MODELING THE HEBER GEOTHERMAL RESERVOIR

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Abstract

In this paper we briefly describe the lithology, temperature, and pressure of the Heber Geothermal Reservoir. This we base on the extensive data gathered in the past few years through well drilling and testing. We then describe our three-dimensional, heterogeneous, single phase water flow simulator, including the equations solved, and the assumptions made. We present several applications of the numerical simulator, in predicting the reservoir behavior with time. Conclusions based on an analysis of simulator results are finally presented.

Introduction

The Heber Geothermal Anomaly, located in the Imperial Valley of California, could be the first commercial hot water power generation project in the United States. Chevron Resources Company will operate the proposed Heber Unit. Currently, plans are for developing a nearly circular area of 7500 acres, with each plant increment representing a pie-shaped segment. Producers will be placed at the temperature high which is at the center. The processed fluid will be reinjected at the periphery of the reservoir. Wells will be drilled from centrally located surface islands, most of them being directionally drilled. Production rates at Heber will ultimately reach several millions of barrels per day. This requires large surface facilities and large well equipment. Revenues cannot be realized until a power plant is constructed. Due to large initial investment, an accurate reservoir performance prediction becomes an important factor. The predictions in this paper are limited by the accuracy of the data collected and analyzed, and by our modeling assumptions.

Reservoir Description

The Heber Geothermal Anomaly is a circular shaped, moderate temperature, low salinity, water dominant reservoir. It is characterized by high heat flow, low electrical resistivity and high gravity. It is part of the Colorado River deltaic environment, consisting of interbedded sandstones and shales. Shales are thick and predominant from the surface to 2000 feet. Sand layers become predominant below 2000 feet, where shale layers become thinner. At 8000 to 10,000 feet sands are predominant with minor shale breaks. A few faults have been identified, others are probably present; however, any occurring in the predominantly sandy section would not be significant barriers to fluid flow. Reservoir continuity of several sand layers have been confirmed by interference tests. Pressure drawdown and buildup tests have indicated a radius of investigation greater than 20,000 feet.

Porosity and horizontal permeability of the sand layers at Heber were determined by using available density logs and core analysis information. Good correlations were found between density log porosity and core porosity, also between core porosity and core permeability. Permeability of each sand was calculated from the latter correlation and the log derived porosity values. It was possible to correlate these permeabilities to permeabilities computed from flow test analysis. In general, sandstone layers demonstrated decreasing permeability and porosity with depth.

The Heber Geothermal Anomaly has a mushroom-shaped temperature profile. The maximum temperature at the center of the field is around 375°F. Conductive heat flow at shallow depths could be deduced from high temperature gradients and the presence of thick impermeable shales. Below this depth heat flow is naturally convective, as temperature gradients become small and sandstones dominate. To a reference temperature of 200°F, the heat in place under approximately 7500 acres, and between 2000 to 6000 feet is 5.4 quadrillion (10^{15}) BTU's. Heber could be classified as a normal pressured reservoir with measured static gradients of 0.42 psi/foot.

Reservoir Model

To predict Heber's performance under various development schemes, a three-dimensional, radial, heterogeneous, and single phase water flow simulator was used. The simulator basically solves the mass and the energy balances. The equation of continuity, expressing conservation of mass[1], is:

$$\frac{\partial (\rho_\ell \phi)}{\partial t} = - \nabla \cdot \rho_\ell \underset{\sim}{V_\ell} - Q \qquad ....(1)$$

where:

ℓ denotes liquid, ρ_ℓ is liquid density (lbm/ft^3), ϕ is porosity, t is time (days), $\nabla \cdot$ is divergence operator (1/ft), Q is mass production or injection. It is a function of position and time ($lbm/day\ ft^3$), a positive value denotes production. $\underset{\sim}{V_\ell}$ is the Darcy velocity vector of the fluid (ft/day) and expressed as:

$$\underset{\sim}{V_\ell} = - 6.328 \frac{k}{\mu} (\nabla P - \rho_\ell \underset{\sim}{g}) \qquad ....(2)$$

where:

k is permeability (Darcy), μ is viscosity (cp), P is pressure (psi), and g is gravitational vector.

The following assumptions were made:

- Porosity is not a function of time; it can, however, be a function of position.
- Viscosity is a function of temperature.
- Liquid density is a function of temperature, but is independent of pressure, making the model "partially compressible". Zero fluid compressibility is satisfactory for single phase water systems.

Next we expand the density derivatives in equation (1).

$$\phi \frac{\partial \rho_\ell}{\partial T} \frac{\partial T}{\partial t} = -\rho_\ell \nabla \cdot \underline{V}_\ell - \underline{V}_\ell \cdot \nabla \rho_\ell - Q \qquad \text{.......(3)}$$

where T is temperature. We also assume that the reservoir fluid volumes are locally in balance. Therefore:

$$\nabla \cdot \underline{V}_\ell = -\frac{1}{\rho_\ell} Q \qquad \text{.......(4)}$$

Without this assumption we could not let density vary with temperature without using a fully compressible two-phase model. The produced fluid at Heber will be initially at $\simeq 360^{o}F$, the injected water will be at $\simeq 200^{o}F$. In order to maintain a mass balance between production and injection, we assumed that the required mass came across the outer reservoir boundary at a temperature under $200^{o}F$. Thus, we avoided solving - complicated and costly - coupled mass and energy balances.

The equation for conservation of energy[1] is:

$$\frac{\partial}{\partial t} [(\rho C_v)^* T] =$$

$$\phi C_{v_\ell} \frac{\partial}{\partial t} (\rho_\ell T) + (1-\phi)\rho_s C_{v_s} \frac{\partial T}{\partial t} = \nabla \cdot (K^* \nabla T) - C_{v_\ell} \nabla \cdot (\rho_\ell T \underline{V}_\ell) - Q\, C_{v_\ell} T_N \qquad \text{.......(5)}$$

where:

s denotes solid, C_v is specific heat at constant volume ($BTU/lbm^{o}F$), K is thermal conductivity ($BTU/ft\ day^{o}F$), T_N is injection fluid temperature if $Q<0$, T_N is produced fluid temperature if $Q>0$.

The left hand side of equation (5) represents heat accumulation; the terms on the right hand side are respectively, conduction, convection and injection and/or production.

In relation to equation (5) we have defined the following volumetric averages:

$$K^* = \phi \, K_\ell + (1-\phi) \, K_s \qquad \text{.......(6)}$$

$$\rho C_v^* = \phi \rho_\ell C_{v_\ell} + (1-\phi) \, \rho_s C_{v_s}$$

And we made the following assumptions:

- The solid and liquid are locally in thermal equilibrium.
- The viscous dissipation energy losses are negligible.
- Specific heats are independent of pressure, temperature, and position.
- Thermal conductivities are independent of pressure and temperature.
- Rock densities are constant.

Solution - We have independently solved equations (4) and (5). Equation (4) gave us a steady-state solution for pressure, and provided the velocity terms required by the energy balance, equation (5). We conservatively used two temperature time steps per pressure solution. The need for recomputing pressures arose when: (a) the temperature dependent viscosities materially changed, (b) injection and/or production rates changed with declining reservoir temperature in order to maintain constant energy.
Time Dating of Terms - In equation (4) the latest temperatures were used to calculate liquid density and viscosity. In the finite difference form of equation (5), temperature was used implicitly in the conduction term, explicitly in the convection term. Densities were evaluated at start of time steps.
Overburden and Underburden - The first four and the last four layers of the model were used as overburden and underburden with zero fluid permeabilities.
Numerical Dispersion - In an effort to reduce smearing of the temperature profiles, a two-point-upstream approximation[2], for temperature, was used in the convection term. The illustration below shows two cell blocks.

$\longrightarrow$ flow direction | T_1 | T_2 | $\longleftarrow$ cell face

In evaluating the temperature T in the $\rho_\ell T \underline{v}_\ell$ term at the cell face, T_1 and T_2 are linearly extrapolated to the cell face. A one-point-upstream approximation uses only T_2 and results in excessive smearing of temperatures. Averaging upstream and downstream values gave temperature oscillations and was discarded.
Flow Splitting - Flow rates for production wells were supplied and were split among the layers according to the product of productivity index and pressure drawdown - difference between current cell and well bore pressure. Injection wells used either fixed pressures or supplied flow rates.

Applications

Based on lithological correlations and production constraints, we defined two zones: zone 1, 2000 to 4000 feet: zone 2, 4000 to 6000 feet. We then subdivided zone 1 into 15 and zone 2 into 13 horizontal sand and shale layers of field-wide averaged thickness. Figure 1 shows the geometry we used. We further divided Heber into 8 areal pies, each pie having 15 rows. Therefore, 1800 cells in zone 1, 1560 cells in zone 2 represented the reservoir. We also made the following assumptions:

- The sand and shale layers themselves are continuous, homogeneous and isotropic.
- The initial temperatures are a function of radial coordinate; they do not vary with vertical coordinate in a given zone.
- The regional northerly ground water movement is small, hence negligible.
- There is no heat recharge from the underburden.

Pies initially were chosen such that their boundaries coincided with stream lines as obtained from the previous streamtube model runs. Most 3-D simulator runs were made assuming no cross flow between the pies.

Figure 2 shows bottom hole temperatures at the producers versus time for 100 megawatts (MW) constant energy production from each zone. Equivalent starting rates are 1.24×10^6 barrels per day per zone. Also shown on this figure are the previous predictions using the streamtube model. The difference in predictions can be explained as follows: the 3-D simulator has the capability of solving a rigorous heat conduction equation, given the actual thicknesses of sand and shale layers. The streamtube model assumed vertical thermal equilibrium between sand and shale in each reservoir layer. It could handle the shales as thin layers of infinite thermal conductivity. The injected fluid, upon contacting these shales, absorbed all their heat. In zone 1, the streamtube model predicted a greater temperature decline and in zone 2 it predicted about the same temperature decline as the 3-D simulator. We think the small difference in zone 2 is due to the use of slightly less shale. The difference in general was due to a better vertical lithological description and a more rigorous heat conduction equation. The 3-D model shows a 30°F decline in thirty years for both zones.

Figure 3 shows the bottom hole temperature at the producers versus the cumulative water produced. This figure indicates the large volume of water required to produce 100 MW constant energy from each zone.

Figure 4 shows heat recovery from Heber versus bottom hole temperature at the producers. This plot is for two zones combined. The 200°F temperature is used as a lower bound in determining the heat in place. We have tentatively decided to place the injectors near the 265°F isotherm. If we use an economic temperature of 320°F for the power plant, as a cut-off point, Figure 4 shows a recovery of 30% of the heat in place.

Figure 5 shows the predicted average pressure drops between injectors and producers versus time.

The following case studies showed little or no difference in our predictions:

- Combining both zones - simultaneous injection and production in both zones.
- Introducing shale breaks - making 10% of the shale volume permeable to flow.
- Introducing a few "idle pies" - by partitioning the bigger ones, with no injection and production, and allowing crossflow between all pies.

Conclusions

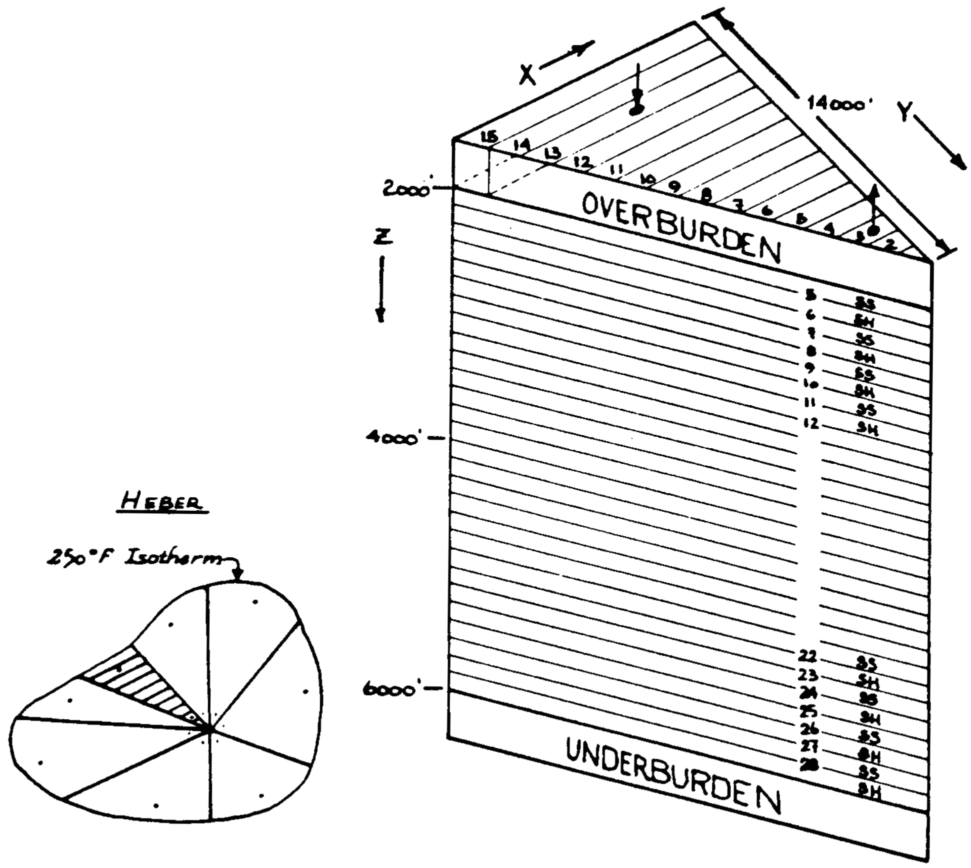
As a result of our modeling studies to date, we conclude the following:

- Heber has 5.4 quadrillion (10^{15}) BTU's in place to a temperature of 200°F. This heat is under approximately 7500 acres within the 265°F isotherm, and between 2000 to 6000 feet.
- 30% of this heat in place is recoverable with respect to the plant economic temperature of 320°F.
- Heber Reservoir between 2000 to 6000 feet alone can support a 250 MW development.
- At Heber, development in general will be more restricted by pressure drops than by temperature decline.
- Economics will govern the power plant type and the development potential at Heber.

References

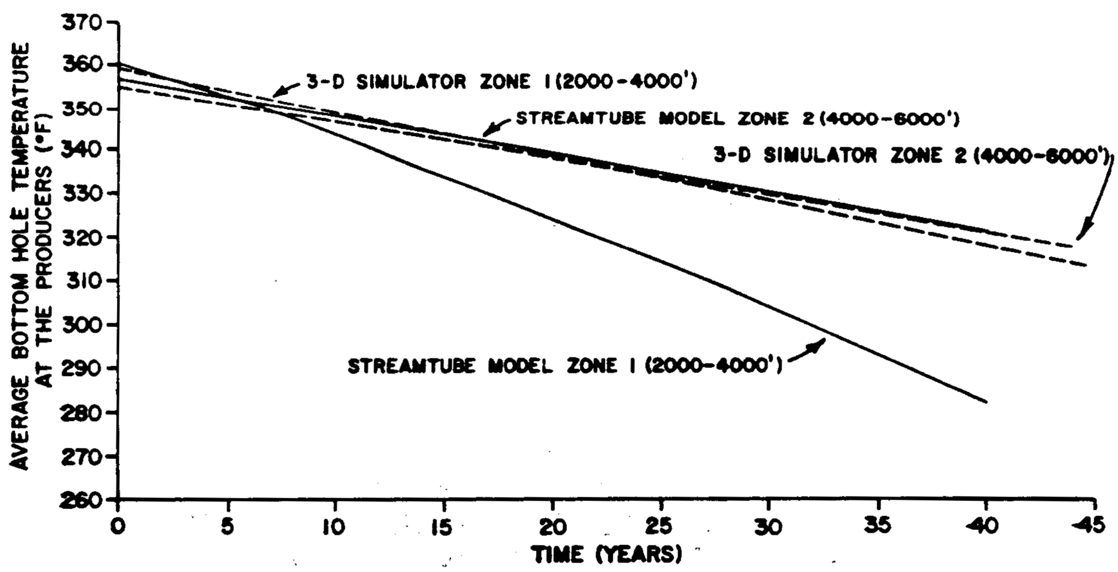
1. Bird, R. B.; Stewart, W. E.: and Lightfoot, E. N., Transport Phenomena, Wiley, 1960.

2. Todd, M. R.; O'Dell, P. M.: and Hirasaki, G. J., Methods for Increased Accuracy in Numerical Simulators, Society of Petroleum Engineers Journal (December 1972), pp 515-530.



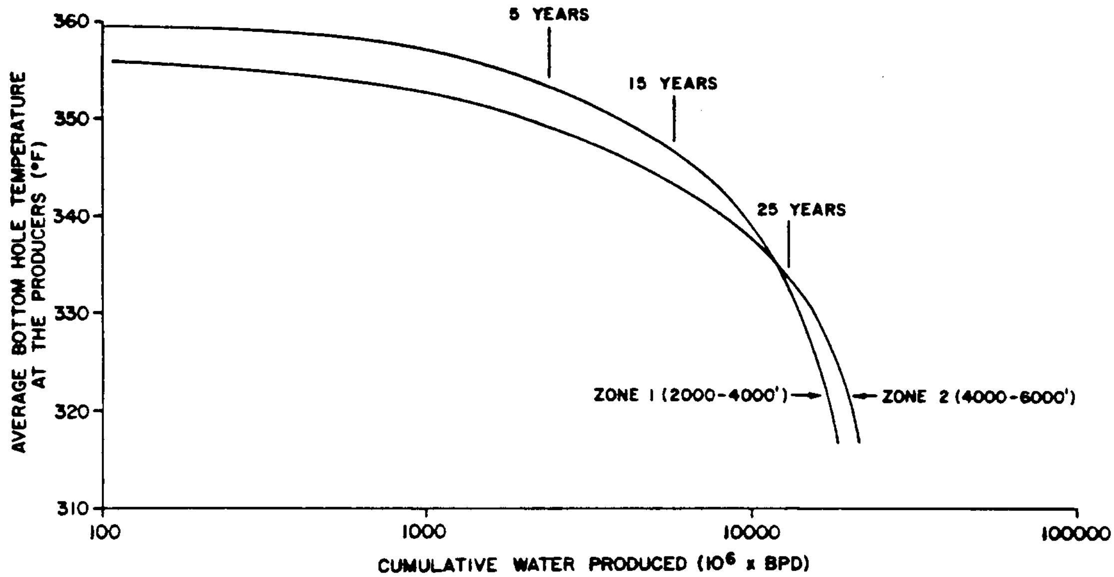
GEOMETRY OF 3-D RESERVOIR MODEL

FIGURE 1



BOTTOM HOLE TEMPERATURE AT THE PRODUCERS VS. TIME FOR 100 MW CONSTANT ENERGY PRODUCTION PER ZONE

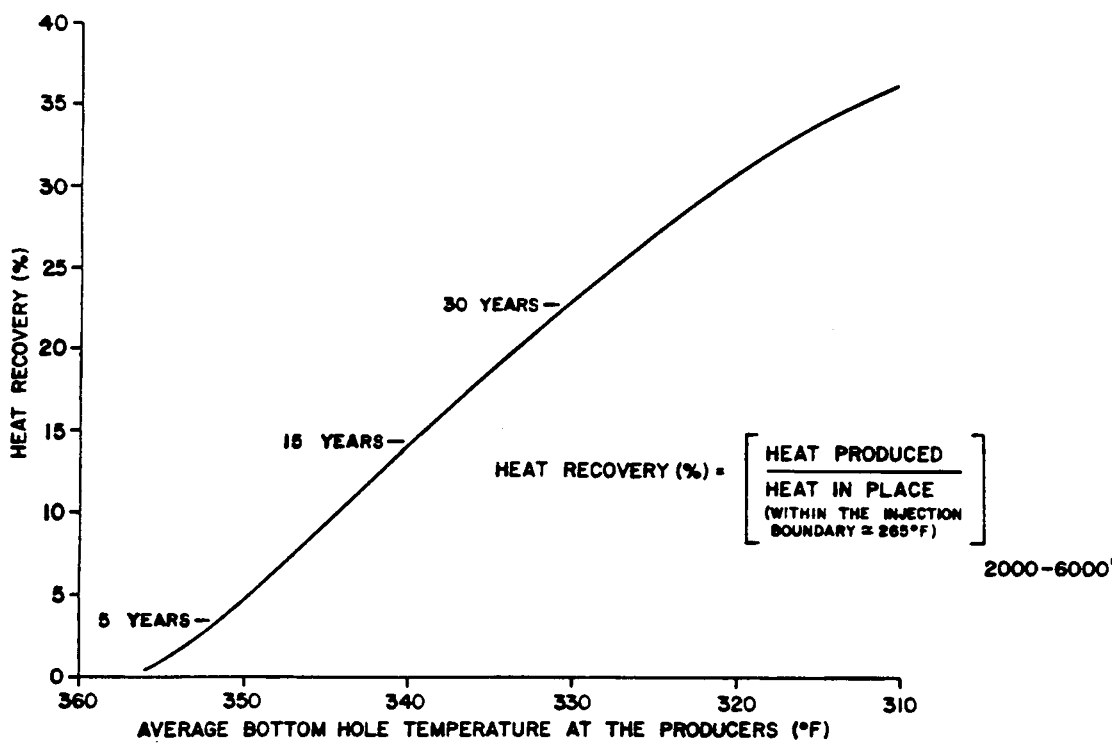
FIGURE 2



BOTTOM HOLE TEMPERATURE AT THE PRODUCERS VS. CUMULATIVE PRODUCTION

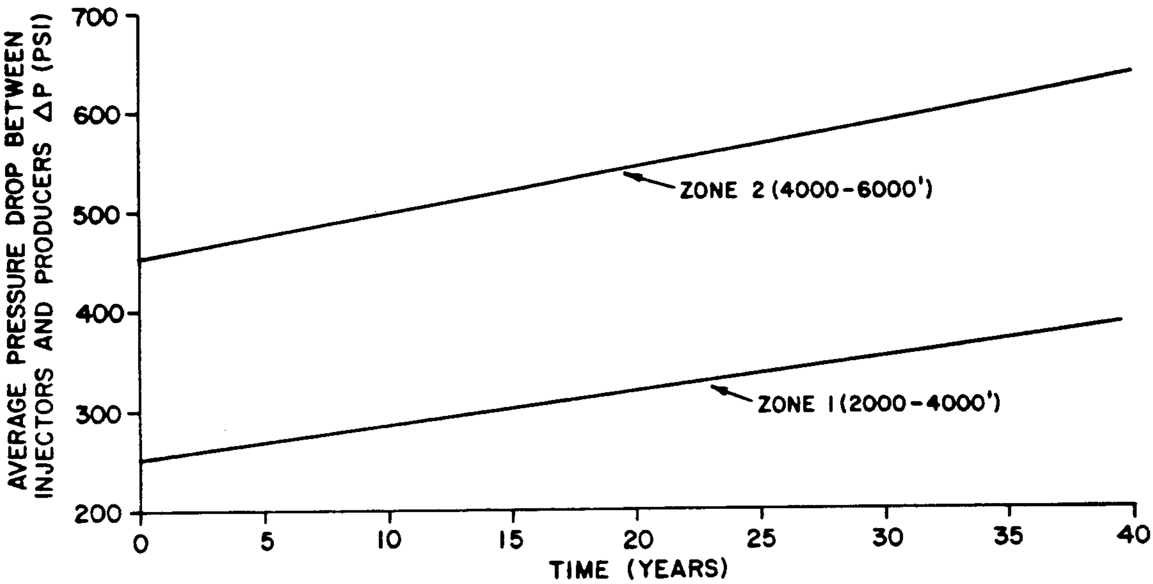
(100 MW CONSTANT ENERGY FROM EACH ZONE)

FIGURE 3



HEAT RECOVERY VS. BOTTOM HOLE TEMPERATURE AT THE PRODUCERS
(200 MW CONSTANT ENERGY FROM TWO ZONES COMBINED)

FIGURE 4



AVERAGE PRESSURE DROP
BETWEEN INJECTORS AND PRODUCERS VS. TIME
(100 MW CONSTANT ENERGY FROM EACH ZONE)

FIGURE 5