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ANALYSIS OF THE T-F&S GLADYS McCALL NO. 1 WELL TEST RESULTS AND HISTORY MATCHING SIMULATIONS FOR SAND ZONE NO. 8

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ABSTRACT

The flow and bottomhole pressure data have been analyzed for the two sands (Nos. 8 and 9) tested by the Gladys McCall No. 1 well. The more productive sand (No. 8) appears to be bounded by two linear faults at distances of ~ 740 feet and ~ 1360 feet from the well and there appears to be a decrease in the formation transmissivity away from the well. The formation properties inferred from the well test analysis have been used with a reservoir simulator to match the bottomhole drawdown/buidup history measured during the Reservoir Limits Test of Sand Zone No. 8. Wellhead pressure data measured during the long-term production testing of Sand Zone No. 8 have been employed to estimate the corresponding downhole pressures. The simulation model based solely on the Reservoir Limits Test is found to be in remarkably good agreement with the estimated bottomhole pressures for the first six months of production testing, but enlargement of the reservoir volume, by moving the boundary most remote from the well outward, is required to adequately match the full production history.

INTRODUCTION

As part of the DOE Geopressured-Geothermal Design Wells Program, Technodril-Fenix and Scisson (T-F&S) drilled, completed and is testing the T-F&S/DOE Gladys McCall No. 1 well located in Cameron Parish, Louisiana. A description of the geology of the field, well completion, log data and the test plan is presented in a report by T-F&S (1982). The test program was planned primarily to demonstrate the technological and economical feasibility of recovery of natural gas from geopressured-geothermal fluids and to generate data to define the nature and size of the reservoir, characterize the brine and natural gas produced, confirm the adequacy of the test well and surface facilities design, and control the associated scaling/corrosion problems.

The geologic interpretation of the Gladys McCall prospect by Magma Gulf Company is based solely on well logs from the subject well and five nearby deep wells. The approximate locations of three major growth faults considered to control the structure of the prospect are shown at 15,500 feet in Fig. 1; the east-west length of the fault block can not be determined from available information.

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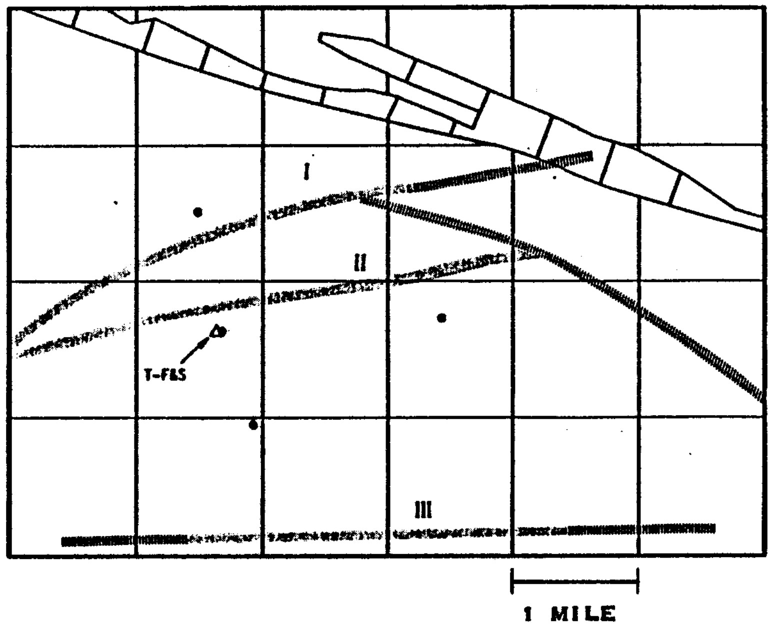

Fig. 1. Major growth faults at 15,500 feet with locations of T-F&S and nearby deep wells. Geology map prepared by Magma Gulf Company.

The Gladys McCall No. 1 test well was spudded on May 27, 1981, drilled to a total depth of 16,510 feet, and plugged-back to 15,831 feet. A 7-inch casing string (run as a liner) was cemented from the surface to 15,958 feet, and the well was completed with 5-inch production tubing. There are approximately 1,100 net feet of sand in the target Miocene sand penetrated by the test well. Over two-thirds of the productivity appears to be contained in three massive sand zones (Nos. 2, 8 and 9). To date only Sands 8 and 9 have been tested.

Laboratory tests (Kelkar and colleagues, 1982) gave average values for porosity and permeability of 0.168 and 83 md respectively. The formation rock was found to be quite stiff; a typical uniaxial compaction coefficient reported was 0.2 x 10^{-6} psi^{-1}. Since this value appears to be unrealistically small, we use a value for total formation compressibility (C_T = 6.27 x 10^{-6}psi) based on correlations for consolidated sandstone (Earlougher, 1977).

Brine chemistry studies by Rice University have shown that fluids produced from Sand Zones Nos. 8 and 9 are essentially identical. Weatherly Laboratories, Inc. reported the following properties of fluid samples recombined to approximate reservoir conditions (Sand Zone No. 8): brine compressibility = 2.76 x 10^{-6} psi^{-1}, dynamic viscosity = 0.31 centipoise, and bubble pressure = 9200 psia. Tests on Sand Zone No. 8 showed that the recovered gas increases from 22.9 to 29.7 SCF/STB as the separator pressure is reduced from 1000 to 250 psig. The incremental gas production (~ 6.8 SCF/STB), however, contains a large fraction of CO_2. The average for the total gas production from the well is ~ 30.15 SCF/STB. Average salinity of the brine is 97,800 mg/L.

SAND ZONE NO. 9 RESERVOIR LIMITS TEST

The 7-inch casing was perforated from 15,511 to 15,627 ft in preparation for testing Sand Zone No. 9 (15,508 - 15,636 ft). A Panex gauge positioned at 15,460 feet recorded the reservoir pressure (P_i = 12,911 psia) and temperature

(T_i = 298°F) prior to the Reservoir Limits Test. The well was opened on March 21, 1983 and production continued until April 14, 1983, (t_p = 570.6 hrs). Although there were intermittent gauge problems, transient downhole pressures were recorded during both the drawdown and buildup phases of the test.

The actual flow rates during the early stages of the drawdown ($t < \sim 20$ hrs) are not known, but for longer production times $q \simeq 4190$ sep bbl/day. The uncertainty in the early-time flow rate data does not allow reliable estimates of reservoir parameters for Sand Zone No. 9 to be made from the drawdown data, but the pressure data appear to indicate a doubling of the slope in the semi-log plot at $t = t_x \sim 29$ hrs. The Horner plot of the buildup pressure data is approximated by a straight line of slope $m_1 = -25$ psi/cycle up to the time at which gauge problems were encountered ($\Delta t \sim 18$ hrs). This fit holds for more than two log cycles and may be used to estimate formation properties. With $q = 4190$ sep bbl/day, $\mu = 0.31$ centipoise, formation factor $B = 1.01$ and $h = 128$ feet, the inferred formation permeability is $k = 162\ q\mu B/mh = 67$ md. A skin factor of $s = +0.54$ is computed from the buildup data.

Using $k = 67$ md, $\phi = 0.16$, $\mu = 0.31$ centipoise and $C_T = 6.27 \times 10^{-6}$ psi^{-1}, the distance to the fault corresponding to the doubling of the drawdown slope at 29 hrs is $L = 0.012\ [kt_x/\phi\mu C_T]^{1/2} \sim 960$ ft. The Cartesian plot of the recorded downhole pressures over the final ~ 145 hrs of the drawdown period are closely approximated by a straight line of slope $m^* = -0.332$ psi/hr. The slope may be still decreasing but can be used to compute a lower bound on the connected pore-volume, $V_p > 0.0418\ qB/C_T m^* = 85 \times 10^6$ res bbls. Because of the apparently limited volume of Sand Zone No. 9 it was sealed off with a plug set at ~ 15,500 feet in preparation for testing Sand Zone No. 8.

SAND ZONE NO. 8 RESERVOIR LIMITS TEST

Well Test Analysis

The 7-inch casing was perforated from 15,160 ft to 15,470 ft to test Sand Zone No. 8. A Panex pressure/temperature gauge was fixed at a depth of 15,100 feet to record stable conditions: P_i = 12,784 psia and T_i = 289°F. Production started on October 7, 1983, and the drawdown phase of the Reservoir Limits Test of Sand Zone No. 8 continued for 21 days (total flow $Q = 2.98 \times 10^5$ sep bbl; t_p = 505.5 hrs). Transient pressure data were recorded at 15,100 ft during the drawdown and subsequent buildup phases of the test (Figs. 2 and 3). There were no large variations in flow rates during the drawdown period. During the first ten hours $q \sim 13{,}800$ sep bbl/day; the average flow rate over full drawdown period is $q = 14{,}170$ sep bbl/day.

Significant portions of the semi-log plot of the bottomhole drawdown pressure data (Fig. 2) are approximated by four straight line segments. The data approximated by slope m_1 are influenced by fluid compression and thermal changes in the wellbore (wellbore storage effects). The second line segment, of slope $m_2 = -18.2$ psi/cycle, fits the data for a full log cycle and approximates data not significantly influenced by wellbore effects. The value of m_2 is assumed to reflect the reservoir response and will be used to estimate formation parameters. The third line segment (slope $m_3 \sim 2\ m_2$) appears to indicate the presence of a reservoir boundary which causes a doubling of the slope at $t = t_x \sim 9.5$ hrs. The fourth segment (slope $m_4 \sim 4\ m_2$), beginning at $t_x \sim 31.5$ hrs, probably represents a more distant boundary. With $q \sim 13{,}800$ sep bbl/day, $m = m_2 = 18.2$ psi/cycle, $\mu = 0.31$ centipoise, $B \sim 0.984$ and $h \sim 332$ ft, we obtain $k = 162.6\ q\mu B/mh = 113$ md. The associated skin factor is computed to be $s = +0.98$.

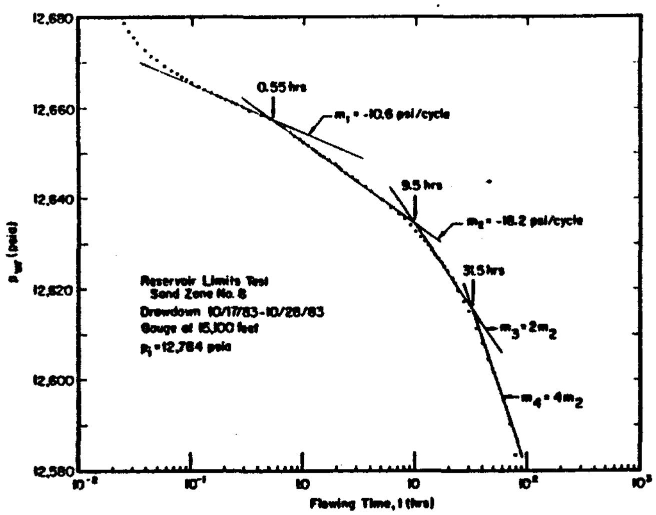

Fig. 2. Sand Zone No. 8 pressure drawdown semi-log plot.

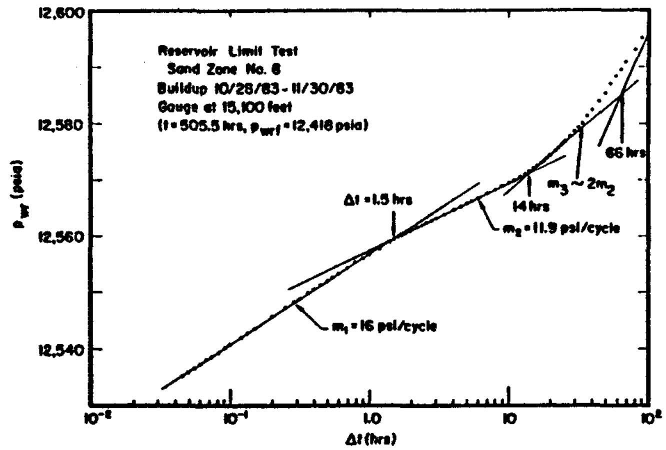

Fig. 3. Sand Zone No. 8 early pressure buildup semi-log plot.

The semi-log plot of the buildup (Fig. 3) data is approximated by three straight line segments. The segment of slope $m_1 = 16$ psi/cycle fits the data for one and a half time cycles, well beyond the duration of wellbore storage effects, and is assumed to reflect the infinite reservoir response portion of the buildup data. The buildup analysis yields estimates of $k = 133$ md and $s = +2.55$.

The doubling of the slope of the semi-log plot during drawdown at $t \sim 9.5$ hrs and $t_x \sim 31.5$ hrs (Fig. 2) can be used to estimate the distances to the two nearest faults, $L = 0.01217[kt_x/\phi\mu C_T]^{1/2}$. With $k = 133$ md, $\phi = 0.16$, $\mu = 0.31$ centipoise and $C_T = 6.27 \times 10^{-6}$ psi^{-1}, we compute $L_1 \sim 780$ ft and $L_2 \sim 1410$ ft.

The Cartesian plot of the recorded drawdown pressures over the final ~ 200 hrs of buildup are closely approximated by a straight line of slope $m^* = -0.347$ psi/hr, but the slope is still decreasing and hence corresponds to late-stage transient flow. If the drawdown had attained semi-steady state flow, the volumetric average pressure within the closed reservoir would be $\bar{P} = P_i + t_p m^* \sim 12{,}784 + (505.5)(-0.347) = 12{,}609$ psia. In fact, a value of $P_{ws} = 12{,}655$ psia was measured at $\Delta t = 785.5$ hrs, and the pressure appears to be still rising at that point. To estimate the reservoir volume, we hypothesize the P_{ws} in approaching $\bar{P}$ exponentially, i.e., $P_{ws} = \bar{P}(1 - \exp[-\Delta t/\tau])$. A semi-log plot of $(\bar{P} - P_{ws})$ versus shutin time yields a straight line for $\bar{P} = 12{,}676$ psia. With $Q = 2.98 \times 10^5$ sep bbl, $B = 0.984$, $C_T = 6.27 \times 10^{-6}$ psi^{-1} and $\Delta P = 12{,}784 - 12{,}676 = 108$ psi, the corresponding estimate for the connected pore-volume is $V_P = QB/C_T\Delta P = 433 \times 10^6$ bbl.

History Matching Simulation

The geologic map prepared by Magma Gulf Company (Fig. 1) shows two west-east growth faults (Faults II and III) to the north and to the south of the Gladys McCall No. 1 well, but their locations could not be fixed. The reservoir boundaries at the distances approximated by L_1 and L_2 are probably west-east growth faults. Since there are no wells to provide geologic constraints on the reservoir to the east and west of the subject well, we assume the east and west boundaries are equally distant from the well; this distance can be estimated from the reservoir volume approximation.

A rectangular reservoir configuration was used in the history matching simulation of the Reservoir Limits Tests of Sand Zone No. 8. Since the reservoir simulator employs the International System of Units, reservoir dimensions used in the history matching calculations were round numbers in SI units. The distances from the well to the two nearest boundaries (growth faults) are assumed to be $L_1 = 240$ m (787 ft) and $L_2 = 400$ m (1312 ft). The distances from the well to each of the two most distant boundaries are assumed to be 3300 meters (10,827 ft); the reservoir thickness is assumed to be $h = 100$ m (328 ft).

The simulations employed the following reservoir input parameters: initial pressure = 12,784 psia, fluid density = 64.33 lbm/ft^3, fluid viscosity = 0.31 centipoise, formation porosity = 0.16 and total compressibility = 6.27 x 10^{-6} psi^{-1}. The connected pore-volume assumed is $V_p = \phi V = V(0.16)\ (100)\ (640)\ (6600) \sim 67.6 \times 10^6\ m^3$ (425×10^6 res bbl).

The calculations employed a single-phase linear reservoir simulator to treat an areal representation of the reservoir. Each half of the symmetrical reservoir configuration is represented by a 13 x 18 numerical grid with the zone dimensions increasing away from the well. During the drawdown period ($t < 505.5$ hrs) of the Reservoir Limits Test the production rate from the well is 14,170 sep bbl/day; the diameter of the well is 7 inches.

A number of simulations were made in which the choices of the reservoir formation permeability (k) and skin factor (s) were varied. It was necessary to assume a decrease in the reservoir transmissivity (kh product) away from the well to account for the slowly changing slope in the Cartesian plot of the drawdown pressures and the slow buildup after shutin. A match to the drawdown/buildup bottomhole pressure history measured during the Reservoir Limits Test of Sand Zone No. 8 can be obtained by setting $s = 4.3$ and simply assuming a "near-well" permeability, ($k_1 = 160$ md) abruptly decreasing to a "reduced" permeability ($k_2 = 20$ md) at a distance of 1100 meters from the well (Fig. 4). The resulting excellent history match over the entire production/injection test period is presented in Fig. 5.

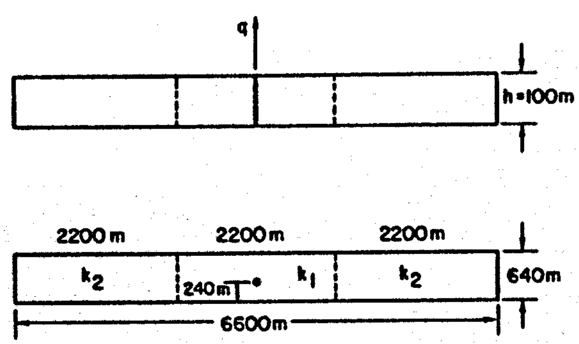

Fig. 4. Simulation model for Sand Zone No. 8 Reservoir Limits Test pressure history matching.

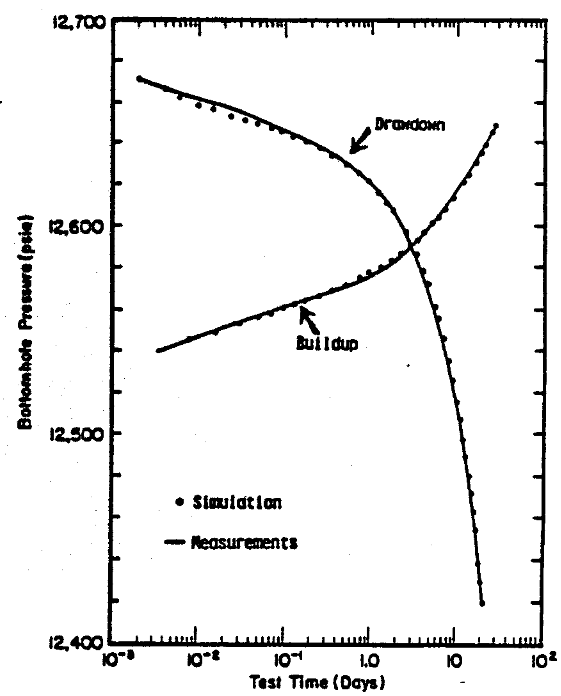

Fig. 5. Comparison of simulated and measured pressures for Sand Zone No. 8 Reservoir Limit Test.

The reservoir model described by Fig. 4 and the above reservoir parameters is by no means unique. An alternative history match simulation of the Reservoir Limits Test of Sand Zone No. 8 has been presented which is based on a conceptual model in which both reservoir thickness and permeability decrease with distance (Ancell, 1984). Predictions of future long-term reservoir response might differ substantially for simulations that are based on the different conceptual models.

SAND ZONE NO. 8 PRODUCTION HISTORY

Wellhead Versus Wellbottom Data

The cumulative production during the Reservoir Limits Test of Sand Zone No. 8 was $Q \sim 2.98 \times 10^5$ sep bbl whereas the cumulative production from this sand had reached $Q \sim 4.51 \times 10^6$ sep bbl by September 1984. Figure 6 shows the cumulative production and the approximate variations (over 60 rate changes) in the flow rate of the Gladys McCall No. 1 well during this one year period.

Since completion of the Reservoir Limits Test, only wellhead pressure (P_{WH}) measurements are available to estimate bottomhole values (P_{WB}). Under semi-steady state flow conditions, $P_{WH} = P_{WB} - \Delta P_{fric} - \Delta P_{hydr}$. Estimation of ΔP_{fric} is complicated in the Gladys McCall well by scaling on the inner wall of the production tubing, especially at production rates $> \sim 20{,}000$ bbl/day. When the well is shut, $\Delta P_{fric} = 0$ and it is only necessary to add the hydrostatic pressure to P_{WH} in order to approximate P_{WB}. Since the approximation ignores wellbore storage effects (afterflow and cooling in the wellbore), the inferred values for P_{WB} during the transient period following shutin may be in significant error. To evaluate the reliability of estimating P_{WB} from P_{WH} measurements made immediately after shutting the well, we examined the data from the Reservoir Limits Test of Sand Zone No. 8 during which both were measured. It was found that during the latter stages of the drawdown portion of the test ($q = 14{,}200$ sep bbl/day), $P_{WB} - P_{WH} = \Delta P_{fric} + \Delta P_{hydro} \sim 6992$ psi. Immediately after shutin, the measured pressure drop in the wellbore was $P_{WB} - P_{WH} = \Delta P_{hydr} \sim 6626$ psi. The corresponding frictional pressure drop (prior to significant scaling of the production tubing) is $\Delta P_{fric} \sim 6692 - 6626 = 366$ psi at $q = 14{,}200$ sep bbl/day.

The Reservoir Limits Test data also show that the measured values for ($P_{WB} - P_{WH}$) increase rapidly after shutting the well. Provided that P_{WH} is read at $\Delta t < \sim 3$ min, however, the error in estimating wellbottom shutin pressures from $P_{WB}]_{\Delta t=0+} = P_{WH}]_{\Delta t=0+} + \Delta P_{hydr} = P_{WH}]_{\Delta t=0+} + 6626$ psi should be less than ~ 40 psi. The values at $\Delta t = 1$ to 3 minutes are considered to be the best estimates since afterflow effects should be completed, but wellbore cooling should not yet be significant.

Figure 7 presents a plot of the available recorded shutin wellhead pressures and corresponding estimated bottomhole pressures. Although the production rates varied widely, the averaged rate (slope of the cumulative production curve in Fig. 6) is nearly constant through August 1984. The apparent change in the pressure decline curve (at $Q \sim 2 \times 10^6$ sep bbl) in Fig. 7 would not be anticipated on the basis of the reservoir model described above. The production history implies that there may be additional reservoir recharge that was not evident during the Reservoir Limits Test of Sand Zone No. 8.

There have been a number (see Fig. 6) of rather long periods during which the production was sustained at a rate $q \sim 15{,}000$ sep bbl/day. Since semi-steady state is approximated towards the end of each of these periods, the wellbottom flowing pressure just prior to shutin is $P_{WB}]_{\Delta t=0-} = P_{WH}]_{\Delta t=0-} + \Delta P_{fric} + \Delta P_{hydr}$. Prior to scale buildup (during the Reservoir Limits Test;

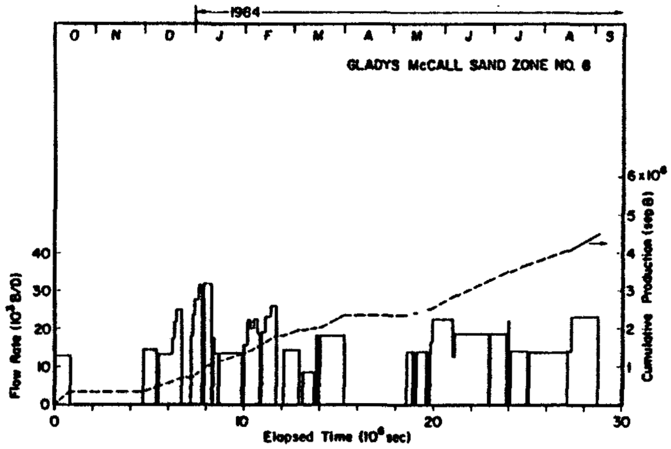

Fig. 6. Gladys McCall Sand Zone No. 8 production history through September 4, 1984.

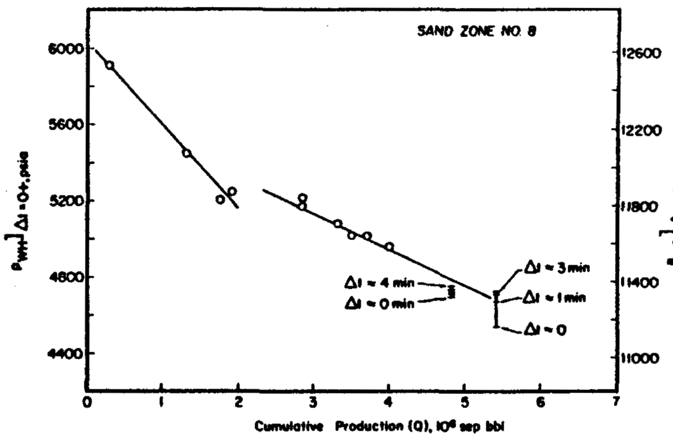

Fig. 7. Wellhead and estimated well-bottom (15,000 ft) shutin pressures during production testing of Sand Zone No. 8.

q = 14,200 sep bbl/day), (ΔP_{fric} + ΔP_{hydr}) ~ 6992 psi. The value of (ΔP_{fric} + ΔP_{hydr}) subsequent to scale buildup will increase by the amount that ΔP_{fric} increases. To illustrate the increase in ΔP_{fric} we have plotted the values of $P_{WH}]_{\Delta t=0-}$ + 6992 psi for production periods for which q ~ 15,000 sep bbl/day (Fig. 8; points denoted by *). The deviation of these estimates from the corresponding calculated wellbottom flowing pressures increases up to the time (~ 13 x 10^6 sec) when the first acid treatment was conducted by T-F&S.

Simulation of Production Testing

To test the adequacy of the reservoir simulation model described above (which gives an excellent match to the detailed downhole pressure history measured during the Reservoir Limits Test of Sand Zone No. 8) the calculation was continued through the numerous rate changes illustrated in Fig. 6. Figure 8 depicts the bottomhole drawdown and buildup pressure history that is predicted by the reservoir model over the simulated production period. The nine estimated values for the bottomhole shutin pressures, $P_{WB}]_{\Delta t=0+}$, during the production period are also shown in Fig. 8 (points denoted by o). The first four of these estimates are in excellent agreement with the simulated initial buildup values, but the last five estimates lie several hundred psi above the wellbottom pressures produced by the simulation. The late-time discrepancy corresponds to the late-time deviations in the average pressure decline curve (Fig. 7).

It is apparent that either the reservoir volume estimate based on the Reservoir Limits Test of Sand Zone No. 8 is too small, or there is some other operative reservoir response mechanism not considered in the simulation; we will simply assume that the volume is larger. Since the model provides an excellent fit for the earlier portion of the data, the required increase in the reservoir volume of the model is "remote" from the production interval of the Gladys McCall well.

Revised Reservoir Model

Figure 9 illustrates the reservoir simulation configuration employed in a series of calculations made to provide a match to the entire production history. Since

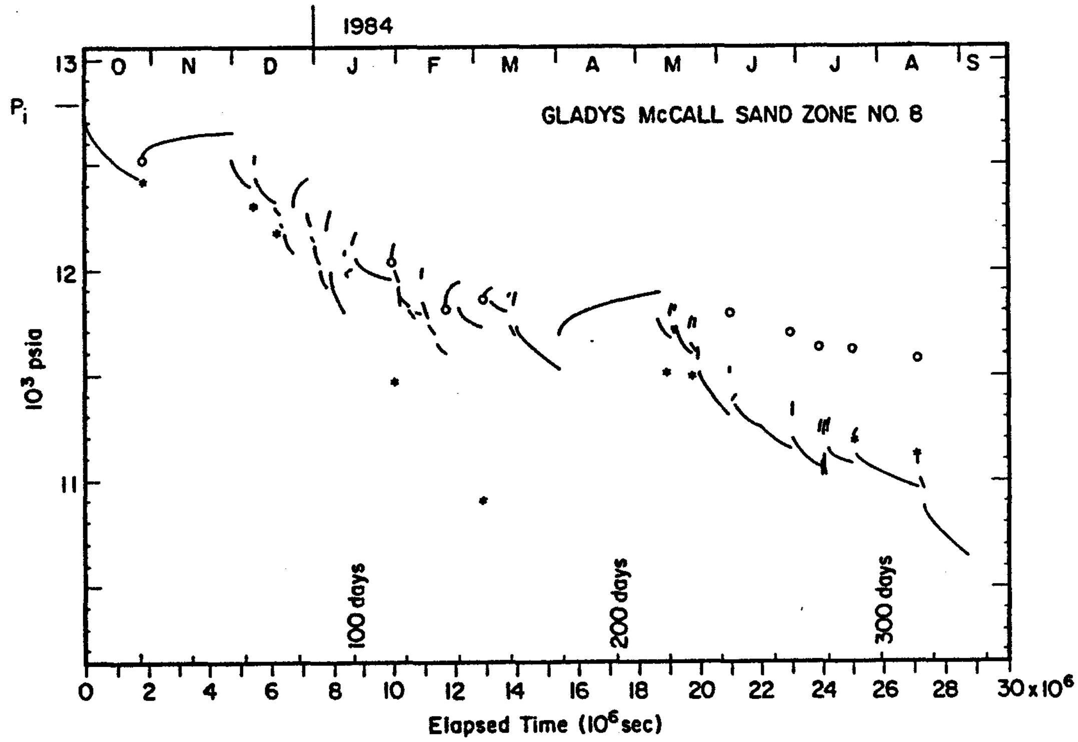

Fig. 8. Calculated bottomhole pressure during production testing of Sand Zone No. 8 using model based solely on downhole data for Reservoir Limits Test.

there is no information on the location of the hypothesized "remote" additional reservoir volume, half is added to each end of the configuration. The series of simulations employed the reservoir formation fluid and rock properties presented earlier. It was found that a match to the production history could be obtained by assuming that the "near-well" permeability (k_1 = 160 md) extends to a distance of 1100 meters as before and that the "reduced" permeability (k_2 = 20 md) applies for all of the reservoir volume that lies beyond a distance of 1100 meters. The reservoir thickness was taken as 100 meters (as before) out to 3500 meters distance from the well, but the "remote" volume beyond this distance was taken as 400 meters thick. The extent of the remote reservoir volume was varied in the series of seven simulations (Cases A through G) by changing the single parameter L (see table below).

Simulation No.	L 10^3m	V 10^6m^3	øV 10^6m^3	øV 10^6bbl
A	0.0	448	71.68	451
B	0.5	704	112.64	708
C	1.0	960	153.60	966
D	1.5	1216	194.56	1224
E	2.0	1472	235.52	1481
F	3.0	1984	317.44	1996
G	4.0	2496	399.36	2512

Case A (L = 0) is essentially the same reservoir configuration as used to match the Reservoir Limits Test of Sand Zone No. 8, but all seven cases give the same results over both the drawdown and buildup portions of the test. Even after 150 days the maximum difference in the calculated bottomhole pressures for the seven cases (i.e., between Cases A and G) is only about 40 psi. All seven cases may be considered to match the production history equally well up to this point in time since 40 psi is within the likely error in the values for the bottomhole buildup pressures estimated from the wellhead values. For elapsed times greater than 150 days, however, the effect of the remote volume becomes increasingly important. The simulated wellbottom pressures for $L \geq 1.5$ km (Cases D, E, F and G) are within 40 or 50 psi of each other for the full production history. On the other hand, the difference between Case A ($L = 0$) and Case G ($L = 4$ km) exceeds 500 psi at the end of the history.

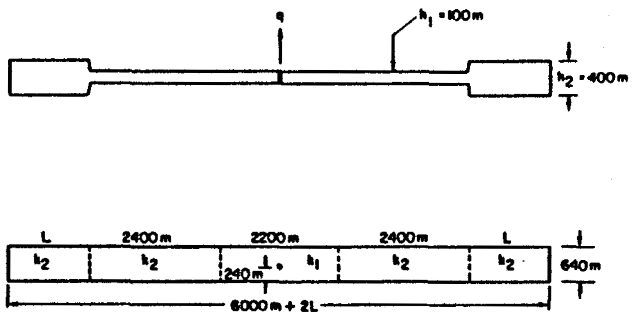

Fig. 9. Simulation model for Sand Zone No. 8 production history matching.

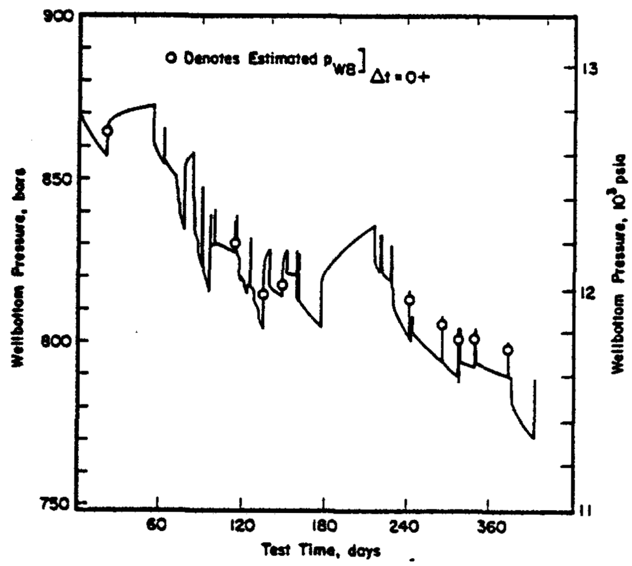

Fig. 10. Comparison of simulated (Case D) bottomhole pressures with estimates.

The late-time discrepancy between the simulated wellbottom pressures and the estimated wellbottom buildup pressures is eliminated by choices of $L \geq 1.5$ km. Figure 10 is a plot of the calculated bottomhole pressures over the production history of Sand Zone No. 8 for Case D ($L = 1.5$ km); the superposed nine estimates for the downhole buildup pressures are seen to be in good agreement with the simulated buildup pressures.

Cases E, F and G provide matches to the available pressure history data that are almost as good as that provided by Case D. The value of $L = 1.5$ km for Case D is therefore considered a lower bound and the revised estimate for the connected pore-volume is $V_p = \phi V > \sim 195 \times 10^6$ m^3 (1224×10^6 res bbl). This is approximately three times the pore-volume estimated solely on the basis of the data from the Reservoir Limits Test of Sand Zone No. 8.

CONCLUDING REMARKS

The available downhole measurements (for Sand Zones No. 8 and No. 9) give no indication of any nonlinear processes operating in the reservoir. The total production during the Reservoir Limits Test of Sand Zone No. 8, however, was less than two percent of the production to date and no further downhole measurements have been made in the Gladys McCall No. 1 well.

Estimated values for the downhole pressures in Sand Zone No. 8 (based on wellhead mesurements) during the production period indicate an apparent change in the slope of the pressure decline curve after a pressure drop of $\Delta P \sim 1,000$ psi (Fig. 7). In the absence of any direct evidence of nonlinear reservoir behavior, we have chosen to retain the assumption of linear formation properties in the reservoir model and to match the full production history by hypothesizing a larger reservoir volume; extra remote reservoir volume was added to the original reservoir model. The simulation model is not unique, however, and equally satisfying history matches might be obtained using alternate models. Even in the context of a linear model, the location of the added reservoir volume cannot be determined on the basis of limited data from a single well. The added "remote" reservoir volume may actually represent sands that immediately overlie or underlie Sand Zone No. 8. These neighboring sands may provide vertical recharge (crossflow) to Sand Zone No. 8 at some distance where intervening shale layers are pinched out. The fluids produced from Sand Zones No. 8 and No. 9 are indeed almost identical chemically.

Alternatively, the apparent change in the slope of the pressure decline curve could be the result of some nonlinear reservoir response mechanism. We note that the reservoir pressure drop at which the slope change occurs is essentially the same value as the pressure drop in the DOW/DOE L. R. Sweezy No. 1 well ($\Delta P \sim$ 900 - 1,100 psi) at which there was an apparent change in the rate of pressure decline (Garg and Riney, 1984). The Sweezy geopressured geothermal design well, however, displayed nonlinear response mechanisms during short-term flow tests.

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