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DOWNHOLE PRESSURE,TEMPERATURE AND FLOWRATE
MEASUREMENTS IN STEAM WELLS AT THE GEYSERS FIELD

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ABSTRACT

Recently developed pressure-temperature-spinner (PTS) tools are used to collect reliable downhole measurements in geothermal systems, such as at The Geysers. PTS surveys in several flowing Geysers steam wells were used to quantify steam entry location and magnitude, wellbore heat loss, pressure drop due to friction, thermodynamic properties of the steam, and maximum rock temperature. Interwell cross flow/interference was identified in one well. Finally, a single-phase saturated steam wellbore model used to compare calculated to measured downhole values, was found to adequately predict the flowing pressure versus depth curves in vapor filled holes.

INTRODUCTION

Geysers Geothermal Company (GGC), the managing general partner for Freeport-McMoRan Resource Partners, Limited Partnership, supplies steam to Pacific Gas and Electric (PG&E) Units 13 and 16 and Sacramento Municipal Utility District (SMUD) GEO #1 plant. The combined generating capacity of the above plants is 320 MW net. Construction of GGC's two new projects, Bear Creek Canyon (BCC) and West Ford Flat (WFF), is underway. In the BCC and WFF projects, GGC will be both steam supplier and plant operator. These plants are scheduled to commence operations in late 1988 to early 1989 and will generate a combined 47 MW net.

GGC initiated a PTS logging program in 1986 to obtain baseline reservoir data on designated steam wells throughout GGC leases at The Geysers field, California. The purpose of this paper is to discuss and interpret PTS logs of several flowing steam wells.

A BRIEF DESCRIPTION OF PTS TOOL

Until the recent development of the PTS tool, reliable downhole information under producing conditions was difficult to obtain with conventional logging tools due to the high temperature environment of 480 °F and high fluid velocities. A sophisticated dewer-type insulator allows the tool to operate for an extended time period (up to 8 hours) in the high temperature environment. The PTS tool simultaneously measures pressure, temperature and spinner revolutions per second (rps). The independent signals are transmitted to the surface microprocessor via a single high temperature (600 °F) conductor and are then processed and recorded.

Two companies, Hot Hole Instruments Los Alamos (HHI) and Dresser Atlas, presently run PTS tools in The Geysers field. The PTS runs discussed in this paper were logged using the HHI tool. An example of a Dresser Atlas log output is shown in Figure 1.

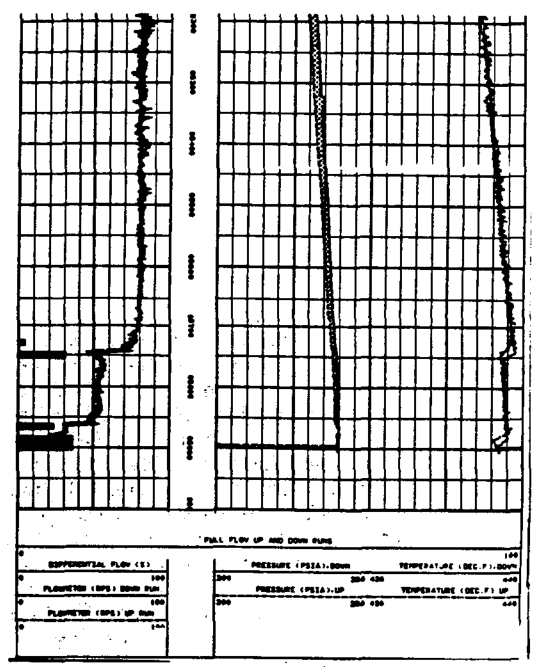

Figure 1
Example of Dresser Atlas PTS Log

USES OF PTS TOOL

Knowledge of certain reservoir parameters is essential to properly develop and model any geothermal field. The PTS tool improves measurements of key reservoir characteristics including steam entry location and magnitude, pressure and temperature profiles in the wellbore under varying flow conditions, pressure drop due to friction, wellbore heat loss, thermodynamic properties of the steam, etc.

One of the most valuable uses of the tool is to quantify the location, size and enthalpy of steam entries. Prior to the development of the PTS tool, both enthalpy and size of steam entries could only be crudely estimated while drilling the well. Newly encountered steam entries are indicated by abrupt changes in air compressor or injection pressure and/or flowline temperature increases while air drilling. These estimations are generally adequate for determining the steam entry location in the wellbore. Drilling data is often the only steam entry information available for most wells. However, since this drilling data is obtained only upon encountering new steam entries, it is often unclear how the recent entry affects production of previous steam entries. Consequently, a thief zone, for example, may be undetected unless it is extremely large.

A major advantage of the PTS over the Kuster-type tools is the ability to provide continuous surface readout of the pressure, temperature and spinner data in a producing well. Although Kuster-type tools are run frequently at The Geysers to obtain downhole pressure and temperature profiles for wells at relatively low flowrates, these profiles do not allow adequate interpretation as how individual entries perform at various flow conditions.

The PTS survey often proves to be a valuable diagnostic tool in the evaluation of problem wells. Producing wells in The Geysers may at times suffer significant losses in production due to mechanical problems in the wellbore such as scale formation, casing collapse, or bridging of the open hole. Large water entries (either injection or meteoric) into the wellbore can also cause major loss of steam production due to quenching. A PTS survey can often pinpoint the cause of the problem and allows the engineer to make recommendations for workover solutions (i.e. cleaning out the well, running a casing liner, reducing injection from offset injectors, etc).

Finally, reservoir characteristics can be determined by conducting pressure buildup, drawdown, interference, or injectivity tests in the wellbore using the PTS tool. Figure 2 is actual HHI log output of a tool hung just inside the casing shoe of a well while partially closing in the well. This type of testing is useful in wells containing water or noncondensible gas where surface pressure measurements do not yield adequate results in conventional well test analysis.

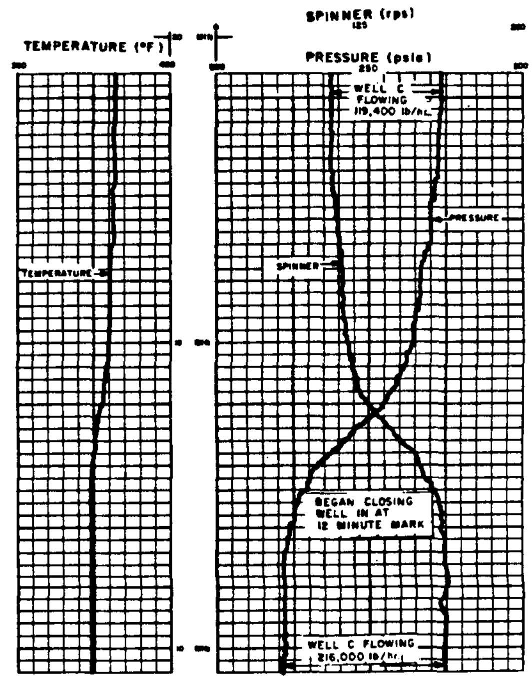

Figure 2
HHI PTS Log during partial shutin of well

EXAMPLES OF SEVERAL SURVEYED WELLS

Figures 3 and 4 represent pressure, temperature and spinner data (obtained with a PTS tool) plotted versus depth for two different GGC wells. The PTS survey indicated six distinct steam entries in Well A. Their location and casing shoe depth is noted on Figure 3 on the x-axis. The spinner data plotted versus depth on Figure 3 (Well A) indicates that all of the steam enters the wellbore above 4300'. Since the total depth of this well is approximately 5200', 900' of wellbore is a "dead-leg". Well A's temperature profile approaches a maximum rock temperature of 465 °F (Figure 3). It is also noteworthy that the pressure gradient decreases from 4.6 to 0.3 psi/100'as the tool enters the static steam column.

Well B (Figure 4) represents a well with four distinct steam entries and a 980' liquid column just below the deepest entry at 6300'. The pressure gradient increases from 2.5 to 33.9 psi/100' as the PTS tool enters the liquid column. Although Well B contains liquid, a maximum rock temperature of 480 °F is reached in its dead-leg. Figure 5 is actual output of the HHI PTS tool which illustrates the two deepest steam entries and the top of the water column at 6300'. The 17 rps increase in spinner data from 6070' to 6100' (Figure 5) results from a slight diameter decrease in the open hole at this depth.

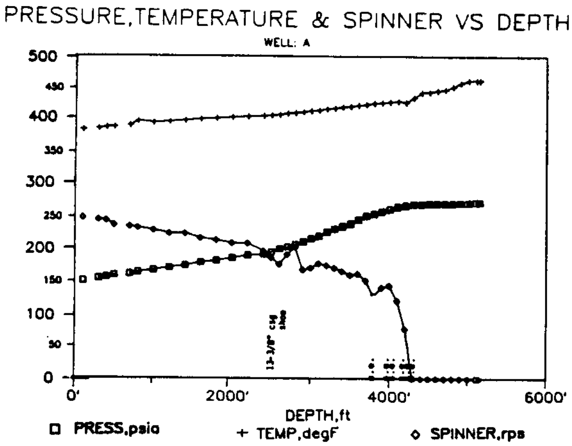

Figure 3

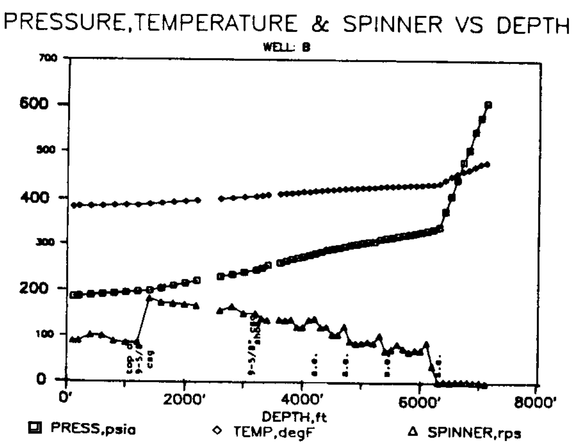

Figure 4

Enthalpy data plotted versus depth is shown in Figure 6 for Wells A, B and C. Note Well A's higher enthalpy values throughout the wellbore compared to Wells B and C. Well A had been on production for over six years at the time it was logged and is located in a more mature, depleted section of the field. Wells B and C had only been on production for eight months and are located in an area of the field more indicative of initial reservoir conditions. Typically wells producing in older portions of The Geysers field exhibit higher enthalpy due to a "drying out" of the reservoir over time. This occurs as the liquid fraction of the reserves is boiled away. All three wells exhibited greater enthalpy decreases in the cased versus open hole sections due to wellbore heat loss (except in Well B's liquid column). The minimum enthalpy value at 6800' in Well B (Figure 6) probably results from cold water entering the wellbore at this depth. Below this water entry, the standing liquid column is heated to 480 °F by conduction from the reservoir rock.

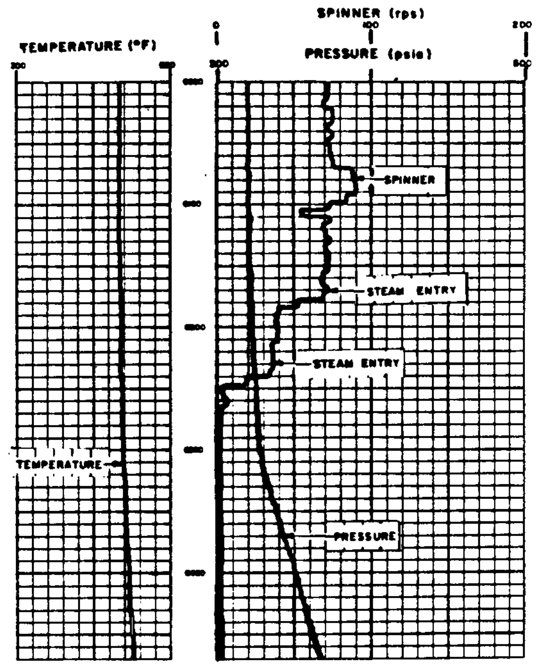

Figure 5
HHI PTS Log of Well B

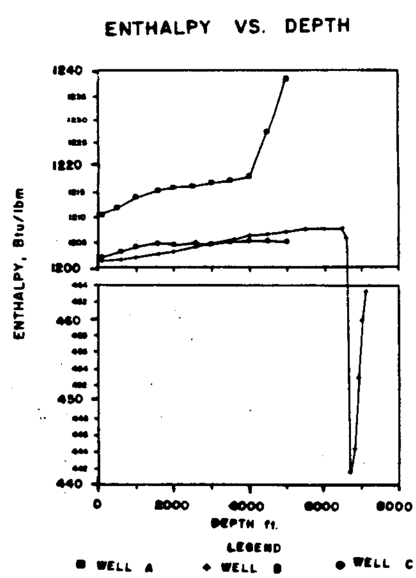

Figure 6

A zone of interwell cross flow/interference between Well C and an offset producer was pinpointed using the PTS tool. Well C was logged at three different flowrates, 190, 216 and 119 klb/hr respectively. During the first and last PTS runs, the offset producer flowed at its normal rate of 178 klb/hr at 173 psia. However, the offset well was throttled back to 40 klb/hr at 313 psia during the second PTS run, causing an increase in flow at Well C. Figure 7 illustrates pressure and spinner data plotted versus depth for the first and second runs (Well C flowing 190 and 216 klb/hr respectively).

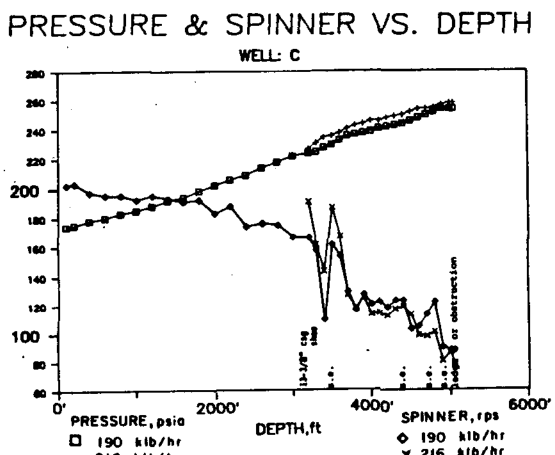

Figure 7

Although the flowrate had increased 26 klb/hr for the second run, the pressure was also greater. The spinner data from the second run exhibited a marked increase in flow at the shallowest steam entry at 3655'. However, contributions from the deeper entries tended to be lower for the second run. From this data it is evident that the 3655' zone is in direct communication with the offset producer and "shares" steam between the two wells.

Figure 8 illustrates Well C's percent of total flow versus steam entry depth for the three PTS runs. An obstruction or ledge at 5050' prohibited logging the entire wellbore. The PTS survey showed that about half of the flow is entering the well below 5000' (Figure 8). This verifies air drilling data which indicated that an additional six steam entries were encountered below 5000'. Also, the cross flow/interference zone at 3655' contributes proportionately more flow at higher flowrates since it "shares" steam with an offset producer. Conversely, a greater percentage of total flow is contributed by deeper entries (below 5000') at lower flowrates.

Apparently the flow from the shallowest entry is very sensitive to slight changes in wellhead pressure and to the flowrate of the offset well.

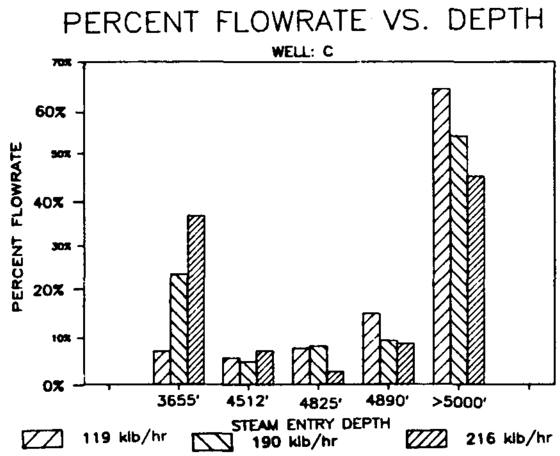

Figure 8

A shallow thief zone was detected by PTS surveys in Well D and is illustrated in Figures 9 and 10. When Well D's surface pressure was increased by only 14 psi (189 to 202 psia) the flowrate dropped 50% (150 to 75 klb/hr). The spinner reversal at 2450' identifies the thief zone in Figure 9.

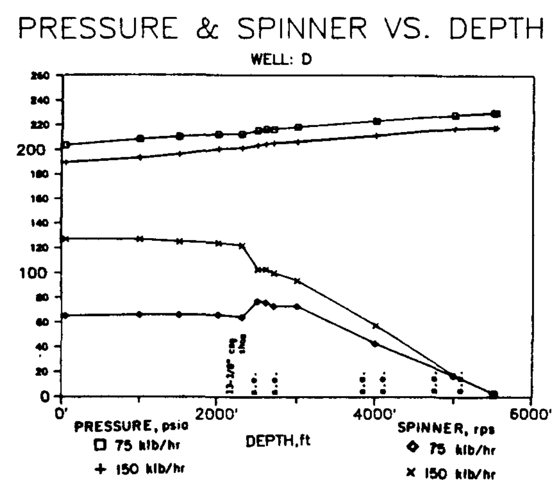

Figure 9

About 14% or 10 klb/hr of the total flow (75 klb/hr) exits the wellbore at 2450' (Figure 10). The detection of the thief zone by PTS data explains the unusual flowrate sensitivity to small changes in wellhead pressure.

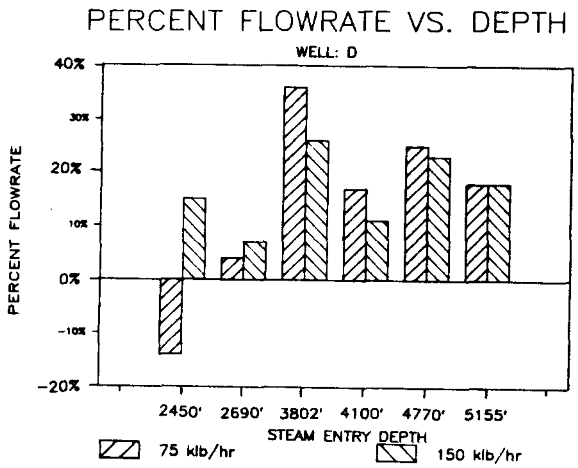

Figure 10

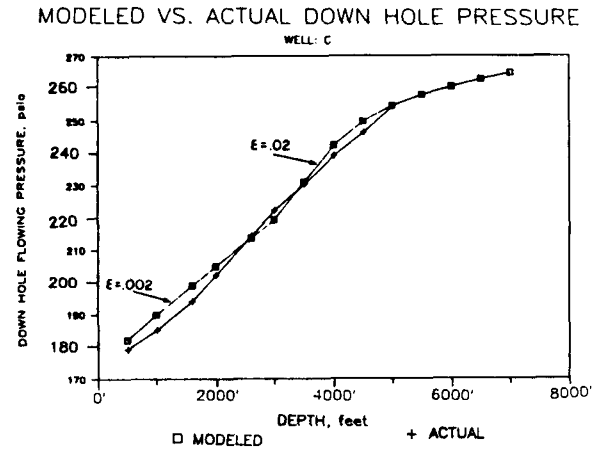

Figure 12

WELLBORE MODEL

Actual downhole flowing pressures were modeled by a single-phase saturated steam wellbore model. This model assumes adiabatic conditions and negligible kinetic energy. The pressure drop solution is based on the Cullender-Smith method. This in-house wellbore model was developed for the PC using a Lotus 123 spreadsheet.

A good match was obtained between the calculated and actual pressures for Well A in Figure 11. Although Well C could not be logged to total depth, reasonable downhole flowing pressures (below 5000') were predicted using the model (Figure 12). Well B's calculated downhole pressures provided an excellent match with measured values throughout the cased and steam producing sections of the wellbore (Figure 13). However, the model did not accurately predict actual pressures in the portion of the wellbore containing the liquid column and two phase flow because it is limited to single-phase steam conditions.

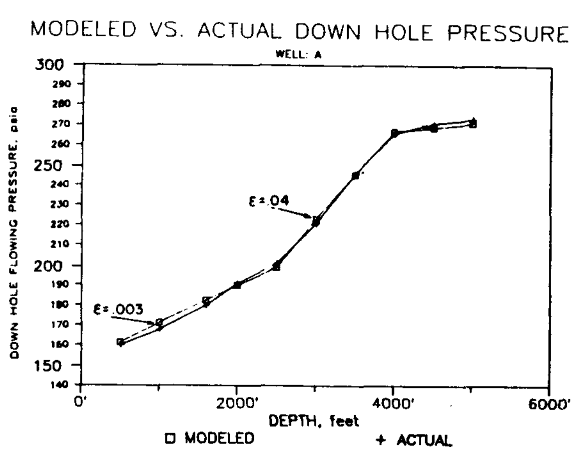

Figure 11

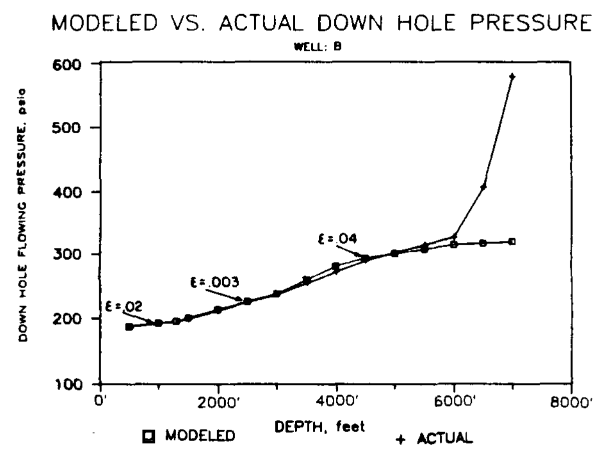

Figure 13

CONCLUSIONS

O PTS surveys provide reliable downhole information such as steam entry location and magnitude, wellbore heat loss, pressure drop due to friction, and maximum rock temperature in geothermal wells at The Geysers.

O Interwell cross flow/interference and thief zones in the wellbore can be detected with the PTS tool.

O PTS information aids the engineer in interpreting characteristics such as interwell behavior, pressure and temperature profiles, pressure decline and location of fluid entry or exit points in the wellbore. This knowledge is essential in order to arrive at practical solutions to production and reservoir problems in addition to reservoir modeling.