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ESTIMATING RESERVOIR PROPERTIES AND WELL PERFORMANCE USING SURFACE PRODUCTION DATA

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ABSTRACT

Reliable and sufficient welltest data is necessary for the evaluation of reservoir properties and well performance. Best results are usually obtained by monitoring downhole pressure and flow rate continuously during a transient test. However, a recurring problem for geothermal welltests has been the failure of the downhole pressure instrument in the high temperatures and hostile environments, typical of these wells. Usually an incomplete set of data or data without downhole pressure is used for analysis which provides only limited or erroneous results.

This paper presents a technique of applying a wellbore simulator and a reservoir simulator sequentially to the surface data in order to simulate the downhole condition during a flowtest, thus allowing estimation of the reservoir properties and well performance.

Comparisons of the estimated results and the results obtained from the conventional welltest analysis indicate that this technique can provide a good estimate of the reservoir properties and well performance when downhole data is lacking.

INTRODUCTION

Pressure transient tests performed in wells during field evaluation and development constitutes one of the reservoir engineer's most important source of data. Analysis of these data can provide information about reservoir characteristics, well performance, well condition, etc. During the past few decades considerable interest has been generated in well test analysis. Several analytical and graphical techniques have been derived to provide solutions for the pressure transient data. All of these techniques require reliable and sufficient data from the well test, and downhole pressure monitored continuously during a transient test is preferred (1,2). However, a recurring problem for geothermal well tests has been the failure of the downhole pressure instruments to withstand the high temperature and high salinity environments to which they are subjected. In many cases an incomplete data set or data without downhole pressure will be used for analysis, which provides only very limited or erroneous results. Converting wellhead pressures to downhole values in geothermal wells, where flashing usually occurs, then applying conventional analysis techniques is a difficult if not impossible, task. Chevron uses a technique of sequentially applying a wellbore simulator and a reservoir simulator to the surface data during a well test to simulte the downhole condition and to estimate reservoir properties and well performance.

APPROACH

The basic idea is dividing the problem into two parts: (1) the wellbore through which single or two-phase fluid flows upwards and (2) the reservoir which feeds a single phase fluid to the well. First, the wellbore simulator is used to estimate a few bottomhole flowing pressure (BHFP) values corresponding to the measured wellhead temperatures, pressures and surface flow rates. Usually the BHFP at shut-in and at a few points during the flow period, when the flow was stabilized, are preferred. Then from these estimated bottomhole flowing pressures and the production history of the flow test, a simple radial flow reservoir simulator is used to simulate a complete set of downhole flowing pressures. The reservoir simulator also provides the estimate of reservoir parameters, and well performance, through the recursive estimation techniques.

WELLBORE SIMULATOR

The Chevron wellbore simulator is a highly generalized steady state pressure flow simulator for single or multi-phase fluid flow piping systems. It is a computerized mathematical description of the fluid flow laws within a producing or injection system consisting of well tubing and/or annulus and surface facilities. Pressure losses, flow rates and temperature of the system can be calculated at any point in the network for any combination of reservoir deliverability, fluid types, etc., by applying the mass, momentum, and energy conservation principles. In a steam/water system as the program proceeds through a traverse, the change in pressure is determined by a pressure drop correlation:

$$\underset{\text{total}}{\frac{\partial p}{\partial z}} = \underset{\text{elevation}}{\frac{\partial p}{\partial z}} + \underset{\text{friction}}{\frac{\partial p}{\partial z}} + \underset{\text{acceleration}}{\frac{\partial p}{\partial z}}$$

where p = pressure
z = distance

The change in temperature is determined by a complete energy balance of the system including heat loss, heat of vaporation, and specific heat calculation, then related to pressure by the thermodynamic properties of the fluid.

RESERVOIR SIMULATOR

Chevron has developed a computer program designed for estimating reservoir parameters using pressure - production data from well tests. It does not require constant production rates and even if flow measurements are not available during certain phases of the test, the program can still be used to recover some estimates from the data on the remainder of the producing period.

The simulator is built around a series of idealized models for various reservoir configurations and a series of models for wellbore dynamics. The simplest model assumes a slightly compressible single fluid flowing radially into a well in an infinite system:

$$\frac{1}{r}\frac{\partial}{\partial r}\left[k(r)r\ \frac{\partial p}{\partial r}\right] = \phi\mu CB\frac{\partial p}{\partial t}$$

where ϕ is the porosity, μ the viscosity, C the total compressibility in the formation, and B the formation volume factor. k (r) is the permeability distribution function:

$$k(r)=\begin{cases} k_1, & r_w \leq r \leq r_I \\ k_2, & r_I \leq r \leq r_e \end{cases}$$

where r_I is the interface or the radius of damage. The boundary conditions are: no flow at r_e, as $r_e \to \infty$ and given $p(t, r_w) = p_w(t)$. The initial condition is a given pressure p_i, uniform throughout the field.

The transient behavior is to be simulated using the given production history q(t) and calculating the downhole pressure p using the pressure drawdown at the sand face as the boundary condition:

$$q(t)=-2\pi\frac{k_1 h r_w}{\mu}\frac{\partial p}{\partial t}(t, r_w)$$

If there is wellbore storage, the rate of fluid accumulation in the wellbore is subtracted from the above equation to provide the surface production rate. Long term tests where boundary effects are felt can be analyzed using either finite reservoir models or infinite reservoir models with one or two intersecting faults. These models can be modified for gas reservoirs to account for the real gas behavior.

The basic method used to determine reservoir parameters is to history match a numerical model to the observed data. The history matching part of the program is based on the algorithm known as Recursive Estimation which was described in detail by Padmanabhan and Woo(3).

CALCULATION PROCEDURE

The objective is to find a set of bottomhole flowing temperature, pressure and reservoir parameters to satisfy the wellhead conditions and production data. The following assumptions are normally made in the calculations:

1. Steady state flow in the wellbore.
2. Single phase, radial flow in the reservoir.
3. k and ϕ are uniform anywhere in the reservoir or at most exhibit one radial discontinuity.

Following is the iteration sequence for calculating the reservoir parameters and well performance.

1. Bottomhole flowing temperature and pressure are assumed for the well based on the static condition and wellhead condition.
2. The flowing single stream pressures and temperatures are calculated by the wellbore flow simulator in a forward traverse from the assumed bottomhhole flowing temperature and pressure - resulting in a set of wellhead pressures and temperatures.
3. The calculated wellhead temperatures and pressures are compared with measured values. If tolerances are not met, new bottomhole flowing pressure and/or temperature are assumed.
4. Steps 1 through 3 are repeated until the tolerances are met.
5. The calculated bottomhole pressures, the production and buildup data, the fluid properties and the range of expected k, ϕ, Pi values are entered into the reservoir simulator. Here, prior knowledge of the reservoir is useful for the estimation of the range of k, ϕ, Pi values and in selecting the reservoir model.
6. The Reservoir simulator will simulate the transient behavior of the reservoir using the given production history q(t) and estimates the downhole flowing pressure p(t).

Once the reservoir parameters and bottomhole flowing pressures are known the well performance can be easily obtained. The estimation procedure is summarized in Figure 1.

EXAMPLES

A few field examples will be utilized to demonstrate the validity of the method to analyze the production data. In every case, bottomhole pressures estimated from the surface data will be compared with the measured values to show the quality of the estimations.

1. Production Test on Well A.

Well A was produced for 3 days and during the flow test its flowrate was kept relatively constant between 280,000 lb/hr. and 290,000 lb./hr. Using the wellhead temperature, wellhead pressure and flowrate at shut-in, the wellbore simulator estimated that the flowing pressure at 5000' was 1841.6 psig compared to the measured value of 1842.7 psig. The estimated flowing temperature also compared very well with the measured value. These estimated temperatures and pressures provide a base for the determination of fluid properties such as viscosity, density, etc. The estimated flowing pressure, along with the fluid properties, were incorporated with the measured flow rates during the test, at four hour intervals, and input into the reservoir simulator to simulate the flowing pressures at 5000' and to estimate reservoir parameters. Figure 2 shows the comparison of the simulated and measured pressures. The measured flowrates are also plotted on the same figure. The simulated pressures correlated very well with the measured pressures, and they are very sensitive to the flow rates. The simulated values responded to every change in the flowrate while in some cases the measured values didn't. The estimated transmissivity (kh/μ) and the flow efficiency (FE) are $1.73 \times 10^6 \pm 0.25 \times 10^6$ md-ft/cp and 0.34 respectively. Using the build-up data, Horner analysis gave $kh/\mu = 1.65 \times 10^6$ md-ft/cp and FE = 0.48. It would be more appropriate to compare the estimated results with the Horner analysis of the drawdown data, however in this case the drawdown data are not sufficient for analytical or graphical analyses.

2. Production Test on well B

During this test well B was flowed for 300 hours at three different rates. Bottomhole flowing pressure was monitored throughout the test. Figure 3 presents the measured flowrate and bottomhole pressure history. The wellhead conditions and flowrates were used to estimate the downhole flowing pressures and temperature at shut-in and at three different points during the early parts of flowing period. These estimated values in conjunction with the production data were used to simulate the downhole pressure during the flowtest and to estimate reservoir parameters. For comparison the simulated pressures were also plotted on Figure 3. Generally the simulated pressures agreed very well with the measured pressures. As pointed out before, the simulated flowing pressures are very sensitive to the values of flowrate, and validity of the estimated results is strongly dependent on the accuracy of measured flowrates. Some discrepancies between the two pressures are most likely due to the inaccuracy of the measured flowrates. The estimated formation kh/μ is $247{,}000 \pm 33{,}000$ md. ft/cp and the estimated F.E. is 0.74. The multirate analysis of the buildup data gave kh/μ = 306,000 md-ft/cp and FE = 0.63.

3. Production test on well C

Well C produced for 60 hours with varying flowrates between 29,000 B/D and 27,000 B/D. Using the estimated bottomhole pressure at shut in and a few flow rates during the flow test the reservoir simulator gave $kh/\mu = 229{,}400 \pm 58{,}800$ md ft/cp and FE = 0.92. The Horner analysis of the buildup data gave $kh/\mu = 223{,}500$ md. ft/cp and FE = 0.99. In this case, the estimated results are in good agreement with the Horner analysis results, although the variance increases because of the lack of production data. Since the first downhole measurement was not made until 2 hours prior to shut-in, only the simulated and measured pressures can be compared (Figure 4). During the first 10 minutes of shut-in, which was effected by the wellbore storage, there are discrepances in the measured and the simulated pressures. However, as the shut-in time increased, these two pressures converged and approached the same value.

Table I summarizes the results of these examples. Other sets of field data have also been compared to their estimated values, with results as satisfactory as was obtained in the above examples. In every case the technique provides not only the estimates of the parameters but also their confidence limits so that one can gauge the quality of the estimates. It is important to point out that applying this technique to analyze well test data is not an automatic process. Engineering judgement and prior knowledge of the reservoir always play an important role in selecting data, reservoir model, and interpreting the results obtained.

Conclusion

Comparisons of simulated and measured downhole pressures, and estimated reservoir parameters with those calculated by the conventional techniques indicate good agreement. This demonstrates that the sequential use of wellbore and reservoir simulators can provide a good estimation of the reservoir parameters and well performance in case of lack of downhole pressures.

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References

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Table I
Comparison of Different Analysis Methods

Well	Horner/Multirate Analysis kh/μ (md-ft/c.p.)	Horner/Multirate Analysis F.E.	Estimation kh/μ (md-ft/c.p.)	Estimation F.E.
A	1.65×10^6	0.48	$1.73\pm0.25\times10^6$	0.34
B	3.06×10^5	0.63	$2.47\pm0.33\times10^5$	0.74
C	2.23×10^5	0.99	$2.29\pm0.59\times10^5$	0.92

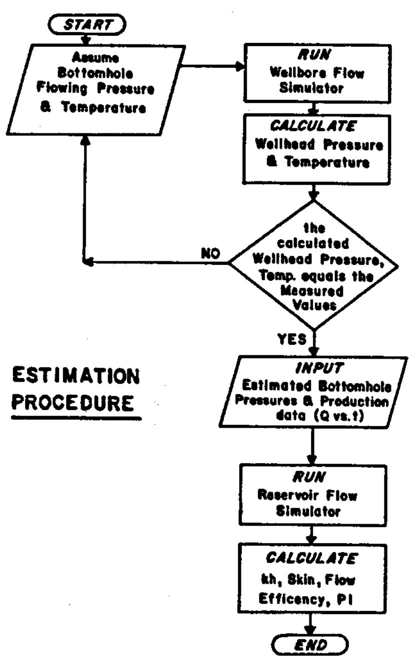

FIGURE I

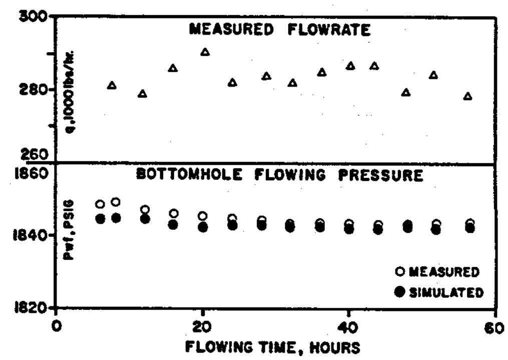

FIG. 2 – COMPARISON OF MEASURED AND SIMULATED PRESSURES OF WELL 'A'

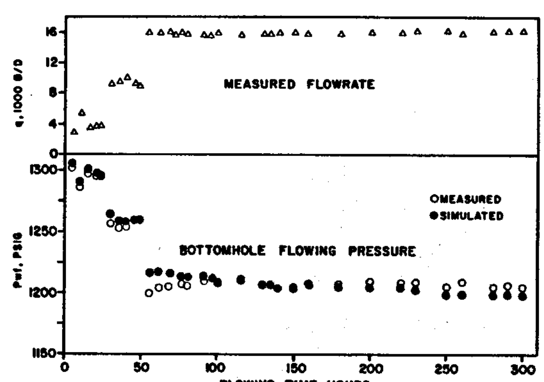

FIG. 3 – COMPARISON OF MEASURED AND SIMULATED PRESSURES OF WELL 'B'

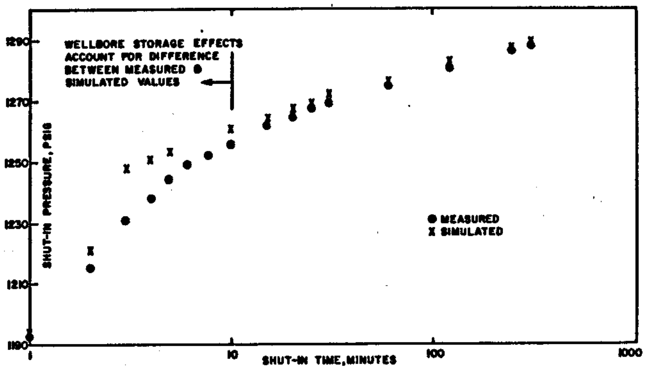

FIG. 4 – COMPARISON OF MEASURED AND SIMULATED PRESSURES OF WELL 'C'