DOE/ET/27112--3

DOE/ET 27112-3

DE83 005668

U.S. GULF COAST GEOPRESSURED-GEOTHERMAL RESERVOIR SIMULATION:
FINAL TASK REPORT (YEAR 4)

FINAL REPORT
for the Period

1 August 1979 - 31 July 1980

R. C. MacDonald
Kamy Sepehrnoori
H. Ohkuma

October 1982

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Printed in the United States of America

Available from:

National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, Virginia 22161

Price: Printed Copy: \$10.50
Microfiche: \$ 4.00

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CHAPTER 1

INTRODUCTION AND SUMMARY

The work described herein was performed for the Department of Energy's Geopressured-Geothermal Division under contract with The University of Texas at Austin. The purpose of this work is to develop methods for analyzing geothermal-geopressured reservoir production behavior and to predict such behavior in the future given specific exploitation scenarios.

This report summarizes work accomplished during the fourth year of this effort. During this year production well test data became available from the DOE's Pleasant Bayou #2 design well. Two relatively short term test periods during this year provided the first in-situ data for analysis. The results of the analysis of this data are given in Chapter 2. As yet, test periods sufficiently long in duration to ascertain in-situ compaction and shale dewatering effects have not been experienced.

During the fourth contract year a study was made of the effects of reservoir heterogeneities on production behavior. In particular permeability distribution and faulting of the reservoir sand were studied to determine the sensitivity of recovery to these parameters. The results of this work are presented in Chapters 3 and 4. In general, the results suggest that the permeability in the vicinity of the well is a significant factor in determining the life of the well. It follows that locating wells in high permeability areas is desirable. In addition, it was determined that faults occurring in the reservoir would have to be virtually sealing to have significant effect on recovery. This also suggests, as did the permeability study, that permeabilities remote from the

well are rather unimportant in determining the life of a well. Of course, these results are based on the study of the Pleasant Bayou reservoir and cannot be applied to other situations without careful analysis.

Another study completed during the fourth contract year was that of the effect of gas buildup around a producing well. This work is reported in Chapter 4. Gas will evolve from solution as the pressure is reduced on the aquifer water. The pressure reduction is expected to be greatest around the producing well. As the gas evolves from the water flowing to the production well it becomes trapped until a critical or residual free gas saturation is attained. This gas saturation may impede the flow of water and thus lower the productivity of the well. The results of this study indicate that this mechanism may indeed cause productivity loss for reasonable relative permeability relationships. Roberts¹³ has obtained the necessary gas-water relative permeability measurements for immobile gas saturations and determined that the gas blockage effect may be of significance.

Finally, rock mechanics research has indicated that specimens obtained from the Pleasant Bayou well have a tendency to creep. This phenomenon indicates that the uniaxial compaction model now incorporated into the reservoir model may not be appropriate given the relative significance of compaction in the production behavior of a geopressured-geothermal reservoir. Work is continuing on the incorporation of this phenomenon in a more rigorous manner into the reservoir simulation model.

CHAPTER 2

PRELIMINARY TEST RESULTS OF THE FIRST GEOPRESSURED-GEOTHERMAL DESIGN WELL, BRAZORIA COUNTY, TEXAS

The Pleasant Bayou #2 Geopressured-Geothermal test well was completed in the summer of 1979. The C sand of the Frio formation was selected for completion on the basis of core analysis, well logs, and drillstem tests. The purpose of this chapter is to summarize the results of the short-term production tests run on the Pleasant Bayou #2 well during 1979 and the Fall of 1980. These tests were analyzed using conventional transient pressure test analysis methods.

The most significant test run during 1979 was a ten-day drawdown test from December 3 to December 14 followed by a 20-day buildup period during which reservoir pressure response was observed. After a hiatus of nine months, a second production test was conducted over a period of 45 days beginning on September 16, 1980. The well was shut in on October 31, 1980. Pressure buildup data continues to be monitored.

Both production tests indicate a formation permeability of 200 millidarcies. The presence of a permeability interruption located approximately 3700 feet from the wellbore is also suggested by these tests.

During the last production test, a producing gas-water ratio of 20 standard cubic feet per barrel of produced water was observed. An additional 9-12 standard cubic feet of gas per barrel was found in the water downstream of the separator. The total gas-water ratio of 29-32 SCF/bbl is in reasonable agreement with laboratory data and correlations for this produced brine.

The major growth fault which forms the reservoir boundary to the northwest of the well is evident from the pressure drawdown data obtained during the last production period. The last production test also indicates an apparent rate-dependent skin effect.

2.1 Reservoir Parameters

The C sand reservoir is separated from the other sand members of the Frio formation by shale zones. As shown on the isopach map of the C sand after Bebout et al.¹, Figure 2-1, the reservoir is approximately 30 miles long in the southwest-northeast direction along the major growth fault which bounds the reservoir and averages 5 miles in width perpendicular to this major fault. The C sand reservoir body may be fragmented by cross faulting perpendicular to the major fault. However, the effects of this cross faulting on reservoir continuity must await the results of flow testing over extended production periods.

The C sand found in the Pleasant Bayou #2 well is 60 feet thick with a porosity of 17.6% determined from standard core analysis. Compaction coefficients on the order of $5 \times 10^{-7} \text{ psi}^{-1}$ have been reported by Gray et al.⁸ for the reservoir sand. However, these investigators have noted that this material exhibits creep behavior and therefore caution must be observed when using these data under the assumption of elastic rock behavior. Water properties have been computed from correlations by J. D. Clark³ assuming a gas saturated brine containing 130,000 ppm of dissolved solids. The following table summarizes the data used in the transient pressure test calculations:

Reservoir thickness	60 feet
Average porosity	17.6%
Uniaxial compaction coefficients	$5 \times 10^{-7} \text{ psi}^{-1}$
Pore compressibility	$2.3 \times 10^{-6} \text{ psi}^{-1}$
Water compressibility	$4 \times 10^{-6} \text{ psi}^{-1}$
Water viscosity	0.25 cp
Water formation volume factor	1.05 RB/STB
Wellbore radius	3.5 inches

2.2 Production Test Data

Clark³ has summarized the production test information obtained during the initial period in 1979. The first production from the well occurred on July 9-10, 1979, immediately after the well was perforated. Surface pressure measurements were taken as the pressure gauge would not operate at bottom hole conditions. Clean up of the perforations during this flow period caused interference with the test results.

From November 15 to November 18, 1979, three production periods occurred, the first two of rather short duration. The third flow period lasted over 2 days and provided the first significant test data. Problems with the bottom hole pressure gauge forced the termination of this test. The well was again put on production on November 23, 1979, and was shut-in on November 25 due once again to gauge problems. This testing period served primarily as a checkout of the equipment and procedures, as well as providing preliminary reservoir data.

The first substantial flow period for the well occurred from December 3, 1979 to December 14, 1979. During this ten day period, the well produced at an average rate of approximately 13,500 barrels per day. During this test, it was necessary to periodically move the pressure gauge in the well and, thus, the

pressure information is somewhat suspect, although later tests have confirmed the general validity of the results obtained from this drawdown period.

The first definitive data with respect to reservoir properties were obtained from the pressure buildup behavior observed after the December 3-14 ten-day production test. These data are presented in Figure 2-2 in the form of the conventional Horner plot, in which the logarithm of the time factor

$$\frac{T + \Delta t}{\Delta t} \quad (2.1)$$

is plotted against the observed pressures. The flowing time, T , is taken as the cumulative production divided by the last sustained flowrate before closing in the well. The time after shutin, Δt , corresponds to the measured bottom hole pressure observations. In this case, the cumulative production was taken to be 240,000 barrels, which includes all production from tests since July 1979. The last sustained production rate was 13,650 barrels per day, resulting in an equivalent Horner flow time of 422 hours.

Beginning on September 16, 1980 a 45-day variable rate production test was carried out. The production rate schedule for this test is given below:

<u>Time Period</u>	<u>t (Hours)</u>	<u>Production Rate (bbls/day)</u>
Sept. 16 11:30 am	127	6750
Sept. 21 7:50 pm	232	10920
Oct. 1 11:00 am	67	19102
Oct. 4 6:00 am	103	14060
Oct. 8 12:45 am	555	13500
Oct. 31 5:32 am	to present	well shut in

The results of this multirate drawdown test are given in Figure 2-3, in which the data have been reduced by the superposition principle as discussed by Earlougher⁵ to a plot of

$$\frac{P_i - P_{wf}}{q_n} \quad \text{versus} \quad \sum_{j=1}^N \frac{q_j - q_{j-1}}{q_n} \log_{10}(t - t_{j-1}) \quad (2.2)$$

If only one flowrate occurred in the test, then this plot would reduce directly to the more familiar plot of pressure drawdown versus the logarithm of the time. The initial pressure for this test was measured at 11116 psig @ 14560 feet.

The well was closed in on October 31, 1980, and the pressure buildup data continue to be monitored. The Horner plot of this information is given in Figure 2-4 and includes data through November 24, 1980. In reducing this buildup data, it was assumed that the reservoir had stabilized over the 10 month period, since the last production in December 1979, and that only production during the current testing period would affect the pressure buildup results. The Horner flow time, T , was computed to be 1011 hours based on a cumulative production since September 16, 1980, of 568,900 barrels of water and a final sustained rate of 13,505 barrels per day.

The buildup data obtained in December of 1979 and the multirate production test, together with the subsequent pressure buildup data, form the basis of the analysis presented in this paper.

2.3 Formation Permeability

Formation permeability is computed from the slope of the pressure buildup or drawdown plots shown in Figures 2-2 to 2-4 by the relationship:

$$K = \frac{162.6 q \mu B}{m h} \quad \text{or} \quad \frac{162.6 \mu B}{m' h} \quad (2.3)$$

where

q - production rate (bbls/day)

μ - viscosity (cp)

B - formation volume factor (RB/STB)

h - formation thickness (feet)

m - buildup slope (psi/ $\sim$)

m' - multirate drawdown slope (psi/ $\sim$ - bbls/day)

It is important to select the slope from pressure data which are no longer affected by wellbore storage effects caused by flowrate changes, but as yet are not affected by reservoir boundaries or lateral changes in formation properties. The permeability computed from the three tests is as follows:

<u>Buildup Tests</u>	<u>Production Rate (bbls/day)</u>	<u>m (psi/$\sim$)</u>	<u>Permeability (md)</u>
December 1979 (Figure 2-2)	13650	54.5	178
November 1980 (Figure 2-4)	13505	48.0	200

<u>Drawdown Test</u>	<u>m' (psi/$\sim$ - bbls/day)</u>	<u>Permeability (md)</u>
October 1980 (Figure 2-3)	0.0034	209

The somewhat lower permeability computed from the December 1979 buildup test data may be the result of uncertainties in the measurement of production rates during the preceding drawdown period.

Based upon these results and discounting the December 1979 test, we conclude that the formation permeability in the neighborhood of the well is 200 md.

2.4 Faulting and Boundaries

A perceptible change in the initial slope was observed in each of the three tests analyzed in this study. These slope changes are too subtle to be construed as a boundary or a sealing fault. However, they do indicate the presence of a change in formation transmissivity. The presence of a non-sealing fault could produce such an effect. The distance away from the wellbore at which this interruption might be found can be estimated from the relationship given by Earlougher⁵:

$$r_{inv} = \sqrt{0.00105 \frac{kt}{\phi \mu c_T r_w^2}} \quad (2.4)$$

where

- k - permeability (md)
- t - time of investigation (hours)
- ϕ - formation porosity
- μ - viscosity (cp)
- c_T - total effective compressibility (psi^{-1})
- r_w - wellbore radius (feet)

The following table summarizes these computations:

<u>Test</u>	<u>Time at slope change (hours)</u>	<u>Radius (feet)</u>
Dec. 1979 buildup	20	3672
Oct. 1980 drawdown	25	4449
Nov. 1980 buildup	18.4	3733

As observed on the plots, Figures 2-2 to 2-4, the time at which the slope changes is open to broad interpretation. Minor changes in the slope will substantially alter this time value. It is felt that the drawdown data is the most

tenuous in this respect, and thus it is concluded that the alteration in formation transmissivity occurs at a distance of approximately 3700 feet from the well.

Neither buildup test has indicated as yet any evidence of sealing boundaries. However, the multirate production test data do indicate the presence of a sealing fault, which we interpret to be the major growth fault that bounds the reservoir to the northwest. The slope of the data taken during the last half of the test is 0.0096 psi/(~ bbls/day) as compared to a consistent of 0.0053 psi/(~ - bbls/day) slope before this time. The virtual doubling of the slope is usually interpreted as indicating a sealing boundary. Determining the precise time at which the change in slope occurs is made difficult by the multirate effect on the generation of the reduced data used in the drawdown analysis. A time value of 530 hours was selected as the best estimate of the time when the slope change occurs. This value corresponds to a distance of investigation of 3.9 miles which agrees reasonably well with the geological interpretation of the growth fault. The buildup data presently being monitored should provide more definitive results in this regard.

2.5 Skin Effect

Analysis of the recently concluded multirate production test suggests that apparent near well damage effects (i.e., the skin effects) are dependent on the production rate. The skin effect may be computed from the pressure drawdown equation as documented by Earlougher⁵:

$$P_i - P_{wf} = m \left[\log_{10} \left(\frac{kt}{\phi \mu c T_w^2} \right) - 3.23 + 0.875 \right] \quad (2.5)$$

It is the usual convention to select the drawdown time as one hour, or

$$b = P_i - P_{wf}(1 \text{ hour}) = m \left[\log_{10} \left(\frac{kt}{\phi \mu c_T r_w^2} \right) - 3.23 + 0.87S \right] \quad (2.6)$$

where $P_{wf}(1 \text{ hour})$ is the pressure inferred from the straight line portion of the drawdown plot at a flow time of one hour. In the case of a multirate test, the analysis is similar except that both the slope, m , and the intercept (i.e., $t = 1$ hour), b , are normalized with respect to the last flowrate

$$m' = \frac{m}{q_n} \quad b' = \frac{b}{q_n} \quad (2.7)$$

and the skin factor is computed as

$$S = 1.151 \left[\frac{b'}{m'} - \log_{10} \left(\frac{k}{\phi \mu c_T r_w^2} \right) + 3.23 \right] \quad (2.8)$$

As shown in Figure 2-3, the initial flow period of the drawdown test exhibits a slope of 0.0034 psi/($\sqrt{t}$ - bbls/day) and an intercept of 0.0316 psi/(bbls/day). The skin effect computed from the above equation for these conditions is 2.96, indicating moderate well damage.

The method of superposition is used to analyze the effects of the multiple production rates on the drawdown behavior. As such, the plot of,

$$\frac{P_i - P_{wf}}{q_n} \quad \text{versus} \quad \sum_{j=1}^N \frac{q_j - q_{j-1}}{q_n} \log_{10} (t - t_{j-1}) \quad (2.2)$$

should be a continuous progression of points. However, as observed in Figure 2-3 there is a noticeable upward discontinuous shift in the data as the production rate is stepwise increased. The slope of each curve does remain the same. We have interpreted this behavior as an indication of a rate-dependent skin effect.

The skin factor for each flowrate has been computed from equation (2.5) by extrapolating a value for the intercept b' , taking into account the change in slope observed during the initial flow period. The skin factors computed are:

<u>Flowrate (bbls/day)</u>	<u>Skin Factor</u>
6750	2.96
10920	4.96
19100	6.98

These skin factors are plotted versus production rate in Figure 2-5. Also shown on Figure 2-5 are the skin factors computed from each of the buildup tests. The buildup test skin factors fall below the multirate drawdown trend, but are greater than the initial low flowrate skin factor.

The most plausible explanation for this behavior is the possibility that particle fines loosened in the formation near the wellbore during drilling and completion are pushed into pore throats at high production rates, thus reducing the permeability near the well.

An alternative explanation may be that non-darcy or "turbulent" flow occurs near the well at higher flowrates. For this to occur, only a relatively small portion of the perforated interval could be open to flow in order to generate localized fluid velocities high enough to cause the non-darcy effect. Furthermore, if it were postulated that only a few feet of perforations were open to flow, then the skin effect caused by limited entry alone would be substantially higher than that observed.

The effects of gas evolution about the wellbore, should it occur, would not explain the observed behavior since the accumulation process is a gradual one, rather than an abrupt transition, as indicated by the test data.

2.6 Future Testing

In the short term, the pressure buildup following the last 45-day production test will continue to be monitored. It is hoped that a buildup period of at least 90 days will be observed before production begins again, so that the maximum amount of reservoir information, such as the presence of boundaries and potential reservoir depletion, can be extracted. Although the sensitivity of the pressure measurements are excellent, the degree of accuracy in the measurements necessary to detect depletion at the current cumulative production level is questionable. Note the pressure discontinuity shown in Figure 2-4 at the late time buildup due to pulling and rerunning the pressure gauge in the hole for necessary maintenance.

The most crucial reservoir data to be obtained will require an extended production period. Specifically, the continuity of the reservoir laterally along the growth fault and the overall areal extent of the reservoir must be detected by depletion. The contribution of water from the contiguous shale zones and the accessibility of other sands through the shale zones will require extended production and reservoir pressure monitoring.

Finally the in situ effects of reservoir compaction on reservoir production may only become evident after a substantial pressure drawdown is obtained in the reservoir.

The analysis of long-term production behavior and the effects described above will require the use of reservoir simulation models.

2.7 Conclusions

Analysis of test data from the Pleasant Bayou #2 well completed in the Frio C sand indicates:

1. The reservoir permeability is approximately 200 md.
2. The producing gas-water ratio is 20 SCF/Barrel and the total gas-water ratio is 29 to 32 SCF/Barrel.
3. A permeability alteration due to a change in sand characteristics or, alternatively, a non-sealing fault is located about 3700 feet from the well.
4. The major growth fault that bounds the reservoir to the north is evident in the last multirate pressure drawdown test data.
5. An apparent rate sensitive skin effect has been interpreted from the multirate production test data.
6. Moderate skin damage in the well has been determined from each of the pressure transient tests.

CHAPTER 3

GEOPRESSURED-GEOTHERMAL RESERVOIRS

3.1 Geology of Deltaic Systems

Geologically determined parameters are crucial in determining reservoir performance. The fact that the Pleasant Bayou Well #2 is completed in a deltaic system offers insight into the reservoir parameters that will influence production behavior. The geological history of similar deltaic structures aids in this evaluation. The parameters to be investigated are porosity, permeability, thickness, and faulting. They directly influence behavior of the reservoir, and isolations in their values across the reservoir may be determined through geological analysis. In this chapter descriptions of the deltaic systems, specifically those in the Pleasant Bayou well area, will be discussed.

To create a reservoir capable of producing reservoir fluid, that rock body must have been deposited and later buried so that the desired fluid components were trapped. The most significant sedimentary process resulting in depositional units is the deltaic system. "A delta is a river-fed depositional system that results in an irregular progradation of the shoreline."⁶ The deltaic system is an extremely complex one, composed of many different distinct depositional environments and their resulting facies. The delta is an extremely active system, continually altering locations and reworking sediments.

Several variables directly affect deltaic formation, such as deposition rate. Also important are the nature of the discharging water body as well as that body it is emptying into, the reservoir body's energy (tides, currents, waves), and

the structure of the basin being formed.

Near the mouth of the river where it flows into a basin, a channel mouth bar (or distributary bar) is formed by bed load being deposited due to sudden velocity decrease at the river mouth. If flood occurs, these bars may be breached as well as the levees along the sides of the channel. The result is a crevasse. Bed loads carried by channels tend to move to areas of low velocity. So when a crevasse occurs, some of the bed load is diverted, creating a crevasse splay. The splays increase the areal extension of deltaic plains already present. A deltaic cycle occurs when these channels and splays continue to "create the delta" until the distributaries overextend. Then abandonment results, characterized by "subsidence and a reworking of the deltaic deposits by marine processes."⁶

Sand facies make up the foundation of the delta, i.e., distributary channels, delta front facies. Active channels are mainly filled with the coarsest material the river is carrying. There is a great deal of crossbedding since the detritus is continuously being swept out during flooding with more being laid in its place when the flooding recedes. The sand is normally uniform in thickness up and down channel, generally poor to moderately well sorted. When the channel is being abandoned the sediments become finer with decreasing velocity. The result is an "upward fining sequence."¹¹

Subaerial levee facies are originated from bank overflow during flooding. The levees themselves are mainly sands, being the thickest and coarsest adjacent to the channels. It grades laterally outward into the interdistributary muds and organics. Trees and plants in nearby marsh-like environments are the sources for these organics.

Delta front facies are the coarsest sediments associated with delta

progradation, according to Scott and Fisher,⁶ and average about 75% or more sand. These sediments come from deposition on the channel mouth bar or material that has been swept by currents from the channel mouth bar.

Distal delta-front facies comprise the base of the progradational depositional sequences. These deposits grade upward into fine to very fine grained sandstones interbedded with thick shale.¹ The sand originates from sporadic flooding.⁶ Porosity may be as low as 5%.¹

Distributary mouth bar sands are clean sands with abundant, multidirectional cross bedding. "As the distributary bar advances seaward, it overrides highly compactable pro-delta muds, burying organics in the muds."⁶

3.2 Geology of the Frio Sands

Several sand systems of geopressure-geothermal potential exist parallel to the Gulf Coast of Texas. Of these, the Brazoria system or fairway is considered to be the most promising in Texas. The Brazoria Fairway extends 30 miles inland, centered at Galveston Island, Texas, as is seen in Figure 3-1. The fairway is characterized in general by high temperatures greater than 300°F, permeabilities over 75 md as well as relatively thick sands, each in the range of 30-60 ft. It is divided on the NW flank by a major vertical NE/SW trending fault, the downthrown side being to the SE. The Brazoria Fairway is broken up by many growth faults also trending NE/SW with the downthrown sides usually to the south. Three major dome structures (salt) are found in the west and southwestern areas.

Two geopressured wells, Pleasant Bayou Wells #1 and #2 have been drilled into the Oligocene-aged Frio Sandstones in the Brazoria Fairway. Well #1 was

drilled but lost and ultimately plugged back to 8581 ft. Well #2 was then drilled 500 ft from Well #1 and was completed to 16,500 ft. Pleasant Bayou Well #2 is located in the SW 1/4 of Section 7, 6S-39E, Brazoria County, Texas.

These two wells, within the Austin Bayou prospect, lie on the southwest flank of a subsurface dome that is centered beneath the oil producing Chocolate Bayou Reservoir. The wells are surrounded by a series of growth faults which pinch out generally parallel to the Gulf Coast, as is seen in Figure 3-2.

The Frio Sandstones at the Pleasant Bayou well location begin at a depth of 13,960 ft. The sequences are shale-sandstone cycles, with prodelta shale at the base, delta-front shale and sand in the middle, and delta-plain sandstone and shale at the top.² A repetition of these cycles, in vertical sequences, is seen in Austin Bayou. This sequence in general describes the historic advance of the delta into the sea.

The shape of the front of the delta is fan-like. As sediment is brought downstream to the river mouth the delta begins to broaden as well as thicken. Coarser material is taken further out and deposited, creating a channel system. The result is shale silt at the delta base with gradually increasing coarseness occurring upwards. Correspondingly, the sediments alter from silty clay material to fine sand and later coarse sand. Increasing porosity usually follows this facies change forming a lobate delta,² as is seen in Figure 3-3. The change in river velocity intensity has direct effect on the rock grain size and matrix. The result is a characteristic variation in permeability for each area of the delta. To be able to estimate the permeability of a sand as a function of the location in the delta is very important to this study. Not all areas in the reservoir have been drilled or logged, so information about the general reservoir characteristics of that area is

still needed. Estimates of porosity and permeability as well as thickness can be made from knowledge of the reservoir's geological history.

It is these deltaic cycles that are seen in the Austin Bayou area. Each time a new cycle begins, a new deltaic structure is formed, accounting for the different sand layers totalling 660 net feet of sandstone found at Well #2. This is broken into six different facies sequences of sandy sediments each thought to be continuous. They are entirely embedded in thick sections of continuous shales. This isolation serves to restrict flow between the sands, since fluid flow cannot pass through the shales. The six sands were identified by the Bureau of Economic Geology (BEG) as Sands, A, B, C, D, E, F, with Sand A being at the top. This means of identification has been adopted in this study. Sands D, E, F were combined into one thick unit by the BEG due to lack of information at those depths. Because of lack of well control at those depths, this study is limiting its scope to Sands A, B, C.

3.2.1 Sand C

Sand C is a fairly thick sequence of deltaic sands assumed to be interconnected, as is seen in Figure 2-1. Some shale interbedding exists but does not halt flow. One hundred feet of net sandstone were encountered at Well #2. According to Loucks¹⁵ the C Sand contains approximately 60 ft of good sand, high quality being medium to coarse grained. This provides for the best conditions for fluid flow. The remaining 40 ft is considerably less permeable due to a fine silt to clay size matrix. It is characterized as a "dirtier sand". Within the entire 100 ft section are three main sand thicknesses of 5 ft, 60-70 ft, 10-15 ft.

Dimensions of Sand C indicate a length of at least 34 miles along the fault and maximum width of 17 miles. Five fingerlike lobes extend southward from the fault. Well #2 is located in the thick central area of one of these lobes. Being in the main channel allows for more sand coarseness. Also in the channel there is usually better sorting, resulting in more uniform reservoir characteristics--better porosities and permeabilities. With still thicker sands northwest of the location it seems reasonable that the porosities and permeabilities should stay fairly constant in the updip direction. Downdip will result in change from the medium coarse grain size to fine and eventually grading into shales. According to Loucks¹² the quality of C Sand may extend as far as 2 miles E and W of Pleasant Bayou Well #2, as well as 4 miles NW to the major growth fault and 2-1/2 miles downdip before facies changes are encountered. He also noted that it is unusual to find the coarseness of sand downdip that is found at Well #2.

Occasional calcified lenses have been found at the top of C Sand at 14,650 ft. At Well #2, the lense was 4 ft thick but was mpm-existent at Well #1. Other 1 ft thick calcified streaks were found in Well #1. Whether these streaks are actually lenses is unknown due to lack of well control.

3.2.2 Sand B

The younger deltaic sediments of Sand B are also thinner and have reduced extent in comparison to Sand C. Sand B has a maximum of 50 to 60 ft of sand as is seen in Figure 3-4. Only four major lobes extend southward. The maximum width attained by Sand B south of the major fault is about 12 miles, with many bays reaching back nearly to the scarp.

Much less force originating from the river system resulted in less protrusion into open water. Drainage was concentrated into the four lobes. A change in conditions resulted in abandonment of the southern-most distributary. A broad floodplain composed of fine silty sands lies about 10 miles SW of Well #2.

The well is located on the eastern flank of one of the major midsand lobes. About 50 ft of sand are present at Well #2. Being on the edge of the lobe may result in finer sands with some siltiness, rather than the coarser sands found in C Sand. From SP logs the cleanest sands are in the central third of the B Sand. There is a great deal of thin sand-shale interbedding. Two-10 ft sand sections above and below the central portion show more promise of sand homogeneity.

3.2.3 Sand A

Sand A is a thicker zone than Sand B, with thicknesses reaching 120 ft in a main lobe, as is seen in Figure 3-5. Its deltaic structure is also more complex than that in Sand B. It extends for at least 30 miles along the south side of the major growth faults. It is composed of a major distributary channel, 10 miles SW of Pleasant Bayou Well #2, depositing 120 ft of sand in a broad flood plain.

Well #2 is located on the NE flank of a major depositional lobe to the east, with a crevasse splay separating the two major depositional areas. The channel at this location is quite narrow - 3/4 mile wide at the sand top. About 50 ft of continuous sand was found in Pleasant Bayou Well #2.

From the SP log a shale zone is found at the base of Sand Sequence A at Well #2. Two sandy sections in the upper half of the zone, each 7-10 ft thick, are separated by shaley interbedding. This is indicative of relatively short

environmental change-- from fine, silty delta-front to levee sands. Radical porosity changes correspond to the facies change.

In the analysis of Pleasant Bayou Well #2, no evidence of faulting was found cutting the well,¹² despite the extensive fault history in the area. Many of the smaller branching growth faults within 5 miles of Well #2 are 4-5 miles long and pinch out in the well's vicinity. The slip along the fault plane is generally greater than the width of the sand bodies.¹² This separates the zones in the fault blocks. It is not known how much actual sealing has resulted across the fault which might serve to isolate the well from the reservoir fluid flow. The fault planes may be clean or they may be heavily fractured with a disturbed zone extending outward from the fault.

The lateral path that the fluid may take may be assumed to be distorted due to the faulting. Most of the faults in the area extend to at least 15,000 ft, while many have been found reaching 18,000 ft depths in the Southern Chocolate Bayou area, 7 miles SE of Well #2. If the fault zones are not considered too extensive, with little sealing then the flow of fluid through the reservoir may be slowed but not halted.

Vertical communication should be good within the sand layers, especially where little shale interbedding is present. Occasional calcified lenses should have only very localized effect resulting in no regional, vertical communication problems.

It must be noted, however, that while some sands of substantial size have been found and traced laterally throughout the Austin Bayou area and northeastward into Chocolate Bayou, this is still an overall series of shale-dominated sediments. The sands are locally continuous but do pinch out eventually. It is the

shales which are the true continuous feature on large scale, serving to totally isolate the major Sand A, B, C zones.

3.3 Engineering Aspect of Geothermal Energy in Geopressured Conditions

Beneath the earth's surface two types of energy environments are present. In one the forces are in equilibrium, while in the second, they are not. In the latter case, the result is fluid flowing in an attempt to attain this potential energy balance.¹² It is known as a hydrodynamic environment. It is this concept that is to be dealt with in this study.

Within this changing environment, two main concepts must be recognized. First, most burial of sediments, especially those connected with organics, occurs under water. Some water is trapped and buried along with the sediment. Further deposition causes a tremendous overburden weight. Rocks are not totally impermeable, even clays. Therefore, overburden pressure results in expulsion of the trapped water until the excess internal pressure is dissipated. However, those rocks (clays) that have very low permeability do not release the confined fluid at a very rapid rate. Abnormally high pressures may be present for an extended length of time until the confined water which has assumed the load is expelled. The result of this pressure differential across the rock membrane is fluid movement.

Potential energy is created by the sediments' weight, that of the trapped water, or both. According to Smith and Thomas,¹⁴ the compaction mechanism of the Gulf Coast sedimentary system is typical of the first weight of sediments. As overburden increases, compaction of the underlying sediments continues. The result is the accumulation of excess waters within the sediments. A potential

energy in the deeper water is generated by the sediment weight and hydrodynamic flow is initiated.¹⁴ The fluids may move vertically or laterally but always toward areas of lesser potential energy in obedience to Darcy's Law. If the fluid flow is restricted by low permeabilities, then the interstitial fluid must assume more of the weight of the overlying rock. Abnormal pressure will then be generated within the confined fluid. This generation of abnormally high potential energy by compaction and by inhibition of fluid flow is the origin of geopressed fluids.

The origins of abnormal subsurface pressures lie in several natural elements as discussed by Hubbert & Rubey.¹¹ Compaction, time, lithology, rate of deposition, as well as resistance to fluid expulsion contribute to the creation of abnormal pressure.

By mechanically imposing a load upon the fluids in excess of the weight of the overlying waters, abnormal pressure may be generated. Generally the greater the inhibition to flow, the higher the fluid pressure.

3.3.1 Static Load

Static load is that vertical force that is exerted downward by shallow sediments on deeper sediments during burial and compaction. Abnormal pressure will be generated in the formation fluids within the reservoir rock if the static load increases at a higher rate than the excess water can be expelled. While the system is still in equilibrium, fluid pressure is higher than hydrostatic for a given depth in order that the rapidly adding external pressures may be equalized. Harkins and Baugher⁹ have shown that where continental and transitional sands

overlie deep water shales, abnormal pressures will usually first occur regionally within the section where the sand percentage has decreased to 5-10%. Time has been observed to be an integral part of this process of dissipating the high potential energies that have been created in the fluids, since generally the younger the reservoir rock the higher the pressure.

Vertical compression has been an important factor in the origin of Gulf Coast abnormal pressures. The tectonic history of the Gulf Coast indicates that the youngest shales have never been disturbed by any major structural movements. Therefore, it is felt that vertical compression is the only mechanical stress which has been imposed on them.¹⁴

A "normal" hydrostatic gradient may vary from 0.426 psi/ft to 0.465 psi/ft.²⁰ The normal gradient in subsurface strata varies widely among geologic provinces due to fluid, pressure, and temperature differences. The density of the fluid is markedly affected by its salinity. Harkins and Baugher⁹ showed that the most practical "normal" gradient for the Gulf Coast region is 0.465 psi/ft, corresponding to a NaCl equivalent of 80,000 mg/l TDS.

The top of the abnormal pressure section can be encountered anywhere below 3000 ft but the top is usually consistent within regional fault blocks.⁹ With vertical compression, the top may vary both in depth and gradient value. Abnormal pressure gradients may increase upward gradually from normal values to 0.67 psi/ft over an interval of 2000 ft, or may increase abruptly to 0.88 psi/ft in less than 300 ft.¹⁴ In the Gulf Coast area, especially in younger rocks, fluid pressures may increase to a value almost equal to the entire lithostatic weight of the overburden, or about 1.0 psi/ft.¹⁴

3.3.2 Uplift

Uplift may also cause abnormal pressures. It must be accompanied by a process which decreases the depth of a compacted rock below the surface. If the uplift proceeds at a rate faster than the potential energy that is being generated by the compaction within the interstitial fluid can be dissipated, then the fluid pressure which is gradually lessening will be abnormally high for that new depth. It appears that only a high-energy structure such as a salt or shale diapir, is responsible for generating the high pressures seen in the Gulf Coast areas.¹⁴ However, simple uplifting is not really sufficient unless as the buried rock is moved upward there is further change in reducing the relief between the buried rock and the ground surface. The latter occurs through erosion or tension faulting.

3.3.3 Fluid Density Contrast

Abnormal fluid pressures may also be generated in sediments if there is an accumulation of low density fluids (i.e., oil, gas) that displaces formation waters. The potential energy in the column of fluid is similar to the buoyant effect of the displaced water. The formation fluid pressure within the water at the base of the column will be distributed upward throughout the entire fluid column.

Abnormal pressure gradients would range for this system of fluid (gas) over water from 0.50 to 0.55 psi/ft, depending on depth.¹⁴ According to Smith and Thomas,¹⁴ the pressure abnormality is more severe when the gas accumulation is at a shallow depth.

An average oil gradient is about 0.325 psi/ft. The potential energy at the

top of an oil column can then be estimated by subtracting the oil gradient from the normal hydrostatic gradient of 0.465 psi/ft.

The Brazoria Fairway topography is characterized by folding punctuated by salt domes. Uplift of the deltaic sands and shales due to salt flows below is a major cause of the abnormal pressure gradients in the area. Since shales of low permeability limited the rate at which the interstitial fluid could be dissipated, the high pressures remained in the formation. More pressure is applied by continual burial. The static load, increasing faster than water can be expelled, also builds high pressures. The resulting pressure gradient for Brazoria County lies between 0.465 and 0.98 psia/ft.¹ It is these two origins of abnormal surface pressures working together that have created the geopressured conditions in the Brazoria Fairway.

CHAPTER 4

PRELIMINARY ASSESSMENT OF PRODUCTION PERFORMANCE AT THE AUSTIN BAYOU GEOPRESSURED RESERVOIR

4.1 Characterization of the Austin Bayou Reservoir

A series of computer simulations were carried out to demonstrate the potential importance of several reservoir mechanisms and at the same time to obtain a preliminary assessment of the Austin Bayou geopressured geothermal prospect.

4.1.1 Fluid Property Data

Common to all the cases studied were the fluid data and the production strategy. The fluid properties were estimated based on the assumption that the water was saturated with methane, 26 SCF/STB at the representative initial reservoir condition of 11,000 psia and 300 °F. This solution gas-water ratio corresponds to the total solid of over 200,000 ppm that considerably differs from the observed total solids, 130,000 ppm. The estimation was made in favor of the solution water-gas ratio measured at the Pleasant Bayou #2 well. The fluid properties were input as piecewise linear functions of pressures at the assumed uniform reservoir temperature, 300 °F. Figure 4-1 shows the liquid formation volume factor B_w and the solution gas-water ratio R_s , Figure 4-2 the vapor formation volume factor B_v , and Figure 4-3 the viscosities of liquid and vapor, μ_w and μ_v , respectively. The combined effect of liquid expansion, liberation of solution gas, and expansion of liberated gas (vapor) is equivalent to the total fluid

compressibility of $4.5 \times 10^{-6} \text{ ps}^{-1}$. The liquid viscosities slightly increase with pressure but remain essentially constant for the range of pressures encountered in geopressured aquifers during production.

4.1.2 Areal Study of Sand C

Cases 1 through 10 were the areal model studies of the Sand C reservoir. The areal domain was superimposed with 34×13 finite difference grid net, each grid cell being a 1 mile by 1 mile, with the x-axis coinciding the northwest boundary fault (Figure 4-4). The parameter distributions were based on the geological interpretation described in Chapter 3. The thickness was digitized for each grid cell from the net sandstone map. The isopach map of Sand C generated from the digitized thicknesses at grid nodes is shown in Figure 4-5. The porosity distribution throughout the reservoir (4-6) was estimated from the geological interpretation of the structure and depositional history, acknowledging extensive secondary porosity. The permeabilities were calculated from porosities assuming a linear relation between the two parameters. This linear relation (Figure 4-7) was established from data at a number of wells penetrating into geopressured zones within and near the Austin Bayou prospect. The permeability was assumed to be isotropic. Figure 4-8 illustrates the permeability distribution of Sand C. The change of the reservoir depth in the direction perpendicular to the northwest boundary fault (y-axis) were sufficiently small and ignored in this study. Grid cells outside the southern reservoir boundary were given small values for thicknesses, porosities and permeabilities. The depth varied along the x-axis from 18,300 to 13,200 feet with the updip of about 1.6° toward the northeast reservoir boundary (Figure 4-9). These parameter distributions can be considered as the best estimates at this early stage of exploration.

Uniaxial compaction coefficient of Sand C was assumed to be 5×10^{-7} psi^{-1} as reported by Gray et al.⁸ and was independent of pressures. This value is equivalent to the pore compressibility of 2×10^{-6} psi^{-1} for the sandstone having 20 percent porosity. Rock matrix compressibilities were neglected throughout this study. The capillary pressure curve assumed in this study is shown in Figure 4-10. The relative permeabilities were estimated from Corey's formula with the critical gas saturation of 36 percent and the irreducible water saturation of 20 percent (Figure 4-11).

A single well was placed at the location of the Pleasant Bayou #2 well and produced at the constant rate of 20,000 BWPD. When the reservoir became unable to sustain the rate, the well continued to produce at reduced rates with flowing bottom hole pressures held at the minimum required pressure, 7,000 psia.

Varied parameters for the areal studies of the Sand C reservoir are summarized in Table 4-1. Cases 1 and 2 were to investigate the effects of reservoir compaction. In Case 1 uniaxial compaction coefficients were set to zero so that the reservoir would produce by fluid expansion only. Case 2 assumed the above-mentioned compaction constant. To study the impact of permeability level, uniform permeabilities of 150, 100 and 50 md were assigned to the reservoirs of Cases 3, 4 and 5, respectively. The porosities for these cases were also uniform at 21%, while the other reservoir characteristics were unchanged from Case 2.

Minor faults trending perpendicular to the NE/SW major growth faults are known to exist in the Austin Bayou area but their areal and vertical extents are vastly unknown. Cases 6 through 10 were to study sealing effects of these minor faults. The basic data in these cases were the same as those in Case 2 except two

minor faults. The faults were located at about 2.5 miles west and east of the well and extended across the reservoir from the northwest boundary fault to the south reservoir boundary (Figure 4-4). The fault's sealing capability or leakage was accounted for by the permeability across the fault; 0.001, 0.1, 1.0, 5.0, and 30.0 md for Cases 6 through 10, respectively.

4.1.3 Cross-Sectional Study of Sand/Shale Sequence

Reservoir parameters used for the cross-sectional studies are listed in Table 4-2 and varied parameters are summarized in Table 4-3.

The areal study discussed hitherto did not take into account shale dewatering effects. However, undercompacted and hence slightly permeable shales may considerably contribute to the sandstone reservoir pressure maintenance as observed in some geopressed gas reservoirs (Harville and Hawkins,¹⁰ Wallace,¹⁵). To investigate the effects, a Cartesian cross-sectional model was employed for Cases 11, 12 and 13. A vertical sequence of sand/shale alternation included the three sand units A, B, and C. Each sand assumed uniform porosity and permeability; 14 percent and 27 md for Sand A, 18 percent and 75 md for Sand B, and 21 percent and 150 md for Sand C. The vertical permeabilities were set to one-tenth of the horizontal permeabilities. Thicknesses of Sands A, B, and C were also uniform at 50, 50 and 100 feet, respectively. The three sand layers were interbedded with shale layers of thicknesses of 320 feet and 200 feet. In addition there were shales above Sand A (30 feet thick) and below Sand C (100 feet thick). The porosity and horizontal permeability assumed for shales were 10 percent and 10^{-4} md, respectively. The vertical shale permeabilities were varied from case to case so that shales had various intensities of shale dewatering; 10^{-4} , 10^{-5}

and 10^{-5} md in Cases 11, 12 and 13, respectively. A uniaxial compaction constant for sandstone was $5 \times 10^{-7} \text{ psi}^{-1}$, the same as that assumed for Sand C of the areal study. With lack of reliable data on shale compaction constants, they were assumed to be twice larger than those of sandstone. The same capillary pressure function and relative permeability curves as those for Sand C in the areal study were employed for sandstone and shale in Cases 11 through 13, although it might not be appropriate. All the layers were assumed to be horizontal with the depth of Sand C coinciding with that at the well location for the areal cases. The vertical cross-section of 34 miles by 850 feet was discretized into 34×10 finite difference grid cells so that a sand/shale interface corresponded to one of the grid cell interfaces. The discretization in the x-axis direction was uniform and was the same as the areal model. The reservoir width of approximately 6 miles was chosen so that the initial water-in-place in Sand C would agree with that in the areal model. Only Sand C was perforated for production. Thus Sands A and B communicated with the producing zone; Sand C, only through the thick interbedded shale layers.

To study the influence of gas saturation buildup near a wellbore, a radial cross-sectional model was employed for Cases 14 through 17. An external radius was 12,000 feet, which was equivalent to a drainage area of 16 square miles. The well was located in the center of the drainage area. A fine grid system was used in the vicinity of the well and larger grid cells were used away from the well; $0.292 \text{ ft} = r_w$, 4.8, 10.6, 23.0, 49.8, 149, 448, 1340, 4010, 12000 = r_e . The vertical sequence of sand/shale alternation and its discretization were the same as those in Case 11. The three sand layers were communicated through the area between the radii 7290 ft and 12000 ft by setting the vertical permeabilities of the outmost shale grid cells to those of sandstone. Porosities, permeabilities,

compaction constants, and capillary pressure function were unchanged from those of Case 11. Relative permeabilities were estimated by Corey's formula with the critical gas saturation of 0% for Case 14 and 36% for Case 15 (see Figure 4-11). For Cases 16 and 17 straight lines were assumed for relative permeabilities with the immobile gas saturation being 0% and 36%, respectively, as seen in Figure 4-12. The irreducible water saturation was set to 20% for all the radial cross-sectional cases.

4.2 Discussion of Results

All the cases were simulated for a period of 15 years. In the following discussion cases are compared by reservoir's productive lives. The productive life is defined as a time span that the well can produce at the required rate, 20,000 BWPd, with the flowing bottom hole pressure above 7,000 psia. For the cases where the bottom hole pressures were over 7,000 psia at the end of the simulation period, the productive lives were calculated from the bottom hole pressures and the decline rates at the end of the simulation.

4.2.1 Effects of Reservoir Compaction

The Sand C reservoir of Cases 1 and 2, where porosities were varied throughout the reservoir, contained the initial water-in-place of 20.8×10^9 STB and the initial gas-in-place of 576×10^9 SCF. All the gas was in a dissolved state.

Figure 4-13 shows the depletion behaviors of the non-compacting (Case 1) and compacting (Case 2) reservoirs. After producing at the desired rate, 20,000 BWPd, for 15 years, the flowing bottom hole pressure was about 700 psi higher and its decline rate was twice smaller in the non-compacting reservoir of Case 1

than in the compacting reservoir of Case 2. The projected productive lives were 28 and 50 years for Cases 1 and 2, respectively, and the ultimate recoveries at the end of the productive lives were calculated as 1.0% in Case 1 and 1.7% in Case 2 of the initial water-in-place. It is often stated that reservoir compaction should not be ignored for undersaturated reservoirs. The effect seems even greater for geopressured aquifers.

The total fluid compressibility was $4.5 \times 10^{-6} \text{ psi}^{-1}$ as mentioned earlier. The combined effect of pore compressibility and porous medium compaction was $2.5 \times 10^{-6} \text{ psi}^{-1}$ for the medium having porosity of 20%. Since rock matrix compressibility was neglected in this study, the pore compressibility was a function of the uniaxial compaction only. Therefore, the reservoir in Case 1 had a driving energy 36% less than Case 2. Judging from the quartz grain compressibility, $1.8 \times 10^{-7} \text{ psi}^{-1}$, neglecting the rock matrix compressibility might not be justified.

4.2.2 Effects of Permeability Level

Cases 3, 4, and 5 assumed the uniform porosity of 21% over the entire Sand C reservoir. This reservoir initially had slightly more water and gas (22.4×10^9 STB and 620×10^9 SCF, respectively) than the reservoir of varied porosity in Case 2. But the influence on the reservoir behavior by the difference would be negligible.

The permeability was also uniform at 150 md in Case 3 and it was reduced to 100 md and 50 md in Cases 4 and 5, respectively. The plots of bottom hole pressures versus time of Cases 2 through 5 are displayed in Figure 4-14. All the cases exhibited almost equal pressure decline rates after the reservoir reached

pseudo-steady state. The reduction in permeability from 150 md (Case 3) to 100 md (Case 4) resulted in the well pressure 430 psi lower throughout the production period. Similarly, the reduction from 100 md (Case 4) to 50 md (Case 5) shifted the pressure curve downward by 1280 psi. The reservoirs of Cases 3, 4, and 5 would produce at the rate of 20,000 BWPD for 60, 62 and 29 years recovering 2.0%, 1.7% and 0.9% of the initial water, respectively.

In Figure 4-14 it is seen that Case 2 (variable permeability) and Case 4 (uniform permeability, 100 md) generated almost identical reservoir performance. The permeability at the grid cell where the well was located was 95 md in Case 2. Though it is not conclusive from the limited number of cases studied, the observed agreement would be attributed to the similarity in the permeability of the well grid cell since a substantial part of pressure gradient would be occurring in the one-square mile area around the well. This postulate then implies that permeabilities remote from a well are rather unimportant and to efficiently drain an entire reservoir, locating wells in high permeability spots would be desired.

4.2.3 Effects of Leaky Faults

In Cases 6 through 10 the reservoir assumed two leaky faults located about 2.5 miles west and east of the well and extending from the northwest boundary fault to the southern reservoir boundary (Figure 4-4). The permeabilities across the faults were 0.001, 0.1, 1.0, 5.0 and 30 md for Cases 6 through 10, respectively.

In the following discussion the three blocks fragmented by the leaky faults are referred to as the west block, well block and east block. The initial water-in-place in the well block was 3.3×10^9 STB, and those of the west and east blocks

were 14.9×10^9 STB and 3.5×10^9 STB, respectively.

Figure 4-15 compared the bottom hole pressure histories of the cases with less leaky faults (Cases 6, 7 and 8) with that of Case 2 having no faults. The reservoir of Case 6 with the fault permeability of 0.001 md could sustain the rate, 20,000 BHPD, for only 8.3% of the initial water in the entire reservoir. The increase of the fault's leakage to 0.1 md (Case 7) did not greatly improve the reservoir performance, the productive life being 9.4 years and the recovery rate then being slightly over 0.3%. Figure 4-16 shows how drastically the production rates decreased in Cases 6 and 7 when the well continued to produce by maintaining the bottom hole pressure at 7,000 psia. Thus the continuation of production at the reduced rates would not add substantial recoveries to the above-mentioned values.

Table 4-5 demonstrates the fault sealing effects by means of the depletion history of each block. The number listed in this table as depletion level is the ratio of water that flowed out of the block minus water that flowed into the block's initial water-in-place. The depletion levels of the west and east blocks in Cases 6 and 7 were negligibly small, as seen in this table. It can be concluded that faults of leakage as small as 0.1 md would isolate reservoir blocks that they separated.

The further increase of the fault leakage to 1.0 md (Case 8) markedly prolonged the productive life, from 9.4 years in Case 7 to 20.7 years. The ultimate recovery in Case 8 was 0.8% relative to the initial water of the whole Sand C reservoir. The depletion levels of the west well, and east blocks were 0.02%, 0.49% and 0.08%, respectively, after 3 years' production, and 0.23%, 1.47% and 0.81% after 15 years. Therefore, the blocks which communicated with the

producing well block through the faults supplied a substantial amount of water and the supply rates increased as the pressure differences across the faults increased.

The bottom hole pressure histories of Cases 2, 8, 9 and 10 are shown in Figure 4-17. The increase of the fault leakage from 1.0 md in Case 8 to 5.0 md in Case 9 doubled the reservoir's productive life and hence the recovery rate. Meanwhile, the faults of leakage as large as 30 md (Case 10) resulted in only a small deviation of the well pressure performance from Case 2 without faults.

Summarizing the results from the study of fault sealing effects, it would be appropriate to say that the faults of leakage on an order of 0.1 md or less would totally isolate each block from the others. Even the reservoir fragmented by faults as leaky as 1.0 md would need at least one well for each block in order to effectively drain the entire areal extent. If fragmentation by faults is severe; that is, a reservoir is broken into small blocks as often is the case for geopressured formations (Fowler⁷ and Duggen⁴), the development of such a geopressured aquifer would be critical or even infeasible. On the other hand, though not included in this report, additional simulation cases indicated that, if minor faults did not extend entirely from one reservoir boundary to another, such faults affect little in restricting fluid flows between partially separated blocks regardless of fault leakage levels.

4.2.4 Shale Dewatering Effects

Cases 11, 12 and 13 were Cartesian cross-sectional studies for the sand/shale layered system. The vertical shale permeabilities varied from 10^{-4} md in Case 11 to 10^{-5} md in Case 12 and further to 10^{-6} md in Case 13.

Table 4-6 summarizes the depletion level of each layer at the end of

the simulation period, 15 years. The depletion level was defined in Section 4.2.3 and was calculated from the remaining water-in-place at the 15th year. Also listed in Table 4-6 are the percentages of total shale water influxes relative to the initial water-in-place in Sand C. When the shale layers were as permeable as 10^{-4} md (Case 11) the shale water influx provided 0.314% out of the total recovery, 0.514%. That is, more than half the produced water was due to the displacement by the shale water. Also, the shale layers adjacent to the producing zone, Sand C, depleted to the level close to that of the producing zone. However, the layers including Sands A and B remained rather undisturbed and contributed little to maintaining the pressures in the producing sand layer, indicating that sandstone layers could not be tapped by a single perforated producing zone if they were separated by thick shale layers.

The reduction of the vertical shale permeability from 10^{-4} md in Case 11 to 10^{-5} md in Case 12 markedly decreased the shale dewatering; the shale water influx supplied only 0.128% out of the total recovery, 0.514%, and three quarters of the produced water originated from the producing zone itself. The depletion of the shale layers contact with Sand C was about one-sixth of that of Sand C, the producing zone.

The results from Case 13 implied that if the shale layer's permeabilities were in the range of 10^{-7} md the influence of shale dewatering would be only marginal and could be neglected. However, as is seen on the improvement of pressure decline rates in Table 4-7, the shale dewatering intensified in later stages of depletion as the pressure differences between sand and shale layers increased. In Case 13, the annual pressure decline rate improved from 63.9 psi/year at the fifth year of production to 57.0 psi/year at the end of the simulation. Since this

improvement would continue for further production the shale dewatering effect might be significant, if not substantial, over the entire history of the reservoir depletion.

Figure 4-18 displays the comparison of the well pressure decline curves of Cases 11, 12 and 13 with that of Case 2, the areal model having no shale influence. It is noted that Cases 2 and 13 showed almost identical decline rate but the pressures in Case 2 were consistently lower by about 850 psi throughout the simulation period. For the cross-sectional studies of Cases 11, 12 and 13, the horizontal permeability of Sand C was set to 150 md. But, as discussed in Section 4.2.2 the permeability of the well grid cell was the controlling factor for the behavior of the reservoir having non-uniform permeabilities. If the horizontal permeability of Sand C had been set to 100md in Cases 11, 12 and 13, their depletion curves would shift downward by 450 psi. The remaining difference of 400 psi between the depletion curves of Cases 2 and 13 would be ascribed to the intrinsic difference between areal and cross-sectional model assumed very elongated grid cells, 1 mile by 6 miles by 100 feet, and the variance of pressures in the direction perpendicular to the northwest boundary fault was not accounted for. The fluid flow pattern occurring under such circumstances would be quite different from that assumed in the areal model. It is postulated that the cross-sectional model used for Cases 11 to 13 generated overly optimistic results. Therefore, on interpreting Figure 4-18, the curves of Cases 11 to 13 should be shifted downward by 850 psi such that Case 2, the areal model case without shale effects, would agree with Case 13, the cross-section case having only marginal shale water influx. To obtain more realistical results for the sand/shale alternating reservoirs, the three dimensional model would be necessary, though it

would be costly and practically impossible to run from a central memory the size of the computers available at The University of Texas at Austin

Interpreting the results from the Cartesian cross-sectional models, Cases 11 through 13, in the way explained above, the productive lives and corresponding recovery rates of the Sand C reservoir with the shale water influx were calculated and are summarized in Table 4-8. It should be noted that the productive lives were calculated using the pressure decline rates at the last year of the simulated period, 15 years, while the shale dewatering was yet to increase and the decline rates were improving. Therefore, the estimates in Table 4-8 should be considered to be conservative. Yet, an increase of shale permeability from 10^{-6} md to 10^{-5} md extended the reservoir productive life by 50% -- 50.9 years to 76.1 years. Shale layers as permeable as 10^{-4} md would increase the recovery more than three-fold than would be the case without any shale effects.

The geology of sand/shale alternation in the Austin Bayou prospect is not as simple as assumed for Cases 11 through 13, as explained in Chapter 3. Thin, discontinuous shale lenses would expel significant amounts of shale water to the producing sandstone layer if total volume of such shales is sufficiently large.

4.2.5 Gas Saturation Buildup near the Wellbore

The magnitude of critical gas saturation is highly dependent on a flow pattern, imbibition or drainage. At first glance it appears that in the case of geopressed reservoirs, the saturation of water (the wetting phase) decreases and the saturation change will be in the drainage direction. If this is the case, the critical gas saturation will be very small. There will be no large gas buildup to affect inflow into the well. However, in a geopressed well, the production rates

have to be very high for economic reasons. It is possible that the water will be moving so quickly that it will displace the gas coming out of solution rather than the gas displacing the water. This may be particularly true around the wellbore. If this is the case, the flow pattern is an imbibition and there will be a large gas saturation buildup near the wellbore that lowers the relative permeability to water and greatly reduces the well productivity.

At the present time, it is unknown whether the flow of fluids in a geopressured reservoir will behave as a drainage or an imbibition process. To study the impact, a radial cross-sectional model was used for Cases 14 through 17 by varying relative permeability curves and critical gas saturation values.

For Cases 14 and 15 the relative permeabilities were calculated by Corey's formula with the irreducible water saturation of 20%. The critical gas saturation was 0% in Case 14, drainage process, and 36% in Case 15, imbibition process (See Figure 4-9). The gas saturation in the reservoir of Case 14 remained very small throughout the simulated period because of the free gas movement. On the other hand, the gas saturation in Case 15 quickly built up near the wellbore as seen in Figure 4-19. At some radius near the well the buildup of gas increased until a mobile gas saturation was reached. At this stage the gas began to flow and the saturation remained more or less constant, slightly over the critical gas saturation of 36%. During this buildup, the relative permeability to water at this radius reduced to one-tenth of that at the initial condition. The zone of high gas saturation expanded outward from the well but the velocity of the advancing saturation front gradually decreased as the radial distance increased.

Figure 4-20 shows the change of the well productivity index (PI) with time. The productivity index was calculated by dividing the production rate by

the pressure drop between the well and the external radius, 12,000 ft. The productivity index of Case 14 slightly decreased during the first year but stayed almost constant in the rest of the simulated period. Meanwhile, the productivity index of Case 15 sharply decreased in the first few months of production and then the decrease became very gradual. This observation agrees well with the argument made above regarding the gas saturation buildup.

Figure 4-21 compares the well pressure histories of Cases 14 and 15. The pressures in Case 15 were about 2000 psi lower than Case 14 throughout the simulated period. Obviously this amazingly large difference was caused solely by the lower productivity due to the gas saturation buildup near the well. The initial water-in-place contained in the three sand layers and "windows" within shales amounted to 5.34×10^9 STB. The productive life of Case 14 was 42.3 years and the recovery then was 5.8%, while the critical gas saturation of 36% (Case 15) shortened the life to 16 years with the recovery of 2.2%.

Relative permeabilities being unknown at the present time, straight lines were assumed for Cases 16 and 17. These cases can be considered as the extreme cases of clean sand with very well sorted grain sizes. The critical gas saturation was 0% in Case 16 and 36% in Case 17. The results from Case 16 were almost identical with Case 14. Since the critical gas saturation was 0% in both cases, the free gas moved towards the well as soon as it evolved from solution and was produced from the well. Thus the gas saturation in the reservoir, even in the vicinity of the well, remained very low. The shapes of relative permeability curves, therefore, affected the reservoir pressure behavior very little.

In Figure 4-22 the gas saturation profiles of Case 17 at four time levels were demonstrated. The gas buildup state in Case 17 was similar to that in Case

15. However, the relative permeability to water in Case 17 decreased only by 45%, from 1.0 to 0.55, when the gas saturation buildup to the critical saturation, 36%. The effects on the productivity index and the well pressure behavior were relatively small as seen in Figures 4-23 and 4-24, respectively. The productive life of the reservoir in Case 17 was estimated to be 38.8 years with a recovery of 5.3%. Although straight line relative permeabilities led to a very optimistic reservoir forecast even when the critical gas saturation was large, a sand reservoir consisting of well sorted sand grains would show a similar reservoir behavior. In other words, a flow pattern, drainage or imbibition, and hence critical gas saturation would not be a severe problem if a reservoir consists of clean, well-sorted sand.

4.3 Conclusions

With the limited number of simulations carried out in this study and many unknowns still involved, it would be premature to draw conclusions regarding the productivity of the Austin Bayou geopressured reservoir. Yet, it is believed that some important reservoir mechanisms in a geopressured reservoir were identified by this study.

1. Without shale water influx, production by natural depletion would recover at most 2% of the initial water-in-place from a geopressured reservoir. In particular, the single well, Pleasant Bayou #2, in the Austin Bayou prospect would be able to produce at the rate of 20,000 BWPD for 50 years. However, these estimates should be understood as preliminary assessment. The two-thirds of the total driving force is considered to be provided by fluid expansion and the remaining one-third would be the combined effect of pore and formation

contractions.

2. If the geopressed prospect is fragmented by minor faults with leakage on the order of 1 md, each isolated block would need a well to effectively drain. The productive life of each well depends on the size of a reservoir block, but would be very short compared with the estimate cited above for Pleasant Bayou #2.

3. Locating a well in a high permeability spot with a radius of at least 1 mile would be extremely important in developing a geopressed reservoir. In this study a simple porosity-permeability correlation was used to evaluate the permeability distribution in the Austin Bayou prospect. More elaborate geological consideration of deltaic sedimentation environments would be necessary to pinpoint high permeability spots.

4. If interbedding shale layers are undercompacted and have vertical permeabilities in the range of 10^{-5} to 10^{-4} md, significant driving energy would be provided by their dewatering. Their effects would not be felt in early stages of production but would gradually improve the producing zone's pressure decline rates, extending the productive lives by 50% to more than 300%. However, a single producing layer would not tap other sand layers separated by thick shale layers from the producing layer.

5. At the present time the flow process in a geopressure reservoir, especially near a well, is unknown. If it is a drainage process due to high velocity, the critical gas saturation would be high and a large gas saturation would build up near the wellbore. This gas buildup will cause drastic reduction of well productivity and shorten the reservoir's productive life by a factor of two or more. The effects will be more eminent for poorly sorted, dirty sand reservoirs.

FIGURE 2-1
NET SAND THICKNESS
C-SAND FRIO FORMATION
BRAZORIA COUNTY

FIGURE 2-2
PLEASANT BAYOU #2
DECEMBER 1979 BUILDUP TEST
 $q = 13650$ B/D

FIGURE 2-3
 PLEASANT BAYOU #2
 OCTOBER 1980 DRAWDOWN TEST
 $q_3 = 19100 \text{ B/D}$

FIGURE 2-4
PLEASANT BAYOU #2
NOVEMBER 1980 BUILDUP TEST
 $q = 13500 \text{ B/D}$

FIGURE 2-5
PLEASANT BAYOU #2
RATE SENSITIVE SKIN FACTORS

FIGURE 3-1¹

FRIO GEOTHERMAL FAIRWAYS,
DEPOSITIONAL MODELS,
AND RESERVOIR QUALITY

FIGURE 3-2¹

STRUCTURAL MAP OF BRAZORIA FAIRWAY

FIGURE 3-3¹

SAND PATTERNS OF HIGH-CONSTRUCTIVE LOBATE DELTA SYSTEM, GULF COAST

FIGURE 3-4¹

NET - SANDSTONE MAP OF SAND B

FIGURE 4-1

WATER FORMATION VOLUME FACTOR
AND SOLUTION GAS WATER RATIO

FIGURE 4-2
GAS FORMATION VOLUME FACTOR

FIGURE 4-3
WATER AND GAS VISCOSITIES

FIGURE 4-4

GEOPRESSURED - GEOTHERMAL RESERVOIR STUDY
SAND C IN AUSTIN BAYOU PROSPECT
GRID SYSTEM MAP

FIGURE 4-5

GEOPRESSURED - GEOTHERMAL RESERVOIR STUDY
SAND C IN AUSTIN BAYOU PROSPECT
CONTOUR MAP OF NET THICKNESS OF SAND C (FT)

FIGURE 4-6

GEOPRESSURED - GEOTHERMAL RESERVOIR STUDY
SAND C IN AUSTIN BAYOU PROSPECT
CONTOUR MAP OF POROSITY OF SAND C (PER CENT)

FIGURE 4-7
POROSITY - PERMEABILITY RELATION

FIGURE 4-8

GEOPRESSURED - GEOTHERMAL RESERVOIR STUDY
SAND C IN AUSTIN BAYOU PROSPECT
CONTOUR MAP OF PERMEABILITY OF SAND C (MD)

FIGURE 4-9

GEOPRESSURED - GEOTHERMAL RESERVOIR STUDY
SAND C IN AUSTIN BAYOU PROSPECT
CONTOUR MAP OF DEPTH OF TOP OF SAND C (FT)

FIGURE 4-10
CAPILLARY PRESSURE FUNCTION

FIGURE 4-11

RELATIVE PERMEABILITIES TO WATER AND GAS
ESTIMATED BY COREY'S FORMULA

FIGURE 4-12

RELATIVE PERMEABILITIES TO WATER AND GAS
STRAIGHT LINES

FIGURE 4-13

EFFECTS OF RESERVOIR COMPACTION
(CASES 1 AND 2)

x — x — x CASE 1 CM = 0.0 /PSI
 □ — □ — □ CASE 2 CM = 5×10^{-7} /PSI

FIGURE 4-14

EFFECTS OF VARIANCE IN PERMEABILITY
(CASES 2, 3, 4 AND 5)

FIGURE 4-15

EFFECTS OF LEAKY FAULTS ON WELL PRESSURE (1)
(CASES 2, 6, 7 AND 8)

x — x — x	CASE 2	NO FAULT
□ — □ — □	CASE 6	FAULT K = 0.001 MD
+ — + — +	CASE 7	FAULT K = 0.1 MD
Δ — Δ — Δ	CASE 8	FAULT K = 1.0 MD

FIGURE 4-16

EFFECTS OF LEAKY FAULTS ON PRODUCTION RATES
(CASES 2, 6, 7 AND 8)

x—x—x	CASE 2	NO FAULT
□—□—□	CASE 6	FAULT K = 0.001 MD
+—+—+	CASE 7	FAULT K = 0.1 MD
Δ---Δ---Δ	CASE 8	FAULT K = 1.0 MD

FIGURE 4-17

EFFECTS OF LEAKY FAULTS ON WELL PRESSURE (2)
(CASES 2, 8, 9 AND 10)

x—x—x	CASE 2	NO FAULT
□—□—□	CASE 8	FAULT K = 1.0 MD
+—+—+	CASE 9	FAULT K = 5.0 MD
Δ---Δ---Δ	CASE 10	FAULT K = 90.0 MD

FIGURE 4-18

EFFECTS OF SHALE DEWATERING
(CASES 2, 11, 12 AND 13)

x—x—x	CASE 2	NO SHALE DEWATERING
□—□—□	CASE 11	SHALE K = 10 ⁻⁴ MD
+—+—+	CASE 12	SHALE K = 10 ⁻⁵ MD
Δ---Δ---Δ	CASE 13	SHALE K = 10 ⁻⁶ MD

FIGURE 4-19

GAS SATURATION PROFILES IN CASE 15
 COREY RELATIVE PERMEABILITIES
 CRITICAL GAS SATURATION = 36 PER CENT

x	x	x	TIME = 0.1 YEARS
□	□	□	TIME = 1.0 YEARS
+	+	+	TIME = 3.0 YEARS
△	△	△	TIME = 15.0 YEARS

FIGURE 4-20

CHANGE OF PRODUCTIVITY ASSOCIATED
WITH GAS BUILDUP NEAR WELLBORE
COREY RELATIVE PERMEABILITIES

FIGURE 4-21

EFFECTS OF GAS BUILDUP NEAR WELLBORE
COREY RELATIVE PERMEABILITIES

FIGURE 4-22

GAS SATURATION PROFILES IN CASE 17
 STRAIGHT LINE RELATIVE PERMEABILITIES
 CRITICAL GAS SATURATION = 36 PER CENT

x—x—x	TIME = 0.1 YEARS
□—□—□	TIME = 1.0 YEARS
+—+—+	TIME = 9.0 YEARS
Δ---Δ---Δ	TIME = 15.0 YEARS

FIGURE 4-23

CHANGE OF PRODUCTIVITY ASSOCIATED
WITH GAS BUILDUP NEAR WELLBORE
STRAIGHT LINE RELATIVE PERMEABILITIES

FIGURE 4-24

EFFECTS OF GAS BUILDUP NEAR WELLBORE
STRAIGHT LINE RELATIVE PERMEABILITIES

x — x — x CASE 16 SGC = 0 PER CENT
□ □ □ CASE 17 SGC = 96 PER CENT

Table 4-1

Summary of Varied Parameters for Areal Study of Sand C Reservoir

<u>Case No.</u>	<u>Thickness</u> ft	<u>Porosity</u> md	<u>Permeability</u> md	<u>Fault</u> <u>Permeability</u> md	<u>Relative</u> <u>Permeability</u>	<u>Critical Gas</u> <u>Simulation</u> %
1	1-170	11-22	10-180	no fault		
2	1-170	11-22	10-180	no fault		
3	1-170	21	150	no fault		
4	1-170	21	100	no fault		
5	1-170	21	50	no fault	Corey's	36
6	1-170	11-22	10-180	0.001	formula	
7	1-170	11-22	10-180	0.1		
8	1-170	11-22	10-180	1.0		
9	1-170	11-22	10-180	5.0		
10	1-170	11-22	10-180	30.0		

Table 4-2

Summary of Reservoir Parameters for Cross-Sectional
Study of Sand/Shale Sequence

<u>Layer</u>	<u>Thickness</u>	<u>Porosity</u>	<u>Permeability</u>		<u>Compaction Coefficient</u> psi ⁻¹
			<u>Horizontal</u>	<u>Vertical</u>	
	ft	%	md	md	
Sand A	50	14	27	2.7	5 x 10 ⁻⁷
B	50	18	75	7.5	
C	100	21	100	10.0	
Shale Top	30				
Between Sands A & B	320				
Between Sands B & C	200	10	10 ⁻⁴	10 ⁻⁴ -10 ⁻⁶	10 x 10 ⁻⁷
Bottom	100				

Table 4-3

Summary of Varied Parameters for Cross-Sectional
Study of Sand/Shale Sequence

<u>Case No.</u>	<u>Model Type</u>	<u>Shale Vertical Permeability</u> md	<u>Relative Permeabilities</u>	<u>Critical Gas Saturation</u> %	<u>Remarks</u>
11	x-z Cartesian	10^{-4}	Corey's formula	36	Sand layers were separated by shales. No windows com- municated sand layers. Only Sand C was perforated.
12		10^{-5}			
13		10^{-6}			
14	r-z cylindrical	10^{-6}	Corey's	0	Sand layers were communi- cated through windows in shale layers extending from a radius 7,290 ft to the exter- nal radius, 12,000 ft.
15			Corey's	36	
16			Straight lines	0	
17			Straight lines	36	

Table 4-4

**Expected Productive Lives of Sand C Reservoir and
Ultimate Recoveries Estimated by Areal Study**

<u>Case No.</u>	<u>Bottom Hole Pressure at t=15 yrs</u>	<u>Pressure Decline Rate at t=15 yrs</u>	<u>Productive^{—*} Life Length</u>	<u>Ultimate Water Recovery</u>
	psia	psi/yr	years	%
1	8372	10.4	28.1	0.99
2	9046	59.0	49.7	1.74
3	9533	55.9	60.3	1.96
4	9100	56.4	52.2	1.69
5	7823	60.1	28.7	0.93
6	7000	-	8.30	0.29
7	7000	-	9.39	0.33
8	7567	100.4	20.7	0.72
9	8632	65.5	39.9	1.40
10	8982	59.4	48.4	1.70

*Productive life is defined as a length of time span that the well was able to produce at the rate of 20,000 BWPD with the flowing bottom hole pressure above 7,000 psia. For the cases in which the productive lives were longer than 16 years, they were estimated from the performance at the 15th year.

Table 4-5
Depletion Histories of Blocks
Fragmented by Leaky Faults

<u>Case No.</u>	<u>Fault Leakage md</u>	<u>Block</u>	<u>Depletion Level*</u>		
			<u>t = 1yr</u> %	<u>t = 3yr</u> %	<u>t = 15yr</u> %
2	No Fault	Well	0.0855	0.1877	0.6245
		West	0.0189	0.0729	0.4813
		East	0.0490	0.1557	0.6091
6	0.001	Well	0.2200	0.6598	2.441
		West	4.28×10^{-6}	4.24×10^{-5}	0.00102
		East	1.49×10^{-5}	1.57×10^{-4}	0.00361
7	0.1	Well	0.2166	0.6304	2.275
		West	4.50×10^{-4}	3.59×10^{-3}	0.0585
		East	1.48×10^{-3}	1.38×10^{-2}	0.2540
8	1.0	Well	0.1939	0.4912	1.471
		West	0.0034	0.0295	0.230
		East	0.0111	0.0779	0.811
9	5.0	Well	0.1510	0.3177	0.862
		West	0.0092	0.0448	0.3874
		East	0.0286	0.1450	0.7595
10	30.0	Well	0.1033	0.2109	0.6606
		West	0.0163	0.0665	0.4662
		East	0.0452	0.1595	0.6352

*The depletion level is defined as the ratio of the water that flowed out of the block minus the water that flowed in to the block's initial water-in-place.

Table 4-6

Shale Dewatering Effects on Recoveries

<u>Case No.</u>	<u>Water Recovery at t = 15yrs</u> (% Sand CIWIP)	<u>Shale Water* Influx</u> (¢ Sand C IWIP)	<u>Depletion Level of Layer</u>						
			<u>Sand A</u>	<u>Sand B</u>	<u>Sand C</u>	<u>Top Shale</u>	<u>Shale Between Sands A & B</u>	<u>Shale Between Sands B& C</u>	<u>Bottom Shale</u>
				(%	of each	layer's	IWIP)		
11	0.514	0.314	0	0.007	0.185	0	0.014	0.156	0.144
12	0.514	0.128	0	0.0012	0.395	0	0.006	0.063	0.059
13	0.514	0.026	0	0.0008	0.498	0	0.006	0.011	0.009

Table 4-7

Shale Dewatering Effects on Pressure Declines

Case No.	Shale Vertical Permeability md	<u>Well Pressure Decline Rate</u> (psi/year)		
		<u>t = 5yr</u>	<u>t = 10yr</u>	<u>t = 15yr</u>
2	No Shale	65.7	60.0	59.0
11	10^{-4}	24.0	17.9	15.8
12	10^{-5}	54.8	42.8	36.6
13	10^{-6}	63.9	58.5	57.0

Table 4-8

Summary of Productive Lives of Sand C
Reservoir with Shale Water Influxes

<u>Case No.</u>	<u>Shale Vertical Permeability</u>	<u>Bottom Hole Pressure at t = 15yr</u>	<u>Pressure Decline Rate at t = 15yr</u>	<u>Productive Life</u>	<u>Ultimate* Water Recovery</u>
	md	psia	psi/yr	years	%
2	No Shale	9046	59.0	49.7	1.74
11	10^{-4}	9614	15.8	180.4	6.18
12	10^{-5}	9235	36.6	76.1	2.61
13	10^{-6}	9046	57.0	50.9	1.75

*Relative to the initial water-in-place of Sand C.

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