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U.S. GULF COAST GEOPRESSURED- GEOTHERMAL
RESERVOIR SIMULATION
FINAL REPORT (YEAR 3)

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CHAPTER 1

INTRODUCTION AND SUMMARY

The purpose of the ongoing research performed for the Department of Energy's Geopressured Geothermal Division under contract with The University of Texas at Austin (UTA) is to develop reservoir modeling techniques to be used in conjunction with field data to estimate the long-term behavior of geopressured-geothermal reservoirs for various exploitation scenarios.

This report summarizes the work accomplished during the third year of this effort. Unfortunately, because of delays in the drilling, completion, and testing of the DOE's Pleasant Bayou #2 well (the first geopressured-geothermal "design" well), no significant field data were available to be incorporated into the work reported herein.

Chapter 2 of the report describes several reservoir model improvements incorporated into the UTA model during this contract period. The most significant modification to the model was the inclusion of semiimplicit treatment of transmissibilities so as to better handle two-phase flow problems associated with flow near the wellbore. Chapter 2 also includes a description of the reservoir mechanics presumed operative in geopressured-geothermal reservoirs. A mathematical model describing two-phase two-dimensional flow in compacting porous media is developed from the Lagrangian point of view. Chapter 2 concludes with a description of the way the differential equations are approximated by finite differences and subsequently solved by means of numerical procedures.

Chapter 3 describes various sensitivity studies made with the reservoir model. Particular emphasis was given to the study of potential shale dewatering

effects on reservoir depletion and the effects of compaction on fluid recovery. To study shale dewatering, the shale thickness and the shale vertical permeability were treated as variables in several simulation experiments. The effects of compaction were modeled with optimistic and pessimistic values for the uniaxial compaction coefficient in an attempt to define a region of expected reservoir performance. In this regard it must be emphasized that the results are to be treated as a range of possibilities rather than a definitive statement of recovery expectations since very few corroborative data are available from the geopressured-geothermal prospects. However, laboratory analysis of core samples obtained from the geopressured-geothermal test well was completed by the end of year 3. These data indicate that the uniaxial compaction coefficient is of the same order of magnitude as the pessimistic value used on the sensitivity studies. Because of this the expected fluid recovery from geopressured reservoirs has been reduced to a nominal 5% of the in-place volumes rather than the previously reported 10%.

During year 3 personnel from this research project participated in several joint meetings with operators, DOE representatives, and other researchers to discuss completion design well testing procedures and other matters related to the Pleasant Bayou #2 design well. Testing had not proceeded far enough to allow any meaningful interpretation of data.

Systems, Science, and Software, Inc. (SSS) has delivered a computer code to UTA in partial fulfillment of its subcontracting obligations to this project. Implementation of this code on UTA computer facilities has not been successful because of conversion problems from the SSS Univac Fortran used to develop the programs to the standard ANSI Fortran used at UTA.

CHAPTER 2

MODEL IMPROVEMENTS

Until the previous year of this project the numerical simulation model used was based on a fully implicit formulation in approximating governing differential equations, but it treated nonlinearities by a simple successive substitution technique. However, this technique has been known to suffer from severe restriction of time step sizes for convergence, particularly in simulating a reservoir in the vicinity of a well by a cylindrical r - z cross-sectional model. As single-well simulations will be necessary in the near future to investigate the effects of gas build-up near a wellbore, the two-phase, isothermal geopressured aquifer problem was reformulated by employing a semiimplicit procedure for nonlinearities. Because the semiimplicit treatment in general leads to a nonsymmetric coefficient matrix, the LSOR (Line Successive Over-Relaxation) routine was supplemented with a direct solution technique (Gaussian Elimination) should the LSOR method fail to converge.

The routines that calculate well production rates and flowing bottom hole pressures were also changed to reflect Peaceman's results [1,2]. The new simulator needs less storage and has better execution time than the old one. In particular, it has an overlay structure. The user's manual of this simulator was compiled and was published by the Center for Energy Studies. This chapter summarizes reservoir mechanics in geopressured aquifers and describes the semiimplicit formulation.

2.1 RESERVOIR MECHANICS OPERATIVE IN GEOPRESSURED-GEOTHERMAL AQUIFERS

The reservoir problem associated with geopressured-geothermal aquifers is

no different from that associated with petroleum reservoirs. However, the influence of water expansion and formation compaction on the behavior of a geopressured-geothermal reservoir is relatively dominant as compared to the rather minor role played in the production behavior of petroleum reservoirs.

Before discussing each of the potentially important production mechanisms extant in a geopressured-geothermal reservoir it may be helpful to describe some of the general characteristics of such a reservoir. The fact that the reservoir is overpressured (i.e., the pressure exceeds the normally expected hydrostatic pressure) would seem to indicate that the aquifer is bounded and limited in extent. The geopressured zone usually consists of sand bodies of varying thickness encased in shale beds. The more permeable sand bodies are, of course, most attractive as producing horizons. However, much of the resource may be located in less permeable sands which are more difficult to produce. The capability, if any, of water to flow from and through the shale bodies will be a significant factor in the ultimate availability of this type of reserve. Given this brief background, we may now discuss the required features in a simulation model that are necessary to analyze this type of resource.

One of the predominant mechanisms available to produce fluids from the reservoir will be the expansion of the water itself. Normally, when associated with petroleum production, water is assumed to be slightly compressible. This assumption also appears valid for the case of geopressured-geothermal reservoir production even though the reservoir pressure response is considerably more sensitive to the value of water compressibility than in the case of conventional petroleum reservoirs.

Gas is known to be dissolved in almost all formation waters, including geopressured-geothermal aquifers. Evidence suggests that in many cases the gas

completely saturates the formation water (i.e., the aquifer pressure is also the gas saturation pressure for the water). This being the case, gas will evolve from solution as pressure on the reservoir is reduced. Except in the immediate vicinity of the producing wellbores, the effect of this evolved gas is principally on the compressibility of the system.

To put this into perspective, consider the effect of evolving 11 SCF/bbl of gas at a 5,000 psia formation pressure (300°F formation temperature). This represents the most extreme case that might be encountered in producing a geopressured-geothermal reservoir. Reservoir pressures below 5,000 psia would require too much lifting energy input to justify continuing production. At these conditions the evolved gas will occupy less than 1% of the pore space. Further, the compressibility of the total system will be approximately 50% higher than it would have been had the gas been absent at this point in the depletion. At higher pressures the effect of gas evolution on the total system compressibility would be diminished. Using a conventional material balance analysis and assuming that the only active production mechanisms are water compressibility, formation compaction, and gas evolution, we compute a recovery of 2.7% of the water in place for a pressure decline from 10,000 psia to 5,000 psia. Of this recovery, 2.1% can be attributed to the formation compaction and water compressibility effects, while 0.6% is due to water being displaced by evolved gas. In summary, evolved gas will affect recovery from a geopressured-geothermal reservoir but will not dominate the total system compressibility as is often the case in petroleum reservoirs.

Formation compaction is important as a production mechanism and in the potential effect it may have on ground subsidence. In the formative, investigative stages of geopressured-geothermal reservoir potential, it had been speculated that formation compaction would play a substantive role in fluid production. It was

speculated that the magnitude of compaction during the depletion of a geopressured sand would be substantially greater than that experienced in normally pressured environments. Subsequent data have indicated that the geopressured reservoir rocks have compaction in the same range of values as is found in normally pressured reservoir material. Detailed testing of rock samples from the Frio formations at Brazoria has indicated that much of the geopressured reservoir material has a tendency to creep [3]. This creep phenomenon may play an important role in geopressured-geothermal reservoir production, since compaction energy is a significant factor in the production of fluids from the reservoir. The implications of the observed transient rock behavior are currently under study.

Shale dewatering during reservoir depletion is another important possibility which may affect the ultimate reserves associated with geopressured-geothermal aquifers [4,5]. It has been recognized that shales exhibit permeability to water. Even though this permeability is measured in microdarcies, it may result in additional reserves and pressure support for a given geopressured aquifer. Both water in the shales and water in inaccessible sands passing through the shales may be significant in terms of resource recovery. The effect of shale dewatering is expected to become apparent after a substantial pressure decline has been experienced in the reservoir. The importance of this effect must await the results of field testing.

The reinjection of water into the reservoir has been proposed as a way to greatly increase both the heat energy and the gas recovered from geopressured-geothermal reservoirs. Whether or not the net economic recovery is sufficient to justify such a scheme will depend to a large extent on external economic factors. Field testing these alternatives would not be justified in light of the information to be learned about the reservoir. Mathematical modeling of these schemes will provide sufficiently definitive results to judge their value and applicability. To

analyze these alternatives it is necessary to include a thermal energy balance in the reservoir model formulation.

Another aspect of producing a geopressured-geothermal reservoir is the single-well problem. The ability to produce water at the flow rates necessary to be economically feasible will depend largely on the reservoir performance in the vicinity of the wellbore. It is therefore necessary to have available modeling capability adequate to understand the potential phenomena occurring near the well area. The additional capability required is the ability to handle multiphase convergent flow problems. The simulator was rewritten for this purpose by employing a semiimplicit procedure. One aspect of the single-well-producing problem is the potential buildup of immobile gas around the wellbore, thus blocking the flow of water. This effect is also currently under study. Finally, it is necessary that the model handle all heterogeneities and variances that might occur in the reservoir.

2.2 MATHEMATICAL DESCRIPTION

Natural depletion in a geopressured-geothermal aquifer is considered isothermal. To describe fluid flow in a deforming porous medium such as a geopressured aquifer, two coordinate systems need to be introduced, the spatial coordinates $\underline{x} = (x, y, z)$ and the material coordinates $\underline{X} = (X, Y, Z)$. The material coordinate axes are attached to the porous medium. The motion of the porous medium is described by $\underline{x} = \underline{x}(\underline{X}, t)$, where t denotes time. As fluids are extracted from the porous medium, fluid pressures decrease, but the weight of overburden sediments remains unchanged. Under such circumstances, it is believed that, because of the small thickness compared to the areal extent of the reservoir, the porous medium deforms predominantly in the vertical direction [6,7]. The spatial coordinates at the initial configuration are taken as the material coordinates.

Furthermore, it is possible to choose the coordinate systems such that their origins remain coincident with each other. Then, the assumption of vertical deformation leads to the relationships: $x = X$; $y = Y$; and $z = z(X, t)$. The displacement vector $\underline{u} = \underline{x} - \underline{X}$ has the components $u_x = u_y = 0$ and $u_z = z - Z$. Assuming sufficiently small deformation, the component ϵ_z of the Eulerian strain tensor is given by

$$\epsilon_z = \frac{\partial u_z}{\partial z} . \quad (1)$$

The velocity of the porous medium (rock matrix) $\underline{v}_r = (v_{rx}, v_{ry}, v_{rz})$ becomes

$$v_{rx} = v_{ry} = 0 , \quad v_{rz} = \frac{dz}{dt} = \frac{du_z}{dt} \quad (2)$$

where d/dt is the material time derivative following the motion of the porous medium.

The vertical deformation of sediments is often assumed to be elastic and is characterized by the constant called uniaxial compaction coefficient C_m . Let ℓ_z be a small vertical line segment and P be some representative fluid pressure. The uniaxial compaction coefficient C_m is defined by

$$C_m = \frac{1}{\ell_z} \left(\frac{\partial \ell_z}{\partial P} \right)_T \quad (3a)$$

where T indicates the gradient to be evaluated at a constant subsurface temperature [6,7,8]. Alternatively, C_m can be written in terms of the Eulerian tensor ϵ_z :

$$C_m = \left(\frac{\partial \epsilon_z}{\partial P} \right)_T \quad (3b)$$

From Eqs. (1), (2), and (3b), it follows that

$$\frac{\partial v_{rz}}{\partial z} = \frac{d\epsilon_z}{dt} = \left(\frac{\partial \epsilon_z}{\partial P} \right)_T \frac{dP}{dt} = C_m \frac{dP}{dt} \quad (4)$$

The mass balance of the solid phase (rock matrix) is given by

$$\frac{\partial}{\partial t} \{ \rho_r (1 - \phi) \} + \nabla \cdot \{ \rho_r (1 - \phi) \mathbf{v}_r \} = 0 \quad (5a)$$

where ρ_r is the rock matrix density, ϕ the porosity, and $\partial/\partial t$ is the spatial time derivative. Using the material time derivative and the assumption $v_{rx} = v_{ry} = 0$, Eq. (5a) becomes

$$\frac{d}{dt} \rho_r (1 - \phi) + \rho_r (1 - \phi) \frac{\partial v_{rz}}{\partial z} = 0 \quad (5b)$$

Define the rock matrix compressibility C_{rm} and the pore compressibility C_ϕ as:

$$C_{rm} = \frac{1}{\rho_r} \left(\frac{\partial \rho_r}{\partial P} \right)_T, \quad C_\phi = \frac{1}{\phi} \left(\frac{\partial \phi}{\partial P} \right)_T$$

respectively. Expanding the first term of Eq. (5b) and applying Eq. (4) to the second term, Eq. (5b) is further transformed to

$$C_{rm} \rho_r (1 - \phi) \frac{dP}{dt} - C_\phi \rho_r \frac{dP}{dt} + C_m \rho_r (1 - \phi) \frac{dP}{dt} = 0 \quad .$$

Therefore, the rock matrix mass balance reduces to

$$C_\phi = \frac{1 - \phi}{\phi} (C_{rm} + C_m) \quad (6)$$

Two fluid phases, liquid and vapor, will exist in a geopressed aquifer during its depletion. In the range of pressures and temperatures encountered in a geopressed aquifer, the vapor phase consists of only hydrocarbon gas, while the liquid phase is represented as a mixture of water and dissolved gas. Here, water and gas refer to components. The governing differential equations are written for this fluid system of two components, water and gas, and two phases, liquid and vapor, as isothermal mass balances for the components.

$$\frac{\partial}{\partial t} (m_{wl} \rho_l S_l \phi) + \nabla \cdot (m_{wl} \rho_l S_l \phi \mathbf{v}_l) = -q_w \quad (7a)$$

$$\frac{\partial}{\partial t} (\rho_v S_v \phi + m_{gl} \rho_l S_l \phi) + \nabla \cdot (\rho_v S_v \phi \mathbf{v}_v + m_{gl} \rho_l S_l \phi \mathbf{v}_l) = -q_g \quad (7b)$$

where ρ denotes the density, S the saturation, $\mathbf{v}$ the phase velocity vector, and q the component sink. The subscripts l and v indicate the liquid and vapor phases, respectively, and the subscripts w and g indicate the water and gas components, respectively. The mass fractions of the water and gas components in the liquid phase, m_{wl} and m_{gl} , are defined by

$$m_{wl} = \frac{\rho_w}{\rho_l B_l}, \quad m_{gl} = \frac{R_s \rho_g}{\rho_l B_l} \quad (8)$$

Here B_l is the liquid formation volume factor and R_s is the solution gas-water ratio. The component stock tank densities (i.e., densities at standard conditions), ρ_w and ρ_g , are constant. The formation volume factors can be expressed as

$$B_l = \frac{\rho_w}{\rho_w + R_s \rho_g}, \quad B_v = \frac{\rho_g}{\rho_v} \quad (9)$$

The fluid velocities relative to the deforming solid phase are given by

$$\tilde{\mathbf{v}}_{r\ell} = \tilde{\mathbf{v}}_{\ell} - \tilde{\mathbf{v}}_r \quad , \quad \tilde{\mathbf{v}}_{rv} = \tilde{\mathbf{v}}_v - \tilde{\mathbf{v}}_r \quad . \quad (10)$$

Substitution of Eqs. (8), (9), and (10) into Eqs. (7a) and (7b) yields the fluid mass balance equations in which the solid phase is regarded as a reference.

$$\frac{d}{dt} \left(\frac{\phi S_{\ell}}{B_{\ell}} \right) + \left(\frac{\phi S_{\ell}}{B_{\ell}} \right) \frac{\partial \mathbf{v}_{rz}}{\partial z} = - \nabla \cdot \left(\frac{\phi S_{\ell}}{B_{\ell}} \tilde{\mathbf{v}}_{r\ell} \right) - q_w \quad (11a)$$

$$\begin{aligned} \frac{d}{dt} \left(\frac{\phi S_v}{B_v} + \frac{R_s \phi S_{\ell}}{B_{\ell}} \right) + \left(\frac{\phi S_v}{B_v} + \frac{R_s \phi S_{\ell}}{B_{\ell}} \right) \frac{\partial \mathbf{v}_{rz}}{\partial z} \\ = - \nabla \cdot \left(\frac{\phi S_v}{B_v} \tilde{\mathbf{v}}_{rv} + \frac{R_s \phi S_{\ell}}{B_{\ell}} \tilde{\mathbf{v}}_{r\ell} \right) - q_g \end{aligned} \quad (11b)$$

Eqs. (11a) and (11b) are the results of division by the constant stock tank component densities and express component balances in terms of component volumes.

By Darcy's law, the relative fluid velocities are written as

$$\phi S_{\ell} \tilde{\mathbf{v}}_{r\ell} = - \frac{k_{r\ell}}{\mu_{\ell}} \underline{\underline{K}} \cdot \nabla \phi_{\ell} \quad (12a)$$

$$\phi S_v \tilde{\mathbf{v}}_{rv} = - \frac{k_{rv}}{\mu_v} \underline{\underline{K}} \cdot \nabla \phi_v \quad (12b)$$

where $k_{r\ell}$ and k_{rv} are the relative permeabilities, μ is the viscosity, and $\underline{\underline{K}}$ is the absolute permeability tensor. The gradient of the liquid flow potential is

defined by

$$\nabla\phi_{\ell} = \nabla P_{\ell} - \gamma_{\ell} \nabla h \quad (13)$$

and $\nabla\phi_v$ is similarly defined, where P_{ℓ} is the liquid pressure, h the depth, and $\gamma_{\ell} = \rho_{\ell}g/g_c$, g being the gravity acceleration and g_c an appropriate conversion factor.

The final forms of governing differential equations are obtained by substituting Eqs. (12a), (12b), and (13) into Eqs. (11a) and (11b):

$$\frac{d}{dt} \left(\frac{\phi S_{\ell}}{B_{\ell}} \right) + \left(\frac{\phi S_{\ell}}{B_{\ell}} \right) \frac{\partial v_{rz}}{\partial z} = \nabla \cdot (\tilde{T}_{\ell} \nabla \phi_{\ell}) - q_w \quad (14a)$$

$$\begin{aligned} \frac{d}{dt} \left(\frac{\phi S_v}{B_v} + \frac{R_s \phi S_{\ell}}{B_{\ell}} \right) + \left(\frac{\phi S_v}{B_v} + \frac{R_s \phi S_{\ell}}{B_{\ell}} \right) \frac{\partial v_{rz}}{\partial z} \\ = \nabla \cdot (\tilde{T}_v \nabla \phi_v + R_s \tilde{T}_{\ell} \nabla \phi_{\ell}) - q_g \end{aligned} \quad (14b)$$

where the transmissibilities $\tilde{T}_{\ell}$ and $\tilde{T}_v$ have been introduced

$$\tilde{T}_{\ell} = \frac{k_{r\ell}}{B_{\ell} \mu_{\ell}} K, \quad \tilde{T}_v = \frac{k_{rv}}{B_v \mu_v} K.$$

The mathematical description of the fluid component balances is completed with the capillary pressure function

$$P_v - P_{\ell} = P_c(S_{\ell}) \quad (15)$$

and the saturation identity

$$S_v + S_\ell = 1. \quad (16)$$

The mathematical model obtained above differs from conventional models in the inclusion of terms to account for the deformation of the porous medium. Since total driving energy of a geopressured aquifer is considered to be very limited, neglecting these deformation terms would lead to erroneous results. The material coordinate axes are taken to coincide with the principal axes of the absolute permeability tensor. The deformation is assumed to be so small that permeability with respect to the spatial coordinate system at a deformed state may be approximated by that of the material coordinate system.

2.3 NUMERICAL APPROXIMATION

The domain on which the governing equations are defined is made discrete into $N_x * N_y * N_z$ grid blocks. For a two-dimensional areal model $N_z = 1$, while $N_y = 1$ for a two-dimensional cross-sectional model. In the following description, the upper-case index J is an integer vector of three components identifying a grid node (or grid block), and the index $J + (i)$ refers to the node adjacent to the node J in the positive i -th axis direction, where x , y , and z axes are the first, second, and third axes, respectively. Then for example, the coordinates of the grid node J are denoted by $\underline{x}_J = (x_J, y_J, z_J) = (x_{1J}, x_{2J}, x_{3J})$. The grid block interface between the nodes J and $J + (i)$ is labeled $J + (i)/2$.

By the conventional numerical approximation of governing differential equations, diffusion terms are replaced by the second-order differences, time derivatives are approximated by backward time differences, and then grid block volumes are multiplied to obtain the difference analogs in the actual dimension of grid blocks. Here, a slightly different approach is employed. As the first step the

governing Eqs. (14a) and (14b) are integrated over each grid volume. It can easily be shown that the integral of the left-hand side of Eq. (14a) becomes

$$\begin{aligned} & \int_{V_J} \left\{ \frac{d}{dt} \left(\frac{\phi S_\ell}{B_\ell} \right) + \left(\frac{\phi S_\ell}{B_\ell} \right) \frac{\partial v_{rz}}{\partial z} \right\} dV \\ &= \frac{d}{dt} \int_{V_J} \frac{\phi S_\ell}{B_\ell} dV \end{aligned} \quad (17)$$

where $\int_{V_J} dV$ indicates the integral over the volume of the grid block J. The integration of the right-hand side results in

$$\begin{aligned} & \int_{V_J} \nabla \cdot (T_\ell \cdot \nabla \phi_\ell) dV - \int_{V_J} q_w dV \\ &= \sum_i \left\{ \int_{A_{iJ+(i)/2}} \left(T_{\ell i} \frac{\partial \phi_\ell}{\partial x_i} \right)_{J+(i)/2} dA \right. \\ & \quad \left. - \int_{A_{iJ-(i)/2}} \left(T_{\ell i} \frac{\partial \phi_\ell}{\partial x_i} \right)_{J-(i)/2} dA \right\} - Q_{wJ} \end{aligned} \quad (18)$$

where Q_{wJ} is the total rate of water component sink from the grid block J. $A_{iJ+(i)/2}$ is the area of the grid block interface between the nodes J and J+(i) and perpendicular to the i-th axis. $\int_{A_{iJ+(i)/2}} dA$ represents integral over this interface area. The i-th principal component of the transmissibility tensor is indicated by $T_{\ell i}$. The term in the brace shows the difference between the water flowing in and that flowing out through the grid block interfaces. As the second step, the integral signs are removed by means of the mean value theorem for

integrals and then derivatives are approximated by appropriate finite differences. For example,

$$\frac{d}{dt} \int_{V_J} \frac{\phi S_\ell}{B_\ell} dV \doteq \frac{1}{\Delta t} \Delta_t \left(\frac{V \phi S_\ell}{B_\ell} \right)_J^{n+1} \quad (19)$$

$$\begin{aligned} & \int_{A_{iJ+(i)/2}} \left(T_{\ell i} \frac{\partial \phi_\ell}{\partial x_i} \right)_{J+(i)/2} dV \\ & \doteq \left(\frac{A_i T_{\ell i}}{\Delta x_i} \right)_{J+(i)/2}^{n+1} \left[\Delta_i \phi_{\ell J+(i)/2}^{n+1} \right] \end{aligned} \quad (20)$$

where the superscript indicates time level, Δt is time step size, Δ_t is the backward time difference, and Δ_i is the centered space difference in the i -th axis direction.

$$\Delta_i \phi_{\ell J+(i)/2} = \phi_{\ell J+(i)} - \phi_{\ell J}$$

Other terms are similarly treated. The same procedure is applied to the gas balance equation. As a consequence, the following difference equations have been generated

$$\begin{aligned} \frac{\Delta_t V_{wJ}^{n+1}}{\Delta t} &= \sum_i \left\{ \lambda_{\ell J+(i)/2}^{n+1} \Delta_i \phi_{\ell J+(i)/2}^{n+1} \right. \\ &\quad \left. - \lambda_{\ell J-(i)/2}^{n+1} \Delta_i \phi_{\ell J-(i)/2}^{n+1} \right\} - Q_{wJ}^{n-1} \end{aligned} \quad (21a)$$

$$\begin{aligned}
\frac{\Delta_t v_{gJ}^{n+1}}{\Delta t} = \sum_i \left\{ \left(R_s \lambda_{\ell} \right)_{J+(i)/2}^{n+1} \Delta_i \phi_{\ell J+(i)/2}^{n+1} \right. \\
- \left(R_s \lambda_{\ell} \right)_{J-(i)/2}^{n+1} \Delta_i \phi_{\ell J-(i)/2}^{n+1} \\
+ \lambda_{vJ+(i)/2}^{n+1} \Delta_i \phi_{vJ+(i)/2}^{n+1} \\
\left. - \lambda_{vJ-(i)/2}^{n+1} \Delta_i \phi_{vJ-(i)/2}^{n+1} \right\} - Q_{gJ}^{n+1} \\
J=1,2, \dots, N_x N_y N_z
\end{aligned} \tag{21b}$$

where the symbols are simplified by the replacements

$$v_w = \frac{V \phi S_{\ell}}{B_{\ell}}, \quad v_g = \frac{V \phi S_{v\ell}}{B_v} + \frac{R_s V \phi S_{\ell}}{B_{\ell}},$$

$$\lambda_{\ell J+(i)/2} = \left(\frac{A_i^T \ell_i}{\Delta x_i} \right)_{J+(i)/2}, \quad \lambda_{vJ+(i)/2} = \left(\frac{A_i^T v_i}{\Delta x_i} \right)_{J+(i)/2}$$

The derivation of the difference equations emphasizes the sense of discrete balancing of components more strongly than the conventional numerical formulation. The parameters in Eqs. (21a) and (21b) should be understood as the averaged parameters over a grid block volume or interface rather than the parameters at nodes.

Eqs. (21a) and (21b) are nonlinear difference equations. Nonlinearities are treated by the semiimplicit procedure, that is, nonlinear terms are linearly expanded about their values at the beginning of a time step [9]. Choosing the liquid pressure and saturation as the primary dependent variables, the expansions

are done as

$$v_{wJ}^{n+1} = v_{wJ}^n + v_{wJ}^{(P)} \Delta t_{\ell J}^{n+1} + v_{wJ}^{(S)} \Delta t_{\ell J}^{n+1} \quad (22)$$

where

$$v_{wJ}^{(P)} = \frac{v_w(p_{\ell J}^{n+1}, s_{\ell J}^n) - v_w(p_{\ell J}^n, s_{\ell J}^n)}{p_{\ell J}^{n+1} - p_{\ell J}^n} \quad (23a)$$

and

$$v_{wJ}^{(S)} = \frac{v_w(p_{\ell J}^{n+1}, s_{\ell J}^{n+1}) - v_w(p_{\ell J}^{n+1}, s_{\ell J}^n)}{s_{\ell J}^{n+1} - s_{\ell J}^n} \quad (23b)$$

Each fluid flux term is dependent on the variables of two grid blocks. The transmissibilities are approximated as the harmonic mean of two values except the relative permeabilities, for which the full upstream weighting is used. Hence, the expansion of the flux term,

$$\lambda_{\ell J+(i)/2}^{n+1} \Delta \phi_{\ell J+(i)/2}^{n+1},$$

involves variations due to the changes of

$$P_{\ell J}, S_{\ell J}, P_{\ell J+(i)} \text{ and } S_{\ell J+(i)}.$$

The linearized difference equations are solved for the changes of the liquid pressures and saturations,

$$\left\{ \Delta_t P_{\ell J}^{n+1} \right\} \text{ and } \left\{ \Delta_t S_{\ell J}^{n+1} \right\}.$$

The process is iterated at least once; the first solution is obtained with the chord slopes such as

$$V_{wJ}^{(P)} \text{ and } V_{wJ}^{(S)}$$

approximated by the gradients at the beginning of a time step. The chord slopes are updated by using the first solution to generate the final solution for a new time level. The iteration can be repeated till convergence.

No flux boundary conditions are assumed for the two fluid phases. Generally, natural equilibrium conditions are used to generate initial state. The deformations of grid blocks are calculated using grid liquid pressures, for the liquid phase remains as a dominant phase throughout the depletion process. Wellbore flowing pressures are evaluated from well grid block pressure assuming radial steady state flow about the well [1,2].

CHAPTER 3

RESERVOIR PERFORMANCE PREDICTION

The Bureau of Economic Geology and the Department of Petroleum Engineering at The University of Texas at Austin have conducted for three years a study to locate potential geopressed geothermal reservoirs along the Texas Gulf Coast. Among the several prospects found in the search, the Austin Bayou prospect was considered to have the greatest potential and thus was selected for the site of experimental well drilling [10]. The Austin Bayou prospect is located between the Chocolate Bayou field and the Danbury Dome in Brazoria County, Texas (Figure 1). It is believed to extend over an area of 60 square miles. The reservoir is a sandy sequence near the base of the Frio formation and the depth of the reservoir top varies from about 14,000 feet below sea level in the Danbury Dome area to 12,000 feet to the northeast of the Chocolate Bayou field. The reservoir thicknesses are estimated to range from more than 1,100 feet near the Danbury Dome to 200 feet at the Chocolate Bayou field (Figure 1). As indicated in Figure 1, faults exist around the Austin Bayou prospect. In particular the northwest side of the prospect is considered to be completely bounded by the major fault trending NE/SW. The areal and vertical extent of other faults and hence the reservoir boundaries of the Austin Bayou prospect are uncertain at present.

Reservoir temperatures and pressures of the geopressed-geothermal reservoir at the Austin Bayou prospect were estimated using the measured data at the wells in Brazoria County obtained from the Railroad Commission of Texas. In the vicinity of the proposed well location, the geothermal gradient is about 1.85 °F/100 feet between the depths of 10,000 feet and 17,000 feet, while the reservoir temperature at the depth of 10,000 feet is approximately 220 °F [10].

Figure 1 Structure on Top of the T5 Marker within the Geopressed Reservoir of the Austin Bayou Prospect.

Bebout et al. reported that the reservoirs in the Chocolate Bayou field are commonly geopressed below the depth of 10,000 feet and the pressure gradient lies between 0.465 and 0.98 psi/foot. The wells in the area of the Austin Bayou prospect indicated the pressure gradient of nearly 1 psi/foot.

The measurements on unstressed cores indicated that porosities and permeabilities are high in the northeast region of the Chocolate Bayou field, porosity ranging from 20% to 27% and permeability being as high as 500 millidarcys. In the southwest of the field, porosity decreases to 9% to 24% and permeability becomes less than 100 millidarcys. This degradation appears to continue into the Austin Bayou prospect: the well about 2 miles southeast of the Danbury Dome showed sandstones tightly cemented with quartz and calcite, and the secondary porosity due to leaching was poor compared with the Chocolate Bayou reservoirs. The in situ porosity and permeability would be reduced by 50% or more from the values indicated above because of overburden stress and high temperature [11].

Well tests conducted at the wells in the Chocolate Bayou field include pressure buildup tests, absolute open-flow potential tests, and pressure drawdown tests. The pressure buildup analysis of 16 Chocolate Bayou wells indicated the effective permeability of 1.6 to 36 millidarcys, while absolute open-flow potential tests showed the permeability ranging from 1.2 to 140 millidarcys. Pressure buildup tests at some wells revealed reservoir boundaries at distances of 300 to 600 feet from the wells, reflecting the complex faulted reservoir at the Chocolate Bayou field.

Compressibilities of the reservoir at the Austin Bayou prospect are presently unknown. Geertsma [7] reported that the uniaxial compaction coefficient of

sandstone varies between $0.2 \times 10^{-6} \text{ psi}^{-1}$ for tight rock and 1.4 to $2.8 \times 10^{-6} \text{ psi}^{-1}$ for loose sands for the effective stress ranging from 1,400 to 8,500 psia. The Bureau of Economic Geology at The University of Texas at Austin estimated rather large uniaxial compaction coefficients because of undercompacted sediments, $6.6 \times 10^{-6} \text{ psi}^{-1}$ for sandstones and $1.1 \times 10^{-5} \text{ psi}^{-1}$ for shales. Rock matrix compressibilities are relatively small. For example, quartz, the important constituent of sandstones, has the compressibility of $1.9 \times 10^{-7} \text{ psi}$.

Fowler [12] showed that water salinity averages about 40,000 ppm for depths from 8,600 to 10,000 feet, then it increases sharply to 50,000 to 87,000 ppm at a depth of 12,000 feet in the Chocolate Bayou field. The lower salinity water is found in the sandstones at the base of the Frio formation, implying that these sandstones received freshwater from underlying shales in the course of compaction. The solubility of methane in water decreases as water salinity increases and it increases with temperatures and pressures. Based on the data by Dodson and Standing [13] and by Culberson and McKetta [14], the solubility of methane is estimated to be about 45 cu ft per barrel of water at the depth of 15,000 feet in the Austin Bayou prospect.

Capillary pressures and relative permeabilities of the Austin Bayou reservoir are yet to be determined. Leverett's functions [15,16] are frequently used to estimate capillary pressures. Similarly Corey's equations [17] are widely used in the absence of actual data on relative permeabilities.

3.1 RESERVOIR BEHAVIORS EXPECTED IN THE AUSTIN BAYOU GEOPRESSURED-GEOTHERMAL PROSPECT

A series of numerical simulations were conducted to assess the production from the Austin Bayou geopressured-geothermal reservoir. Since many of the

reservoir characteristics are uncertain at present, several reservoir parameters were varied in this study. Varied parameters include drainage area, uniaxial compaction coefficients, thicknesses of over- and underlying shales, and the presence of a middle shale layer. All cases assumed a cylinder-shaped domain in the r - z cylindrical coordinate system with a single well along the z axis. The wellbore diameter was 5.5 inches, and axisymmetric fluid flow was assumed.

The water properties were estimated as functions of pressures at the assumed reservoir temperature of 325 °F and water salinity of 65,000 ppm. The gas properties were those of pure methane. The fluid properties are summarized in Table 1. Because of the lack of real data, the 5-function curve of a clean sand from the Woodbine formation at the Hawkins reservoir [18] was used to estimate capillary pressures of the Austin Bayou reservoir. Relative permeabilities were calculated by Corey's equation with negligible critical gas saturation and 20% of irreducible water saturation. Although shales would have quite different capillary pressure and relative permeability functions, the same functions as for sandstones were used in this study. Capillary pressures and relative permeabilities are tabulated in Table 2 as functions of water saturations.

More than ten sandstone layers are identified in the sandy sequence of the Frio formation. They were simplified by the two sandstone layers of uniform properties with or without the intermediate shale of 500 foot thickness. The upper sandstone layer assumed thickness of 180 feet, porosity of 23%, and permeability of 25 millidarcys, while the lower sandstone layer had 660-foot thickness, 15% porosity, and 15 millidarcy permeability. All the shale layers were initially given the same porosity and permeability, 20% and 10^{-4} millidarcys, respectively, but their thicknesses were varied from case to case. Uniaxial compaction coefficients were $6.6 \times 10^{-6} \text{ psi}^{-1}$ for sandstones and $1.1 \times 10^{-5} \text{ psi}^{-1}$ for

Table 1 Fluid Properties as Functions of Pressures at Reservoir Temperature of 325⁰F.

Press. (psia)	Water Formation Volume Factor (bbl/STB)	Gas-water Solubility (SCF/bbl)	Water Viscos. (cp)	Gas Formation Volume Factor (bbl/MCF)	Gas Visco. (cp)
IPRS	DENW	RSW	VISW	DENG	VISG
5000.	1.0946	27.308	0.1781	0.849	0.02245
5500.	1.0935	29.040	0.1788	0.783	0.02326
6000.	1.0924	30.938	0.1794	0.741	0.02406
6500.	1.0912	32.670	0.1801	0.699	0.02484
7000.	1.0902	34.365	0.1808	0.667	0.02562
7500.	1.0890	36.053	0.1818	0.637	0.02639
8000.	1.0880	37.703	0.1824	0.609	0.02715
8500.	1.0868	39.270	0.1828	0.586	0.02790
9000.	1.0857	40.920	0.1833	0.568	0.02865
9500.	1.0845	42.405	0.1841	0.550	0.02939
10000.	1.0835	43.725	0.1849	0.534	0.03913
10500.	1.0823	44.963	0.1856	0.519	0.03086
11000.	1.0813	46.283	0.1863	0.505	0.03157
11500.	1.0802	47.520	0.1870	0.492	0.03226
12000.	1.0790	48.840	0.1877	0.481	0.03290
12500.	1.0779	50.140	0.1884	0.471	0.03348
13000.	1.0768	51.440	0.1891	0.462	0.03398
13500.	1.0757	52.740	0.1898	0.454	0.03438
14000.	1.0746	54.040	0.1905	0.447	0.03466

Table 2 Capillary Pressures Estimated from J Function of a Clean Sandstone from Woodbine Formation, Hawkins Reservoir, and the Relative Permeabilities to Water (k_{rw}) and Gas (k_{rg}) Calculated by Corey's Equations.

Water Saturation	Capillary pressure	Relative permeability	
	P_c - (psi)	k_{rw}	k_{rg}
1.00	10.7	1.000	0.000
0.90	11.0	0.620	0.015
0.80	11.3	0.330	0.042
0.70	11.6	0.150	0.090
0.60	11.9	0.055	0.195
0.50	12.3	0.015	0.370
0.04	12.9	0.004	0.530
0.30	14.2	0.001	0.700
0.20	21.6	0.000	1.000
0.15	44.6	0.000	1.000
0.10	770.0	0.000	1.000

shales in most cases. They were reduced to $4.9 \times 10^{-7} \text{ psi}^{-1}$ for sandstones and $1.1 \times 10^{-6} \text{ psi}^{-1}$ for shales in Cases 6A, 6B, and 6C to see the effects of uniaxial compaction coefficients on reservoir performance. Rock matrix compressibilities were assumed negligible. The Austin Bayou prospect is considered to extend over an area of more than 60 square miles. The drainage areas of 64, 16, and 4 square miles were considered in the case study. The cases of 16 and 4 square mile drainage areas may be interpreted as the case where the entire prospect is produced by multiple wells either because large production is needed from the economical point of view or because the prospect is broken into several blocks by faults. The varied parameters are summarized in Table 3, and the sequences of sandstone-shale alternation are illustrated in Figures 2 and 3.

The well was perforated over the entire sandstone interval and produced at the constant rate of 40,000 BWPd. When the flowing bottom hole pressure declined to 7,000 psia, that pressure was held constant and the well continued to produce with reduced rates. Most of the simulations were made over the 10-year period. For the cases where flowing bottom hole pressures were above 7,000 psia at the end of simulations, the reservoir life spans and recoveries were estimated by extrapolating flowing bottom hole pressure curves to 7,000 psia. This procedure is justified since the transient period is short, -- less than a year -- for all the cases studied. Case 1A was run with three grid systems: the external radius was partitioned into 10, 15, and 19 intervals with the innermost grid blocks having the outer radius of 16.4, 9.24, and 6.11 feet, respectively. The vertical interval was divided into 4 intervals (5 grid blocks) such that grid block interfaces coincided with layer interfaces. The three grid systems generated no substantial differences on the well pressure performances. The rest of the case study was carried out with the radial partition of 15 intervals.

Table 3 Summary of Varied Parameters in Case Study.

<u>Case No.</u>	<u>Drainage Area</u> Sq. mile	<u>Uniaxial Compaction Coefficient</u>		<u>Vertical Shale Permeability</u> md.	<u>Thickness of Top and Bottom Shale Layers</u> ft.	<u>Thickness of Middle Shale Layers</u> ft.
		<u>Sand</u> psi ⁻¹	<u>Shale</u> psi ⁻¹			
1A	64	6.6x10 ⁻⁶	1.1x10 ⁻⁵	10 ⁻⁴	100 ea	0
1B	16	"	"	"	"	"
1C	4	"	"	"	"	"
2A	64	6.6x10 ⁻⁶	1.1x10 ⁻⁵	10 ⁻⁴	200 ea	0
2B	16	"	"	"	"	"
2C	4	"	"	"	"	"
3A	64	6.6x10 ⁻⁶	1.1x10 ⁻⁵	10 ⁻⁴	200 ea	500
3B	16	"	"	"	"	"
3C	4	"	"	"	"	"
4C	4	6.6x10 ⁻⁵	1.1x10 ⁻⁵	10 ⁻⁵	200 ea	0
5C	4	6.6x10 ⁻⁶	1.1x10 ⁻⁵	10 ⁻⁵	200 ea	0
6A	64	4.9x10 ⁻⁷	1.1x10 ⁻⁶	10 ⁻⁴	100 ea	0
6B	16	"	"	"	"	"
6C	4	"	"	"	"	"

Figure 2 Cross-Sectional View of the Sandstone-Shale Sequence Without a Middle Shale Layer.

Figure 3 Cross-Sectional View of the Sandstone-Shale Sequence With a Middle Shale Layer (Cases 3A to 3C).

Cases 1A, 1B, and 1C have shale layers of 100 feet on the top and bottom of the two-sandstone-layer reservoir but assume a drainage area of 64, 16, and 4 square miles, respectively. Case 1A (4 square miles) and Case 1B (16 square miles) showed such extremely long reservoir lives that such production schemes would be impractical. Extrapolating the bottom hole pressure curves to 7,000 psia, the ultimate recoveries of Cases 1A and 1B are predicted to be 12.2% and 12.8% respectively. Case 1C (4 square mile drainage are) was simulated for a period of 30 years. After 24 year production at the rate of 40,000 BWPd, the bottom hole pressure reached the minimum required pressure of 7,000 psia (Figure 4). The recovery rate then was 13.6% of the water initially in the sandstone layers. The shale layers expelled to the sandstones 2.2% of their initial water. The amount is equivalent to 0.6% of the sandstone initial water. It implies that 0.6% of the 13.6% water recovery from the sandstones is attributed to the displacement by the water expelled from the shales. In other words, the shale dewatering provided about 4.4% of the total driving energy. During the year before the bottom hole pressure reached 7,000 psia, the pressure decline was 123.38 psi/year. At the tenth year it was 128.45 psi/year, and only 0.7% of the 5.45% sandstone recovery resulted from the shale dewatering. The shale dewatering supplied only 1.8% of the total driving energy until the tenth year. The reservoir of Case 1C continued to produce for 30 years with the constant bottom hole pressure of 7,000 psia. The production rate gradually declined to 20,800 BWPd at the time of 30 years (Figure 4). The recovery rate at that point was 15.8% of the initial water in the sandstones, of which 0.9% was due to the shale dewatering (about 7% of the cumulative total driving energy). It is obvious from the above observation that shale dewatering is negligibly small at early stages of sandstone reservoir depletion but becomes more and more important as the depletion proceeds.

Figure 4 Reservoir Performance of the Geopressured Aquifer with Top and Bottom Shale Layers and 4 Square Mile Drainage Area (Case 1C).

The thicknesses of the top and bottom shales were increased to 200 feet in Cases 2A, 2B, and 2C, from the corresponding Cases 1A, 1B, and 1C. In doing so, a layer of shale grid blocks was added to both top and bottom of the domain, instead of increasing the thicknesses of the existing shale grid block layers. No substantial differences were observed between the corresponding cases, implying that only the small portion of shales near the contact with sandstones expel water to sandstones. In Cases 3A, 3B, and 3C, a middle shale layer 500 feet thick was inserted between the two sandstone layers of Cases 2A, 2B, and 2C, respectively. Again, Cases 2A and 3A, and also Cases 2B and 3B generated almost identical results, the bottom hole pressures differing less than 1 psi at the end of a 10-year simulation. However, Cases 2C and 3C, both of which were simulated until the late stages of reservoir depletion (30 years), showed small but significant differences in reservoir performance (Figure 5). In Case 2C, the bottom hole pressure reduced to 7,000 psia after 24.4 years, recovering 13.6% of the initial water in the sandstones. Case 3C produced 1.6 years longer with the bottom hole pressures above 7,000 psia, and its recovery was 14.5%. Both cases continued to produce thereafter with the constant bottom hole pressure and reduced rates. After 30 years the production rate of Case 3C was lowered to less than 28,000 BWP D. The recovery was 16.3% of the initial water in the sandstones, of which 0.93% was attributed to dewatering of the top and bottom shales and 1.15 percent was due to the expelled water from the middle shale. When the production rate in Case 2C declined to about 28,000 BWP D (27.6 years), the water recovery was 15.1% and the boundary shale contributed only 0.76%.

To study further the effects of shale dewatering, the shale vertical permeabilities were reduced from 10^{-4} millidarcys in Case 2C to 10^{-5} in Case 4C. The other data of Case 4C were identical with those of Case 2C. The results

Figure 5 Comparison of Well Pressure Histories of Reservoirs with and without a Middle Shale Layer (Cases 2C and 3C).

showed that if shale vertical permeabilities were as low as 10^{-5} millidarcys in Case 4C, the reservoir could produce at the rate of 40,000 BWP D with the bottom hole pressures above 7,000 psia for 23.6 years, 0.8 years shorter than Case 2C. The recovery of Case 4C at that point was 13.1%, of which merely 0.07% was contributed by the shale dewatering, while in Case 2C it was 13.6%, 0.6% being due to the shale dewatering. The same study was conducted for the case with an intermediate shale layer: Case 5C assumed the same data as Case 3C except vertical shale permeabilities which were decreased from 10^{-4} millidarcys to 10^{-5} . The two cases are compared in Figure 6. The reservoir in Case 5C could retain the rate of 40,000 BWP D with the bottom hole pressures over 7,000 psia for 23.3 years, 2.7 years shorter than Case 3C. The recovery rates when the bottom hole pressures declined to 7,000 psia were 14.5% and 13% in Cases 3C and 5C respectively. The shale dewatering provided only 0.15% of the 13% recovery in Case 5C against 1.6% of 14.5% in Case 3C. From the study here the shale dewatering can be said to be insignificant if shale vertical permeabilities are about 10^{-5} millidarcys, although the intensity strongly depends on shale distributions. On the other hand, the shales of the vertical permeability as large as 10^{-4} millidarcys are expected to serve as an important driving energy, particularly in late stages of reservoir depletion.

Since magnitudes of uniaxial compaction coefficients are presently quite uncertain, the additional cases, Cases 6A, 6B, and 6C, were simulated with the estimates based on Geertsma's data [7]; $4.9 \times 10^{-7} \text{ psi}^{-1}$ for sandstones and $1.7 \times 10^{-6} \text{ psi}^{-1}$ for shales. The other conditions of Cases 6A, 6B, and 6C were the same as those of Cases 1A, 1B, and 1C, respectively. The result of Case 6A indicates that it would take about 60 years of production at the rate of 40,000 BWP D before the bottom hole pressure declines to 7,000 psia, but the reservoir with a 64 square mile drainage area could recover only 2% of the sandstone's initial water in place.

Figure 6 Shale Dewatering Effects on Reservoirs with a Middle Shale Layer (Cases 3C and 5C).

The productive reservoir lives of Cases 6B (16 square miles) and 6C (4 square miles) for the rate of 40,000 BWP D would be 16 and 3.8 years, respectively, and the recoveries are expected to be about 2% for both cases. Compared with the recoveries of 12% to 14% in Cases 1A through 1C, where compaction coefficients were larger by a factor of 10, this 2% recovery in Cases 6A through 6C is surprisingly small, implying the necessity of actual data of uniaxial compaction coefficients to assess realistic forecasts of geopressured reservoir performance. Figure 7 illustrates large differences of well pressure histories due to uniaxial compaction coefficients for the cases of 4 square mile drainage areas. In Case 6C, the production with the constant bottom hole pressure of 7,000 psia would last only a short period of time before the rate sharply declines. If uniaxial compaction coefficients of the Austin Bayou reservoir are of the magnitude of those used for Cases 1A through 6C, at least 15 square miles would be necessary as a drainage area per well even for large pay thickness such as is assumed in this study (840 feet). Furthermore, production would not be feasible if the reservoir of such compaction coefficients lacks sufficient areal continuity.

It is noted that the discussion has been made in terms of water recoveries, but gas recoveries were almost equal to them in all cases studied despite free gas phase flows under the assumption of negligible critical gas saturation.

3.2 SUMMARY OF RESERVOIR STUDY

It has been seen in the previous section that the uniaxial compaction coefficients of geopressured reservoirs would be a decisive factor in determining the feasibility of the reservoirs' development. Should the coefficients be of the magnitudes the Bureau of Economic is expecting, the prospect with the estimated area of more than 60 square miles will be able to produce for more than 20 years by

Figure 7 Effects of Uniaxial Compaction Coefficients on Well Pressure Histories (Cases 1C and 6C).

15 wells at the rate of 40,000 BWP D per well. However, if the uniaxial compaction coefficients fall about the values of $4.9 \times 10^{-7} \text{ psi}^{-1}$, extremely large reservoir volumes must be allocated to each production well. Combined with such compaction coefficients, thin geopressed reservoirs or reservoirs separated into small blocks by faults would make their development less promising.

Shales will serve to maintain reservoir pressures provided they are sufficiently permeable and are distributed as thin interbedded layers with substantial total thickness. The shale effects are anticipated to become important only in late stages of reservoir depletion, and improvement of reservoir behaviors will be rather moderate.

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