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A CASE STUDY OF TWO-PHASE FLOW AT THE ROOSEVELT HOT SPRINGS, UTAH KGRA

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ABSTRACT

A well in the Roosevelt Hot Springs, Utah KGRA was flowed in 1978 and 1979 to obtain pressure and temperature profiles in the two-phase (steam/water) zone. Both parameters were measured simultaneously and in real time, as a function of depth. Under flowing conditions, the maximum temperature recorded was 503°F (262°C) and maximum pressure, 954 psia (6.58 MPa). Flow rates as high as 580,000 lb/hr (73.3 kg/sec) total flow were measured using a modified James method.

Comparison of test results with output of a two-phase flow computer model was performed. Model results matched test data quite well at flow rates below 300,000 lb/hr (38 kg/sec); above that level, increasing deviation from test data was noted with increasing flowrate. The computer model was used to investigate the effects of casing diameter and Productivity Index on the flowrate that could be sustained for a fixed wellhead pressure. For example, a well with 13 3/8 inch diameter casing is predicted to have a 24% greater flowrate than can be sustained in the current 9 5/8 inch diameter well. The impacts of both diameter and PI are significant, and results show that well design can be optimized to maximize production when reservoir parameters are known.

INTRODUCTION

As part of the Department of Energy "Industry-Coupled" Program to promote the development of geothermal resources, the Denver Research Institute (DRI) has peformed a case study of two-phase flow in a well at the Roosevelt Hot Springs, Utah Known Geothermal Resource Area (KGRA). The project had two objectives:

- o to obtain pressure and temperature logs as a function of depth from a geothermal well flowing in a two-phase mode;
- o to use the acquired data for validation of a two-phase flow predictive computer model and in the definition of reservoir conditions for use in an optimization of the casing schedule by analysis with the computer model.

Although there were problems with several components in the logging and flow measuring equipment, sufficient data was obtained to perform the analyses noted above.

Research on two-phase flow in vertical geothermal wellbores has been under way at DRI for the past four years. Because of the unique nature of the interaction between physical, chemical and thermodynamic parameters, two phase flow has been characterized empirically rather than theoretically. Further, the equations used to describe the pressure drop are a function of the relative volumetric fractions of liquid and gas as well as of the flow regime. A computer model to test appropriate correlations from the literature has been developed by Coury and Associates as a part of this research. Data from several field tests has been compared to output of the model, and correlations which provide the best match of computer simulations to test data have been identified. The Roosevelt Hot Springs tests presented an opportunity to obtain further data for validation of the computer model as well as to extend the analysis to study the effect of casing diameter and productivity index on the flowrate that could be sustained for a given set of reservoir and wellhead conditions. This application represents the initial use of the computer model for the type of optimization envisioned when the research was begun. Certainly, upon review of the results, the significance of such an exercise can be easily seen.

FIELD TESTS

Tests with the DRI pressure/temperature probe were conducted in May 1978 and May 1979. Wireline services were provided by the USGS Water Resources Division Borehole Geophysics Group which operates a seven conductor rig out of Denver. The well was opened and logged during about three days of flow for each of the two test periods. Several organizations took surface samples of the fluid while the 1978 tests were under way. Thermal Power personnel acted as operators, and controlled well flow at all times; they also calculated well total mass flowrates by use of the James method. Other companies provided support services in flow line modification, pit reconstruction, mast service truck and equipment rentals. Coordination and direction of all the organizations involved was carried out jointly by DRI and Thermal Power.

The site for these tests was well "Utah State" 14-2, operated by Thermal Power Company and owned jointly by Thermal Power, AMAX Exploration and O'Brien Resources. This well is drilled to a total depth of 6100 ft. (1860 m), and is cased with 9 5/8 inch (24.4 cm) diameter grade K-55 steel to 1805 feet (550 m). Below that level, the well completion is open hole, drilled with an 8 ½ inch (21.6 cm) bit.

Logs were made with the DRI pressure/temperature probe, which uses resistance-type elements in the sensors. Details of design and operation of this tool are presented in Butz (1979). The probe provides a simultaneous, real time record at the surface of downhole pressure and temperature as a function of depth.

During the 1978 tests, a problem was experienced with the electrical performance of the logging cable. At temperatures above 450°F (232°C) conductor insulation resistance dropped to 200 ohms. This effectively short circuited the resistance elements of the pressure and temperature sensors. Temperature data was lost; pressure data was recovered because the step changes in output of the wire-wound potentiometer were seen on the stripchart, and could be translated back to pressure values. This permitted a limited amount of information to be salvaged, and a decision was made to conduct further tests after scheduled replacement of the logging cable.

The second series of tests was run in May 1979, and proved to be quite successful in the acquisition of both temperature and pressure data at several flowrates. Some operational problems with the connector inserts in the cable head remained, and field replacement was necessary several times. An improved version of the probe was tested, and had to be replaced when materials failed under the extreme temperature of the geothermal fluid.

Data from the pressure and temperature sensors was recorded on a strip chart where the chart drive was slaved to a depth counter on the cable. The output was a record of pressure and temperature resistance values plotted as a function of depth. Logs were run at 25 ft. per minute (7.6 m per min.) with periodic stops to assure that sensor response was not lagging actual parameter changes in the wellbore. Temperature sensors were purchased with a factory calibration, and pressure transducers were calibrated in-house prior to each field test. Data reduction consisted of obtaining resistance values off the strip chart for points at regular intervals, then finding the corresponding engineering value on the calibration curves. This reduced data is presented in both tabular and graphic form in the project final report (Butz and Plooster, 1979).

ANALYSIS

In a single phase (all liquid) flow, the pressure gradient as a function of depth is constant and consists primarily of hydrostatic head with the friction term contributing up to about 3% of the total. On the other hand, in a two-phase flow, there are three terms--holdup (head), friction and acceleration--whose relative contributions to the gradient vary as a function of the amounts of gas and liquid in the flow. Until relatively large volumes of gas have evolved in the flowstream, the two-phase gradient is smaller than the single phase gradient, and is not constant. At the point of transition to two-phase flow, a decrease in the pressure gradient can be clearly identified, which gives a sure indication of the location of the flash horizon.

Analysis of the 1978 data revealed a pressure gradient anomaly. At pressures greater than the saturation level for pure water, the gradient was significantly smaller than that expected for single phase flow. An explanation for this effect would be the initiation of two-phase flow at much higher pressures due to the dissolved gas content of the geothermal fluid. Data obtained from surface samples confirmed a carbon dioxide content of 0.8% by weight. Calculations then showed that the flash pressure is raised about 200 psi (1.4 MPa) at that concentration. The measured gradients were definitely reflecting the effect of the dissolved gas content.

The initial use of the data was to provide a base of information against which to validate the predictions of the computer model. Input conditions as measured at some point in the well were used, along with the known casing schedule. In order to put all comparisons on a similar basis, the production horizon was chosen as 2950 ft. (900 m). This level was thought to be a source of at least a significant portion of the flow, from previous log information contained in Glenn and Hulen (1979) as well as from indications in several of the pressure/temperature logs. Flowrates as measured by the James method for each of the test cases were also input to the model, which then predicted wellhead pressure, temperature and quality.

Runs were made with and without consideration of the dissolved gas content, which had a significant impact on the results. With dissolved gas included, computer predictions at selected flowrates up to 300,000 lb/hr (38 kg/sec) compared quite well with the test data, showing a maximum deviation of 5%. At higher flowrates, the model predicted pressure drops much higher than those measured in the wellbore. The error increased with increasing flowrate, and appeared to arise in the calculation of the friction component of the two-phase pressure drop.

The second objective of this project was to produce a comparison of maximum flowrate that could be sustained from a given reservoir, as a function of casing diameter. Upon consideration of the equations which define pressure drop in the reservoir as well as that in the wellbore, an approach was developed. Wellhead pressure could be fixed along with a flowrate, temperature and casing diameter. Computer model results could then be manipulated to calculate a Productivity Index capable of producing the input flowrate under the given conditions. This can be expressed as:

$$\Delta P_{flow} + Q/J = P_o - P_{wh}$$

where P_o is the reservoir shut-in pressure; P_{wh} is the fixed wellhead pressure chosen for the comparison (the difference of these two pressure is a constant for all cases); ΔP_{flow} is the calculated pressure drop due to two phase flow over the known interval from the production horizon to the wellhead; Q is the input mass flowrate.

Since all other elements of the equation are known, the Productivity Index J can be found. For other input flowrates, corresponding values of J can be calculated. The results can then be graphed for each of several casing diameters, as shown in Figure 1.

Since maximum flowrate as a function of PI was known, the determination of the PI of the test well would permit the preparation of a comparison of maximum flowrate as a function of casing diameter. A linear least-squares fit was applied to flowrates and corresponding pressures at the production horizon to determine the PI. Some of the production horizon pressures used were projected from values further up the wellbore because log data did not extend to the necessary depth. The result was a PI of 589 lb per hour per psi (5.22×10^{2} kg/sec - kPa), with a coefficient of determination of -0.9257.

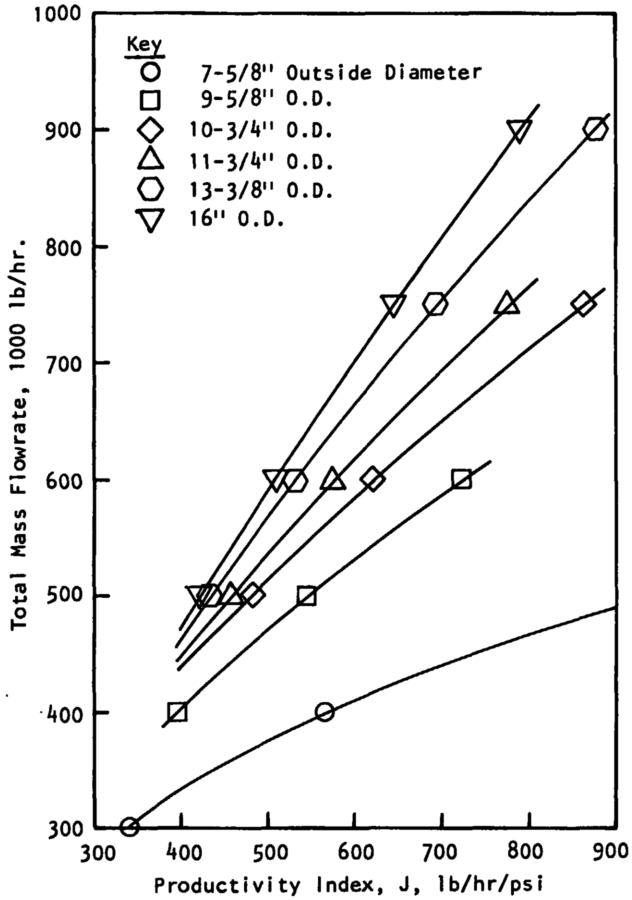

Figure 1. Computer Model Results of Flowrate vs. Productivity Index.

RESULTS AND CONCLUSIONS

The deviation of model results from test data at high flowrates was of concern. Several causes were postulated for this phenomenon. It is possible that under conditions of high flowrate and relatively large volumes of gas in the fluid, the chosen correlations for calculation of two phase pressure drop are not suitable. Computer runs to be compared with additional data from other high temperature reservoirs may help determine if this is the case.

It should be noted that at the higher flowrates where the deviation was most severe, the pressure at the production horizon was well below the saturation level. This implies that flashing and two-phase flow occur in the reservoir. There are two mechanisms which should cause a rise in fluid enthalpy under such conditions. The first is the preferential migration of steam to the wellbore, which promotes a greater steam fraction in the fluid than would result if the flash occurred in the bore itself. The second is the addition of heat to the two-phase fluid from the reservoir rock matrix, which is now at a temperature above that of the fluid, due to the drop in fluid temperature that drives the phase transformation process. Several runs were made with the computer model with inputs adjusted to account for a 7% increase in fluid enthalpy. Results were no better in their predictive capability than earlier runs; however, the mechanisms put forth for an increase in enthalpy seem quite reasonable, and the impact on two phase flow warrants further study.

The information shown in Figure 1 can now be used to construct a graph which quantifies the effect of casing diameter on maximum sustainable flowrate for a fixed wellhead pressure of 100 psia (689 KPa). This value of wellhead pressure was chosen as sufficient to move fluid from the wellhead through gathering lines to a central power station, yet low enough to present minimal back pressure to flow in the well. By taking a vertical slice at the calculated PI, maximum flowrate values for the various casing diameters can be found, and are replotted in Figure 2. Two other PI's are also shown.

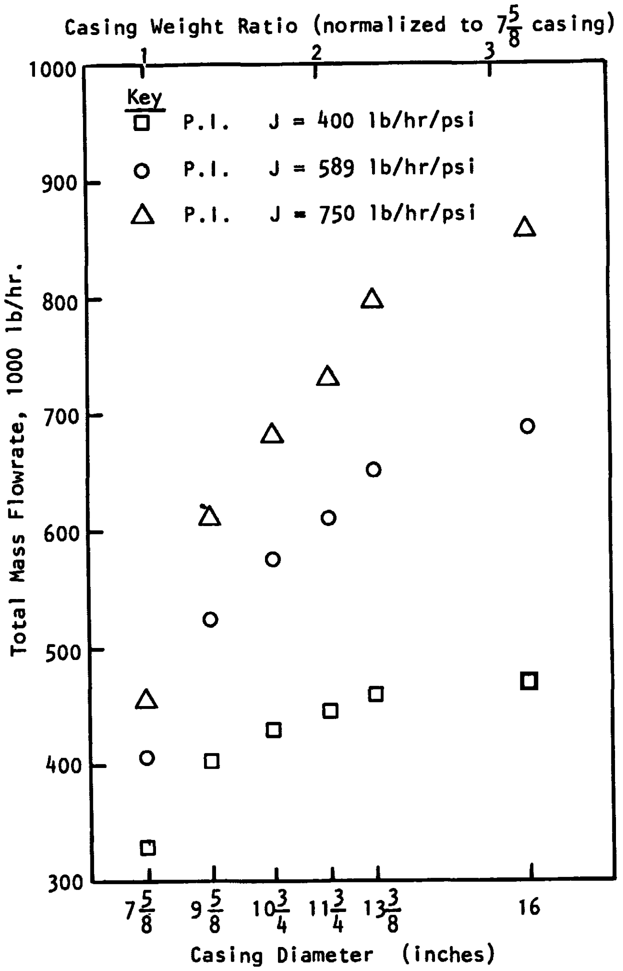

Figure 2. Flowrate as a Function of Casing Diameter & Productivity Index.

The effect of casing diameter is seen to be quite dramatic. For example, if 13 3/8 inch diameter (3.40 cm) casing were specified in place of the existing 9 5/8 inch (24.4 cm), a 24% increase in flowrate is predicted. This optimization could easily lead to a requirement for fewer wells in the development of a given field, and therefore has a significant impact on the economics of development. In some cases, a larger diameter well may be cheaper to drill because of higher drill string weights and subsequent increased drilling rates.

The results here are site-specific and it should be noted that increased diameter does not always lead to increased flowrates in two-phase systems. Because of the nature of the two phase pressure drop mechanisms, larger diameter casing may cause a drop in maximum sustainable flowrate; a determination must be made on a case by case basis.

The effect of Productivity Index on the maximum total mass flowrate is also interesting. An improvement in the significance of the effect of diameter changes at a higher PI would be expected due to the fact that under such conditions a lower fraction of the available pressure drop would be attributed to the reservoir component. This means that a greater portion of the pressure drop is taking place in the wellbore and thus can be influenced by a change in the flow patterns due to diameter differences.

A higher PI was included in the results to present the performance that would be predicted if stimulation of the well caused an increase to 750 lb per hour per psi (6.65 X 10 ^{2} kg/sec - KPa). The effect of scale due to flash on reduced permeability of the formation could be reflected in a PI of 400 lb per hour per psi (3.54 X 10 ^{2} kg/sec - KPa) as also shown on the graph.

Because of the problem encountered with the computer simulations at high flowrates, a comment on their use in the parametric cases which form the basis for the performance predictions is in order. Pressure gradients calculated for the parametric computer cases were well behaved in comparison to those in the deviant simulations. The second derivative of the parametric runs was positive, as were those of the test data; therefore greater confidence can be placed in the model's representation of the physical process occurring in the wellbore for these runs.

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