Successful Well Design and Remedial Cementing By Top Squeeze Method at Steamboat, NV, USA

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ABSTRACT
Properly cementing geothermal well casing strings is critical to protecting casing material and maintaining mechanical integrity for the duration of the well’s life. Operators and regulators are collaborating on strict well design to ensure mechanical integrity prior to permitting the well’s construction and operation. Well, casing, and cement engineering of geothermal wells must consider geologic conditions in order to drill and operate the well. These criteria include expected reservoir geochemical conditions, pressure, temperature, and zones of lost circulation.

This paper serves as a successful case study of well design, construction and implementation of the top squeeze remedial cementing method in the Steamboat geothermal field, in fractured and potentially corrosive reservoir. We cite several previous case studies in the literature which serve as continuing examples of how to manage and succeed in challenging geothermal environments.

1. Introduction
Ormat drilled well 42A-32 in the Steamboat field in 2018 to support injection at its Steamboat complex. Injection well 42A-32 was drilled to replace existing injection well 42-32 in the Steamboat field. Geologic conditions present at the well location include an unconfined NCG (non-condensible gas) entrained steamzone above a highly fractured and permeable reservoir. Well 42-32 had issues with lost circulation, lack of cement returns on the intermediate casing string, and later during its operating life, the well had cement and casing corrosion requiring multiple scab liners. As a result, the well operated for less than 10 years. Despite the challenging geologic environment, the site of this injection well has been critical for reservoir management in that it provides pressure support to both Steamboat Hills and Lower Steamboat (Figure 1), while being isolated from nearby ground water aquifers.
Well 42A-32 was planned as a vertical injection well with the geologic objective of twinning the high permeability feed zones in offset well 42-32 between 900-1400 ft. The planned total depth was 1400 ft and the completed total depth was 1030 ft.

The well utilized CO₂ resistant ThermaLock cement on the surface and intermediate casing strings to prevent degradation of the cement. ThermaLock cement is chemically different from Portland cement and thermally stable to over 1,000°F. It is known to resist carbonic acid attack in corrosive geothermal environment due to its unique chemistry that does not contain Portland cement, a component that decomposes in the presence of wet CO₂. Casing for these sections were made of corrosion resistant steel to provide additional protection. While cementing the intermediate casing string, a low-density foamed cement blend was utilized to ensure minimal to no cement fall back in the annular space. Despite these efforts, the primary cement job was incomplete due to highly fractured formations. Remedial cementing employed a top squeeze to pump foamed cement from surface and displace the annular space. The top squeeze was successful in bringing cement to surface.

Figure 1: Steamboat Wellfield Map
2. Geologic Conditions

The Steamboat geothermal field is located along the western margin of the Great Basin, lying in the Truckee Meadows basin and flanked on the west by the Carson Range and the east by the Virginia Range. The geologic section consists of thin Quaternary-Tertiary aged alluvium (<50 ft thickness) underlain by Tertiary basaltic andesite (<50 ft thick) underlain by Cretaceous granodiorite (Thompson and White, 1964). Stratigraphic horizons were well constrained by the proximity of offset well 42-32 (<50 ft separation). Triassic metasedimentary units comprise basement rocks into which the Cretaceous granodiorite has intruded. Production and injection wells feed to permeable steeply dipping (60-80°) fractures penetrating the granodiorite and metasedimentary section (Walsh et al., 2010).

The drill pad is located in the hanging wall of a highly permeable fault intersection. There are several thermal features including steaming ground and vegetation anomalies surrounding the pad. Gas (H₂S and CO₂) from the underlying reservoir disassociates to form sulfuric acid (H₂SO₄) and carbonic acid (H₂CO₃) (Figure 2). These in turn alter silicate minerals to clay. The surrounding geologic units have undergone argillic alteration where feldspar minerals have been altered to quartz+kaolinite+alunite (Schoen et al., 1974). Figure 1 shows the distribution of this alteration pattern highlighted as orange with an aerial photo base map. This alteration process and pattern are closely associated with permeable faults indicating the importance of fractures to fluid flow. In addition to altering the surrounding rock the CO₂ gas degrades conventional cement blends via carbonization while H₂S corrodes steel casing.

A dense fracture network developed within the granodiorite hosts reservoir conditions of 300°F and hydrostatic pressure conditions with a static water level of ~350 ft below ground surface. The natural state pressure-temperature regime indicates near liquid-vapor saturation and there is a mapped hydrothermal breccia sourced from a suspected violent hydrothermal eruption (White,
1955). The source of the hydrothermal eruption material is located ~0.5 miles north of the 42-32 pad (Figure 1). The known near-boiling conditions, hazardous gas, and inferred hydrothermal eruption craters necessitated a surface casing point to be selected at a depth to minimize safety issues.

3. Utilization of \( \text{CO}_2 \) resistant and foamed cement in geothermal wells

\( \text{CO}_2 \) gas degradation of geothermal well cements has long been an issue leading to loss of well integrity. Numerous reports in the geothermal literature discuss the carbonization process by which cement is carbonized and the resulting byproducts are dissolved by acidic fluids (Milestone and Aldridge, 1990). Portland cement is well-known to be degraded by carbonic acid due to the decomposition of portlandite and calcium silicate hydrates, the components that exist within the conventional Portland cement system, by wet \( \text{CO}_2 \). ThermaLock cement is a \( \text{CO}_2 \)-resistant cement blend originally developed in by Brookhaven National Labs, Halliburton, Unocal Corporation, and CalEnergy Operation Corporation (Sugama, 2006). The lack of decomposable Portland cement components is unique to the Thermalock cement. The cement contains calcium aluminate phosphate (CaP) which helps reduce \( \text{CO}_2 \) gas attack on cement. Latex cement is another option to reduce \( \text{CO}_2 \) attack.

Foamed cement has been used in the geothermal industry since the 1980’s e.g. Rickard, 1985. This technique involves blending nitrogen gas with cement to lighten the slurry density. Foam cement stabilization is achieved by the use of a foaming surfactant to ensure the Nitrogen bubbles does not coalesce under downhole conditions. The use of foam cement is advantageous in highly fractured formations where fall-back is expected. The foam lightens the equivalent circulating density (ECD), especially in reservoirs with low fracture gradients and allows for downhole expansion to fill large voids and fractures.

The combination of foamed and \( \text{CO}_2 \) resistant cement is required in special circumstances where a lightened hydrostatic head of the cement is required. The overlap of acidic conditions overlying a highly fractured reservoir occurs in many geothermal reservoirs around the world. Several examples of case studies are available in the literature e.g. Hernandez and Nguyen, 2009 and Peters et al., 2013.

4. Well Design

The well design was determined as follows:

- Conductor casing would be set and cemented at 101 ft.
- The surface section would include 20-inch hole and 16-1/2-inch casing set at 220 ft.
- The intermediate section was planned to be 14-3/4-inch hole and 10-3/4-inch casing set at 800 ft (Figure 3).
- The production section would be 9-1/2-inch hole to 1400 ft or until significant permeability was encountered. Slotted production liner would be run in the well if hole instability was observed during drilling/testing.

The surface and intermediate casing depths were chosen based on several criteria. The overall goals were to 1) set casing prior to drilling into hazardous conditions such as a steam kick, 2)
choosing a casing setting depth to ensure a competent cement job, and 3) utilize cement and casing materials to resist acidic corrosion from CO₂ and H₂S.

Both surface and intermediate casing strings would be made from corrosion resistant materials. The casing strings would be made from corrosion resistant steel, surface casing of wall 304L stainless steel and the intermediate casing made of 60.77 lb/ft 13CR-L80 (chromium steel). Both would be cemented with ThermaLock cement to prevent corrosion and to ensure well integrity. The 10-3/4-inch intermediate casing string was planned to be cemented just above the fractured reservoir where heavy fluid losses were observed in offset well 42-32. A foamed cement was chosen to mitigate lost circulation issues encountered while drilling and prevent cement fall back in low fracture gradient formations.

Figure 3: Well completion diagram for Steamboat 42A-32.
4. Drilling Operations

Well 42A-32 was spud-in on September 24, 2018. Surface hole (20 inch) was drilled and 16-inch casing set to 222 ft. Minor mud losses up to 7 barrels per hour (bph) were healed with lost circulation material (LCM). Halliburton cemented the surface casing string with ThermaLock cement and full returns.

The 14-3/4” intermediate hole was drilled to 790ft. Minor mud losses (<3 bbls each) were encountered between 558- 681 ft. A larger loss zone was encountered between 785-790 ft with loss rates between 100-200 bph. Ormat’s team decided to heal the larger lost circulation zone and cement the open hole to a shallower depth prior to running casing. A casing setting depth of 750 ft was selected because solid rock was present at this depth, and only minor mud losses had occurred above this depth. The losses eliminated through a combination of lost circulation material, cinders to fill the loss zone, and an 80 linear foot cement plug. The top of cement was tagged at 701 ft and cemented drilled out to 750 ft for the casing point.

5. Cementing of the 10-3/4-inch intermediate casing string and top squeeze

The intermediate casing material for this section was selected as 13CR-L80 for corrosion protection. Halliburton cemented the intermediate casing with a nitrogen foamed ThermaLock blend (12 ppg lead, 15.5 ppg tail, 100% excess). The cementers initially observed full returns to surface, before circulation was lost while displacing cement; 50 bbls of 12 ppg cement returned to surface before the level dropped. Typically, pressure is held on surface after pumping foamed cement to maintain the density of the foamed cement. Since the returns were lost down the annulus, no pressure was held on surface while waiting on cement.

Afterwards, the top of cement in the annulus was tagged at 616 ft. The top of cement (TOC) roughly correlated to the midpoint of a minor loss zone interval (598-691 ft) that had been encountered during drilling. The correlation of the tag depth and minor losses suggest that the TOC was related to this small loss zone. The 100% excess cement volume that had been pumped into the well had filled the bottom of the hole from the casing shoe at 750 feet, but apparently had opened up, and flowed out into, this (initially) small loss zone.

6. Remedial cementing- top squeeze

Due to the deep top of cement in the annular space a conventional top job utilizing tremie pipe could not be performed. Instead, the top job was performed as a top squeeze. Several varieties of this method are described by Rickard et al., 2013. In this particular case, a program was developed whereby the annular BOP was shut and cement pumped through both side outlet valves below the BOP. Cement pumped from surface displaces any water in the annular space and flows downward, and then out into the lost zones. To ensure cement reaches the loss zone at the bottom of the open annular space (TOC), the cement volume is well in excess of that of the annular space volume.

The primary alternative considered included performing a top fill with tremie pipe on a deep top of cement, but this was expected to be difficult due to friction pressures of cement flowing through small diameter pipe. Additionally, it would be difficult to pull the long string of tremie pipe out of the annular space before the top job cement would set.
The top squeeze consisted of 110 bbls of 12 ppg nitrogen foamed ThermaLock cement (84 bbls unfoamed equivalent) (Figure 4). A reverse Nitrogen gas schedule was utilized to ensure constant density throughout the column of cement. The pumped cement displaced the annulus water, which likely moved out into the formation along the minor loss zones that were encountered above 621 feet. After the cement was pumped, pressure (138 psi) was held on surface for 12 hours after cement was in place to maintain the density of the foamed cement. The top of cement was later tagged at 213 ft; 7 ft above the surface casing shoe. A second top job was performed with a tremie pipe and brought cement to surface (15.2 ppg).

**Figure 4: Foamed ThermaLock top squeeze job data.**

Geophysical logs were collected within the intermediate casing to determine the cement quality and bond with casing. Schlumberger ran their Isolation Scanner log to evaluate cement from surface to 700 ft. The bottom of the logging interval was limited to 10 ft above the top of the 40 ft float collar (shoe at 750 ft). The first set of logs were collected in unpressurized casing. A second run was collected with the casing pressure set to 600 psi.

After collecting the logs, a mechanical integrity test (MIT) was performed on the 10-3/4” casing to 600 psi. The casing passed the MIT. The rig crew then ran in with a drilling assembly, drilled out 40 ft of cement, float collar, cement in shoe track, float shoe, and down to 1 ft below the shoe. A shoe test was performed to 0.55 psi/ft gradient with 77 psi at surface and 8.6 ppg mud. The mudlogger logged good quality cement below the shoe. The cement held pressure which indicated a positive test result. The 9-1/2” production hole section drilled through 14-3/4” plugged back hole (750-790 ft) with full returns. These data highlight solid cement around the 10-3/4” casing shoe.
7. Injection interval and well completion

The 9-1/2” hole below 750 feet was drilled with full returns to 867 ft where partial circulation losses were encountered before total losses occurred at 930 ft. The well was drilled without returns down to 1030 ft and an injection test was performed to determine the well’s injection capacity. The test results indicated very high injectivity.

Additional measures to maintain well integrity included regrading of the well pad to slope away from the well and cellar. This keeps excess water runoff from accumulating in the cellar and potentially seeping down the casing. Cathodic protection equipment was also installed to promote corrosion on a sacrificial anode away from the well casing.

8. Conclusions

There are several lessons learned in spite of the overall success of the drilling of Steamboat 42A-32. Success can be attributed to the teamwork of geologist and engineers who designed a well around the challenging geologic conditions present. Resource should drive well design and engineering, not the opposite. The utilization of corrosion resistant cement and casing ensures that the new well will have a long usable lifespan. Cementing in highly fractured rocks and low fracture gradients poses the risk of cement fall-back during primary cementing. Fallback still occurred, despite attempts to heal drilling losses, selecting a shallower casing depth, and lightening the cement slurry with foam. The top squeeze method was very effective in displacing water from annular space and filling it with cement.

Other important criteria for well design include casing setting depth. Our experience in previous drilling campaigns at Steamboat gave critical information in the casing setting depths for 42A-32. Casing should be set as shallow as necessary to ensure a proper cement seal around the casing, most importantly at the casing shoe. Potential issues include severe lost circulation, incompetent rock leading to hole collapse, shallow water bearing zones, and shallow steam or near-boiling reservoir conditions. Incorporating these data into well design prevents losing the open hole portion of a well, costly drilling fluids bills while drilling with lost circulation, and preventing any cross-flow between deeper and shallow water bearing units such as shallow groundwater aquifers. An additional consideration for surface casing setting depth is to allow drilling ahead with blow out prevention equipment (BOPE) through shallow steam zones.

If possible, a pressure log from an offset well should be used to determine reservoir static water level, pressure gradient, and to calculate the boiling point for depth (BPD). These data will enable geologists and drilling engineers to select shallow casing depths to avoid surface blowouts and intermediate/production casing shoes to depths at which the drilling fluid column pressure will not exceed the fracture pressure gradient at the previous casing shoe.

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