INITIATING GEOTHERMAL WELL DISCHARGE WITH COILED TUBING

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ABSTRACT

Geothermal wells, with shallow feedzones and with subsurface conditions close to boiling, will often discharge naturally or with help from an artificial or natural gas cap. However, for deep-feeding geothermal wells in under-pressured reservoirs, the requirements to initiate discharge using a gas cap increase substantially. Furthermore, wellhead pressure of more than 60 bar may be needed in order to achieve boiling when the well is opened. This method increases the potential to cause casing and cement damage through rapid heating.

To reduce the thermal shock loading on the cemented casing by heating the well in a controlled fashion, injection of gas through coiled tubing (gas lift) can be employed to initiate flow. This method reduces the density of the overburden of cooler water to the extent that it will flow to surface, even when the water level is several hundred meters below the wellhead. The cool fluids are gradually replaced with hot fluids from the deep feedzones and the wellbore is heated in a controlled manner until the well can self-discharge.

This paper presents a case study of a gas lift to initiate well discharge using coiled tubing and nitrogen gas injection. The project planning and equipment specifications are discussed. The data collected during the stimulation is compared with predictions which were made using correlations from empirical data.

1. INTRODUCTION

There are various methods which can be employed to initiate geothermal discharge of a geothermal well which will not do so on its own. Such methods include: natural or artificial gas cap, steam injection from other wells or a steam generation plant, swabbing and gas lift using coiled tubing. The method selected is largely dictated by three factors: technical feasibility, risk exposure and cost.

In Contact's normal operations the most common of these is the gas cap method, this compresses the cold overburdening water downwards into the hotter zone of the well. Once the well is opened and the pressure rapidly removed, the water is able to achieve boiling and discharge to surface.

Some recently completed deep wells have feedzone temperatures in excess of 300 °C, but stand open with a water level more than 300 m below ground level. As the depth of the water level and the length of the cold water column above the feed zone increase, so too does the wellhead pressure required to initiate flow using the gas cap method; sometimes more than 60 bar is required . When this method is used a rush of hot water is discharged through the cold upper section of the casing, the well bore is heated in a sudden uncontrolled manner. This increases the potential to cause casing and cement damage through rapid heating. The rapid heating increases the risk of casing damage and this risk may outweigh the benefits of simplicity and low cost.

This paper discusses the use of coiled tubing with compressed gas to initiate discharge of a well in the Ohaaki steam-field. This method was selected due to its isolated location to existing steam field assets and 1000 m of cold overburdening water column.

2. DISCHARGE OF GEOTHERMAL WELL

The most common methods to artificially initiate geothermal well discharge are the gas cap method, steam injection and gas lift with coiled tubing.

2.1 Gas Cap Method

The gas cap method compresses the water table down into the reservoir allowing the water to heat up. In some cases this cap is generated naturally when the well is left in a shut-in state, or it may be generated artificially with a compressor or nitrogen.

Figure 1 below shows an example of a well where the gas cap method can be successfully applied. In this case the well stands open with a water level 300 m below the wellhead and the temperatures throughout the complete depth are below boiling point: i.e. the boiling point for depth (BPD) profile is to the right of the measured wellbore fluid temperature, as such the well bore fluid is too cold to boil at any depth. If an artificial gas cap with 35 bar pressure is added, the fluid level can be depressed by 350 m and the BPD profile from the depressed water intersects and is to the left of the natural temperature profile down to 1250 m depth. When the pressure is suddenly released the water column rebounds to its natural level and all of the fluid above the pressurized saturation temperature will boil. In this case the fluid between 700 m and 1250 m. As the well discharges the fluid will be replaced by hot feedzone liquid.

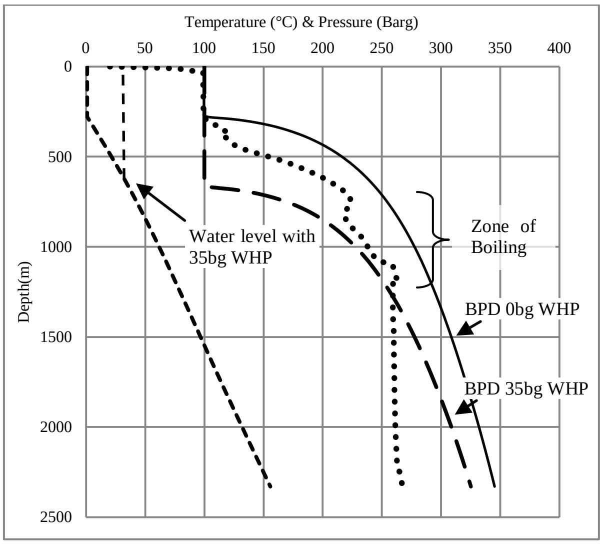

Figure 1: Well with 35barg Gas Cap

The initial discharge of the well is much more sudden than other methods at hand; as such there is no control of the rate of heating of the production casing. Where temperatures are relatively low, say <260 °C, and the cement is known to be "good", such rapid change is not of great concern. However when there may be defects in the cement and feedzone temperatures are >300 °C there is increased potential for casing damage.

2.2 Steam Injection Method

Steam injection can be done via two-phase fluid or steam only utilizing existing online geothermal wells. Alternatively a temporary steam boiler can be used, although this is relatively expensive where high pressures and flows are required. This method slowly heats the well bore to the saturation temperature of the inlet pressure of the fluid supply. When using other wells to provide a two-phase supply a large stimulation line is required between wells, up to 250 NPS/10", allowing for higher mass flow rates to effectively heat the wellbore. (Siega et al., 2005)

This method provides a high level of control on the rate of heating of the well.

2.3 Gas Lift Method

For the gas lift method coiled tubing or flush joint drillpipe is introduced into the well to a predetermined depth, then gas is pumped through the tubing. This reduces the density of the wellbore fluid to such an extent that the fluid level reaches the wellhead and the well flows. This removal of shallower cool fluid allows for hot reservoir fluids to flow into the well at the feed zone. Once enough hot fluid is introduced and the wellbore temperature is above the saturation temperature, the well can self discharge.

When considering the gas lift method there are many variables which need to be considered, however the two crucial factors are: the depth of tubing in relation to the water depth and the volume flow rate of gas delivered through the tubing.

The gases which are typically used are nitrogen gas, gasified on site from liquid nitrogen or compressed air. Nitrogen gas, as opposed to air, is used in the Oil and Gas Industry as a safety precaution against explosion or fire.

2. MODELING GAS LIFT

Modeling the gas lift is vital to specify minimum performance requirements for the equipment to be used. This is particularly important if the contractor/operator has had no prior experience or no published literature of similar well circumstances is available.

Various authors have produced models from both empirical correlations and analytical derivations. The complexity of the analytical methods amplify with increasing lift depth, more flow regimes are present due to larger variation of pressure throughout the depth of the well.

2.2 Empirical Correlation

F.A. Zenz (1993) made an empirical correlation from various publications to predict water flow rate with varying airflow rate. The data used to develop the model came from lift height ranging from 5in to 65ft and pipe diameters from half an inch to 15 inches.

The graphical representation of this data is shown in figure 2 below. Where;

$$V_G = Gas\ flow\ at\ discharge, SCFM$$
$$V_L = Liquid\ flow, gal/min$$
$$A = Pipe\ Cross\ sectional\ area, sq.ft$$
$$D = Pipe\ ID, inches$$
$$L = Lift\ height, ft$$
$$S = Submergence, ft$$
$$\rho_G = Gas\ density, lb/ft^3$$
$$\rho_L = Liquid\ density, lb/ft^3$$
$$D = Pipe\ ID, inches$$

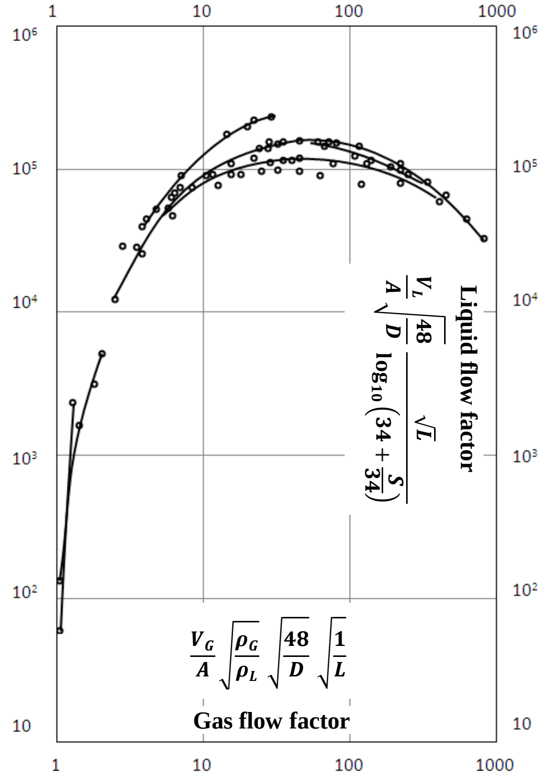

Figure 2: "Correlation" of air-water lift data, after Zenz (1993)

In this model the volume and density of the gas are based on the discharge conditions; these won't change significantly for the lift heights used to derive the correlation, however for the lift heights in geothermal wells theses values change significantly, increasing the error of the correlation.

3. OHAAKI WELL CASE STUDY

A well in the Ohaaki steamfield, NZ, has been brought on production using the air lift method; this technique was selected in preference to the others discussed earlier.

Similar to some other wells in the Ohaaki steamfield, the water level inside the well is around 350 m. This well has 9-5/8" 47 ppf production casing to 1500 m. Figure 3 below shows the expected returns to the flow rate of nitrogen, the coil outside diameter is 2" and the coil depth is 700 m.

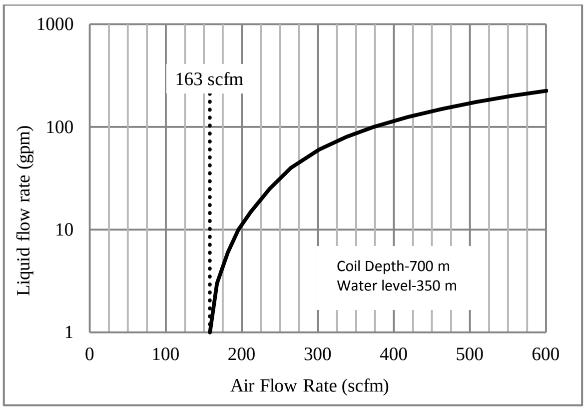

Figure 3: Predicted Air flow rate and returns for case study well

It was predicted that this well and coil configuration would need a minimum gas flow rate of 163 standard cubic feet per minute (scfm) to see any returns. A more desirable flow rate would be in the order of 200 gallons per minute (gpm) and would require 550 scfm, at this rate it is predicted to take one hour to remove one well bore volume (water table to major feed zone).

3.1 Job planning

The predicted minimum performance requirement of the gas delivery system was 43 bar/ 623 psi @ 550 scfm. This is made up from dynamic losses from delivering 550 scfm in a 2" (1.68" ID) coil of roughly 8 bar/ 115 psi from dynamic losses and 35 bar/ 508 psi to overcome the submergence head. Note that in this example the spool of coiled tubing was 2.5 km in length.

A compressor/booster kit able to deliver a minimum of 43 bar / 623 psi at 550 scfm is not commonly available in New Zealand. A contractor with a nitrogen gasification plant exceeding these requirements was available at roughly the same cost; this also added a substantial safety factor for additional gas flow and pressure if required. One of the down sides of using nitrogen is the finite volume of nitrogen on site. For this reason two 2000 gal tanks of liquid nitrogen were brought onto the site. This would allow for 10 hours of flow at 550 scfm, including any losses.

The wellhead was connected to a temporary silencer and a weir box, where the flow of separated water from the well was measured. The fluid is initially below boiling, thus all returns pass through the weir box.

Wellhead pressure (WHP) and a weir box water level transmitters were installed to monitor fluid flow and pressure.

3.2 Post Job Review

During the job data loggers were installed to monitor the WHP and fluid height in the weir box, this was in addition to the data collected on the coiled tubing unit, such as coil depth and delivery pressure. The gas flow rate was recorded from the liquid nitrogen converter. The data logger information is graphed in Figure 4 below. Returns were first seen when the coil end was run into a depth of 855 m and 450 scfm injection rate of nitrogen, much later than expected. The flow to the weir box was irregular and stopped after about 20min. The average flow rate over this time was 140 gpm. There was a coil circulation drop of 50 psi and an additional 25 psi WHP, it is assumed that these pressures contributed to the loss of the returns. A 50 psi drop is equivalent to a 35 m submergence head loss (due to well drawdown) and the 25 psi WHP to a 17 m addition to the lift height. This resulted in an unstable system and a decision was made to increase the nitrogen flow rate to 500scfm and keep tripping in with the coil. Unstable returns were seen and the nitrogen flow was once more increased to 600scfm with a final coil depth of 900m.

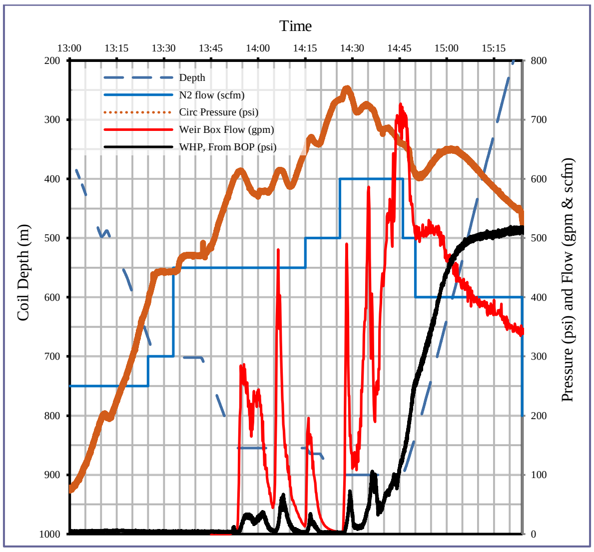

Figure 4: Data collected during air lift

The fluid needing to be removed prior to sustaining discharge was 80 m^3, this is equivalent to roughly 1.3 times the fluid volume from the original water level to the major feed zone. It should be noted that this can vary greatly from well to well; other authors have discussed this in great length. (Menzies at el., 1995)

Figure 5: Well sustaining discharge

3.3 Comparison to Correlation

There were three regions of flow during the coiled tubing air lift. These are tabulated in Table 1, below. Coil depth and water outflow are averaged and the WHP and drawdown not adjusted for.

Table 1: Periods of returns

Time Period	Coil depth (m)	N2 flow (SCFM)	Average flow (gpm)	Predicted (gpm)	Liquid Flow Factor (actual)	Gas Flow Factor
13:53-14:15	855	450	140	141	20000	3.033
14:15-14:26	873	500	50	171	7142	3.402
14:26-14:46	900	600	360	230	51565	4.081

This data has been superimposed onto the empirical correlation by Zenz in Figure 6, below. The largest error occurred in the time period 14:15-14:26 with a predicted flow of 171 gpm and actual flow of 50 gpm, however if this is compared to the original model, it is just outside the range of the empirical data points. The reduced outflow is assumed to be accounted for by the significant drawdown occurring during the lift, which was discussed earlier.

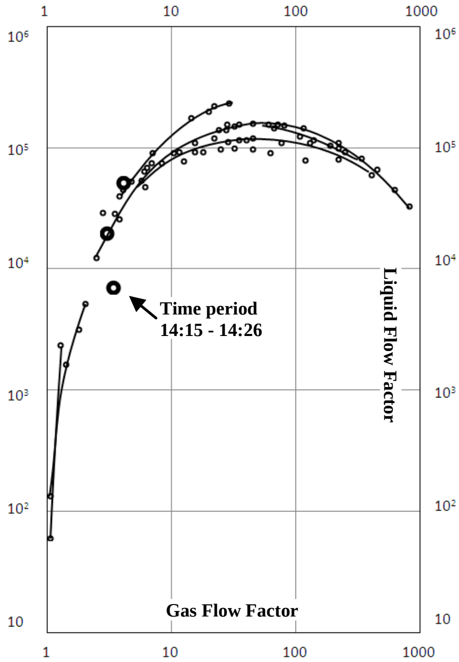

Figure 6: Case study data on empirical data by Zenz (1993)

3.4 Key findings

The model developed by Zenz can be used to predict the fluid returns based on gas flow air lift a geothermal well with coil tubing.

The results of this case study indicate that the submergence ratio, as defined in equation 1 below, is above 0.6 and a gas flow factor greater than 3 is used to predict when first returns are seen.

$$Submergence\ ratio = \frac{Coil\ submergence}{Coil\ submergence + Lift\ Height} \quad (1)$$

Although not measured, it was found that the fluid return temperature increased at a slow gradual rate compared to that when using the gas cap method.

5.0 CONCLUSION

Using coiled tubing to spot compressed gas at depth in a geothermal well can be used to initiate discharge. Other methods, such as gas caps and steam injection, as well as the one reviewed, have positives and negatives aspects and all methods should be assessed on a well by well basis.

The empirical model by Zenz can be used to estimate expected fluid flow returns with respect to gas flow rates, but the results of this example indicate that it is advisable to stay above a submergence ratio of 0.6 and a gas flow factor of 3 for the model when it is being used for deep wells.

Where the productivity index is expected to be low, the stable return flowrate may not be achieved. If the productivity index of the well is known beforehand this could be incorporated into the model to better predict equipment requirements.

The gas lift and steam injection methods provide a high level of control on the rate of heating of the well casing. The preferred method used to initiate flow should be assessed on a well by well basis, taking into account factors such as reservoir temperature, casing design and grade, cementing quality and shallow formation temperature.

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