**HYDROCARBON CONTENT OF
GEOPRESSURED BRINES**

**THE DOW-DOE L.R. SWEET NO. 1,
THE MG-T/DOE AMOCO FEE NO. 1,
THE PLEASANT BAYOU NO. 2,
and
THE T-F&S/DOE GLADYS McCALL NO. 1**

Final Report

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IGT--65064

DE86 005964

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IGT Project No. 65064

**Under Subcontract No. S1-00006
(University of Texas-Austin/Institute of Gas Technology)**

**Under Prime Contract No. DE-AC0⁷-79ET 27112
(United States Department of Energy/University of Texas-Austin)**

August 1985

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BACKGROUND

In the mid-1970's interest arose in exploiting the energy available from geopressured-geothermal aquifers. These aquifers are permeable sandstone bodies surrounded by impermeable shales, located thousands of feet below the ground surface along the Texas and Louisiana Gulf Coast and elsewhere. They contain hot, pressurized brine, which, in turn, contains dissolved natural gas. The brine and natural gas can be produced by drilling a well into the aquifer. The gas and brine can be separated on the surface, where three different energy forms become available. The gas can be burned, heat can be extracted from the hot brine, and mechanical energy can be derived from the pressurized fluids.

Much less mechanical energy is available than gas or thermal energy. In the beginning, the recovery of thermal energy was of primary interest. A number of factors, including lower than anticipated temperatures of these aquifers, limitations on flow rates, and the energy crisis and the resulting increase in the price of natural gas, caused increased interest in the recovery of natural gas.

Studies of the geopressured-geothermal resource under government energy agency sponsorship began in 1975. These were mainly geologic assessments of the Gulf Coast. In 1977 the first tests of a geopressured-geothermal aquifer took place when the abandoned Edna Delcambre #1 gas well was reopened. It was re-completed into both the No. 1 and No. 3 Sands, which were independently tested. This project was sponsored by the United States Energy Research and Development Administration (ERDA). Later, the United States Department of Energy (DOE) sponsored a two-part geopressured-geothermal research and development program known as the "Wells of Opportunity" and the "Design Wells." Wells of Opportunity were abandoned wells drilled by industry into or through geopressured-geothermal reservoirs (aquifers) in search of oil and gas and made available by industry to DOE for testing. Design Wells were wells purposely drilled into the most favorable, known aquifers. Because the wells already existed, the advantages of the Wells of Opportunity were that the cost of the test was lower and that the test could begin sooner; the disadvantages were believed to be the well's location and completion. The Wells of Opportunity are commonly drilled on-structure or near structural closure for entrapment of hydrocarbons. This fact and the smaller tubing size commonly

used in their completion were believed to limit the flow rate capability.* A limited flow rate and short-term test duration meant that only the fluid properties and reservoir characteristics around the wellbore could be studied. The advantages of the Design Wells were that they could be drilled in the most favorable, known aquifers and completed to allow long-term high flow rates, and thus allow more extensive determinations of fluid and reservoir properties. Disadvantages were the higher cost and the longer start-up times that result from drilling the wells.

During 1979 Gruy Federal, Inc., of Houston, Texas, successfully tested two Wells of Opportunity: the Fairfax Foster Sutter No. 2 Well and the Beulah Simon No. 2 Well. In December 1979, DOE awarded Eaton Operating Company, Inc., of Houston, Texas, the prime contract for the Wells of Opportunity program. The Institute of Gas Technology (IGT) was awarded a subcontract under this program. IGT's duties included instrumentation for collection and storage of all data (temperatures, pressures, flow rates) except bottomhole pressure; sample collection and analyses of produced gas, oil, brine, and solids, as well as solids that precipitated; and data interpretation of all of the above except for the drawdown and buildup test interpretation. Five wells were successfully tested by Eaton and IGT before the Wells of Opportunity program ended: the P. R. Girouard Well No. 1, the Lear G. M. Koelemay No. 2 Well, the Saldana Well No. 2, the HO&M Prairie Canal Co., Inc., Well No. 1, and the Crown Zellerbach Well No. 2. In addition to these, IGT was involved to some extent in the test of the earlier Wells of Opportunity, each Design Well, and the Edna Delcambre #1.**

Gruy Federal concluded that brines from both the Fairfax Foster Sutter No. 2 Well (Willits et al., 1979) and the Beulah Simon No. 2 Well (Dobson et al., 1980) were saturated with natural gas. IGT concluded that both the No. 1

*Indirectly, the real limiting factor for the flow rate was the low salinity guidelines imposed by DOE in selecting Wells of Opportunity. Most reservoirs have high salinities and low permeability. Thus, the probability of finding a reservoir with low salinity and high permeability is small. In fact, none were found. Adhering to the low-salinity guidelines therefore resulted in low-permeability reservoirs being chosen for testing. The low permeability of the reservoir was the limiting factor for the flow rate.

**The term "Wells of Opportunity" was coined following the Edna Delcambre #1 test.

and No. 3 sands tested in the Edna Delcambre #1 produced gas in excess of what could have been dissolved in the brine, but could not determine whether the free gas was native to these sands or whether it had been introduced from other sands during commercial gas production. Both the No. 1 and No. 3 sands are known to have free gas caps, but at some distance from the Edna Delcambre #1 (Rogers and Randolph, 1979). The P. R. Girouard No. 1 Well was possibly undersaturated (Eaton, 1981a). The HO&M Prairie Canal Co., Inc. Well No. 1 was thought to be saturated or possibly slightly oversaturated (Eaton, 1981b). The Saldana Well No. 2 produced gas in excess of solubility in brine at reservoir conditions (Eaton, 1981c). The Lear G. M. Koelemay No. 2 Well gas water ratio (GWR) went from relatively small values, such as would be expected for solution gas only, to commercially viable oil and gas production in less than two weeks (Eaton, 1981d).

The Crown Zellerbach Well No. 2 GWR of about 32 standard cubic feet per barrel (SCF/bbl) is considerably lower than the extrapolated PVT laboratory value of 55.7 SCF/bbl and the values of 47.5 and 49.5 SCF/bbl given by the Haas (n.d.) and the Price (1981) algorithms, respectively. Nevertheless, IGT did not conclude that the Crown Zellerbach Well No. 2 was undersaturated (Eaton, 1981e). The following were among the reasons for not reaching this conclusion. The Crown Zellerbach Well No. 2 produced an estimated 2 to 5 barrels of liquid hydrocarbons (oil) per 10,000 barrels of brine. The Haas and Price algorithms were written to fit experimental laboratory data on the solubility of methane in water and water containing sodium chloride, but not oil. Thus, they should not be expected to correctly predict natural gas solubility in the Crown Zellerbach brine, which contained oil. The discrepancy between the 55.7 SCF/bbl obtained from the PVT work and the value of 32 SCF/bbl measured during the field test might be explained by non-representative sampling. If the brine and liquid hydrocarbon phases were even partially separated in the separator, the liquid sample taken from the separator had an oil/brine ratio lower than that of the reservoir, and the bubble point measured with the sample would not be the same as the reservoir bubble point. Another reason for IGT's reluctance to conclude that the Crown Zellerbach is not saturated is that this well is drilled in a Tuscaloosa sand. The Tuscaloosa shales associated with this sand are generally believed to be the source bed for the large quantities of gas and smaller quantities of oil produced from surrounding wells completed in the Tuscaloosa. With these

facts, it is very difficult to conclude that the Crown Zellerbach is not saturated. This last argument holds for both sands tested; one alone and two co-mingled.

Thus, of the ten sands from the seven Wells of Opportunity and the Edna Delcambre #1, it appears that only one may be undersaturated, one definitely produces gas in excess of solubility in reservoir brine, and eight appear to be at least saturated, if not oversaturated. This is in sharp contrast to the Design Wells. Dow (1984) concluded that the Dow-DOE L. R. Sweezy No. 1 Well was undersaturated. Durrett (1984a) concluded that both sands tested of the MG-T/DOE Amoco Fee No. 1 Well were about 20% undersaturated and that both sands tested at the T-F&S/DOE Gladys McCall #1 were about 20% undersaturated. No written conclusion was found concerning the saturation of the Pleasant Bayou No. 2. Thus, of six sands from the four Design Wells, five were concluded to be undersaturated, and no decision was made on the sixth. Apparently, the results of PVT studies on recombined reservoir fluids were exclusively relied upon in reaching these conclusions. In addition to PVT work, the good production data, the frequent sampling, and sample analyses were used in reaching the conclusions on the Wells of Opportunity.

The results of a PVT study on recombined reservoir fluids are questionable if the samples are not representative of the reservoir. The fluid property data obtained from such samples will not be the same as the fluids in the reservoir, no matter how accurately the laboratory tests are done. If the reservoir brine is initially saturated, the pressure reduction near the well bore due to production will cause gas to exsolve from the brine. The gas will remain trapped in the reservoir.* The bubble point determined by PVT measurements would thus be closer to the bottomhole pressure at the time of sample collection than to the initial reservoir pressure.

If oil/brine separation occurred in the separator, the samples taken for the Design Wells and the Wells of Opportunity would not be representative. Even if the samples were representative when they were taken, the samples could leak; they could precipitate; the gas phase that forms in the brine sample cylinder when the brine volume decreases due to cooling** may not all

*This is discussed in more detail in the following section, "INTRODUCTION."

**A sampling technique developed and used later avoids this problem.

go back into solution before the brine is transferred to the PVT cell; an oil phase may separate from the brine upon pressure reduction and cooling; and the samples might react with the sample cylinders and/or valves.

The PVT recombinations were done at the reported reservoir temperature. Thus, an error would be introduced if the reservoir temperature were incorrectly measured or if the thermostat on the PVT oven did not control to the set point.

The bubble point of the reservoir is taken as the pressure derived from the PVT work that is necessary to dissolve all the gas at the produced gas/water ratio. Thus, errors in measuring the produced gas/water ratio would result in an error in predicting whether the reservoir is saturated or not. There were known problems associated with measuring the produced gas/water ratio during part of the test of each of the Design Wells.

The economics of energy production from geopressured-geothermal reservoirs is not attractive at the present time if dissolved natural gas is the only energy source.* If free gas can be produced, the economics become more attractive, and the attractiveness increases with the amount of free gas that can be produced.

If a geopressured-geothermal aquifer is not saturated with natural gas, it is highly unlikely that any free gas exists in the reservoir. On the other hand, if the aquifer is saturated with natural gas, it is highly likely that free gas does exist in the reservoir. This free gas would increase the economic inducement to develop this aquifer. Thus, "Is the aquifer saturated?" becomes a very important question — one that will probably impact the nation's energy program.

During IGT's involvement with the Wells of Opportunity program, reservoir models were developed to try to answer that question without using PVT results. This report describes IGT's investigation of Design Well data in an attempt to determine if the Design Wells are saturated.

* Heat and mechanical energy could also improve the economics.

INTRODUCTION

The following describes the development of the reservoir models used by IGT to study Design Well data for this project. These models were first used during IGT's involvement with the Wells of Opportunity program to help deduce if the reservoir brines were saturated with natural gas. These models are independent of PVT results.

A sandstone reservoir consists of an immense number of tiny pores between sand grains. These are, in turn, connected by a three-dimensional maze of pore throats. Both the pores and the pore throats have an extremely broad distribution of sizes.

If the pores are filled with free gas and brine, only the brine will flow in response to an applied pressure gradient unless the free gas occupies more than a certain minimum percentage of the pore volume. The percentage of pore volume that must be occupied by free gas before the gas can flow is called the "critical gas saturation." Although it has not been measured, critical gas saturation is generally assumed to be in the range of 2% to 3% of the total pore volume (Christian, 1979; National Petroleum Council, 1980).

The amount of gas that will dissolve in brine depends on the temperature, pressure, gas composition, and brine composition. In general, more gas will dissolve with an increase in pressure, and gas will exsolve if the pressure is dropped below the bubble point pressure. The bubble point pressure is the pressure at which a liquid phase coexists with an infinitesimal quantity of gas phase in equilibrium. In other words, the brine would be saturated with gas at those conditions.

The natural gas in these reservoirs is a multicomponent mixture containing methane, ethane, propane, other heavier hydrocarbons, carbon dioxide, and other gases. Because these individual components have different solubilities, the gas phase in equilibrium with the brine phase has a different composition than the gas dissolved in the brine phase. Generally, the heavier hydrocarbon/methane ratio in the gas phase is greater than the heavier hydrocarbon/methane ratio of the gas dissolved in the brine phase with which it is in equilibrium. In other words, the ethane/methane ratio in the free gas phase would be greater than the ethane/methane ratio of the dissolved

gas. These ratios tend to decrease as the pressure decreases (Osif et al., 1983). These facts can be used to generate the following models.

Model 1. Reservoir Contains Gas Dispersed in the Pores and the Gas Saturation is Greater Than Critical

Under these conditions, the produced gas/water ratio could be greater than the dissolved gas/water ratio in the reservoir. The amount of free gas produced would depend on reservoir properties and producing conditions. Relative permeabilities calculated using Corey's equations (1954) were used in Darcy's equation to approximate how much free gas would be produced at different gas saturations. The results are presented in Table 1. Based on the Haas (n.d.) and Price (1981) equations, the brine should contain between 18 and 19 SCF/bbl dissolved gas.

Table 1. APPROXIMATE AMOUNT OF FREE GAS THAT WOULD BE PRODUCED FROM A 200°F RESERVOIR AT 10,000 psi, WITH A 500 psi DRAWDOWN, A 3% CRITICAL GAS SATURATION, A 20% IRREDUCIBLE WATER SATURATION, AND SALINITY OF 135,000 mg/L AS A FUNCTION OF GAS SATURATION

(The Gas and Brine Viscosities Used Were 0.0345 and 0.43, Respectively.)

<u>Gas Saturation, %</u>	<u>Free Gas Produced, SCF/bbl</u>
4	1.2
5	6.2
6	17.6
7	38.4
8	72.0

A gas saturation of 4%, which is 1% greater than the assumed critical saturation, would give a GWR only 6% higher than that of solution gas alone. A gas saturation of 5% would give a GWR about 30% higher than that of solution gas alone, and a gas saturation of 6% would give a GWR about twice that of solution gas alone. The amount of free gas produced increases dramatically as the gas saturation increases.

If the brine production rate were suddenly increased so that the bottomhole pressure was significantly reduced, the gas saturation around the well bore would increase as the gas expanded in response to the pressure drop, and more free gas would be produced. Thus, the GWR would increase. Also, because the free gas has higher ethane/methane and propane/methane ratios than the dissolved gas (Osif et al., 1983), the increase in GWR would be

accompanied by an increase in the ethane/methane and propane/methane ratios in the produced gas.

Model 2. Reservoir Brine is Gas-Saturated. If Free Gas is Present, It is Less Than Critical Gas Saturation

Because the brine is saturated, it is highly likely that free gas exists somewhere in the reservoir. If initial production does not lower the bottomhole pressure enough for the free gas that may be present near the wellbore to reach critical gas saturation, the produced GWR will be less than that of solution gas. This would be caused by gas exsolving in response to the pressure reduction caused by production. The exsolved gas would be trapped in the reservoir as long as the critical gas saturation was not reached. Because the heavier hydrocarbon gas would preferentially exsolve in the reservoir, the produced gas would contain less heavy hydrocarbons than the gas originally dissolved in the reservoir brine. The produced GWR would continue to decrease with decreasing bottomhole pressure until enough gas had exsolved to reach critical gas saturation. If, after critical gas saturation had been obtained, the brine production rate was increased enough to significantly increase the gas saturation near the wellbore, the produced GWR and ethane/methane and propane/methane ratios of the produced gas would increase as the gas previously exsolved in the reservoir near the well bore was produced. It is possible to produce enough gas to significantly lighten the weight of fluids in the production string. This results in an increase of wellhead pressure and thus a decrease in the difference between bottomhole pressure and wellhead pressure. The changes in GWR, pressure, and produced gas composition would be very transient. As the free exsolved gas was produced, the gas saturation would approach critical, and the rate of free gas production would decline dramatically. Thus, timing of measurements and sample collection is very important. With further production, the produced GWR and the ethane/methane and propane/methane ratios will continue to drop below those being produced before the rate increase.

Model 3. Bubble Point Below Hydrostatic Pressure

For this case, the composition of the produced gas and the produced GWR will be independent of changes in the production rate or bottomhole pressure. They will be representative of gas in solution in the brine, provided the brine is not pumped from the reservoir.

Model 4. Bubble Point Between Hydrostatic Pressure and Reservoir Pressure

This reduces to Model 3 as long as the bottomhole pressure is above the bubble point and reduces to Model 2 when the bottomhole pressure becomes equal to or lower than the bubble point.

In the following section, Design Well data (bottomhole pressure minus wellhead pressure, GWR, and hydrocarbon composition) will be presented as a function of producing conditions. These will be examined in conjunction with the above models to attempt to deduce the reservoir brine saturation level.

Introduction

The Dow-DOE L. R. Sweezy No. 1 Well was drilled in Parcperdue Field, in Vermilion Parish, Louisiana, approximately 12 miles south of Lafayette. The target upper Oligocene "Cib jeff" sand occurs at a depth of 13,350 feet and is approximately 50 feet thick. The areal extent of the Cib jeff reservoir within the target fault block is approximately 1 square mile. This reservoir was chosen because the Dow Chemical Company felt that much could be learned about the long-term behavior of geopressed reservoirs if a small, well-defined reservoir could be depleted and intensively studied over a short period of time — a year or two. Production testing of the well began in April 1982. On February 5, 1983, a massive sanding incident shut down the production well permanently.

Pressures and Flow Rates

Bottomhole pressure, brine flow rate, and bottomhole pressure minus wellhead pressure are presented for some of the flow tests in Figures 1 through 6. Only the first 6.1 hours of the flow test from 6/2 to 6/28/82 are presented in Figure 5 because surface pressure data are not published for the rest of the test. During the next 115.16 hours, the brine flow rate varied between 9455 and 9518 RESBPD, and the bottomhole pressure decreased from 10262.60 to 10191.81 psia. No data are published for the rest of that test. Surface pressure data are not available for the 7/6 to 8/27/82 flow test; flow and bottomhole pressure data are available for only 15.3 hours of the test and are not plotted. The data are also sparse for the 8/31 to 11/2/82 flow test.

The data plotted in Figures 1 to 6 were manually entered into a computer at IGT from data presented by Otis Engineering Corporation in Appendix B of Hamilton and Stanley (1984). They are the best data available (Hamilton, 1984). Otis Engineering Corporation was responsible for the pressure measurements, which were recorded on magnetic tape cassettes. The readings were "instantaneous" (Coble, 1984), rather than averages. The general procedure was to record pressures at 1-second intervals for the first minute, 2-second intervals for the following 2 minutes, 5-second intervals for the

*Most of the information in this section comes from Hamilton and Stanley (1984).

Figure 1. DOW-DOE L. R. SWEETZ NO. 1 4/26 TO 4/28/82 FLOW TEST

Figure 2. DOW-DOE L. R. SWEETZY NO. 1 5/12 TO 5/13/82 FLOW TEST

Figure 3. DOW-DOE L. R. SWEETZ NO. 1 5/17 TO 5/18/82 FLOW TEST

Figure 4. DOW-DOE L. R. SWEZY NO. 1 5/20 TO 5/26/82 FLOW TEST

Figure 5. DOW-DOE L. R. SWEZY NO. 1 6/2 TO 6/28/82 FLOW TEST

Figure 6. DOW-DOE L. R. SWEETZ NO. 1 11/15/82 TO 1/19/83 FLOW TEST

next 3 minutes, 15-second intervals for the next 10 minutes, and 1-minute intervals thereafter. However, all these points are not presented in Appendix B of Hamilton and Stanley (1984) and thus are not included in Figures 1 to 6. The data points are connected by straight lines in these figures.

Johnston-Macco/Schlumberger (now Flopetrol-Johnston) was responsible for the brine and gas flow rates. The general procedure was to manually record the brine flow rate at 1/2-hour intervals. Thus, the brine rates are averages over the time period between readings. Gas measurement was quite difficult due to the low volume of gas produced and the inability to maintain a constant back pressure on the gas line and condensation or water carryover from the separator. An orifice meter, used initially to meter gas, was replaced with a positive displacement meter; finally, the two were used in conjunction. The positive displacement meter was considered more reliable, but it did experience numerous malfunctions. In May 1982, gas volumes measured on a Daniels Sr. orifice meter were erratic due to surging and indicated a GWR of only 10 or 12. A Rockwell P.D. gas meter was installed, and it indicated a GWR of approximately 20. Jack Hamilton felt that the brine rate measurements were good, but that the gas rate measurements were poor, probably not better than $\pm 30\%$ (Hamilton, 1984). An uncertainty this large makes the GWR useless in deducing reservoir saturation by monitoring changes in GWR as a function of flow rate or bottomhole pressure because the uncertainty is larger than the expected change.*

In the Model 2 reservoir, the gas that might be freed with a sudden decrease in the bottomhole pressure could lighten the weight of fluids in the production string. This would increase the wellhead pressure and thus decrease the difference between bottomhole pressure and wellhead pressure.

In Figure 1, the BHP-WHP is seen to decrease and then increase during the first flow. The decrease is caused by the lightening of the well bore fluids caused by the heating associated with flow. The straight line segment showing the increase has data points only at its ends: one at 0.88 hours and one at 2.23 hours. The difference is caused by a change in the WHP and is likely due to sand being introduced into the wellbore. This was a continual problem.

*The uncertainty in the GWR's also makes them of limited value in recombination work.

If a "slug" of gas becomes mobile and enters the wellbore due to a BHP reduction, the greatest effect this would have on BHP-WHP would occur when the gas slug arrived at the wellhead. This is because the gas slug's volume would be greatest at the wellhead where the pressure is the lowest in the column. The gas slug should reach the wellhead at about bottoms-up. The Sweezy wellbore volume is approximately 325 bbl. Thus, at a flow rate of 14,016 bbl/day (the highest reported rate ever attained), bottoms-up would occur about 0.56 hours after the rate increase. There are only 21.7 minutes of data in Figure 1 after the minimum BHP was reached, which is less than the estimated 33 minutes needed for bottoms up. Also, the increases seen in BHP-WHP are probably due to sand production, which could mask a lightening caused by a gas slug. Sand production contributed to the termination of this test. It is important to note that, because the brine rates are manually recorded averages (Coble, 1984), rate changes are "out of sync" with pressure changes, and short-term rate changes cannot be seen.

Figure 2 shows only very modest rate changes during this test; the vast majority of the drawdown occurred at start-up. Bottoms-up occurred about 1.25 hours later. The wellbore was heating during this time, which could mask a lightening caused by a gas slug. Also, at about the time of bottoms-up, reported data points are 10 or 20 minutes apart. Thus, a gas slug that passed through the choke in less than 10 or 20 minutes could go completely unseen. The BHP and WHP were recorded by computer on magnetic tape, and if the measurements were taken at the planned schedule, sufficient BHP and WHP data exist on the tapes to see a gas slug if one was produced. Early in this project it was learned that the computer tapes were incompatible with all the computers at IGT. Rather than spend the time and money to get the data transferred from the tapes to an IGT computer, it was decided that the data of interest from Appendix B of Hamilton and Stanley (1984) would be manually entered into an IGT computer. It was only near the end of this project, after it was too late to get the tapes, that Appendix B was recognized as an incomplete data listing.

The initial rapid increase in BHP-WHP, seen in Figure 2 and others, is the result of many contributing factors. Gas that came out of solution in the wellbore due to pressure reduction would migrate to the top during shut-in. This gas is produced when the choke is first opened. The WHP goes down when

the column gets heavier as brine displaces the gas. The pressure wave that results from opening the choke takes a finite time to travel downhole. Thus, the WHP is reduced before the BHP. Based on the speed of sound, this is estimated to be 3 seconds. Flowing pressure drop is also involved when the choke is opened. In addition, the WHP is very sensitive to choke adjustments.

Figure 3 shows modest rate changes that have little or no effect on the BHP. The only significant drawdown occurred at start-up. Again, bottoms-up occurs during well bore heating, and a gas slug could go unseen because of the time between reported data points.

No mention was found in Hamilton and Stanley (1984) of the decrease in brine flow rate shown in Figure 4 at about 691 hours. The well might have been shut in for a time period less than the time interval used in averaging the flow, resulting in a non-zero flow rate. The only significant drawdown occurred at start-up, and bottoms-up occurred about 0.7 hours after that. Again, bottoms-up occurred during heatup, and data points are reported 10 to 20 minutes apart.

Figure 5 is similar to the other figures, except that the initial decrease in BHP-WHP occurs faster and appears to be over before bottoms-up. However, at about bottoms-up, 15 to 20 minutes elapse between reported data points. Again, this is enough time for a gas slug to go through unnoticed.

Figure 6 is similar to Figure 3, and the same comments apply. Thus, no conclusion can be drawn on the level of gas saturation of Sweezy brine based on changes in BHP and WHP.

Gas Composition

The University of Southwestern Louisiana (USL) was responsible for analyses of gas from the Sweezy. Gas was sampled from the separator and analyzed by gas chromatography. The results were made available by D. F. Keeley and J. R. Meriwether of USL; some of the results are presented in Table 2. There were, in addition, 9 values at 0.00, 25 values at 0.01, and 1 value at 0.02 for i-C₆. All reported values for n-C₅ and C₆⁺ were <0.01 mole percent. Keeley and Meriwether feel that the C₃ analysis of 6/14/82 is a bad data point. Neglecting that point, there is little or no change in the reported gas compositions.

Table 2. USL ANALYSES OF SEPARATOR GAS FROM THE DOW-DOE L. R. SWEET NO. 1

DATE	TIME	*NOTE 1	N2	C1	CO2	C2	C3	iC4	nC4	N2/C1	CO2/C1	C2/C1	C3/C1	iC4/C1	nC4/C1	TC4/C1
05/12/82	1705	383.55	.43	93.82	2.79	2.46	.36	.10	.04	.00458	.0297	.0262	.00384	.00107	.000426	.00149
05/13/82	908	399.58	.42	93.81	2.70	2.46	.36	.10	.03	.00448	.0288	.0262	.00384	.00107	.000320	.00139
05/18/82	1245	522.95	.48	93.77	2.77	2.46	.37	.10	.04	.00512	.0295	.0262	.00395	.00107	.000427	.00149
05/20/82	1603	574.53	.50	93.87	2.65	2.48	.37	.08	.03	.00533	.0282	.0264	.00394	.00085	.000320	.00117
06/08/82	1425	1028.75	.39	93.94	2.54	2.48	.38	.10	.06	.00415	.0270	.0264	.00405	.00106	.000639	.00170
06/11/82	1430	1100.80	.35	94.29	2.37	2.48	.37	.09	.03	.00371	.0251	.0263	.00392	.00095	.000318	.00127
06/14/82	1430	1172.80	.36	93.60	2.54	2.53	.83	.10	.03	.00385	.0271	.0270	.00887	.00107	.000321	.00139
06/17/82	1348	1243.98	.36	94.30	2.42	2.48	.31	.09	.03	.00382	.0257	.0263	.00329	.00095	.000318	.00127
06/21/82	1455	1341.05	.35	94.27	2.44	2.49	.32	.09	.03	.00371	.0259	.0264	.00339	.00095	.000318	.00127
06/25/82	1341	1435.91	.51	94.12	2.41	2.47	.37	.09	.03	.00542	.0256	.0262	.00393	.00096	.000319	.00127
07/07/82	1418	1724.68	.42	94.18	2.49	2.45	.31	.10	.03	.00446	.0264	.0260	.00329	.00106	.000319	.00138
07/16/82	1454	1941.04	.37	94.17	2.56	2.45	.31	.09	.03	.00393	.0272	.0270	.00329	.00096	.000319	.00127
07/28/82	1412	2228.62	.36	94.24	2.48	2.46	.31	.09	.03	.00382	.0263	.0261	.00329	.00096	.000318	.00127
08/05/82	1420	2420.70	.42	94.18	2.45	2.45	.36	.09	.03	.00446	.0260	.0260	.00382	.00096	.000319	.00127
08/16/82	1057	2681.07	.39	94.22	2.49	2.47	.31	.09	.03	.00414	.0264	.0262	.00329	.00096	.000318	.00127
08/23/82	1034	2848.84	.37	94.25	2.47	2.47	.31	.09	.03	.00393	.0262	.0262	.00329	.00095	.000318	.00127
09/01/82	1200	3066.50	.37	94.33	2.38	2.48	.31	.09	.03	.00392	.0252	.0263	.00329	.00095	.000318	.00127
09/20/82	1445	3524.95	.40	94.28	2.40	2.47	.31	.09	.03	.00424	.0255	.0262	.00329	.00095	.000318	.00127
09/27/82	1000	3688.50	.38	94.26	2.38	2.48	.37	.09	.03	.00403	.0252	.0263	.00393	.00095	.000318	.00127
10/04/82	1430	3860.80	.36	94.22	2.43	2.48	.37	.09	.03	.00382	.0258	.0263	.00393	.00096	.000318	.00127
10/11/82	1525	4029.75	.35	94.32	2.40	2.51	.29	.09	.03	.00371	.0254	.0266	.00307	.00095	.000318	.00127
10/14/82	957	4096.07	.44	94.16	2.39	2.50	.37	.09	.03	.00467	.0254	.0266	.00393	.00096	.000319	.00127
10/29/82	1100	4457.50	.35	94.32	2.40	2.50	.29	.09	.03	.00371	.0254	.0265	.00307	.00095	.000318	.00127
11/02/82	948	4551.98	.37	94.26	2.36	2.51	.38	.09	.03	.00393	.0250	.0266	.00403	.00095	.000318	.00127
11/26/82	1017	5128.67	.37	94.40	2.30	2.51	.30	.09	.03	.00392	.0244	.0266	.00318	.00095	.000318	.00127
11/30/82	1123	5225.73	.38	94.22	2.38	2.51	.37	.09	.03	.00403	.0253	.0266	.00393	.00096	.000318	.00127
12/02/82	958	5272.08	.39	94.20	2.40	2.51	.37	.09	.03	.00414	.0255	.0266	.00393	.00096	.000318	.00127
12/10/82	1024	5464.74	.36	94.21	2.41	2.51	.38	.09	.03	.00382	.0256	.0266	.00403	.00096	.000318	.00127
12/20/82	1010	5704.60	.38	94.28	2.41	2.50	.29	.09	.03	.00403	.0256	.0265	.00308	.00095	.000318	.00127
12/27/82	1020	5872.70	.36	94.30	2.40	2.52	.29	.09	.03	.00382	.0255	.0267	.00308	.00095	.000318	.00127
01/03/83	1000	6040.50	.45	94.21	2.36	2.49	.36	.09	.03	.00478	.0251	.0264	.00382	.00096	.000318	.00127
01/10/83	1000	6208.50	.35	94.26	2.38	2.51	.37	.09	.03	.00371	.0252	.0266	.00393	.00095	.000318	.00127
01/16/83	1400	6356.50	.37	94.22	2.40	2.51	.37	.09	.03	.00393	.0255	.0266	.00393	.00096	.000318	.00127
01/25/83	1020	6568.70	.38	94.37	2.25	2.50	.37	.09	.03	.00403	.0238	.0265	.00392	.00095	.000318	.00127
02/02/83	1010	6760.60	.37	94.22	2.41	2.51	.37	.09	.03	.00393	.0256	.0266	.00393	.00096	.000318	.00127

*NOTE 1; HOURS SINCE 1730 HOURS ON 4/26/82

As explained earlier, the produced gas composition will change when some free gas is produced from the reservoir. The largest change in gas composition would occur when the gas that existed in the gas phase in the reservoir reaches the separator. This should occur at about bottoms-up after a significant brine flow rate increase. No gas samples were collected during these times. As explained by Model 4, the produced gas composition should remain the same as long as the BHP is above the bubble point, but it should change and continue to change as the BHP drops further and further below the bubble point and the gas saturation remains below critical. The changes under these conditions would be quite small — very likely much smaller than the uncertainty in the values presented in Table 2. No conclusions can be drawn on the level of gas saturation of Sweezy brine based on changes in gas composition.

The results of the Sweezy gas analysis from IGT (Doherty and Poonawala, 1983, Appendix C), USL (Hamilton and Stanley, 1984), and Lawrence Berkeley Laboratory (LBL) (Weres et al., 1984) are presented in Table 3. Plots such as those seen in Figures 1 to 6 are not available for the times these samples were taken because the data were not published. However, according to the written report (Hamilton and Stanley, 1984), there were no significant rate changes during this time. A rate change from 9,500 bpd to 10,500 bpd and back to 9,500 bpd was reported for August. No rate change was reported for September after the resumption of flow on September 9, 1982.

It was concluded, based on the USL analyses, that the gas composition did not change. The differences seen in Table 3 are common when different laboratories do analyses. Part of these differences are due to differences in sampling and handling procedures and analytical techniques. USL's nitrogen analysis includes air if it is present. Because geopressured-geothermal aquifers are highly reducing, if IGT finds oxygen is in a gas sample it is assumed to be due to air contamination, and the measured nitrogen is appropriately reduced. IGT and USL both used Teflon-lined sample cylinders, but IGT heated the cylinders both before sampling and before analysis, and USL did not. LBL did not report any techniques. Because IGT reported analyzing flare line gas samples, USL reported analyzing separator gas samples, and LBL reported analyzing wellhead gas samples, it is not clear that all the gas samples were taken at the same place. IGT and LBL used mass spectrometry and

USL used gas chromatography. These differences demonstrate the desirability of having the same people and laboratory do all the sampling and analyses when looking for small changes in composition.

Table 3. IGT, USL, AND LBL ANALYSES OF SEPARATOR GAS FROM
THE DOW-DOE L. R. SWEETZ NO. 1

Date Laboratory	9/23/82 IGT	9/24/82 IGT	9/27/82 USL	8/12/82 LBL
N ₂	0.12	0.08	0.38*	<0.3
CO ₂	1.08	1.65	2.38	2.0
C ₁	95.61	95.93	94.26	95.1
C ₂	1.95	1.93	2.48	2.0
C ₃	0.32	0.30	0.37	0.24
n-C ₄	0.11	0.03	.03	0.12**
i-C ₄	0.06	0.07	0.09	—
Benzene	0.02	0.01	—	0.009
Tolulene	0.01	0.00	—	0.006
Xylene	0.00	0.00	—	0.004
Water	—	—	—	0.5
N ₂ /C ₁	0.0013	0.0008	0.0040	<0.003
CO ₂ /C ₁	0.0113	0.0172	0.0252	0.02
C ₂ /C ₁	0.0204	0.0201	0.0263	0.02
C ₃ /C ₁	0.0034	0.0031	0.0039	0.0025
n-C ₄ /C ₁	0.0012	0.0003	0.0003	—
i-C ₄ /C ₁	0.0006	0.0007	0.0010	—
TC ₄ /C ₁	0.0018	0.0010	0.0013	0.0013

IGT: Institute of Gas Technology

USL: University of Southwestern Louisiana

LBL: Lawrence Berkeley Laboratory

*Includes air if present.

**Only total butanes were reported.

IGT also reported two analyses for the amount and the composition of gas remaining in the brine going to the disposal well. These analyses are also needed when looking for gas composition changes, especially when the separator pressure is not constant. A change in separator pressure will cause a change in both the amount and composition of gas leaving the separator, both in the gas phase and dissolved in the brine going to the disposal well, even though the composition of the fluid entering the well bore downhole did not change. However, the total amount and total composition of the gas (gas phase and dissolved in the brine) leaving the separator is constant. These two IGT

analyses and one done by John Neal (1982) are believed to be the only ones done on the Sweezy and are far too few to rigorously look for gas composition changes. The separator pressure was kept between 600 and 650 psi throughout the test, and it was assumed that the amount and composition of the gas remaining in the brine would remain constant throughout the test and that changes would be reflected by changes in the gas phase gas that was analyzed. This assumption was believed to be good for the composition changes expected if a slug of gas were produced. (In other words, the change would be large enough to see.) The changes expected because gas was liberated and trapped in the reservoir are probably smaller, and the dissolved gas measurement and analysis thus become more important. Also, the need for these analyses increases as the variation in separator pressure increases.

NOTE: Also see section "OTHER HYDROCARBONS" and section "PVT MEASUREMENTS AND BUBBLE POINT ALGORITHMS."

Conclusions

Use of the reservoir models presented herein was inconclusive in determining if the DOW-DOE L. R. Sweezy No. 1 brine was saturated with natural gas for the following reasons. Use of these models requires accurate measurements of GWR, gas compositions, and pressures. Because small transient changes in GWR, gas compositions, and pressures are being looked for, these parameters must be measured accurately and must be measured during the expected transients. Great difficulty was experienced in measuring GWR's, and the accuracy was less than needed for this study. The BHP and WHP were probably measured with enough accuracy and frequency, but only selected data points were published. No transients were seen in the data published, but transients might have occurred between the times of reported data. The transient change in produced gas composition caused by producing a slug of gas would be greater than the very gradual change in produced gas composition caused by the BHP dropping below the bubble point and producing only dissolved gas that did not exsolve from the brine in response to the pressure reduction. Gas samples were not taken at the times a gas slug was most probable. The small changes in gas composition expected during other times are probably less than the uncertainty in the measurement.

Concentration gradients probably exist in the reservoir brine. If they exist, they introduce more uncertainty in PVT bubble point determinations and in the algorithms used to calculate bubble points.

THE MG-T/DOE AMOCO FEE NO. 1*

Introduction

The MG-T/DOE Amoco Fee No. 1, also known as the Sweet Lake Well, is located in Section 13, T12S-R8W, Cameron Parish, approximately 15 miles south of Lake Charles in southwestern Louisiana. The well was drilled and operated by the Magma Gulf-Technadril joint venture. The total depth was 15,740 feet, and the target sand was the Miogypsinades sands at a depth of the upper Frio. The production and disposal wells were drilled during August 1980 to February 1981.

The first sand tested was sand 5, which is located between 15,385 and 15,415 feet. The original pressure and temperature were 12,052 psi and 299°F, respectively. Three tests were conducted. The initial flow test began at 6:18 p.m. on June 19, 1981, and ended at 8:04 p.m. on June 22, a total of 3.03 days. During this time, 10,574 barrels of brine were produced at an average rate of 3,444 bbl/day. The variation in the flow rate (2,820 to 4,680 bbl/day) was due primarily to restrictions in the disposal well which necessitated diverting the flow to the blowdown tanks. The bottomhole pressure was drawn down 900 psi (Durrett, 1983). The reservoir limit test began at 6:15 p.m., June 30, 1981, and ended at 5:00 p.m., July 17, a total of 17 days. The average flow rate was 13,350 bbl/day, and approximately 226,300 barrels of brine were produced. The flow rate varied from a high of 16,000 bbl/day at the start of the test to nearly 10,000 bbl/day at the end. The bottomhole pressure dropped from 11,974 psi to 7,804 psi. The long-term testing began July 17, 1981, and ended February 10, 1982. The flow rate varied from a high of 38,000 bbl/day to a low of 1,000 bbl/day, for a total production of approximately 1.1 million barrels of brine.

The second sand tested was sand 3 located from 15,246 to 15,285 feet. The initial reservoir pressure and temperature at 15,245 feet were 11,887 psi and 293°F, respectively. The initial cleanup flow, which lasted 24 hours at somewhat under 3,000 bbl/day, drew the bottomhole pressure down to 10,133 psi. An 8-day buildup terminated at 0847 hours on November 22, 1983, when the

*Most of the following information comes from Hoffman (n.d.) for sand 5 and from C. K. Geoenergy Corporation (Jan. 1984) for sand 3.

drawdown test began. The brine flow rate was about 2,200 bbl/day the first 7 days of the test. The well was then opened for the maximum production rate of about 6,600 bbl/day. The downhole pressure tool was in the hole for more than 14 days of this test. The well was shut in for the last time at 6:44 p.m. on March 13, 1984, before plugging and abandonment activities began on June 28, 1984 (Magma-Gulf Technadril inter-office memo).

Sand 5

The first measurements of gas production rates yielded an estimate of dissolved methane of 7 to 8 SCF/bbl for the MG-T/DOE Amoco Fee No. 1. These values are much less than those expected, based on Wells of Opportunity tests and the solubility algorithms (see "PVT MEASUREMENTS AND BUBBLE POINT ALGORITHMS" section). John Neal of Weatherly Laboratories, Inc., performed a recombination using 8.1 SCF/STB as the produced gas-brine ratio and found the corresponding bubble point to be approximately 2,006 psia (Neal, 1981b). Accumulation of gas in the high-pressure corrosion coupon bypass line provided evidence that two phases existed at the wellhead when the wellhead pressure was higher than 2,000 psi. This suggested that more than 8.1 SCF/STB were actually being produced. The operator recognized that there were flow metering problems and took steps to correct them. However, one problem which was not corrected was the physical location of the orifice differential pressure transmitter. The transmitter was located below the orifice. Two tubes, one on each side of the orifice plate, connected the orifice to the transmitter. Thus, liquids that condense out of the gas stream enter the tubing and cause erroneous readings. Hoffman (n.d.) reported GWR ranges of 25 to 28 SCF/bbl on pages 22 and 39, but 23 to 27 SCF/bbl on page 27. It is not clear if these include the gas that remains in the brine after passing through the separator, whether the barrels are stock tank or separator barrels, or during which part of the test these values were obtained. The GWR's presented in the Daily Reports for the first two tests are obviously in error. Therefore, changes in GWR could not be used to determine the reservoir bubble point.

During August 1981, IGT personnel collected and analyzed gas and brine samples from the separator during testing of the MG-T/DOE Amoco Fee No. 1 sand 5. The work and related reviews of data were performed in accordance with the statements of work for IGT's DOE-sponsored project, "Computer Simulation of

Geopressured Aquifers," IGT's GRI-sponsored project, "Gas Saturation in Formation Waters," and a purchase order to IGT from Magma Gulf-Technadril. A report written by Hayden, Randolph, and Osif (1981) appears as Appendix B of Doherty and Poonawala (1983). The data dealing with gas composition changes are provided below.

A set of samples consisted of a flare line gas sample and two separator brine samples. A set of samples was collected as quickly as possible to minimize the chance that changes would occur during sample collection. Gas samples were collected in preheated Teflon-lined stainless steel sample cylinders after thorough purging of the cylinder with the gas. The brine samples were caught in the Teflon-lined stainless steel pressure vessels at separator pressure and temperature. After sample collection, all cylinder valve ends were capped and the brine cylinders were cooled by immersion into a cold water bath. The gas samples and one of each pair of brine samples were shipped to IGT for analyses. The other brine samples were analyzed on site. The on-site analysis was measurement of the GWR of the separator brine. This was done by attaching a large syringe (500 or 1000 mL) to the top valve of the vertically held cylinder. Pressure reduction to about 1 atmosphere was accomplished when the top cylinder valve was opened, allowing gas to expand into the syringe and push the plunger. The gas volume was read directly from the syringe after the cylinder was struck several times with a wrench to enhance gas dissolution. The brine was then emptied into a graduated cylinder and its volume measured. The difference between the cylinder volume and the brine volume was added to the gas volume read from the syringe.

The gas samples were analyzed at IGT in Chicago with a mass spectrometer after heating the samples. The GWR of the brine samples were measured as on site. The exsolved gas composition was also determined with a mass spectrometer. A portion of the brine was treated with sodium hydroxide. It was then treated with acid and purged with nitrogen. The released carbon dioxide was quantitatively trapped and weighed. Alkalinity was determined by titrating a portion of the untreated brine with sulfuric acid. The remaining untreated brine was acidified and analyzed for calcium.

On-site and Chicago measurements of the amount of gas dissolved in the brine leaving the separator are compared in Table 4. Note that all GWR's measured in Chicago are lower than the GWR's measured in the field. These

Table 4. COMPARISON OF FIELD AND LABORATORY MEASUREMENTS OF GAS REMAINING DISSOLVED IN BRINE LEAVING THE SEPARATOR DURING TESTING OF THE MG-T/DOE AMOCO FEE NO. 1 SAND 5 IN 1981

Data	Time	Pressure,* psia	Temperature,* °F	Gas-Brine Ratio	
				Field**	IGT-Chicago*** SCF/STB
8-7	1030	236	160	1.56	1.39
8-7	1800	239	160	1.62	1.12
8-8	0800	248	167	1.71	
8-10	1205	256	165	1.67	1.53
8-11	1840	480	244	2.91	2.10
8-12	1130	464	275	2.99	
8-12	1130	464	275	3.05	
8-12	1420	348	275	2.36	1.96
8-12	1605	569	275	3.76	3.15

* Pressures and temperatures were provided by MG-T.

** Pressure reduction done in the field less than one hour after sample collection.

*** Pressure reduction and analyses done at IGT-Chicago several days after sample collection.

pairs of samples were collected as close in time as possible. Note also the agreement between the two samples collected at 1130 hours on 8/12 and flashed on site. The sample cylinders were Teflon-lined, most were equipped with new valves, and the valves were all capped. Still, it appears that leaks occurred. This was not a problem in the Wells of Opportunity test when analyses were completed on site within 30 minutes of sampling. The chemical analyses of the gas dissolved in the brine leaving the separator are presented in Table 5, and the chemical analyses of flare line gas is presented in Table 6. Ethane/methane, propane/methane, and butane/methane ratios are plotted against time in Figure 7.

Table 5. ANALYSES OF GAS REMAINING DISSOLVED IN BRINE LEAVING THE SEPARATOR DURING TESTING OF THE MG-T/DOE AMOCO FEE NO. 1 SAND 5

<u>Component</u>	<u>8-7-81</u> <u>1030 h</u>	<u>8-7-81</u> <u>1845 h</u>	<u>8-10-81</u> <u>1215 h</u>	<u>8-11-81</u> <u>1836 h</u>	<u>8-12-81</u> <u>1420 h</u>	<u>8-12-81</u> <u>1605 h</u>
Methane, mol %	74.09	79.10	74.81	78.91	80.28	77.17
Ethane, mol %	1.17	1.20	1.15	1.18	1.03	1.00
Propane, mol %	0.13	0.15	0.14	0.15	0.10	0.11
n-Butane, mol %	0.004	0.003	0.003	0.004	0.003	0.003
iso-Butane, mol %	0.002	0.001	0.001	0.003	0.001	0.001
Benzene, mol %	0.02	0.03	0.03	0.03	0.02	0.04
Toluene, mol %	0.005	0.004	0.004	0.006	0.006	0.008
Carbon Dioxide, mol %	24.58	19.51	23.86	19.72	18.56	21.67
Caloric Content, Btu/SCF	763	815	771	812	822	791
Specific Gravity	0.801	0.752	0.794	0.754	0.742	0.772

Table 6. ANALYSES OF FLARE LINE GAS DURING TESTING OF THE MG-T/DOE AMOCO FEE
NO. 1 SAND 5

Date	8-7-81	8-7-81	8-10-81	8-11-81	8-11-81	8-12-81	8-12-81	8-12-81
Time, hours	1045	1830	1220	1840	1937	1130	1420	1605
Brine Rate, BPD*	~1400	~1400	~2000	~34,000	~34,000	~24,000	~24,000	~24,000
Separator Pressure, psia**	236	239	256	480	445	464	348	579
Brine Temperature, °F**	160	160	165	244	275	275	275	275
Methane***	89.28	88.77	90.04	90.14	89.45	89.15	88.87	89.78
Ethane	1.74	1.73	1.68	1.83	1.72	1.50	1.40	1.48
Propane	.39	.35	.33	.38	.35	.23	.23	.23
n-Butane	.05	.06	.04	.06	.05	.03	.03	.03
i-Butane	.02	.04	.02	.02	.00	.00	.00	.01
Penetanes	.01	.01	.01	.02	.02	.00	.01	.00
Hexanes	.00	.00	.00	.00	.00	.00	.00	.00
Benzene	.10	.13	.03	.05	.05	.04	.06	.03
Tolulene	.07	.09	.01	.03	.03	.02	.03	.01
Xylene	.00	.01	.00	.00	.00	.00	.00	.00
Hydrogen	.01	.00	.04	.02	.04	.00	.00	.00
Nitrogen	.20	.22	.37	.15	.23	.24	.21	.24
Carbon Dioxide	8.13	8.59	7.43	7.30	8.06	8.79	9.16	8.18

* from Hoffman (n.d.)

** provided by MG-T

*** gas compositions in mole %

Figure 7. ETHANE/METHANE, PROPANE/METHANE AND BUTANE/METHANE RATIOS OF FLARE LINE GAS DURING TESTING OF THE MG-T/DOE AMOCO FEE NO. 1 SAND 5

To be strictly correct, it is changes in total produced gas composition (flare line gas plus gas remaining dissolved in the brine) that should be monitored when using the models presented in the INTRODUCTION. However, combining the dissolved gas analyses using either the field or Chicago measured GWR's with the flare line gas analyses using GWR's ranging from 23 to 29 SCF/STB results in hydrocarbon ratios that are not much different than the flare line hydrocarbon ratios. In other words, the changes that result from including the dissolved gas are small compared to the changes seen in Figure 7. Because the changes in the flare line gas composition are so large in this particular case and because there are more flare line gas analyses than dissolved gas analyses, the flare line analyses are shown in Figure 7.

Table 7. UNCERTAINTY IN MEASURED GAS COMPOSITION

<u>Mol % Component</u>	<u>% Uncertainty</u>
0.01 to 0.09	50
0.1 to 0.9	10
1.0 to 90	5

The percent uncertainty (according to the mass spectrometer manufacturer) in the gas composition is presented in Table 7. The methane and ethane measurements have the least uncertainty, the propane measurements are more uncertain, and the butanes measurements are most uncertain. Therefore, the ethane/methane plot in Figure 7 is better than the other two. Because the propane/methane ratio at 58.75 hours and the butanes/methane ratio at 66.50 hours do not fit the models, they are believed to be inaccurate. Ignoring those two points, Figure 7 shows that all the hydrocarbon ratios initially increased after the rate increase,* and then the ratios decreased to values smaller than those before the rate increase. Note that the increase was very transient. The first sample taken after the rate increase (which also has the highest ratios) was taken after producing 1.5 well volumes (after 0.4 hours). The next sample taken after the rate increase was taken after producing 5.5 well volumes (after 1.3 hours). All the ratios in this sample are lower than the prior sample and higher than those in the next sampling, which is lower than those in the samples taken before the rate increase. This is the behavior expected when the bottomhole pressure before the rate increase

*The rate increase occurred at 1820 hours on 8/11/81.

is lower than the bubble point. Gas that is differentially liberated in the reservoir has higher ethane/methane, propane/methane, and butane/methane ratios than the gas remaining in solution. This gas is trapped in the pore space until the pressure reduction caused by an increase in production rate allows the gas to expand to critical gas saturation. This gas is now produced, which raises the ethane/methane, propane/methane, and butane/methane ratios of the gas reaching the surface. As the liberated gas is produced and the pressure drops, the saturation approaches critical and the production of liberated gas drops dramatically. More gas is differentially liberated and trapped in the reservoir in response to the new lower pressure. This results in the gas now reaching the surface having lower ratios than before the rate increase.

The differences among the ratios of the last three samples are probably due to the uncertainties in the measurements, but could conceivably be due to time-dependent phenomena (such as trapped gas re-dissolving in the brine) triggered by the decrease in rate from ~34,000 to ~24,000 bbl/day, which occurred before the last three samples were taken. Accurate GWR's would give more insight into this. Also, if accurate GWR measurements existed and if they varied in the expected way with the observed hydrocarbon ratios, they would provide additional evidence that the near wellbore reservoir had been drawn down below the original reservoir bubble point sometime prior to the sampling shown in Figure 7. Without accurate GWR measurements, the same conclusion is reached but with somewhat less certainty. The initial bottomhole pressure was 12,064 psia. The bottomhole pressure had been drawn down from 11,974 psia to about 7,806 psia from 6/30/81 to 7/17/81. The flow ranged from 16,000 to 10,500 bbl/day during this time. On 7/17/81, the downhole pressure tool was removed; bottomhole pressure measurements are not available thereafter. The flow rate remained between 10,000 and 11,000 bbl/day until it was decreased to 2400 bbl/day on 7/22/81. The rate was less than 3000 bbl/day from then until IGT began collecting samples on 8/7/81, except for a few hours on 7/30/81 when the rate was 10,000 bbl/day (Hoffman, n.d.). The bottomhole pressure obviously increased with the rate decrease on 7/22/81, and some of the exsolved trapped gas might have gone back into solution. This would depend on a number of parameters, including the reservoir bubble point, the pressure history, and the rate at which the free gas would re-dissolve in the brine in the reservoir. For example, if the

pressure around the well bore after the rate reduction was above the original reservoir bubble point, free gas would be re-dissolved at some rate. If, on the other hand, the pressure around the well bore after the rate reduction were below the original reservoir bubble point (which it would be if the reservoir was originally saturated), additional gas would be exsolved from the brine in the reservoir. Again, this gas would be trapped until it reached critical gas saturation. Because state-of-the-art reservoir simulators do not take these factors into account, it is not possible to calculate how much higher than the lowest prior bottomhole pressure the original reservoir bubble point is. Thus, one can conclude from the above that the original reservoir bubble point is higher than 7,800 psia, but not how much higher. It is important to do these tests before the reservoir is drawn down significantly so that the range of uncertainty is reduced.

Karkalits and Hankins (1981) from McNeese State University analyzed separator gas samples; the results are presented in Table 8. Note that the ethane/methane, propane/methane, and butane/methane ratios are about equal for the first two samples, but they are all considerably less for the third. Karkalits and Hankins report that the first sample was taken at 4:00 p.m. on June 20. They do not give times for the other two samples or operating conditions for any of them. The first two samples were taken during the initial flow test which began at 6:18 p.m. on June 19, 1981, and ended at 8:04 p.m. on June 22, and the third sample was taken during the reservoir limit test, which began at 6:15 p.m., June 30. Thus, the well was shut in for 8 days between the collection of the second and third samples. Liberated gas might have redissolved during this time.

Table 8. CHEMICAL ANALYSES* OF SEPARATOR GAS FROM THE MG-T/DOE AMOCO FEE NO. 1 SAND 5 ANALYZED BY McNEESE STATE UNIVERSITY

(All values in mol % unless otherwise noted.)

Component	6-20-81	6-21-81	7-2-81
NH ₃ (ppmv)	(<0.2)	(<0.2)	(<0.2)
H ₂ S (ppmv)	(0.6)	(20)	(32)
He (ppmv)	(28)	(25)	
H ₂ (ppmv)	(210)	(90)	(25)
Oxygen	<0.01	<0.01	<0.01
Nitrogen	0.22	0.22	0.24
Methane	86.74	89.21	87.28
Carbon Dioxide	10.81	8.36	10.59
Ethane	1.76	1.82	1.63
Propane	0.30	0.31	0.23
i-Butane	0.03	0.03	0.01
n-Butane	0.04	0.04	0.02
i-Pentane	0.01	0.01	0.00
n-Pentane	<0.01	<0.01	0.00
Hexane +	<0.01	<0.01	0.00
Total	100.00	100.00	100.00
C ₂ /C ₁	0.0203	0.0204	0.0187
C ₃ /C ₁	0.0035	0.0035	0.0026
C ₄ /C ₁	0.00081	0.00078	0.00034
BHP, psia**	11,272	11,329 to 11,110	8914 to 8426
Sep. P, psia**	508	511 to 462	510 to 503
Sep. T, °F**	206	215 to 203	270 to 250
Brine Rate, B/D**	~ 4500	~3800	~15,000

* Karkalits and Hankins (1981).

** Magma Gulf-Technadril daily testing reports.

The separator pressure is about the same for all three samples, but the temperature is higher for the third. Because the amount and composition of the gas remaining dissolved in the brine was not measured, it is not possible to tell from Table 8 if the changes in the hydrocarbon ratios are due to changes in separator temperature or due to gas being exsolved and trapped in the reservoir. Table 6 shows the separator temperatures and pressures when IGT took samples. As stated earlier, under these conditions, combining the dissolved gas analyses with the flare line gas analyses results in hydrocarbon ratios that are not much different than the flare line hydrocarbon ratios. Assuming the same is true for the samples collected by McNeese State

University, most of the changes seen in the hydrocarbon ratios in Table 8 are due to gas exsolving and being trapped in the reservoir. The bottomhole pressure was 8914 psia and 8426 psia at the beginning and end of July 2, 1981, respectively, and had never been drawn down this far before. The original reservoir bubble point pressure must therefore be higher than 8426 psia. If the time (hour) the sample was collected were known, this lower limit on the bubble point could be more precisely determined between the 8914 psia and 8426 psia pressure limits.

This 8426 psia pressure is a lower limit on the original reservoir bubble point. The models presented do not predict how far above this limit the original bubble point is. However, this lower limit is higher than the 7800 psia limit deduced from the work done by IGT, which was presented earlier.

Sand 3

Sand 3 is located at 15,245 to 15,285 feet. The original reservoir pressure was 11,887 psia and the temperature was 293°F at 15,245 feet (C. K. Geoenergy, Jan. 1984). The Initial Flow Test (cleanup) lasted 24 hours and began at 11:50 a.m. on Saturday, November 12, 1983. The rate was about 2,800 bbl/day until bottoms-up when the rate increased to about 4,000 bbl/day. The bottomhole pressure decreased from 11,883 psia to 10,133 psia (at 15,200 ft.) during this test. The well was shut in until 8:50 a.m. on Tuesday, November 22, 1983, when the drawdown phase of the Reservoir Limit Test began. The bottomhole pressure and temperature were 11,794 psia and 294°F, respectively, at 15,200 feet.

Reservoir Dynamics, Inc. (RDI), of Houston, Texas, recorded the bottomhole pressure, wellhead pressure, bottomhole temperature, and brine flow rate on magnetic tape for the first part of this test. Nathan Waldman of RDI sent a copy of the tapes to IGT after he received permission from Larry Durrett, Manager - Testing for this well. The bottomhole pressure, the brine flow rate, and the difference between the bottomhole pressure and wellhead pressure from November 22 (day 325) to December 8, 1983 (day 341) are presented in Figure 8. The data were not edited by IGT and are plotted as received from RDI. Each curve in Figure 8 goes through over 3000 data points. The larger time tick marks are 0000 hours of the day below the tick.

Figure 8. BOTTOMHOLE PRESSURE, BRINE FLOW RATE, AND BOTTOMHOLE PRESSURE MINUS WELHEAD PRESSURE AS RECORDED BY RESERVOIR DYNAMICS, INC., FOR THE MG-T/DOE AMOCO FEE NO. 1 SAND 3 FROM NOVEMBER 22 TO DECEMBER 8, 1983, INCLUSIVE

The cyclic variations in BHP-WHP seen before the rate increase on day 332 are due to temperature fluctuations of the pressure sensor. From day 327 to 332, the minimum occurs about mid-day when the air temperature is warmest, and the maximum occurs during the night when the air temperature is coolest. The end of day 329 and the beginning of day 330 are a little different. This is probably due to temperature changes caused by the thunderstorm that occurred during this time.

Within 4 hours after the rate increase (concurrent with the BHP decrease) that occurred during day 332, the BHP-WHP is lower than it ever was before the rate increase and the daily cyclic variations are less pronounced. These are believed to be the result of the increased temperature. The flow increase caused the surface temperature to increase by 60° to 70°F. The higher temperature would lighten the fluid column in the well bore which, in turn, would decrease BHP-WHP. It was just shown that the signal given by the pressure sensor is temperature-dependent and an increase in temperature causes a decrease in the signal. The increase in surface temperatures would probably decrease the daily variation in the pressure sensor output due to changes in air temperature. This would definitely be true if thermal insulation were placed around the pressure sensor when the rate was increased.

The most significant rate increase occurred during day 332. The same data for days 332 and 333 that are plotted in Figure 8 are also plotted in Figure 9 to expand the time around this increase. Each curve in Figure 9 goes through 690 data points. It is obvious from the bottomhole pressure curve that the brine flow rate was not zero between 332.50 and 332.75 days. The brine flow rate signal must have been lost during this time. The increase in rate just before 332.5 days and the decrease in rate early in day 333 are also inconsistent with the bottomhole pressure curve and must be in error. Note that elsewhere changes in rate are accompanied by changes in bottomhole pressure.

The decrease in BHP-WHP occurring between about 332.3 days and the rate increase is caused by the daily temperature variations discussed earlier. If the increase in brine flow rate caused free gas around the well bore to expand to critical gas saturation, the BHP-WHP should decrease. The maximum decrease should occur about bottoms-up when the free gas reaches the wellhead, where the pressure is the lowest in the well column. The free gas volume would be

Figure 9. BOTTOMHOLE PRESSURE, BRINE FLOW RATE, AND BOTTOMHOLE PRESSURE MINUS WELLHEAD PRESSURE AS RECORDED BY RESERVOIR DYNAMICS, INC., FOR THE MG-T/DOE AMOCO FEE NO. 1 SAND 3 FROM NOVEMBER 29 TO NOVEMBER 30, 1983, INCLUSIVE

largest then and it would have its maximum effect in lightening the fluids in the well column. Flow rates are not available during this time, but bottoms-up certainly occurred within 4 hours after the rate increase. The minimum in BHP-WHP occurring at 332.58 days is very unlikely a result of free gas. The average flow rate would have had to have been greater than 10,000 bbl/day since the rate increase for bottoms-up to occur at this time. A flow rate this high is inconsistent with the bottomhole pressure response. Whatever caused the inflection in the bottomhole pressure probably also caused the minimum in the BHP-WHP. Thus, the BHP-WHP gives no indication of production of a slug of free gas. Although this is the behavior expected if the original reservoir bubble point is lower than the 10,046 psia bottomhole pressure before the rate increase, it is not proof that there was no free gas present significantly above the critical gas saturation just after the rate increase.

Separator gas composition was studied as a function of bottomhole pressure. The ethane/methane ratios are presented in Table 9. Higher hydrocarbon concentrations were not reported. The analyses were done on the separator gas and thus do not include the gas left dissolved in the brine. As explained previously, the gas dissolved in the brine would have a different composition than the free gas in the separator. Thus, the composition of the total (dissolved and any free) gas being produced from the reservoir would be different than the separator gas. The operators offset this somewhat by keeping the separator pressure approximately constant at 500 psi. However, the amount and composition of the gas dissolved in the separator brine is also dependent on the temperature, which was not constant. The separator temperature was about 170°F when the reservoir pressure was above 10,000 psi and about 230°F when the reservoir pressure was 9,030 psi and below. This and the standard analytical uncertainties mean that the ratios in Table 9 are all probably the same within experimental error. However, it is striking that, with the exception of the last point, the ratios are constant at pressures of 8,780 psia and above and then decrease with decreasing pressure. With the uncertainties involved in the ratios, these measurements should not be considered proof, but they are consistent with the PVT bubble point of 8,800 psia measured by John Neal (1983c).

Table 9. ETHANE/METHANE RATIOS OF SEPARATOR GAS FROM THE MG-T/DOE AMOCO FEE NO. 1 SAND 3 AT DIFFERENT BOTTOMHOLE PRESSURES*

Bottomhole Pressure, psia	Ethane/Methane Ratio**
10,720	0.020
10,550	0.020
10,400	0.020
10,118	0.020
9,030	0.020
8,780	0.020
8,554	0.018
8,310	0.018
8,024	0.018
7,625	0.017
7,614	0.017
7,603	0.018

*Data from page 91, CK Geoenergy, Corporation, Jan. 1984.

**Brine/gas separator pressure was 500 psig.

The amount of separator gas produced was about 19.5 to 20 SCF/bbl with about 3 or 4 SCF/bbl remaining dissolved in the separator brine for a total of 22.5 to 24 SCF/bbl during the early testing of this sand (CK Geoenergy Corporation, Jan. 1984). At the end of the drawdown test, the surface tubing pressure was 290 psia, the separator pressure and temperature were 250 psig and 189°F, respectively, the flow rate was 2000 STB/day, and the separator GWR was 19.5 SCF/bbl. Although there were some problems with GWR measurements, almost all the separator GWR's were between 19 and 20 throughout this test (Magna Gulf-Technadril). Figure 8 shows that, for a flow rate of about 2000 bbl/day, the BHP-WHP is 7000 to 7060 psi. Using these values and the measured WHP of 290 psia gives a BHP of 7290 to 7350 psia. Using the reported final separator GWR of 19.5 SCF/bbl and estimated values of 2 to 2.5 SCF/bbl for the gas remaining dissolved in the separator brine gives a total produced GWR between 21.5 and 22.0 SCF/bbl at the end of the test. With these uncertainties, it is not clear if the total produced GWR changed during this test or not. Neal (1983c) reports a bubble point of 7900 psia for a GWR of 21.5 and a bubble point of 8100 psia for a GWR of 22.0 SCF/bbl based on recombination studies. His differential liberation results give a bubble point of 6500 psia for a GWR of 21.5* SCF/bbl and a bubble point of 6800 psia

for a GWR of 22.0* SCF/bbl. There is a discrepancy of 1300 to 1400 psi between the recombination and differential liberation results. The recombination results are believed more reliable. In any event, the highest laboratory bubble point of 8100 psia is higher than the estimated BHP at the end of the test and the lowest laboratory bubble point of 6800 psia is lower than the estimated BHP at the end of the test. Thus, the laboratory work is inconclusive as to whether the final BHP was above or below the original reservoir bubble point. If the final BHP was above the original reservoir bubble point, then the produced gas composition and GWR would have remained constant. If the final BHP was below the original reservoir bubble point, then the produced gas composition and GWR would have changed during production. It has been shown that there is too much uncertainty in both the produced gas composition and GWR to tell if they changed or not. Thus, they cannot be used to determine if the reservoir was originally saturated or not.

NOTE: Also see section "OTHER HYDROCARBONS" and section "PVT MEASUREMENTS AND BUBBLE POINT ALGORITHMS."

Conclusions

Use of the reservoir models presented herein led to the conclusion that the original bubble point of sand 5 in the MG-T/DOE Amoco Fee No. 1 well is higher than 8426 psia, but no conclusion could be made as to how much higher.

No conclusion could be reached concerning the original bubble point of sand 3 in the MG-T/DOE Amoco Fee No. 1. Good bottomhole and wellhead pressure measurements were made and recorded on magnetic tape during the first part of the drawdown test. There is no transient in these measurements after the brine flow rate increase that could have been caused by the production of a slug of free gas. If such a transient existed, the conclusion could be made with a great deal of certainty that the original reservoir bubble point was higher than the lowest BHP before the rate increase. However, lack of such a transient does not mean that the opposite conclusion can be drawn. The uncertainty in the gas composition and GWR measurements is too great to reach any conclusion about the original bubble point.

*Because Neal's wet GWR's have more uncertainty than his dry GWR's, the dry GWR's are reported here. The GWR's reported for the well are wet, but the uncertainty in them is greater than the correction to make them dry. In any case, the correction would result in even lower laboratory-measured bubble points.

Low-pressure gas can leak from Teflon-lined stainless steel pressure cylinders fitted with new, capped valves.

Concentration gradients probably exist in the reservoir brine. If they exist, they introduce more uncertainty in PVT bubble point determinations and in the algorithms used to calculate bubble points.

Zarella et al. (1967) observed that brines in normally pressured reservoirs in contact with conventional crude oil deposits contained dissolved benzene but brines from gas fields with no oil production contained no benzene. Benzene was found in all the Design Well sands that were flow tested except sand 5 in the Amoco Fee, which was not tested for benzene. If the above observation holds for geopressured-geothermal aquifers, then most if not all the flow tested Design Well sands contain conventional oil deposits. Two of the sands were flow tested long enough for the conventional oil production to commence.

THE PLEASANT BAYOU NO. 2*

Introduction

The Pleasant Bayou No. 2 is the first of the Design Wells. It is in Brazoria County about 40 miles south of Houston, Texas, and was drilled to a total depth of 16,500 feet. Drill stem tests of the sand between 15,988 and 16,064 feet and the sand between 15,576 and 15,586 feet showed these sands were not suited for further testing. The sand from 14,647 to 14,707 feet was suitable and the entire length was perforated with four shots per foot. The bottomhole pressure was 11,275 psia at 14,750 feet after the perforations were cleaned out, and the bottomhole temperature was 309°F.

Three flow tests were conducted under phase "0" using portable testing equipment, from November 15 to December 14, 1979. The Phase I Production Test began at 1143 hours on September 16, 1980, and ended October 31, 1980, at 1535 hours. The Phase II Part A test began at 1950 hours on July 3, 1981. The static bottomhole pressure at 14,560 feet was 11,074 psia. There were many interruptions before Phase II Part A ended July 17, 1981, when the bottomhole pressure gauge and wire line were lost in the hole. Phase II Part B testing began at 1715 hours on September 23, 1982, and ended at 2400 hours on October 22, 1982.

The production well bottomhole pressure and the disposal well bottomhole pressure were measured and recorded on magnetic tape by Reservoir Data Inc. for Phase I and Phase II Part A testing. Weatherly Engineering used electronic sensors to measure surface temperature, pressures, differential pressures, and rates. These data were processed by a computer and printed on paper. Comments were also printed on the paper. None of these data or comments were recorded on magnetic media (Frier, 1984). There were problems with gas rate measurements. At the beginning of Phase I testing, the data collected by Weatherly Engineering was instantaneous. The differential pressure used in calculating gas flow rates would make rather large oscillations, and the differential pressure was read and recorded once every 5, 15, or 30 minutes. Because these readings could be at any point along the oscillations, very large errors can be made in the calculated gas rate. This

*Most of the information in this section comes from Rodgers (1982).

was recognized as a problem, and differential pressures were read every several seconds and averaged over 5, 15, or 30 minutes.* This was begun either during or after Phase I testing. Frier (1984) could not remember if the other data were also then recorded as averages or not. He also said there were transducer problems and, when the ambient temperature was low, problems with hydrates plugging lines to the transducers. Unstable separator operation was also a problem (Goldsberry, 1981). The daily orifice charts were integrated for gas rates (Frier, 1984).

The Pleasant Bayou No. 2 has also undergone tests that have not formally been reported. Copies of handwritten daily reports for December 23, 1982, to April 14, 1983, inclusive, have been obtained by IGT.

Phase I Testing

A brief synopsis of Phase I testing is presented in Table 10. Two brine rate increases occurred during Phase I testing. The BHP minus WHP for the Pleasant Bayou No. 2 was examined for times around these increases, and no indication of free gas production was found. Anacon analyzed separator gas samples taken on September 17, 1980, September 18, 1980, and every second day thereafter until October 30, 1980, inclusive. Because no samples were taken on the days of the rate increases, none of the samples contained produced free gas unless the free gas production continued for something like a day; i.e., transient free gas production would not be seen.

The separator gas analyses (Rodgers, 1981) showed no systematic variations that can be attributed to either free gas production or to gas being exsolved and trapped in the reservoir.** To be strictly correct, it is the total gas production (separator gas plus gas remaining in the brine after passing through the separator) that should be analyzed for compositional changes. During the time these samples were taken, the separator pressure varied between 770 and 900 psi and the temperature varied between 235°F and

*This will not completely correct the problems. What is actually needed is the average of the square root of ΔP , not the square root of the average ΔP .

**Goldsberry (1981) reported that the LPG (i.e., hydrocarbons heavier than methane) varied from 1.3 to 1.7 gallons per thousand cubic feet. The high LPG production occurred once (9/24/80). The timing makes it hard to explain this increase by free gas production caused by a rate increase.

283°F (Weatherly Engineering Data Systems Field Test Data, Volume II of Rodgers, 1982). The possibility exists that the separator temperature and pressure changes masks changes in the total gas composition by changing the composition of the gas remaining dissolved in the separator brine. This becomes increasingly true as the magnitude of reservoir changes decrease, which, in turn, would decrease the magnitude of surface changes. Table 10 shows that the total drawdown through the end of the 10,900 bbl/day rate was only 596 psi and through the end of the 19,200 bbl/day rate was only 1070 psi. It is unlikely under these conditions that enough gas would have been exsolved near the well bore to reach critical gas saturation or that the produced gas composition would have changed much even if the reservoir were originally saturated. Therefore, seeing no compositional changes is not evidence that the reservoir was not originally saturated.

Table 10. PHASE I PRODUCTION TEST OF THE PLEASANT BAYOU NO. 2*

<u>Prod Rate, bbl/day</u>	<u>Time Flowed, Days</u>	<u>BHP** Start, psia</u>	<u>BHP End, psia</u>
6,624	5	10,872	10,846
10,900	10	10,636	10,591
19,200	3	10,134	10,117
15,500	4	10,325	10,426
13,200	23	10,428	10,388

*From Table 7-2 in Rodgers (1982).

**Original BHP was 11,275 psia at 14,750 feet. BHP's during Phase I and Phase II production were measured at 14,560 feet (Rodgers, 1983). Using a pressure gradient of 0.461 psi/ft (Figure 7-11, Rodgers 1982) gives an original BHP of 11,187 at 14,560 feet.

Phase II Testing

There were no drawdowns during Phase II Part A testing that were much lower than the drawdown achieved during Phase I testing. The most probable time for free gas production was when the well was first opened for this test. Because the flow rate was changed soon after start-up and because the well bore had cooled during the 8-month shut-in, changes in the difference between the bottomhole pressure and the wellhead pressure are functions of the rate change, well bore heating, and free gas production if it occurred. This is too complicated to sort out. No bottomhole pressure gauge was used during

Phase II Part B testing. No analyses of gas samples taken during Phase II testing were found. Thus, no Phase II testing data were found that could be used with the models presented herein to deduce the level of gas saturation in the Pleasant Bayou No. 2 brine.

Other Testing

Plots of GWR, brine flow rate, and separator pressure were made using the data presented in hand written daily reports covering the period 12/23/82 to 4/14/83 inclusive. Careful examination of these plots gave no insight into the level of gas saturation. Nevertheless, because the data has not been published, these plots are presented here in Figures 10 to 14 inclusive. Note that these are plots of daily numbers. However, if the well flowed 20,000 BPD for 12 hours and was shut in for the other 12 hours, the rate would be plotted at 20,000 and not 10,000 BPD.

NOTE: Also see section "OTHER HYDROCARBONS" and section "PVT MEASUREMENTS AND BUBBLE POINT ALGORITHMS."

Conclusions

Use of the reservoir models presented herein was inconclusive in determining if the Pleasant Bayou No. 2 was saturated with natural gas. Use of these models requires accurate measurements of GWR, gas compositions, and pressures. Because small transient changes in GWR, gas compositions, and pressures are being looked for, these parameters must be measured accurately and must be measured during the expected transients. Difficulty was experienced in measuring GWR's, and the accuracy was less than needed for this study.

The fact that no evidence of free gas production was found when studying the difference between the bottomhole and wellhead pressures for Phase I is not surprising. With the bottomhole pressure so high, the drawdown so small, and the flow times so short, it is unlikely that enough gas would have been exsolved to reach critical gas saturation. The Phase II Part A test had no drawdowns that were significantly greater than those of Phase I, and no bottomhole measurements were taken during Phase II Part B.

Analysis of separator gas samples were found only for Phase I testing. None were taken when free gas might have been produced. The total produced gas (separator gas plus gas remaining dissolved in the separator brine)

Figure 10. PLOTS OF PLEASANT BAYOU NO. 2 BRINE FLOW RATE, GWR, AND SEPARATOR PRESSURE FOR 12/23/82 TO 12/31/82 INCLUSIVE

Figure 11. PLOTS OF PLEASANT BAYOU NO. 2 BRINE FLOW RATE, GWR, AND SEPARATOR PRESSURE FOR 1/1/83 TO 1/31/83 INCLUSIVE

Figure 12. PLOTS OF PLEASANT BAYOU NO. 2 BRINE FLOW RATE, GWR,
AND SEPARATOR PRESSURE FOR 2/4/83 TO 2/28/83 INCLUSIVE

Figure 13. PLOTS OF PLEASANT BAYOU NO. 2 BRINE FLOW RATE, GWR, AND SEPARATOR PRESSURE FOR 3/1/83 TO 3/31/83 INCLUSIVE

Figure 14. PLOTS OF PLEASANT BAYOU NO. 2 BRINE FLOW RATE, GWR, AND SEPARATOR PRESSURE FOR 4/1/83 (Day 91) TO 4/14/83 INCLUSIVE

composition is expected to change if the bottomhole pressure goes below the original reservoir bubble point. Only separator gas samples were analyzed and the separator temperature and pressure changed during the course of testing. These separator changes might have masked changes that actually occurred in the total gas composition. Again, with the relatively small drawdown that occurred, the changes in gas composition might have been quite small — perhaps smaller than the accuracy of the analysis.

Zarrella et al. (1967) found that brines in normally pressured reservoirs in contact with conventional crude oil deposits contained dissolved benzene, but brines from gas fields with no oil production contained no benzene. Benzene was found in all the Design Well sands that were flow tested except sand 5 in the Amoco Fee, which was not tested for benzene. If the above observation holds for geopressured-geothermal aquifers, then most, if not all, of the flow tested Design Well sands contain conventional oil deposits. Two of the sands were flow tested long enough for the conventional oil production to commence.

Concentration gradients probably exist in the reservoir brine. If they exist, they introduce more uncertainty in PVT bubble point determinations and in the algorithms used to calculate bubble points.

Introduction

The T-F&S/DOE Gladys McCall No. 1 is located approximately 2-1/2 miles south of Highway 82, Cameron Parish, Louisiana, at the western edge of the Rockerfeller Wildlife Refuge. It is in Section 27, Township 15 South, Range 5 West, Tidal Marsh Country, about 55 miles southeast of Lake Charles (Pyron, 1981).

The well has 11 sand zones from 14,412 to 15,860 feet for a total net thickness of 1,092 feet. Sand zone 9 was tested first. A 90-foot interval was perforated in the sand, extending from 15,508 to 15,636 feet (Durrett, 1983). A preliminary flow test beginning December 19, 1982, at a brine production rate of 2,000 to 2,200 bbl/day was increased to 9,200 bbl/day (7,840 STB/day) around December 22, and shut in around December 24, 1982 (Technadril-Fenix & Scisson, Inc.). A 24-day drawdown was conducted from March 20, 1983, to April 14, 1983. The initial pressure at 15,460 feet was 12,910 psia and the temperature was 298°F. In total, 99,416 barrels were produced at an average rate of 4,181 bbl/day during this 24-day test (Durrett, 1983).

The other sand tested was sand No. 8 located from 15,158 to 15,490 feet. A test begun on September 27, 1983, was aborted after little more than half a day because of equipment problems. The rate was 13,000 to 15,000 bbl/day. A 21-day drawdown test was conducted from October 7 to October 28, 1983. The initial pressure at 15,100 feet was 12,784 psia and the temperature was 294°F (Durrett, 1984a). Long-term testing began December 1983 (Durrett, 1984b), and the well was still flowing in July 1985 (Cogar, 1985).

Reservoir Dynamics, Inc., recorded the bottomhole pressure, wellhead pressure, bottomhole temperature, and brine flow rate on magnetic tapes for at least part of the tests of both sands. After receiving permission from Larry Durrett, Nathan Waldman sent a copy of these tapes to IGT. All other data were manually recorded on paper.

Sand 9

The bottomhole pressure, brine flow rate and bottomhole minus wellhead pressure for sand 9 of the T-F&S/DOE Gladys McCall No. 1 from March 21, 1983, to April 17, 1983, are presented in Figure 15. The data were obtained on magnetic tape from Reservoir Dynamics, Inc., and were not edited by IGT. The

Figure 15. BOTTOMHOLE PRESSURE, BRINE FLOW RATE, AND BOTTOMHOLE PRESSURE MINUS WELHEAD PRESSURE FOR SAND 9 OF THE T-F&S/DOE GLADYS McCALL NO. 1 FROM MARCH 21, 1983, TO APRIL 17, 1983

major ticks on the time axis are at 0000 hours on the day beneath the tick. Each curve in Figure 15 goes through 4799 data points. There were six or seven bottomhole pressure gauge failures during this time (Durrett, 1983). This would account for the gaps in the bottomhole pressure curve.

There are several changes in the bottomhole pressure curve when it exists. The reasons for most of these are not known, but two of the changes are very well documented and are discussed below. The spikes in the bottomhole pressure minus wellhead pressure curve are due to problems with the wellhead pressure measurements, but no reason could be found for the decreases occurring between 81.7 and 82.6 days or at 84.7 days. There are also some gaps in the brine flow rate curve. It is obvious from the bottomhole pressure curve that the flow rate was not zero during these gaps except for the shut-in that occurred at about day 103.5. The change in the flow rate curve occurring at about day 83.5 is not due to any real change in flow rate but is caused by using a different flow meter (log on data tape and Clark, 1983). Figure 15 shows that almost the entire flow test was conducted at a rate just over 4000 bbl/day. An exception occurred on day 82. The same data are presented in Figure 16 for day 82. Each curve goes through 142 data points. Note that these data were taken with the first flow meter. The spikes that occur during the seventh hour are real; the bottomhole pressure increases in response to the decrease in flow rate. According to the daily report, the well was shut in for about 3 minutes at 6:30 a.m. because of a malfunction in the Emergency Shut-In System. The negative spike in flow rate at hour 19 is not real judging from the lack of response in the bottomhole pressure. The spike in bottomhole pressure minus wellhead pressure occurring during hour 14 is caused by one wellhead pressure reading that was about 3000 psi lower than the others. The increase in rate occurring next is real and occurred on purpose. This is supported by the bottomhole pressure response and the log statement (on the tape with the data) that the rate increase was to make up for loss occurring during the momentary shutdown that occurred during the seventh hour.

If a slug of free gas was produced because gas that had previously been trapped in the reservoir near the well bore became mobile (reached critical gas saturation) in response to the pressure decrease associated with the rate increase, the bottomhole pressure minus wellhead pressure would decrease. The

Figure 16. BOTTOMHOLE PRESSURE, BRINE FLOW RATE, AND BOTTOMHOLE PRESSURE MINUS WELLHEAD PRESSURE FOR SAND 9 OF THE T-F&S/DOE GLADYS McCALL NO. 1 ON MARCH 24, 1983

free gas would lighten the fluid column in the well bore and cause the wellhead pressure to increase. The maximum effect would be seen when the gas slug reached the wellhead where the pressure is the lowest in the well bore and the gas volume would be the largest. Under the conditions shown in Figure 16, this should occur in less than an hour after the rate increase. There is a slight dip in the bottomhole pressure minus wellhead pressure curve after the rate increase, but it is smaller than the fluctuations seen elsewhere in the curve. There is no evidence that any free gas was produced during this rate increase. However, the minimum BHP before the rate increase was about 12,650 psia, for a total drawdown of only 260 psi. Assuming the reservoir was originally saturated, a back-of-the-envelope-type calculation will show that, for the given conditions, critical gas saturation would be reached if all the gas were uniformly liberated within 1 foot of the well bore, but would not be reached if all the gas were uniformly liberated within 2 feet of the well bore. Because gas would have been exsolved at distances much greater than 2 feet from the well bore, free gas would not be seen even if the reservoir were originally saturated. Furthermore, even if the reservoir were at critical gas saturation (assumed 3%) when the rate increase occurred, the perfect gas law shows that the gas saturation after the rate increase would be only $3\% \times (12690/12490) = 3.05\%$. Such a small increase in gas saturation would have had very little effect on the total gas production. Thus, lack of evidence of free gas production after the rate increase is NOT proof that the reservoir is not saturated with natural gas.

Four sets of gas analyses performed by Weatherly Laboratories, Inc., were found. A set of analyses consists of analysis of separator gas and the analysis and GWR of gas flashed from separator brine. The total gas composition was calculated for total GWR's ranging from 29 to 35 SCF/bbl.* The direction of changes in the ethane/methane, propane/methane, and butane/methane ratios with time were the same for each of the GWR's, and the changes were small and random. If the total gas composition did change, the change was less than the errors associated with the measurements. The change in composition due to small quantities of gas exsolving in the reservoir is expected to be quite small.

*The total GWR is almost certainly between these limits.

Sand 8

The bottomhole pressure, brine flow rate, and bottomhole pressure minus wellhead pressure for sand 8 of the T-F&S/DOE Gladys McCall No. 1 from October 7 (day 279) to November 1, (day 304) 1983 are presented in Figure 17.* The data were obtained on magnetic tape from Reservoir Dynamics, Inc., and were not edited by IGT. Each curve in Figure 17 goes through 4297 data points. Because this drawdown was done at a constant brine rate, no changes in bottomhole pressure minus wellhead pressure due to a slug of free gas production caused by a rate increase are expected. The initial fall-off in bottomhole pressure minus wellhead pressure is due to heating of the well bore and heating of the pressure sensor. Most of the wiggles in this curve are due to daily temperature fluctuations of the pressure sensor. The wellhead pressure curve (not shown in Figure 17) was seen to drop about 100 psi in the first day after shut-in even though the bottomhole pressure was increasing. This is also believed to be due to the temperature sensitivity of the pressure sensor. Thus Figure 17 gives no clues as to whether sand 8 is saturated or not.

Durrett (1984b) shows results of separator studies done from January 14 to 24, 1984, and during July 1984, to study the effects of different pressures in the first- and second-stage separators on the amount and composition of recovered gas. No gas analyses were given for the January study and only carbon dioxide concentrations were given for the first- and second-stage gas in the July study. Presumably, complete analyses were done on the first- and second-stage gas in the July study. It is not known if analyses were done on the gas remaining in the second-stage separator brine. The project for which this report is being written ran out of time and money before this point could be explored further.

NOTE: Also see section "OTHER HYDROCARBONS" and section "PVT MEASUREMENTS AND BUBBLE POINT ALGORITHMS."

Conclusions

Use of the reservoir models presented herein was inconclusive in determining if sand 9 of the T-F&S/DOE Gladys McCall No. 1 was saturated with

*Buildup data exist until November 30, 1983, but are not presented here.

Figure 17. BOTTOMHOLE PRESSURE, BRINE FLOW RATE, AND BOTTOMHOLE PRESSURE MINUS WELLHEAD PRESSURE FOR SAND 8 OF THE T-F&S/DOE GLADYS McCALL NO. 1 FROM OCTOBER 7, 1983, TO NOVEMBER 1, 1983

natural gas. Good bottomhole and wellhead pressure measurements were made and recorded on magnetic tape. Four sets of appropriate gas analyses were found. These consist of separator gas compositional analyses and analyses of the amount and composition of gas remaining dissolved in the brine leaving the separator. However, the production and the drawdown were so small that exsolved gas could not have become mobile and been produced during the test even if the reservoir was originally saturated. Also, the change in total produced gas composition under these conditions is believed to be smaller than the uncertainty in the analyses.

Use of the models was also inconclusive in determining if sand 8 of the Gladys McCall was saturated with natural gas. Again, good bottomhole and wellhead pressure measurements were made and recorded on magnetic tape, but only for part of the test. Because no rate increases occurred during this time, no free gas production is expected.

A report describing a separator study was found. The study was conducted to determine the effects of different pressures in both the first- and second-stage separators on the amount and composition of recovered gas. The only gas quantified in the report was carbon dioxide. It is presumed that complete compositional analyses were performed. It is not known if the amount and composition of the gas leaving the second-stage separator in the brine were determined. These points could not be investigated further because of lack of time and money.

Zarrella et al. (1967) found that brines in normally pressured reservoirs in contact with conventional crude oil deposits contained dissolved benzene, but brines from gas fields with no oil production contained no benzene. Benzene was found in all the Design Well sands that were flow tested except sand 5 in the Amoco Fee, which was not tested for benzene. If the above observation holds for geopressured-geothermal aquifers, the most, if not all the flow tested Design Well sands contain conventional oil deposits. Two of the sands were flow tested long enough for the conventional oil production to commence.

Concentration gradients probably exist in the reservoir brine. If they exist, they introduce more uncertainty in PVT bubble point determinations and in the algorithms used to calculate bubble points.

OTHER HYDROCARBONS

A highly aromatic (benzene and benzene derivatives) oil was first found to be produced early in the testing of the Sweezy. It appeared to increase during production (Hamilton and Stanley, 1984). Because flow testing of sand 5 in the Amoco Fee had already ceased, this sand was not tested for aromatic hydrocarbons. However, all the other flow tested geopressured-geothermal Design Well sands were tested for aromatic hydrocarbons and they were found in all (Keeley and Meriwether, 1985). The Sweezy produced 15, the Gladys McCall produced 86, and the Pleasant Bayou produced 123 mL aromatic hydrocarbons per MCF gas (Hamilton and Stanley, 1984). Keeley and Meriwether (1985) reported that the amount of aromatic hydrocarbons ("cryocondensates") increased with production volume — from 22.5 to 35 microliters/liter during the production of approximately 6 million barrels of brine at the Gladys McCall sand 8.

Both LBL (Weres et al., 1984) and IGT (Doherty, 1983, Appendix C) concluded that the aromatic hydrocarbons were dissolved in the brine in the Sweezy reservoir; in other words, they were not produced as a free gas or liquid hydrocarbon phase. Zarrella et al. (1967) found that normally pressured brines in contact with conventional crude oil deposits contained dissolved benzene, whereas the amount of benzene dissolved in brines from gas fields (with no oil production) was below their detection limit of 0.01 ppm. They found variability in the amount of benzene dissolved in the brine in different oil fields, but they also found that, in a field, the nearer the brine to the oil accumulation, the higher the concentration of dissolved benzene. If this holds true for geopressured-geothermal aquifers, all the flow tested geopressured-geothermal sands in the Design Wells (with the possible exception of sand 5 in the Amoco Fee, for which no measurements of aromatic hydrocarbons were made) contain paraffinic oil in addition to the aromatic oil. Indeed, two of the sands were produced long enough for the paraffinic oil production to commence.

Paraffinic oil was produced from the Sweezy after an induction of about 1.3 million barrels of brine production. In November 1982, about 1 barrel of this oil was found while the separator was being cleaned. The Sweezy was plugged and abandoned after a sanding incident, which occurred soon after the paraffinic oil production began. As a result, no rate measurements on the oil production were possible (Hamilton and Stanley, 1984).

Paraffinic oil was also produced from sand 8 of the Gladys McCall after an induction of about 7 million barrels of produced brine (Keeley and Meriwether, 1985). Because the paraffinic oil had an induction period, the oil was not dissolved in the brine, but an oil phase began being produced at the Sweezy and the Gladys McCall. A sample of oil collected from the Gladys McCall on January 19, 1985, was analyzed by Southern Petroleum Laboratories, Inc. The oil was found to have an API gravity of 32.9, a pour point of 90°F, a paraffin wax content of 65.1 weight percent, a sulfur content of 0.12 weight percent, and an asphaltene content of 2.8 weight percent (Berning, 1985). The first oil volume was measured on February 7, 1985. Berning (1985) provided the data plotted in Figure 18, which shows the daily and cumulative oil production from sand 8 of the T-F&S/DOE Gladys McCall No. 1 during February 1985. The production is in units of gallons of oil produced per million gallons of brine produced during the same time interval. The oil was drained from the separator each weekday and its volume measured. Spikes are seen in the daily oil production curve in Figure 18. It is not known how much these spikes are dependent on sampling conditions (perhaps not getting all the oil out one day, but getting it out the next) or on actual changes in oil production rate. Nevertheless, the overall trend is an increase in oil production. If the rate continues to increase, this oil could become very important in the economics of geopressured-geothermal energy development.

Figure 18. DAILY AND CUMULATIVE OIL PRODUCTION FROM SAND 8 OF THE T-F&S/DOE GLADYS McCALL DURING FEBRUARY, 1985

PVT MEASUREMENTS AND BUBBLE POINT ALGORITHMS

The PVT work was done by John Neal of Weatherly Laboratories, Inc., Lafayette, Louisiana. The bubble point results for the six sands tested in the four Design Wells are presented for comparison in Figures 19 through 24. They are presented in order of date sampled. The Pleasant Bayou No. 2 (Figure 19) was sampled 10/8/80 (Neal, 1981a), the MG-T/DOE Amoco Fee No. 1 sand 5 (Figure 20) was sampled 6/22/81 (Neal, 1981b), the Dow-DOE L. R. Sweezy No. 1 (Figure 21) was sampled 5/12/82 (Neal, 1982, or Hamilton and Stanley, 1984, Appendix K), the T-F&S/DOE Gladys McCall No. 1 sand 9 (Figure 22) was sampled 3/23/83 from 1000 to 1523 hours (Neal, 1983a), the T-F&S/DOE Gladys McCall No. 1 sand 8 (Figure 23) was sampled 10/8/83 (Neal, 1983b), and the MG-T/DOE Amoco Fee No. 1 sand 3 (Figure 24) was sampled 11/25/83 at 1700 hours (Neal, 1983c). Recombinations as well as differential liberations were done for all but the Amoco Fee sand 5, for which only a recombination was done. The pressure limit of Neal's PVT cell is 11,000 psi. His data points at 13,300 and 16,000 psi for the Sweezy were obtained by extrapolation.

The recombinations were done by charging a known amount of dry separator gas and separator brine into the cell and determining the pressure at which a vanishingly small bubble coexists with the brine. The differential liberations were done by charging the cell as above. The pressure was increased, the system allowed to equilibrate, and the pressure decreased in steps. The gas liberated at each pressure reduction was removed from the cell and its volume and composition measured.

Also presented in Figures 19 to 24 are bubble points calculated using reported total dissolved solids for each sand and the temperature used by Neal for each sand in the algorithms of Garg et al. (1978), Price et al. (1981),* and Haas (n.d.). The following limitations should be kept in mind. For the most part, these algorithms were fit to laboratory data on the solubility of methane in water and sodium chloride brines. A limited amount of data was available on the solubility of a natural gas in two oil field brines. Amirijafari and Campbell (1972) studied the solubility of methane-ethane, methane-propane, ethane-propane, and methane-ethane-propane mixtures in water. However, the conditions of their study are not applicable to

*Note that the Price et al. (1981) algorithm is not valid below 3500 psi.

Figure 19. COMPARISON OF PLEASANT BAYOU NO. 2 BUBBLE POINTS

Figure 20. COMPARISON OF MG-T/DOE AMOCO FEE NO. 1 SAND 5 BUBBLE POINTS

Figure 21. COMPARISON OF DOW-DOE L. R. SWEETZ NO. 1 BUBBLE POINTS

Figure 22. COMPARISON OF T-F&S/DOE GLADYS McCALL NO. 1 SAND 9 BUBBLE POINTS

Figure 23. COMPARISON OF T-F&S/DOE GLADYS MCCALL NO. 1 SAND 8 BUBBLE POINTS

Figure 24. COMPARISON OF MG-T/DOE AMOCO FEE NO. 1 SAND 3 BUBBLE POINTS

geopressured aquifers in that the mole fractions of the heavier hydrocarbons are much higher than those found in the aquifers, the highest pressure they studied was 8,000 psi, and they did not use brine. Also, use of the rather complex empirical correlation they present requires prior knowledge of the solubility of the pure components. These solubilities are not known for the temperatures and pressures of these aquifers. No studies of hydrocarbon gas mixture solubility in water or brine in the temperature and pressure range of interest were found, let alone such studies also containing oil. Thus, these algorithms do not take into account effects of other dissolved "gaseous" hydrocarbons, or paraffinic or aromatic "oil" hydrocarbons.

Gas from all the Design Well sands except the Amoco Fee sand 5 was sampled and tested for aromatic hydrocarbons. Aromatic hydrocarbons were produced from all the sands tested, but in different amounts. The Sweezy produced 15, the Gladys McCall produced 86, and the Pleasant Bayou produced 123 mL aromatic hydrocarbons/MCF gas (Hamilton and Stanley, 1984). Keeley et al. (1983) reported that, according to preliminary data, the amount of aromatic hydrocarbons that remained in the brine is about twice that exsolved with the gas. IGT (Doherty and Poonawala, 1983) found that the brine leaving the separator contained about 5 times the amount exsolved with the gas at the Sweezy during September 22 to 24, 1982. One might argue that these reservoir brines could be saturated with aromatic hydrocarbons, and the differences in the amounts exsolved with the gas are due to differences in the individual reservoirs (temperature, pressure, brine composition, and hydrocarbon composition), differences in separator operating conditions (temperature, pressure, residence time), and point of sampling (distance from separator and temperature). However, Keeley and Meriwether (1985) reported that the amount of aromatic hydrocarbons ("cryocondensates") is increasing as a function of production volume — from 22.5 to 35 microliters/liter during the production of approximately 6 million barrels of brine at the Gladys McCall sand 8. This observation suggests that another phase (gas or oil) that contains aromatic hydrocarbons is being produced or that there are aromatic hydrocarbon concentration gradients in the reservoir brine. Indeed, the Gladys McCall sand 8 did begin to produce a paraffinic oil, but Keeley and Meriwether (1985) reported that the aromatic production did not increase with the advent of paraffinic oil production. There was no reported increase in gas production. A logical conclusion is that there are aromatic hydrocarbon

gradients in the reservoir brine. This is consistent with the observation of Zarrella et al. (1967) that within an oil field the amount of benzene dissolved in the brine was a function of the distance to the oil accumulation.

Another limitation in the use of the solubility algorithms is uncertainty about the proper temperature and pressure to use in them. Laboratory studies of methane solubility in sodium chloride brines are done in rather small pressure vessels (cells) with internal dimensions of perhaps a few inches in diameter and 1 to 3 feet in length. The distribution of temperatures throughout the cells is unknown, but with good design, temperature differences between different points in the cell should be small. Thus the cell temperature can be adequately described by a single temperature. For a cell as long as 3 feet charged with even a 0.5 psi/ft brine, the pressure difference between the top and bottom of the cell is only 1.5 psi. The difference is quite small — less than the uncertainty in the measurement when the pressures of interest are thousands of psi. Thus, the pressure in the cell can be adequately described by a single pressure. If the solubility is properly measured, the bubble point is known for that temperature and pressure.

Now consider an ideal reservoir that contains only methane and sodium chloride brine; in other words, the complications of effects of other components are eliminated. The reservoir is 100 feet thick and has a gas cap 2,000 feet updip from the production well, and the brine contains 100,000 mg sodium chloride/L. The temperature and pressure of the midpoint of the formation at the well bore is 12,000 psi and 230°F, respectively. Using a pressure gradient of 0.46 psi/ft and a temperature gradient of 1.67°F/100 ft gives a pressure and temperature of 11,057 psi and 195.8°F, respectively, at the gas/brine interface. It is clear that what was measured in the laboratory is the amount of methane dissolved in the brine at the gas/brine interface, and this can be calculated using the interface temperature and pressure. But what is the amount of methane dissolved in the brine around the well bore? Is it appropriate to use the interface temperature and pressure? The temperature and pressure at the top perforations? The bottom perforation? Some kind of average? Or are none of these approaches appropriate? Using the numbers presented above in the Garg et al. (1978), Price et al. (1981), and Haas (n.d.) algorithms gives methane concentrations downdip that are 14% to 17%

higher than those updip. Thus, if the downdip temperatures and pressure were used but the interface temperatures and pressure were the correct ones to use, the logical but incorrect conclusion would be that the reservoir is 14% to 17% undersaturated.

A simple thermodynamic treatment shows that it is reasonable to expect concentration gradients. Denbigh (1955) shows that, for a constant temperature system at equilibrium, a concentration gradient will occur as a result of gravity. A vertical concentration gradient will occur for all species even if there is only one phase present. In a system with vertical extent large enough for this to be important, a gas phase and a liquid phase can be in equilibrium, but the GWR will depend on the vertical position of the portion of liquid under consideration. Thus bubble point and equilibrium are not synonymous. It should be emphasized that the above statements apply to a system of constant temperature. When considering a reservoir with temperature gradients and thus heat flow, even "equilibrium" loses meaning. It is reasonable to expect that the temperature and pressure gradients in the reservoir would also contribute to concentration gradients. These concentration gradients introduce more uncertainty into PVT measured bubble points. Implicit in the whole PVT procedure is the assumption that concentration gradients do not exist within a phase.

These points deserve very careful consideration because, if these effects were all understood, they could be used as an exploration tool. Measuring concentrations could conceivably allow calculation of how far updip gas and/or oil accumulations are located.

Other problems associated with PVT measurements were presented in the BACKGROUND section of this report. The problem of representative sampling will be discussed here in more detail. It is clear that five of the six Design Well sands produced aromatic hydrocarbons. The sixth probably did, but no measurements were made on it. Arnold et al. (1958) measured the solubility of benzene in water at atmospheric pressure from 0.4 to 69°C (32.7 to 156°F). They found a minimum in the solubility around 17°C (62.6°F) and found that the solubility increases with increasing temperature.

If the amount of aromatic hydrocarbons dissolved in the reservoir brine is greater than the solubility at separator conditions, the aromatic hydrocarbons will come out of solution in the separator and form a separate

phase. Because the densities of the aromatic hydrocarbons are less than the density of the brine, the hydrocarbons will float on top of the brine. Additional aromatic hydrocarbons will be lost to the gas phase in the separator. The brine collected for PVT work would almost certainly contain less aromatic hydrocarbons per unit of brine than the reservoir. Even if the amount of aromatic hydrocarbons dissolved in the reservoir brine is less than the solubility at separator temperature and pressure, some aromatic hydrocarbons would be lost to the gas phase in the separator. The brine collected for PVT work would almost certainly contain less aromatic hydrocarbons per unit of brine than the reservoir, but more than when a liquid hydrocarbon phase exists in the separator. However, in both cases, proper gas sampling should recover the hydrocarbons lost to the gas phase. The hydrocarbons lost to the liquid hydrocarbon phase in the separator would not be recovered.

If the solubility of the aromatic hydrocarbons in the sample cylinder at room temperature is less than the amount collected, a hydrocarbon phase will form on top of the brine. If this hydrocarbon phase is displaced into the PVT cell when it is charged, the PVT cell will contain too much of the aromatic hydrocarbons. However, the volume of this hydrocarbon phase is quite small — on the order of microliters. It is quite likely that this amount could get trapped in a local high in the sample cylinder (such as where the end of the valve screws into the cylinder), and none would be introduced into the PVT cell. In this case, the PVT cell will contain too little aromatic hydrocarbons.

As stated above, in either case the gas sample will contain aromatic hydrocarbons. The possibility exists that these will partially condense on the walls of the sample cylinder as it cools. If this occurs and proper steps are not taken when charging gas to the cell, too little aromatic hydrocarbons will be introduced into the cell with the gas.

Thus, it is impossible to deduce if the PVT cell contains too little or too much or just the right amount of aromatic hydrocarbons. It could vary from study to study. Even if this could be deduced, the effect could not be predicted because the effect of these aromatic hydrocarbons on the solubility of natural gas in brine is unknown. They might increase or decrease the solubility.

In examining Figures 19 through 24, it is seen that for all sands except the one in the Sweezy the pressures obtained by differential liberation are lower than all the algorithms. For the Sweezy, the pressures obtained by recombination and differential liberation are in very good agreement in that they all lie on one smooth curve. The differential liberation pressures are all higher than all the algorithms. The relationship between the recombination pressures and the algorithms varies. The two highest recombination pressures were not measured but were obtained by extrapolation. These are the only two points which are lower than all the algorithms.

The pressures obtained from recombination are higher than those obtained from differential liberation for both sands in the Gladys McCall and sand 3 in the Amoco Fee (differential liberation was not done on sand 5), but the recombination pressures are low when compared with the algorithms for sand 8 of the Gladys McCall and sand 3 of the Amoco Fee. The recombination pressures are high for sand 9 of the Gladys McCall — only the pressures of Garg et al. (1978) are higher. The recombination pressures for sand 5 of the Amoco Fee are lower than all the algorithms. The recombination and differential liberation curves cross for the Pleasant Bayou, but both are lower than all the algorithms.

These differences suggest that something not well understood is occurring. Perhaps the sampling scenario described above and effects of other gaseous hydrocarbons would explain at least part of it. The PVT results alone should not be taken as absolute proof that these reservoirs contain less gas than they could.

RECOMMENDATIONS

There are a number of problems associated with testing geopressured-geothermal wells and disseminating the data. Production well bottomhole pressures and production wellhead pressures or disposal well bottomhole pressures and sometimes brine rates were recorded on magnetic tape for part of the test of each of the Design Wells. Other data, however, were manually recorded on paper (daily reports). This presents a number of problems. Several hundred sheets of paper are difficult to handle. A year's worth of daily reports from the Gladys McCall is a stack of 8-1/2 x 11-inch papers 4-1/2 inches thick. They often are copies of copies and sometimes are impossible to read. Data handling is very time consuming and, therefore, very costly. Just determining the range of separator pressure during a test requires someone to manually examine a stack of daily reports and keep track of minimum and maximum values. Calculations are much worse. They must be done by hand (or data hand-entered into a computer), and usually require several variables to be entered per calculation. Plots must be made by hand or data must be hand-entered into a computer. Recording all data on magnetic media greatly reduces or eliminates these problems.

The quality of GWR measurements is poor. This is due to pressure fluctuations in the separator, liquids condensing in lines between the orifice plate and differential pressure gauge, hydrate formation, and perhaps use of orifices that are too large. The GWR's that are reported are generally for wet gas and in terms of separator barrels and not stock tank barrels and do not include the gas left in solution after passing through the separator. GWR's in terms of total produced dry gas per stock tank barrel are needed to better understand what is occurring in the reservoir.

Gas analyses are usually done only on separator gas samples. The separator gas composition is a function of the total produced gas composition and the separator temperature, pressure, and possibly residence time. The composition of the total gas produced is needed to better understand what is occurring in the reservoir.

Some transient compositional changes occur. Usually only the day on which a sample was taken is reported. Sample collection times should be reported to at least the nearest 15 minutes. A better technique would be to

report the time (to the minute) at which sample collection began and the time at which it ended.

Below is a list of specific recommendations to help reduce these problems and to gain more insight into reservoir dynamics.

- The Design Wells program should be continued, even though it is not certain that the reservoir brines are saturated with natural gas. If the rate of oil production continues to increase, the oil could provide the necessary economic incentive for private industry to develop the resource. Also, information gathered on reservoir properties could be useful in analyzing geopressured gas wells.
- A program should be developed to study the possibility of concentration gradients in a reservoir, ascertain their importance to the nation's energy supply, and measure them if deemed appropriate.
- All raw data (times, temperatures, pressures, brine turbine rates, orifice differential pressures, sand detector signals, pH, etc.) as well as results (calculated brine rates at stock tank conditions, flare and/or sales line gas rates, amount of gas remaining in solution in the separator, the recovered GWR, the total GWR, all at standard conditions, etc.) should be recorded on magnetic media.
- All computer-collected data, except turbine meter data, should be collected frequently — on the order of every few seconds. These readings should be averaged over an operator-selected time interval (print interval) and these averages recorded on magnetic media. When the numbers are or are expected to be changing rapidly, this print interval should be short, and when the measured numbers are changing slowly, a larger print interval should be chosen.
- Turbine meter pulses should be continually counted, and this total should be recorded at the end of each print interval. The cumulative flow at each time can be calculated from these totals, and the average flow rate over the print interval can be calculated from the change in the total over the time interval. These numbers should then be recorded.
- The square root of the product of the orifice gas pressure and the orifice differential pressure should be used to calculate gas flow. Thus, the square root of these should be averaged over the print interval and recorded in addition to the average of the pressures.
- The separator bbl should be converted to STB by using the equation of Rowe and Chou (1970) or the equivalent.
- The following procedure should be used in calculating gas flow rates: The actual gas composition should be used in the orifice meter formulas. Dry gas production should be calculated by correcting the orifice gas pressure for the vapor pressure of water. The amount of gas remaining in solution in brine to the disposal well should be added to the amount of gas going through the meter run to obtain the total amount of gas produced. IGT found during the Wells of Opportunity test that a

computer algorithm developed by Systems Science and Software for methane solubility in distilled water (Garg et al., 1978) could be used for this calculation. Whatever algorithm is used should be checked by actually flashing and measuring the gas from the disposal brine. The average of the square root of the orifice gas pressure and the square root of orifice differential pressure should be used, not the square root of the averages.

- A log should be kept on magnetic media of times of changes and changes made to help analyze the data. Examples would be changes of turbine meters and their calibration factor, of orifice plates, of flow rates, of separator pressure, and of gas composition used in calculating gas rates.
- Copies of these tapes and/or disks should be made available to parties desiring to do their own data interpretation. This is far superior to copies of handwritten or even typed daily reports. The amount of data on a single disk or tape would be equivalent to a stack of written reports inches, if not feet, thick. Paper copies are often unclear and/or difficult to read, particularly when they are copies of copies of copies. On the other hand, fresh hard copies of all or selected parts of the data on the tape can be obtained at will. Any mathematical calculations or plotting requires manual handling of numbers presented on paper, but calculations and plotting of numbers presented on tape can be handled by a computer in a very small fraction of the time. There is a limit to the frequency at which manually read data can be taken, and the times are not accurate. If a person is recording totalized flow every half hour to calculate flow rates and is 5 minutes early on one reading and 5 minutes late on the next, the calculated flow rate is in error by 33%. Values change with time. If someone looks at a strip chart recorder or Barton meter and notes a fluctuation since the last reading, but can only record one number, what does he report? — the current reading, or something he perceives as the "average"? In either case, large but transient changes will go unrecorded. Continual manual recording of data requires that more than one person record data. Differences in which different people read pressure gauges, perceive "averages," or report current readings, time reports, etc., all add inconsistency to the data. Using a computer to put the data on magnetic media completely eliminates or greatly reduces these problems.
- The surface equipment should be sized to minimize the magnitude of separator pressure oscillations. The orifice size should be such that the differential pressure is large enough that the zero shifts in the differential pressure transmitter are acceptable.
- The differential pressure transmitter should be mounted close to and above the orifice meter run. Pressure connections should be made with nothing with an ID smaller than the ID of 3/8-inch tubing, and the tubing should always slope down with no horizontal runs. This is to prevent condensed liquids from forming a leg in the tubing and thus making the measured differential pressure incorrect.
- Heating tapes or other preventive measures should be taken to prevent hydrate formation. Hydrates have formed at Wells of Opportunity and Design Wells.

- A clock should be designated as master to which all other clocks and watches are synchronized so that times of events, including sample collection, can be accurately recorded.
- A large increase in the brine flow rate should be made after the well has flowed long enough to heat surface hardware, the separator is operating smoothly and good separator GWR's are being obtained, separator gas analyses are done, and gas remaining in the brine after passing through the separator has been quantified and analyzed. The increase should be accomplished in as short a time span as possible, and the separator controls should not be touched. The separator gas samples should be collected and analyzed, and the gas remaining in the brine after passing through the separator should be quantified and analyzed when about 0.75, 1, 1.25, 2, and 4 well bore volumes of brine have been produced since the flow increase. If there are any signs that a slug of gas is being produced, such as an increase in the orifice differential pressure, the samples should be collected and analyzed at that time. Changes in GWR and gas composition should be monitored.
- Gas analyses should be performed as soon as possible. The same people should collect samples and the same people should do the analyses so that the same sampling techniques and the same analytical procedures will always be used. This will help reduce errors.

ACKNOWLEDGMENTS

The author wishes to express thanks to J. L. Berning of Technadril-Fenix & Scisson, Inc., L. E. Coble of Otis Engineering Corp., J. Cogar of Technadril-Fenix & Scisson, Inc., L. R. Durrett of Technadril, J. Frier of Weatherly Engineering, J. R. Hamilton of Dow Chemical USA, D. F. Keeley of the University of Southwestern Louisiana, J. R. Meriwether of the University of Southwestern Louisiana, J. Neal of Weatherly Engineering, Inc., J. A. Rodgers of Gruy Federal, Inc., and N. Waldman of Reservoir Dynamics, Inc., for providing data, information, and helpful discussions. The author also wishes to express appreciation to P. L. Randolph, S. Weil, S. Foh, and R. Rose of IGT for helpful discussions.

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