FOAM SLURRY FOR CEMENTING CASING IN GEOTHERMAL WELLS

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ABSTRACT

One of the more difficult aspects in geothermal well construction is ensuring a quality cement job to support the entire length of the casing. Good "anchoring" of the casing string is imperative to restrain the casing against thermal expansion and contraction upon cyclic exposure to hot geothermal fluids. The cement sheath also serves as a barrier against the ingress of potentially corrosive fluids.

Unfortunately, the physical characteristics of a conventional cement slurry exerts a hydrostatic pressure and equivalent circulating density while pumping that are higher than the formation strength can withstand here in New Zealand. For long casing strings, it is common to experience total losses during the primary cement job that require several remedial or "backfill" cement jobs with risks of channeling or voids forming when cement is placed from above and no guarantee of a complete cement sheath around the pipe. Casing damage from post drilling well discharges have almost always been traced to either casing collapse or buckling as a result of a poor cement job. A collapsed production casing or pressure containment vessel of the wellbore may be catastrophic as it means the loss of the well. The loss of an already expensive well is compounded by further losses in production, hence, revenue.

This paper sets out Mighty River Power's (or MRP) development of cementing techniques to bring the primary cement slurry back to surface or, in the case of a liner cement job, to get the slurry to the top of the liner.

INTRODUCTION

MRP operates or manages close to 200 geothermal wells across 5 different fields in the Taupo Volcanic Zone (or TVZ, see Figure 1) of the North Island, New Zealand.

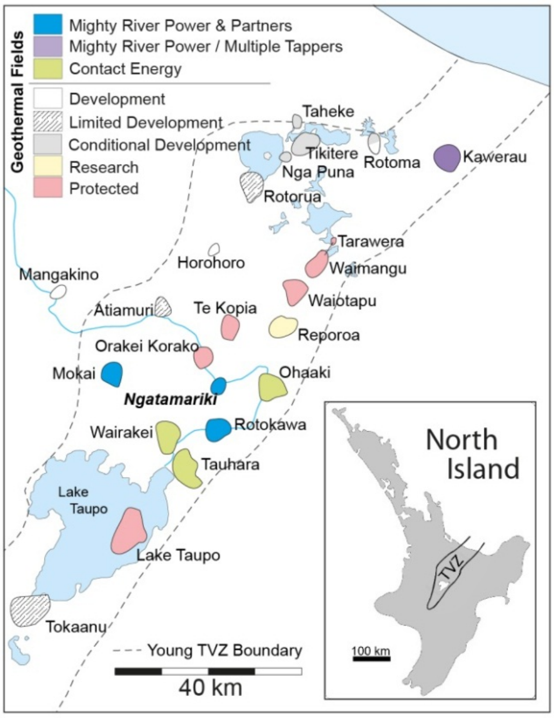

Figure 1: The Taupo Volcanic Zone (TVZ) in the North Island of New Zealand

As with most geothermal power operators, MRP's wells are a mix of:

- Producers, injectors and monitors
- Standard, big bore, ultra big bore and slim hole
- Vertical and deviated
- Single to multi string casing design, with 3-string most common

Geothermal wells are designed and constructed to satisfy particular requirements for extracting energy and managing the geothermal resource. Figure 2 shows a schematic view of a typical deep geothermal well. Apart from the actual drilling of the wellbore, the other common area of risk and uncertainty inherent during well construction is the use of casing and cement.

Proper cement materials selection and placement techniques are crucial to ensure that the well is able to be safely and commercially operated for 25 years or more under the typically harsh geothermal conditions. In the TVZ, the geothermal environment combine to being permeable, fractured and under pressured. They are under pressured because the static reservoir pressures are less than a full column of cold water from surface. This imposes a challenge that needs to be overcome while the well is constructed.

Two other hurdles are the higher natural state temperatures and the deep location of the geothermal reservoir.

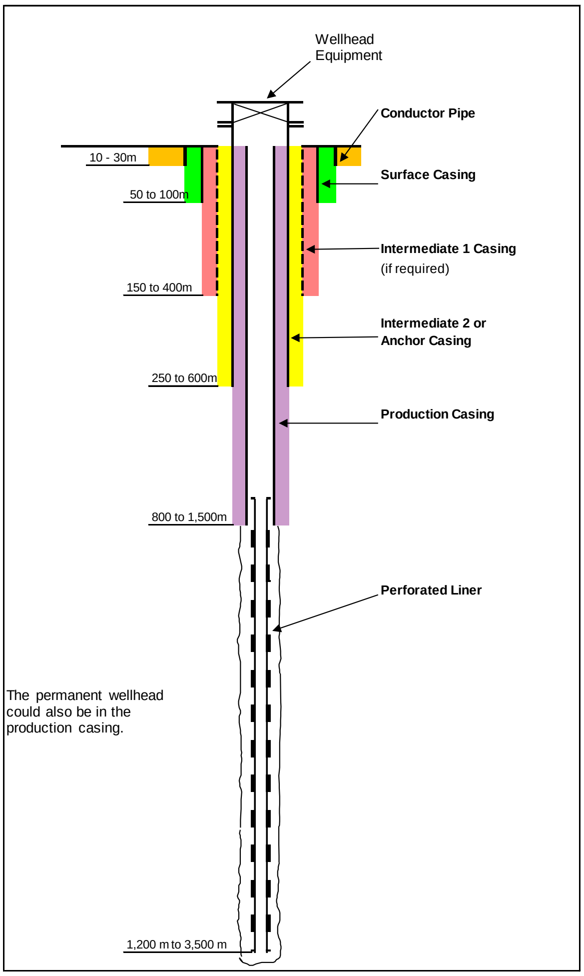

Figure 2: Typical deep geothermal well

PURPOSE OF GEOTHERMAL CEMENTING

As part of constructing a well, cement is pumped to protect and support the casing, stop the movement of fluids into different formations, and prevent the movement of fluid through the annular space outside the casing.

For geothermal wells, the top hole sections down to just into the reservoir are cased and cemented to effect zonal isolation of undesirable formations and support the wellbore. Unlike most cased sections in oil and gas wells, where typically only half to two third of the casing is cemented, geothermal wells require their entire casing string to be completely sheathed by cement (i.e. casing to open hole annulus and the casing-to-casing sections). This is necessary to preclude unacceptable growth of the casing from thermal expansion, while maintaining a barrier between the zones such as fresh and salt water aquifers or corrosive sections.

When the well is subsequently operated, the wide fluctuation in temperature imposes considerable stress on the casing and the cement. This requires that both materials should have sufficient capability to maintain integrity and withstand exposure to the corrosive chemistry and high temperature of geothermal fluids. For cement this means being strong and resistive to corrosion and temperature.

CONVENTIONAL CEMENT PLACEMENT TECHNIQUES

There are many ways to cement casing but the more common systems used include:

a) Travelling plug systems
b) Inner string cementing
c) Stage cementing using a stage collar
d) Liner and tie-back system

In all of these approaches, the traditional or conventional way of cementing the casing is with an API Class "G" cement + silica blend lead slurry, usually at 13.4ppg, with a smaller volume of denser tail slurry, around 15.4ppg, placed around the shoe of the casing string. This is fraught with risks and difficulties as the hydrostatic pressure from the dense and viscous cement slurry is more likely higher than the strength of the formation in the open hole causing partial, and oftentimes total, losses. Hence, full circulation during the primary job is not achieved. This necessitates the immediate pumping or flushing of the casing-to-casing annulus with water, followed by a remedial cement or "back-fill" or "top-job" into the annulus. More often than not, several of these "backfill" jobs need to be pumped in stages until cement slurry is seen at surface. The complexity also increases when the length of the casing string increases.

While the remedial job is time consuming, there is also no guarantee that each top up is "layered" right on top of the one before it. The pumped slurry will always want to follow the path of least resistance to the weakest formation that breaks down and accepts it. This is not necessarily on top of the previous cement. Even inside the casing-to-casing section, the top job liquid slurry would also want to track along the quickest flow path. Channeling can occur along and/or around the casing.

Both scenarios increase the likelihood of a trapped fluid, whether water or mud, in pockets around the casing. When the well is later heated up by flowing, any trapped water will expand or convert to steam and can collapse the inner pipe.

The weak formations (low fracture gradients), requirements for full cement coverage of the casing string, deep setting depths, high temperature, combined with the high slurry density and viscosity of conventional cement slurries all work against having competent cement pumped around and supporting the entire casing string. Likewise, the required quality of the cement, the complexity and corresponding cost of placing it down the well increases exponentially with depth and temperature.

THE MRP EXPERIENCE

Like many geothermal operators, MRP has experienced problems with casing-cement jobs and has had instances of well impairment as a consequence of sub-optimal cement placement. This provided the drive to explore alternatives to ensure quality cement to surface, which would support the entire casing string, by engineering the slurry and modifying the placement technique and equipment. While it was realized that the alternative approaches would bring with it complexity and potentially higher cost, this was outweighed by the lifecycle cost of low quality cement jobs. Two high level approaches were considered: reverse cement circulation and the use of lightened cement.

The reverse circulation method would mean doing the primary job through the annulus with conventional slurry. The operational requirement of using a radioactive tracer and risk of losses being still possible was considered less than ideal. Artificially lightening the slurry was evaluated.

For lightening cement, there are three choices;

1) Adding water
2) Adding hollow spheres or low density additives
3) Adding gas bubbles such as nitrogen – i.e. foam cement

Of these, foam cement was considered optimal for MRP's well conditions. The technology was first trialed in 2009. Since that time MRP has applied the technology across 3 drilling campaigns for:

- Long strings back to surface via the inner string method
- A cemented liner with a tie-back option
- Triples and super single rigs
- Vertical and deviated wells
- Big and standard bores
- Producer and injector wells
- API Class "G" + silica blend and calcium phosphate cement

Over this period, lessons were learned that allowed fine tuning in planning and executing the job. Fig 3 shows a typical foam equipment set-up which requires adding a foam package to the already existing conventional cement package (i.e. slurry pumps, silos and P-tanks). The major additions include:

- Nitrogen unit consisting of nitrogen tanks, N_2 generator and treating iron (usually 1-1/2" diameter)
- A small flow-back manifold and double variable choke to handle returns and provide a means of pumping cap cement. This was used in conjunction with the rig's blowout preventers (or BOP) to control back pressure from the nitrogen-energized fluids.
- A surfactant injection package to measure and add the right quantity of foaming agent to the base slurry
- Temperature sensors, flow meter and pressure transducers are used to collect data and feed it to a computer to make sure the nitrogen, cement and surfactant rates are within design limits.

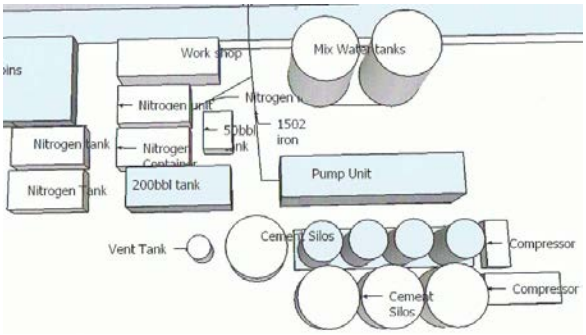

Figure 3: Typical footprint for foam cementing equipment

For hooking up or integrating the foam cementing package with the well or rig, Fig 4 shows the schematic of this set up.

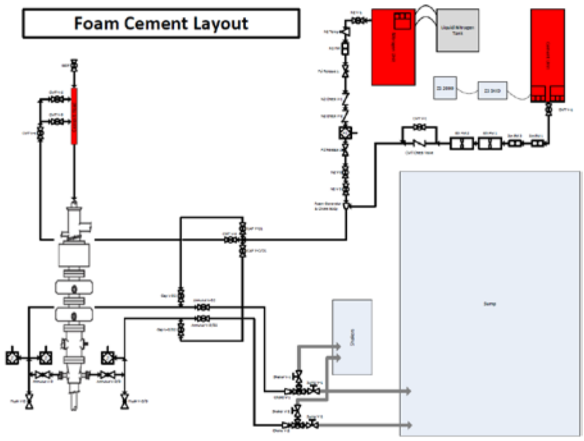

Figure 4: Schematic of valves and lines from foam cementing equipment to the well

Foam cementing of geothermal wells has been performed since 1995. Prior to that, it was used on oil and gas wells that were steam stimulated such as steam assisted gravity drainage wells (SAGD). These were at temperatures between 285^{O}C to 340^{O}C which is the same operating range as geothermal wells. Extensive research and testing over several wells and years have also been done.

A foamed cement is a mixture of cement slurry, called base slurry, foaming agents and gas which is usually nitrogen. Visually it resembles gray shaving cream. Its main characteristic is as a low-density cement matrix with low permeability and relatively high strength. Other advantages it has over conventional slurry include:

- Since it has the same base slurry composition (ratio of cement binder and the silica), resistance to temperature retrogression is still the same as an unfoamed slurry
- better ability at sealing lost circulation due to the expansive nature of the energized fluid.
- more elastic and better able to accommodate thermal induced expansion/contraction and resistance to cracking
- better mud displacement properties
- insulating properties due to the reduced heat transfer rate. More geothermal energy is therefore allowed to reach surface.

However, the following are challenges for the foamed approach that require adequate planning:

- It is important that the BOP's are checked and are working properly as they are a critical component in the foam job. It is ideal to have casing rams as the primary seal around the casing while having the annular BOP as the back-up.
- As there is only one supplier of nitrogen in New Zealand, it is important that timely delivery is managed properly considering that the gas vendor has other major clients it prioritizes.
- The complexity of the job requires around 10 to 12 people for a full nitrogen crew including back-ups.
- Cement equipment footprint is about 100% more than in a basic or conventional job. This has to be considered during pad construction or preparing the rig up plan.
- The entire foam job package is generally around 25 – 40% more costly than a conventional and is driven more by the service (equipment rentals and personnel costs) rather than the material category.
- The nitrogen truck driver and cementing provider need to be certified and experienced handlers particularly when transferring liquid nitrogen from a tanker to onsite tanks. MRP experienced an incident of a burst disc from over charging a storage tank.

The key to a successful foam cement job is having accurate information and quality materials, equipment and personnel as there are more variables that need to be considered. Planning for a conventional cement job requires knowing bottomhole circulating and static formation temperatures, offset well geologic information and data while drilling the current hole interval. Planning for foam cement needs the same information plus the following:

1) fracturing pressure or gradient at the previous casing shoe. This means doing a leak off test right after drilling out the upper casing's shoe,
2) Open hole diameter by running a four- or more finger calliper, and
3) Formation or pore pressure

These three additional pieces of information are used to engineer the foam slurry for the correct scheduling of nitrogen and surfactant addition to allow for a uniform density of the foam slurry over the entire casing interval upon job completion. Likewise, the consistency of the energized slurry needs to be controlled to stay below the fracturing gradient but above formation pressure, otherwise the well may flow.

While such a balance of fracturing pressure and pore pressure may be considered difficult to achieve, greater flexibility is actually afforded by the nitrogen. The gas additive can be used to lighten not only the base cement slurry, but also the drilling fluid, water spacers and scavenger slurry. In extremely fractured and permeable formations, it can be injected into the annulus to push the water level down prior to pumping the foamed liquids of the primary job.

Where required, the base slurry may be physically lightened first with glass spheres or spherelite before further being lightened with nitrogen.

<u>Long String Cementing</u>

MRP has used foam cement on 9-5/8" to 20" sized long strings of intermediate and production casing from surface to depths that ranged from 400 to 1,600m. All of these were done using the inner string method for better control and savings in time and material.

The general sequence of a normal long string foam job includes:

1) Pump foam mud
2) Pump foamed water spacer. Optionally an additional step may be to pump calcium chloride x sodium silicate flushes interspersed with water spacers if massive losses have been experienced while drilling
3) Mix and pump foamed scavenger slurry
4) Pump foamed lead cement
5) Pump unfoamed tail cement (N2 addition to slurry is stopped)
6) Drop DP dart and displace to FC with water. Check floats and bleed off
7) Mix and pump unfoamed cap cement thru the annulus. A cap length of 100m or the casing to casing annulus interval may be considered.

The last 8 wells with long string to surface had the foam cement made to reach surface from learnings of the earlier jobs. Apart from maturing the technology, the important step was to regain returns first before the foam cement and succeeding cap is pumped.

As mentioned earlier, the degree of loss severity and length of casing interval is addressed by engineering the different fluids used and their placement sequence. The long string approach is also optimal for deeper casing strings. On one particular well, the hole interval was drilled blind with total losses for most of its length and yet had its casing successfully cemented back to surface.

It is better to do the foam cement job as an inner string than using the travelling plug system. However, effects of temperature change on the inner string need to be taken into account, requiring closely monitoring the hook load on the inner string to ensure that it stays stabbed-in to the float collar. A diverter on top of the landing joint may also be needed as a precaution on hot wells in case there is a leak around the stab-in nipple and the float collar or if the annular fluids reach high temperature prior to circulating the annulus and boil on coming to the surface. The alternative is not to circulate out energized fluids leaking out of the nipple seal area and instead pullout slowly and carefully while continually topping up with mud while coming out of the hole. The casing overdrive or a MacClatchie head can then be used to seal the top of the landing string.

Liner Only Cementing

MRP cemented 9-5/8” and 13-3/8” production liners on 7 wells either as part of a liner tie-back job or as a stand-alone casing string. Liner intervals over a thousand meters were cemented to as deep as 1,500m.

From MRP’s experience, this was a more challenging job to execute. It was difficult to see the differential U-tube pressure on top of the liner after breaking the nut and unstinging from the liner hanger. On jobs where the liner top was closer to surface, the risk of energized fluids reaching surface had to be specifically engineered and managed. This would not be an opportune time to close the BOP as there is still the drillpipe landing string and hanger release tool down the well.

As such, the long casing inner-string foam cementing is favored over the liner tie-back or 2-stage approach. The liner approach can be implemented with foam where the top of the liner is deeper, with little risk. Where the top of the liner would be shallow, a long string should be used instead.

Other Observations and Learnings

- There was never an incident of cementing up the BOP’s while these were holding back pressure, as there was a cushion of foamed mud or water ahead, which placed it just below the rams or annular that served as a barrier against the foamed scavenger or lead as well as the cap slurry that came afterwards.
- A visible dye such as iron oxide on the last few barrels of the scavenger slurry aids in being a visible tracer for when the scavenger is about to be circulated out and followed by the lead slurry.
- Back pressure information and adjustment are important because the down hole pressure has to stay above pore pressure and below fracture pressure.
- There was an attempt to monitor the quality of the foam returns and determine the interface between the scavenger and lead slurries. Two methods were tried. The first involved collapsing the foam cement with defoamer and the samples weighed, but it only gave rough indications of cement density. Another considered real time chloride measurement but it would be masked by the chloride content already in the mix water.
- It was observed that the foam mud reached surface a few barrels sooner than computed and the information was used to fine tune the back pressure.
- In an unrelated incident, the foam equipment already onsite was used to free a differentially stuck drill string by pumping nitrogen around the BHA to reduce hydrostatic pressure in the wellbore.
- On some wells, minor bubbling was observed in the annulus after a long string job. But it is not advisable to put surfactant or foaming agent on the unfoamed cap cement, which might reduce the risk of nitrogen breakout, as the surfactant has retarder properties and the cap slurry needs to set quickly. The better approach is to increase the cap slurry length.
- The high pressure and cryogenic nature of nitrogen must be given the respect it demands when being used. Having robust safety systems and plans should be followed to manage its use.
- Cement bond logging tools do not work well due to the attenuation properties of the set foam cement.

CONCLUSIONS

For MRP’s particular geothermal fields with under pressured and permeable top hole formations, foam cement is currently proving to be the best method to ensure that long production casing strings are fully enveloped and supported by cement. This has greatly improved the integrity of the pressure containment casing string of the well while offering secondary benefits of good displacement properties, resistance to stress cracking and insulation properties.

The use of nitrogen and other lightening agents to engineer the slurry or other liquids used on a cement job offers considerable flexibility and control to make this a possibility.

While more complex in its planning and execution compared to a conventional casing-cement job, having the processes, tools and experienced personnel is the way to manage the successful application of this technology. The cost for ensuring this outcome is far outweighed by the risk of losing a well as a result of poor cement placement.

Geothermal well cementing remains a high risk aspect of well construction. Both the geothermal industry and the much larger oil and gas industry are working on improvements for both placement and longevity (chemistry). We consider that at the right density, the more uniform placement and higher ductility of the lightened cement sheath will endure favorably as compared to conventional class “G” blend slurry.

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