

RECENT DEVELOPMENTS IN CARBONATE SCALE INHIBITION AND RESERVOIR MONITORING HARDWARE AT THE DIXIE VALLEY, NEVADA GEOTHERMAL FIELD

Dick Benoit

Oxbow Power Services Inc., Reno, Nevada

ABSTRACT

Inhibiting calcium carbonate scaling in geothermal production wells requires delivering small amounts of a chemical below the flash point. In geothermal fields with relatively shallow flash points this can be accomplished by simply hanging 6.35 mm stainless steel capillary tubing in the wellbore. In fields with flash points below 600 m the tubings frequently fail if not protected.

At the Dixie Valley geothermal field the initial form of protection consisted of running capillary tubing strings inside a 1200 m long hangdown string. For 10 years this system proved generally reliable with some systems operating continuously for over 1200 days. However, about one third of the time the downhole assembly become stuck and while pulling, the cap tubing parted. This resulted in well workovers to pull and rerun the hangdown strings.

In 1998 new inhibition systems were installed with capillary tubings strapped to the outside of the hangdown string. Most wells now have two capillary tubings strapped to the hangdown string for scale inhibition. A research system has five capillary tubing strings providing for scale inhibition, continuous downhole pressure measurement, a thermocouple for continuous temperature measurement, and two optical fibers for distributed temperature sensing measurements which allow for obtaining temperature profiles to the bottom of the hangdown string. The open hangdown string can accommodate logging with small diameter tools and repeated well kickoffs with compressed air. These systems will cut operating costs of production wells by reducing the number of workovers needed to keep scale inhibition systems operating.

1.0 INTRODUCTION

In the late 1980's a number of flash power plants commenced operation in the United States on fields where carbonate scale precipitated in production wells. This led to a flurry of activity in testing various inhibitor chemicals and implementing carbonate scale inhibition programs. Experiences and circumstances of individual workers at different fields resulted in a number of different chemicals and delivery systems being utilized (Benoit, 1990, Lovekin, 1990, Osborn et al., 1990).

The simplest and perhaps ideal delivery system is to simply use 6.35 mm capillary tubing with only a dispersion head and sinker bars (the downhole assembly) on the bottom (Robson et al., 1990). There is no protection for the capillary tubing inside the wellhead and wellbore. This was the method initially attempted in most fields and has the two advantages of having the lowest cost and being most easily run into and retrieved from a flowing well, without having to shut-in the well.

Running unprotected capillary tubing is a simple matter if the upper part of the wellhead has a large diameter (25 cm or larger) "T" type of configuration. Inside the large diameter components of the wellhead there is some room for the capillary tubing to move as the flow stream attempts to push the tubing down the flow line. In some cases the capillary tubing can actually rub against the bottom edge of a flow "T" requiring that the tubing be periodically moved. At one well in the Beowawe geothermal field the tubing must be moved every six weeks as about half the wall thickness is abraded in this time.

Running unprotected capillary tubing in a well with a sweeping elbow at the top of the wellhead is more difficult. A hole must be cut through the outside of the elbow and this hole will generally be less than 10-cm in diameter. As the capillary tubing enters the flow stream the flow easily pushes it downstream to rub against the edge of the cut. This can cut

the tubing in half in a matter of hours to days. This system requires that a short piece of protective pipe (a stinger) be run through the cut in the elbow. Experience has shown that the capillary tubing will rotate around the inside of the bottom of the stinger and again, it can be cut in a matter of hours to days. Some additional protection such as a teflon sleeve must be installed in the bottom of the stinger.

At the Dixie Valley and Coso geothermal fields there were repeated failures of the capillary tubing, both **6.35 mm** and **9.5 mm**, which necessitated the development of downhole protective measures (Benoit, **1990**, Lovekin, **1990**). These cap tubing failures do not appear to be related to flow rate, temperature, or chemistry. At Beowawe unprotected capillary tubings have been in well **77-13** without incident since mid **1991** while this well is producing **150 kg/sec** of total mass flow. Similar unprotected cap tubings have been installed at the Roosevelt geothermal field at temperatures of **270°C** for several years. Many of the failures at Dixie Valley and Coso were obviously of a mechanical origin and some occurred so quickly there was obviously no time for a chemical problem to manifest itself.

The commonality between Coso and Dixie Valley is the relatively great depths of **900** to **1200** m to which the unprotected capillary tubings were run in the well. The deepest that unprotected capillary tubing strings have been successfully operated for nearly a decade is **600** to **700** m at the Steamboat, Nevada geothermal field. At greater depths damage to the tubings occurs more frequently.

At Coso the preferred protective measure has been to install the capillary tubing inside a **2.54** cm mild steel coiled tubing. At Dixie Valley a **4.82** cm tubing string was hung down from the wellhead to depths of **1200** m and then the capillary tubing was run inside this "hangdown" string (Benoit, **1990**). The hangdown string also served additional duty in delivering compressed air below the fluid level to kick off the wells. At Miravilles, Costa Rica a very short hangdown string, known as a stinger, with a teflon sleeve protects the capillary tubing in the wellhead. All of these methods have been successful in that mechanical scale cleanouts in these fields have been greatly reduced or largely eliminated. However, each of these systems has unique drawbacks and occasional problems which demonstrate there is room for improvement. At Dixie Valley capillary tubings become stuck inside the hangdown strings. At Coso the tubing strings can be damaged by fluid getting inside the annulus and there is the requirement of a coiled tubing unit. At Miravilles the wells must be periodically shut down so that the teflon at the bottom of the stingers can be rebuilt.

This paper describes recent improvements to the Dixie Valley hangdown strings which should lower overall costs, improve the reliability of downhole scale inhibition, and provide intermittent or continuous temperature and pressure data below the flash point for improved wellbore/reservoir monitoring.

2.0 ORIGINAL DIXIE VALLEY HANGDOWN SYSTEM

The original hangdown strings tested at Dixie Valley were **6.03** cm O.D. as this sized tubing was on site when the concept was first tested. The only addition to the **6.03** cm tubing was a short piece of tubing with a slightly reduced diameter at the very end. This piece of tubing is referred to as the end nipple and the reduced diameter portion at the very bottom is called the no go as it does not allow the entire downhole assembly to be lowered out the bottom of the hangdown string. If it were to be lowered out of the hangdown string it may not reenter the hangdown string during retrieval. In the downhole assembly a slightly enlarged ring, called the no go ring, was installed between the dispersion head and the sinker bars (Figure 1). The no go ring is larger than the no go and will not pass through the no go.

When the no go ring is lowered onto the no go there is a clearly audible sound which allows the operator to know that the downhole assembly is in the proper position. In normal operation the ports in the bottom of the dispersion head stick out of the bottom of the end nipple to inject the inhibitor chemical directly into the flow stream. If the downhole assembly does not reach its intended position then the inhibitor chemical will be injected inside the hangdown string and not perform its intended purpose. If an acidic inhibitor chemical is utilized, the hangdown string can be chemically damaged or cut.

It was later determined that **4.82** cm O.D. (**4.06** cm I.D.) tubing would be satisfactory and its smaller diameter would leave more of the wellbore open for geothermal fluids. Strings smaller than **4.82** cm have not been tested as the internal diameter is getting so small that the downhole assembly (sinker bars, no go ring, and dispersion head) may not have adequate weight to pull the capillary tubing down the inside of the hangdown string.

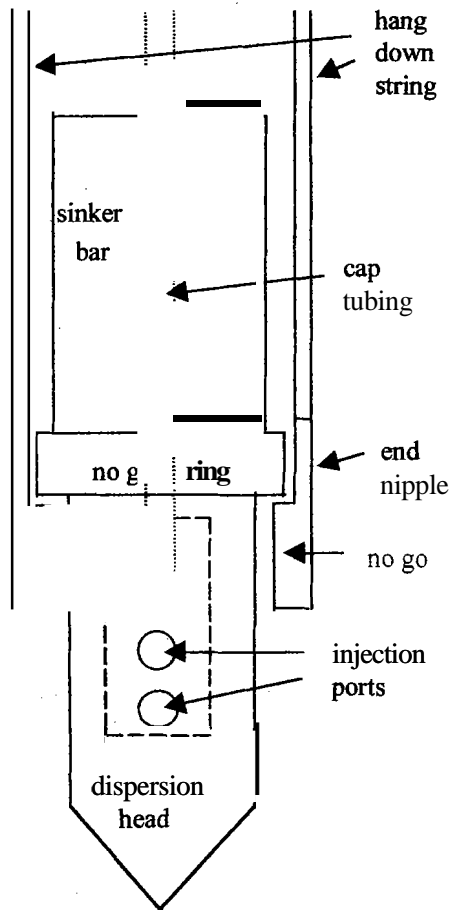


Figure 1: Not to scale drawing of a downhole assembly showing the relationships of its various components.

The addition of the hangdown string to the wellbore required that a tubing hanger be added to the top of the wellhead. This is a simple matter of the wellhead has a flow AT \cong s. At Dixie Valley long radius elbows have been replacing the wellhead AT \cong s, which required cutting holes on the outside of the elbows and utilizing elbowlets and risers large enough to pass the 5.71 cm couplings of the 4.82 cm hangdown string. Running capillary tubing through the relatively small diameter holes on the outsides of elbows requires that the tubing be protected as it will very quickly abrade by rubbing on the downstream side of the entry hole in the elbow.

Once the hangdown string is installed in the well, with either a crane or a small workover rig, the well is kicked off by blowing compressed air through the hangdown string. After the well is flowing then the capillary tubing and downhole assembly are run into the hangdown string through a lubricator and inhibition can commence.

Ideally, the capillary tubing can be pulled out of the hangdown string so small diameter temperature and pressure tools can log the well and the capillary tubing can be rerun. Also, in theory the downhole assembly can also be removed so the well can be restarted if it has been accidentally killed during abnormal plant operations. This has occasionally been done at Dixie Valley but about 1/3 of the time it has not been possible to pull the dispersion head and sinker bars out of the hangdown strings. Once this happens, defined by the breakage of the capillary tubing, the hangdown string has to be removed from the well for clean up purposes. This requires shutting in the well. A system to allow retrieval of the hangdown strings under flowing conditions was installed but was never actually utilized due to safety concerns.

This original system has proven to be quite reliable with some operating for over 1200 days and scale cleanouts of the Dixie Valley production wells are now almost never done. However, this system tended to give unpredictable results when

attempts were made to retrieve the cap tubing. As a worst case, one cap tubing **string** was stuck and pulled apart when attempts were made to retrieve it after only 7 days in the well. Scale, possibly from the inhibitor flowing up the side of the dispersion head into the hangdown string, would occasionally grow inside the hangdown string making retrieval of the downhole assembly impossible. Any solid fragments from inside an unclean hangdown string would tend to settle on top of the downhole assembly and solidly lock it in place. A variety of diameters of no gos, downhole assemblies, and slots in the bottom joint of the hangdown string were tested to alleviate this problem but none seemed to guarantee successful retrieval.

The fear of breaking a cap tubing during retrieval severely limited the ability to run downhole temperature and/or pressure logs in the wells. The inhibition systems themselves were successfully utilized to obtain downhole pressure **data** in selected wells 3 or 4 times a year during productivity tests. This was done by simply flushing the chemical out of the capillary tubing with clean water, purging the capillary tubing with nitrogen, and performing a productivity test. At the end of the test the tubing would be filled with clean, filtered water and then pumping of the chemical could resume.

3.0 DOWNHOLE RESEARCH SYSTEM

With the advent of distributed temperature sensing (DTS) systems (Benoit and Thompson, 1998) a research program was developed at Dixie Valley to test multiple optic fibers in both single-ended and looped configurations. This system **was** also designed to be calibrated with a downhole thermocouple and downhole flowing temperature logs. This test required multiple capillary tubing strings to protect the optical **fibers** and the thermocouple. The easiest way to accomplish this was to strap these capillary tubings on the outside of the hangdown string (Benoit et al., 1999).

In fact, five 6.35 mm capillary tubing strings were strapped on the outside of a hangdown string in well 74-7 in July 1998. Two of the strings were actually a single 3048 m long loop of capillary tubing with an optic fiber inside. One was a 1524 m long piece with a different optical fiber. One capillary tubing had a thermocouple inside it. The ~~last~~ 6.35 mm capillary tubing was for chemical inhibition purposes and had a 2.39 mm capillary tubing inside it which was used for downhole pressure monitoring (Figure 2). This particular inhibition system has now operated successfully for 5 months and led to the installation of similar types of systems in all Dixie Valley production wells in October 1998.

To accommodate the 5 capillary tubing strings coming out of the wellhead, a new and larger 3 piece tubing hanger had to be installed on the top of the wellhead. The design of this particular hanger required that the capillary tubings pass through holes in the "doughnut" and then penetrate out through the upper part of the hanger. It was installed with some difficulty due to difficulties in bending the stiff capillary tubings in the confined space inside the tubing hanger.

Unfortunately the optic fibers installed in the research system deteriorated within one month and failed to produce acceptable long term temperature information. However, in the short term the system was utilized to record dozens of temperature logs over the space of one hour **as** the well was kicked off with compressed air. This short term test also suggested that looped DTS systems do provide more accurate temperatures than single ended systems (Smithpeter et al., 1999).

The thermocouple has now operated for several months and has provided useful information on the well. During routine flowing conditions the thermocouple shows temperatures varying by $\pm 0.3^{\circ}\text{C}$. Under shutin conditions the thermocouple provides much steadier readings with less than 0.06°C variation. It may be suggesting that during flowing conditions the temperature of the well below the flash point actually cycles over about a 0.5°C range. When the well was shutin for a major power plant maintenance outage in October 1998, the thermocouple provided a complete history of the cooldown of the well at one depth (Figure 3). Similarly the downhole pressure monitoring capability of this system is providing a continuous pressure record of the flowing well (Figure 3), without impacting routine operations. Downhole thermocouples and pressure monitoring equipment **was** installed in two other production wells in Oct. 1998.

As this is the first thermocouple to ever be installed for the long term in a flowing production well, there are uncertainties about how well it will remain calibrated and working. It does appear to be capable of giving quite precise temperatures. For instance, when the pressure bomb is purged with helium soon thereafter the thermocouple detects a cooling of 0.5 to 1°C in the flow.

Pruett Industries Oxbow Dixie Valley Temperature/Pressure/Chemical Injection System

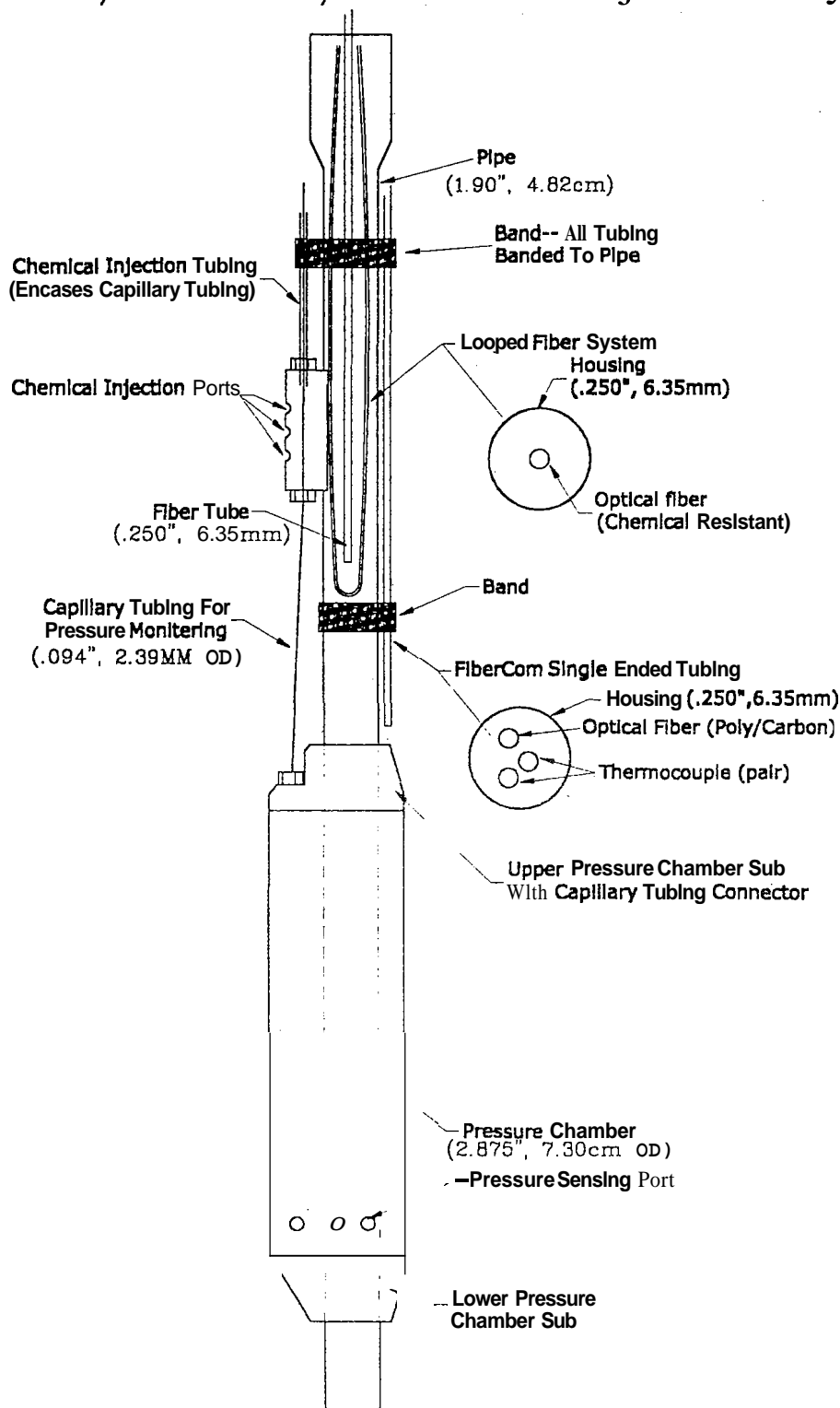


Figure 2. Not to scale drawing of the bottom joint of the hangdown string for the research system.

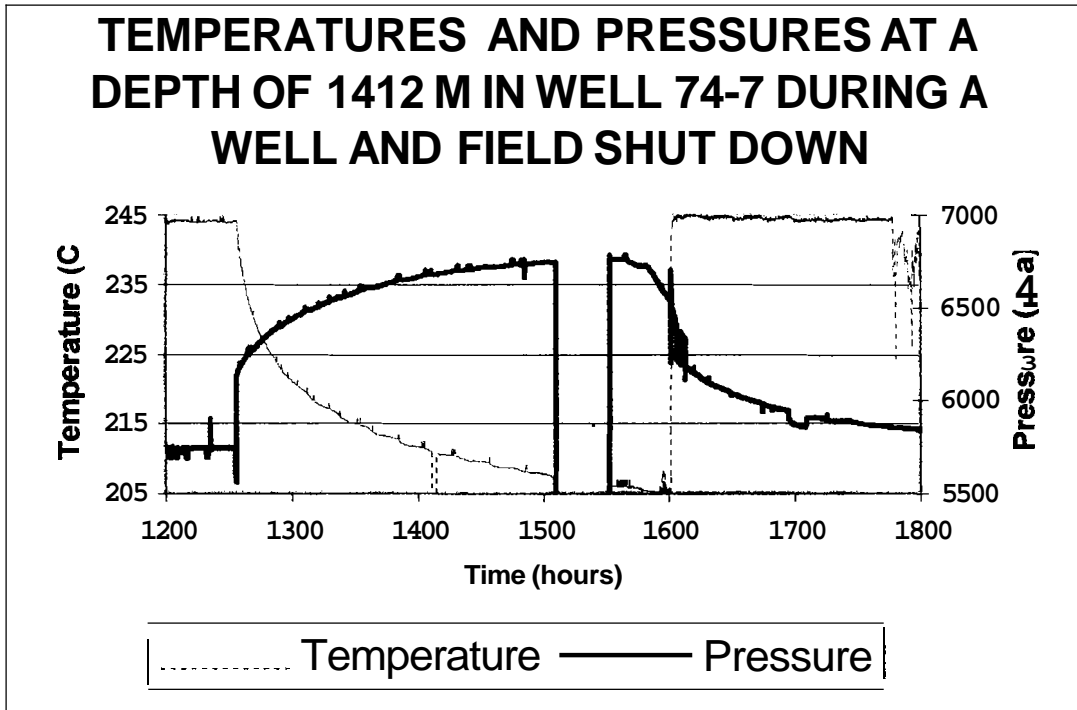


Figure 2. An example of continuous downhole temperature and pressure monitoring during a field shutdown. The small regularly spaced spikes result from an error in programming the data logger that recorded this information.

4.0 NEW DIXIE VALLEY SCALE INHIBITION SYSTEMS

With the short term success of the research downhole system in well 74-7 a simpler scale inhibition/reservoir monitoring system with external capillary tubings was installed in all remaining production wells in October 1988.

The standard Dixie Valley system now consists of two scale inhibition capillary tubing strings strapped on the outside of the 4.82 cm hangdown string. Both cap tubings terminate in stainless steel injection heads approximately 10 cm long with three injection ports to dribble the chemical into the flow stream. The primary capillary tubing for scale inhibition is run open ended into an injection head with a cap on the bottom of the head. It is periodically purged with clean water during installation to avoid possible plugging problems from dirty wellbore fluids getting up inside of the tubing. The cap on the bottom of the primary injection port is a measure to prevent debris from getting inside the capillary tubing and plugging it.

A small plug is silver soldered over the end of the spare or secondary cap tubing. This plug is located within the injection head. If or when this cap tubing is needed for service the plug can be blown off with a couple thousand kilopascals of pressure and inhibition can then start. The injection head for the secondary or backup capillary tubing has no cap on the bottom as there is concern such a cap would allow debris to settle out in the injection head and not allow room for the plug to be blown off at a later date.

During the installation of these systems, the entry holes in the elbows on top of the wellhead and the elbowlet and risers needed to be enlarged so that the bottom joint of the hangdown string with the injection heads welded on the outside would be able to enter the wellbore.

The most evident drawback to installing the capillary tubings on the outside of the hangdown strings is the extra rig time required to install the system. A hangdown string with no capillary tubing on the outside can be installed in 2 or 3 hours. It takes about 6 hours (not counting rig up or rig down time) to install a string with capillary tubings on the outside to a depth of 1400m. Extra personnel and a banding machine are also required.

5.0 NEW DIXIE VALLEY SYSTEMS WITH TEMPERATURE AND PRESSURE MEASUREMENT CAPABILITY

In two wells an additional two capillary tubings are strapped on the outside of the hangdown strings. One of these is 6.35 mm, sealed on the bottom and contains a thermocouple for temperature measurements. The second is a 3.18 mm capillary tubing which is attached to an eccentric pressure bomb on the bottom joint of the hangdown string. The pressure bomb consists of about 5 m of 7.30 cm tubing which is tack welded to the 4.82 cm tubing. The eccentric annulus between the two tubings is sealed and pressure monitoring ports are drilled through the 7.30 cm tubing. The annulus between the 4.82 cm and 7.30 cm tubings is the pressure chamber.

The thermocouple temperature data and downhole pressure data will be attached to the power plant distributed control system. This will provide the power plant operators with on-line information on the well performance and improve their ability to properly manage the wells and gathering system.

6.0 CONCLUSIONS

As geothermal fields age or power output is maximized, it becomes increasingly important that reservoir management decisions are based on high quality temperature and pressure data. At the Dixie Valley geothermal field improvements in scale inhibition concepts and hardware provided an opportunity to bring back downhole temperature and pressure equipment on the basic scale inhibition system at relatively low cost. This is intended to reduce routine traversing temperature and pressure logging and its associated costs as well as providing continuous data to assist field operators. By putting capillary tubings on the outside of hangdown strings multiple scale inhibition capillary tubings can be installed giving backup capabilities in case the primary tubing becomes plugged. This is expected to reduce the number of workovers required to maintain continuous scale inhibition in the production wells.

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