TPS: A RESERVOIR MONITORING SERVICE

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ABSTRACT

A wireline instrument system is described for the simultaneous recording of data related to pressure, temperature, and flow velocity in a geothermal well. The information from the system enhances reservoir monitoring and promotes better management of geothermal fields.

Techniques are described for processing the recorded data to determine important steam properties such as the quality of the steam and its mass flow rate profile, which are useful for identifying the productive intervals.

Pressure-transient data permit determination of formation properties such as permeability, skin factor, pressure loss due to skin, and absolute open-flow potential. A field log example is shown and the analysis method is described.

INTRODUCTION

In recent years, the growing number of geothermal fields has resulted in further utilization of the existing geothermal reservoirs and in the development of new fields. Reservoir characteristics of a geothermal well are determined by recording temperature, pressure, and spinner flowmeter response (TPS) during the actual production of the fluid.

With the development of new instruments, measuring downhole fluid parameters in hostile environments is feasible. This tool has made it possible to verify the active zones and their capabilities under different flowing conditions.

Three main topics are addressed in this paper: instrument descriptions, data analysis, and pressure-transient testing.

The first section is a general description of the instruments and their applications in geothermal wells. Methods of recording log data from each instrument are also detailed.

For more accurate interpretation of field log data, an overall analysis method of TPS instrument responses and parameters is described in the second section. The types of parameters measured are explained as well as the use of a computer program which helps determine thermodynamic properties of steam. The method by which steam properties, such as saturation temperature and pressure, mixture fluid density, wellbore fluid enthalpy, and steam quality, are calculated from temperature and pressure-response data is also discussed. An average fluid velocity of the wellbore fluid is calculated from spinner flowmeter data and knowledge of the wellbore diameter. Knowing the fluid velocity and mixture density, the wellbore mass flow rate is determined thus making it possible to profile water and steam production.

The third section presents a more detailed discussion on the analysis of pressure-transient data and their use in reservoir evaluation. A description of how reservoir parameters, such as permeability, productivity, and skin, are determined concludes the paper.

INSTRUMENT DESCRIPTIONS AND APPLICATIONS

A new generation of instruments has been developed to withstand the hostile environment of the geothermal wells. The instrument electronics are packaged in a flask which provides protection against extended high-temperature exposure. These instruments are capable of operating at 600°F and 15,000 psi for 12 hours. The simultaneous transmission of all instrument responses depends on the logging method. When recorded versus depth, the data are transmitted at the rate of four samples per foot. If data are recorded versus time, the sample rate, ranging from one second to one full hour per data point, is requested by surface-computer command.

Complementing the logging string are various mechanical tools consisting of centralizers, maximum-thermometer cablehead subs, and openhole lead-in devices.

Temperature Instrument

The temperature instrument measures the wellbore fluid temperature. From recorded data versus depth, the geothermal gradient is established. The computed differential temperature curve, the change of the gradient slope, is useful for detection of active zones and determination of fluid phase changes.

Pressure Instrument

Data from this instrument is recorded in two ways; versus depth and versus time. When recorded versus depth, the real-time downhole pressure gradient is derived. The state of fluids in the wellbore is determined from a change of the gradient slope. If recorded versus time, the logging data at the prescribed depth is used for determining reservoir parameters, such as productivity index and permeability. This type of data is often recorded for pressure build-up, drawdown, or multirate tests.

Continuous Turbine Spinner Flowmeter

The turbine spinner flowmeter measures the wellbore flow velocity through a rotating impeller, the speed of which is converted to velocity. As the velocity varies in the wellbore, the instrument's response changes. To determine the volumetric flow rate, the exact hole diameter should be known. The turbine spinner flowmeter is sensitive to fluctuations in the wellbore flow velocity. These fluctuations may be caused by production from a zone, a change in hole diameter, a thief zone, a cross flow, or by a fluid phase change.

Logging Procedure

Recording downhole parameters by the TPS tool string serves two purposes: fluid identification from temperature and pressure data and flow rate measurement from spinner flowmeter data. Overcoming external factors from affecting accurate spinner flowmeter response is achieved through downhole calibration, by making several passes at different logging speeds.

During logging, temperature and pressure data are more accurately measured if the following are observed:

1. Record the data as the instrument is lowered into the well.
2. Record log data at a constant logging speed and moderate velocity for increased measurement resolution.
3. Maintain a constant flow rate and pressure at the wellhead.
4. Monitor the wellhead temperature, pressure, and flow rate.
5. Allow sufficient time for the stationary readings at any chosen depth.
6. Recheck the active part of the log for further verification.

DATA ANALYSIS

As stated before, TPS data is recorded for two different purposes, each using its own specific data analysis method. A typical field log data analysis is shown in Figure 1. A description of each method follows.

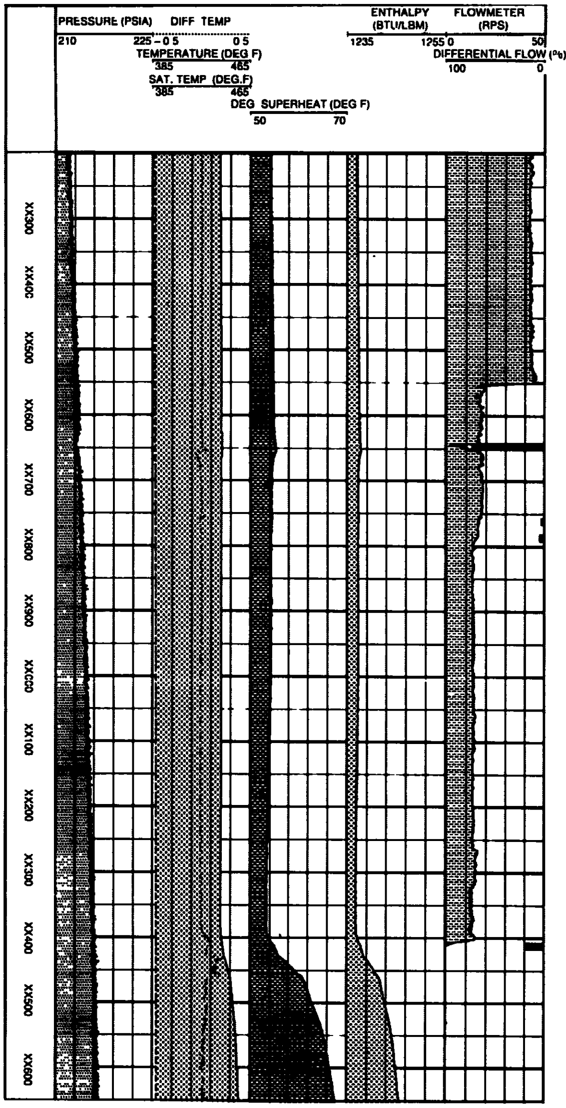

Figure 1. Typical field log data analysis presentation

Fluid Properties Data Analysis

Supplemented by the published steam tables, the recorded downhole temperature and pressure data help determine steam properties.

In surveying a geothermal well, different fluid phases may be recognized for any recorded interval. These include hot water, saturated steam (two-phase), and dry steam (single-phase gas) at the bottom, middle, and top of the well, respectively. Phase variations which occur are mainly due to the changes in wellbore pressure and temperature.

Several points need to be highlighted in determining the steam properties from the temperature and pressure log data:

1. Parameters in the program's steam tables are developed from pure water.
2. The log data and type of flow in the wellbore should be examined closely. They are clearly reflected in the instruments' response when fluid phases change in the wellbore.
3. Various impurities exist in the produced fluid.

Considering these principles, the saturation temperature is calculated from the measured pressure using published steam tables. By comparing the saturation and measured temperatures, the fluid state is determined, which must agree with the fluid phase indicated by the log responses. If the calculated saturation temperature is above the measured temperature, the fluid is considered to be single-phase hot water. If, however, it is below the measured temperature, the fluid is determined to be single-phase gas or dry steam. In each case the fluid properties, such as enthalpy, degrees superheat (if dry steam), density, and saturation pressure, are estimated.

If the fluid type falls into the two-phase region, two independent variables, such as temperature or pressure and specific volume (inversion of mixture density), are needed for calculation of steam properties. From log data, the temperature or pressure values are available, but the mixture density needs to be calculated. With some assumptions, the mixture density is computed from the pressure gradient.

A brief description of the method and the assumptions follows:

It is known that the total pressure gradient, $(dp/dz)_{total}$, is the sum of the static head, $(dp/dz)_{elev.}$, friction head, $(dp/dz)_{fric.}$, and acceleration head, $(dp/dz)_{acc.}$. So, the total pressure gradient is written as:

$$(dp/dz)_{total} = (dp/dz)_{elev.} + (dp/dz)_{fric.} + (dp/dz)_{acc.}$$

In a liquid-dominated wellbore, the pressure loss is mainly due to the hydrostatic head (Hasan and Kabir, 1988) and often accounts for more than 95% of the total gradient. For a small interval (five feet or so), it is reasonable, therefore, to ignore the pressure drops due to the friction and acceleration components. With this in mind, we assume that the total pressure loss is equal to pressure loss due to the hydrostatic head, which is directly related to the mixture density. Under these conditions,

$$(dp/dz)_{elev.} = (dp/dz)_{total}$$

having

$$(dp/dz)_{elev.} = DEN_{mix.}$$

So,

$$(dp/dz)_{total} = DEN_{mix.}$$

A computer program, which continuously computes the pressure drop over a prescribed depth interval, calculates the wellbore fluid density in the interval. A depth interval of five feet usually gives an adequate result. This interval may be varied if the fluid phase in the wellbore changes. Once the fluid density is known, the specific volume (inversion of density) is computed. The steam properties, such as quality, mixture enthalpy, and mixture density, are calculated from the computed specific volume and the measured temperature.

Flowmeter Data Analysis

The spinner flowmeter response curves generated from the multiple passes or stationary readings determine the sensitivity of the instrument (slope). A new slope needs to be calculated if the fluid phase changes, which brings about a change in the instrument's response. Also, to accurately calculate the wellbore flow rate from the instrument response, the borehole diameter must be known. The fluid velocity is calculated from simultaneous solution of instrument response, logging speed, and hole diameter over a desired interval and consequently the wellbore flow profile is determined. Knowing the fluid density from the previous step, the mass flow rate (product of fluid velocity, borehole cross sectional, and density) is calculated.

As mentioned before, different phases may exist in a geothermal wellbore. The recorded log data accuracy depends on the homogeneity of the flow region. In single-phase flow (dry steam or hot water), the TPS responses can be analyzed accurately. However, in two-phase flow, due to its unsteady state, some attention needs to be given in analysis of log data. Overall, a two-phase flow can be divided into several types. Many investigators categorize these as bubble, churn, slug, annular, and mist flow. Within each classified region, an area of transition exists. The range of this area varies, based on the fluid physical properties and wellbore geometry.

Since the calculation of mixture density was based only on the hydrostatic component, the accuracy of this assumption declines as the liquid phase evaporates.

PRESSURE-TRANSIENT TESTING

Well testing and pressure-transient analysis techniques have been widely applied to geothermal wells for determination of formation flow parameters. The interpretation methods, with some modifications, used in petroleum engineering are also valid for geothermal reservoirs. The productivity of a geothermal well is influenced by damage or improvement to the well permeability near the wellbore, or by turbulence caused by high-velocity flow phenomena. Flow rate and performance prediction of wells are factors of economic importance to the geothermal industry.

The most common types of testing for a geothermal well are pressure build-up, drawdown, and multirate tests.

These tests require an extensive amount of data for accurate determination of reservoir parameters. Introduction of the TPS tool string makes data recording for these methods possible.

The following flow equations are generally used to determine the formation parameters such as permeability, skin, and pressure loss due to the skin. The flow model is assumed to be a single-phase steam and radial (Economides et al., 1980). The reservoir is considered homogeneous and infinite acting.

Drawdown Test

$$p_{wf}^2 = p_i^2 - \left[\frac{7457.4\ w\ \mu\ z\ T}{M\ k\ h}\right] \times \log(dt) \qquad \text{(Eq.1)}$$

A semilog plot of the pressure-squared difference versus log (dt) of Eq. 1 yields a straight line. The slope (m) of the straight line equals the group of variables multiplying the time function. The formation permeability is calculated using:

$$k = -\frac{7457.4\ w\ \mu\ z\ T}{M\ m\ h} \qquad \text{(Eq. 2)}$$

The skin effect is found by using p_{1hr}, the pressure value from the straight line in a semilog plot at one hour of flowing time.

$$S_{skin} = 1.151\left[\frac{p_{1hr}^2 - p_{wf}^2}{m} - \log\left(\frac{k}{\phi\ \mu\ c_t\ r_w^2}\right) + 3.23\right] \qquad \text{(Eq. 3)}$$

Build-up Test

In the pressure build-up test, Eq. 1 is transformed into:

$$p_s^2 = p_i^2 - \frac{7457.4\ w\ \mu\ z\ T}{M\ k\ h} \times \log\left(\frac{t_p + dt}{dt}\right) \qquad \text{(Eq. 4)}$$

The permeability in this case is calculated using Eq. 2. To calculate the skin factor from pressure build-up tests, the following equation is used:

$$S_{skin} = 1.151\left[\frac{p_{1hr}^2 - p_i^2}{m} - \log\left(\frac{k}{\phi\ \mu\ c_t r_w^2}\right) + 3.23\right] \qquad \text{(Eq. 5)}$$

Extrapolation of the straight line of a semilog plot to an infinite shut-in time, $(t_p + dt)/dt = 1$, yields a pressure p* from which the average reservoir pressure is determined.

The pressure drop caused by the skin factor for both drawdown and build-up is:

$$dp_{loss} = 0.87\ m\ S \qquad \text{(Eq. 6)}$$

Type Curve Analysis

Type curves have long been used for the analysis of limited test data, identification of flow region, and verification of results obtained by other methods. All type curves generated for hydrocarbon well testing are applicable for geothermal wells, however, the dimensionless variable definitions must be redefined for geothermal fluids:

$$\text{Dimensionless pressure, } p_D = \frac{k\ h\left(p_i^2 - p_{r,t}^2\right)}{359.7\ w\ \mu\ z\ T} \qquad \text{(Eq. 7)}$$

$$\text{Dimensionless time, } t_D = \frac{.000264\ k\ t}{\phi\ \mu\ c_t\ r_w^2} \qquad \text{(Eq. 8)}$$

Application of TPS for Pressure-Transient Testing

Geothermal well testing is conducted more efficiently by running the TPS tool string and simultaneously recording the bottomhole temperature, pressure, and sandface flow rate. Application of TPS tool provides better well test control, such as extension of test if unforseen downhole phenomena occur or termination of test if the objectives are achieved. Because the tool measures afterflow rate in addition to build-up pressure data, it allows analysis of afterflow-dominated build-up data. The application of rate-convolution analysis allows detection of semilog straight line at least one log cycle earlier than the conventional semilog data-plotting method. Figure 2 shows a conventional pressure-derivative plot of build-up data plotted on pressure-derivative-type curves (Bourdet et al., 1983). Data acquisition is extended to one and a half cycles in the log-log data plot in normal time-pressure well tests or when it shows a horizontal trend in the pressure-derivative plot. This condition usually indicates radial flow. Using the TPS data and constructing a rate-convolved time function versus pressure, the semilog straight line is detected in the afterflow-controlled region.

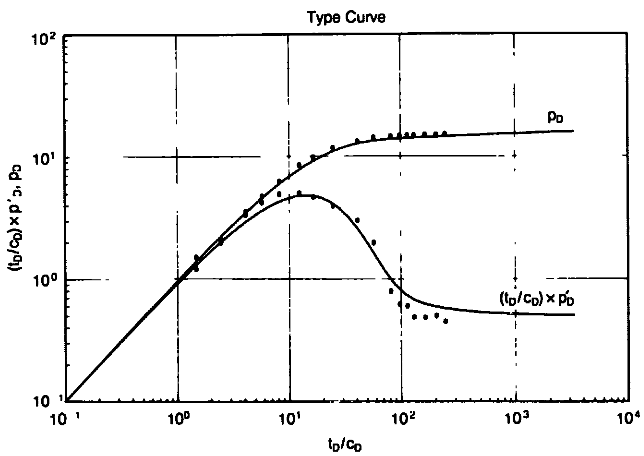

Figure 2. Pressure-derivative plot of build-up data

Figure 3 compares conventional and modified Horner graphs indicating early detection of the semilog straight line in the afterflow (Meunier and Stewart, 1985).

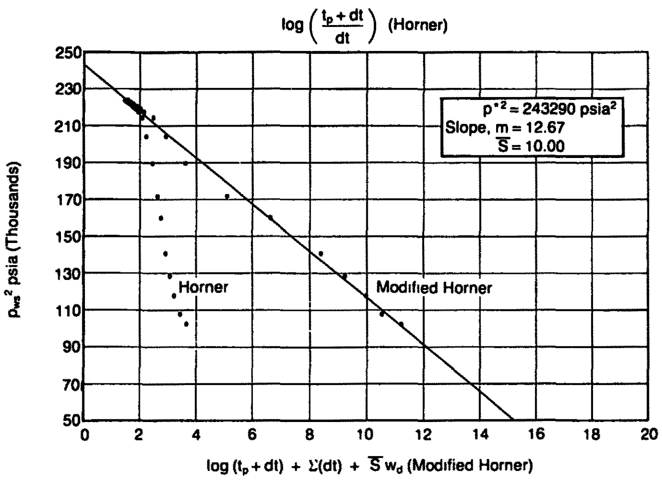

Figure 3. Comparison of conventional and modified Horner graphs indicating early detection of the semilog straight line in the afterflow

Multirate Tests - Deliverability Test

There are several methods for calculating Absolute Openhole Flow Potential (AOFP) and performance coefficients. One is the back-pressure test, commonly used for monitoring and forecasting geothermal reservoirs.

Field Log Example - Deliverability Test

To verify the theoretical calculation of the deliverability of a steam-producing reservoir, field log data were recorded. The selected method was a multirate test. Three different production rates were tested and stationary readings were made of temperature, pressure, and flow rate. The rates and pressures of each test are shown in Table 1. The AOFP of the subject well was computed using both the empirical (Figure 4), and the theoretical (Figure 5) relationship of flow rate and pressure (Smart and Fertl, 1988). The equation used for each method follows;

Table 1

Pressure mode	Meas. Pres. (psia)	Flow rate (lb/hr)
Initial	305.0	0
Flowing	235.8	220,000
Flowing	253.8	170,000
Flowing	274.4	110,000

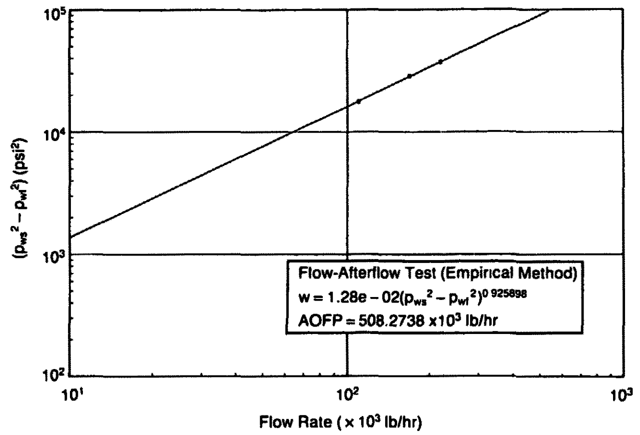

Figure 4. Flow-afterflow test (empirical method)

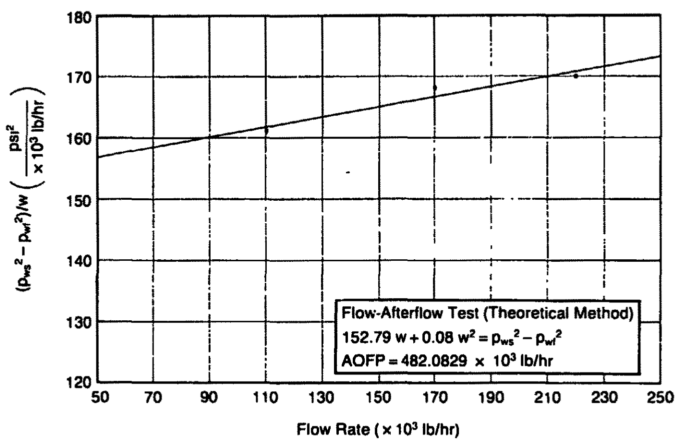

Figure 5. Flow-afterflow test (theoretical method)

1. Empirical method $w = A\,(p_{ws}^2 - p_{wf}^2)^n$ (Eq. 9)
2. Theoretical method: $B\,w + C\,w^2 = p_{ws}^2 - p_{wf}^2$ (Eq. 10)

The following coefficients of Eq. 9 and 10 were derived by plotting the data presented in Table 1;

A = 0.01.28E-02
n = 0.925898
B = 152.79
C = 0.08

The corresponding AOFP for the above methods is calculated to be:

Flow-Afterflow (Empirical) AOFP = 508,000 lb/hr
Flow-Afterflow (Theoretical) AOFP = 482,000 lb/hr

These results indicate that both methods agree reasonably well with an AOFP value of about 500,000 lb/hr.

SUMMARY AND CONCLUSION

The development of the TPS tool string makes it possible to measure the downhole fluid parameters during actual production. The instrument string withstands the hostile environment for a long period of time, thus ensuring the quantity and quality of data. The TPS data are useful for several purposes such as:

1. Simultaneous recording of instrument responses to any changes in flow rate or composition instantly
2. Profiling the well under actual flowing conditions
3. Determining the downhole steam properties
4. Obtaining comprehensive data for pressure-transient tests
5. Using TPS data and rate-convolved time function method, thus determining the flow parameters in the early time region and shortening the pressure-transient test duration

Nomenclature:

c = Isothermal compressibility psi^{-1}
c_D = Dimensionless wellbore storage
h = Pay thickness, ft
k = Permeability, md
M = Molecular weight
m = Slope
p^* = Extrapolated pressure psia
p_i = Initial pressure, psia
$p_{r,t}$ = Pressure dependent on distance and time
p_{ws} = Shut-in pressure, psia
p_{1hr} = Pressure intercept at 1 hour
P_D = Dimensionless pressure
r_w = Wellbore radius, ft
S = Skin
T = Absolute temperature, °R
t_D = Dimensionless time
$(t_D/c_D) \times P'_D$ = Dimensionless pressure derivative group
t_p = Flowing time, hours
dt = Shut-in time, hours
w = Mass flow rate, lb/hr
z = Steam compressibility factor
μ = Viscosity, cp
ϕ = porosity, frac.

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