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Abstract

Cementing wells with severe temperatures and/or pressures has become a common matter over the years. Running casing and designing the cement job is very difficult with temperatures above 150°C (300°F) which is a common temperature range in geothermal steam- and HPHT wells. The downhole temperature controls the pace of cement hydration and one major concern in geothermal- and HPHT wells is maintaining strength stability in cementing compositions at 370°C (700°F).

Cementing thermal wells requires solutions for obstacles, such as increased thickening time, strength retrogression, thermal shock, lost circulation and corrosion. These obstacles requires for a complex job design, not only in, a chemical properties design view, but also in placement technique and pumping pace of the slurry. Comprehensive research to enhance the integrity of the cement in thermal environments has been done, and previous work failures has contributed to several finding that has improved the cementing solutions for geothermal well conditions, especially the ones containing corrosive formation fluids.

Three cases have been studied, together with a literature review to provide an overview of the cement job designs chosen, integrity of the cement slurry, and reasons for failure. Furthermore, the cementing solutions were studied to look at what additives improved integrity and stability. What kind of laboratory tests were performed to support the design solutions.

The study has shown that certain cement additives are here to stay, such as silica flour, pozzolans, and elastic-behaving chemicals. A key issue in successful cement sheath integrity has proven to be directly related to proper hole preparations and drilling fluid removal. Knowing as much as possible about the wellbore parameters is necessary to provide proper computer software simulation testing of the cement slurry. Laboratory tests and simulations should be as real as possible, and as many as possible of these tests should be performed to to ensure the cement slurry can withstand the actual well conditions.

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List of Abbreviations

HPHT	—	High Pressure High Temperature
API	—	American Petroleum Institue
HAC	—	High-Alumina Cements
ECD	—	Equivalent Circulating Density
BOP	—	Blow-Out Preventer
BHCT	—	Bottomhole Circulating Temperature
BWOC	—	By Weight of Cement
HAC	—	High-Alumina Cement
RCPT	—	Reverse Circulation Placement Technique
FEA	—	Finite Element Analysis
ACS	—	Optimized Elsatic-Thermal-Cement System
SF	—	Safety Factor
SEM	—	Scanning Electron Microscopy
O grade	—	Ordinary Grade
MSR	—	Moderate Sulfate Resistance
HSR	—	High Sulfate Resistance

List of Chemical Compounds

C-S-H	—	Calcium Silicate Hydrate
CO_2	—	Carbon Dioxide
HCl	—	Hydrochloric Acid
α-C_2SH	—	Crystalline Alpha-Dicalcium Silicate Hydrate
CaO	—	Calcium Oxide
MgO	—	Magnesium Oxide
$Ca(OH)_2$	—	Calcium Hydroxide
$Mg(OH)_2$	—	Magnesium Hydroxide (Brucite)
$Ca_3Al_2O_6$	—	Tricalcium Aluminate
$Ca_6Al_2(SO_4)_3(OH)_{12}{\cdot}26H_2O$	—	Ettringite
$CaSO_4{\cdot}2H_2O$	—	Gypsum
$MgCl_2$	—	Magnesium Chloride
HF	—	Hydrofluoric Acid
SiO_3	—	Amorphous Silica
H_2CO_3	—	Carbonic Acid
$CaCO_3$	—	Calcium Carbonate (Calcite)
$Ca(HCO_3)_2$	—	Calcium Bicarbonate
SiO_2	—	Silicon Dioxide
CaP	—	Calcium Aluminate Phosphate
N_2	—	Nitrogen Gas
CaF_2	—	Calcium Flouride
Mn_3O_4	—	Manganese Tetraoxide

1 Introduction

Todays population and energy consumption makes the search for good resources, such as ground water and petroleum, essential. Drilling into the earths crust has become a common fashion in the search for energy resources. The increased demand has forced the industry to operate in a more advanced matter. Drilling in deeper waters and arctic regions are examples of this. Wells that were previously undrillable have now become drillable with improved technology.

Drilling in arctic regions (66.65° north of equator) and in water depths up to 4500 m (15,000 ft) requires for high-tech equipment that is able to withstand extreme temperature- and pressure differences. The average geothermal- and hydrostatic pressure gradient of the earth's crust is 25°C/1000m (15°F/3281ft) and 9.792 kPa/m (0.465 psi/ft) . At a well depth of 5000 m the bottom hole temperature will be somewhere around 125°C (275°F) and a reservoir pressure of 48.96 MPa (7100 psi). Some wells may have a significantly higher pressure and/or temperature than this. High pressure high temperature wells (HPHT) are classified as wells that have a temperature equal to or above 149°C (300°F) and a pore pressure gradient that exceeds 18.1 kPa/m (0.8 psi/ft). Geothermal steam wells usually have a bottom hole temperature range of 250°C to 400°C (400°F to 750°F). With downhole conditions like these one must take caution when drilling, completing, and later, producing the well.

High temperature gradients create severe conditions on all aspects of drilling and completion of the well (Ostroot 1964). Running casing and designing cement jobs is very difficult with temperatures above 150°C (300°F) which is a common temperature range in geothermal steam- and HPHT wells. The temperature effects on casing and cement strength can be severe. High temperatures may cause elongation or creeping on casing and strength retrogression and increased permeability of the cement. The downhole temperature controls the pace of cement setting time and strength development (Kutasov 1999). One major concern in geothermal- and HPHT wells is the strength stability in cementing compositions at 370°C (700°F). Creating a cement slurry that will be strong enough to withstand the extreme temperatures fluctuations throughout the life of the well is a challenge. This thesis will look at the obstacles in cementing geothermal steam- and HPHT wells. What solutions have been made to meet the challenges and what lessons learned can be used for future wells.

2 Cementing

The major objective of primary cementing in an oil, gas or water well is to provide zonal isolation. If several producing zones or aquifers are present, cement will exclude these from each other by creating a hydraulic seal in the annular space between the casing and the well-bore, while at the same time prevent fluid channels in the cement sheath. The cement will also protect and support the casing from corrosion by formation fluids. This makes the cementing operation of a well one of the most critical and important steps in drilling and completing the well (Calvert 2006). If the primary cement job is done poorly, the well might never reach its full producing potential and future well stimulation operations will not be as successful. In situations like these a remedial cementing operation will have to be done to repair the faulty in the primary cementing job. Remedial cementing operations are costly and time consuming, and are often not able to fully repair the primary cement problems.

2.1 Cement Composition

The cement slurry used in oil and gas wells consist of dry bulk cement together with preferred additives mixed with water. The most widely used bulk cement, is Portland cement. A calcined (burned) blend of limestone and clay (Crook 2006). Portland cement is essentially a calcium silicate material and upon of addition of water it hydrates to form a gelatinous calcium silicate hydrate, commonly known as «C-S-H-phase», and portlandite. The C-H-S phase occurs in fine needles and during cement hydration they grow in length and grab onto each other like a zipper, which is responsible for the strength and dimensional stability of the set cement (Nelson et al 2006). The portlandite consists of large hexagonal crystals between the C-S-H phases, it does not contribute to any strength and therefore considered the weak point in the cement matrix. The amount of portlandite present in set cement depends on the degree of hydration, temperature, exact clinker-phase composition, water-to-cement ratio and composition of formed C-S-H phases (Brandl et al 2010). Portland cement is easily pumped down and hardens readily, even under water. It can be manufactured to meet certain chemical- and physical requirements that depend upon their application. These manufacturers are a classification systems established to promote consistency in the industry (Nelson et al 2006). The best know classification system of Portland Cement is the ones formed by The American Petroleum Institute (API) defined in API SPEC 10A (2002) (Crook 2006). The API classifications of Portland Cement is described in Appendix B. However, some of these may not fully cover HPHT well cementing.

2.1.1 Cements Developed for HPHT Wells

Pozzolanic Cements. A pozzolan is a siliceous og silica-aluminous material that in finely divided form and with presence of water, at ordinary temperatures, produce strength developing insoluble compounds. Volcanic materials and diatomaceous earth are the most common sources of pozzolanic materials. Pozzolanic cements is usually used when lightweight slurries are preferred and where well conditions dictate that an increased compressive strength and reduced permeability of the cement is wanted.

Pozzolan/Lime Cements. These cements are usually blends of fly ash (silica), hydrated lime, and small amounts of calcium chloride. This lightweight cement has a lower initial reaction time than Portland cement, and better strength stability at high temperatures. As this cement is naturally retarded it is usually preferred in wells that have a temperature that exceeds 284°C (140°F).

Microfine Cements. These cements are either composed of finely ground sulfate-resisting Portland cements, alkali-activated ground granulated blast-furnace slag, or Portland cement blends with ground granulated blast-furnace slag. This cement has a high penetrability and hardens fast. This cement is usually used in squeeze cementing operations such as, repairing of casing leaks.

Calcium Aluminate Cements. These high-alumina cements (HAC) are used in wells that can experience high temperature fluctuations, such as thermal recovery wells. It can easily be retarded or accelerated as wished because it is a highly stable cement in temperature extremes from permafrost zones with temperatures at 0°C (32°F) or below, to fire flood wells where the temperature may range from 400°C to 1093°C (750 to 2,000°F).

Latex Cements. This special cement is a blend of API class A, G or H with latex. Latex provides the cement system with elasticity and improve the bonding strength between cement/steel and cement/formation interfaces. By adding latex to the cement, the slurry will have an improved pumpability and decreased permeability.

Cements for Carbon dioxide (CO_2) Resistance. The products of hydration is what gives the cement its compressive strength. If the cement is exposed to carbonation for a longer time, this strength will decrease overt time. Carbonation is when calcium carbonate ($CaCO_3$) is produced from CO_2 in formation waters or from injection processes dissolved in the aqueous pore solution of the hydrated cement. Adding calcium phosphate (CaP) to the cement will minimize the carbonation process. CaP cements is resistant to both CO_2 and acid and stable at a wide temperature range.

Several other special cements are developed to meet different well conditions, such as *Gypsum Cements;* commonly used in low-temperature wells, *Permafrost Cement;* cement system developed for arctic conditions, *and Resin or Plastic Cements;* system developed for plugging open holes, squeezing perforations and cementing waste disposal wells, however these are not commonly used in geothermal- or HPHT wells and therefore not described in detail.

2.1.2 Additives

Additives are chemical compounds that effectively alter the hydration chemistry of the slurry. They are used to modify the properties of the cement slurry to best meet the well conditions. The additives are categorized after what advantage they provide the cement slurry with.

Accelerators. Chemicals that are added to speed up the reaction time of the slurry to become a hardened mass, i.e. increase in rate of compressive strength and reduction in thickening time. Accelerators are beneficial to wells that encounter low temperatures and require low density-slurries. Examples of accelerators are calcium chloride ($CaCl_2$), Sodium chloride (NaCl) and potassium chloride (KCl).

Retarders. Commonly used cements in well applications have a very short thickening time. In wells with high temperatures the thickening time will increase further and cause problems wit premature setting of the cement during pumping of the slurry. To avoid this problem chemicals that delay the thickening time are added to the slurry, these chemicals are called retarders. Examples of typical retarders are lignosulfonates, cellulose derivatives and hydroxycarboxylic acid and organophosphonates.

Extenders. Many of the commonly used cements will have, after adding water, a specific gravity of 1.78 g/cm^3 (15 lbm/gal). Wells that have a small operating window, weak and fractured formations and a low fracture gradients require a much lighter cement slurry than this. Extenders (lightweight additives) are added to reduce the weight of the cement slurry to avoid problems such as, lost circulation and fracturing of the formation. Extenders come in different types and these include physical extenders (clays and organics), chemical extenders (sodium silicate and gypsum), and gases (nitrogen [N_2]). Usually any material with a lower specific gravity than the cement will act as an extender when added to the slurry.

Weighting Agents. Weighting agents are heavyweight additives that are used to increase the slurry density for better control in high pressure wells. They are normally used when a specific gravity greater than 2.04 (17 lbm/gal) is required. Main requirement for a weighting agent is that its specific gravity is higher then the cement. They have low water requirement and chemically inert in the cement slurry. Typical weighting agents are hematite (Fe_2O_3), ilmenite ($FeO \cdot TiO_2$), hausmannite (Mn_3O_4) and barite ($BaSO_4$).

Dispersants. Dispersants are added to the cement to improve the rheological properties of the slurry. They are known as friction reducers because of their impact on the flow behavior of the slurry and lowering of frictional pressure gained when the cement is pumped into the well. Examples of dispersants are polysulfonated naphthalene and hydroxycarboxylic acids.

Fluid-loss Control Agents. When placing cement slurries across permeable zones under pressure, a filtration process will occur. However, if this filtration is not controlled, and the fluid loss become severe, the hydrostatic pressure will drop and formation fluids may enter the wellbore or the remaining cement will increase the equivalent circulating density (ECD) above the fracturing pressure. Fluid-loss control agents are added to control this filtration process and they exist in two principal classes; finely divided particulate materials, and water-soluble polymers.

Lost-circulation Control Agents. Lost circulation is a common problem in fractured formations and formations that break down at relatively low hydrostatic pressures. Lost circulation is costly and may result in remedial cementing due to severe losses of slurry into the formation. The lost-circulation agents are added to the slurry to prevent this problem by either bridge over the fractures (bridging materials) or provide the cement slurry with thixotropic properties.

Pozzolans. Pozzolans are essentially a subset of cement extenders, but as it is the most important group of cement extenders it is described as a separate additive. They are defined by the American Society for Testing and Materials as «a silicious or siliceous and aluminous material, which in itself possesses little or no cementitious value, but will, in finely divided form and in the presence of moisture, chemically react with calcium hydroxide at ordinary temperatures to form compounds possessing cementitious properties». The addition of pozzolans to cement is an effective way of reducing the amount of portlandite. The pozzolanic material reacts with portlandite and converts it to further C-S-H phase and hence strengthens the cement matrix and decreases the water permeability of the set cement (Brandl *et al* 2010). Pozzolans are either natural (volcanic ashes, and diatomaceous earth) or artificial (certain fly ashes) and are usually added in large volumes to the cement. They have a lower specific gravity then Portland cement and adding them to the slurry, results in a reduction in the slurry density and at constant slurry density the addition of pozzolanic materials will reduce the water-solids ratio. Pozzolanic cements tend to give a set cement, that is more resistant to attacks by corrosive formation waters.

Miscellanous Cement Additives. These additives are a number of materials that do not fit into a general category. Some of these are, Antifoam Agents; Some cement additives may cause the slurry to foam during mixing. Polyethylene glycol is the most widely used antifoam agent, Strengthening Agents; Fibrous materials that are added to increase cements resistance to stresses. Examples of such materials are nylon fibres, metallic micro ribbons, and particulated rubber, Radioactive Tracing Agents; Tracers added to the cement to help determine their location behind the casing. The most common radioactive agent used is Iodine, and Mud Decontaminants; Certain chemicals used in drilling fluid may retard the cement slurry. To minimize this effect, chemicals such as paraformaldehyde or blends of paraformaldehyde and sodium chromate are used.

2.2 Primary Cementing

An optimized production starts with a good completion, and a good completion depends on the integrity of the primary cement job. Well parameters such as, depth, wellbore geometry, temperature, and formation pressure, are important to consider when designing the primary cement job. Chemicals are added to enhance the cement slurry and different placement techniques are developed to simplify the operation and best meet the well conditions.

The most important requirement for a good primary cement job is good mud removal. Cement slurries and drilling fluids are usually incompatible with each other. To prevent them interfering a chemical washer or spacer is pumped between mud and cement. Another important factor to consider is casing centralization. The casing will never be at the center of the borehole, but it is required to have as little stand-off as possible. The fluid will naturally flow more readily on the wider side of the casing and mud-displacement strategies will be compromised unless there is adequate casing centralization. These are important factors to consider before placing the primary cement in the well.

2.2.1 Placement Techniques

Cement Through Drillpipe. Two different methods exists for cementing through drillpipe: (1) stab-in and (2) inner-string cementing. Stab-in cementing is a commonly used primary cementing placement technique. Casing is run in place by help of a stab-in flat shoe (**Fig. 1**). It is set in casing slips so it is suspended from bottom. The drill pipe, equipped with a stab-in stinger is run inside the casing until 1 m (3 ft) above the casing shoe. Drilling fluid circulation is then established and all returns are to arrive from annulus between the drill pipe and casing. When the circulation is sufficient it is stopped and drill pipe is lowered, enabling the stinger to stab or screw into and seal in the float shoe. After this the cement slurry is mixed and pumped down through the drill pipe and up the annulus. When the slurry is no longer evident in the cement returns, mixing will be stopped and drill pipe volume displaced. Should lost circulation occur, one should immediately stop mixing and cement should be displaced, to avoid pumping large quantities of cement into the formation. If this placement technique is not done carefully it can cause casing collapse, due to the excessive differential pressure between the outer annulus and the drill pipe casing annular space. The stab-in cementing technique is preferable because it does not require accurate hole volumes, this is because the cement slurry is mixed and pumped down until returns are observed at the surface. The technique also eliminates the need for large diameter swages or cement heads because minimal contamination occurs during through-drillpipe cementing. There are various options for this placement technique, such as the use of backup check valve (float collar and float shoe) or stab in float shoe alone. Several simpler stab-in tools have been developed; Latch in design, and simply rely on the drill pipe weight to hold the stinger in place while cementing. This method can only be used on land rigs or jackups and platform rigs.

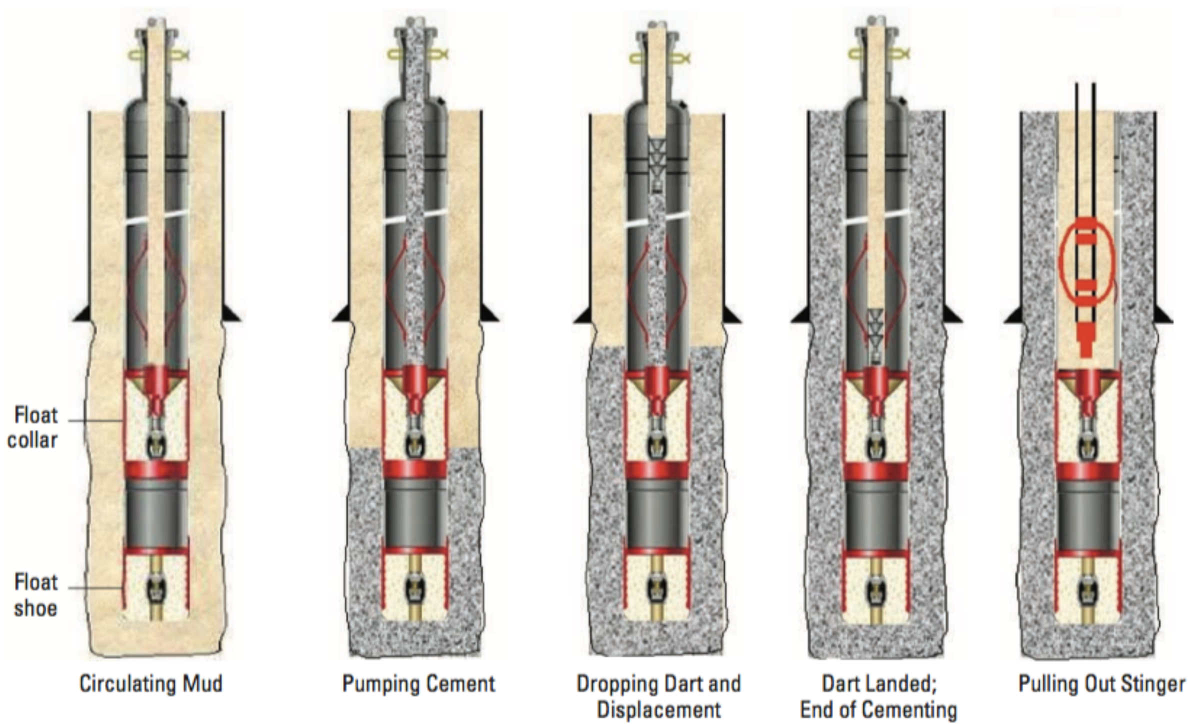

Fig. 1—Through drill pipe stab-in cementing (Piot and Cavillier 2006)

If the annulus is blocked during stab-in cementing there is a great risk of casing collapse. Inner-string cementing has become a preferred adaption of through drill pipe stab-in cementing. By the use of a cementing mandrel together with the drill pipe (tubing) hanging freely to within 4.6 to 9.2 m (15 to 30 ft) of the shoe or collar it offers an additional possibility of casing reciprocation and the method can be used on floating rigs offshore. The method eliminates the possibility of casing collapse, because the pressure in the annulus and within the casing are equal. The pressure inside the casing can also be monitored by a pickoff head, however this is only possible on stationary (non-floating) rigs. Caution should be taken during U-tubing of the fluid because the fluid in drillpipe-casing annulus cannot be controlled and this may result in possible cement contamination.

Grouting (top up cementing). If lost circulation occurs during large-casing slurry displacement the immediate solution is to re-cement the annulus. To do this, a small-diameter tubing (usually 5 cm [$1^7/_8$-in] tubing is common) is run down the annulus between casing and the open wellbore (**Fig. 2**). If necessary several joints can be made up and pushed down. A high pressure unit will connect the tubing to the cementing unit. The cement slurry is then mixed and pumped down until cement slurry is circulated to the surface. Both lines and tubing is flushed with water, and tubing is withdrawn from the annulus afterwards. Cement may also be mixed and pumped directly into the annulus with the tubing string in place. Extreme cases requires that these steps are repeated several times until the cement reaches the surface and it has sufficient gel strength built to support the slurry until it sets. The drawback with this method is that there is no method to determine how far the cement has fallen and the annulus may never be uniformly cemented. It is also difficult to use this cementing method offshore.

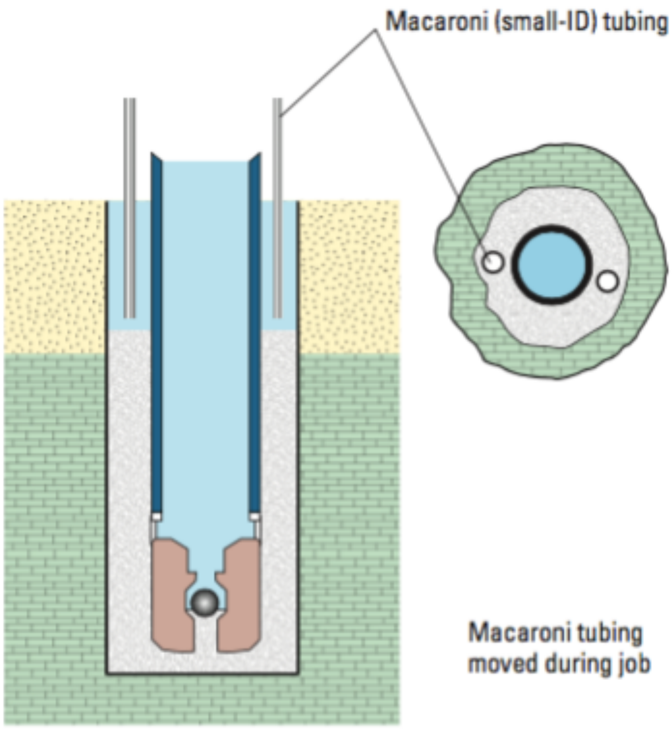

Fig. 2—Top-up cementing (Piot and Cuvillier 2006)

Single Stage Cementing. The development of ultralow-density cements has reduced the need for multistage cementing drastically. Single stage cementing has become the most common cementing technique. Low density, high solids or foamed cement can now be placed in the annulus in one stage without fracturing or breaking down weak formations. Like the cementing through drill pipe technique, good mud removal is required. The casing string together with cementing accessories (float collar, float shoe and centralizers) is run in the hole until the shoe is located 1 to 2 meters (3 to 6 ft) above the hole bottom. A cementing head will be connected to the top of the casing string to establish drilling fluid circulation. The casing is circulated until there are no longer traces of drilling mud. A wiper plug is used to wipe the inside of the casing clean and to act as a small seal between the drilling fluid and the spacer. When the wiper lug reaches the bottom (float collar) its rubber diaphragm is ruptured and it allows the spacer and cement slurry to keep going around the shoe and up the annulus. When the displacement process starts a shut-off plug is released. When it reaches the float collar it will land on the bottom plug and create a seal that stops the displacement process. Throughout the cementing job it is important to monitor the drilling fluid returns from the annulus to ensure that the formation has not been fractured.

Multistage Cementing. Although single stage cementing is more commonly used, multistage cementing has to be done in certain cases. Downhole formations that are unable to support the hydrostatic pressure exerted by a long column of cement require multistage cementing. Multistage cementing is mostly done to alleviate high hydrostatic pressures and in cases where the whole casing has to be cemented to prevent corrosion or lost circulation zones are located below the casing shoe. The most common multistage cementing technique is conventional two-stage cementing. In addition to casing equipment, a stage-cementing collar is run to the desired depth. The first stage is cemented as similar to single stage cementing, except that the bottom wiper plug is missing (in cases where the mud and cement is highly incompatible a bottom wiper plug may be run in addition). After the mixing of slurry a first stage plug is dropped and displaced until it lands in the float collar. A caliper log should be run to determine the accurate hole volume to again determine the cement slurry height in the annulus. The first stage cement should always cover the stage collar. The second stage is cemented as soon as the first stage is completed. An opening bomb of a mechanically operated stage collar is dropped to fall until it is seated on the stage collar. When the bomb is seated a pressure will be applied until the lower sleeve is forced to move upward and uncover the ports and a sudden drop in surface pressure is attained. The second stage is then cemented as the first stage. A closing plug is dropped when the slurry mixing and displacement of the cement slurry is completed. It is very important that the well is circulated until the mud is conditioned for the second stage and that the first stage cement has had time enough to set, if not the weak formations may not be able to withstand the increase in hydrostatic pressure. Three stage cementing and continuous two-stage cementing are two other types of multistage cementing techniques, however they are rarely applied in cementing operations and not covered in this thesis.

Reverse Circulation Cementing. This cementing technique is sometimes performed where the well conditions are extreme. Wells with high temperatures and weak formations with lost circulation zones and fractures are a challenge to cement due to the increased thickening time and possible severe losses to formation. Placing a cement slurry that is overly retarded through drill pipe and up annulus is a challenge in such conditions and often it results in primary cement failure. Pumping the cement slurry directly down the annulus is a solution to this challenge. However, the fluid placement is uncontrolled and the casing shoe will never be cemented. Reverse circulation cementing is usually a last resort. The method of this technique is to pump the slurry directly down the annulus and displace the drilling fluid back up the casing. This technique allows for a wider range in slurry compositions and gravity forces will help the fluid-flow process. A back pressure is often applied to have better control of the slurry and fall when pumping it down the annulus. Only parts of the cement will be in contact with the bottomhole temperatures which makes it possible to customize the thickening time of the cement.

2.3 Remedial Cementing

Remedial cementing is a collective term describing cementing operations that is performed to fix a problem that affect the life of the well. These problems can occur during drilling of the well, during production and well stimulation or to place a permanent cement seal before abandoning the well. It may be required to perform a remedial cementing job to maintain wellbore integrity during drilling, cure drilling problems, repair defective primary cementing jobs or used to control gas oil ratio or water production. Remedial cementing is divided into two broad categories: plug cementing and squeeze cementing. Plug cementing consists of placing cement slurry in a wellbore and allowing it to set and squeeze cementing consists of forcing cement slurry through holes, splits or fissures in the casing or wellbore annular space.

2.3.1 Plug Cementing

Balanced Plug Method. This is the most common plug cementing technique. A tubing or drill pipe is run into the hole to desired depth for the plug base. A chemical washer or spacer is used to prevent mud contamination with the cement slurry. It is normal to under-displace the plug, and practice avoids mud flowback and allows for the plug to reach hydrostatic balance. Once the plug is balanced the pipe is pulled out of the cement to a desired depth above and excess cement is reversed out. Caution must be taken when it comes to cement contamination. To avoid or minimize downward migration; fluids with high gel strength are placed as a base (these are typically thixotropic bentonite suspensions or cross linked polymer pills).

Dump Bailer. Dump bailer is a vessel that holds a measured quantity of cement slurry. It is lowered on a cable and it opens when it touches a permanent bridge plug placed below the desired plug interval. The cement slurry is then dumped on the plug by raising the bailer. This is usually done for plug cement jobs at shallow depths. If this method is used in greater depths the cement can only be used if it is properly retarded. This is a relatively inexpensive method and the cement plug is easily controlled. Caution should be made to the fact that the slurry is stationary and special considerations are required when this method is used in high temperature well conditions.

Two-Plug Method. A special tool to set a cement plug at a calculated depth to ensure maximum accuracy and minimum cement contamination is run. The bottom plug is pumped down to clean the drill pipe wall and ensure no interfering between drilling fluid and the cement slurry. A shear pin that is used to connect the dart and the plug is broken by increasing the pump pressure and pumped down through the tailpipe as illustrated in **Fig. 3**. The top plug is pumped down behind the cement slurry to prevent contamination with the displacement fluid. An increase in surface pressure will indicate that the top plug has reached its seat. The drill pipe is then pulled out until the lower end of the tailpipe reaches the calculated depth of the top plug. The shear pin is then broken allowing the sleeve to slide down and open the reverse circulating path and all excess cement is then circulated out from the hole.

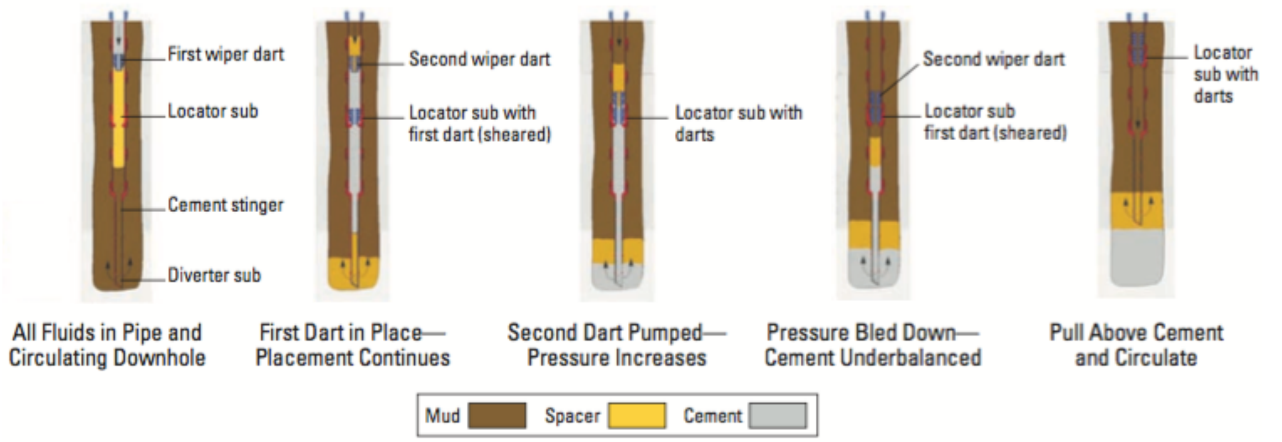

Fig. 3—Two plug method (Daccord et al 2006)

2.3.2 Squeeze Cementing

Squeeze cementing is a technique performed to repair primary cementing jobs, isolating different production zones, eliminate water intrusion, repair casing leaks, sealing lost circulation zones, protect against fluid migration into a producing zone or to plug one or more zones in a multilane injection well. Squeeze cementing is divided into two different classifications, low pressure squeeze and high pressure squeeze. There are two different techniques to perform a squeeze cementing job; Bradenhead squeeze and The Squeeze-Tool Technique. When performing the squeeze job there are two different pumping methods; running squeeze and hesitation squeeze. All classifications, techniques and pumping methods are described under.

Before running a squeeze cementing job it is important to make sure all perforations are receptive to the squeeze cement slurry. To ensure this mechanically a surge tool is used. It is run in the hole with a packer to isolate the desired interval of perforations. A small number of perforations are isolated at a time and a wash fluid is pumped down the tubing and forced into the perforations. It is then forced outside the casing and back in through upper perforations into the annulus. To ensure this is happening by a chemical matter, acids and solvents as spearhead fluids are pumped down to clean the perforations ahead of the cement slurry. Compatibility tests should be performed before the chemical wash job is done to prevent emulsions formed by the formation fluid and the acid.

Low Pressure Squeeze. To perform a low pressure squeeze it is essential that perforations and channels already are cleared for mud and other solids. The aim of a low pressure squeeze is to fill perforation cavities and interconnected voids with cement filtercake. During a low pressure squeeze the cement slurry is not pumped into the formation, but supposed to leave a small node of cement filtercake inside the casing. It is therefore important to encounter precise control of the pump pressure and the hydrostatic pressure of the cement column.

High Pressure Squeeze. Channels that are located behind the casing may not be connected to the perforations. These micro annuli may allow gas flow but not cement slurries. In cases like this a high pressure squeeze will be performed to enlarge these channels so that cement slurries are able to enter. A high pump rate generates large fractures which means that large cement volumes are required, however the location and direction of the fractures cannot be located. It is known that extent of the induced fracture is a function of the pump rate applied after the fracture is initiated (Nelson 2006). To reduce fracture initiation pressure, a wash with high fluid loss rate such as, water or weak hydrochloric acid (HCl) solution, should be pumped down beforehand to open the smaller fractures and clean the perforations and the cement path.

Running Squeeze Method. This method is done by pumping cement slurry continuously down into the hole until final desired squeeze pressure (either above or below the fracture gradient) is attained. When the pumping stops the pressure is monitored and if a decrease in pressure is observed more cement is pumped to attain the desired squeeze pressure. This continues until the well maintains the desired pressure for several minutes without having to add extra cement slurry injection. The cement slurry volume that has to be injected is usually large.

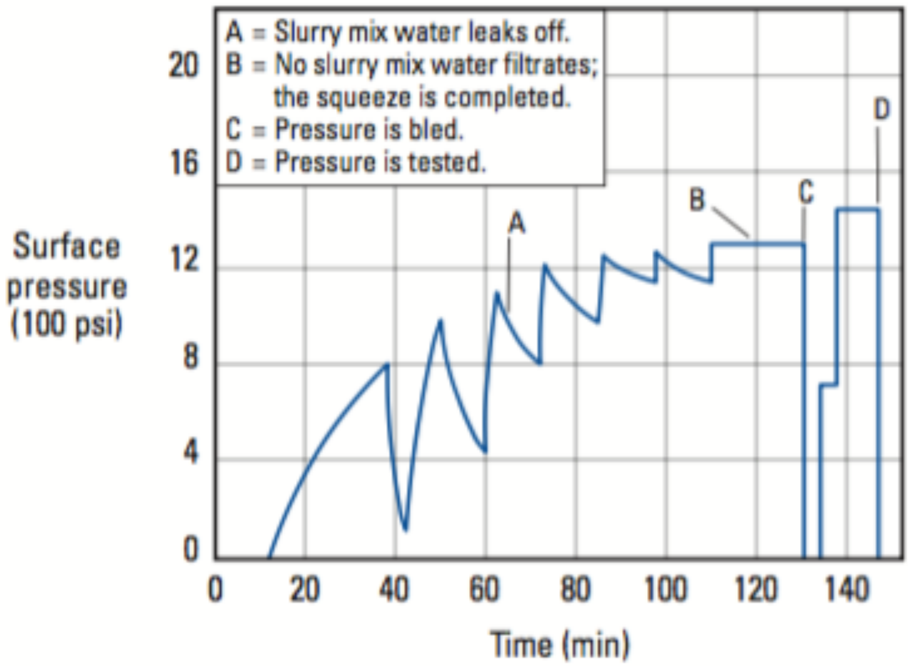

Fig. 4—Hesitation squeeze pressure behavior (Daccord et al 2006)

Hesitation Squeeze Method. When performing a squeeze cementing job the cement filtrate that leaks into the formation is lower than the minimum pump rate of most field equipment. This means that maintaining constant differential pressure is nearly impossible, especially when you do not want to exceed the fracture pressure gradient of the well. The hesitation squeeze method is an intermittent application of pressure. Cement slurry is pumped at a low rate by an interval of 10 to 20 minutes for pressure falloff caused by filtrate loss to the formation. The initial leak off is normally fast. As the filtercake builds up the applied pressure will increase and filtration periods will become longer. The difference between initial and final pressures will become smaller, and at the end pressure falloff will become negligible (**Fig. 4**). The cement slurry volumes necessary for this technique is usually much less than what required for the running squeeze method.

Bradenhead Squeeze. This is a low pressure squeeze technique that is performed without a packer. It is usually practiced when there are no doubts concerning the casing's ability to withstand the squeeze pressure. There are no special tools involved and it is performed by running an open ended tubing to the bottom of the zone that is to be cemented. The Blow-out preventer (BOP) rams are closed over the tubing and an injection test will be performed. The cement slurry is then subsequently spotted in front of the perforations (**Fig. 5**). When the cement slurry is in place the tubing is pulled out until it is above the cement top. The BOP rams are again closed and pressure is applied through the tubing. This method is frequently used because of its simplicity.

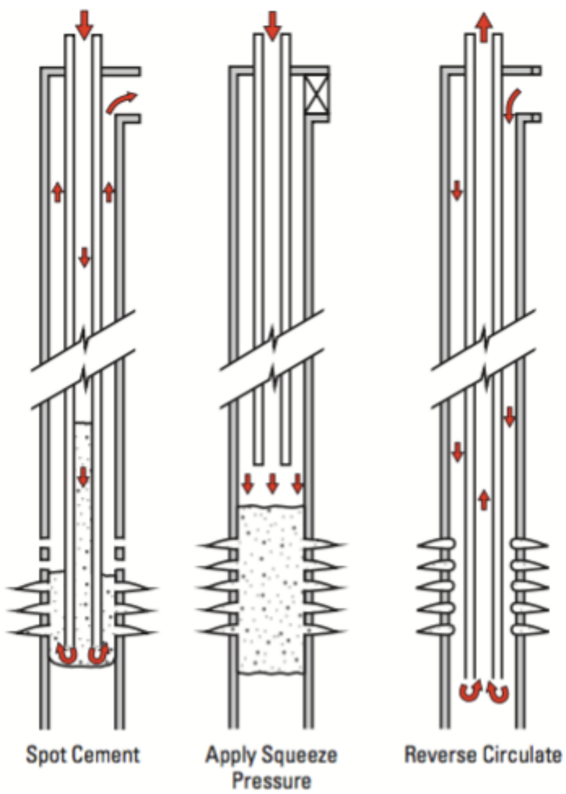

Fig. 5—Bradenhead squeeze technique (Doccard et al 2006)

Squeeze-Tool Placement Technique. This placement technique can be divided into two parts, the retrievable squeeze packer method and the drillable cement retainer method. The retrievable squeeze packer method is done with a compression or tension packer that has a bypass valve to allow circulation of fluids while running in the hole, and after the packer is set. It also helps prevent piston and swabbing effects while running in or out of the hole. The packer allows for tool cleaning after the cementing operation is finished and reversing out excess cement slurry without excessive pressure. It is available in different designs and features to best fit the conditions and it has the ability to set and release multiple times which allows for more flexibility. Drillable cement retainers are drillable packers that are equipped with a valve that is operated by a stinger at the end of the work string. It is used to prevent back flow when no cement dehydration is expected or when a high negative differential pressure may disturb the cement cake. When cementing multiple zones the cement retainer isolates the different zones and one does not have to wait for the cement to set before starting on the next zone. This method gives the operator more confidence of placing the packer closer to the perforations and a smaller volume of fluid below the packer is displaced through the perforations ahead of the cement slurry.

3 Geothermal Energy

Geothermal energy is an energy source coming from the inner part of the earth. It is a renewable energy source that is highly available. It is known as heat that emanates from the earth by either the heating of ground water fairly close to the surface by an intrusive mass of hot rock, steam generation from reservoir of metamorphic rock or water vapor escaping and migrating from molten or semi-molten rock, such as magma, at a considerable depth (Ostroot 1964). Geothermal systems are classified with no temperature below 100°C (212°F) at economic depths. The temperature of the system may vary from 100°C (212°F) all the way up to 400°C (750°F). These systems are mostly found where the geothermal gradient is above the normal (25°C/km [1°F/70ft]) (Dickson *et al* 2004). The plate margin areas are examples where the geothermal gradient is significantly higher than the average, examples of these are, California, Oregon and Utah, USA, Iceland, New Zealand, Italy and The Philippines. Locations of high geothermal gradients are marked in red in **Fig. 6**. The first attempt of using the heat generated by steam from wells was made in Italy around the beginning of the 20th century. Since then it as been utilized world wide and become a highly economically competitive energy source. The US is the worlds largest producer of geothermal power. Iceland, New Zealand and The Philippines are countries that has had a large increase in utilizing geothermal energy over the past years. The Philippines is now the second greatest nation to produce electrical power from geothermal energy.

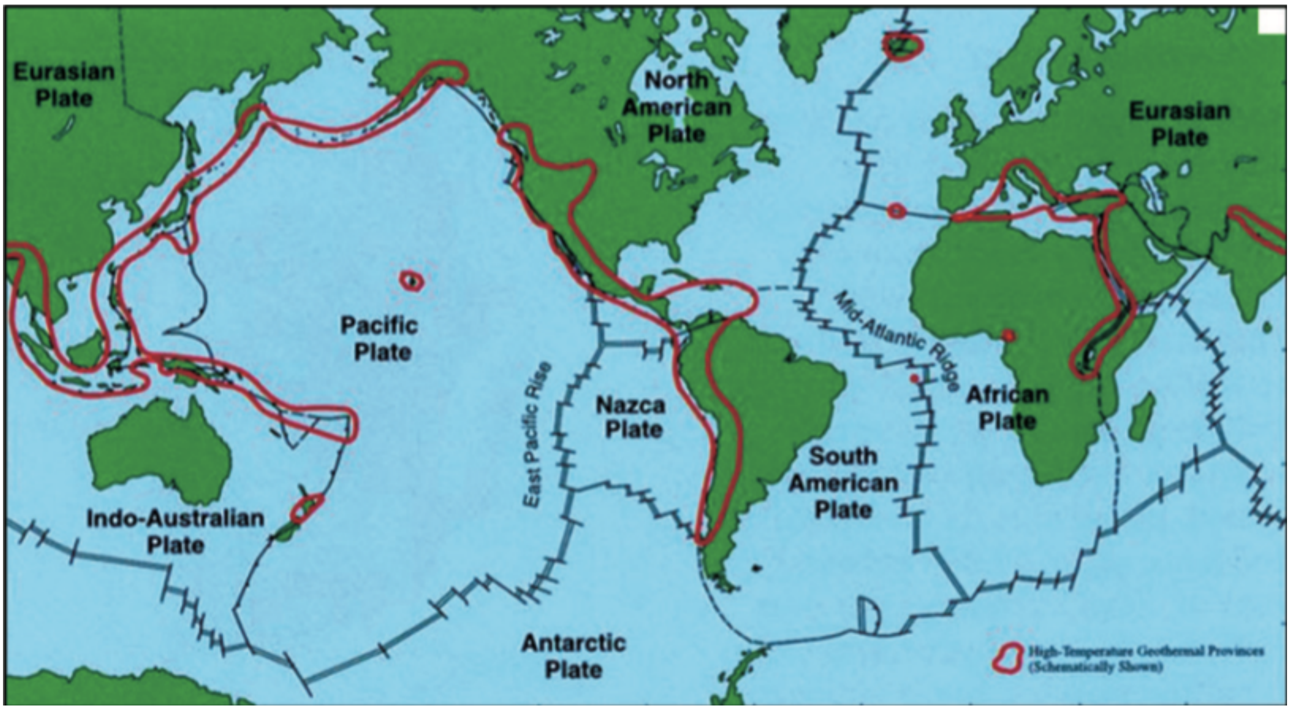

Fig. 6—High temperature geothermal locations worldwide (Salim and Amani 2013)

3.1 Geothermal Steam Wells

Geothermal steam wells are wells that are drilled to exploit the heat generated from inner parts of the earth. They utilize the superheated formation water that lies above the geothermal formation by producing it to the surface and then «flash» it into steam by the use of a flash tank (**Fig. 7**). The steam encountered is used to power a turbine and generate electrical power. The formation waters are often highly saline and corrosive and do often contain toxic heavy metals. It is therefore injected back into the reservoir for environmental reasons (Nelson *et al* 2006).

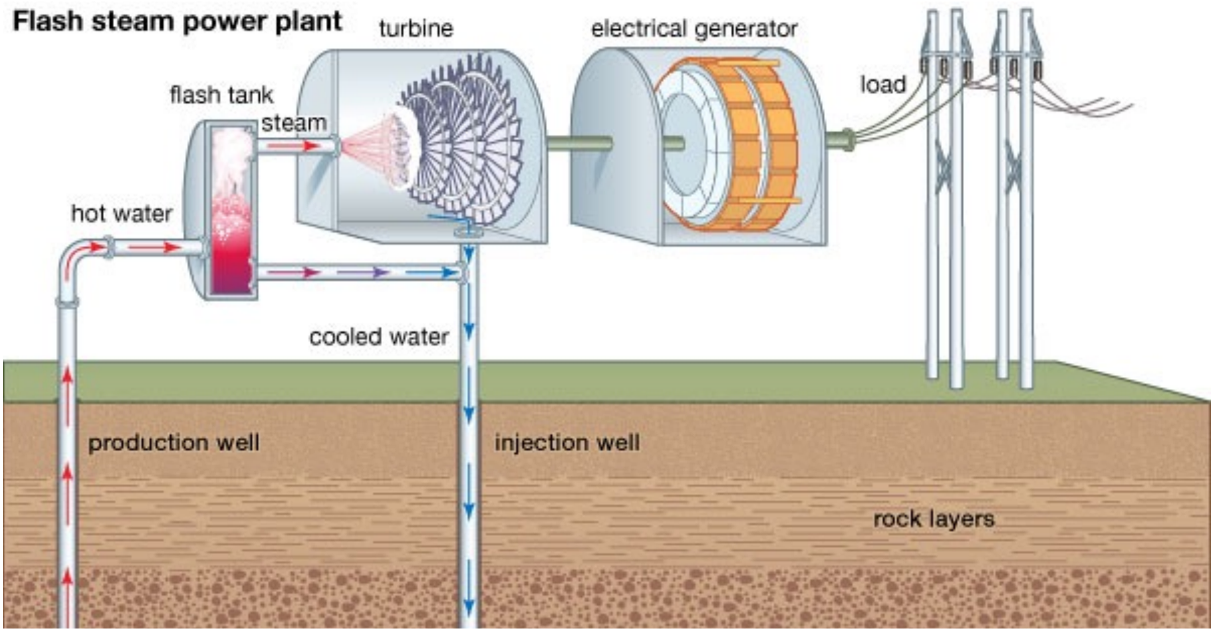

Fig. 7—Flash steam power plant (Lund 2015)

Hot dry rock is a different type of geothermal steam well where the formation temperature is unusually high, but it does not contain any formation water. Two intersecting wells are drilled into the geothermal formation and water from the surface is pumped down one of the wells and become superheated by the formation (**Fig. 8**). The water is then produced out from the other well and «flashed» into steam which is used to generate electrical power (Nelson et al 2006).

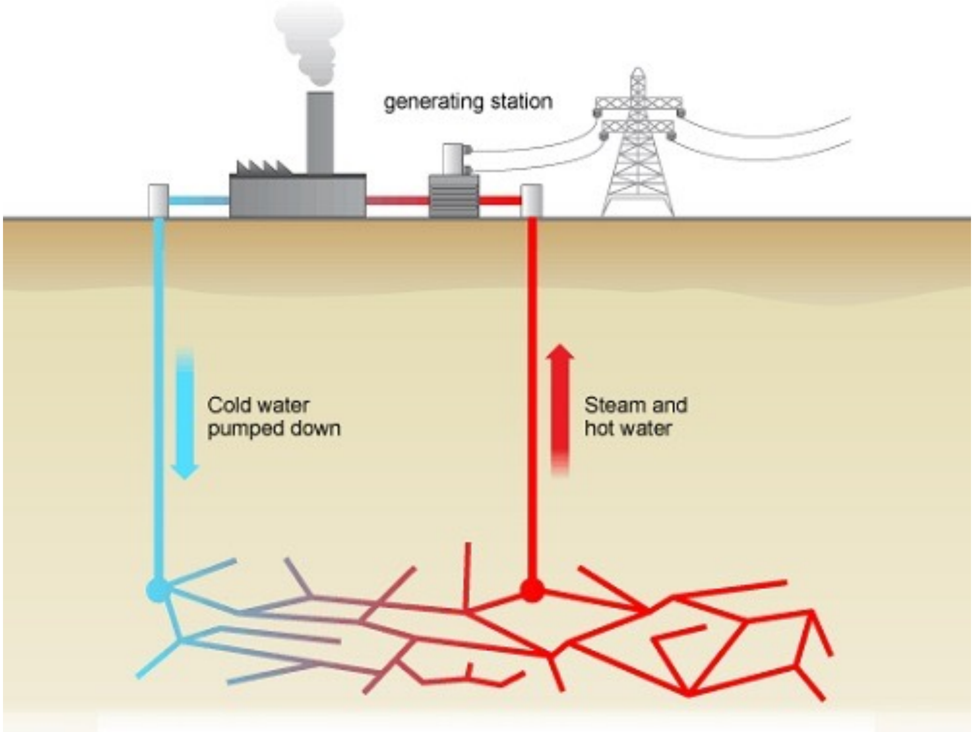

Fig. 8—Hot dry rock geothermal steam well (Geothermal Energy Development 2016)

3.2 Challenges in Completing Geothermal Steam Wells

Geothermal steam wells are usually drilled and completed in the same manner as oil and gas wells, however the environment the cements and casing must contend is frequently much more severe. Failure of geothermal wells in several geothermal fields has been directly attributed to cement failure. As a result of this a lot of research has been conducted to identify cement formulations that perform suitably under such conditions (Nelson et al 2006). The drilling program in such wells call for setting surface- and production casing above the reservoir and it is required to cement the casings all the way up to the surface. This is to prevent casing creep or elongation because of thermal expansion when the well is brought to production.

3.2.1 Increased Thickening Time

Even though the bottomhole temperature in geothermal steam wells can reach up to 370°C (700°F) most of the geothermal steam wells are not cemented under these conditions. The fluids circulated during drilling will cool the well significantly and the bottomhole circulating temperature (BHCT) usually does not exceed 116°C (240°F) so adequate thickening time of the cement is not the major problem (Nelson et al 2006). The large temperature fluctuations the cement slurry undergoes while pumped down the casing and displaced up the annulus are severe and combined with highly fractured formations makes the use of extenders and retarders almost mandatory to make sure the thickening time is modified to best meet the geothermal conditions (Nelson et al 1981).

3.2.2 Strength Retrogression

One of the major concerns when completing geothermal wells is the strength stability in cementing (Ostroot 1964). When Portland cement is exposed to high temperatures it undergoes strength retrogression. This is characterized by the breakdown of the set cement matrix. Above a certain temperature (110°C [230°F]) the basis of compressive strength, the C-S-H-phase, in Portland cement converts to crystalline alpha-dicalcium silicate hydrate, α-C_2SH. This compound is far more dense (lower bulk volume) than C-S-H and a shrinkage within the cement will occur. This results in an increase in cement porosity and water permeability, and hence a decrease in the cement's compressive strength. A study demonstrated by Caritey and Brady (2013) showed that several weighing agents such as hematite, hausmannite and titanium oxide, were not stable at curing temperatures of 302°C (575°F) and 122 MPa (17,680 psi). Observations of analytical data showed that these metal oxides react with xonotlite causing a decrease in strength and an increase in water permeability. The result of this is loss of zonal isolation and pipe support, whom again impacts the operational life span of the wellbore and its eventual abandonment (Gibson 2011). This is why the cement has to be designed with a compressive strength of no less than 7.0 MPa (1,000 psi) and no more than 0.1 mD water permeability (Nelson *et al* 2006).

3.2.3 Thermal Shock

Thermal shock can occur when cement sheath and/or casing is in direct contact with superheated steam or fluid that passes through. It can cause thermal expansion of the casing and stress cracking in the cement. This will damage the bond between the cement and casing, and hence cause the cement to eventually fail over time (Berard et al 2009).

Cement shrinkage or expansion can occur when cement is exposed to harsh geothermal environments over time. The in-situ phase transformation and excess growth of crystalline hydrothermal reaction products is the cause of this (Berard *et al* 2009). Cement expansion or shrinkage is a problem because it impose internal stresses, followed by the initiation of cracks. Cement is used for its ability to avoid the creation and effects of stress and it is therefore required that the slurry is able to withstand tough conditions.

3.2.4 Lost Circulation

The most serious obstacle to successfully cement a geothermal well, is lost circulation. The formation reservoirs are often highly fractured and the integrity of the formation ranges from poorly consolidated to highly fractured and the formation fracturing pressures tend to be low (Salim *et al* 2013). It is common to have losses in the casing strings set above the target reservoir and in many cases total losses occur before the intended setting point for the intermediate string (Nelson *et al* 2006). Lost circulation is very costly, because of large amounts of cement slurry is lost to the formation.

3.2.5 Cement Corrosion

The chemistry of the formation fluids plays an important role on the cement composition and performance in geothermal wells. The formation fluids are usually highly corrosive brines containing large amounts of sulfate and carbonate. The geothermal formations often contain high amounts of carbon dioxide (CO_2) which increases the chances of carbonation of the cement.

Cement Corrosion Caused by Cement Quality. If several poorly chosen cement additives are used in the slurry composition, insufficient conversion of calcium oxide (CaO) and magnesium oxide (MgO) during cement manufacturing process will happen. This results in a high free-lime (CaO) or periclase (free MgO) content of the clinker. The hydration of these compounds after cement setting may cause destructive expansion within the cement with the production of calcium hydroxide ($Ca(OH)_2$) and magnesium hydroxide ($Mg(OH)_2$). This combined with reactive silica aggregates results in a gel, increasing in volume by taking up water, and so exerting an expansive pressure that results in cracks throughout the cement matrix (Brandl *et al* 2010).

Cement Corrosion Caused by Expansive Attack. An expansive attack of the cement happens when the corrosive fluid penetrates the cement pores and forms voluminous water-insoluble products. As these insoluble crystals increase in size, they create high pressures inside the set cement, resulting in cracks, fractures, and fragments in the cement sheath. The most known expansive attack is the attack by sulfates. Sulfate containing formation fluids penetrate into the pores of the cement sheath and reacts with the tricalcium aluminate ($Ca_3Al_2O_6$) phase of the cement and its hydration products to form secondary or delayed ettringite ($Ca_6Al_2(SO_4)_3(OH)_{12}\bullet26H_2O$) crystals whom eventually will fill the cement pores. The ettringite crystals may reach sizes up to 50μm that will cause internal pressures until the cement sheath eventually cracks. The sulfate may also react with portlandite to form secondary gypsum crystals ($CaSO_4\cdot2H_2O$) whom creates the same problem (Bradl *et al* 2010).

A different expansive attack is by magnesium containing formation fluids that precipitate under high pH conditions in the pores of set cement or react directly with the portlandite to form brucite ($Mg(OH)_2$) by ion base exchange. The formation of expansive brucite induces mechanical stresses in the set cement, eventually resulting in destruction (Brandi *et al* 2010). The magnesium will replace the calcium ions in the C-S-H phase of the cement matrix causing strength retrogression and ultimately complete deterioration of the cement sheath. Research has shown (Bradl et al 2010) that the cement will suffer from severe expansion deterioration and loss in integrity only after 6 months in the presence of magnesium chloride ($MgCl_2$), unless it is resistant to such attacks.

Cement Corrosion Caused by Dissolving Attacks. Dissolving attacks are known as attacks where the cement is exposed to corrosive fluids that create water soluble products that eventually cause the cement to leach from the surface (Brandi *et al* 2010). Such attacks may happen during reservoir stimulation with acids, such as hydrochloric- (HCl) and/or hydrofluoric (HF) acid. Conventional set API cements are not able to withstand acidic conditions and will dissolve over time with decreasing pH. Portlandite becomes unstable with a pH below 12.6 and will leach out first. At pHs below 8 the C-S-H phase becomes destabilized by leaching off Ca^{2+} ions and form amorphous silica (SiO_3). The remaining amorphous silica will form a protective coating, that will slow the acid reaction rate, however this coating may be washed away during dynamic conditions.

Cement Corrosion in the Presence of CO_2. The presence of CO_2 is becoming more common (used in enhanced oil recovery, reinjection and/or storage for environmental purposes). The most common concentration of CO_2 in the formation is 5 to 30 vol%, but research has shown that just the presence of CO_2 at elevated temperatures may cause serious problems (Brandl *et al* 2010). The reactions involving CO_2-attacks are thermodynamically driven, i.e. the kinetics depends on temperature given conditions. The CO_2 may boil off from the producing zone, and since the formations are usually highly porous, it can migrate upwards until it is trapped by an overlaying aquifer and dissolves in the water (Milestone et al 2012a). Corrosion of cement in the presence of CO_2 is a special case of dissolving attack and it consists of three sequential steps.
(1) Formation of carbonic acid (H_2CO_3) in the presence of dissolved CO_2 in the formation water; (2) Carbonation of the cement components: H_2CO_3 penetrate the cement matrix and preferentially reacts with portlandite, converting it into calcium carbonate ($CaCO_3$) and water. The production of $CaCO_3$ reduces the pH from 13 to less than 10 and allows the H_2CO_3 to further react with the C-S-H phase to form $CaCO_3$ and amorphous (porous) silica. The carbonation of portlandite is believed to act faster than of the C-S-H phase of the cement, because $CaCO_3$ has a higher molar volume than portlandite (+11%). The total pore volume is reduced and so the permeability of the cement matrix is initially decreased by carbonation; (3) Leaching and deposition process: further H_2CO_3 reacts with the already formed $CaCO_3$ to convert it into calcium bicarbonate ($Ca(HCO_3)_2$), which is highly water soluble and can be leached out of the cement matrix easily (Brandl *et al* 2010). This leads to an increase in porosity and permeability of the cement, and may result in cement failure over time (Salim *et al* 2013).

4 Solutions for Cementing Geothermal Wells

As presented in the previous chapter, cementing geothermal wells, is very challenging, on all aspects of the operation. The extreme temperature influences the thickening time of the cement slurry which again may influence the placement technique and slurry composition. Geothermal formations are often highly fractured or poorly consolidated and lost circulation is destined to happen at some point during pumping of the cement slurry. Aside from being fractured the geothermal formations often contain formation fluids that are highly corrosive and often contain serious amounts of CO_2 which affects the performance of the cement after it has been set in the annulus. This chapter will have a closer look on solutions that has been tried out to withstand the conditions met in geothermal well cementing.

4.1 Slurry Composition

Modification of cement slurry by adding chemicals and/or additives is the first thing the operator can do to best make sure the cement slurry is well suited for the well conditions. Well parameters such as wellbore geometry, temperature, formation characteristics, formation pressure, and depth are important to consider when designing the cement slurry (Crook 2006). Important well tests should be taken beforehand to make sure the cement composition is possible to perform from when it is set in the annulus and until the well undergoes production and eventually its abandonment.

4.1.1 Addition of Silica Flour and Silica Sand

The addition of silica flour or silica sand to Portland cement is probably the most widely used modification in cement composition to ensure it can withstand the geothermal well conditions. Regardless of the type of well, geothermal steam-, steam injection-, thermal recovery- or oil wells, at temperatures above 110°C (230°F) there is a definite need for an appropriate amount of chemically reactive silica as strength stabilizing agent (Ostroot 1964). API specifications recommend a 40% by weight of cement (BWOC) of silica flour to the cement compositon. Silica is added to prevent the cement to undergo strength retrogression and increased permeability over time (Hole 2008).

Portland cement will slowly crystalline into a series of high CaO/SiO_2 ratio phase which have high porosity and low strength. This crystallization is better known as strength retrogression. The CaO/SiO_2 ratio of Portland cement varies with temperature, it becomes silica rich when the temperature increases and hence more calcium hydroxide ($Ca(OH)_2$) is formed. To avoid this silica flour (quartz) is added to allow low CaO/SiO_2 ratio phases, such as tobermorite and xonotlie to form. Tobermorite is the binder phase in autoclaved fibre products while xonotlite act as an insulator and porous support for acetone in acetylene cylinders. These compounds have a low porosity and high strength (Milestone *et al* 2012a). Examples of the effect silica fume and silica flour has on compressive strength and permeability of the cement system is illustrated in **Fig. 9**.

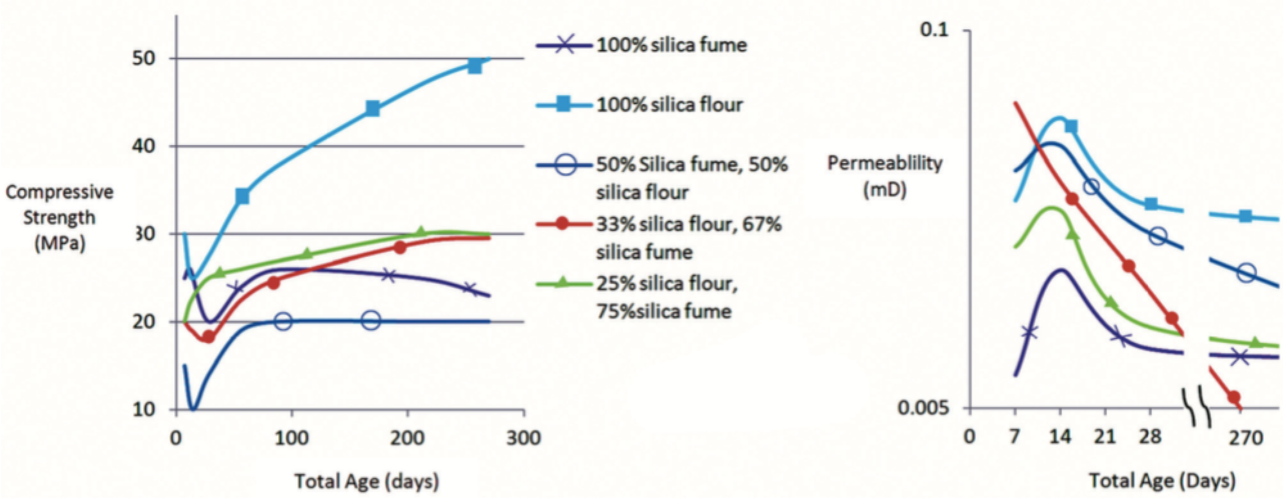

Fig. 9—Effect of compressive strength and permeability behavior of silica-stabilized portland cement system, containing various amounts of silica fume (Salim and Amani 2013)

Several studies (Hole 2008, Milestone *et al* 2012a, Milestone *et al* 2012b, Salim *et al* 2013) have proven that the presence of CO_2 in the formation influences the amount of silica BWOC added to the cement composition. Studies from New Zealand fields, Ohaaki and Rotokawa, has showed that in any Portland cement based system the carbonation rate is dependent on the volume of available calcium in any unit volume and particularly by any calcium hydroxide ($Ca(OH)_2$) present (Milestone et al 2012a). The carbonation resistance is enhanced by a low addition of silica and low water/solids ratio mixes. The carbonation of $Ca(OH)_2$ to calcium carbonate ($CaCO_3$) is either expansive or non-expansive. Expansive carbonation tends to block the pores while non-expansive leads to increased porosity. Whether the carbonation is expansive or non-expansive depends on the formal molar ratio of CaO to SiO_2 (Ca/Si) ratio of the solid hydrate with the neutral point being compounds around Ca/Si ratio equal to 1.5 (Milestone *et al* 2012a). A study done by M. Milestone in New Zealand in the 1980s showed that carbonation of the silica caused cement with higher concentrations of silica to rapidly develop a higher porosity and concluded that if high contents of CO_2 is present in the formation a lower percent of silica BWOC in the cement slurry is preferable (Hole 2008). To retain thermal stability the 40% of silica flour BWOC should be decreased to 15-20% to make sure the cement is not susceptible to attack by the CO_2 present in the formation. An alternate cement composition to prevent carbonation by CO_2 in the formation is calcium phosphate- or calcium aluminosilicate cements. Both of these are more resistant to CO_2 attacks and they have been used with success in Japan and Indonesia since the late 1990s (Salim *et al* 2013).

4.1.2 Use of Calcium Aluminate Phosphate Cement

The corrosion process of Portland cement reduces the cement sheath-volume and increases the incidence of annular and casing communication of well fluids present in the formation. Calcium aluminate phosphate (CaP) cement was first used successfully in the Salton Sea Field of Imperial County, California to enhance long-term zonal isolation in a geothermal well that contained corrosive formation fluids and CO_2 (Berard et al 2009). Earlier attempts to prevent corrosion of Portland cement has been to add pozzolanic materials (fly ash) and/or latex, however this has not had a sufficient effect. **Fig. 10** illustrates the weight loss of Portland cement- and PaC cement systems at 60°C (140°F) in solution of carbonic acid and sulphuric acid.

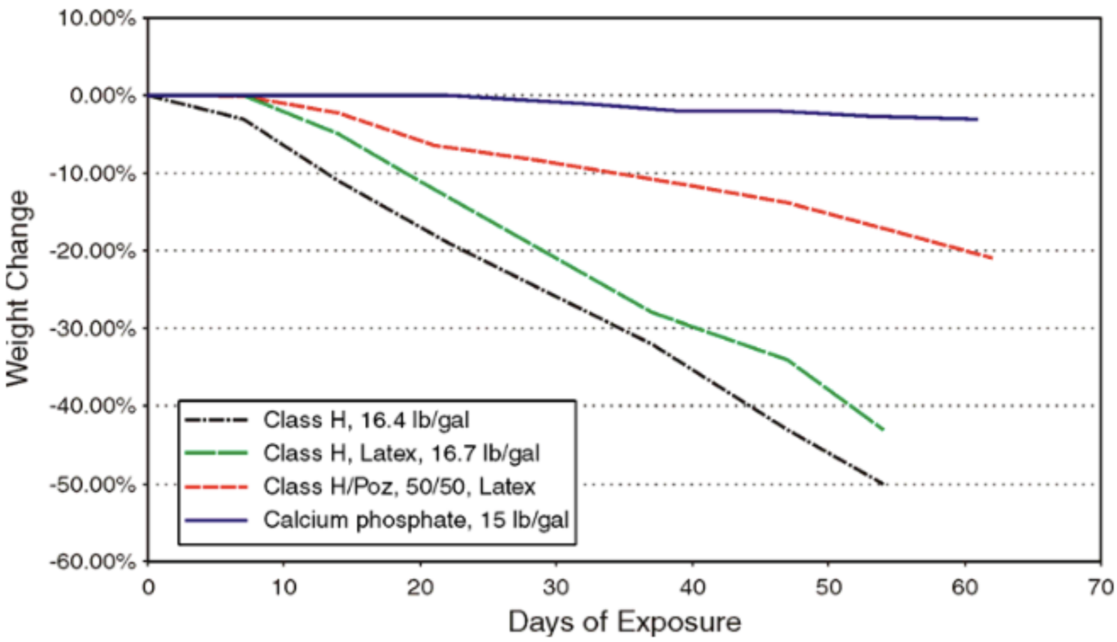

Fig. 10—Weight loss of CaP and Portland cement systems at 140°F in a solution of carbonic acid and sulphuric acid (Bernard et al 2003)

CaP cement is a blend of high-alumina cement (HAC), phosphate and fly ash and has been proved to act sufficiently at temperatures from 60°C to 371°C (140°F to 700°F) by laboratory tests (Berard et al 2009). The crystalline hydrothermal reaction products, hydroxyaplite, boehmite, hydrogarnet and analcive, are responsible for the strengthening, densifying and corrosion resistance of the cement system. Laboratory test showed that the most efficient way of reducing cement slurry density was to inject either air or nitrogen gas (N_2) and that the foamed CaP cement developed a higher compressive strength and lower porosity at (elevated temperatures) than Portland Class G cement with similar densities (Berard et al 2009). However the CaP is very costly and sensitive to contamination with Portland cements and has to be handled separately, which requires for extensive planning and logistics (Brandi et al 2011).

4.1.3 Acid Stimulation Resistant Cement

Research has shown that Portland cement resistance to acid may be increased by 700% when substituting for the cement with greater amounts fly ash in conjunction with the use of liquid-latex dispersion (Brandl et al 2010). An acid resistant cement is preferable where mud-acid systems are being used to stimulate sandstone reservoirs. The fly ash eliminates acid-susceptible portlandite, which reduces the permeability of the set cement, and partly replaces Portland cement with relatively chemically inert siliceous materials. The addition of latex allows it to form an artificial barrier between the cementitious phases and the attacking fluid. Tests proved that pretreating a neat cement mixture of 10% acetic acid and 1.5% HF lead to a protective layer of calcium fluoride (CaF_2) whom significantly improved the resistance to mud-acid attacks (Brandl et al 2010). The weight loss of the pretreated neat cement in mud-acid conditions at 65.5°C (150°F) after two hours was only 2 wt% compared to 32 wt% for the untreated cement. It is therefore recommended to pretreat the cement with a pre-flush of acid before stimulating the reservoir, to protect it from severe acid corrosion.

4.1.4 Addition of Waste Recycled Glass Powder

The use of recycled glass powder creates a great advantage in cement slurry for geothermal wells. It validates as a pozzolanic material when added to cement slurries. Pozzolanic materials are normally byproducts from other industries or naturally occurring materials like fly as from thermal power plants or silica fume waste from silicon industries etc. Waste glass powder is a non-recyclable waste product that acts as a pozzolan material when added to the cement slurry. It creates a great advantage when added to the cement because it prevents strength retrogression at high temperatures and reduces the waste disposal burden on the environment (non-recyclable) (Pandev *et al* 2014).

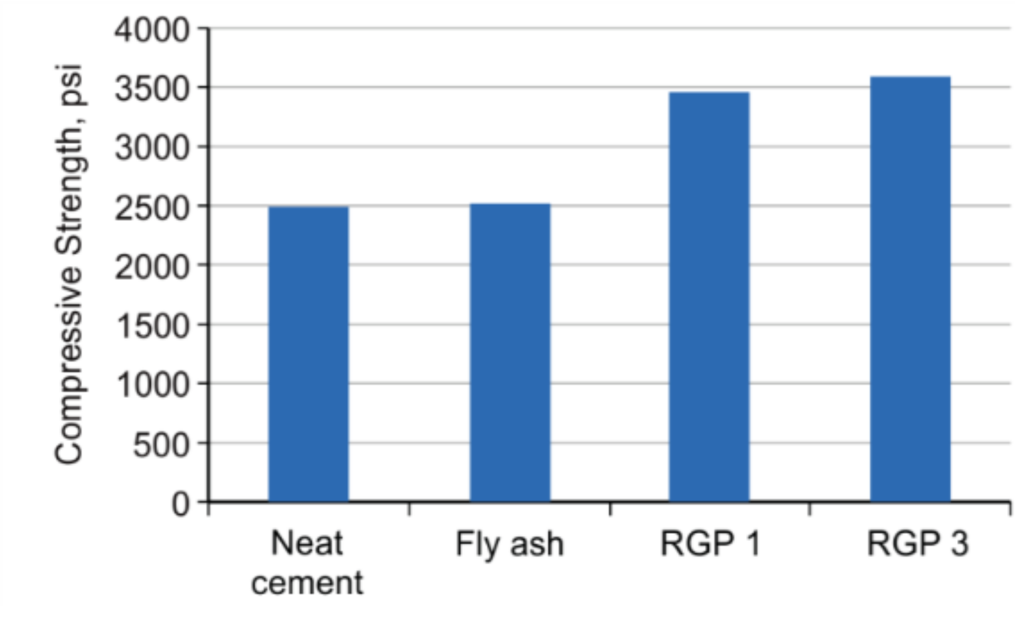

Fig. 11—Compressive strength development at 190°F with 50% BWOC fly ash, soda-lime silicate (RGP1), and borosilicate (RGP3) (Pandey et al 2014)

The waste glass powder contains amorphous silica and alumina which hardens similar to cement when reacting with lime in the presence of water. This leads to prevention of strength retrogression. The study done by Pandev et al (2014) showed that the cement slurries containing higher values of soda lime- and borosilicate glass bubbles showed better compressive strength. The research also proved that the glass did not only work as a filler, but also takes part in the hydration reaction and exhibits pozzolanic behavior. **Fig. 11** shows that the addition of glass bubbles to the cement slurry developed a higher compressive strength than 30% BWOC fly ash and neat cement.

As seen in Fig. 11 the 50% BWOC borosilicate glass bubbles provided the best compressive strength. Pander et al (2014) compared this solution to 50% BWOC fly ash slurry to compare the strength development over a longer time. **Fig 12** shows that the borosilicate system already after 24 days exhibited a 11.03 MPa (1,600 psi) higher compressive strength than the slurry containing fly ash.

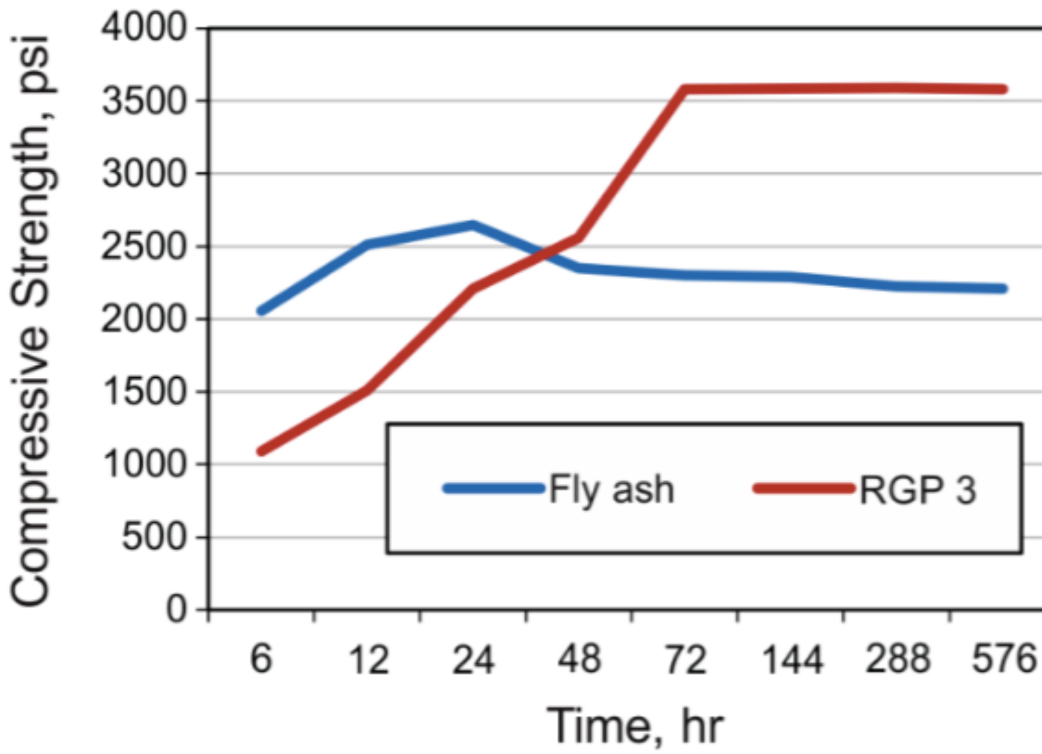

Fig. 12—Compressive strength developments for longer duration (Pandey et al 2014)

4.1.5 Addition of Fibres to Cement

Generally it is required that the cement has a compressive strength of no less than 7.0 MPa (1,000 psi) (Nelson et al 2006) when used in geothermal wells, however this does not cover all the stresses the cement must withstand. Loading scenarios in an operational well will produce several stresses that are not limited to compressive stresses (Berndt et al 2002). This is why the addition of fibres to cement are of potential value because they have a better ability to withstand higher tensile stresses than conventional cements.

Research done by Bernt et al (2002) showed that the addition of round steel fibres could successfully be added to latex- and lightweight cements to increase the tensile. and compressive strength. The inclusion and magnitude of the increase depends on the type of fibres used and the fibre volume fraction. The most significant improvement was achieved by using 13 mm (0.512 inches) long round steel fibres and at relatively low volume fractions of 0.5-1% (Berndt et al 2002).

4.1.6 Foamed Cement Systems

Geothermal formations tend to be poorly consolidated and highly fractured. They usually have a low fracture gradient, which means that the operator has to be careful when pumping the cement slurry. To prevent fracturing the formation even further, lost circulation and severe fluid losses to the formation, light-density cement systems have been developed.

One of the most common lightweight cement systems are foamed cement. N_2 is injected to the ready-mix cement before it is pumped down to create a lower density of the cement. The foamed cement has a higher tensile strength (even at higher temperatures) than Portland Cement whom often suffers from a low tensile strength when exposed to high temperatures. By increasing/ decreasing the amount of N_2 injected controls the density of the cement (Salim et al 2013).

If the lost circulation zone is found above the production zone of the well, it requires for a complex cement job. The production zone has to be completely isolated from the upper intervals to ensure ultimate production of the well. In cases like this glass bubbles are often used as the material to lower the cement density to prevent fluid loss to the formation. The glass bubbles are available in two different grades and in general the glass bubbles that make the highest density are the weakest. Caution in pumping pressure should be made, if the pressure is increased it might cause the bubbles to break, which will increase the slurry density (Salim et al 2013).

4.2 Pumping and Placement Techniques

Low fracture gradients and poorly consolidated formations combined with increased thickening time of the cement slurry because of the extreme temperature has required the operators to develop new pumping- and placement techniques.

4.2.1 Reverse Circulation Method

For conventional circulation cementing techniques the cement must be pumped around the well bottom. This is where the circulation temperature is at its maximum, However the temperature at surface is by far much lower. The first part of the cement slurry is often highly retarded to prevent early thickening when exposed to the high temperatures downhole while pumping. The high retarded loading make it practically impossible to set up at the cooler surface temperatures when it has reached the top (Bour and Russell 2013). To prevent this problem a study done by Moore et al (2003) suggested to perform a reverse circulation method. The reverse circulation placement technique (RCPT) was first tried out in Wyoming, USA by using a 4856 m (15 932 ft) string and showed positive results. More recently the method has been used in central California, USA.

Performing RCPT in geothermal wells are done pretty much in the same manner as the cementing through drill pipe method, only it is reversed. The primary reason why the RCPT is performed in geothermal well cementing is that the formations normally require a lower ECD (Bour and Russell 2013). By pumping the spacer and cement slurry directly down the annulus it reduces the pressure on the formation which again reduces the frictional- and hydrostatic pressures greatly. The cement is never lifted and it minimizes the need for excess cement in a given job. The method is less time consuming, wait-on cement is reduced because the retarder needed to place the cement can be tapered back as the job progresses (Bour and Russell 2013). RCPT allows for gravity-assist placement (slurry is pumped in the same direction as the gravitational force) and it allows for setting the cement at high temperature differentials. However the method is still relatively new, and little software exists to support the technique and the understanding of the drilling fluids used is way more critical (Moore *et al* 2003).

5 Case Studies - Cementing Solutions Worldwide

Contributions in developing advanced cementing systems for geothermal wells is still being done all over the world. Providing a lifetime good solution is still a challenge, especially when one solution provokes a new obstacle to overcome. As presented in previous chapters the cementing operation is a very critical step in well success and it can affect the production rate. A failure in the primary cement job may cause great financial losses in the form of remedial cementing operations, downtime and/or loss in production rate. Three different cases of geothermal cementing solutions have been studied to give an overview of what the industry have overcome and what challenges has to be met.

5.1 Advanced Geothermal Cementing System in Java

The Wayang Windu project is a project, operated by Magma Nusantra Limited, to develop geothermal resources within the contract area as illustrated in **Fig. 13**. The field is located 40 km south of Banding in West Java, Indonesia. The field is planned to develop up to 400 MW of electricity capacity over a period of 42 years, where each unit is scheduled to operate for at least 30 years. The project has the ability to deliver 650 MW of base-load electricity and the first phase power plant of the project has been producing since June 2000 and has the largest turbine in the world, delivering 110 MW of electricity into the Indonesian national grid.

Fig. 13—Map of Wayang Windu (Ravi et al 2008)

The phase one power plant gathers geothermal fluids from three well pads where 10 production wells are located. The fluid is transported to a centralized separator station, where steam is delivered to the power station by two main steam pipelines through two scrubbers located at the station boundary and brine and extra condensate is reinserted into the ground. Geothermal electricity generation has much lower greenhouse gas emissions than almost any other electricity generation. The project was certified by United Nations, and by potential revenue from CO_2 emission credits, it will generate greenhouse credits. This is the main reason that developments of phase two, a second 110 MW unit, was planned and well underway with completed drilling phase in 2007 and expected to be operational by 2009.

5.1.1 Operational Challenges

During developments of phase two it was decided to look at the operational challenges encountered in the phase one wells. It was early noted that the cement failure appeared because of thermal and/or corrosive effects. The geothermal temperature in Wayang Windu is depth dependent and varies from 255°C to 300°C (482°F to 572°F) and the wells were expected to experience extreme thermal fluctuations during their life. Casing inspection logs from 17 out of 21 wells from phase one, done only a year after the plant came to production, reported significant zonal isolation problems. These anomalies found are listed as a summary in **Table 1**. Although conditions are not ideal the phase one wells are still procuding, however a collaborative effort was made to ensure the wells in phase two were better completed to withstand the severe well conditions. A study of the possible causes for the failures in phase one were done and possible necessary measures to help prevent the issues were made.

Table 1—2001 Wayang Wind Phase I Wells Observed Anomalies From Casing Inspection Logs (Ravi et al 2008).

Anomaly Type	Number of Phase I Wells Suffering
Collapse	9
Buckling	10
Fluid Movement	4
Split/Parted Casing	4
Corrosion	3
Restrictions in Couplings	1
No Anomaly Reported	4

The primary cementing job of all the logged phase one wells were evaluated to ensure if this had something to do with the anomalies, especially the ones with zonal isolation problems. Typically the phase one casing strings (13 3/8-in and 20-in) were cemented in place and up to surface and conventional lead and tail cement was used to achieve this. Key facts observed with this solution was that lost returns were a feature of both drilling and cementing phase of well construction which made it impossible to cement all the way up to surface. Several attempts to backfill the annulus on these casing strings with multiple top-jobs were made. Lost circulation during drilling and cementing required for a relatively low displacement rate.

Trapped Fluid Effect. The leading anomaly for trapped fluid effect is casing buckling, 10 out of 21 wells inspected suffered from this, closely followed by casing collapse whom was found in 9 out of 21 wells inspected. Buckling of the casing string may not lead to complete failure of the well, however the contributing factors of casing buckling can lead to casing failure, such as temperature fluctuations, internal and/or external pressure- and density changes, washouts, slack off weight and/or long uncemented sections. Casing collapse on the other hand has a more serious effect on the operational life of the well. In severe cases a collapse may choke the well efficiency with 50% or more. A Collapse in thermal well may be caused by fluid liquid trapped in some way in the casing-to-casing annulus of a well, and as the liquid is heated it expands enough to exceed the collapse resistance of the casing. Multiple phase one top-jobs lead to fluid being trapped and void space left between the primary cement and the base of the initial top out cement job. Evidence proved that the large percentage of wells from phase one, suffering from collapsed casing, supported this theory.

Uncemented Channels in the Annulus. Observations showed that the low displacement rate and unproper mud displacement caused uncemented channels in the annulus. Maximizing drilling fluid displacement rate depends on condition of the drilling fluid, the use of spacers and flushers, movement of the pipe, centralization of the casing and maximizing the displacement rate. Generally it is not possible to optimize all five factors at once, and a trade-off between them may be required. The lost circulation during drilling caused limits in mud conditioner times and relatively low displacement rates to be used during the cement jobs. This lead to uncemented channels in the annulus filled with dehydrated drilling fluid. These observations is the likelihood of contributing in the high percentage of casing anomalies, either through the mechanism of trapped fluid expansion or possible asymmetrical loading of the casing, observed from the casing log inspections after a year in production. Channels like these may also be the reason for the occurring of wellhead growth, whereas the casing strings that are not bonded well to the cement sheath expands vertically.

5.1.2 Cementing Solution

From when the cement is set until it reaches production it can be subjected to a temperature increase of 150°C (300°F) and the well may be cycled through severe temperature changes several times. Conditions like this may cause the cement sheath to fail. In 2002 a method called, Finite Element Analysis (FEA), was developed to model conditions, like the ones in Java, and evaluate the «remaining capacity» of a cement sheath after being subjected to various operations. Remaining capacity is an estimate of how far the cement sheath is from its elastic limit (point of failure). Conclusions that lead to this methodology was that there are no one-size-fits-all solution, and that every unique situation must be examined individually to determine the best cement sheath solution for the given situation.

Since its development, the FEA methodology has been widely used world wide to model and examine the effects of predicted stresses on many different types of challenging wells. It also includes examination of planned geothermal-well cement sheaths and the expected failure mechanisms. When phase one wells were drilled the FEA was not recognized which lead to choosing conventional oil and gas cementing systems designed for short-term slurry placement properties and the sole mechanical property of compressive strength. It was observed that even with a completed conventional cementing to surface on phase one wells would still fail over time. However the failure of cement sheath may have occurred under the operational loadings in geothermal well environments anyways. FEA measures were implemented to avert anomalies when the 12 phase two wells were planned out. Two of the planned wells were to help feed phase one while the other 10 were to feed the new power plant. The measures that were implemented to eliminate anomalies on these wells are described below. The well inspection logs of phase one wells clearly indicated the need for focusing on the application of mud displacement, and hence the importance of proper mud removal. Best practices optimization on mud displacement on phase two wells were done with good results.

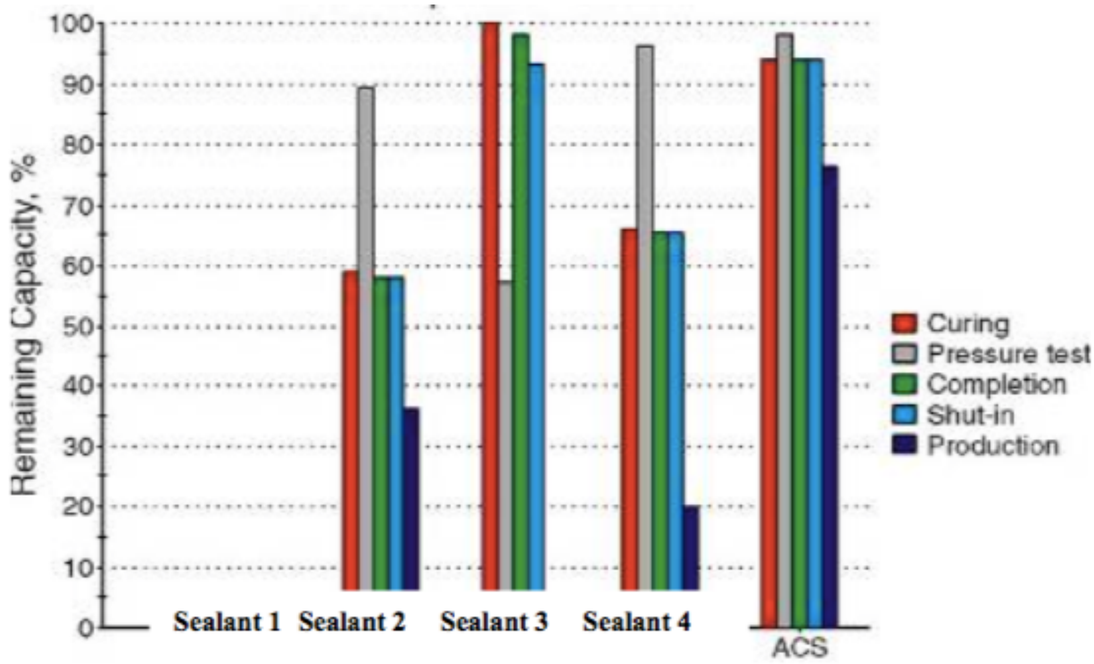

Fig. 14—Remaining capacity of different sealants for Wayang Windu Phase II (Ravi et al 2008)

Advanced Cement Systems. FEA-based modeling and analysis undertaken for an example phase two wells are illustrated in **Fig. 14**. Five different sealants were examined to compare the ability to withstand selected modeled operations. Sealant 1 failed after all loading operations. Sealant 2 and 4 had a fairly low remaining capacity and sealant 3 failed during well production modeling. Optimized elastic-thermal-cement system (ACS) was found to offer superior remaining capacity. The remaining capacity of cement sheath can be considered as a measure of safety factor (SF). The larger the SF the higher probability that the cement sheath will withstand the predicted cyclic well operations. A Portland based cement system was chosen for use in phase two wells on the project. A single cement system designed to suit the specific conditions of the project, optimized for geothermal temperatures and long-term mechanical properties.

The first well in phase two achieved production of 72 kg/s (158.8 lbm/s) dry steam at a wellhead pressure of 1500 kPa (217.5 psi). The well was directionally drilled to 1377 m (4518 ft) MD with a 12 1/4-in production hole. The production was from a two-phase widespread reservoir that overlies a brine reservoir in the northern part of the field. The production was equivalent to more than 40MW_e which according to public knowledge makes it the worlds largest capacity dry-steam well. Each of the other phase one wells, drilled from the same pad, produce on average only half as much as the first phase two well. Based on knowledge from the first phase two well, the originally planned wells were reduced from 10 to six.

Table 2 shows the wellhead growth (elongation) recorded from the phase two wells. The wellhead growth ranges from 1 to 7.4 cm (0.4-3 inches) which is significantly less than what was observed in phase one wells, whom had a casing elongation of 15-40 cm (6-16 inches). Both well 7 and 8 were cemented with conventional cementing system and have a larger wellhead growth, which concludes that the ACS system decreases wellhead growth and proves that proper mud removal is important. Well 1 and 2 had the lower liner string cemented with the ACS material and it was observed that these strings had an additional benefit in the ability to reduce the occurrence of lost circulation.

Table 2—13 3/8 Production casing elongation record for phase II wells (Ravi et al 2008).

Well	Elongation [cm]	Cement for Lower 13 3/8-in Liner	Cement for Upper 13 3/8-in Liner
1	7.4	ACS System	Conventional system
2	3.0	ACS System	Conventional system
3	1.0	Conventional system	ACS System
4	3.3	ACS System	ACS System
5	2.7	Conventional system	ACS System
6	4.9	Conventional system	ACS System
7	3.6	Conventional system	Conventional system
8	3.5	Conventional system	ACS System

Normally this type of geothermal well configurations would not make it possible to achieve cement slurry returns on the initial primary liner job and a liner lap squeeze would be necessary to provide cement courage in the liner lap. The first well where ACS system was used to cement the lower liner, some cement returns were noted during the primary cementation. The liner lap still required squeezing on the first well, however the fact that returns were noted provided some indication that the selected and optimized materials in the ACS system were possibly acting as a bridging agent. The next well that was cemented also achieved cement returns above the top liner and a good liner lap test to negate the requirement for the time and expense of a squeeze job.

The most important conclusions drawn from cementing the phase two wells in the Wayang Windy project was that careful applications of optimized ACS systems and performing the cement job according to best practices has improved the reliability of the wells. There is also evidence that some of the selected materials used to optimize the cementing system may help achieve full circulation of cement slurry where previously was not possible, which in long-term will contribute to the reduction of any remedial work.

5.2 Cementing HPHT Wells in Italy

For over 15 years HPHT wells have been drilled in Italy under challenging and often extreme conditions. Cementing HPHT wells require for special design attention, modified testing procedures and special additives to the cementing systems. The engineer should have encountered as much information as possible about the well conditions and any other problems that occurred during drilling. This case is a study of the difficulties encountered when designing, testing and executing HPHT cementing jobs. The Po Valley in Northern Italy is home to a number of HPHT wells, whereas two cases over a 15 year specter has been studied to illustrate the problem encountered solutions.

5.2.1 Operational Challenges

Designing the cement job for HPHT well conditions will require the use of a design simulator, prediction of BHCT using validated temperature software, specific laboratory testing to meet API guidelines, optimal mud removal, quality control of materials on site, and a contingency plan of things should not go as expected. A cement job design should have the following information prior to getting laboratory slurry report and recommendation; well description, temperature, mud characteristics, pore- and fracture pressure, and information about previous offset wells. The first step is to get as much knowledge as possible about the well structure, such as depth, hole size, casing hardware, and deviation. Another important factor to consider is wellbore irregularities, these may lead to an unproper mud removal, which will contribute to premature setting of the cement slurry and poor cementing bond.

Electric log data, field-validated computer simulation and mathematical calculations ensured that BHCT can be predicted. Knowledge of BHCT is essential to design a good cement job. Predicting BHCT and temperature ramps help ensuring a more precise laboratory test. The ramp time on a consistometer should be equal to the time the slurry is expected to go from the top of the well to the casing shoe, if the ramp temperature changes during pumping of the cement slurry premature cement setting can occur. It is also important to predict the operational time (the time it takes to pump and displace the cement slurry) to ensure that the cement slurry is designed with proper thickening time properties. A notable variation of thickening time was observed after changing the ramp temperature during laboratory testing, examples of when this occurred was when displacement rate or slurry pump rate varied and produced a designed ramp variation. It is very important to follow the laboratory test design during field operation because the depth, high temperature and high pressure can increase the chances of job failure even with the very best design in best possible circumstances.

5.2.2 Cementing Solution

The API classification systems are used as standards for cements used in the industry, however they may not fully cover HPHT conditions and considerations. Quality of the cement depends on raw materials and their manufacturing process. HPHT jobs in Italy are generally performed with API Class G or H cements (described in appendix A). By varying the cement-to-hydrate ratio improves the thermal behavior of the cement slurry. To better predict HPHT cement performance in the laboratory tests and improve the job quality in the field a better cement type was chosen. Normally HPHT slurries use a combination of Class G cement dry blended with 40% BWOC silica flour.

To maintain constant water-to-solids ratio in cement slurries, and hence prevent premature setting of the cement slurry, fluid loss control agents are added. The fluid loss during pumping should never exceed 100 ml in 30 minutes. Retarders are added to the slurry to modify the thickening time of the cement slurry. A small change in temperature may cause a serious change in thickening time of the slurry. Experience shows that synthetic high temperature retarders give a good result in HPHT conditions. HPHT wells usually require for a heavy mud system, usually barite is added. Barite has a high density, but requires significant amounts of water to wet the particle surface, which may lead to thick slurry rheology and reduce the cement's compressive strength. Barite also sets easily with water, which requires it to be dry blended with the cement. Hematite has been introduced to overcome the problems encountered with barite, however hematite also has to be dry blended with the cement.

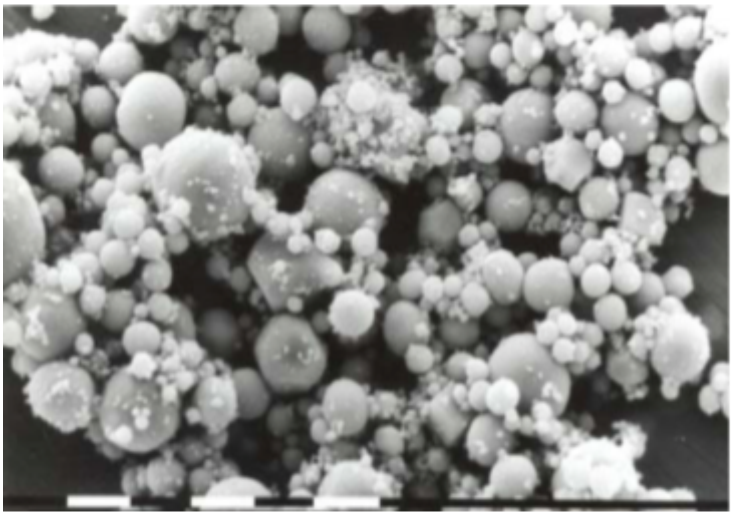

Fig. 15—1µm picture of oxide of manganese (Frittella et al 2009)

Dry blending additives to the cement may cause variations in the percentage as the dry powder is delivered to the cementing unit which makes it difficult to maintain consistent slurry density. Manganese tetraoxide (Mn_3O_4) has been introduced as a new water-dispersible additive illustrated in **Fig. 15**. It is a secondary product of ferromanganese manufacture available in large bags or bulk trucks. The manganese tetraoxide has a fine particle size (5 microns) which improves the suspension properties and enables a more uniform slurry density for improved well control. It can be added directly to the mixing water without severe settling of the material. Which is a great advantage if the cementing circumstances should change location for the job, saves time and money adding it directly to mixing water.

Proper mud removal is important to prevent cement contamination while pumping the slurry. Heavy spacers are generally used to maintain well control because a minimum overbalanced pressure should be maintained throughout the pumping of the cement slurry. It is important to consider density differences between spacer and cement slurry, each difference should be approximately 10%. Studies have shown that to ensure best possible mud removal, a turbulent flow with an annular velocity above 80 m/min (262 ft/min) and at least 200 m (656 ft) of the spacer should be pumped ahead of the slurry and 50 m (164 ft) behind to maintain separation from displacement and avoid slurry contamination. Different factors that will help to provide a good mud removal is casing centralization and proper flow regime and rate.

Cementing simulator, a computer software program, can be used to consider the effect fluid rheology and foresee displacement efficiency and annular velocity. It shows all the job parameters, such as flow behavior, annular velocity, and differential pressure, and by calculations, it can predict the ECD, percentage of casing centralization, thickening time and reynolds numbers. The software is basically used to optimize the cementing operation by recommending the best displacement rate and slurry density based on ECD behavior between pore- and fracture density line. Simulations can ensure that during the cementing operation the downhole pressure neither exceeds the fracturing pressure of the formation nor drops below the pore pressure.

Temperature simulator is a helpful tool to calculate BHCT, which is a function of flow rate, field history, heat capacity of steel, fluid inlet temperature, formation heat property, type of fluid, and rheology. The results from the simulation will show a temperature profile across the wellbore indicating possible hot spots in the formation and the BHCT. Hot spot temperature can be wherever along the wellbore and not necessarily at the shoe or well bottom, it may also differ from BHCT. The software stimulates follows the slurry or any other fluid's behavior from the beginning of the job until slurry placement. Fluid temperature values are reported in all its variations inside the casing and annulus. This helps predict slurry volume, displacement rate, and the BHCT can be used to achieve more realistic slurry laboratory designs.

Table 3—Comparison of slurry results (Frittella et al 2009).

Year	1991	2002	2002	2008
Job type	9 5/8-in liner	9 5/8-in liner	7-in liner	5-in liner
Depth	± 5400m	± 6000m	± 6700m	± 6200m
BHCT	132°C	139°C	145°C	171°C
Volume	140m^3	109m^3	13m^3	16m^3
Density	2.0 kg/L	2.15 kg/L	2.1 kg/L	2.0 kg/L
weight agent, BWOC	21 %	30 %	25 %	10 %

From 1991-2009 several HPHT cementing operations have been performed in Italy. Four different jobs have been studied to look at improvements and a summary of these are illustrated in **Table 3**. Manganese tetraoxide was first introduced in 1991 for a liner depth of ± 5400 m (17,717 ft) with a BHCT of 132°C (270°F). This was a large volume job, with 140 m^3 of 2.0kg/L (16.7 ppg) slurry. The most important improvement was the option to add the weighting agent directly in the mixing water, avoiding having to dry blend with the cement ahead of the job. This gave the job more flexibility, with respect to changing volume and slurry parameters up to the moment of mixing the slurry. In addition to this, the slurry appeared less viscous and was easier to mix, which maintained more stability.

The well drilled in 2002 consist of two jobs. Both jobs were done with a Portland Class G cement with 40% BWOC silica flour. The entire slurry was mixed and pumped on fly into an averaging tank and then pumped into the well with another cement unit. Two types of mixing water with all chemical additives were prepared before the job, after determining the exact volume from caliper logs. No problems were encountered during the execution of these two jobs. Designing these two jobs required for temperature laboratory testing and the main difficulty was to create a slurry that was compatible with the customer testing requests. To meet the desired specifications the cement supplier was changed, to obtain more consistent laboratory testing. After the change of supplier was made, the laboratory test results improved in quality, repeatability and speed. The well that was drilled in 2008 was initially a very critical job, however with the new supplied Portland Class G cement no problems were encountered during the job.

The addition of simulated data from laboratory tests are necessary for the designing and operation of cementing jobs in HPHT wells. The last years HPHT wells have been cemented in Italy without problems. The addition of manganese tetraoxide as a weighting agent has proven to allow for more flexibility in the cementing operation and also recuse the total storage for cement. Batch mixing is recommended because the slurry is sensitive to density variations and any fluctuations may reduce or increase the thickening time. Automatic cement control unit is recommended for large volume jobs to ensure the slurry density can be accurately controlled by a computer during the job. More consistent laboratory tests has proven that it is required with a 40% BWOC silica flour to the cement composition.

5.3 Cementing in Corrosive Well Environments

The main factors that are responsible for the corrosion of the cement sheath in geothermal wells are determined on the basis of laboratory tests and field analysis from literature surveys. A study of chemistry, mineralogy, and physical properties of API well cements and their mechanisms of corrosion in the presence of aggressive formation and injection fluids has become an important research. This is a study that looks at cementing solutions for corrosive well environments using Portland cement-based systems. Important considerations in this study was to look at the mineralogy, chemistry and physical properties of Portland cement-based systems and study the mechanisms of corrosion. Several pozzolan API cement systems where compared to conventional cementing systems for a corrosive well scenario with occurring mechanical downhole stresses. The objective was to compose cementing guidelines for best practices in corrosive well environments.

5.3.1 Operational Challenges

To test the cements for corrosion by CO_2 a pozzolan/API Class G/Silica flour cement-based system was chosen and mixed with seawater at a density of 1.8 g/cm^3 (15 ppg). A full description of the cement system is described in **Table 4**. The pozzolanic cement-based system was directly compared to a conventional cement system; API Class G with 35% BWOC silica flour with the same density. However less mixing water was required for the pozzolanic system. Both systems were added with equal chemical admixture to stabilize the slurry and achieve fluid-loss control and preferred thickening time. Both slurries were cured at 20.68 MPa (3,000 psi) and 149°C (300°F) for 96 hours.

After the curing both specimens were cleaned by soap and water to remove all grease. All specimens that showed cracks or irregularities on their surface was discarded. As illustrated in Table 4 analysis of both systems cured, revealed that they had almost identical composition after treatment. Both systems had a formal content of 47 wt% CaO content, and sufficient silica was present in both cement systems to reduce the formal molar CaO/SiO_2 ratio to approximately 1.1 to prevent strength retrogression. X-ray powder diffraction analysis showed no sign of portlandite in either of the systems.

Table 4—Cement system design, properties and oxide composition (Brandl et al 2010).

Cement System	Pozzolan	Conventioanl
Base blend	Pozzolan + API Class G + silica flour	API Class G + 35% BWOC of silica flour
Slurry density	15.0 lbm/gal	15.0 lbm/gal
Water-solids ratio	0.55	0.72
Portlandite	Not detected	Not detected
	Oxidic Compostion of Set Cement Systems	
CaO [wt%]	46.6	47.5
SiO_2 [wt%]	40.8	39.8
C [wt%]	2.4	2.3
Na_2O [wt%]	0.6	0.6
MgO [wt%]	0.4	0.4
Al_2O_3 [wt%]	2.4	2.2
SO_3 [wt%]	3.1	2.8
Cl [wt%]	0.7	0.6
K_2O [wt%]	0.1	0.2
Fe_2O_3 [wt%]	2.9	3.4
Total [wt%]	100	100

A modified HPHT curing chamber was used to stimulate the CO_2 or carbonic acid (H_2CO_3) attack within the cement specimens under static conditions. Rack with the cement specimens were released into the curing chamber and completely filled with tap water. CO_2 gas was injected constantly from the bottom of the chamber by a high-pressure booster for 5 minutes to generate CO_2-loaded water with a measured pH of 5. To stimulate HPHT conditions the chamber was pressurized with CO_2 gas to a pressure of 20.7 MPa (3,000 psi) and temperature of 149°C (300°F). If a pressure reduction occurred it was cured with further CO_2 injection, to guarantee a continuous supply of CO_2. After a curing of 1, 3, and 6 months the HPHT chamber was gradually decreased over 12 hours to a set of cement specimens were recovered for mechanical and mineralogical analyses.

Testing and Evaluation Methodology. All cement cylinders were cut in half, and one was cured with blue epoxy resin under vacuum to enhance the display of porosity. Young's modulus, poisson's ratio and compressive strength was determined from uniaxial and triaxial stress/strain tests performed on the cylinders under a confining pressure of 6.9 MPa (1,000 psi). The tensile strength was determined from a direct uniaxial tensile-strength method. Brinell hardness was determined by forcing a hard steel sphere of a specified diameter under a specified load into the surface of a material and measuring it by diameter of the indentation left after the test was completed. The cement cylinders were loaded into a preheated pressurized core holder to determine the water permeability. A syringe pump was used to inject deionized water into the chamber and water flow rate was noted.

To determine amount of $CaCO_3$ the cement specimens were dried under vacuum and ambient temperature for 5 days.

Testing conditions Compared to Field Reality. Laboratory tests made de specimens exposed from all sides to the corrosive fluids, however in the field, parts of the cement sheath will be sheltered by the formation and casing, so that only a small contact area is actually attacked. It was also noted that the ratio of corrosive fluid to cement and the availability of moisture was much higher in the laboratory tests. This resulted in a much stronger corrosive attack, which means that these laboratory tests could work as worst case conditions.

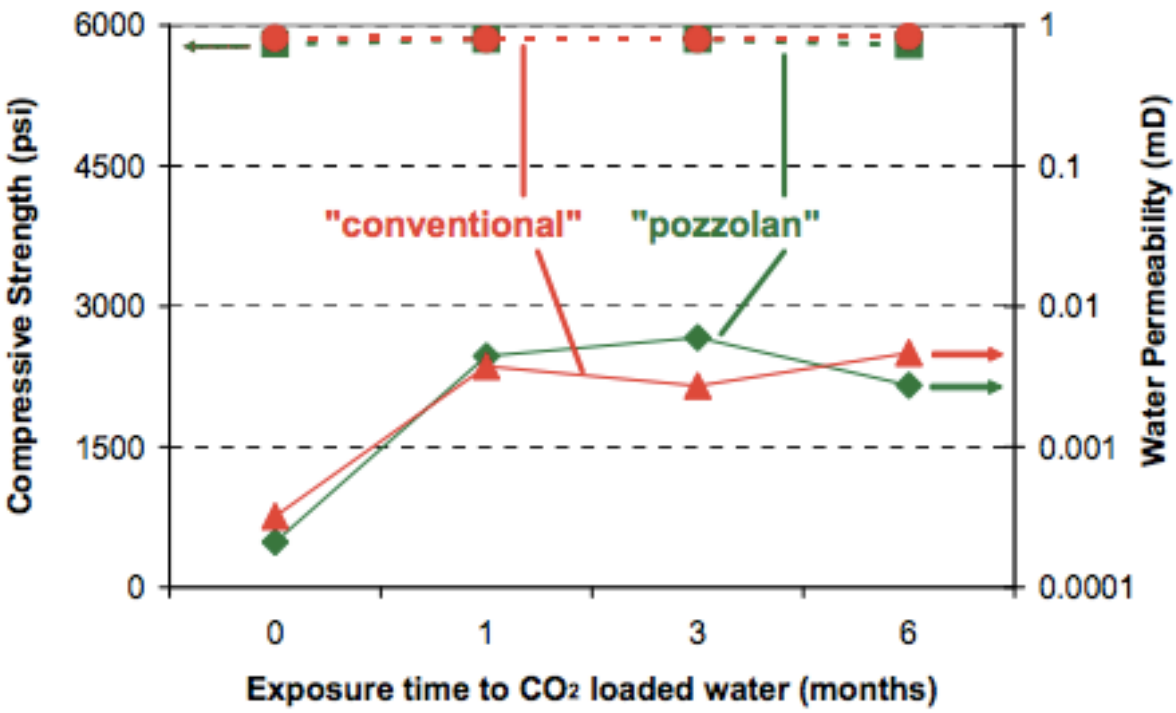

Fig. 16—Confined compressive strengths and water permeabilities of both cement systems as a function of exposure time to CO_2 (Brandl et al 2010).

Evaluation of Results. All cement specimens were evaluated after 1-, 3-, and 6-month exposure to CO_2-loaded water at 149°C (300°F) and 20.7 MPa (3,000 psi). The cement specimens that were exposed for 1 month showed no visual cracks or fractures. All cylinders were cut in half, where one part was used to measure water permeability and micro indentation, and the other half to determine the progress of the CO_2 attack. Phenolphthalein tests indicated that no alkalinity was left along the specimens' profiles for both systems, which means that carbonic acid had completely penetrated the cement samples. To determine the micro indentation tests were taken three times at different locations on the specimens, and then averaged. The outer parts of the specimens had a lower hardness than the interior, because of depletion of $CaCO_3$, indicating that the specimens were less affected by corrosion after 1 month. Both specimens tested for 1, 3, and 6 months retained sufficient low permeabilities (<0.01 mD) and high compressive strengths (> 34.5 MPa [5,000 psi]) to provide zonal isolation which is illustrated in **Fig 16**. Sufficient silica was presented in both specimens, meaning that strength retrogression was not a concern. There were no special changes in length or diameter for the specimens, but both systems gained some weight because of hydration and carbonation (results shown in **Fig. 17**).

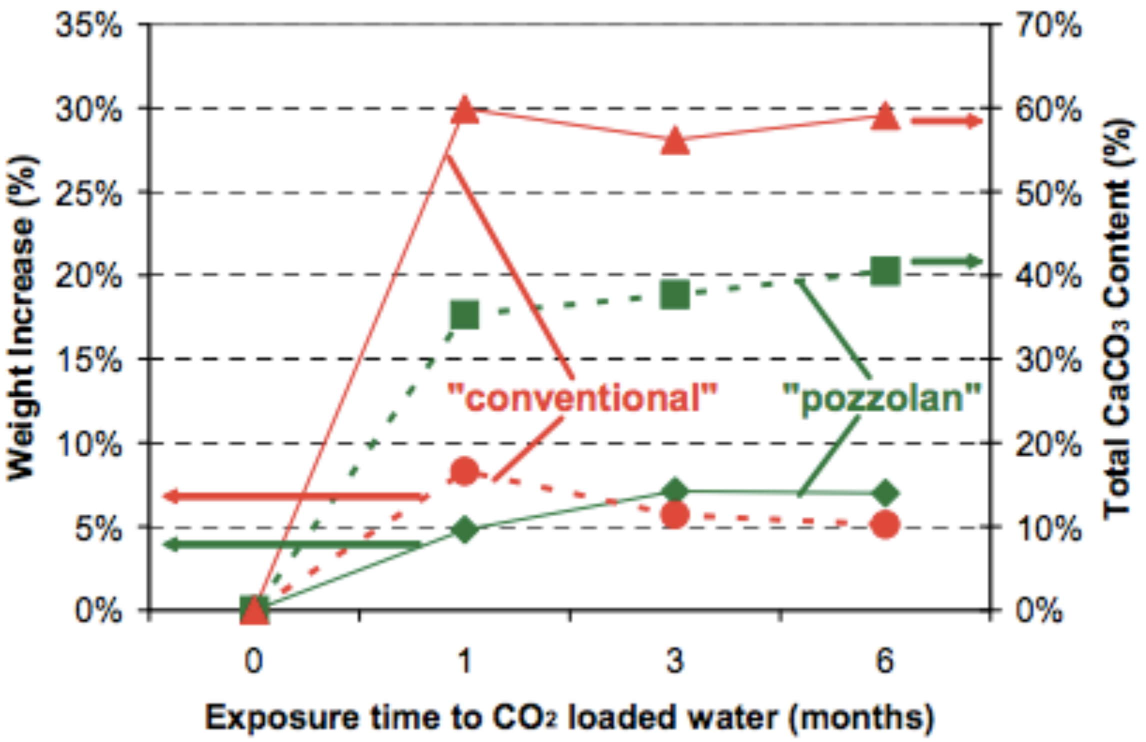

Fig. 17—Weight increase and total $CaCO_3$ content of both cement systems as a function of exposure time to CO_2 (Brandl et al 2010).

The increase in weight of the pozzolan cement specimens are directly correlated to the steady increase in $CaCO_3$ content and confirms that carbonation has probably not been completed even after 6 months. The conventional system on the other hand shows that the maximum carbonation was reached already after a month. After maximum carbonation the weight continuously dropped, indicating that leaching of cementitious materials was occurring. When 6 months passed the total $CaCo_3$ content was significantly less for the pozzolan system than for the conventional one. Which means that C-S-H phases and certain CaO still exist within the pozzolanic system and that this system is less susceptible to carbonation than the conventional system.

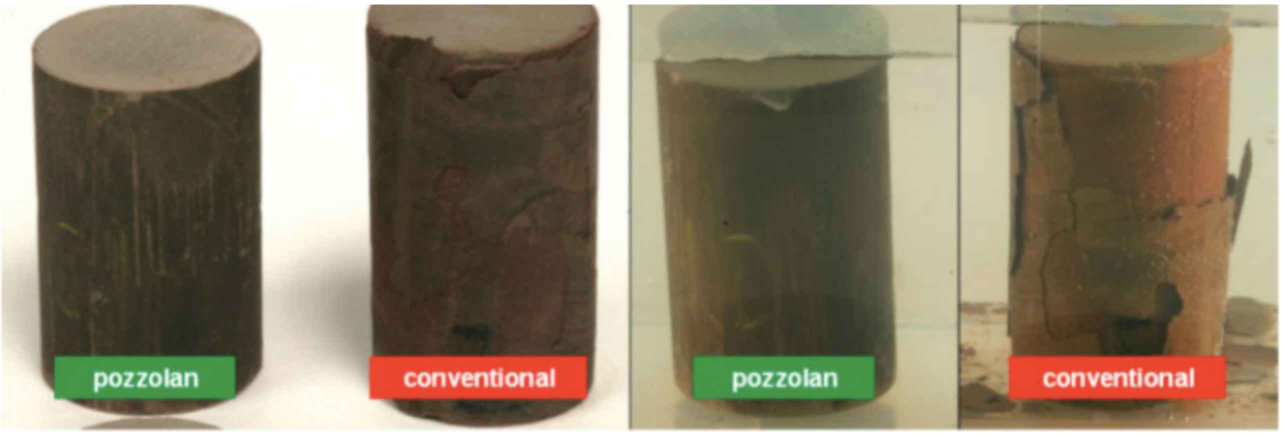

Fig. 18—Left: specimens after recovering from CO_2-exposure for 6 months. Right: specimens stored in fresh water. (Brandl et al 2010).

When the cement cylinders were tested for permeability, severe spellings were observed in the conventional system after a 6 month exposure of CO_2 as shown in **Fig 18**. When the cement cylinders were put back into water, the deterioration on the conventional system, resulted in detrimental spalling all around the specimen (illustrated in Fig 18, right). The result of this was a diameter reduction by 2.4%, which creates a serious concern as it opens for potential channels and migration pathways for corrosive fluids. To verify these findings, a second specimen of each cement system exposed for 6 months was split along the lengths for analyses (**Fig 19**, top).Images from scanning electron microscopy (SEM) confirmed that spallings caused channels at the rim of the conventional system, whereas integrity fully existed for the pozzolanic system (Fig. 19, bottom). These spallings may not occur in the wellbore, however the findings confirm that there is potential of losing effective zonal isolation over time. Conclusions that can be drawn from these findings is that the corrosion process progressed faster in the conventional cementing system, than for the pozzolanic cementing system.

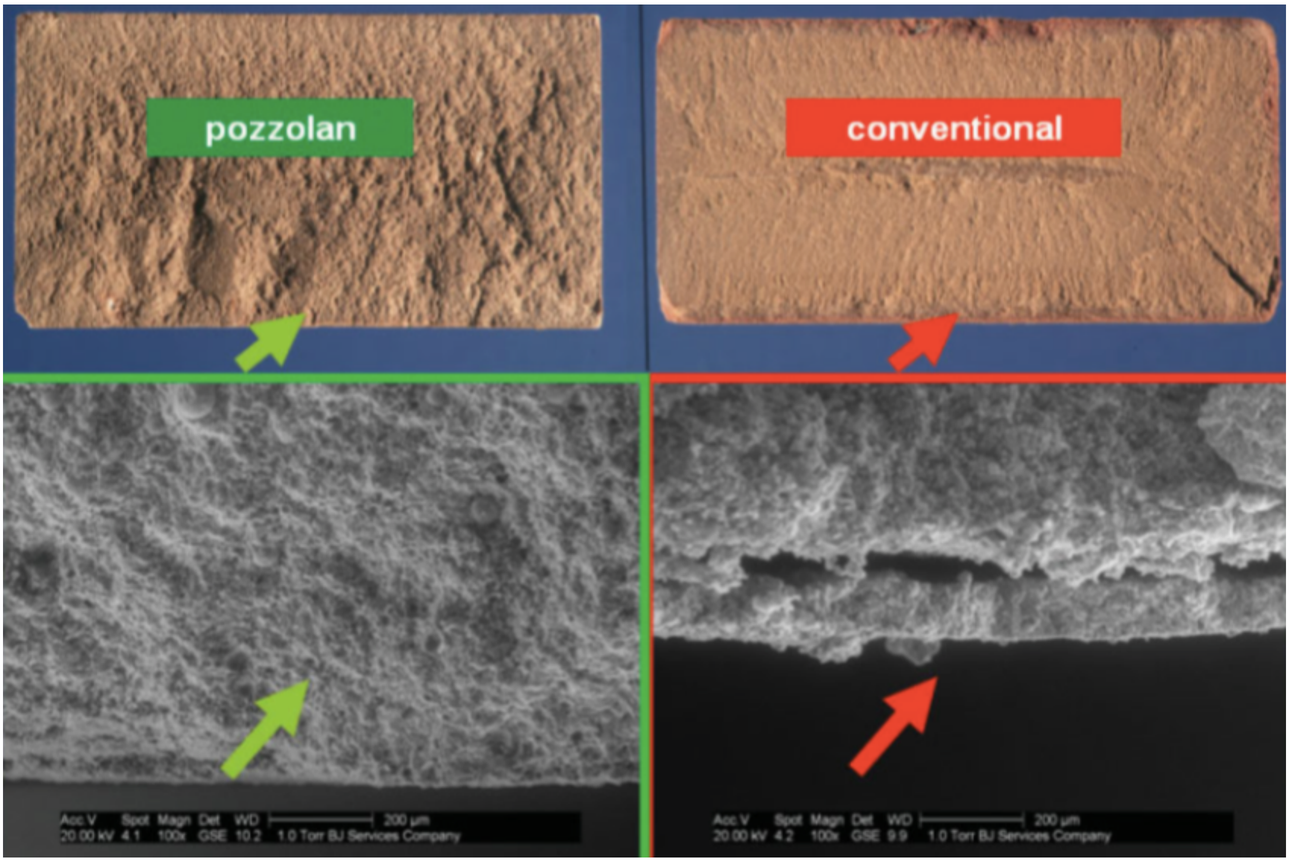

Fig. 19—Top: Specimens cylinder half after recovering from CO_2 exposure of 6 months. Bottom: SEM pictures taken from the rim (arrow) of each specimen. (Brandl et al 2010).

An examination of the effect of pozzolan on the formed C-S-H phases was done to understand the reason why the pozzolanic system showed less carbonation than the conventional system, especially why this system is still able to preserve integrity after 6-months of exposure to CO_2. SEM images showed that during the hydration of the pozzolanic cement system a dublex film of C-S-H phase formed on the surface of the pozzolan. The dublex film has a crystal nucleus that allows the epitaxial growth of further C-S-H phases, which results in a sheath of densified C-S-H phases around the pozzolan spheres. After 6 months these phases could still be found, which can explain the lower $CaCO_3$ content in the pozzolanic system compared to the conventional system. The densified C-S-H phases in the spherical sheaths around the pozzolans has a smaller surface area, which results in better integrity and higher durability during CO_2 attacks.

Mechanical properties of both systems were studied before and after 1 months exposure to CO_2-loaded water (summarized in **Table 5**). The differential in mechanical properties of set cement usually decreases over time because, after setting, cement hydration is diffusion controlled. Even though a large change in mechanical properties were found for the pozzolanic system after a month, these may not give a proper vision, because pozzolanic cement systems typically develop strength slowly and continuously over time. It was noticed that Young's modulus and Poisson's ratio decreased significantly for both systems. The cement carbonation results in higher compressive strengths for the systems and the tensile strength was also observed to increase for both systems. However the conventional system's mechanical properties are more affected after 1 month of CO_2 exposure because of the strong carbonation, than the pozzolanic cement system whom was more inert to carbonation. Because of its high Young's modulus and a relatively low tensile strength makes Portland cement a brittle material by nature. This is why the cement sheath is more likely to fail in tension rather than compression. The pozzolanic cement system has a higher tensile strength and a lower Young's moduli and on the basis of this tends to withstand wellbore stresses better than the conventional cementing system.

Table 5—Mechanical properties of the cementing systems before and after CO2 exposure (Brandl et al 2010).

Cement system	Density [ppg]	Permeability [mD]	Young's Modulus (Mpsi) Confining Stress: 1,000 psi	Poisson's Ratio Confining Stress: 1,000 psi	Compressive Strength [psi] Confining Stress: 1,000 psi	Tensile Strength [psi] Unconfined
After 96 hours curing at 3,000 psi, 300•F and before CO_2 exposure						
Pozzolan	15.0	0.00021	1.52	0.32	>5,800	354
Conventional	15.0	0.00032	2.07	0.33	>5,860	258
After 30 days exposure to CO_2 loaded water at 3,000 psi and 300•F						
Pozzolan	16.1	0.00442	0.85	0.26	>5,850	468
Conventional	16.5	0.00375	1.17	0.23	>5,850	438

5.3.2 Cementing Solution

Previous research has revealed that corrosion occurs mainly along the cement-to-formation interface and to a lesser extent through the cement matrix. Defects in the cement sheath, existing annuli, and leakage pathways for migration allows an increase of contact time and area between the corrosive fluid and the cement, enhancing the corrosion process. Conclusions that can be drawn from this is that good cementing best practices should always be followed for a successful primary cement job. This requires proper well preparation and a properly designed cement slurry for the given well conditions. Which means that engineered spacers, casing centralizing, rotation, and reciprocating in combination with the use of simulation software for the cement pumping process help maximize mud displacement efficiency.

A preflush with a sodium silicate system will improve the cement bond because of an aqueous film of silicates on the surface of the formation and the pipe will form calcium silicate precipitation when in contact with the cement slurry. The permeability of formations containing calcium and magnesium will be reduced because of the precipitation reaction. This sealing is beneficial to minimize chemical attacks on the cement sheath, by corrosive formation fluids. The cement system should be designed with suitable mechanical properties, and mathematical wellbore-stress simulations will help predict if the cement sheath can withstand the induced tensile- and compressive forces created by changing wellbore conditions without failures over the life of the well. The cement slurry should be designed by the knowledge of chemical composition of downhole formation fluids to prevent corrosion. The addition of silica to reduce the Ca/Si ratio in the cement system is necessary to prevent strength retrogression.

API-cement-based systems can be a solution for corrosive well environments. Following good cementing practices is important to minimize corrosion of the cement sheath. This study has proven that API cement systems containing selected pozzolanic materials improve the durability in contact with corrosive fluids. The pozzolanic system was found to be more inert to carbonation than conventional API cementing systems.

6 Discussion

Cementing geothermal steam wells has come a long way since the first well was drilled in the beginning of the 20th century. Comprehensive research to enhance the integrity of the cement in thermal environments has been done. Lessons learned has contributed to several findings that has improved the cementing solutions for geothermal conditions containing corrosive formation fluids. Case studies in the previous chapter and literature review of cementing solutions show several of such findings, solutions and recommendations for cementing geothermal steam wells.

6.1 Summary of Cementing Solutions

6.1.1 Findings in Java

Research and findings from the Wayang Windu project, Indonesia, showed that thermal and corrosive effects could be fatal on the set cement, and hence cause production losses or even casing collapse in the worst cases. Wells exposed to thermal environments proved to have serious zonal isolation problems, and this only after a year in production. Already during pumping of the cement, problems were detected. A key issue was that no cement returns were detected, which meant that the operation suffered from severe lost circulation problems. Lost circulation was a costly problem and in this case it required several top-up (grouting) jobs to ensure the annulus was fully cemented. With several top-up jobs being run to cement the annulus, fluid became trapped between the cementing intervals. With large temperature fluctuations this caused the fluids to expand between the casings, and hence cause the casing to either buckle or in worst case, collapse. The fluid expansion was also the reason for the detection of serious wellhead growth.

These findings contributed to an elaborated research before designing new cementing programs for further planned wells. By a collaboration between FEA and extensive laboratory tests, it was concluded that all cementing operations should be done as close as possible to best practices to ensure the design would hold for long-term well integrity. An important consideration in this conclusion was to examine every unique situation individually, because there is no solution that fits all.

Proper mud displacement/removal of drilling fluid was found to be a key issue in successful long-term cement integrity. An elastic cement based system proved to have less suffering from lost circulation while pumping of the cement. The system also proved to have better mechanical properties after simulated operations and laboratory tests, than conventional Portland cement based systems. Cement returns were observed with elastic cement, which made the need for several top-up jobs limited, and hence limited wellhead growth after setting of the cement.

6.1.2 Findings in Italy

HPHT wells have been drilled for decades in Italy. This has contributed in a lot of research evolving such well conditions and preferred cementing solutions that provides long-term well integrity. Successful cementing designs for HPHT wells in Italy has proven to be particularly related to pre-design simulations and comprehensive laboratory testing. As many simulations and laboratory tests as possible should be done to ensure the cement design is completely able to withstand the severe well conditions. The simulation data is necessary to stimulate real well conditions so the cement design is prepared on all aspects of the well cycle before being set in the well.

In 1991 manganese tetraoxide was added to the cement as a newly developed weighting agent. It gave the cement slurry several advantages, especially in flexibility, with the ability of adding it directly to the mixing water instead of dry blending it with the cement. Its fine particle size improved the suspension properties and enabled a more uniform slurry density for improved well control. Also the findings in Italy proved the necessity of proper mud removal to prevent cement contamination by premature setting and bonding issues.

6.1.3 Findings from Corrosive Environment Studies

Corrosive well environments in combination with high temperatures has proven to be a great challenge to beat in relation to designing, setting and providing long-term integrity of cementing solutions. Corrosion by formation fluids can occur in several different chemical reactions, which demands for an even more complex job. Two different systems' properties, pozzolan-based and conventional Portland cement based, were evaluated for corrosive environments by several extensive laboratory tests.

As in Indonseia, this research concluded in the importance of cementing after best practices with special consideration on on maximizing displacement efficiency during mud removal. After months of exposure to CO_2 attacks the pozzolanic system proved to possess better mechanical properties and was proven to be more inert to influence by carbonation of the system. Carbonation caused the conventional Portland cement based system to turn brittle. SEM images showed cases of spallings that potentially could allow corrosive formation fluids to enter and enhance further carbonation of the cement. Pre-flushing the cement with a sodium silicate solution was found to improve the cement bond because the formation an the pipe will form calcium silicate precipitation when in contact with the cement slurry. Conventional API classified systems with modifications (addition of pozzolanic material) proved its usefulness in corrosive well environments.

6.2 Comparison of the Solutions

The solutions encountered for cementing geothermal steam wells have a lot in common. Cementing after best practices points clearly out as one of the most important considerations when cementing in such environments. Extensive simulation and laboratory tests helps to ensure this practice. Knowing as much as possible about well parameters, challenges during drilling and previous solutions helps, when designing the slurry composition and operation.

Research has proven that hole preparation before placement of the cement slurry is one of the major concerns in well integrity. Several cases (Java, Indonesia and Po Valley, Northern Italy) has proven that a proper mud displacement is important to prevent premature setting- and/or contamination of the cement. These findings amplifies the requirements for cementing after best practices. Although cementing after all parameters in best practices is impossible, it should be a requirement to try and enhance as many as possible of the most preferred practices. The use of FEA, software programs, simulations and laboratory tests beforehand has proven to enhance this practice.

All three studies proved that modified API classification cementing systems has proven to show good cement characteristics in thermal- and corrosive environments. Certain additives like pozzolans, manganese tetraoxide and elastic-materials has proven to enhance the integrity and flexibility of the cementing systems in all of the cases studied.

7 Conclusion

Literature studies and case studies have shown that cementing a geothermal steam- and/or HPHT wells is extremely challenging. The cement is responsible for the well integrity, and a possible failure can cause fatal consequences on production rate, further well stimulation and impact financial costs. This makes the cementing of a well one of the most critical steps in the life of a well. From the researched studies in this thesis the following conclusions can be drawn:

- Knowing as much as possible about the well parameters (depth, wellbore geometry, temperature, and formation pressure) before designing the job helps providing proper laboratory test material to ensure the cement slurry can withstand the well conditions.

- Advanced software should be included in the design phase to improve cement slurry simulations ensuring the design is accurate and specified for the conditions.

- Extensive laboratory tests of the slurry is important to ensure the design of the slurry is best possible for the given situation (conditions).

- Proper hole preparation (mud displacement/removal) should be prioritized to prevent premature setting of the cement and hence cement bonding issues.

- 35-40% BWOC silica flour should be added to the cement to prevent strength retrogression. In corrosive well environments the addition should be reduced to 15-20% to retain susceptible to attacks by CO_2.

- In corrosive well environments a pozzolanic cement system should be used, because of its ability to withstand carbonation attacks, while at the same time provide sufficient compressive strength and low permeability.

These findings are solutions encountered from lessons learned from cementing geothermal steam- and HPHT wells worldwide. They serve as an indication on what challenges that has to be overcome downhole and provide guidelines for further research. Although several solutions have been found, the industry still has a long way to go before all thermal environment obstacles are fully overcome. The demand for renewable energy sources, like geothermal energy keeps increasing and it demands for completing wells in more challenging environments.

With further research and lessons learned from previous work it is believed that the future will push the industry to keep improving the designs of complex cementing systems to complete challenging wells like these.

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Appendix A - Conversion Factors to SI Units

Table 6—Conversion factors for field units to SI units

Field Unit	Conversion Factor	SI Unit
Pounds [lb]	0.45359237	Kilograms [kg]
Feet [ft]	0.3048	Meters [m]
Inches [in]	2.54	Centimeters [cm]
Kilometer [km]	0.62137	Miles [mi]
Square feet [ft^2]	0.09290304	Square meters [m^2]
US gallons [gal]	3.785412	Liters [L]

Appendix B - API Cement Classifications

Class A. Intended for use when no special properties are required. Available only in Ordinary (O) grade.

Class B. Intended for use when the conditions require moderate or high sulfate resistance. Available in both moderate sulfate resistance (MSR) and high sulfate resistance (HSR) grades.

Class C. Intended for use when conditions require high early strength. Available in O, MSR, and HSR grades.

Classes D, E, and F. Products obtained by grinding Portland cement clinker, consisting essentially of hydraulic calcium silicates, usually containing one or more of the forms of calcium sulfate as an inter ground addition. Known as «retarded cements» intended for use in deeper wells. Since these classes were first manufactured, the technology of chemical retarders has significantly improved; consequently, these classes are rarely found today.

Classes G and H. Products obtained by grinding Portland cement clinker, consisting essentially of hydraulic calcium silicates, usually containing one or more of the forms of calcium sulfate as an inter ground addition. This product is intended for use as basic well cement. Available in MSR and HSR grades. Classes G and H were developed in response to the improved technology in slurry acceleration and retardation by chemical means. These classes is by far the most commonly used cements today (Nelson and Michaux 2006).

Table 7—Typical composition and fineness of API cements (Nelson and Michaux 2006 [API spec 10A]).

API Class	Typical potential phase composition [wt%]				Typical blaine fineness [cm^2/g]
	C_3S	β-C_2S	C_3A	C_4AF	
A	45	27	11	8	1,600
B	44	31	5	13	1,600
C	53	19	11	9	2,000
D	28	49	4	12	1,500
E	38	43	4	9	1,500
G	50	30	5	12	1,800
H	50	30	5	12	1,600

Table 8—Chemical requirements for API Portland Cements (Nelson and Michaux 2006 [API spec 10A]).

	Cement class					
	A	B	C	D, E, F	G	H
Ordinary grade (O)						
Max. magnesium oxide (MgO) [wt%]	6.0		6.0			
Max. sulfur trioxide (SO_3) [wt%]	3.5		4.5			
Max. loss on ignition [wt%]	3.0		3.0			
Max. insoluble residue [wt%]	0.75		0.75			
Max. tricalcium aluminate ($3CaO•Al_2O_3$) [wt%]			15			
Moderate sufate-resistant grade (MSR)						
Max. magnesium oxide (MgO) [wt%]		6.0	6.0	6.0	6.0	6.0
Max. sulfur trioxide (SO_3) [wt%]		3.0	3.5	3.0	3.0	3.0
Max. loss on ignition [wt%]		3.0	3.0	3.0	3.0	3.0
Max. insoluble residue [wt%]		0.75	0.75	0.75	0.75	0.75
Max. tricalcium silicate ($3CaO•SiO_2$) [wt%]					58	58
Min. tricalcium silicate ($3CaO•SiO_2$) [wt%]					48	48
Max. tricalcium aluminate ($3CaO•Al_2O_3$) [wt%]		8	8	8	8	8
Max. total alkali content expressed as sodium oxide (Na_2O_2) equivalent [wt%]					0.75	0.75
High sulfate-resistant grade (HSR)						
Max. magnesium oxide (MgO) [wt%]		6.0	6.0	6.0	6.0	6.0
Max. sulfur trioxide (SO_3) [wt%]		3.0	3.5	3.0	3.0	3.0
Max. loss on ignition [wt%]		3.0	3.0	3.0	3.0	3.0
Max. insoluble residue [wt%]		0.75	0.75	0.75	0.75	0.75
Max. tricalcium silicate ($3CaO•SiO_2$) [wt%]						
Min. tricalcium silicate ($3CaO•SiO_2$) [wt%]						
Max. tricalcium aluminate ($3CaO•Al_2O_3$) [wt%]		3	3	3	3	3
Max. tetracalcium aluminoferrite ($4CaO•Al_2O_3•Fe_2O_3$) plus twice the tricalcium aluminate ($3CaO•Al_2O_3$) [wt%]		24	24	24	24	24
Max. total alkali content expressed as sodium oxide (Na_2O_2) equivalent [wt%]					0.75	0.75

Table 9—Physical requirements for API Portland cements (Nelson and Michaux 2006 [API spec 10A]).

Compressive strength test											
8-hr curing time	**Schedule number**	**Curing temperature (°F[°C])**	**Curing Pressure (psi [kPa])**	**Min. compressive strength (psi [MPa])**							
	—	100 [38]	Atmospheric	250 [1.7]	200 [1.4]	300 [2.1]	—	—	—	300 [2.1]	300 [2.1]
	—	140 [60]	Atmospheric	—	—	—	—	—	—	1,500 [10.3]	1,500 [10.3]
	6S	230 [110]	3,000 [20,700]	—	—	—	500 [3.5]	—	—	—	—
	8s	290 [143]	3,000 [20,700]	—	—	—	—	500 [3.5]	—	—	—
	9S	320 [160]	3,000 [20,700]	—	—	—	—	—	500 [3.5]	—	—
24-hr curing time	**Schedule number**	**Curing temperature (°F[°C])**	**Curing Pressure (psi [kPa])**	**Min. compressive strength (psi [MPa])**							
	—	100 [38]	3,000 [20,700]	1,800 [12.4]	1,500 [10.3]	2,000 [13.8]	—	—	—	—	—
	4S	170 [77]	3,000 [20,700]	—	—	—	1,000 [6.9]	1,000 [6.9]	—	—	—
	6S	230 [110]	3,000 [20,700]	—	—	—	2,000 [13.8]	—	1,000 [6.9]	—	—
	8S	290 [143]	3,000 [20,700]	—	—	—	—	2,000 [13.8]	—	—	—
	9S	320 [160]	3,000 [20,700]	—	—	—	—	—	1,000 [6.9]	—	—
Pressure temperature thickening time test											
Specification test schedule number		**Meximum consistency 15-30 min stirring period (Bc)**		**Min thickening time (min)**							
4		30	90	90	90	90	—	—	—	—	—
5		30	—	—	—	—	—	—	—	90	90
5		30	—	—	—	—	—	—	—	120 max.	120 max.
6		30	—	—	—	100	100	100	—	—	—
8		30	—	—	—	—	154	—	—	—	—
9		30	—	—	—	—	—	190	—	—	—

Table 10—Physical requirements for API Portland cements continued (Nelson and Michaux 2006 [API spec 10A]).

	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**
Max. water [% BWOC]	46	46	56	38	38	38	44	38
Min. blaine fineness (specific surface area) [m^2/kg]	150	160	220	—	—	—	—	—
Min. fineness (specific surface area), air permeability [m^2/kg]	280	280	400	—	—	—	—	—
Max. free fluid content [mL]	—	—	—	—	—	—	3.5	3.5