

LIFE CYCLE MODELING OF WELLBORE CEMENT SYSTEMS USED FOR ENHANCED GEOTHERMAL SYSTEM DEVELOPMENT

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ABSTRACT

Coso Operating Company, LLC (COC), and the Energy and Geosciences Institute (EGI) at the University of Utah have been granted funding from the Department of Energy to develop an enhanced geothermal system (EGS) at Coso. Coso is an operating geothermal plant that will provide an excellent opportunity to experiment with methods for enhancing the geothermal reservoir through hydraulic, thermal, and chemical stimulation. Any additional energy produced at this plant can be used immediately. However, stresses to casing and cement during reservoir enhancement could result in the movement of steam around the outside of the casing string if the cement fails, causing lost steam production and possible safety hazards.

COC and Halliburton, a partner in the study team for the EGS project, are using Halliburton's advanced WellLife™ analysis software to predict stresses on casing and cement in a wellbore subjected to the temperature and pressure changes planned for the project. A number of cementing options were modeled, including foamed cement and cements resistant to attack by wet CO₂. Near-wellbore stresses and rock physical properties collected during early phases of the Coso EGS project provided input to the model. Data collected by Brookhaven National Laboratory and Halliburton on the physical properties of cements were also used in the model.

The modeling included pressure changes during fracture breakdown testing and thermal cycling in the production well, as well as hydraulic stimulation and thermal stimulation in the injection well. Results indicate that tensional stresses are most likely to

cause failure. Foamed cements, which are both resilient and non-shrinking, fared the best under both temperature-induced and pressure-induced stresses. Conventional nonshrinking cements also showed a reduced risk of failure.

INTRODUCTION

COC and the University of Utah EGI plan to develop an EGS on the margins of the Coso reservoir. Wells drilled at the edges of the Coso field often have high temperatures with very low permeability at reservoir depths. The EGS project at Coso is designed to test the potential for mining additional heat through artificial stimulation of these low-permeability, high-temperature zones. Stimulating these zones could extend the productive reservoir away from the margins and increase the capacity of the field. The plan is to determine the stress state in the reservoir, drill a production well and an injection well, and stimulate the wells to connect the two wellbores, allowing the circulation of injected fluid and heat mining.

For the EGS project, wells will be stimulated through hydraulic fracturing, thermal fracturing, and chemical dissolution. The stress state of the reservoir will be determined, and the wellbore orientation can be selected in such a way that stimulated zones are critically stressed and ready to fail, allowing fractures that form to remain open, permitting long-term fluid circulation.

In the normal life cycle of a geothermal well, the wellbore is cooled during drilling and logging, flowed at high temperatures, and cooled periodically for logging or injection testing. This process can place very large stresses on the casing and the

cement. Stimulation using hydraulic pressure and thermal cycling only adds to these stresses. The ability to complete a well and maintain wellbore integrity through the stresses anticipated during reservoir enhancement is critical to the success of the EGS project.

On the east flank of the Coso field, several wells have been drilled with very high bottomhole temperatures (BHTs) but little permeability at depth. The shallower parts of the wells may contain zones of lost circulation and steam with CO₂ and H₂S gases. Because these zones will be behind casing, they are usually squeeze-cemented during drilling to control lost circulation. The acid fluids formed from wet CO₂ and H₂S can attack or move through the cement sheath, which eventually can corrode the casing from the outside in, jeopardizing the integrity of the wellbore. Hydraulic stimulation combined with thermal cycling for thermal stimulation may stress the cement further than the limits of its strength, allowing acid fluids to attack the casing sooner.

COC wanted to test cement strategies that could protect the casing and maintain cement integrity under the severe cycling likely during the creation of an enhanced geothermal reservoir. Halliburton recommended modeling the possible cement systems before deciding on a cementing design for the injection well, which would undergo the largest stresses. A foamed, thermal resistant cement (TRC), which was also resistant to CO₂ acid attack, was planned for the production well. Based on the experiences of other wells on the pad, the production well likely will be exposed to shallow CO₂ and steam zones.

The Halliburton WellLife™ model was set up to model the formation, cement, and casing system in the 38C-9 production well to determine how the foamed cement would perform compared to a conventional cement system with no foam. The stresses involved in the well life include: (1) hydration volume reduction, (2) fracture breakdown testing soon after cementing, (3) cooling during drilling, (4) high-temperature production, and (5) cool water injection. Results of this modeling effort will be used to develop a cementing plan for the injector. The injector will then be modeled to determine the impact of adding thermal cycling stimulation and hydraulic stimulation as well as long-term injection to the well life cycle.

DESCRIPTION OF LIFE CYCLE MODEL

Creating a life cycle model for a geothermal well can be very important. Modeling helps determine the stresses that could occur in the well and the risks of cement sheath failure. This can help operators design

a cementing system that will reduce stresses and help prevent failures that could occur.

When developing a life cycle model, the formation, casing design, and cement system should be accurately represented. The cement strength, density, elastic properties, and thermal properties should all be considered. The thermal and pressure stresses should be accurately calculated. Additionally, specific data are required, including the well design, drilling information, completion details, and formation parameters.

Finite Element Modeling and Analysis

To avoid the limitations inherent to an analytical approach to the various processes linked to well sealant integrity, Finite Element Analysis (FEA) modeling was chosen for the study (SPE 56536 and 74497). To determine the sealing properties of the borehole, nonlinear material models were used. For example, Mohr-Coloumb plasticity, used to describe failure under compression/shear, was combined with a smeared cracking description to model failure under tension. As a result, loss of sealing ability caused by both cement cracking and plastic deformation could be analyzed.

For the casing-cement and cement-rock interfaces, a discrete cracking description was used to model interface debonding. This modeling enabled the analysis of microannuli at the interfaces caused by debonding.

Transient conductive heat transport was also included in the nonisothermal simulations. Operations such as well stimulation and production can change the temperature of the casing, cement sheath, and rock. This temperature change was analyzed as a function of time using the transient model. Subsequently, the effects of this temperature change on the cement sheath stress level and integrity were also investigated.

For linear elastic problems, the system of equations to be solved is:

$$\mathbf{Ku} = \mathbf{f} \quad (\text{Eq. 1})$$

Where:

K is the *system stiffness matrix*

u is a vector of the unknown nodal *degrees of freedom*, such as displacements and rotations

f is the vector of the *nodal forces* corresponding with **u**

The load vector **f** is a summation of all the load components. The solution **u** from this system of equations is often the most computation intensive part of a large-scale Finite Element Analysis. Generally, matrix **K** is a known sparse $n \times n$ matrix

with a symmetric structure, while \mathbf{f} is a known right-hand-side vector and \mathbf{u} the unknown solution vector to be computed.

When the force vector and displacement vector is no longer linear, as when the material goes into plastic behavior, nonlinear solution methods are used. Just as with a linear analysis, a displacement vector that equilibrates the internal and external forces should be calculated. In the linear case, the solution vector can be calculated immediately, but in the nonlinear case it cannot. To determine the state of equilibrium, the problems should be made discrete in space (with finite elements) and in time (with increments). To achieve equilibrium at the end of the increment, an *iterative* solution algorithm can be used. The combination of both is called an *incremental-iterative* solution procedure.

The well life cycle model uses the Finite Element Analysis (FEA) method in which the rock, cement, and casing are modeled. The finite element grid is shown in Fig. 1. The outer radius of the rock is such that the far field stresses in the rock remain unchanged from the initial value of the in-situ stresses. Interface elements are used to analyze the interfaces between cement and casing and between cement and rock.

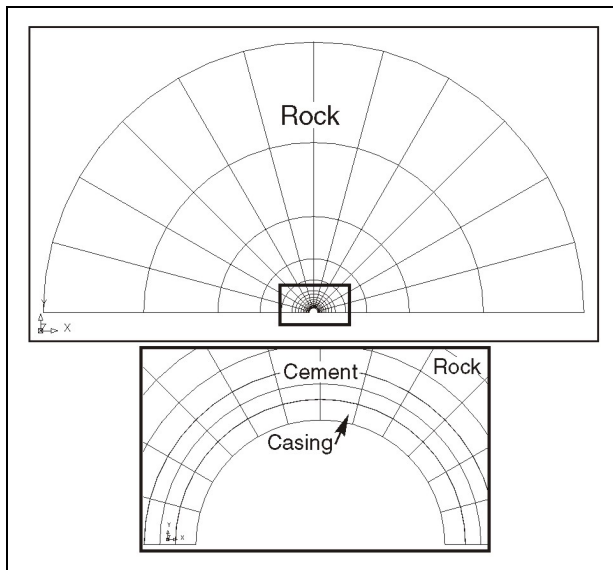


Fig. 1. Finite element grid.

Cement Failure Modes

The following conditions should be met to help ensure that the cement sheath continues to provide zonal isolation throughout the life of the well:

- The cement sheath should retain its integrity.
- The bond at the rock-cement and cement-casing interfaces should be undamaged.

The integrity of the cement sheath could be lost if one of the following conditions occurs:

- The cement sheath cracks (Fig. 2), allowing radial and vertical migration of fluids.
- Plastic deformation occurs in the cement sheath (Fig. 3), allowing radial and vertical migration of fluids.

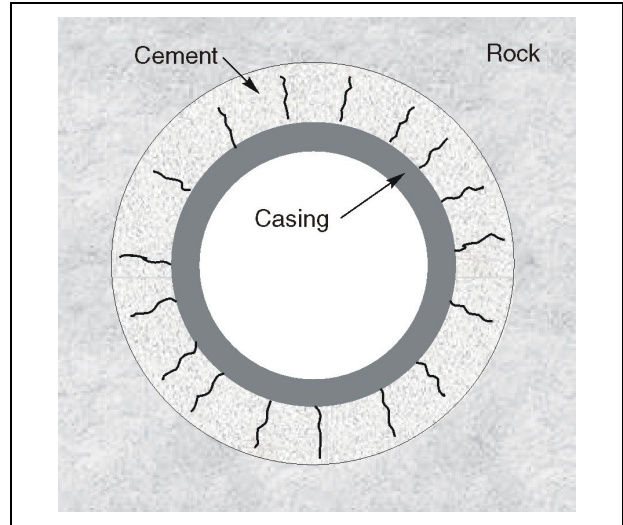


Fig. 2. Cracking of the cement sheath.

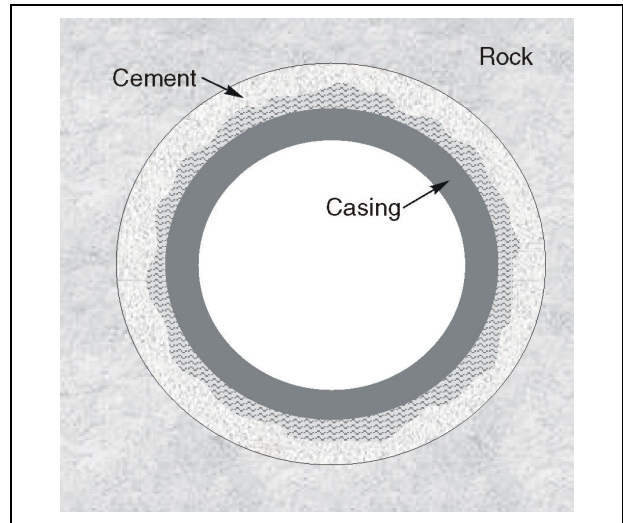


Fig. 3. Plastic deformation in the cement sheath.

The entire cement sheath could crack or fail in tension as a result of the shrinkage of the cement due to hydration volume reduction. Additionally, a part of the cement sheath could crack or fail in tension if the casing expanded from an increase in pressure or a rise in temperature inside the casing. If this occurs, the crack in the cement sheath should propagate from the casing-cement interface.

Compressive shear failure is caused by large differences of principal stresses. This difference can result from a decrease in the tangential compressive

stress, which can occur, for example, during cement shrinkage. This difference can also be caused by an increase in the radial compressive stress, which can occur during the expansion of the casing against the cement sheath.

The cement sheath could debond in one of two ways:

- Debond at the rock-cement interface (**Fig. 4**)
- Debond at the cement-casing interface (**Fig. 5**)

Debonding of cement could lead to vertical migration of well fluids.

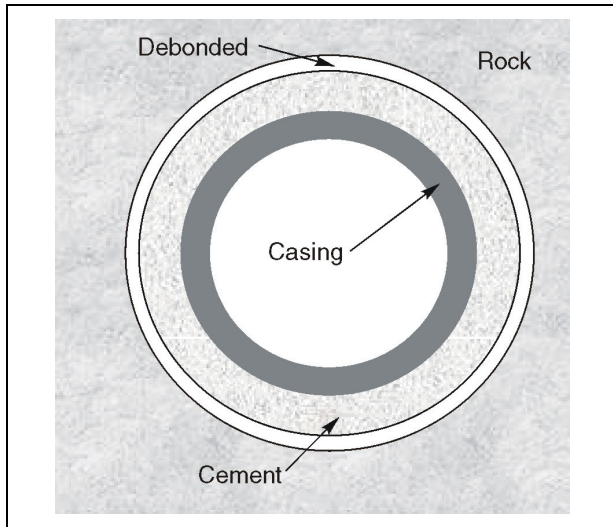


Fig. 4. Debonding at the rock-cement interface.

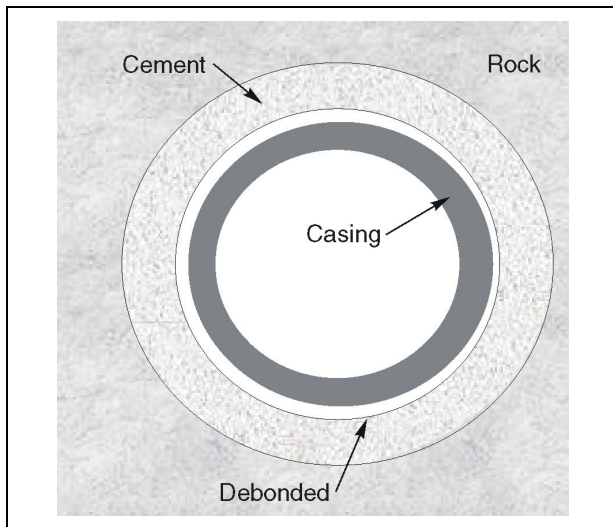


Fig. 5. Debonding at the cement-casing interface.

To simulate these types of problems, a nonlinear material model that included cracking and plasticity was implemented.

The cement is assumed to behave linearly when its tensile strength or its compressive shear strength is not exceeded. The material model adopted for undamaged cement is a Hookean model bounded by a smear-cracking model in tension and a Mohr-Coulomb model in compressive shear. The shrinkage and expansion of cement is included in the material model.

DATA REQUIRED FOR MODEL

To create an accurate model, many parameters are required. Data including the physical properties, thermal properties, and the design of the well, cement, and formation should be entered into the model. During the data-gathering phase of the EGS project, some of these formation parameters will be determined through the analysis of image logs. Although other parameters will be measured through core testing during the EGS project, this early modeling phase requires estimates based on values for similar rocks found in the literature.

The simulation attempted to model all changes in stress that can occur in the cement sheath during the life of the well. Compressive strength is usually the focus of evaluation of cement system. However, FEA models allow for the inclusion variations of critical mechanical and thermal properties of cements including Young's modulus, thermal expansion, and much more.

Well Design

The casing string to be modeled in Well 38C-9 was designed to case off shallow, low-pressure, high-permeability zones. The 13 ³/₈-in. cemented production casing was the only string that was modeled for this well because a liner was to be hung and not cemented (**Fig. 6**). The casing sizes and depths are shown in **Table 1**.

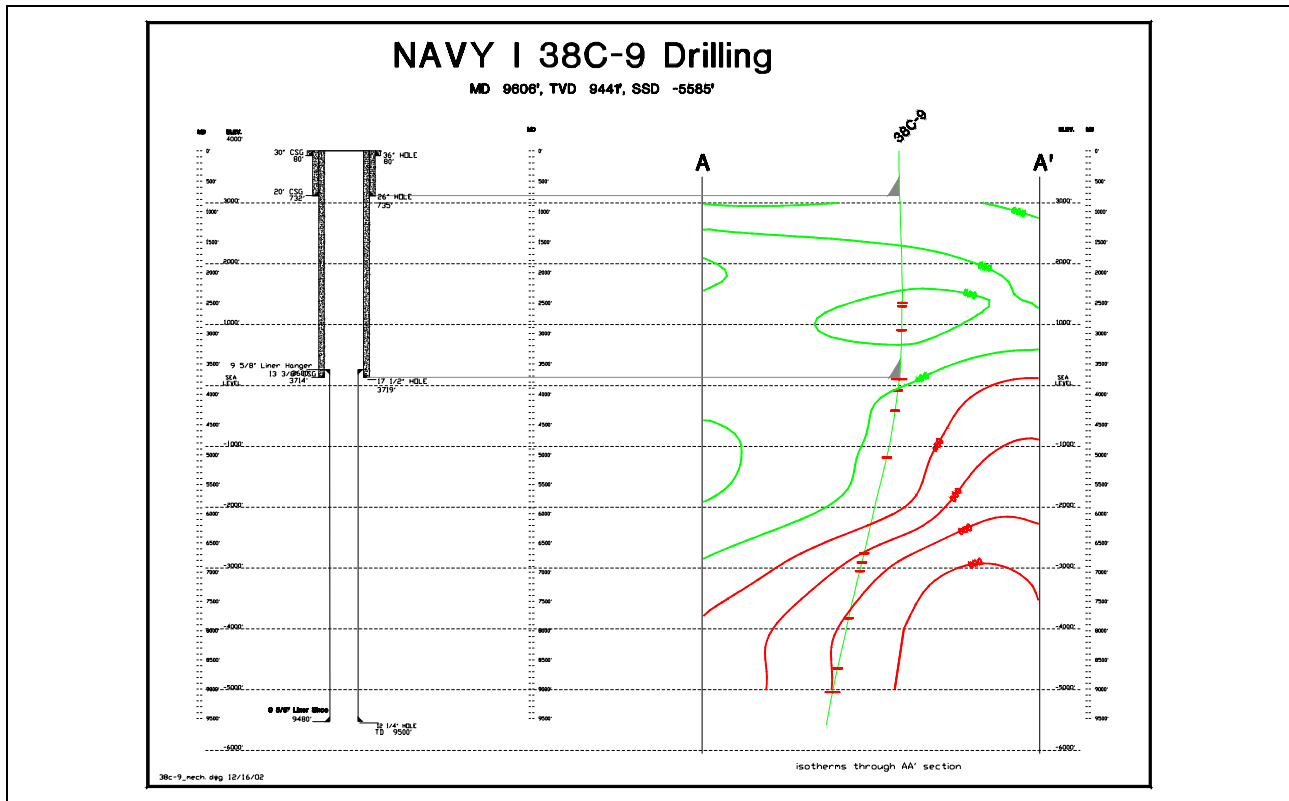


Fig. 6. Formation temperature gradient vs. depth.

Table 1—Casing Design^a

Depth (ft)	Casing Size (in.)	Cement
700	20	Class G
3,750	13 3/8	Foamed TRC
9,500	9 5/8	Hung liner

^aFormation was granodiorite/altered granodiorite

Drilling Information

Stresses during drilling and cementing were modeled using the planned mud weights and the anticipated loss zones. Geothermal wells are typically drilled using low mud weights with density near that of water because the pressure is controlled by cooling the wellbore. Aerated drilling, which reduces wellbore pressures, was performed in the production zone to reduce the risk of formation damage.

Completion Details

As part of the EGS project, a fracture breakdown test was performed below the shoe of the 13 3/8-in. casing. This test was expected to raise the surface pressure to approximately 1,200 psig (8.3 MPa). Because cool water was used in the hole during the test, the pressure downhole was hydrostatic plus the

surface pressure. The model assumed that after completion the well was put on production with a maximum temperature in the bottom of the borehole of 550°F (288°C). In the modeled casing string, the average production temperature is 395°F (202°C). Additionally, a model run was setup to simulate a cool water injection cycle after 50 days of production. This cycle could be necessary if further stimulations were attempted or if logging was needed at lower temperatures. The model assumed that injection at 50°C (122°F) was conducted over three days with a maximum surface pressure of 100 psig (0.7 MPa).

Formation Parameters

The reservoir and most of the rocks at Coso are granodiorite with fine- to coarse-grained texture. Diorite and quartz monzonite also are present, with some basalt and tuffs at shallow depths. The amount of alteration seems to be the largest influence on the characterization of the physical properties of the rocks (Boitnott, 2002). Areas of alteration were mapped in the wellbore. Physical properties of granitic rocks, altered and unaltered, were taken from the literature and were correlated with the zones and used in the modeling (Boitnott, 1999; Boitnott, 2002;

JNC, 1999; Woodward, 1998). The parameters also included the thermal properties of igneous rocks from a study undertaken for the Japanese national nuclear waste repository. Several other sources were used as well.

The well section to be modeled was divided into altered and unaltered zones (**Table 2**). The primary altered zone in the model is also the primary lost circulation zone at 2,400 to 2,500 ft. In fact, this altered loss zone was actually encountered at 2,900 ft. Young's modulus and Poisson's ratio approximately double from the unaltered zone to the altered zone. **Tables 3** and **4** provide the parameters used for each model run. Because the Young's modulus, E, shows a large amount of variation, one

run used a higher value of E for the unaltered formation than for the other runs.

The formation temperature gradient was taken from an equilibrated static profile of a nearby well. Fig. 6 shows the static temperature profile for the modeled section of the borehole.

Geomechanics International (GMI) will evaluate the stress state of the formation as part of the EGS project. The model used the maximum and minimum horizontal stress gradient and the azimuth of the stress from the analysis of Well 38B-9 on the same well pad and roughly parallel to Well 38C-9.

Table 2—TVD of Zones 1 through 4

Zone	Depth to Bottom of Zone ft (m)	Formation
Zone 1	1,200 (366)	1
Zone 2	2,000 (610)	1
Zone 3	2,450 (747)	2
Zone 4	3,750 (1143)	1

Table 3—Parameters for Formation 1 (Upper Zone)

Parameters	Run No. 1	Run No. 2
Bottom TVD ft (m)	2,400 (732)	2,400 (732)
Geothermal Gradient °F/ft (°C/m)	0.0294 (0.53)	0.0294 (0.53)
Vertical Stress Gradient psi/ft (kPa/m)	1 (22.6)	1 (22.6)
Max. Horizontal Stress Ratio	0.52	0.52
Min. Horizontal Stress Ratio	0.52	0.52
Azimuth of Max. H.S. with North	0°	0°
Pore Pressure at Formation Top psi (MPa)	433 (2.9)	200 (1.38788)
Pore Pressure at Formation Bottom psi (MPa)	1,040 (7.16)	200 (1.38788)
Young's Modulus Mpsi (GPa)	10.3 (71)	6.96 (47.98224)
Poisson's Ratio	0.3	0.3
Volumetric Specific Heat Btu/ft ³ , °F	51.66	51.66
Thermal Conductivity Btu/hr, ft, °F (W/m, °C)	1.62 (0.298528)	1.62 (0.295228)
Thermal Expansion 1/°F (1/°C)	7.17E-06 (0.000242)	7.17E-06 (0.000242)

Table 4—Parameters for Formation 2 (CO₂ LC Zone)

Parameters	Run No. 1	Run No. 2
Bottom TVD ft (m)	2,500 (762)	2,500 (762)
Geothermal Gradient °F/ft (°C/m)	0.0294 (0.53)	0.0294 (0.53)
Vertical Stress Gradient psi/ft (kPa/m)	0.75 (16.96358)	0.75 (16.96358)
Max. Horizontal Stress Ratio	0.7	0.7
Min. Horizontal Stress Ratio	0.7	0.7
Azimuth of Max. H.S. with North	0	0
Pore Pressure at Formation Top psi (MPa)	1,040 (7.176976)	200 (1.38788)
Pore Pressure at Formation Bottom psi (MPa)	1,080 (7.454552)	200 (1.38788)
Young's Modulus Mpsi (GPa)	10.3 (71.0082)	3.92 (27.02448)
Poisson's Ratio	0.19	0.19
Volumetric Specific Heat Btu/ft ³ , °F	51.66	51.66
Thermal Conductivity Btu/hr, ft, °F (W/m, °C)	1.01 (0.187786)	1.01 (0.187786)
Thermal Expansion 1/°F (1/°C)	4.17E-06 (0.000141)	4.17E-06 (0.000141)

Cement Parameters

The cement properties required for conducting the FEA simulation include more than just the compressive strength. The properties required and actual values used for the modeling of the EGS are provided in **Table 5**. The values for the foamed TRC were estimated primarily from similar foamed Portland cements. Additionally, the values for the conventional lead and tail cements were estimated based on other similar Portland cement system properties.

Hydration volume reduction is one factor that is often overlooked when evaluating a cement system's ability to provide an annular seal. When Portland cement hydrates with water to form a solid, the absolute volume of the final hydration product is smaller than that of the initial reactants. This result can cause a bulk shrinkage of the final set cement material. This shrinkage can be minimized if an exterior water source is available during the hydration process. However, when cement is hydrating in an annulus between pipe and pipe or next to a formation that has no additional water available, shrinkage can occur in the cement. For this analysis, the assumption was made that no external water was available during hydration. This shrinkage can result in significant damage to the cement sheath even before the well experiences additional stress from temperature and/or pressure changes inside the casing.

One way to mitigate the effects of the hydration volume reduction is to incorporate a gas phase in the cement system (i.e. foam the cement). Foaming the cement minimizes the possibility of shrinkage due to the presence of the internal pressurized gas phase in the cement.

One other major benefit of foamed cement systems is that the Young's modulus is typically reduced. A lower Young's modulus can help increase the elasticity of a cement, allowing it to deform without failing.

Well Operations

After the formation, cement, and casing parameters are determined and entered into the model, the temperature and pressure profile of the well is entered. The planned operations for the well are then enter:

- Cement curing
- Fracture breakdown test
- Drilling
- Production
- Injection to either stimulate the well or cool the well for logging

During the hydraulic fracture breakdown test, cool water at approximately 80°F (27°C) was injected at rates up to 12 bbl/min (36 l/sec) and pressures up to 1,200 psig (8.3 MPa) at the wellhead. After production of the well, thermal cycling is modeled

with injection at approximately 120°F (49°C) for up to three days. This cool injection could be used for preparing the well for logging, or for thermal or chemical stimulation of the well. This injection period is followed by production at normal

production temperatures with a maximum of 550°F (288°C) in the production interval of the well and 395°F (202°C) in the 13 3/8-in. casing.

Table 5—Cement Parameters Used for Modeling

Parameter	Thermal Resistant Cement	Conventional Lead	Conventional Tail
Top of Cement ft (m)	0	0	3,300
Young's Modulus Mpsi (GPa)	0.65 (4.48)	0.8706 (6)	1.20433 (8.3)
Volumetric Specific Heat Btu/ft ³ , °F (MJ/m ³ , °C)	55.35 (3.75)	59.04 (4)	59.04 (4)
Thermal Conductivity Btu/hr, ft, °F (W/m, °C)	0.3585 (0.62)	0.503 (0.87)	0.503 (0.87)
Thermal Expansion 1/°F (1/°C)	4.33E-06 (7.80E-06)	6.11E-06 (1.10E-05)	6.11E-06 (1.10E-05)
Tensile Strength psi (MPa)	217.5 (1.15)	50.76 (0.35)	217.5 (1.15)
Hydration Volume Change	0%	4%	4%

RESULTS

Figs. 7 through 14 show the results of FEA analysis of conventional cement and foamed TRC on the given well. Both the conventional tail cement, which was used to cover all but the bottom 500 ft, and the conventional lead cement show four modes of failure (Fig. 13):

- Debonding at the formation
- Debonding at the casing
- Shear deterioration
- Radial cracking

Fig. 14 indicates that the conventional lead and tail cements at the 2,000-ft interval experienced all modes of failure except plastic deformation in casing. This failure could result in CO₂ migrating into the annulus and causing casing damage. Additionally, casing growth at the surface could result from the lack of cement-to-pipe bonding to hold the casing in place when the wells heat up during production.

The analyses indicate that during curing, pressure testing, production, and injection, the foamed TRC stays intact and no damage occurs to the cement sheath in any mode at 2,000 and 2,450 ft. At 1,200 ft, the foamed TRC shows no damage during curing, pressure testing, and production. During injection at this shallow depth, a slight risk of debonding (approximately 30 μm) exists. However, the analysis of the foamed TRC below this depth indicated no debonding, and the cement is well bonded to the

casing and the formation. No risk of zonal isolation failure is indicated below 2,000 ft. As a result, the formulation of the cement planned for the well did not require modification. A cement inspection log is planned for future evaluation of the cement integrity.

Figs. 7 to 12 show that about 50% or more capacity is left in the foamed cement sheath through all the well events at all depths below 1,200 ft. This remaining capacity is important for the cement sheath to withstand the cycling events.

Eliminating the shrinkage that occurs in conventional cement can help reduce the risk of failure. Fig. 13 shows results for the model run CDWL6 with nonshrinking cement. A comparison of the foamed TRC and nonshrinking cement performance at the same depth (Figs. 8 and 13) indicates that the useful remaining capacity left in foamed TRC is much higher than the nonshrinking cement. The large useful remaining capacity of cement sheath is of great importance when the well is subjected to pressure and temperature cycling.

Sensitivity analysis runs were performed to determine the effect of elastic and thermal properties of rock on the well performance. A threefold increase in the Young's modulus of the formation increased the risk of cement debonding. However, a decrease in the Young's modulus of the rock had little effect on the risk of cement failure.

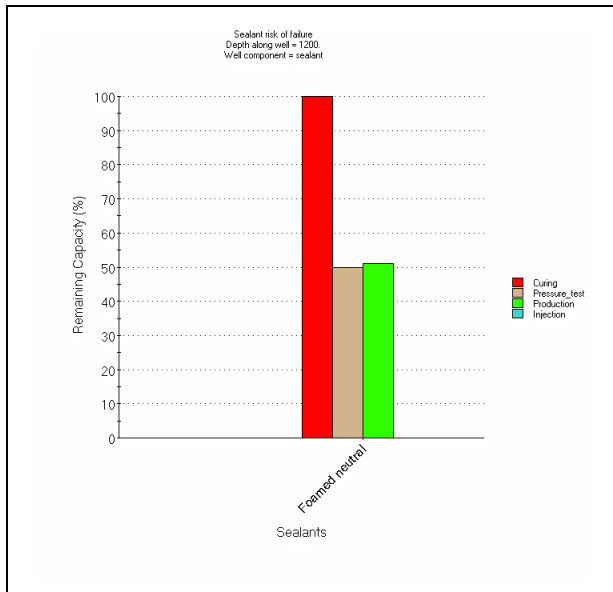


Fig. 7. Foamed TRC risk of failure with injection in CPWL3 (1,200 ft). Note: See Fig. 9 for comparison.

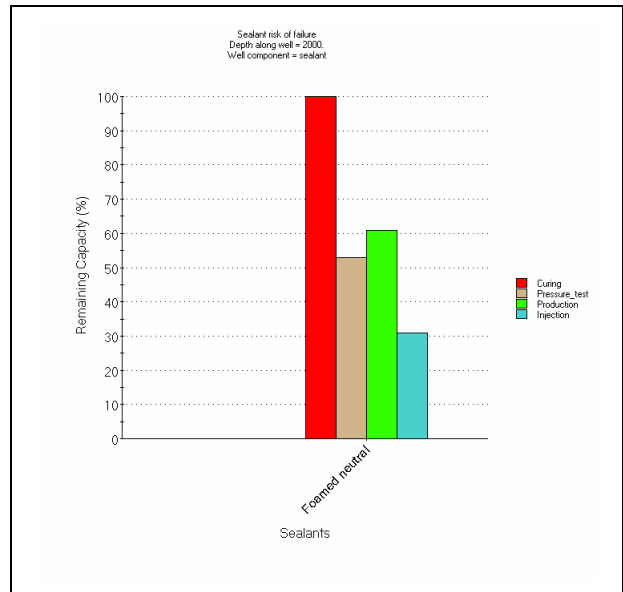


Fig. 9. Foamed TRC risk of failure with injection in CPWL3 (2,000 ft).

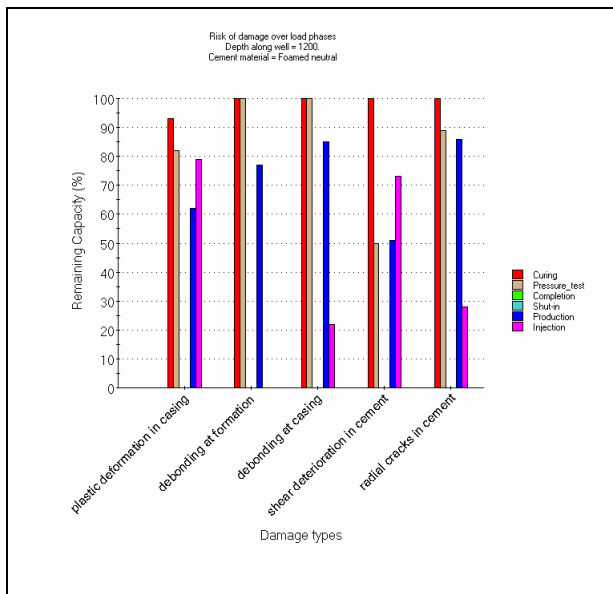


Fig. 8. Failure modes for foamed TRC injection in CPWL3 (1,200 ft). Note: See Fig. 10 for comparison. Shut-in and completion not simulated.

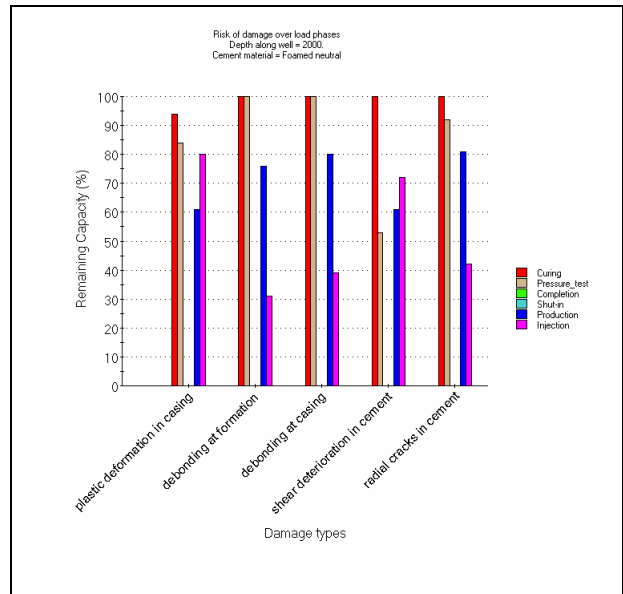


Fig. 10. Failure modes for foamed TRC injection in CPWL3 (2,000 ft). Note: Shut-in and completion not simulated.

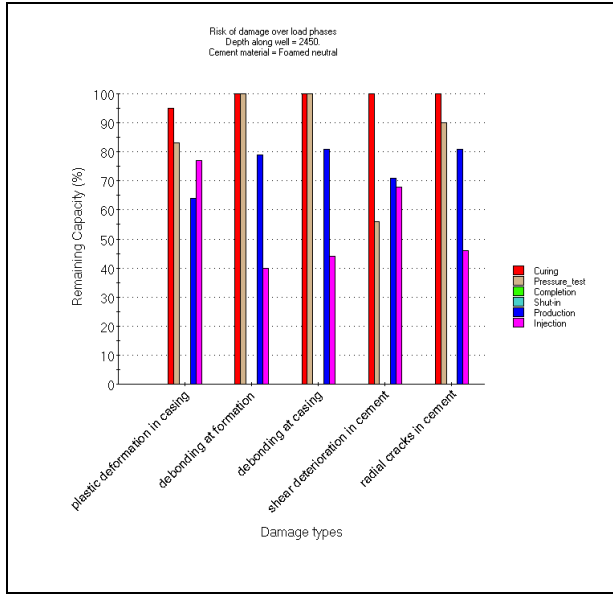


Fig. 11. Failure modes for foamed TRC injection in CPWL3 (2,450 ft). Note: Shut-in and completion not simulated.

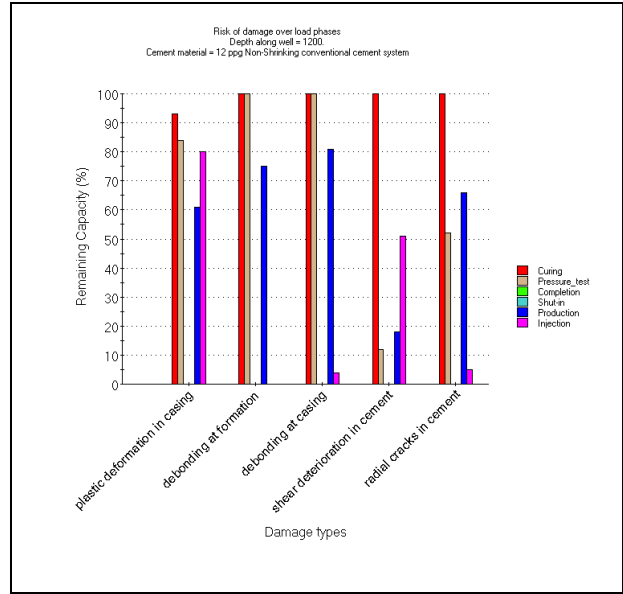


Figure 13. Failure modes for nonshrinking Class G cement in CPWL6 (1,200 ft).

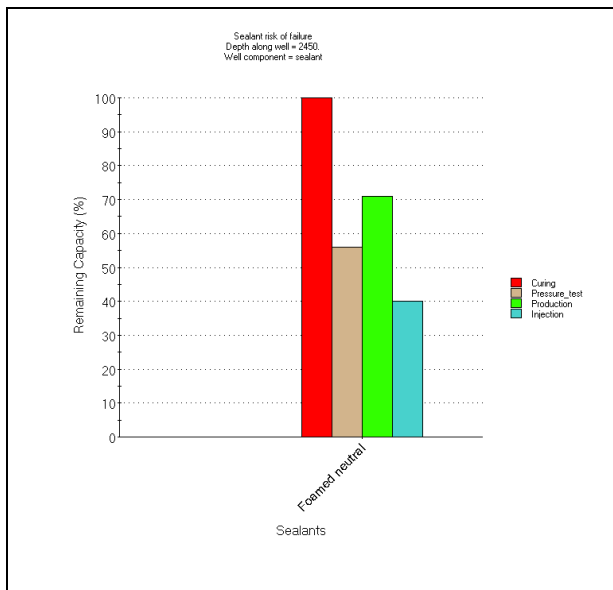


Fig. 12. Foamed TRC risk of failure with injection in CPWL3 (2,450 ft).

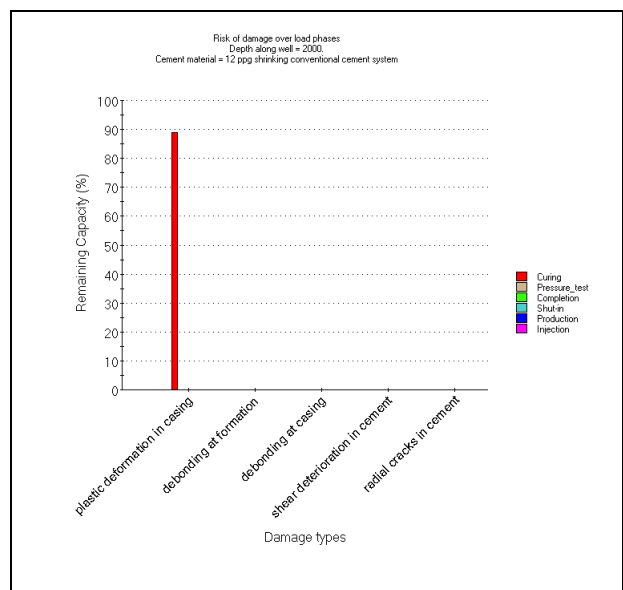


Fig. 14. Conventional lead and tail cement failure modes in CPWL4 (2,000 ft).

CONCLUSIONS

Life-cycle modeling was conducted to help determine the best cement system to use for the EGS project. Modeling helped verify the possible wellbore integrity during all phases of the life of the well. Possible cement and casing design improvements were modeled, and a better understanding of the behavior of cement systems during the life cycle of a geothermal well was gained. The following conclusions were determined:

- Foamed TRC cement should be able to withstand stresses and loads that occur in this well during the curing, pressure test, completion, production, and injection phases of its life and provide zonal isolation during the life of the well.
- Foaming the cement can mitigate the effects of hydration volume reduction. Foaming helps minimize shrinkage due to the presence of the internal pressurized gas phase in the cement.
- Conventional cement without compensation for shrinkage has a high risk of failure during all phases of well operation.
- When hydration volume reduction was compensated, without significantly modifying the mechanical properties, the risk of damage to the cement sheath was significantly lower than the conventional cement. However, the performance was not as good as foamed TRC cement.
- The injection phase of this well, in which 120°F (49°C) water is injected for cooling, appears to pose the greatest risk of causing damage to the cement sheath.

Additional sensitivity analysis will be conducted on both the production and injection wells discussed in this paper.

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