# SIMULTANEOUS TPS LOGGING SYSTEM

J. Davarzani and M. Sloan

Atlas Wireline Services, Western Atlas International, Inc., P.O. Box 1407, Houston, Texas 77251-1407

## ABSTRACT

A new generation of logging instruments has been developed to withstand the hostile environments of geothermal wells. The main measuring sensors are Temperature, Pressure, and Continuous Spinner Flowmeter (TPS). These instruments record simultaneously the wellbore fluid properties and provide a real-time display of the data. A well-site analysis program has been developed which calculates the thermodynamic properties of the steam and locates the active zones by profiling the well. A short description of the hardware and software is presented in addition to field log examples and a description of the methods of data analysis.

## INTRODUCTION

A successful logging operation in geothermal fields requires instruments that can operate in a hostile environment for an extended time period. The temperature encountered in these wells may be up to 600°F (315°C), and steam flow rates may be up to 200 ft/s (61 m/s). To overcome these problems, the TPS system of logging instruments and analysis has been developed. The TPS instruments acquire simultaneous measurements of temperature, pressure, and flow. Due to the longevity of these instruments at elevated temperatures—12 hours at 600°F (315°C)—pressure buildup, drawdown, and multi-flow-rate surveys of a geothermal well are now feasible.

TPS instrument responses are normally transmitted to the surface at the rate of 4 samples/ft (1 sample/dm), regardless of logging speed or direction. Using a special service program, the sample rate may be changed as required. The various sample rates are most useful during pressure-transient surveys. The simultaneous depth-correlated measurements from all sondes are obtained to generate a real-time log data display. Mass storage of data is also available for off-line analysis. A mechanical lead-in device is utilized to bypass open hole washouts and reach total depth of the well. A short description of each instrument and its applications is presented in the following sections.

Using measured wellbore temperature and pressure data and published steam tables, various downhole steam properties can be calculated. In particular, the determination of the fluid phase region at the measurement points leads to a special method of calculating the flowing steam quality. From recorded spinner flowmeter data and pipe diameter, the wellbore volumetric flow velocity may be determined. Selecting one of several available published pressure drop models and using measured pressure and temperature data, the wellbore fluid density may be calculated. Once the fluid density and velocity are known, the steam mass cumulative flow and differential flow of each producing zone can be accurately calculated.

## INSTRUMENT DESCRIPTIONS AND APPLICATIONS

Atlas Wireline Services has implemented the Geothermal Simultaneous Production Logging Instrument TPS string for the purpose of data acquisition in geothermal fields. The string is 2.5 in. (6.35 cm) in diameter with an operation rating of 600°F (315°C) and 15,000 psi (103,350 kPa) for 12 hours. A special high-temperature cable is used for transmitting the data from downhole instruments to the surface computer. In addition to the sensors, there is a telemetry section and several mechanoical devices which complement the string. An illustration of the tool string is shown in fig. 1. A description of each instrument and its application follows.

### PCM Telemetry Instrument

The Pulse Code Modulation (PCM) telemetry instrument is the central device of the TPS digital logging system. The telemetry instrument provides a bi-directional communication interface over the wireline between the surface Computerized Logging Services (CLS) unit and the downhole instruments. Communications software is

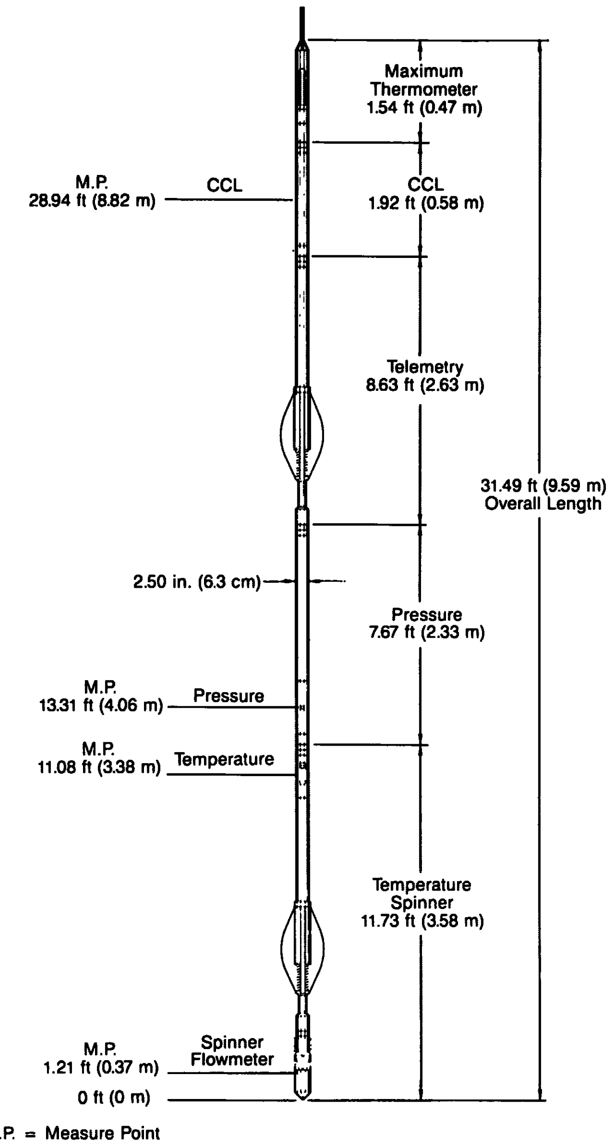


Figure 1. TPS instrument string

downloaded from the surface and includes instructions for the sensor instruments with specific commands for selection of sample rates of each instrument.

Upon software execution at the designated depth interrupts (in stationary data recording, data transmission is based on time), the digitized data is sampled from each instrument at essentially the same time and results in an accurate measurement of the fluid properties at a single point. The data is then transmitted uphole from the telemetry instrument to the surface computer, where data processing yields real-time plots and/or mass storage for off-line playback and analysis.

Temperature Instrument

The temperature instrument measures the geothermal temperature gradient of a well by providing a continuous measurement of the wellbore fluid temperature. Accurate and responsive fluid measurement is provided by exposure of a precision RTD platinum sensor probe directly to the wellbore environment. Continuity of the probe with mass metal is limited as structurally as possible to minimize thermal effects on the measurement.

The surface equipment can also display and/or record the differential temperature. The differential temperature curve is a computed curve from the temperature instrument response. For a constant gradient slope, the differential curve is averaged about the zero point. If a higher temperature is encountered, the differential curve shows a positive value, and if the gradient curve shows an abrupt change to a lower temperature, the curve shows a negative deflection.

The temperature survey determines the geothermal gradient of the wellbore under flowing and shut-in conditions. Also determined is the point of fluid entry when a different temperature from the wellbore fluid can be detected. Recorded log data may be used (in conjunction with pressure data) to determine the wellbore steam properties.

Pressure Instrument

Downhole pressure measurements are recorded and displayed at the surface in real time for accurate determination of wellbore pressure. Accuracy of the measurement is maintained with thermal and pressure packaging which allows the use of a reputable "off-the-shelf" oilfield pressure instrument.

Temperature measurement at the sensor allows for surface-computed temperature compensation of the pressure measurement. A baffled oil reservoir is used to prevent exposure of the pressure sensor to water, steam, and/or wellbore fluids.

A differential pressure curve is also computed from the pressure instrument response. This curve is similar to the differential temperature curve and may be used for detecting any changes on the pressure-gradient slope.

Typical applications of the pressure instrument are:

1. Continuous-pressure survey of a well, as obtained from a continuous logging survey, to determine the flowing and static pressure gradients of the well.

2. Measurement of shut-in and flowing pressure at a

prescribed depth level and sampling time for determination of pressure buildup or drawdown calculations.

3. Calculation of steam properties (in conjunction with temperature log data).

Continuous Spinner Turbine Flowmeter

Continuous spinner turbine flowmeter surveys can be used for metering fluid flow rates within cased or openhole wells. The measurement is obtained from a rotational speed sensor target coupled to a highly efficient impeller. The rotational velocity of the spinner within the instrument is proportional to the velocity of the fluid movement. This relationship is approximately linear in turbulent fluid flow.

Due to the wide range of flows encountered in a geothermal well, various diameter spinner heads, impeller pitch, solids protection, and flow restrictor combinations are utilized. Thus, instrument resolution and sensitivity are dependent on the combination used and the downhole fluid properties. These variations require downhole calibration of the instrument. The resulting calibration plot is used for flow-rate analysis. Measurements made while the instrument is stationary are generally considered to be most accurate. However, the instrument response can be extended (particularly the lower limit) by making measurements while the instrument is in motion. It is recommended that three calibration runs be made at line speeds between 40 and 200 ft/min (13 and 66 m/min) with the well flowing, and repeated with the well shut in. Crossflow patterns can often be established using this procedure.

Units of measurement for the flowmeter are defined as revolutions per second (rps). The flow profile may be derived from stationary or continuous log data. For best results, the continuous spinner flowmeter should be run with centralizers.

Collar Locator Instrument

The Casing Collar Locator (CCL) instrument monitors the local magnetic field surrounding the detector coil. When a change in this field is encountered, such as when the instrument passes a casing collar, it responds with a signal that is recorded on the log.

CCL responses are used to determine positions of casing collars and other well hardware for the purpose of depth correlation with other logs. Usually the measurement point of the CCL is taken as "zero" with the other instrument measurements shift-plotted and depth-corrected to this point.

Mechanical Tools

Complementary mechanical tools have been developed to accompany the TPS geothermal logging instrument string. These include 16-in. (40.6-cm) body, bow spring centralizers, a maximum thermometer cablehead sub, openhole lead-in device, etc.

The body centralizers utilize the electronics housing as the mandrel of the centralizer by using a sleeve sliding over the housing, thus halving the length required for double-acting centralizers.

The openhole lead-in device (fig. 2) consists of a gravity counterbalance nose pivot that always maintains an uphole orientation, regardless of wellbore deviation angle. Jump springs mounted on the pivot nose allow the device to slide up the downhole face of an openhole washout. All hardware is of sufficient strength to withstand repeated bottom impact. In combination with the 30-in. (76.2-cm) centralizer, this device facilitates the re-entry of the instrument string into the drilled wellbore after falling into a large-diameter washout. Appropriate measures have been designed into the device to allow its fail-safe retrieval from the wellbore. Since the device functions are the spinner flowmeter, an integral adjustable flow restrictor has been incorporated into the flow housing mandrel.

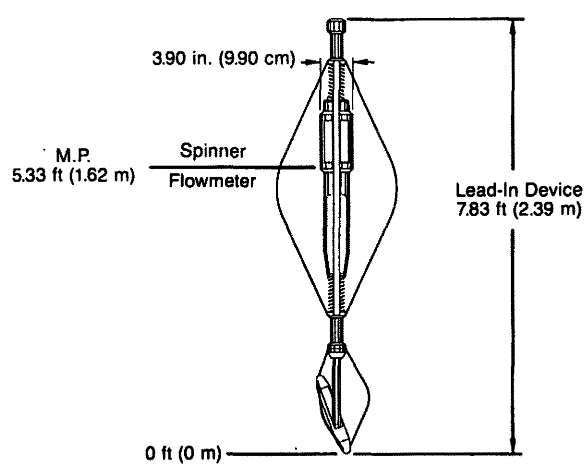


Figure 2. Lead-in device

TPS DATA ANALYSIS

A well-site program has been developed to analyze the TPS log data in conjunction with other wellbore information and surface data. The program is capable of utilizing measured temperature and pressure data for calculation of steam properties and also using spinner flowmeter data for wellbore flow profiling. For better understanding of the flow behavior and usefulness of the program, it is beneficial to describe the types of flows encountered in geothermal fields.

Flows in a geothermal well may be classified into one or more of the following categories:

1. Single-phase gas (dry steam)
2. Single-phase liquid (subcooled liquid)
3. Two-phase flow (saturated)

The parameters needed for estimating the steam properties in any of these regions are temperature, pressure, and density. The geothermal TPS logging instruments provide measured wellbore data of temperature, pressure, and fluid flow rate. A solution to each of the flow categories is presented in the following sections.

## Single-Phase Flow

For single-phase steam flow (dry steam), various thermodynamic properties of the steam such as saturation temperature and pressure, density, enthalpy, and degrees superheat can be estimated using temperature and pressure data and published steam tables. In single-phase water (subcooled liquid), the water properties can also be estimated from published formulas.

In a single-phase flow (steam or water), the spinner flowmeter data, used in conjunction with the borehole diameter information, allows for determination of the flow velocity (or volumetric flow rate) and percent contribution of each active zone. Once the downhole fluid density is known (calculated from temperature and pressure data using corresponding formulas), percentile mass flow rate of each active zone and the cumulative flow of the well can be determined.

## Two-Phase Flow

Analysis of geothermal wells producing two-phase flow requires known temperature, pressure, and volumetric and mass flow rates of the various fluid components in both phases. The basic equations available to solve this problem are mainly the mass, energy, and momentum balance equations. To accurately analyze the wellbore data, the three equations have to be solved simultaneously. Since the flow parameters (such as velocity, density, viscosity), are continuously changing in the wellbore, a different flow regime may exist at various points of the well. Consequently, for each flow regime, a different correlation is needed to calculate the flow parameters. Due to such complexities, a direct solution of this method is almost impossible and requires several assumptions.

Another approach to the solution for estimation of wellbore steam properties is to use the pressure instrument response. With this method, the differential pressure drop is calculated from the pressure instrument response over a known vertical distance. An average mixture fluid density can then be calculated for that interval with reasonable accuracy. The accuracy of this calculation depends upon resolution of the pressure instrument over a measured depth interval. In deviated wells, the differential pressure must be corrected by dividing by the cosine of the deviation angle of the well. Using this method, some errors may be introduced, affecting the accuracy of the calculations. Variations can also occur from one survey to another.

At each point of the well, as determined from the temperature or pressure response curve and the use of steam tables, the specific volume of vapor ($V_g$) and liquid ($V_f$) is estimated. Knowing that the specific volume is the inverse of density, the calculated mixture density allows for computation of the mixture specific volume ($V_m$). In a saturation state, the steam quality is defined as the ratio of vapor mass to the total mass of liquid plus vapor. From this definition, $V_m$ and steam quality (X) relationship can be described as:

$$V_m = X * V_g + (1-X) * V_f$$

where $V_g$ and $V_f$ are specific volumes of liquid and vapor respectively. Solving for X,

$$X = (V_m - V_f) / (V_g - V_f)$$

When the mixture specific volume is known, the steam quality can be determined and the thermodynamic properties of the steam can be easily determined. For example, the enthalpy of a two-phase flow may be calculated by using the steam quality from

$$H_m = X * H_g + (1-X) * H_f$$

where $H_g$ and $H_f$ are saturated vapor and liquid, respectively, for a selected saturation temperature from the steam tables.

Converting the flowmeter data to meaningful units requires some special considerations. This is mainly due to the type of fluid in the wellbore and the method of data acquisition. In all instances, however, downhole

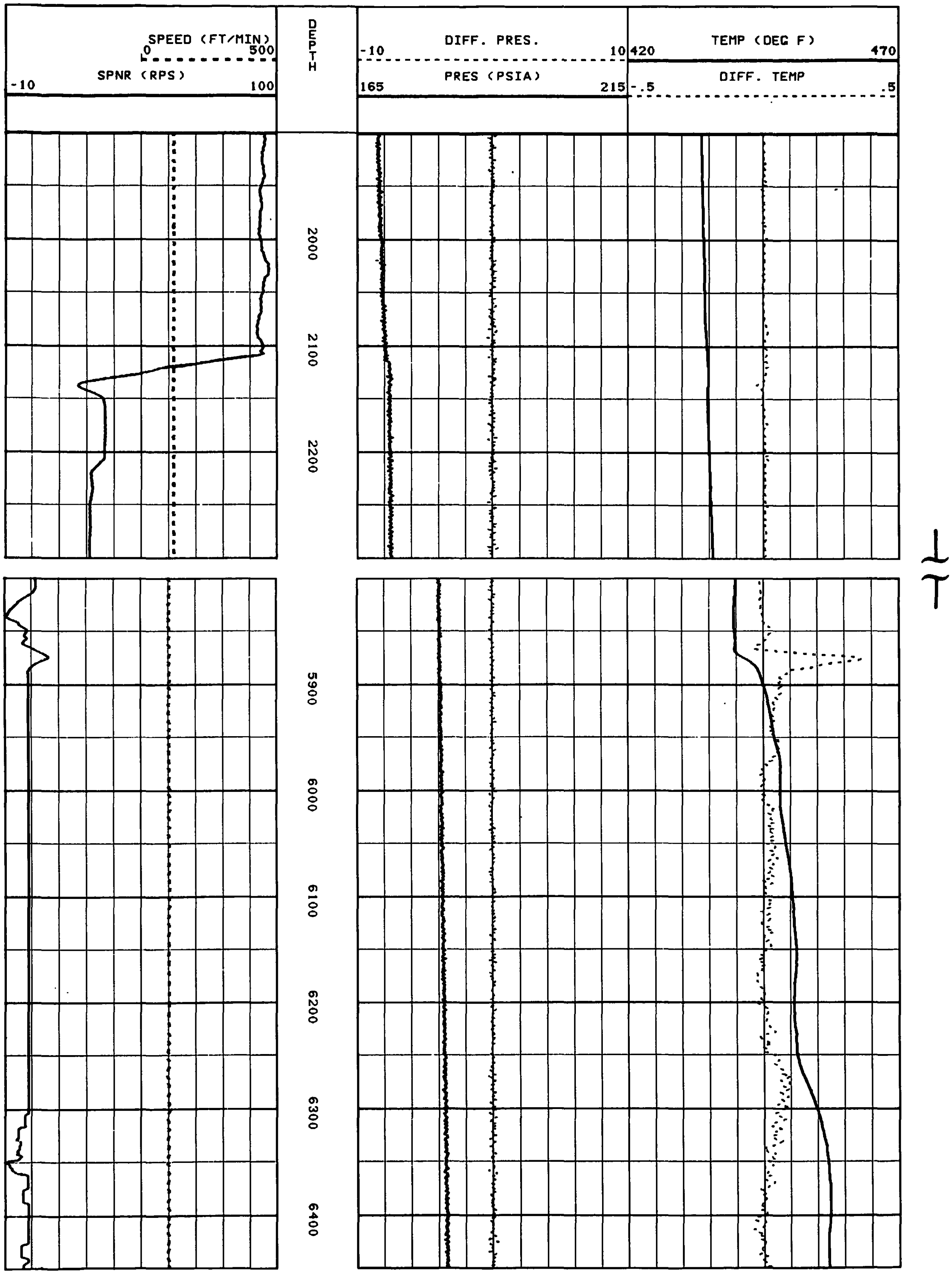


Figure 3. Typical field log presentation described in Log Example 1.

calibration of the flowmeter will give the best results. This calibration is accomplished by one of two methods. The first method is for low-to-intermediate flow-rate wells and the second method is for high flow-rate wells. In the first method, changing the logging speed and recording the flowmeter response over a depth interval requires the construction of a calibration chart. In high flow-rate wells, however, changing the logging speed does not have a significant effect on flowmeter response. This method of flowmeter calibration requires changing the surface production flow rate and recording the log data at the same logging speed. One important consideration with this method is to allow sufficient time for flow stabilization between the flow-rate changes. This time period may be established by monitoring the wellbore flow with logging devices set at a specified depth.

## LOG EXAMPLE 1

A typical log data presentation is shown in fig. 3. The instrument responses are plotted on the log in prescribed tracks. The scale band may be changed at any time during the survey. In this example, spinner flowmeter and cable speed are shown at the left (P-track) with spinner response plotted as a solid line and cable speed plotted as a dotted line. The pressure and differential pressure are presented in the center of the log (R-track, R 0-10) with pressure plotted as a solid line and differential pressure plotted as a dashed line. The temperature and differential temperature are presented on the right-hand side of the log (R-track, R 10-20) with temperature plotted as a solid line and differential temperature plotted as a dashed line.

The subject well is an offset well (fig. 4) that was drilled through a window cut in the casing. This window is typically 30 to 40 ft (9.1 to 12.2 m) long to allow access of the drill string and logging instruments. In the area of the window, the casing and surrounding cement is generally worn away from tool wear during drilling operations. Large-diameter washouts may be created from erosion due to either mud flow, air drilling operations, and/or production flow vortices and eddies. These washouts can have diameters greater than 20 in. (50 cm) as indicated by maximum readings of downhole caliper instruments and a length equal to the casing window. When instruments are lowered into the area of the logging window, the instruments fall into the washout and are usually unsuccessful in locating and entering the original drilled wellbore downhole of the washout. Thus a complete log of the well to total depth is not obtained, leaving unanswered questions in the analysis of the well.

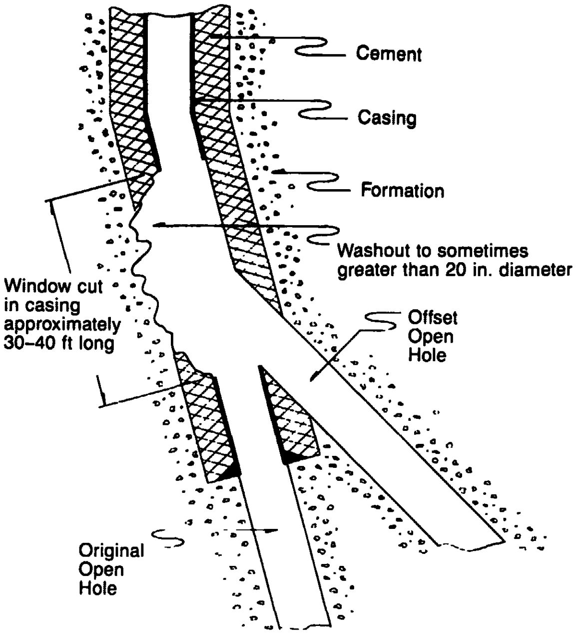


Figure 4. Typical offset well

This problem was solved with the design of the TPS lead-in device. As described earlier, the large centralizer, in conjunction with the counterweight nose pivot, slides up the downhole face of the washout, leading the instrument string into the original drilled wellbore. Thus a complete log of the subject well was obtained whereas all previous logging attempts to reach total depth had failed.

In this example, at a depth of approximately 2120 ft, the instruments move past the offset well casing window into the original hole aided by the lead-in device. Consequently the production flow-rate drops, as indicated by the decreased flowmeter response. At this depth, there are no appreciable changes in the temperature or pressure response curves, indicating that there are no activities such as leaks behind the casing.

The major activities in this well appear to be at approximately 5875 and 6300 ft. At these depths, the temperature indicates a cooling anomaly, which may be determined as a cooler fluid entering the wellbore. The spinner flowmeter did respond to these flow entries but the pressure response (pressure gradient) did not change. This is due to entry of relatively the same type of fluid (same density) as existing in the wellbore.

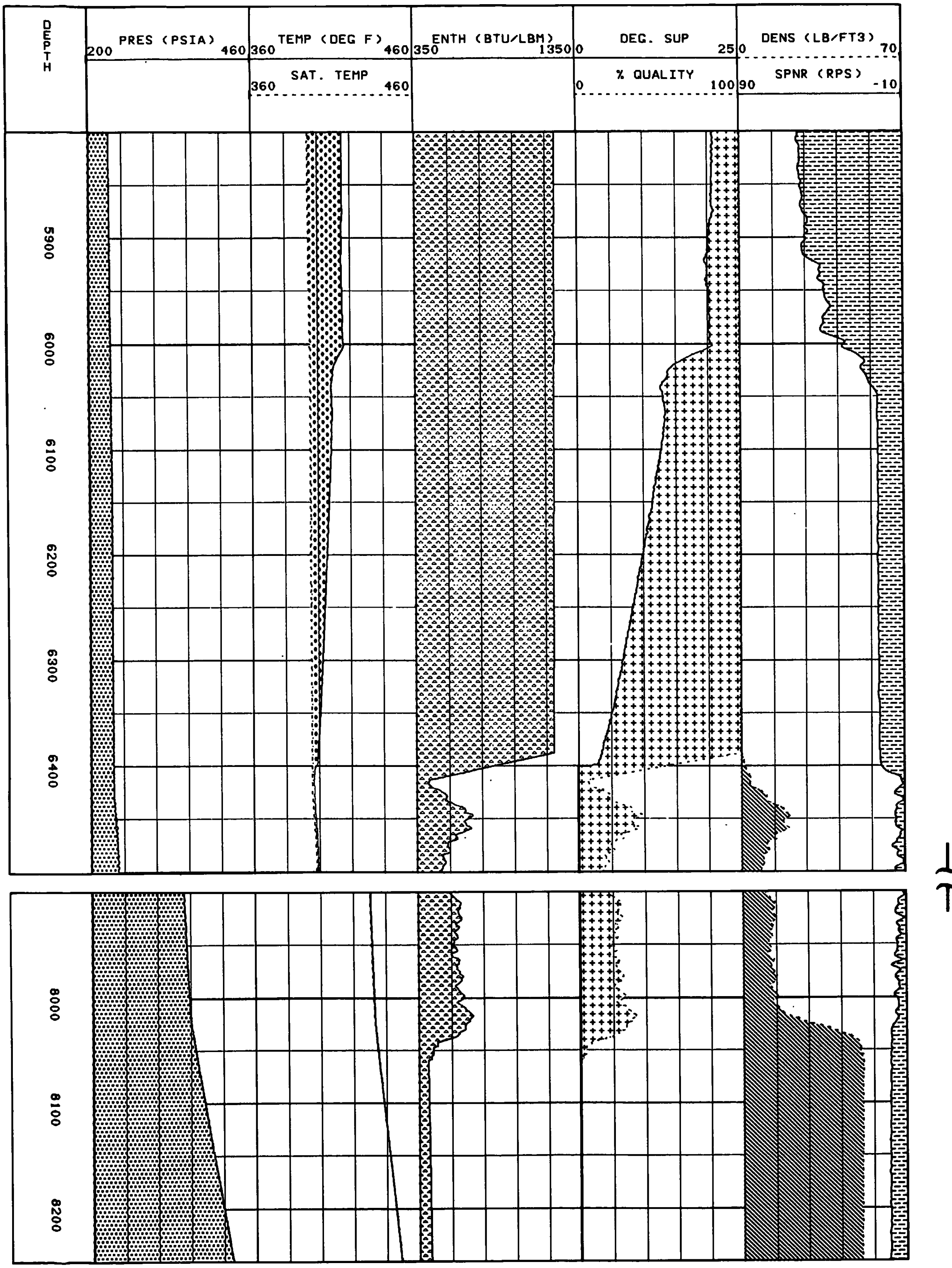


Figure 5. Typical log and analysis data described in Log Example 2.

LOG EXAMPLE 2

This well produces dry steam at the wellhead and the purpose of the survey was to locate the wellbore steam entries and profile the well under flowing conditions. The data was analyzed from a recorded up-run survey as shown in fig. 5. Although dry steam is produced at the surface, the log data shows two-phase flow regime in a section of the well and single-phase hot water in the lower portion of the well. Log data is presented as pressure in track 1, temperature in track 2, and spinner flowmeter in track 5.

Analysis of the temperature log indicates changes in the gradients at depths of 6025, 6410, and 8030 ft. At each of these points, the spinner flowmeter response also changes, indicating additional fluid entering the wellbore. The pressure gradient response, which is indicative of the type of flow in the wellbore, does not change at the depth of 6025 ft. This means that the flow entering at this point is the same as existing in the wellbore (superheated). At depths of 6410 and 8030 ft, the pressure response does change, a consequence of the two-phase and hot water flow, respectively.

Using the temperature and pressure from log data and the analysis program, some steam properties are calculated. These parameters are saturation temperature, degrees superheat, steam quality (in the two-phase region), mixture fluid density, and enthalpy. Saturation temperature is plotted on the same track and scale of the temperature log and shown with shading between them. Enthalpy is plotted on track 3 and fluid density is presented on track 5. The steam quality and degrees superheat are plotted on track 4 with shading between these plots.

As mentioned, the fluid in the wellbore above 6410 ft is superheated steam. From 6410 to 8030 ft, two-phase flow exists in the wellbore. Over this interval, the mixture density and enthalpy are calculated from the pressure gradient. The erratic readings of spinner flowmeter and steam quality are primarily due to sluggish flow in the wellbore. (Note: A deviation survey was not available for this well, and a deviation angle of 10° from vertical has been assumed).

At depth of 8030 ft, the wellbore flow consists of single-phase hot water. This is evident from the smooth response of the spinner flowmeter and gradient changes in the pressure response.

In this field example, the advantages of simultaneous logging instruments are shown. The instrument responses complemented each other and as one instrument response varied, the others also verified these changes. Simultaneous data acquisition is most useful in two-phase flow where the flow regimes are constantly changing.

CONCLUSIONS

The measurement of fluid parameters such as temperature, pressure, and fluid flow rate in geothermal wells can help the management and productive performance of the reservoir. The newly designed TPS instruments make it possible to acquire accurate, downhole data simultaneously with a single logging pass or over a long period of time, allowing the means of pressure buildup or drawdown surveys. In high flow-rate wells, it is possible to use various pitch impellers and/or an adjustable flow restrictor to extend the operating span of the instrument, especially if multi-rate testing is desired. The lead-in device is another advantage of the TPS string for operation in openhole completion or offset wells where possibility of large-diameter washouts exists.

The well-site computer program allows for an expedient and thorough analysis of downhole log data. The steam parameters are calculated with reasonable accuracy and presented in a tabulated and plotted format. The phase regions existing in the wellbore can be distinguished, helping to determine the flash point depth. Wellbore fluid mass flow rate (cumulative and differential) can be calculated if the hole diameter is known.

REFERENCES

ASME Thermodynamic and Transport Properties of Steam, fifth edition, 1983. The American Society of Mechanical Engineering, New York.

Irvin, Jr., T.F. and Liley, P.E., 1984. Steam and Gas Tables with Computer Equations, Academic Press, Inc., Orlando, FL.

Davarzani, J., Sloan, M., 1987. Analysis of Geothermal Wells Using Simultaneous Logging Instruments, SPE Paper 16818 Presented at the 62nd Annual Fall Meeting, Dallas, TX, Sept. 27–30.

Interpretive Methods for Production Well Logs, 3rd Edition, 1986. Dresser Atlas Publications, Houston, TX.