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ANTISCALANT TRIAL AT KAWERAU GEOTHERMAL FIELD

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ABSTRACT

Scale formation is one of the main problems associated with the exploitation of water-dominated Geothermal fields. The deposition of calcium carbonate scale is a severe operational problem in the Kawerau field in N Z necessitating annual workovers to cleanout the calcite in the casings.

Investigations into alternative methods of scale control were conducted. The most promising appeared to be the use of scale inhibitors injected downhole via capillary tubing to a depth below the flash point.

Laboratory tests were conducted to find an inhibitor that would not degrade at the high temperatures encountered in the Kawerau field. Upon selection of a suitable chemical a field trial followed. Teething problems with the surface injection system has resulted in well rundown, however at the time of writing the run down was approximately half of that expected with no injection of inhibitor.

INTRODUCTION

The Kawerau geothermal field is located towards the north eastern end of the Taupo Volcanic Zone in the North Island of New Zealand.

In 1952 the field was chosen as the site for a pulp and paper mill by the Tasman Pulp and Paper Company. Since 1952 thirty one wells have been drilled within the field, five of which are currently used to supply 270 tonnes/hour of geothermal steam for direct and indirect process use and electricity generation in the mill.

The formation of calcium carbonate scale on the walls of the casing in these production wells causes flow restrictions and a subsequent reduction in well output. The deposition of this scale is rapid whenever the producing fluid loses CO_2 gas, which allows the fluid to become supersaturated in calcium carbonate and precipitate from solution.

Previously the scale has been removed mechanically using a drilling rig. To maintain an acceptable level of supply of steam to the mill, the wells require working over every 1-2 years.

Alternative more economical methods of scale control were investigated, the most promising appearing to be the addition of a calcium carbonate inhibitor to the geothermal fluid while the well is producing.

The use of organic phosphonates as CO_2 inhibitors in oil/gas wells and low temperature (<200 deg C) geothermal wells in the Cesano and Latera fields of Italy have been well documented. However, research carried out by the Italian Electricity Board (ENEL) in the Cesano and Latera fields has shown that organic phosphonates degrade rapidly at temperatures above 210 deg C.

It appears no work on calcium carbonate scale inhibitors at elevated temperatures (>270 deg C) has been reported previously.

Kawerau locality Map

LABORATORY TESTS

Extensive laboratory tests were conducted by Exxon Chemicals in Houston on various inhibitors in conditions up to 290 deg C. The tests were performed by injecting various inhibitors through 30 metres of coiled tubing at elevated temperatures. Not only could the effectiveness of the inhibitor to the NACE test be monitored but also viscosity changes, pumpability and corrosivity. After months of tests a product was developed which when subjected to 290 deg C for 1 1/2 hours produced 100% inhibition of calcium carbonate at 30ppm dose rate using the NACE test.

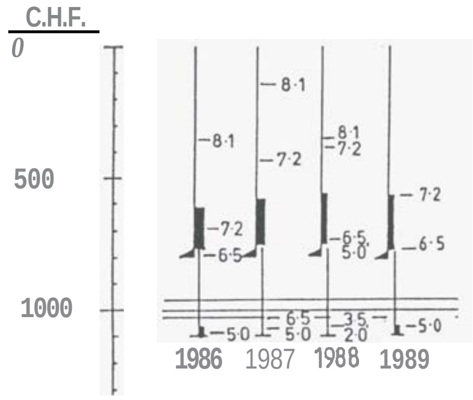
The NACE test uses water with extremely high scaling drive. Water analyses from the Kawerau wells indicate the scaling drive is low. Therefore, in field conditions it was predicted that dose rates of less than 5ppm should be sufficient to inhibit downhole scaling. At this dose rate the trial would be economically viable.

However, before a trial could be instigated the environmental impact of the product had to be assessed. Tests carried out by an independent analytical laboratory in the USA concluded that the product had very low toxicity values and would have no impact on the environment. The next stage was to perform a field trial using Exxon's chemical.

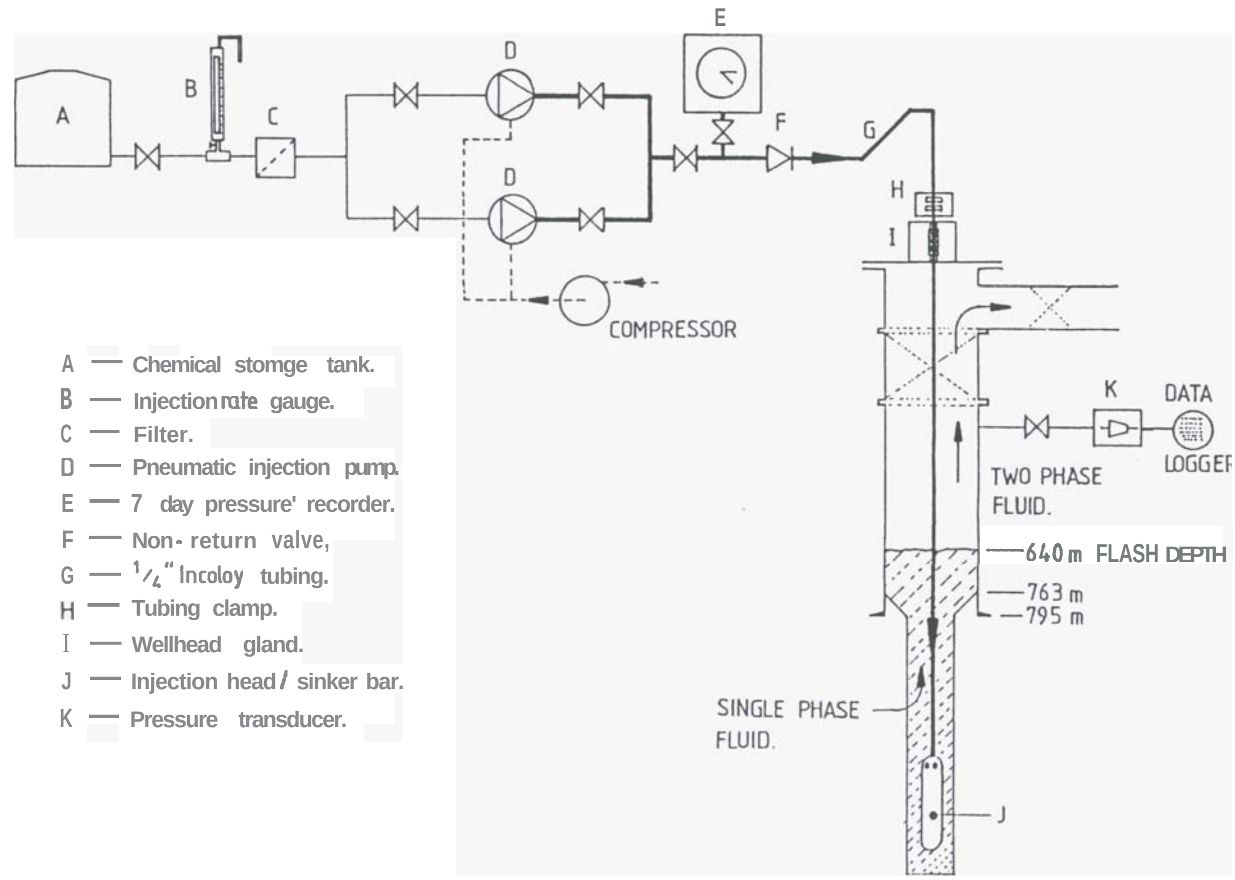
WELL SELECTION

Well KA35 was chosen for the trial as the calcite deposition is mainly in the production casing, with a small amount of deposition in the bottom of the hole. The well has excellent permeability with the main feed zone at 963m. Feed zone temperature is 269 deg C. Smaller feed zones are at 995m (266 deg C) and 1025m (259 deg C). The inhibitor is able to be injected below the deposition zone and thus full mixing of the inhibitor with the production fluids is guaranteed.

KA35 was drilled in March 1985 to a depth of 1095m. It is cased with 9 5/8" casing to 795m and has a 7 5/8" slotted liner which sits on the bottom of the hole with the top of the liner at 763m. The well has been cleaned out four times since it has been on production, in March 1986, April 1987, May 1988 and in April 1989. Deposition was located between approximately 580m and the top of the liner at 765m and in the bottom of the hole. The liner inspections gave no indications of any deposition on either the inside or outside wall of the liner, however some minor deposition was located in the slots during the 1988 inspection.



KA35 Calcite deposition and go devil depths prior to cleanouts.



ANTISCALANT SURFACE AND DOWNHOLE INJECTION SYSTEM.

(Not to scale)

COMPLETION DESIGN

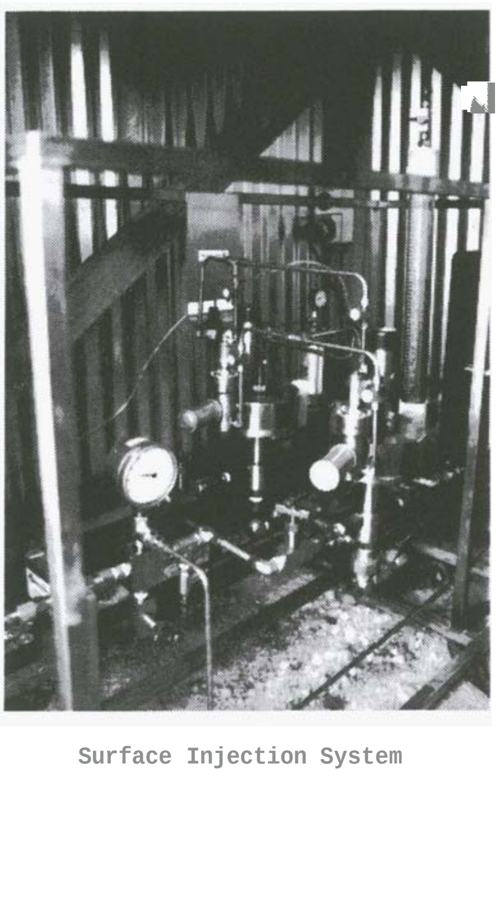
Two options were considered for injecting the antiscalant. The first was to run a liner with the tubing attached to the outside and entering the liner at the shoe through a side pocket mandrel. Unfortunately this necessitated producing the well through the smaller diameter liner which would have an adverse affect on the wells output.

The other option and the one finally selected was to inject the inhibitor through 1/4" capillary tubing to a weighted injection head attached to the bottom of the tubing. The injection head had to be of sufficient weight to keep the tubing in tension under flowing conditions. The tubing /injection head is suspended from the wellhead using a tubing clamp to prevent the tubing from slipping down the well.

Incoloy 825 tubing was selected because of its very low corrosivity (0.008mm/year when immersed in a 10% solution of the inhibitor for 90 hours at 290 deg C) and its good resistance to chloride stress cracking.

The injection head assembly was made from carbon steel and measures 3 metres long, 75mm in diameter and weighs 250kg. The tubing is attached to the injection head using back to back swaglok fittings housed in a specially designed sub for extra strength. The sub also contained a check valve which is designed to prevent the chemical boiling in the tubing.

The surface system consists of two pneumatic variable stroke Williams pumps (one as a standby). The suction end of the pumps is connected to the chemical supply tanks and the discharge end is connected direct to the downhole tubing, with NRV.



Surface Injection System

INSTAUATION

The installation of the injection system was timed to coincide with a drilling workover. This ensured the well was clear of calcite prior to the trial commencing and the well was quenched and off pressure allowing the installation to proceed with the well in an open hole state.

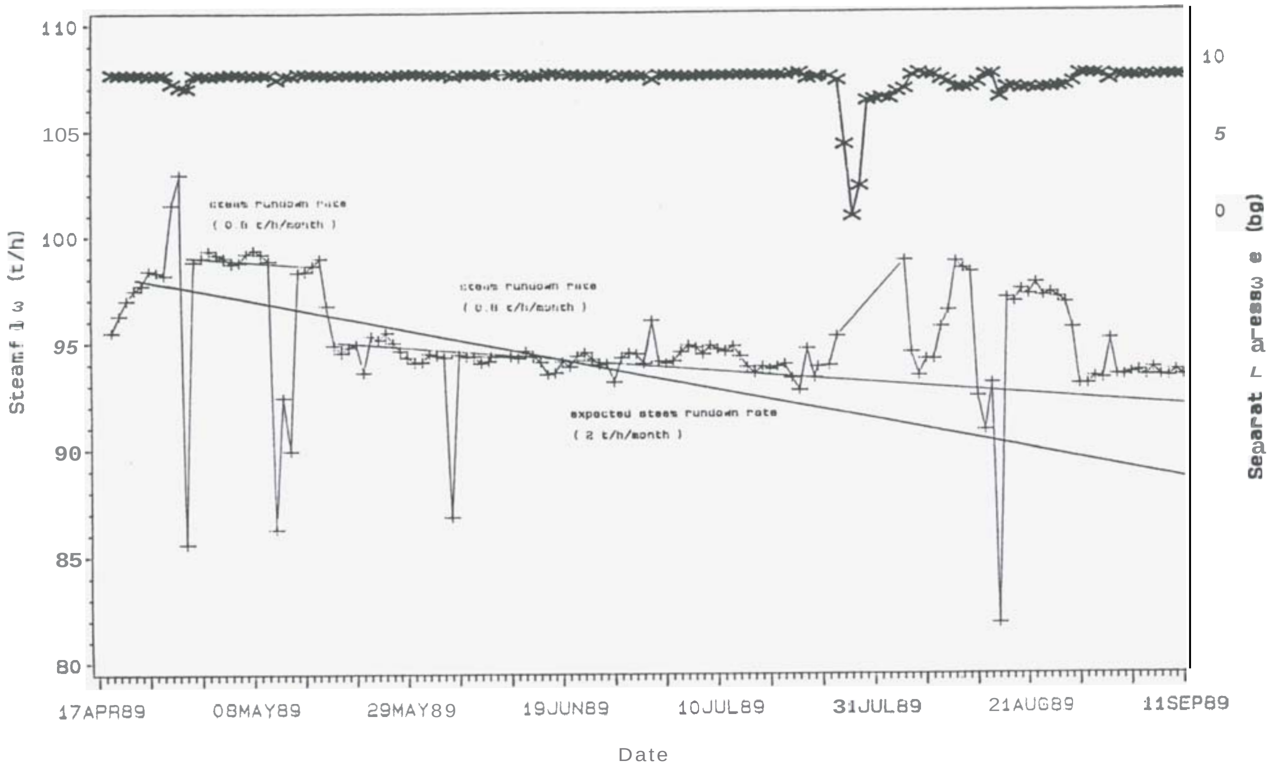
The tubing was fed through the wellhead support flange and cap and made up onto the injection assembly. The tubing was then run over two 18" sheaths, the bottom one attached to the wellhead and the other was suspended directly above the wellhead using a crane. The assembly and tubing was then lowered slowly into the well using a mechanical winch. The tubing was to be lowered to 1000m, however the injection assembly held up at 932m. Rather than risk placing excessive stress on the tubing to injection head connection by attempting to free the assembly from the obstruction it was decided to leave it in its present position.

A 15% solution of chemical was prepared and injection began at an injection rate of 20 litres/hour. This gave a dose rate of 5ppm and a residence time in the tubing of 16.5 minutes.

Wellhead pressure, separator outlet pressure, steam and water flows were monitored to check well performance. Hourly averages were recorded by a datalogger at the site office.

Wellhead Support Flange

KA35 Production



Daily Averages

RESULTS

The well was placed back on production on 17 April 1989 following the completion of the cleanout and the installation of the injection system.

After four weeks continuous operation the mass output of the well had not changed and no rundown was evident. However, at the beginning of week five the air compressor supplying the,pneumatic pumps broke down. Two days elapsed before the air supply was reinstated and during this time the well's output had run down by approximately 4 tonne/hour of steam and 20 tonne/hour of mass flow.

Based on the success of the first four weeks operation the dose rate of the chemical was decreased to 3ppm. This was done by maintaining the same concentration but decreasing the injection rate to 12 litres/ hour.

Problems with air and electrical supply continued during May, June and July. During this period well rundown has been detectable and has averaged 0.8 t/hr/month. This is less than half of the expected run down of 2 t/hr/month.

A new air supply system is being installed to make the surface system more reliable.

The results to date show that well rundown has occurred at times of surface system failure when the inhibitor was not injected, rather than due to the inhibition qualities of the antiscalant chemical.

CONCLUSION

From the data available to date it is difficult, because of the numerous injection system breakdowns, to quantify the success of the antiscalant trial. More data over a longer period without breakdowns is required before one could predict with confidence that zero rundown is achievable. However, from the data collected to date, we know that the antiscalant chemical significantly reduces the production rundown at a dose rate of 3ppm. With improvement in the reliability of the surface system the well rundown could be further reduced.

ACKNOWLEDGEMENTS

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REFERENCES

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