be as simple as providing support for the casing to prevent pipe movement or as complex as providing full zonal isolation in a wellbore while maintaining integrity for the life of the well.

Once the objectives are clear the cement job can be planned and the slurry (and spacers) can be designed. The objectives will dictate the design approach. Refer to sections 25.2 Cement Job Design, 25.3 Spacer Design and 25.4 Slurry Design for more information about the specific design considerations for the planning step.

Ignoring this first step can result in either unnecessary or inadequate products or services.

25.13.2.2 Do

The do step is the execution phase of the job. The execution phase is the application of the plan and design. There are a large number of variables with the potential to impact the final outcome of a cement job. Success can only be evaluated when there is proper execution with accurate recording of job details and result.

Refer to 25.7 Pre-Job Preparation, 25.8 Cement Slurry Placement, 25.9 Post-Placement Considerations and 25.12 Management of Change for more information about the specific areas of job execution that should be considered.

25.13.2.3 Check

The check step is the post job evaluation phase of the job. Evaluate the treatment after proper planning and diligent execution of the plan. Consider the following indicators for evaluating a cement job:

- Whether the job met the objectives of the initial plan.
- Whether the cement treatment is holding the pipe in place successfully.
- Whether the cement job has prevented SCVF/GM.

> **Note:** Not all of measures of success are immediately available (e.g., long term prevention of SCVF or GM) so a process to evaluate success over time is necessary.

Refer to 25.10 Post-Job Evaluation for more information about the methods and tools for evaluating the cement job. Refer to Appendix H: Continuous Improvement Evaluation Approach for an example of an evaluation method.

25.13.2.4 **Act**

The act step is the implementation of change. Recommendations need to be formulated based on the results of the check phase, documented and communicated to all parties involved in the planning, execution and evaluation processes. The changes then become part of the planning, execution and evaluation processes and feed back into the continuous improvement loop.

Appendix A: Revision History

Table 24. Revision History

Edition	Sanction Date	Remarks/Changes
1	April 1995	Initial publication
2	2016	The document was reworked to the new DACC Style Guide and Template with all new content for primary cementing. Remedial cementing is to be addressed at a later date.

Appendix B: Cement Job Challenges

This IRP outlines practices and contingency plans for planning and executing any cement job and includes suggestions for addressing these challenging situations. The tables below discuss some of the challenges, potential consequences, possible solutions and the section of the document to reference for recommended practices.

Challenge: Field History/Well Risk Factors

This section outlines the potential consequences and possible solutions for fields with a history of gas migration, SCVF or influx or if the well has risk factors such as over or under-pressured zones or lost circulation zones.

Table 25. Potential Consequences and Solutions: Field History/Well Risk Factors

Potential Consequences	Possible Solutions	Document Reference
Increased difficulty and cost associated with remediation/ abandonment.	Optimize rheology and follow rheological hierarchy	Spacer Design sections: • 25.3.2.2.1 Friction Pressure Hierarchy • 25.3.2.2.2 Density Hierarchy Slurry Design section 25.4.8 Rheology
	Add expanding agents	Slurry Design section 25.4.11 Expansion
	Decrease fluid loss and free water as low as possible	Slurry Design sections: • 25.4.6 Fluid Loss • 25.4.7 Free Water
	Add gas blocking products into slurry	Slurry Design section 25.4.3 Additives
	Utilize surfactants	Spacer Design section 25.3.8 Wettability.

Potential Consequences	Possible Solutions	Document Reference
	Ensure proper wellbore cleaning while drilling (wiper trips, reamer runs, drilling fluid properties, bit hydraulics)	Wellbore Construction sections: • 25.6.2.1 Wiper Trips and Backreaming • 25.6.2.2 Drilling Tools/Technology to Remove Cuttings
	Circulate and condition drilling fluid prior to cementing	Wellbore Construction section 25.6.2.4 Circulating/Conditioning Drilling Fluid Prior to Running Casing
	Use a simulator and optimize centralization	• Cement Job Design section 25.2.7 Centralization • Wellbore Construction section 25.6.1.11 Centralization
	Run full-bore Port Collars as a means of selective annular access for contingency stage/remedial cementing operations	Wellbore Construction section 25.6.1.3 Casing and Connection selection
Lack of zonal isolation	Follow density hierarchy	Spacer Design section 25.3.3 Density Hierarchy
	Optimize static gel strength transition time	Slurry Design section 25.4.9 Static Gel Strength
	Increase annular hydrostatics	Slurry Design section 25.4.1 Slurry Density
	Adjust casing points	Wellbore Construction sections: • 25.6.1.3 Casing and Connection Selection • 25.6.2.3 Running Casing
	Ensure wellbore is clean and optimize hole conditions prior to cementing	Wellbore Construction sections: • 24.6.2.1 Wiper Trips and Backreaming • 25.6.2.2 Drilling Tools/Technology to Remove Cuttings
	Use mechanical barriers	Abandonment Plugs sections: • 25.11.2.4 Chemical Plugs Support Plugs • 25.11.2.4 Mechanical Support Wellbore Construction section 25.6.1.14 Cement Baskets

Potential Consequences	Possible Solutions	Document Reference
	Run inflatable packer(s) above potential flow zone(s) to prevent annular channeling and/or slurry contamination above the packer	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats Abandonment Plugs sections: • 25.11.2.4 Chemical Support Plugs • 25.11.2.5 Mechanical Support Wellbore Construction section 25.6.1.14 Cement Baskets
	Run inflatable packer(s) and stage tool(s) above potential flow zone(s) so that the second stage cementing operation ensures adequate cement coverage and viable annular isolation	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats
Loss of zones, productivity	Decrease cement column length	Cement Job Design section 25.2.2 Simulations Wellbore Construction section 25.6.1.4 Stage Tools
	Increase annular hydrostatics	Slurry Design section 25.4.1 Slurry Density
	Increase solids fraction of slurry	Slurry Design section 25.4.12 Solids Volume Fraction
	Increase annular gap for optimal slurry placement	Wellbore Construction section 25.6.1.2 Hole Size and Annular Spacing
	Increase annular overburden pressure	Wellbore Construction section 25.6.1.1 Formations

Challenge: Highly Deviated or Horizontal Wells

This section outlines the potential consequences and possible solutions for highly deviated or horizontal wells. The implications of highly deviated wells are discussed in 25.6 Wellbore Construction (see sections 25.6.1.1 Formations and 25.6.1.7 Directional Planning).

Table 26. Potential Consequences and Possible Solutions: Highly Deviated or Horizontal Wells

Potential Consequences	Possible Solutions	Document Reference
Difficulty removing drilling fluid resulting in poor slurry placement	Optimize rheology and follow rheological hierarchy	Spacer Design sections: • 25.3.2.2.1 Friction Pressure Hierarchy • 25.3.2.2.2 Density Hierarchy Slurry Design section 25.4.8 Rheology
	Pump additional spacer and/or slurry volumes	• Cement Job Design section 25.2.3 Cement Volumes • Spacer Design 25.3.3 Spacer Length and Contact Time
	Ensure proper wellbore cleaning while drilling (wiper trips, reamer runs, drilling fluid properties, bit hydraulics)	Wellbore Construction sections: • 25.6.2.1 Wiper Trips and Backreaming • 25.6.2.2 Drilling Tools/Technology to Remove Cuttings
	Circulate and condition drilling fluid prior to cementing	Wellbore Construction section 25.6.2.4 Circulating/Conditioning Drilling Fluid Prior to Running Casing
	Use a simulator and optimize centralization, utilize integral centralizers to prevent pile-up	• Cement Job Design section 25.2.7 Centralization • Wellbore Construction section 25.6.1.11 Centralization
	Run full-bore Port Collars as a means of selective annular access for contingency stage/remedial cementing operations	Wellbore Construction section 25.6.1.3 Casing and Connection Selection
Lack of zonal isolation	Optimize rheology and follow rheological hierarchy	Spacer Design sections: • 25.3.2.2.1 Friction Pressure Hierarchy • 25.3.2.2.2 Density Hierarchy Slurry Design section 25.4.8 Rheology

Potential Consequences	Possible Solutions	Document Reference
	Pump additional spacer and/or slurry volumes	• Cement Job Design section 25.2.3 Cement Volumes • Spacer Design section 25.3.3 Spacer Length and Contact Time
	Lower free water to 0.0%	Slurry Design section 25.4.7 Free Water
	Use slurry stabilizers or anti-settling additives	Slurry Design section 25.4.10 Stability
	Increase annular gap for optimal slurry placement	Wellbore Construction section 25.6.1.2 Hole Size and Annular Spacing
	Reciprocate and/or rotate casing as much as possible	• Job Design section 25.2.9 Pipe Movement • Wellbore Construction section 25.6.2.5 Ability to Rotate/Reciprocate During Cementing
	Use a simulator and optimize centralization, utilize integral centralizers to prevent pile-up	• Cement Job Design section 25.2.7 Centralization • Wellbore Construction section 25.6.1.11 Centralization
	Run swellable packers in the horizontal to mitigate drilling fluid channels on the low side of the open hole	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats
Loss of zones, productivity	Follow density hierarchy	Spacer Design section 25.3.2.2.2 Density Hierarchy
	Attempt turbulent flow (spacer or slurry) if well conditions allow	Wellbore Construction section 25.6.1.12 Spiral Centralizers
	Use slurry stabilizers or anti-settling additives	Slurry Design section 25.4.10 Stability
	Minimize DLS, washouts, spiraling	Wellbore Construction section 25.6.1.7 Directional Planning
	Ensure wellbore is clean and optimize hole conditions prior to cementing	Wellbore Construction sections: • 25.6.2.1 Wiper Trips and Backreaming • 25.6.2.2 Drilling Tools/Technology to Remove Cuttings

Potential Consequences	Possible Solutions	Document Reference
	Use a simulator and optimize centralization, utilize integral centralizers to prevent pile-up	• Cement Job Design section 25.2.7 Centralization • Wellbore Construction section 25.6.1.11 Centralization

Challenge: Slim Holes

This section outlines the potential consequences and possible solutions for wells with slim holes. Hole size is discussed in detail in the 25.6 Wellbore Construction (see 25.6.1.2 Hole Size and Annular Spacing).

Table 27. Potential Consequences and Possible Solutions: Slim Holes

Potential Consequences	Possible Solutions	Document Reference
Difficulty removing drilling fluid resulting in poor slurry placement	Understand ECDs through simulator and adjust densities, rheologies and pump rates accordingly	Cement Job Design sections: • 25.2.2 Simulations • 25.2.5 Pump Rates Spacer Design sections: • 25.3.2.2.1 Friction Pressure Hierarchy • 25.3.2.2.2 Density Hierarchy Slurry Design section 25.4.8 Rheology Wellbore Construction section 25.6.1.8 Equivalent Circulating Density
	Attempt turbulent flow (spacer or slurry) if well conditions allow	Wellbore Construction section 25.6.1.12 Spiral Centralizers
	Pump additional spacer and/or slurry volumes	Cement Job Design section 25.2.3 Cement Volumes Spacer Design section 25.3.3 Spacer Length and Contact Time
	Utilize slurry with sufficient set properties for thin cement sheath	25.4 Slurry Design
	Ensure proper wellbore cleaning while drilling (wiper trips, reamer runs, drilling fluid properties, bit hydraulics)	Wellbore Construction sections: • 25.6.2.1 Wiper Trips and Backreaming • 25.6.2.2 Drilling Tools/Technology to Remove Cuttings
	Circulate and condition drilling fluid prior to cementing	Wellbore Construction section 25.6.2.4 Circulating/Conditioning Drilling Fluid Prior to Running Casing

Potential Consequences	Possible Solutions	Document Reference
	Use a simulator and optimize centralization	Cement Job Design section 25.2.7 Centralization Wellbore Construction section 25.6.1.11 Centralization
	Run swellable packers in horizontal to mitigate drilling fluid channels on the low side of the open hole	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats
Lack of zonal isolation	Reduce viscosity, optimize rheology and follow rheological hierarchy	Spacer Design sections: • 25.3.2.2.1 Friction Pressure Hierarchy • 25.3.4 Compatibility Slurry Design section 25.4.8 Rheology
	Pump additional spacer and/or slurry volumes	• Cement Job Design section 25.2.3 Cement Volumes • Spacer Design section 25.3.3 Spacer Length and Contact Time
	Use slurry stabilizers or anti-settling additives	Slurry Design section 25.4.10 Stability
	Minimize DLS, washouts, spiraling	Wellbore Construction section 25.6.1.7 Directional Planning
	Reciprocate and/or rotate casing as much as possible	Job Design section 25.2.9 Pipe Movement Wellbore Construction section 25.6.2.5 Ability to Rotate/Reciprocate During Cementing
	Use a simulator and optimize centralization	Cement Job Design section 25.2.7 Centralization Wellbore Construction section 25.6.1.11 Centralization
	Run swellable packers in the horizontal to mitigate drilling fluid channels on the low side of the open hole	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats

Potential Consequences	Possible Solutions	Document Reference
Loss of zones, productivity	Follow density hierarchy	Spacer Design section 25.3.2.2.2 Density Hierarchy
	Pump additional spacer and/or slurry volumes	Cement Job Design section 25.2.3 Cement Volumes Spacer Design section 25.3 5 Spacer Length and Contact Time
	Attempt turbulent flow (spacer or slurry) if well conditions allow	Wellbore Construction section 25.6.1.12 Spiral Centralizers
	Use slurry stabilizers or anti-settling additives	Slurry Design section 25.4.10 Stability
	Minimize DLS, washouts, spiraling	Wellbore Construction section 25.6.1.7 Directional Planning
	Ensure wellbore is clean and optimize hole conditions prior to cementing	Wellbore Construction sections: • 25.6.2.1 Wiper Trips and Backreaming • 25.6.2.2 Drilling Tools/Technology to Remove Cuttings
	Use a simulator and optimize centralization	Cement Job Design section 25.2.7 Centralization Wellbore Construction section 25.6.1.11 Centralization

Challenge: Inability to Move Pipe

This section outlines the potential consequences and possible solutions for situations where it is not possible to move pipe (i.e., rotate and/or reciprocate). Pipe movement is discussed in detail in the Cement Job Design section 25.2.9 Pipe Movement and Wellbore Construction section 25.6.2.5 Ability to Rotate/Reciprocate During Cementing.

Table 28. Potential Consequences and Possible Solutions: Inability to Move Pipe

Potential Consequences	Possible Solutions	Document Reference
Difficulty removing drilling fluid resulting in poor slurry placement	Optimize rheology and follow rheological hierarchy	Spacer Design sections: • 25.3.2.2.1 Friction Pressure Hierarchy • 25.3.2.2.2 Density Hierarchy Slurry Design section 25.4.8 Rheology
	Attempt turbulent flow (spacer or slurry) if well conditions allow	Wellbore Construction section 25.6.1.12 Spiral Centralizers
	Pump additional spacer and/or slurry volumes	Cement Job Design section 25.2.3 Cement Volumes Spacer Design section 25.3 5 Spacer Length and Contact Time
	Utilize slurry with sufficient set properties for thin cement sheath	25.4 Slurry Design
	Ensure proper wellbore cleaning while drilling (wiper trips, reamer runs, drilling fluid properties, bit hydraulics)	Wellbore Construction sections: • 25.6.2.1 Wiper Trips and Backreaming • 25.6.2.2 Drilling Tools/Technology to Remove Cuttings
	Circulate and condition drilling fluid prior to cementing	Wellbore Construction section 25.6.2.4 Circulating/Conditioning Drilling Fluid Prior to Running Casing
	Use a simulator and optimize centralization	Cement Job Design section 25.2.7 Centralization Wellbore Construction section 25.612.11 Centralization

Potential Consequences	Possible Solutions	Document Reference
	Run swellable packers in horizontal to mitigate drilling fluid channels on the low side of the open hole	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats
Lack of zonal isolation	Follow density hierarchy	Spacer Design section 25.3.2.2.2 Density Hierarchy
	Pump additional spacer and/or slurry volumes	• Cement Job Design section 25.2.3 Cement Volumes • Spacer Design section 25.3.3 Spacer Length and Contact Time
	Minimize DLS, washouts, spiraling	Wellbore Construction section 25.6.1.7 Directional Planning
	Use a simulator and optimize centralization	• Cement Job Design section 25.2.7 Centralization • Wellbore Construction section 25.6.1.11 Centralization
	Run swellable packers in the horizontal to mitigate drilling fluid channels on the low side of the open hole	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats
Loss of zones, productivity	Follow density hierarchy	Spacer Design section 25.3.2.2.2 Density Hierarchy
	Pump additional spacer and/or slurry volumes	Cement Job Design section 25.2.3 Cement Volumes Spacer Design section 25.3.3 Spacer Length and Contact Time
	Minimize DLS, washouts, spiraling	Wellbore Construction section 25.6.1.7 Directional Planning
	Ensure wellbore is clean and optimize hole conditions prior to cementing	Wellbore Construction sections: • 25.6.2.1 Wiper Trips and Backreaming • 25.6.2.2 Drilling Tools/Technology to Remove Cuttings

Potential Consequences	Possible Solutions	Document Reference
	Use a simulator and optimize centralization	Cement Job Design section 25.2.7 Centralization Wellbore Construction section 25.6.1.11 Centralization
	Run swellable packers in the horizontal to mitigate drilling fluid channels on the low side of the open hole	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats

Challenge: Cyclic Well Stresses (Including Fracturing)

This section outlines the potential consequences and possible solutions for situations where there are cyclic well stresses (including fracturing).

Table 29. Potential Consequences and Possible Solutions: Cyclic Well Stresses

Potential Consequences	Possible Solutions	Document Reference
Lack/loss of zonal/hydraulic isolation after placement	Modify operational practices to reduce the severity of number of cycles.	IRP3: In Situ Heavy Oil Operations
	Utilize simulators to understand the effect extreme temperatures and future stresses will have on the integrity of the cement sheath	Cement Job Design section 25.2.2 Simulations
	Utilize self-healing cements, expanding agents and permeability modifiers	25.4 Slurry Design
	Increase annular gap for optimal slurry placement	Wellbore Construction section 25.6.1.2 Hole Size and Annular Spacing
	Utilize slurry with sufficient set properties for thin cement sheath	25.4 Slurry Design
	Circulate and condition drilling fluid prior to cementing	Wellbore Construction section 25.6.2.4 Circulating/Conditioning Drilling Fluid Prior to Running Casing
	Use a simulator and optimize centralization	Cement Job Design section 25.2.7 Centralization Wellbore Construction section 25.6.1.11 Centralization
	Run swellable packers in the horizontal to provide a means of microannulus mitigation and stress-induced sheath failure prevention	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats

Potential Consequences	Possible Solutions	Document Reference
Loss of productivity, early abandonment	Optimize rheology and follow rheological hierarchy	Spacer Design sections: • 25.3.2.2.1 Friction Pressure Hierarchy • 25.3.2.2.2 Density Hierarchy Slurry Design section 25.4.8 Rheology
	Utilize simulators to understand future stresses	Cement Job Design section 25.2.2 Simulations
	Utilize self-healing cements, expanding agents and permeability modifiers	25.4 Slurry Design
	Add tensile strength or flexible additives for possible cyclic steam injection	Slurry Design section 25.4.3 Additives
	Rotate and/or reciprocate casing	Cement Job Design section 25.2.9 Pipe Movement Wellbore Construction section 24.6.2.5 Ability to Rotate/Reciprocate During Cementing
	Use a simulator and optimize centralization	Cement Job Design section 25.2.7 Centralization Wellbore Construction section 25.6.1.11 Centralization
	Run swellable packers in the horizontal to mitigate drilling fluid channels on the low side of the open hole	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats
Increased difficulty and cost associated with remediation and/or abandonment	Follow density hierarchy	Spacer Design section 25.3.2.2.2 Density Hierarchy
	Use flexible cement systems or slurries with sufficient set properties to withstand wellbore stresses	25.2 Cement Job Design 25.4 Slurry Design
	Reduce fluid loss and free water as low as possible	Slurry Design sections: • 25.4.6 Fluid Loss • 25.4.7 Free Water

Potential Consequences	Possible Solutions	Document Reference
	Minimize DLS, washouts, spiraling	Wellbore Construction section 25.6.1.7 Directional Planning
	Use mechanical barriers such as liner top packers, fracture strings, etc.	Abandonment Plugs section 25.11.2.4.3 Mechanical Barriers Wellbore Construction section 25.6.1.5 External Casing Packers
	Ensure wellbore is clean and optimize hole conditions prior to cementing	Wellbore Construction sections: • 25.6.2.1 Wiper Trips and Backreaming • 25.6.2.2 Drilling Tools/Technology to Remove Cuttings
	Use a simulator and optimize centralization	Cement Job Design section 25.2.7 Centralization Wellbore Construction section 25.6.1.11 Centralization

Challenge: Lost Circulation

This section outlines the potential consequences and possible solutions for lost circulation during cementing.

Table 30. Potential Consequences and Possible Solutions: Lost Circulation During Cementing

Potential Consequences	Possible Solutions	Document Reference
Low cement top, inadequate cement coverage, inadequate hydraulic isolation	Add LCM to spacer and cement blends	Slurry Design section 25.4.14 Lost Circulation
	Use low density/lightweight blends with sufficient set properties	Slurry Design section 25.4.2 Cement Type
	Ultra-lightweight cement	Slurry Design section 25.4.2 Cement Type
	Adjust casing point(s)	Wellbore Construction sections: • 25.6.1.3 Casing and Connection Selection • 25.6.2.3 Running Casing
	Ensure lost circulation has been healed prior to cementing	Wellbore Construction section 25.6.2 Drilling Operations
	Adjust pumping rate to reduce ECDs	Cement Job Design section 25.2.5 Pump Rates Wellbore Construction section 25.6.1.8 Equivalent Circulating Density
	Run inflatable packer(s) and stage tool(s) above potential flow zone(s) so that the second stage cementing operations ensures adequate cement coverage and viable annular isolation.	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats
	Run full-bore Port Collars as a means of selective annular access for contingency stage/remedial cementing operations	Wellbore Construction section 25.6.1.3 Casing and Connection selection

Potential Consequences	Possible Solutions	Document Reference
Additional costs associated with top-ups, squeezes, etc.	Optimize ECDs	Cement Job Design section 25.2.2 Simulations Wellbore Construction section 25.6.1.8 Equivalent Circulating Density
	Consider a multi-stage cement job	25.2 Cement Job Design
	Thixotropic cement	Slurry Design section 25.4.14 Lost Circulation
	Foam cement	25.4 Slurry Design
	Ensure lost circulation has been healed prior to cementing	Wellbore Construction section 25.6.2 Drilling Operations
	Adjust pumping rate to reduce ECDs	Cement Job Design section 25.2.5 Pump Rates Wellbore Construction section 25.6.1.8 Equivalent Circulating Density
	Consider Managed Pressure Drilling (MPD)	See IRP 22: Underbalanced and Managed Pressure Drilling Operations Using Jointed Pipe.
	Run inflatable packer(s) and stage tool(s) above potential flow zone(s) so that the second stage cementing operations ensures adequate cement coverage and viable annular isolation	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats
	Run full-bore Port Collars as a means of selective annular access for contingency stage/remedial cementing operations	Wellbore Construction section 25.6.1.3 Casing and Connection selection

Challenge: High Drilling Fluid Weight

This section outlines the potential consequences and possible solutions for high drilling fluid weight.

Table 31. Potential Consequences and Possible Solutions: High Drilling Fluid Weight

Potential Consequences	Possible Solutions	Document Reference
High circulating pressure, increased chance for losses	Density hierarchy with slurry density > spacer density > drilling fluid weight by 150 kg/m^3	Spacer Design sections: • 25.3.2.2.1 Friction Pressure Hierarchy • 25.3.2.2.2 Density Hierarchy Slurry Design section 25.4.8 Rheology Wellbore Construction section 25.6.1.9 Drilling Fluid Selection
	Densify by reducing water and adding dispersant	25.3 Slurry Design
	Utilize sized particles to increase density and optimize rheology	Spacer Design sections: • 25.3.2.2.1 Friction Pressure Hierarchy • 25.3.2.2.2 Density Hierarchy Slurry Design section 25.4.8 Rheology
	Increase annular gap to reduce ECD and improve slurry placement	Wellbore Construction sections: • 25.6.1.2 Hole Size and Annular Clearance • 25.6.1.8 Equivalent Circulating Density
	Circulate and condition drilling fluid prior to cementing	Wellbore Construction section 25.6.2.4 Circulating/Conditioning Drilling Fluid Prior to Running Casing
	Adjust pumping rates based on simulations to reduce ECDs	Cement Job Design sections: • 25.2.2 Simulations • 25.2.5 Pump Rates Wellbore Construction section 25.6.1.8 Equivalent Circulating Density

Potential Consequences	Possible Solutions	Document Reference
	Run inflatable packer(s) and stage tool(s) above the potential loss zone(s) so that the second stage cementing operations minimize the hydrostatic load	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats
Difficulty removing drilling fluid resulting in lack of zonal isolation	Density hierarchy with slurry density > spacer density > drilling fluid weight by 150 kg/m^3	Spacer Design sections: • 25.3.2.2.1 Friction Pressure Hierarchy • 25.3.2.2.2 Density Hierarchy Slurry Design section 25.4.8 Rheology Wellbore Construction section 25.6.1.9 Drilling Fluid Selection
	Add weighting agent(s) such as barite or hematite	25.3 Slurry Design
	Utilize sized particles to increase density and optimize rheology	Spacer Design sections: • 25.3.2.2.1 Friction Pressure Hierarchy • 25.3.2.2.2 Density Hierarchy Slurry Design section 25.4.8 Rheology
	Increase annular gap to reduce ECD and improve slurry placement	Wellbore Construction sections: • 25.6.1.2 Hole Size and Annular Clearance • 25.6.1.8 Equivalent Circulating Density
	Ensure wellbore is clean and optimize hole conditions prior to cementing. Increase preflush volumes and pump a scavenger slurry to help clean up the wellbore.	Wellbore Construction sections: • 25.6.2.1 Wiper Trips and Backreaming • 25.6.3.2 Drilling Tools/Technology to Remove Cuttings
	Use a simulator and optimize centralization	Cement Job Design section 25.2.7 Centralization Wellbore Construction section 25.6.1.11 Centralization

Potential Consequences	Possible Solutions	Document Reference
	Run swellable packers in the horizontal to mitigate drilling fluid channels on the low side of the open hole	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats

Challenge: Large Temperature Gradient Over Cement Column

This section outlines the potential consequences and possible solutions for situations where there is a large temperature gradient over the length of the cement column.

Table 32. Potential Consequences and Possible Solutions: Large Temperature Gradient

Potential Consequences	Possible Solutions	Document Reference
Delayed set cement properties at top of cement	Simulate job to get accurate placement times and temperatures	Cement Job Design section 25.2.2 Simulations
	Increase wait on cement time	Cement Job Design section 25.2.11 Wait on Cement Time
	Adjust casing points	Wellbore Construction sections: • 25.6.1.3 Casing and Connection Selection • 25.6.2.3 Running Casing
	Circulate casing to decrease BHCT	Wellbore Construction section 25.6.2.3 Running Casing
	Consider multi-stage cement job Run inflatable packer(s) and stage tool(s) so that the second stage cementing operations ensures adequate cement coverage and viable annular isolation	25.2 Cement Job Design Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats
Influx and/or damage to cement sheath before set	Run temperature simulations to obtain accurate top and bottom of cement temperatures	Cement Job Design section 25.2.2 Simulations
	Use 2-3+ slurries to cover zones	25.2 Cement Job Design Slurry Design section 25.4.2 Cement Type
	Use specialized hydration control additives in conjunction with accelerators	Slurry Design section 25.4.3 Additives

Potential Consequences	Possible Solutions	Document Reference
	Adjust casing points	Wellbore Construction sections: • 25.6.1.3 Casing and Connection Selection • 25.6.2.3 Running Casing
	Circulate casing to decrease BHCT	Wellbore Construction section 25.6.2.3 Running Casing
	Run inflatable packer(s) and stage tool(s) above potential flow zone(s) to prevent annular channeling and/or slurry contamination above packer	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats
	Add swelling additives to provide a means of mitigation for microannulus, channeling, and stress-induced sheath failure	Slurry Design sections: • 25.4.3 Additives • 25.4.11 Expansion

Challenge: Sensitive Formations

This section outlines the potential consequences and possible solutions for situations where there are sensitive formations. Formations are discussed in detail in Wellbore Construction section 25.2.61 Formations.

Table 33. Potential Consequences and Possible Solutions: Sensitive Formations

Potential Consequences	Possible Solutions	Document Reference
Hole problems such as swelling, sloughing, washout	Proper Drilling Fluid Selection	Wellbore Construction section 25.6.1.9 Drilling Fluid Selection
	Add salts or clay control to spacers and cement that come into contact with clay or shale formation.	25.3 Spacer Design Slurry Design sections: • 25.4.2 Cement Type • 25.4.3 Additives
	Add 5-10% salt against salt-containing formations. Use salt-saturated cement slurry against pure salt formations.	25.4 Slurry Design
	Ensure proper wellbore cleaning while drilling (wiper trips, reamer runs, drilling fluid properties, bit hydraulics)	Wellbore Construction sections: • 25.6.2.1 Wiper Trips and Backreaming • 25.6.2.2 Drilling Tools/Technology to Remove Cuttings
	Circulate and condition drilling fluid prior to cementing	Wellbore Construction section 25.6.2.4 Circulating/Conditioning Drilling Fluid Prior to Running Casing
	Use a simulator and optimize centralization	Cement Job Design section 25.2.7 Centralization Wellbore Construction section 25.6.1.11 Centralization
Lack of zonal isolation due to poor slurry placement	Add salts or clay control to spacers and cement that come into contact with clay or shale formation.	25.3 Spacer Design 25.4 Slurry Design
	Add 5-10% salt against salt-containing formations. Use salt-saturated cement slurry against pure salt formations.	25.4 Slurry Design

Potential Consequences	Possible Solutions	Document Reference
	Ensure proper wellbore cleaning while drilling (wiper trips, reamer runs, drilling fluid properties, bit hydraulics)	Wellbore Construction sections: • 25.6.2.1 Wiper Trips and Backreaming • 25.6.2.2 Drilling Tools/Technology to Remove Cuttings
	Adjust casing points	Wellbore Construction sections: • 25.6.1.3 Casing and Connection Selection • 25.6.2.3 Running Casing
	Ensure wellbore is clean and optimize hole conditions prior to cementing	Wellbore Construction sections: • 25.6.2.1 Wiper Trips and Backreaming • 25.6.2.2 Drilling Tools/Technology to Remove Cuttings
	Use a simulator and optimize centralization	Cement Job Design section 25.2.7 Centralization Wellbore Construction section 25.6.1.11 Centralization
	Run inflatable packer(s) in competent formation above potential flow zone(s) to ensure adequate annular isolation is achieved even in washed-out formations	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats
	Run inflatable packer(s) and stage tool(s) so that the second stage cementing operations ensures adequate cement coverage and viable annular isolation	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats
	Run full-bore Port Collars as a means of selective annular access for contingency stage/remedial cementing operations	Wellbore Construction section 25.6.1.3 Casing and Connection Selection

Challenge: Corrosive Environments

This section outlines the potential consequences and possible solutions for situations where there is a corrosive environment.

Table 34. Potential Consequences and Possible Solutions: Corrosive Environments

Potential Consequences	Possible Solutions	Document Reference
Lack of zonal/hydraulic isolation due to degradation of tubulars and cement sheath	Decrease fluid loss and free water as low as possible	Slurry Design sections: • 25.4.3 Additives • 25.4.6 Fluid Loss • 25.4.7 Free Water
	Add expanding agents	Slurry Design sections: • 25.4.3 Additives • 25.4.11 Expansion
	Switch to non-Portland based cements, use Pozzolan systems.	25.4 Slurry Design
	Decrease water to cement ratio	Slurry Design sections • 25.4.2 Cement Type • 25.4.10 Stability
	Add permeability modifiers	25.4 Slurry Design
	Adjust casing points	Wellbore Construction sections: • 25.6.1.3 Casing and Connection Selection • 25.6.2.3 Running Casing
	Circulate and condition drilling fluid prior to cementing	Wellbore Construction section 25.6.2.4 Circulating/Conditioning Drilling Fluid Prior to Running Casing
	Ensure wellbore is clean and optimize hole conditions prior to cementing	Wellbore Construction sections: • 25.6.2.1 Wiper Trips and Backreaming • 25.6.2.2 Drilling Tools/Technology to Remove Cuttings

Potential Consequences	Possible Solutions	Document Reference
	Use a simulator and optimize centralization	• Cement Job Design section 25.2.7 Centralization • Wellbore Construction section 25.6.1.11 Centralization
	Run cement-inflated inflatable packer(s) in competent formation above corrosive flow zone(s) to provide a mechanical barrier and ensure quality of slurry above the packer is not compromised	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats
	Run cement-inflated inflatable packer(s) and stage tool(s) so that the second stage cementing operations ensures adequate cement coverage and viable annular isolation	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats

Challenge: Thermal Wells

This section outlines the potential consequences and possible solutions for thermal wells.

Table 35. Potential Consequences and Possible Solutions: Thermal Wells

Potential Consequences	Possible Solutions	Document Reference
Compressive strength regression	BHST > 110°C add 35-45% silica	Slurry Design sections: • 25.4.2 Cement Type • 25.4.10 Stability • 25.4.11 Mechanical and Thermal Properties
	BHST >360°C use calcium aluminate cement	Slurry Design section 25.4.2 Cement Type
Loss of zonal/hydraulic isolation	For SAGD and CSS use expanding thermal thixotropic cements	Slurry Design section 25.4.5 Compressive Strength
	Optimize spacer design and pump rates	Cement Job Design section 25.2.5 Pump Rates 25.3 Spacer Design
	Circulate and condition drilling fluid prior to cementing	Wellbore Construction section 25.6.2.4 Circulating/Conditioning Drilling Fluid Prior to Running Casing
	Use a simulator and optimize centralization	Cement Job Design section 25.2.7 Centralization Wellbore Construction section 25.6.1.11 Centralization
	Run temperature simulator to obtain BHCT	Cement Job Design section 25.2.2 Simulations Lab Testing section 25.5.1 Testing Temperature
	BHST > 110°C add 35-45% silica	Slurry Design sections: • 25.4.2 Cement Type • 25.4.10 Stability • 25.4.13 Mechanical and Thermal Properties
	BHST >360°C use calcium aluminate cement	Slurry Design section 25.4.2 Cement Type

Potential Consequences	Possible Solutions	Document Reference
	Ensure wellbore is clean and optimize hole conditions prior to cementing	Wellbore Construction sections: • 25.6.2.1 Wiper Trips and Backreaming • 25.6.2.2 Drilling Tools/Technology to Remove Cuttings
	Use a simulator and optimize centralization	Cement Job Design section 25.2.7 Centralization Wellbore Construction section 25.6.1.11 Centralization
	Add swelling additives to provide a means of micro annulus mitigation and stress-induced sheath failure prevention (consider temperature ratings of material)	Slurry Design sections: • 25.4.3 Additives • 25.4.11 Expansion
	Add tensile strength or flexible additives for possible cyclic steam injection	25.2 Cement Job Design Slurry Design section 25.4.3 Additives

Challenge: Low Temperature Wells

This section outlines the potential consequences and possible solutions for low temperature wells.

Table 36. Potential Consequences and Possible Solutions: Low Temperature Wells

Potential Consequences	Possible Solutions	Document Reference
Delayed set cement properties at top of cement	Heat mix water	Section 25.7.2.2 Material and Equipment Checks (Table 14)
	Introduce blends with high gypsum contents	25.2 Cement Job Design Slurry Design section 25.4.2 Cement Type
	Switch to non-Portland based cements	Slurry Design section 25.4.2 Cement Type
	Run inflatable packer(s) and stage tool(s) so that the second stage cementing operations ensures adequate cement coverage and viable annular isolation	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.1.15 Floats
	Run full-bore Port Collars as a means of selective annular access for contingency stage/remedial cementing operations	Wellbore Construction section 25.6.1.3 Casing and Connection Selection
	Run inflatable packer(s) above potential flow zone(s) to prevent annular channeling and/or slurry contamination above packer during critical hydration period	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats
Arctic/Permafrost Cements	Permafrost cements have the ability to set at temperatures as low as -10ºC. They have a low heat of hydration which maintains the integrity of the permafrost.	25.2 Cement Job Design 25.4 Slurry Design

Potential Consequences	Possible Solutions	Document Reference
Influx and/or damage to cement sheath before set	Increase accelerator concentrations	25.2 Cement Job Design 25.4 Slurry Design
	Add tensile strength or flexible additives for possible freeze/thaw cycles	25.2 Cement Job Design Slurry Design section 25.4.3 Additives
	Run inflatable packer(s) and stage tool(s) so that the second stage cementing operations ensures adequate cement coverage and viable annular isolation	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats
	Run full-bore Port Collars as a means of selective annular access for contingency stage/remedial cementing operations	Wellbore Construction section 25.6.1.3 Casing and Connection Selection
	Run inflatable packer(s) above potential flow zone(s) to prevent annular channeling and/or slurry contamination above packer during critical hydration period	Wellbore Construction sections: • 25.6.1.4 Stage Tools • 25.6.1.5 External Casing Packers • 25.6.1.6 Liners • 25.6.2.15 Floats

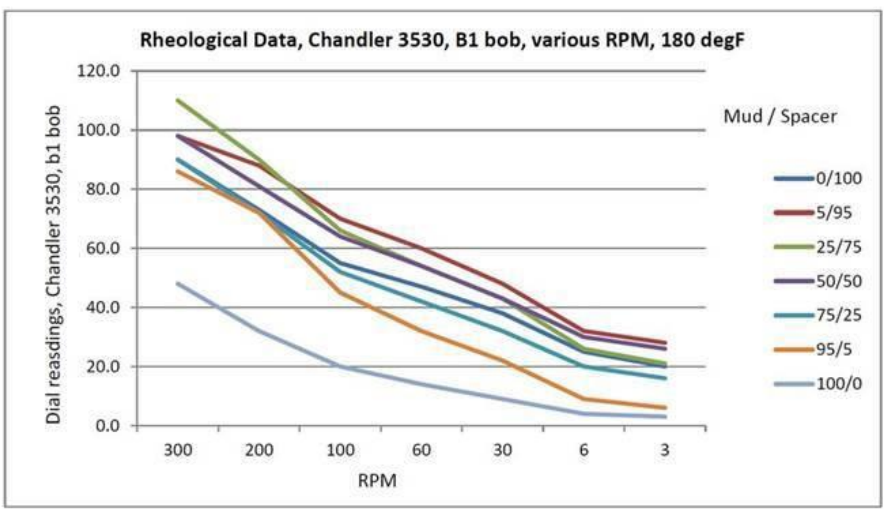
Appendix C: Fluid Compatibility

Compatible fluids are fluids that are “capable of forming a mixture that does not undergo undesirable chemical and/or physical reactions.” Incompatible fluids can create numerous problems including excessive pressure during the job, failure to obtain zonal isolation due to inefficient drilling fluid-removal and a permeable pathway in terms of channeling or micro-annuli for wellbore fluids to migrate through. Incompatibility may include increased viscosity, reduced viscosity, flocculation sedimentation separation of fluid phases or alteration of cement properties.

Any fluid being displaced needs to be compatible with the fluid displacing it.

API RP 10-B2 Section 13 Compatibility of Wellbore Fluids outlines guidelines for the testing of wellbore fluids. These include the mixture ratio of fluids to be tested, preparation of fluids, a testing flowchart to guide the reader to further testing based on rheological readings and a section on interpretation. From a rheological perspective, fluids with mixtures that fall between the lowest and highest reading of each base fluid are deemed compatible.

Figure 4. Plotted Fluid Mixture Ratios



The API interpretation guidelines are non-prescriptive so other methods have been developed to interpret the rheological readings from mixture testing. Some of these methods are outlined below.

R Value

The ‘R Value’ technique is used to quantify the amount of incompatibility between fluids. The ‘R Value’ is the highest fluid-mixture 100 rpm reading minus the highest individual-fluid 100 rpm reading. The ‘R Value’ difference obtained suggests the level of compatibility between the fluids. The fluid mixture ratios used follow the guidelines outlined in API RP10-B2 Section 13 using an R1B1 configuration. Table 37 can be used as a guideline to determine acceptable fluid compatibility.

Equation 2. ‘R Value’ Definition

$$R_{Value} = HVCM - HVIF$$

Where:

- HVCM = Highest viscosity of combined mixture (drilling fluid/spacer)
- HVIF = Highest viscosity of individual fluids

Table 37. Fluid Compatibility ‘R Value’

$R_{value\ (cP)}$	Compatibility	Best Practice
< 0	Compatible	Pump as per design
0-40	Compatible	Adjustments to spacer design may need to be considered to optimize placement
41-70	Slightly Incompatible	Adjustments to spacer design may need to be considered to optimize placement
>70	Incompatible	Redesign spacer

10% Method

In the 10% method, the various mixture ratio readings are compared to the 100% cement viscometer readings (or +10% viscometer readings). See Table 38 below for an example. There is fluid compatibility when the various mixture readings (shaded rows) don’t exceed the 100% cement reading +10% (the first row). If mixture values are significantly higher then consider redesigning the spacer system. This method with “sound engineering judgment” can be used as a guideline to determine acceptable fluid compatibility.

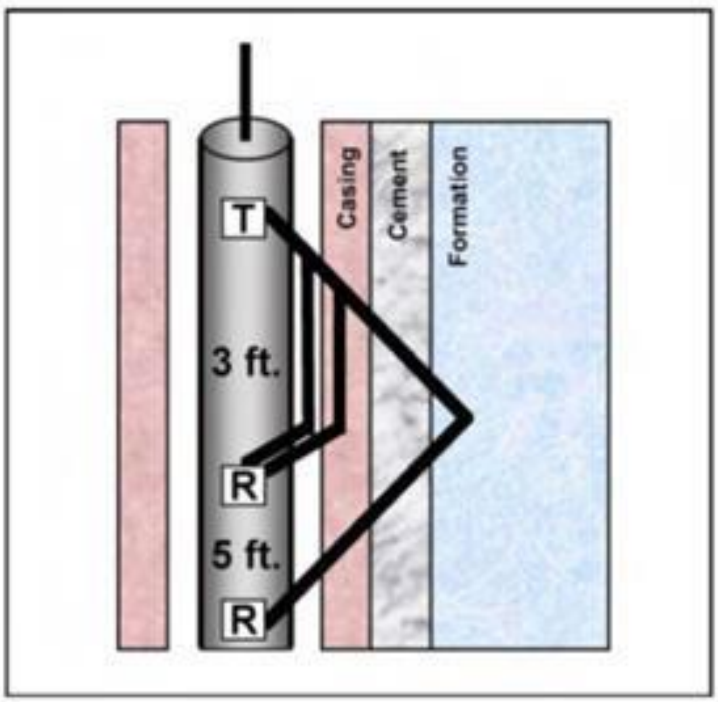
Table 38. Example Cement/Spacer Ratio Fluid Compatibility Chart

	Speed Settings for the Rotational Viscometer (RPM)							
Cement/Spacer Ratio	**600**	**300**	**200**	**100**	**60**	**30**	**6**	**3**
100% Cement (Readings + 10%)	249	205	147	84	59	35	15	9
100% Cement	226	186	134	76	54	32	14	8
95% Cement / 5% Spacer								
75% Cement / 25% Spacer								
50% Cement / 50% Spacer								
25% Cement / 75% Spacer								
5% Cement / 95% Spacer								
100% Spacer	86	64	46	34	26	20	10	6

Appendix D: Sonic Bond Logs

The following diagrams and charts show configuration and output samples for the various types of sonic bond logs.

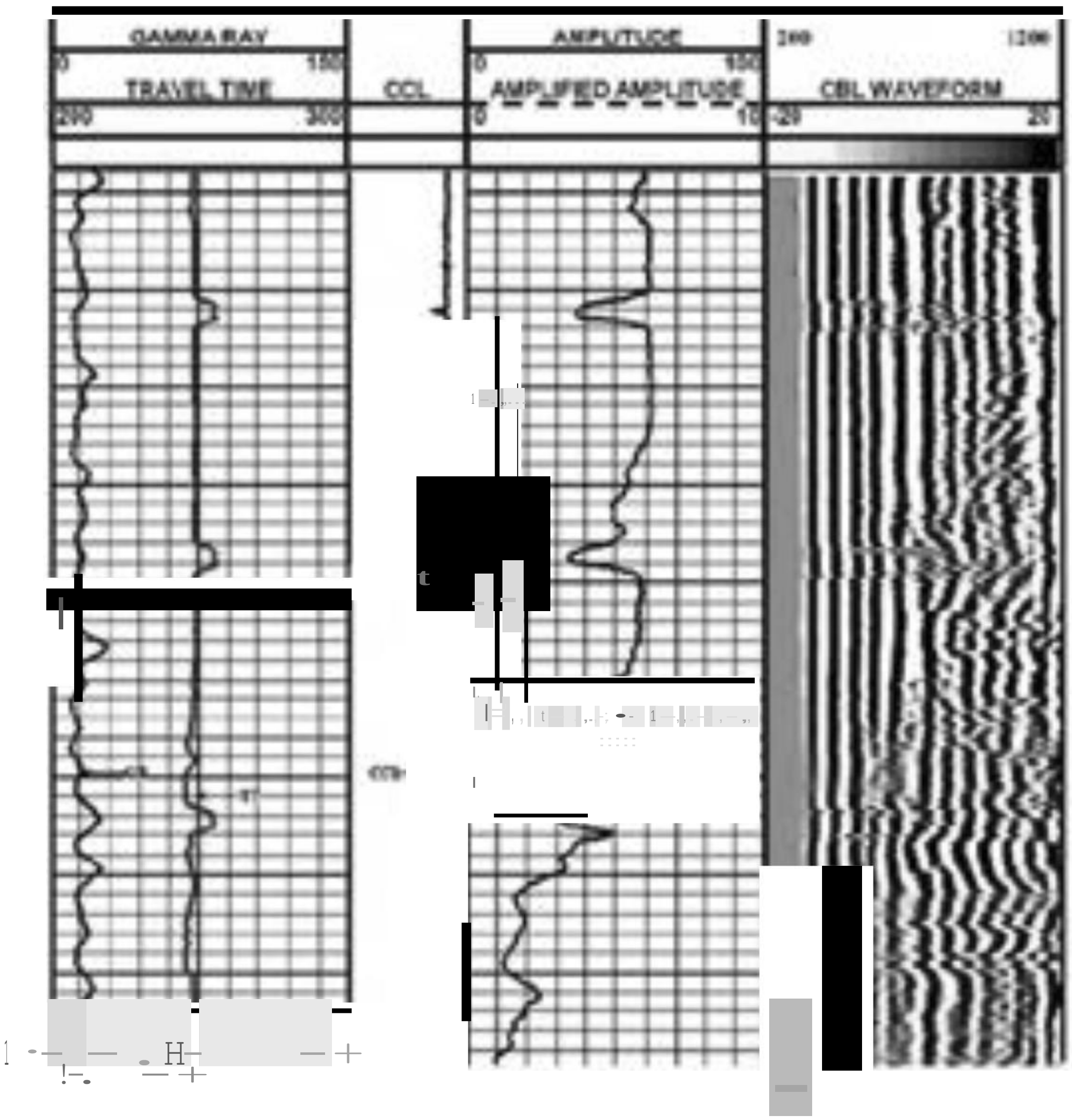
Figure 5. Cement Bond Log Tool Configuration[1]



The transmitter excites the casing by emitting a sonic signal. The signal reflections on the CBL will be larger if the casing is not bonded to cement. These reflections will be reduced in amplitude if the casing is coupled to the cement sheath and the sound will attenuate more quickly.

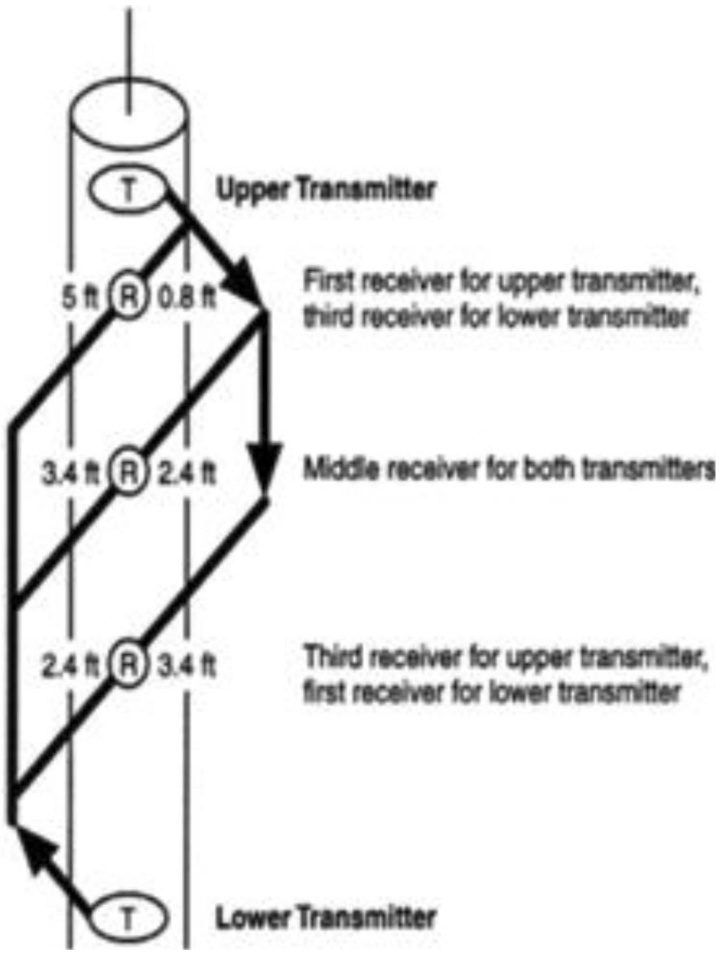
[1] Nelson, Erik B. and Guillot, Dominique. *Well Cementing*, second edition. Page 562, Figure 15-13

Figure 6. Sample Cement Bond Log Output2



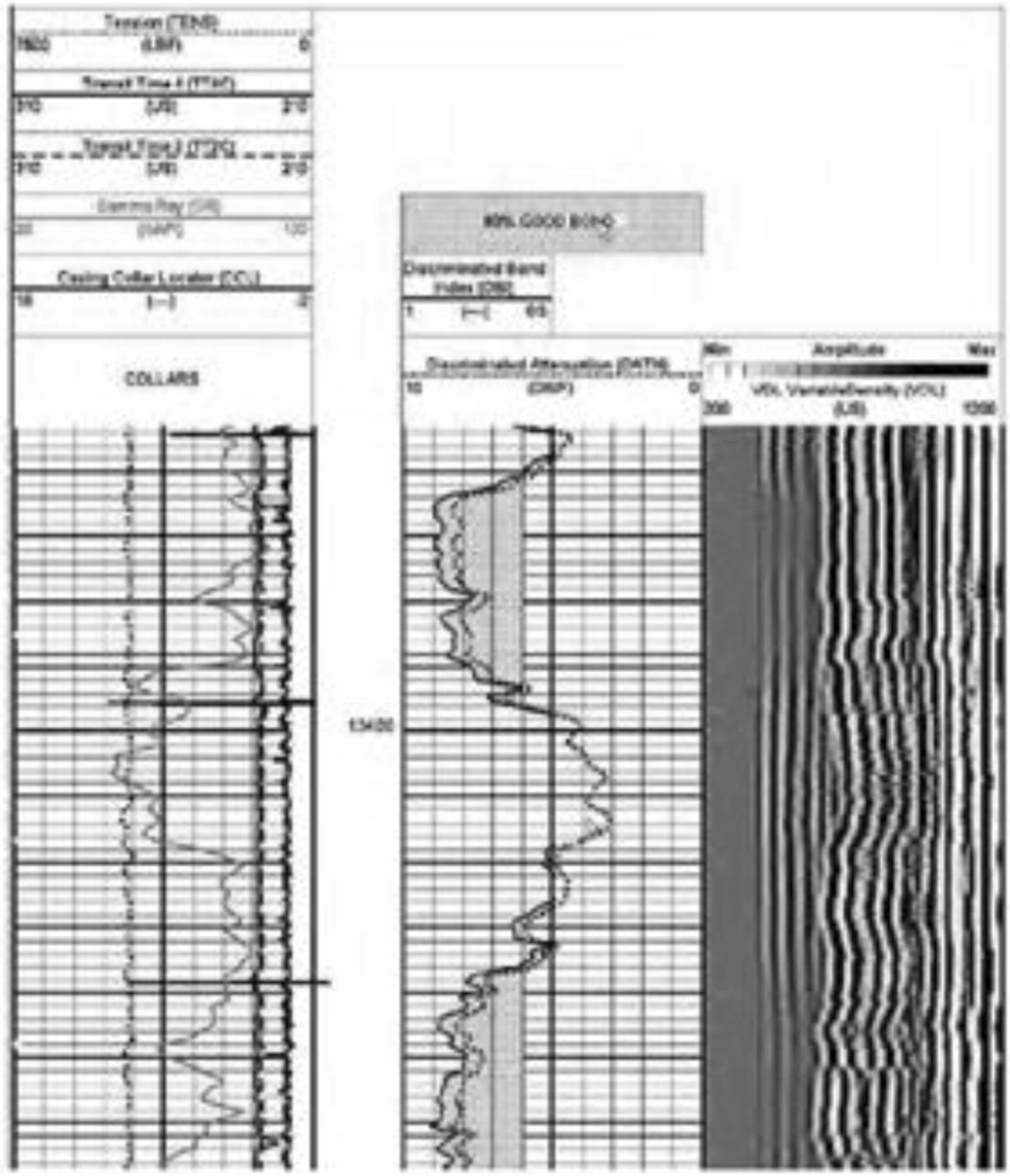
[2] API Technical Report 1OTR1. Page 12, Figure 5.8

Figure 7. Compensated Cement Bond Log Configuration[3]



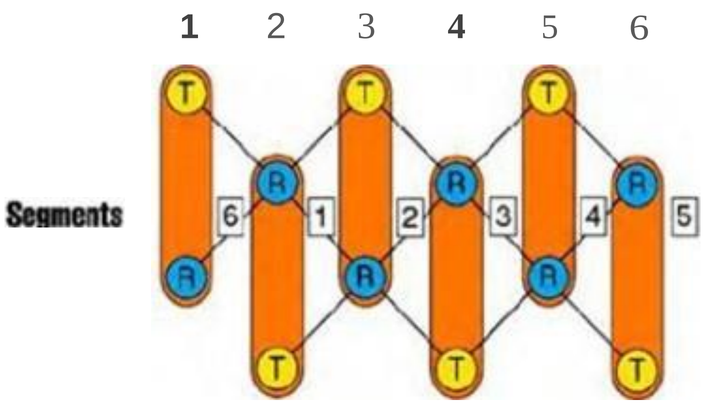
[3] Nelson, Erik B. and Guillot, Dominique. *Well Cementing,* second edition. Page 569, Figure 15-21

Figure 8. Compensated Cement Bond Log Output Sample[4]



[4] API Technical Report 1OTR1. Page 23, Figure 6.2

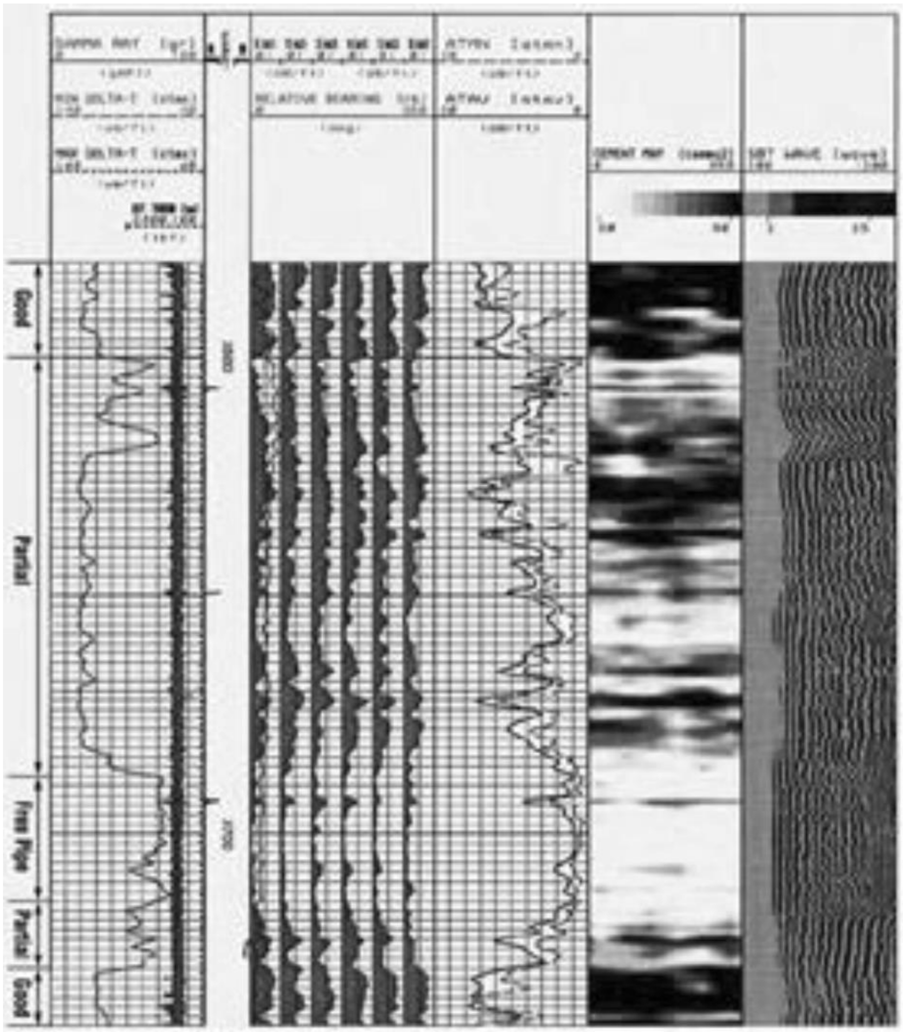
Figure 9. Segmented Bond Tool Image and Contiguratiort



5ToolImage from API Technical Report 10TR1. Page 24, Figure 7.1

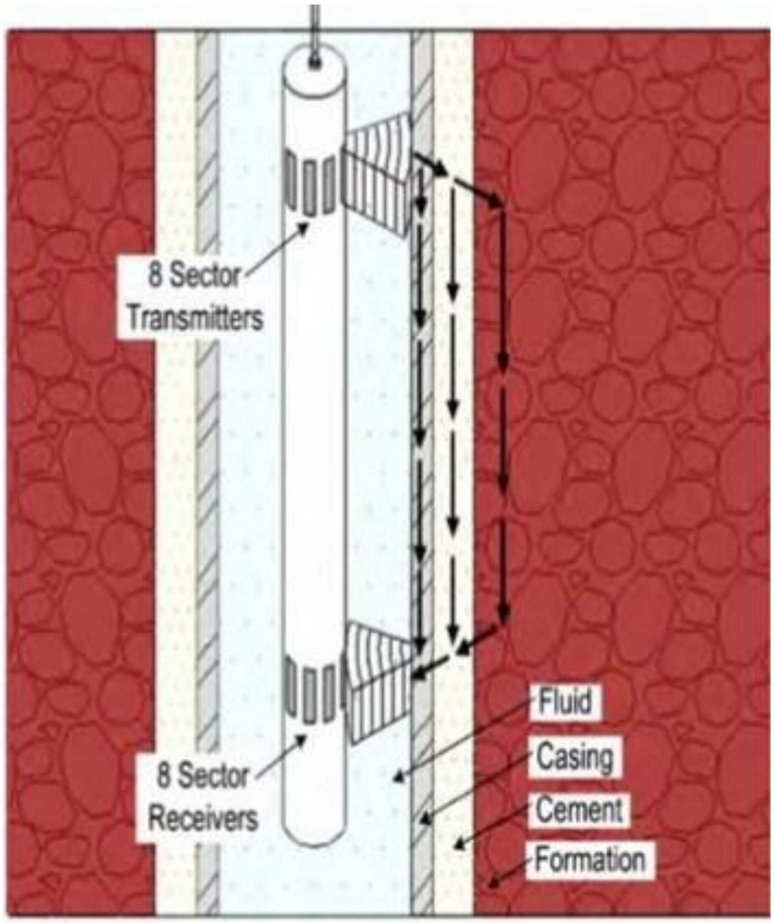
Tool Configuration from Nelson, Erik B. and Guillot, Dominique. *Well Cementing,* second edition. Page 589, Figure 15-41

Figure 10. Segmented Bond Tool Output Sample[6]



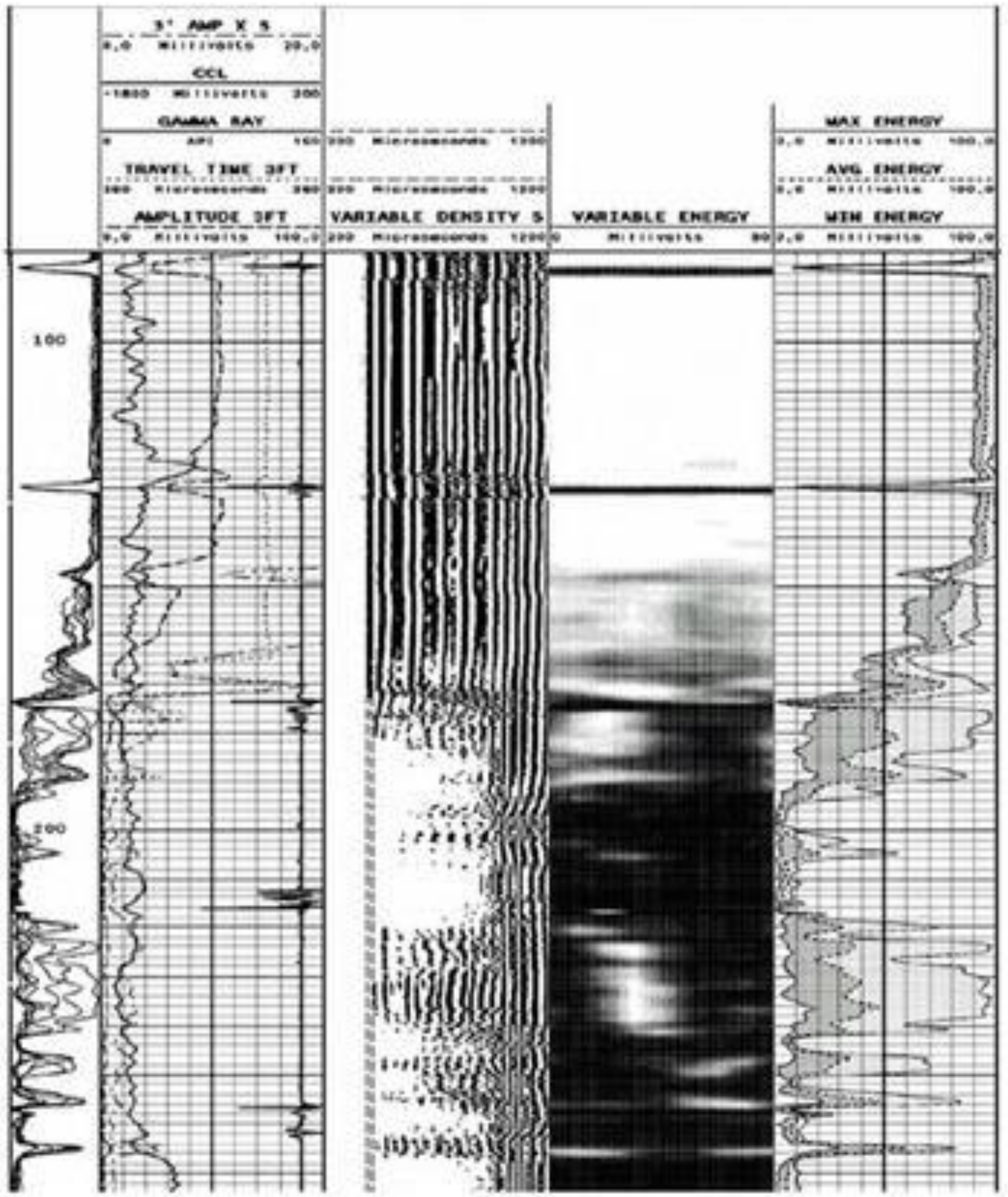
[6] Nelson, Erik B. and Guillot, Dominique. *Well Cementing,* second edition. Page 584, Figure 15-43

Figure 11. Sector Bond Log Configuration[7]



[7] API Technical Report 10TR1. Page 31, Figure 8.1b

Figure 12. Sector Bond Log Output Sample[8]



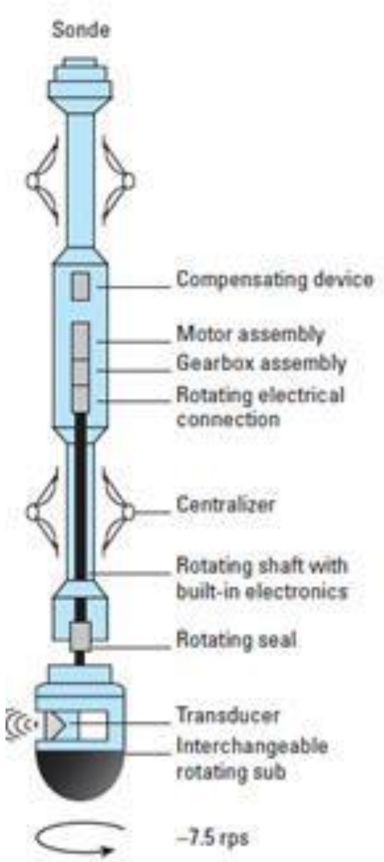
The example above shows one possible output from a tool with eight sectors. Output form each receiver is shown on the left, the VDL in the center along with a cement map and the max and minimum sector readings on the right.

[8] API Technical Report 10TR1. Page 32, Figure 8.2

Appendix E: Ultrasonic Bond Logs

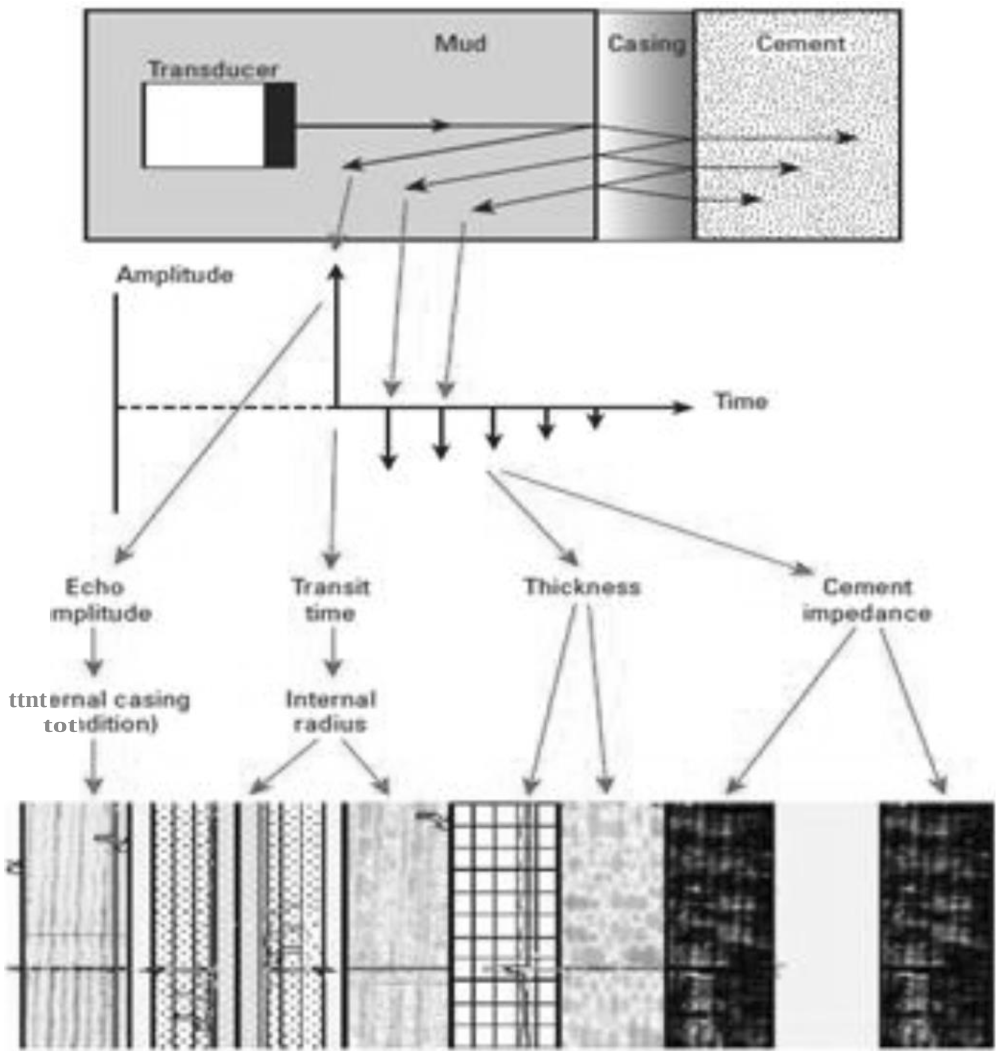
Two critical parameters are needed to derive inner wall radius and acoustic impedance: the slowness (or transit time) and the acoustic impedance of the drilling fluid or borehole fluid. These parameters are derived either in real time using a second transducer or during a down log using the same transducer used for the main log but positioned to face a reference target plate of known thickness and standoff distance

Figure 13: Tool Diagram[9]



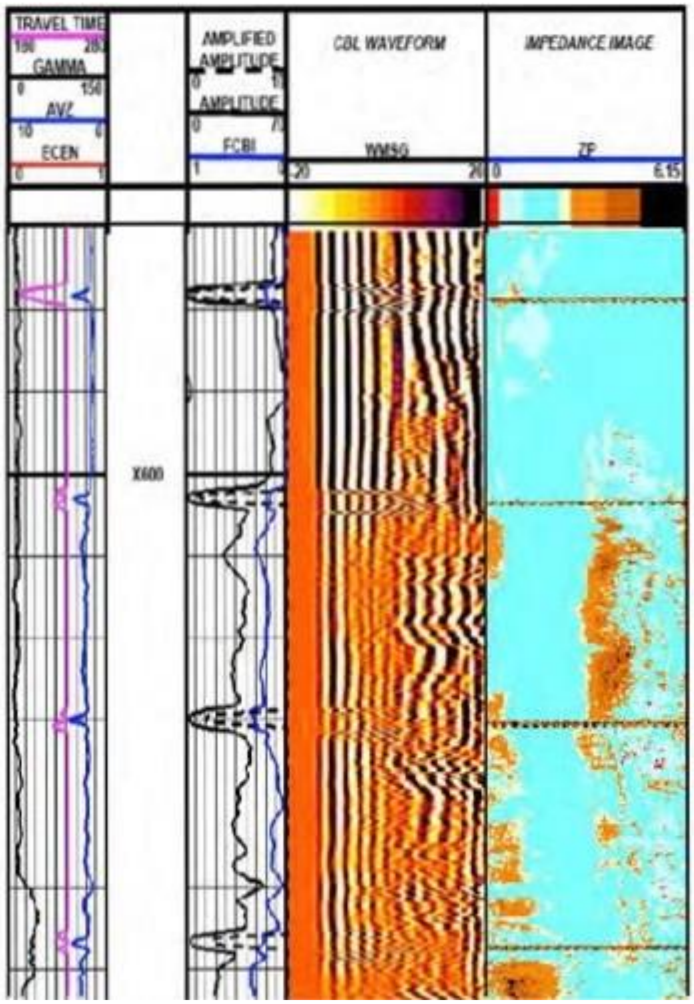
[9] Nelson, Erik B. and Guillot, Dominique. *Well Cementing*, second edition. Page 586, Figure 15-45

Figure 14: UltraSonic Imager Display[10]



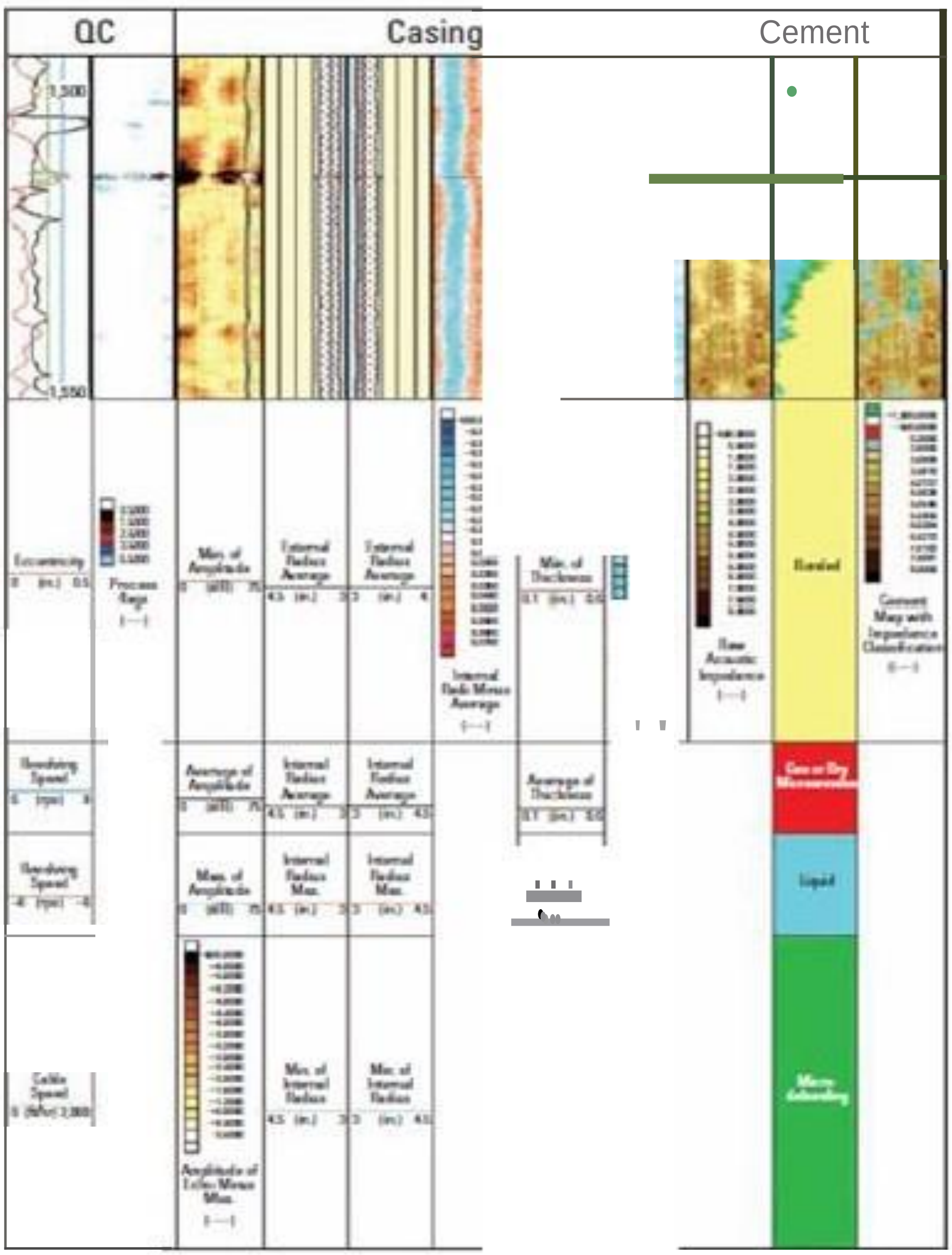
[10] Nelson, Erik B. and Guillot, Dominique. *Well Cementing,* second edition. Page 587, Figure 15-46

Figure 15. CAST-V/CBL with Impedance Map[11]



[11] API Technical Report 10TR1. Page 49, Figure 9.11

Figure 16: UHraSonic Imager Log''

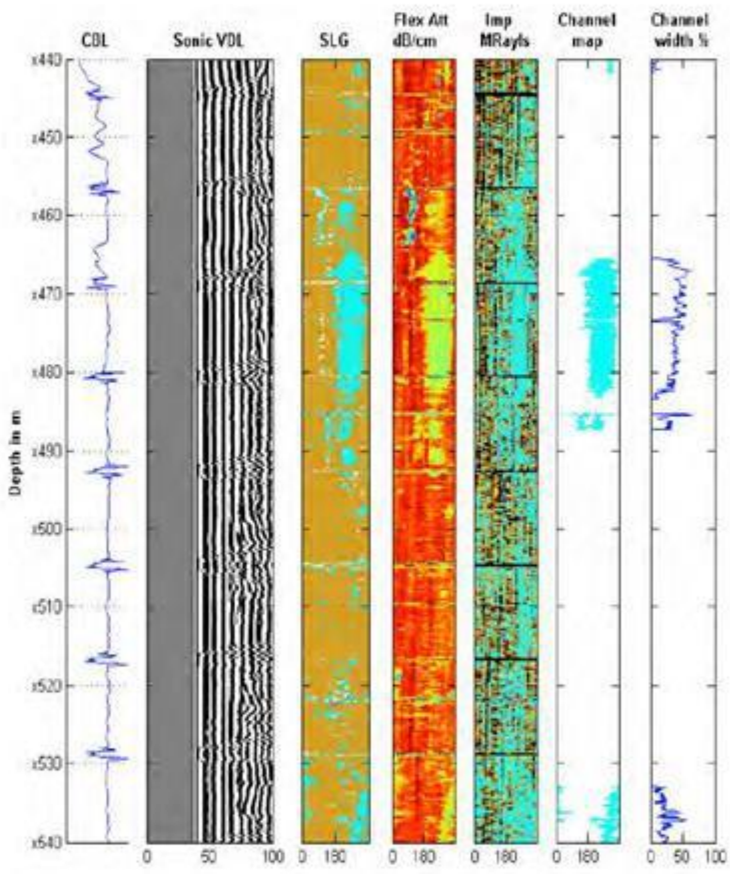


•: Nelson,Erik B.and Guillot,Dominique.*Well Cementiflq*.second edition.Page 5g6,Figure 15-60

Appendix F: Flexural Mode

The following diagrams pertain to Flexural Mode Logging tools.

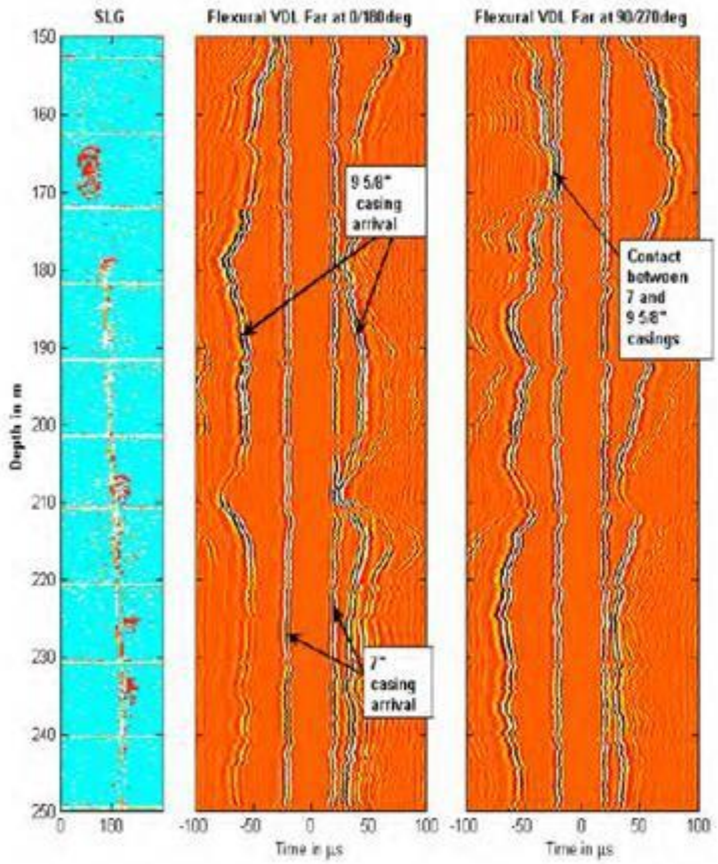
Figure 17: Light Weight Cement Example[13]



With standard BVL-VDL, acoustic impedance and flexural attenuation answers.

[13] API Technical Report 10TR1. Page 76, Figure 9.27

Figure 18: TIE echoes from Flexural Mode[14]



178 and 255 mm casing relative position is shown in two axes.

14 *Cased Hole Log Interpretation Principles/Applications*, 1989. Page 80.

Appendix G: Nuclear Logging

Movement of fluid behind the casing indicates lack of zonal isolation. Two nuclear measurement systems are commonly used to detect the movement of fluid behind the casing:

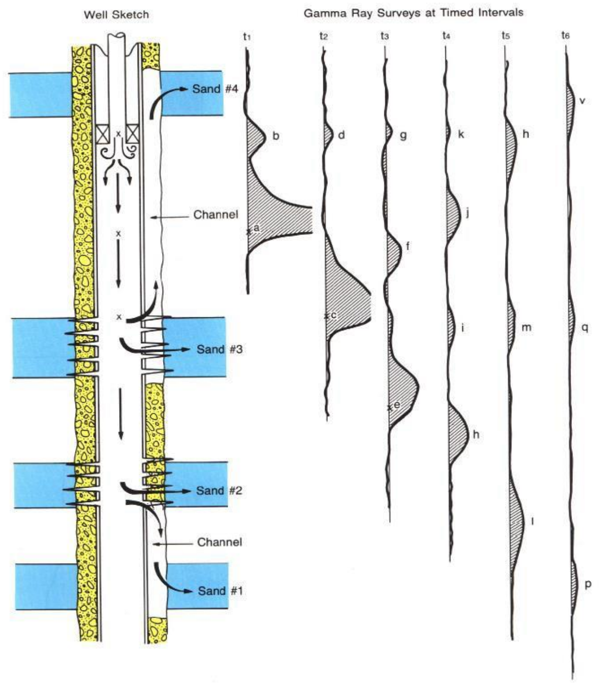
- Tracer Surveys
- Pulsed Neutron Tools

Tracer surveys are run by ejecting small quantities of radioactive isotopes from downhole tools into the wellbore, typically while injecting, then monitoring the movement of the radioactive slug of fluid by using one or more gamma ray detectors. The velocity of the moving isotope slug in the wellbore or in the annulus can be estimated by determining the time between gamma ray peaks with either a stationary tool with multiple gamma detectors or with a single detector using multiple logging passes.

Consider the safe handling and disposal of radioactive materials used for this service. The radioactive isotopes used in this type of survey generally have short half-lives (in the order of days or weeks) to minimize any long-term hazards related to an undesired release.

Figure 19 shows the timed run analysis of a radioactive tracer survey.

Figure 19. Tracer Survey Run Analysis[15]



- 5 time-lapse gamma ray logs run following release of a radioactive isotope slug into the injection fluid stream from the bottom of tubing.
- Diminishing GR peaks b,d,g, and k indicate trapped isotope at the tubing bottom.
- GR peaks a,c,e, and h show the passage of the tracer material in the wellbore.
- GR peaks f,j,h, and v relate to upward channeling from sand 3 to sand 4.
- GR peaks l and p indicate downward channeling from

Pulsed neutron tools can be deployed to measure water flow. Water flow is measured by activating the oxygen molecules in the water flowing within the wellbore or in the annulus. Two detectors monitor the gamma ray emissions related to the movement of the activated water flow. The time of arrival of the gamma ray cloud at each detector and the detector spacing are inputs required to estimate flow velocity. Gamma ray detectors can be positioned to detect either upward or downward flow.

Pulsed neutron tools can also be utilized with a doping material with strong neutron absorbing properties such as boron to greatly enhance the neutron capture cross section (Sigma) log response in areas where the doped fluid has invaded or migrated. A baseline log is recorded prior to injection of the boron doped fluid. Borax is a non-toxic source of boron and is commonly used.

[15] *Cased Hole Log Interpretation Principles/Applications*, 1989. Page 4-13, Figure 4-20.

Appendix H: Continuous Improvement Evaluation Approach

The check phase of the PDCA loop (Plan, Do, Check, Act) is the evaluation of the cement job. The evaluation of a job can be challenging because it requires indirect measures of success. The following provides an example of one approach to evaluation.

Prediction

During the design phase of a job it is possible to predict the likelihood of a good cement job based on specific elements of the job and past performance. This can be done by preparing a list of predictive elements for the job and assigning an importance rating or score for each element based on its importance to the final outcome of the job. This score would be based on past performance and knowledge of the specific job. Comparing the total score to previous jobs can be a predictor of success.

Each organization needs to determine the predictive elements to be evaluated and their importance to the success of the job. Table 39 shows a sample of items that can be considered. Each predictive element requires a method to establish how to assign the score.

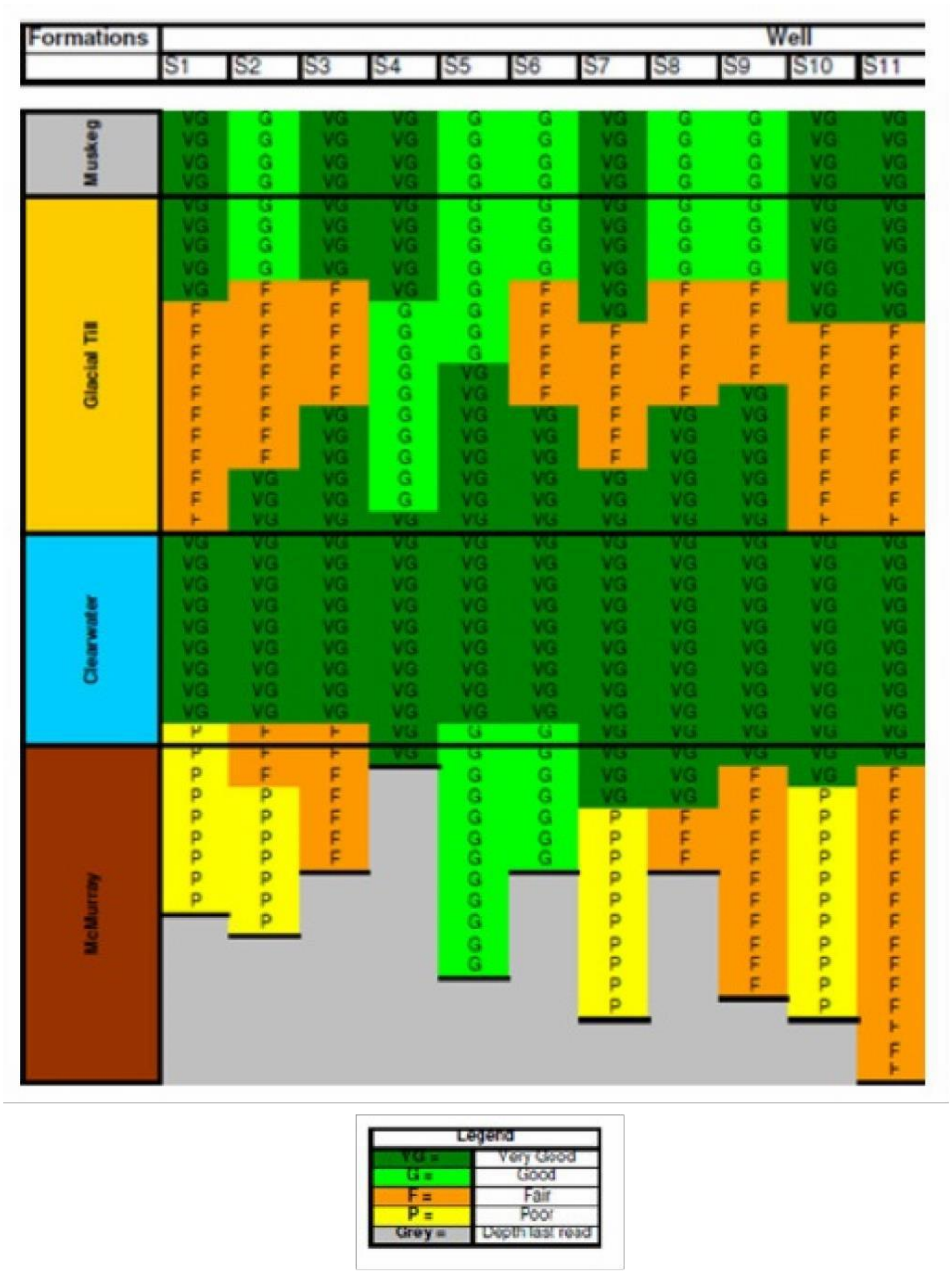
Table 39. Example: Predictive Element Ranking

Predictive Elements	Score				Total
	1	2	3	4	
Execution			X		3
Key Lab Testing		X			2
Drilling Fluid Removal				X	4
Hole Conditions	X				1
Drilling Fluid Conditioning				X	4
Centralization	X				1
Hole Inclination		X			2
Other factors relevant to the specific job					
Totals	**2**	**4**	**3**	**8**	**17**

Interpretation

Figure 20 shows an example of using cement evaluation log results and quantitatively ranking the output.

Figure 20. Interpretive Evaluation Matrix Example



Appendix I: Additional Resources and References

The following provide additional resources and references for cementing practices.

Surface Casing Vent Flow Testing

The following AER directives provide information about SCFV testing in Alberta:

- Interim Directive 2003-01 describes standard test methodology.
- Bulletin 2011-35 describes screening methods to be used for SCVF's where a standard Surface Casing vent flow arrangement is not available.
- Directive 20 requires testing again before well abandonment.

The Alberta regulations are included for informational purposes. Consult jurisdictional regulation for other provinces.

Gas Migration Testing

The following AER directives provide information about GM testing in Alberta:

- Directive 20 describes standard test methodology.
- Interim Directive 2003-1 discusses timing for GM testing.
- Directive 79 outlines testing required for abandoned wells in proximity to surface development.

The Alberta regulations are included for informational purposes. Consult jurisdictional regulation for other provinces.

Alberta References

The following table identifies Alberta government websites, directives and industry documents that can be referenced for wellbore construction and cementing practices.

Table 40. Alberta Regulations and Directives

Regulation	Notes
www.ABSA.ca	Alberta Boilers Safety Association
Alberta Oil and Gas Conservation Act	Available from the Alberta Queens' Printer.
Alberta Oil and Gas Conservation Rules	Available from the Alberta Queen's Printer.

Regulation	Notes
AER Bulletin 2011-35: Surface Casing Vent Requirements for Wells	This bulletin clarifies Section 6.100(4) of the Oil and Gas Conservation Regulations (OGCR) and provide additional surface casing annular flow testing options to AER Interim Directive 2003-01.
AER Directive 008: Surface Casing Depth Requirements	
AER Directive 009: Casing Cementing Minimum Requirements	Outlines casing cementing requirements in accordance with the Oil and Gas Conservation Regulations.
AER Directive 010: Minimum Casing Design Requirements	
AER Directive 20: Well Abandonment	Describes the minimum requirements for abandonments, casing removal, zonal abandonments and plug backs as required under Sections 3.013 of the Oil and Gas Conservation Regulations. Cement placement during well construction can impact abandonment requirements.
AER Directive 36: Drilling Blowout Prevention Requirements and Procedures	
AER Directive 51: Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements	Outlines the requirements for injection into wells. Cement evaluation is a key component of the requirements. Identifies injection/disposal well classifications and approvals for injection/disposal. Outlines cementing and casing requirements for hydraulic isolation and isolation of groundwater. Outlines logging requirements and logging waivers, other tests, submission requirements and operating parameters.
AER Directive 79: Surface Development in Proximity to Abandoned Wells	The abandoned well locating and testing protocol section covers what needs to be done by the licensee in the case of an abandoned well identified in proximity to existing or planned surface development. There are several tests that may need to be done and the response of these tests may reveal an issue with the cement job or the abandonment cement plugs.
AER Directive 80: Well Logging	This directive is not related to cement evaluation but covers the need for surface casing logging for geological purposes.
AER Directive 083: Hydraulic Fracturing – Subsurface Integrity	
AER Interim Directive ID2003-01: 1) Isolation Packer Testing, Reporting, and Repair Requirements; 2) Surface Casing Venting Flow/Gas Migration Testing, Reporting, and Repair Requirements; 3) Casing Failure Reporting and Repair Requirements	ID 2003-01 covers the issues around surface casing vent flows and gas migration that can occur due to the cement job.

British Columbia References

The following British Columbia government directives and industry documents can be referenced for wellbore construction and cementing practices.

- BC Oil and Gas Commission Drilling and Production Regulation
- BC Oil & Gas Commission – Well Completion, Maintenance and Abandonment Guideline

IRPs

The following Enform Industry Recommend Practice documents can be referenced:

- IRP 1: Critical Sour Drilling
- IRP 3: In Situ Heavy Oil Operations
- IRP 5: Minimum Wellhead Requirements

Standards

The following API and NORSOK documents can be referenced for industry standards:

- API TR 10TR1: Cement Sheath Evaluation, 2nd Edition. September 2008.
- API TR 10TR4: Selection of Centralizers for Primary Cementing Operations, 1st Edition. July 2008.
- API TR 10TR5: Methods for Testing Solid and Rigid Centralizers, 1st Edition. July 2008.
- API HF1: Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines, 1st Edition. October 2009.
- API RP 10B-2: Recommended Practice for Testing Well Cements, 2nd Edition. April 2013.
- API RP 10B-3: Recommended Practice on Testing of Deep Water Well Cement Formulations, 2nd Edition, January 2016.
- API RP 10B-4: Recommended Practice on Preparation and Testing of Foamed Cement Slurries at Atmospheric Pressure, 2nd Edition. October 2015.
- API RP 10B-5 (R2015): Recommended Practice for the Determination of Shrinkage and Expansion of Well Cement Formulations at Atmospheric Pressure. 1st Edition. April 2005.
- API RP 10B-6 (R2015): Recommended Practice on Determining the Static Gel Strength of Cement Formulations. August 1010.
- API RP 10D-2 Recommended Practice for Centralizer Placement and Stop Collar Testing, 1st Edition. August 2004.

- API RP 10F: Recommended Practice for Performance Testing of Cementing Float Equipment, 3rd Edition. April 2002.
- API Spec 5CT: Specification for Casing and Tubing, 9th Edition. July 2011.
- API Spec 6A: Specification for Wellhead and Christmas Tree Equipment, 20th Edition. October 2010.
- API Spec 10A (R2015): Specifications for Cements and Materials for Well Cementing. 24th Edition. December 2010.
- API STD 65-2: Isolating Potential Flow Zones During Well Construction, , 2nd Edition. December 2010.
- API TR 5C3: Technical Report on Equations and Calculations for Casing, Tubing, and Line Pipe Used as Casing or Tubing; and Performance Properties Tables for Casing and Tubing, 1st Edition. December 2008.
- ASTM C150/C150M–16e1: Standard Specifications of Portland Cement, ASTM International, West Conshohocken, PA, 2016
- CAPP Hydraulic Fracturing Operating Practice :4: Wellbore Construction and Quality Assurance
- Measurement Canada Certification Requirements for Measuring Apparatus (Government of Canada Website).

Additional References

Halliburton presentation about hole conditioning based on SPE 30514. Permission to use provided via Mike Exner: http://www.halliburton.com/en-US_tech-papers_public/abstracts/spe-30514.page

The following references are for diagrams used in IRP 25 Appendices D, E, F and G:

Table 41. Diagram References

Reference	Notes
Cement Sheath Evaluation – API Technical Report 10TR1, 2nd Edition, September 2008.	
Well Cementing – Erik Nelson and Dominique Guillot, 2nd Edition, copyright Schlumberger 2006.	
Schlumberger (1972) Log Interpretation Volume I – Principles. New York: Schlumberger Limited.	In this reference various logging tools and their interpretations are described. In particular, section 18 describes the cement bond log and temperature logs.
Schlumberger (1989) Cased Hole Log Interpretation Principles/Applications. Houston: Schlumberger Educational Services.	This reference is similar to the previous reference but describes in more detail cement evaluation, corrosion evaluation and many other logs.
Baker Hughes (1990) Cement Evaluation Guidelines. Houston: Western Atlas International Inc.	This reference focuses on the principles of Cement bond logs. It discusses various topics around cement bond including methods and analysis of different cement conditions.

Appendix J: Step-Rate Circulation Test

The Step Rate Circulation Test is used to help identify when the hole is properly conditioned (hole conditioning) and the well is ready for cement. This means the drilling fluid that was in the hole, the fluid used to drill and clean out the cuttings and the partially dehydrated drilling fluid/gel are removed/displaced with the conditioned drilling fluid prior to cementing. Often the industry targets circulation rates such as 80 m/min but in some cases the hole conditions or rig pumps may not be able to handle those rates. At a lower rate there may not be enough flow to remove the drilling fluid (filtercake and partially dehydrated/gelled drilling fluids) and at a higher rate there may be enough friction that filtercake rebuilds/accumulates or ECD causes lost circulation. Use the highest possible rate based on wellbore conditions. If rate is limited, contact times (volumes) can be adjusted to accommodate enhanced drilling fluid removal. Consider industry targets such as 10 minutes of contact time or 300 m of annular linear height (whichever produces the larger volume). Wellbore conditions, geometry, etc. affect and may limit theses targets. Some modeling/simulations can help identify this but not all companies have the capability or the understanding to model properly.

The procedure is as follows:

- With a simulator and casing in the hole, determine max possible safe rate (max ECD's, etc.).
- With a simulator that can simulate drilling fluid erodibility, determine if the drilling fluid/filter cake/partially dehydrated drilling fluid can be removed based on the proposed design
    - If drilling fluid/filter cake/partially dehydrated drilling fluid can be removed:
        - Accurately monitor pressures near the wellhead.
        - Start to circulate at a very low rate (e.g., 200 l/min).
        - Once pressures have levelled off, increase rate by a small amount (about 200 l/min).
        - Repeat increase in rate up to max possible safe rate determined only after pressures have levelled off.
        - Once max safe rate is reached, the pressure has levelled off and the hole is properly conditioned as discussed in 25.2.10 Drilling Fluid Conditioning.
    - If drilling fluid/filter cake/partially dehydrated filtercake cannot be removed:
        - Volumes of spacer, spacer type, cement (sacrificial cement) may be increased/adjusted to improve hole conditioning.

  - Wipers/scratchers may also be required over permeable zones or over zones where good zonal isolation is required.

If no simulator is available then it is difficult to know if the hole is properly conditioned and drilling fluid/filter cake/partially dehydrated drilling fluid will be removed but the same procedure can still be followed.

Important Notes:

- During some of the lower rates and lower rate increases the pressure may not drop. This may be because the rate is not yet high enough to start removing the immobile drilling fluid. Continue with step rate increases.
- Changing the drilling fluid properties (i.e., from the drilling fluid to the conditioning fluid) during this process should be avoided.
- Different drilling fluids behave differently and it can be difficult to simulate their exact properties and formation interaction under dynamic conditions.

It is possible that when increasing the rate, the pressure declines and levels off as expected. However, before the max safe rate is reached an increase in rate can cause pressures to increase. This indicates a potential friction pressure not high enough to exceed ECD but high enough to start building up additional filtercake. Drilling fluid properties may need to be adjusted (i.e., better fluids loss control). If this isn't possible then reduce the rate down to the max safe rate again (where pressure levels off) and perform the cement job at that rate.

Acronyms and Abbreviations

The following acronyms and abbreviations are used in this IRP:

ABSA Alberta Boilers Safety Association

AER Alberta Energy Regulator **API**

American Petroleum Institute **APWD**

Annular Pressure While Drilling

ASTM American Society for Testing and Materials

ATAV Average Attenuation Value

ATMN Minimum Attenuation Value

Bc Bearden Consistency Units

BCOGC British Columbia Oil and Gas Commission

BHCT Bottom Hole Circulating Temperature

BHST Bottom Hole Static Temperature

BOP Blowout Preventer

BWOC By Weight of Cement

CAODC Canadian Association of Oilwell Drilling Contractors

CAPP Canadian Association of Petroleum Producers

CBL Cement Bond Log

CBT Compensated Cement Bond Log

CO_2 Carbon Dioxide

CSS Cyclic Steam Stimulation

DACC Drilling and Completions Committee

DLS Dogleg Severity

DTMN Delta Time Minimum

DTMX Delta Time Maximum

DTS Distributed Temperature Sensing (Systems)

ECD Equivalent Circulating Density

ECP External Casing Packer

EPAC Explorers and Producers Association of Canada

FIT Formation Integrity Test

GFP Gas Flow Potential

GM Gas Migration

H_2S Hydrogen Sulphide

HPHT High Pressure High Temperature

HVCM Highest Viscosity of Combined Mixture

HVIF Highest Viscosity of Individual Fluids

ID Inside Diameter

LCM Lost Circulation Material

LOT Leak-off Test

MOC Management of Change

MWD Measurement While Drilling

NaCl Sodium Chloride (Salt)

OHS Occupational Health and Safety

PSAC Petroleum Service Association of Canada

PWD Pressure While Drilling

RAS Right Angle Set

ROP Rate of Penetration

RPM Revolutions Per Minute

SAGD Steam-Assisted Gravity Drainage

SBL Sector Bond Log

SBT Segmented Bond Tool

SCVF Surface Casing Vent Flow

SVF Solid Volume Fraction

TD Total Depth

TIE Third Interface Echoes

TT Thickening Time

TOC Top of Cement

VDL Variable Density Log

WOC Wait on Cement

YP Yield Point

Glossary

This IRP uses the following terms as defined below:

Aquathermolysis The reaction of organic compounds with superheated water.

Backreaming Tripping while rotating and pumping out of the hole.

Bond Index Bond index is a common indicator used to give some quantitative assessment of the bond log output. 100% bond index means the tool response is the same as the response in fully cemented pipe. 0% bond index means the tool response is the same as the response in un-cemented pipe. Bond index plots show the relative levels of tool response between the two end points. See API 10TR1 for more details on the calculations.

Casing Configuration For purposes of this IRP, casing configurations refers to the casing size, weight, grade, connection and accessories.

Casing Movement For purposes of this document, casing movement refers to reciprocation and rotation of casing.

Cement A powdered substance made from limestone and clay or shale. When mixed with water makes a slurry which hardens upon curing. Portland cement is the most common cementitious material used in the construction and oil industries.

Cement Basket A cement basket is a ribbed casing attachment with either metal petals or a canvas basket between the ribs.

Cementing To prepare and pump cement into place in a wellbore. Cementing operations may be undertaken to seal the annulus after a casing string has been run, to seal a lost circulation zone, to set a plug in an existing well from which to push off with directional tools or to plug a well so that it may be abandoned. Before cementing operations commence, engineers determine the volume of cement (commonly with the help of a caliper log) to be placed in the wellbore and the physical properties of both the slurry and the set cement needed, including density and viscosity. A cementing crew uses special mixers and pumps to displace drilling fluids and place cement in the wellbore. (Source: SLB Oilfield Glossary)

Centralizer A mechanical device that keeps casing from contacting the wellbore wall. A continuous 360-degree annular space around casing allows cement to completely seal the casing to the borehole wall. There are two distinct classes of centralizers. The older and more common is a simple bow-spring design. Since the bow springs are slightly larger than the wellbore, they can provide centralization in vertical or slightly deviated wells. However, they do not support the weight of the casing very well in deviated wellbores. The second type is a rigid blade design. This type is rugged and works well even in deviated wellbores, but since the centralizers are smaller than the wellbore, they will not provide as good centralization as bow-spring type centralizers in vertical wells. Rigid-blade casing centralizers can cause trouble downhole if the wellbore is not in excellent condition. (Source: SLB Oilfield Glossary).

Conductor Pipe A short string of large-diameter casing set to support the surface formations. The conductor pipe is typically set soon after drilling has commenced since the unconsolidated shallow formations can quickly wash out or cave in. Where loose surface soil exists, the conductor pipe may be driven into place before the drilling commences. (Source: SLB Oilfield Glossary)

Coriolis Meter A device that measures the mass flow rate of a fluid travelling through a tube. The device can measure flow rate and density of fluid.

Densometer A device that indirectly measures cement slurry density.

Displacement Efficiency The percentage of the annular cross-sectional area occupied by the cement (% Displacement Efficiency = Cemented area / Annular area x 100).

Distributed Temperature Sensing (DTS) Systems Fibre optic distributed temperature sensing (DTS) systems provide a continuous temperature profile along the entire wellbore that can identify the source of changes in well performance as they occur. DTS cable can be installed permanently or deployed temporarily to achieve the desired characterization of well conditions.

Eccentering The positioning of casing or tools in the wellbore relative to centre (see Standoff).

Effective Porosity The portion of the rock void space which contains mobile fluids. This is different from porosity which includes irreducible fluids.

Equivalent Circulating Density The pressure 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 expressed as a density.

Filtercake The residue deposited on a permeable medium when a slurry, such as a drilling fluid, is forced against the medium under a pressure. Filtrate is the liquid that passes through the medium, leaving the cake on the medium. (Source: SLB Oilfield Glossary)

Floats r Floats are check valves placed at the bottom of the casing as a collar or shoe. Floats are commonly run in pairs for redundancy in case of failure.

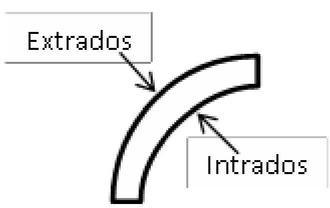
Gas Migration IRP 25 uses the AER definition of Gas Migration as per AER Interim Directive: ID 2003-01. The definition is as follows:

> Gas Migration (GM) is a flow of gas that is detectable at surface outside of the outermost casing string (often referred to as external migration or seepage). A GM is serious if there is a fire or public safety hazard or off-lease environmental damage, such as groundwater contamination. A GM is nonserious if it has not been classified as serious migration.

Hydraulic Isolation One factor of zonal isolation.

Intermediate Casing A length of pipe used below the surface casing string, but before the production casing is run, to isolate one or more zones of the open hole to enable deepening of the well. There may be several intermediate casing strings. Depending on well conditions, these strings may have higher pressure integrity than the prior casing strings, especially when abnormally pressured formations are expected during the drilling of the next open hole section. (Source: SLB Oilfield Glossary)

Intrados and Extrados Intrados is the internal curve of an arch. Extrados is the external curve of an arch. In this document they reference the curvature of pipe (in 25.6 Wellbore Construction).



Liner A liner is a string of casing that does not extend all the way to surface.

Mass Balance Technique A method of measuring the components of cement slurry before mixing. If the water volume, mass of cement and the cement volume are known before mixing then the density of the mixed components can be calculated. This method has application when measuring slurries that have the same or near density of water.

Mud Balances Devices for measuring density (weight) of drilling fluid, cement or other liquid or slurry. There are two types: pressurized and non-pressurized.

Noise Logging Tools Noise logs are commonly used to detect the source of GM and SCVF. Noise logging tools typically consist of a single transducer which converts acoustic energy into an electrical signal. The sound is generally recorded on a logarithmic amplitude scale with the signal levels plotted in a number of frequency bands. In addition, audio files are usually recorded which can help determine the nature of the flow. A noise tool that employs a dual shuttle optical noise detection system is available which promises higher sensitivity and source location information not available from single detector tools.

Premium Connections For this IRP a premium connection refers to a non-API or proprietary connection. The architectures may vary but it most often refers to a specific subset of proprietary connections: threaded and coupled connections with torque shoulders and a radial metal-to-metal seal. These connections are further characterized by run-out threads with thread forms that resist jump-out or jump-in under axial loads. A **Semi-Premium Connection** has the same configuration but without the radial seal.

Production Casing A casing string that is set across the reservoir interval and within which the primary completion components are installed. (Source: SLB Oilfield Glossary)

Scraper A downhole tool incorporating a blade assembly that is used to remove scale and debris from the internal surface of a casing string. Generally run on tubing or drill pipe, casing scrapers are routinely used during workover operations to ensure that the wellbore is clean before reinstalling the completion string. (Source: SLB Oilfield Glossary)

Scratcher A device for cleaning drilling fluid and filter cake off of the wellbore wall when cementing casing in the hole to improve contact and bonding between the cement and the wellbore wall. The scratcher is a simple device, consisting of a band of steel that fits around a joint of casing, and stiff wire fingers or cable loops sticking out in all directions around the band (360-degree coverage). A scratcher resembles a bottlebrush, but its diameter is greater than its height. Importantly, for scratchers to be effective, the casing must be moved. This movement may be reciprocal motion in and out of the wellbore, rotary motion, or both. In general, the more motion, the better the cement job will be. (Source: SLB Oilfield Glossary)

Shoe Track Another term for float joint, a full-sized length of casing placed at the bottom of the casing string that is usually left full of cement on the inside to ensure that good cement remains on the outside of the bottom of the casing. If cement were not left inside the casing in this manner, the risk of over-displacing the cement (due to improper casing volume calculations, displacement drilling fluid volume measurements, or both) would be significantly higher. Hence, the well designer plans on a safety margin of cement left inside the casing to prevent contaminated cement from being pushed outside the casing. . A float collar is placed at the top of the float joint and a float shoe placed at the bottom to prevent reverse flow of cement back into the casing after placement. There can be one, two or three joints of casing used for this purpose. (Source: SLB Oilfield Glossary).

Standoff A measurement of the eccentricity of a casing inside a wellbore. A 100% standoff means the casing is in the centre of the hole. A 0% standoff means the casing is touching the wellbore on one side.

Spacer For the purposes of this IRP, a spacer is any fluid pumped immediately before the cement that is different from the drilling fluid already in the hole (whether it is weighted, non-weighted, viscosified or non-viscosified).

Surface Casing A large-diameter, relatively low-pressure pipe string set in shallow yet competent formations for several reasons. First, the surface casing protects fresh-water aquifers onshore. Second, the surface casing provides minimal pressure integrity, and thus enables a diverter or perhaps even a blowout preventer (BOP) to be attached to the top of the surface casing string after it is successfully cemented in place. Third, the surface casing provides structural strength so that the remaining casing strings may be suspended at the top and inside of the surface casing. (Source: SLB Oilfield Glossary)

Surface Casing Vent Flows IRP 25 uses the AER definition of Surface Casing Vent Flows as per AER Interim Directive: ID 2003-01. The definition is as follows:

> Surface Casing Vent Flow (SCVF) is the flow of gas and/or liquid or any combination out of the surface casing/casing annulus (often referred to as internal migration).
>
> A SCVF is serious if there is a
>
> 1) vent flow where any usable water zone is not covered by cemented surface casing and/or by the cement of the next casing string (Oil and Gas Conservation Regulations, Section 6.080, subsection 4) (see note below.); or
>
> 2) vent flow with a stabilized gas flow equal to or greater than 300 cubic metres per day (m3/d) and/or equal to a surface casing vent stabilized shut-in pressure greater than
>
>> a) one-half the formation leak-off pressure at the surface casing shoe, or

b) 11 kPa/m times the surface casing setting depth; (The criterion of 11 kPa/m, or half the known formation leak-off pressure, was chosen to avoid exceeding the fracture gradient. The surface shut-in pressure may vary with formation leak-off pressure, density of the fluid in the annulus, depth to fluid, lost circulation zones, or other well conditions that would limit the allowable shut-in pressure); or

3) vent flow with hydrogen sulphide (H2S) present; or

4) hydrocarbon liquid (oil) vent flow; or

5) nonusable water vent flow (any water with total dissolved solids greater than 4000 milligrams per litre [mg/l]);

6) usable water (as defined by Alberta Environment) vent flow where the surface shut-in pressure is as in (2)(a) or (b); or

7) vent flow due to wellhead seal failure or casing failure; or

8) vent flow that constitutes a fire, public safety, or environmental hazard.

Note that a SCVF where any usable water zone is not covered by cement may be considered nonserious if

1) the vent flow with a stabilized gas flow is less then 300 m3/d; and

2) the surface casing vent stabilized shut-in pressure does not exceed 9.8 kPa/m times the surface casing setting depth; and

3) the vent flow is only gas (no hydrocarbon or water); and

4) there are no producing domestic or agricultural water wells from the unprotected aquifers within a 1 km radius; and

5) the vent flow is not deemed serious in any other category.

If a producing domestic or agricultural water well from an unprotected aquifer is subsequently established within the 1 km radius, the licensee of a well that has previously been considered to have a nonserious SCVF must complete the reporting and repair requirements outlined in Sections 2.3 and 2.4 of this interim directive.

An SCVF is nonserious if it has not been classified as a serious vent flow.

Temperature Logging Temperature logs can be run to detect fluid movement behind the pipe downhole. The static geothermal gradient is usually established during an initial down log pass followed by additional logging passes during and after either injecting fluids or producing the well. Temperature logging can also be used to determine TOC.

Tractoring A method of deploying tools along a horizontal well. The method uses a mechanical action not unlike tractor locomotion to push a tool along a horizontal wellbore.

Transition State A specific hydration period where the cement begins as a liquid and ends as a gelled mass.

Turbulence Inducing Devices Turbulence inducing devices are similar to straight casing centralizers except they have turbulent veins fitted on each bow. These specialized devices are added to the casing to disturb the flow path and encourage turbulent flow.

Well Integrity Well integrity, in regard to oil wells, is defined by NORSOK D-010 as the "“Application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well”.

Wiper Trip Working the drill bit through a section of hole from the selected depth of wiper trip (not necessarily from the bottom of the hole) using the BHA to sweep cuttings from the wellbore.

Zonal Isolation Zonal isolation is the prevention of communication between discreet porous zones (including between hydrocarbon bearing formations) and freshwater aquifers. This includes communication between hydrocarbon bearing formations.