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COMPUTER SIMULATION OF PRODUCTION FROM GEOPRESSURED-GEOTHERMAL AQUIFERS

Project 61025 Annual Report for October 1, 1978—September 30, 1979

By
Leo A. Rogers

June 1980
Date Published

Work Performed Under Contract No. AC08-78ET27098

Institute of Gas Technology
Chicago, Illinois

U. S. DEPARTMENT OF ENERGY

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For the Period October 1, 1978, Through September 30, 1979

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ABSTRACT

In the Department of Energy test of the Edna Delcambre No. 1 well for recovery of natural gas from geopressured-geothermal brine, part of the test produced gas in excess of the amount that could be dissolved in the brine. Where this excess gas originated was unknown and several theories were proposed to explain the source. This annual report describes IGT's work to match the observed gas/water production with computer simulation. Two different theoretical models were calculated in detail using available reservoir simulators. One model considered the excess gas to be dispersed as small bubbles in pores. The other model considered the excess gas as a nearby free gas cap above the aquifer. Reservoir engineering analysis of the flow test data was used to determine the basic reservoir characteristics.

The computer studies revealed that the dispersed gas model gave characteristically the wrong shape for plots of gas/water ratio, and no reasonable match of the calculated values could be made to the experimental results. The free gas cap model gave characteristically better shapes to the gas/water ratio plots if the initial edge of the free gas was only about 400 feet from the well. Because there were two other wells at approximately this distance (Delcambre No. 4 and No. 4A wells) which had a history of down-hole blowouts and mechanical problems, it appears that the source of the excess free gas is from a separate horizon which connected to the Delcambre No. 1 sand via these nearby wells. This conclusion is corroborated by the changes in gas composition when the excess gas occurs and the geological studies which indicate the nearest free gas cap to be several thousand feet away. The occurrence of this excess free gas can thus be explained by known reservoir characteristics, and no new model for gas entrapment or production is needed.

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Introduction

This is the annual report for 1979 under the Department of Energy contract originally numbered ET-78-C-08-1600 (later changed to DE-AC08-78ET27098) and entitled "Computer Simulation of Production from Geopressured-Geothermal Aquifers." The two year contract beginning October 1, 1978 was just funded for one year and then continued for the second year.

This research contract originated as a result of the test results from DOE's first geopressured-geothermal aquifer, the Edna Delcambre No. 1 well, which found unexpected gas flow. The anomalous well behavior was unexplained, and an understanding of it would have significant implications for the resulting technical and economic aspects of the national geopressured-geothermal energy program. Gas in excess of the quantities dissolved in the brine were produced, and several theories were suggested to explain its origin. The contract was thus funded to evaluate some of the possible theories in detail for the Delcambre well and then continue analysis work on other wells of interest to the DOE national geopressured-geothermal program.

The main theory to be evaluated in detail was the dispersed gas phase theory which followed some preliminary work at the Institute of Gas Technology. This work indicated that if a certain relationship occurred in the relative permeability of gas and water combined with a certain gas generation and trapping mechanism, then the dispersed gas phase could be generated: this would account for the anomalous gas production. Then, on the assumption that this theory could be used to match the experimental data calculations of gas production, the related economic projections would be made for variations in the physical production mechanisms. The work was divided into three phases and tasks as follows:

Phase I. Analysis Based on Existing Data
- Task I-1. Delcambre Well Analyses
- Task I-2. Parametric Economic Analysis

Phase II. Analysis of New Well Test Data
- Task II-1. Additional DOE Well Test Data
- Task II-2. Additional Parametric Economic Analyses

Phase III. Incorporating Lab Data in Projections
- Task III-1. Refinement of Interpretation of DOE Well Test Data
- Task III-2. Update Parametric Economic Analyses

The first year's work, reported here, was mostly on Phase I and the Delcambre well analyses. Phase II was constrained because no new test data or additional test wells became available to IGT until near the end of the year. Phase III was also constrained because of limited amounts of newly reported lab data on the wells of interest.

Computers and Simulators

To carry out the necessary reservoir simulations, an agreement was made to use available reservoir simulators from Intercomp rather than using IGT-developed simulations or acquiring the computer software. It was further decided to establish a data communications link via telephone between the IGT Harris computer in Chicago and the Intercomp Harris computer in Houston. By this means problems could be submitted from IGT to run on the proprietary Intercomp computer program on a royalty use basis.

Initially we thought that it would be relatively simple to establish the communications link since both computers are from the same manufacturer and are nearly identical in physical and operating characteristics. It turned out, however, to be not so simple. When the specified 48K BAUD modem was rented from the phone company, the two computers could not understand each other. There were both controller software and hardware problems. The controller software problems were further complicated by the fact that the key Harris employee who knew the specifics of the communications needs had just left the company and his replacement was not yet knowledgeable in this area. The problems were eventually overcome and the system was finally operational in February, six months after the initiation of the work. In the interim, while the high-speed link was not operating, problems were run either by communication with a teletype-rate low-speed link or by IGT personnel going to Houston and running the programs from the Intercomp office.

IGT also acquired a Tektronix 4051 Graphics computer system to aid in the analysis and display of the data and simulator results. The components arrived at various times so that the system was not able to generate hard-copy graphs until February. This computer proved to be highly valuable to the program since the test data and analysis computations could be more easily handled than by hand or by the larger Harris computer.

Discussions with Intercomp personnel as to which available simulator model should be used resulted in the choice of the two-dimensional radial coning model. This model can calculate three-phase flow in a radial-cylindrical geometry with the well in the center of the cylinder. This was deemed appropriate to model the Delcambre well geometry and the dispersed gas phase hypothesis. Since the simulator allowed dissolution of gas in oil but not in water, it was necessary to modify the input to simulate the geopressured-geothermal aquifer. This was done by giving the oil phase in the simulator the properties of the brine and surpressing the simulator water phase out of the calculation. This left the simulator calculating flow in a reservoir with gas-saturated brine and free gas. Then, by appropriate selection of the relative permeability input tables and the initial free gas in the matrix, the hypothesized dispersed gas phase could be modeled.

Once the simulator and method of operation were selected, it took considerable effort to get the detailed input into proper form and error-free. The output format needed to be altered, and there was an error in the simulator which required some additional mathematical work and software modification to correct. This all resulted in a considerable learning or start-up period before useful computer runs could be made with the two-dimensional radial coning simulator.

In this year's fourth-quarter reporting period it became necessary to use a more complex simulator to match other hypothesized models. Work to this point had shown the dispersed-phase model to be incorrect and that the free-gas-cap model looked more promising. Since the two-dimensional radial coning model could not handle the sloping geometry and geological faults adequately, we decided, upon Intercomp's recommendation, to use their Beta II simulator. This is a full three-dimension simulator and highly sophisticated in its mathematics and the variables it can handle.

Just as there were difficulties in getting the radial coning simulator to work, there were also difficulties in getting the Beta II simulator to model the case of an up-dip gas cap. In spite of the three-dimensional capability of Beta II, it was impossible to get all the desired geometry of the gas cap, well, and boundaries, as deduced from the test data analysis and the previous computer calculations, into the model. Some rather gross approximations were necessary in the input to get a runable problem.

By the end of this year, enough computer simulator runs had been made to complete the analysis and the technical paper included as the Appendix to this report. Some additional simulation is needed that will require further use of the two Intercomp codes used so far and perhaps some other simulators. IGT has written a single phase computer simulator to run on the Tektronix computer. This simulator is based on the work done several years ago at the Louisiana State University and has been useful in generating production schedules for subsequent input to economics calculations. IGT has also had discussions with Science, Systems and Software and others about the possibility of using their software for cases where their approach may be more suited to the proposed models than the Intercomp simulators.

Delcambre Well Test Data

The preliminary calculations made by IGT to postulate the dispersed gas-phase model were made using some early summary data of the 1977 test. After the award of the contract for this study the detailed test data were then made available to IGT. These detailed data were mostly in the form of several reports, prepared by Otis Engineering, which had been engaged to conduct the well tests. In addition to the data reports that DOE provided, a trip was made to Osborn Engineering to obtain copies of logs and some miscellaneous information including consultant reports that were only summarized in the DOE reports. Osborn Engineering had retained much of the written material associated with the test and their part in the project.

For the June-July 1977 test of the Delcambre well, the primary data are the gas flow, brine flow, and downhole pressure for the test period. These data, shown in Figure 1, are for the test of the No. 1 sand where the excess gas in question was found. This flow test consisted of a five-step drawdown followed by a buildup period, and then three more flow periods, each with a following buildup period. The excess gas is seen in Figure 1 to begin on June 30 with an upwards slope on the plot of gas flow rate.

Multirate Drawdown Analysis

The five-step drawdown test was conducted as a multirate isochronal test. This is an accepted engineering test from which the reservoir properties can be obtained using the appropriate mathematical analysis.

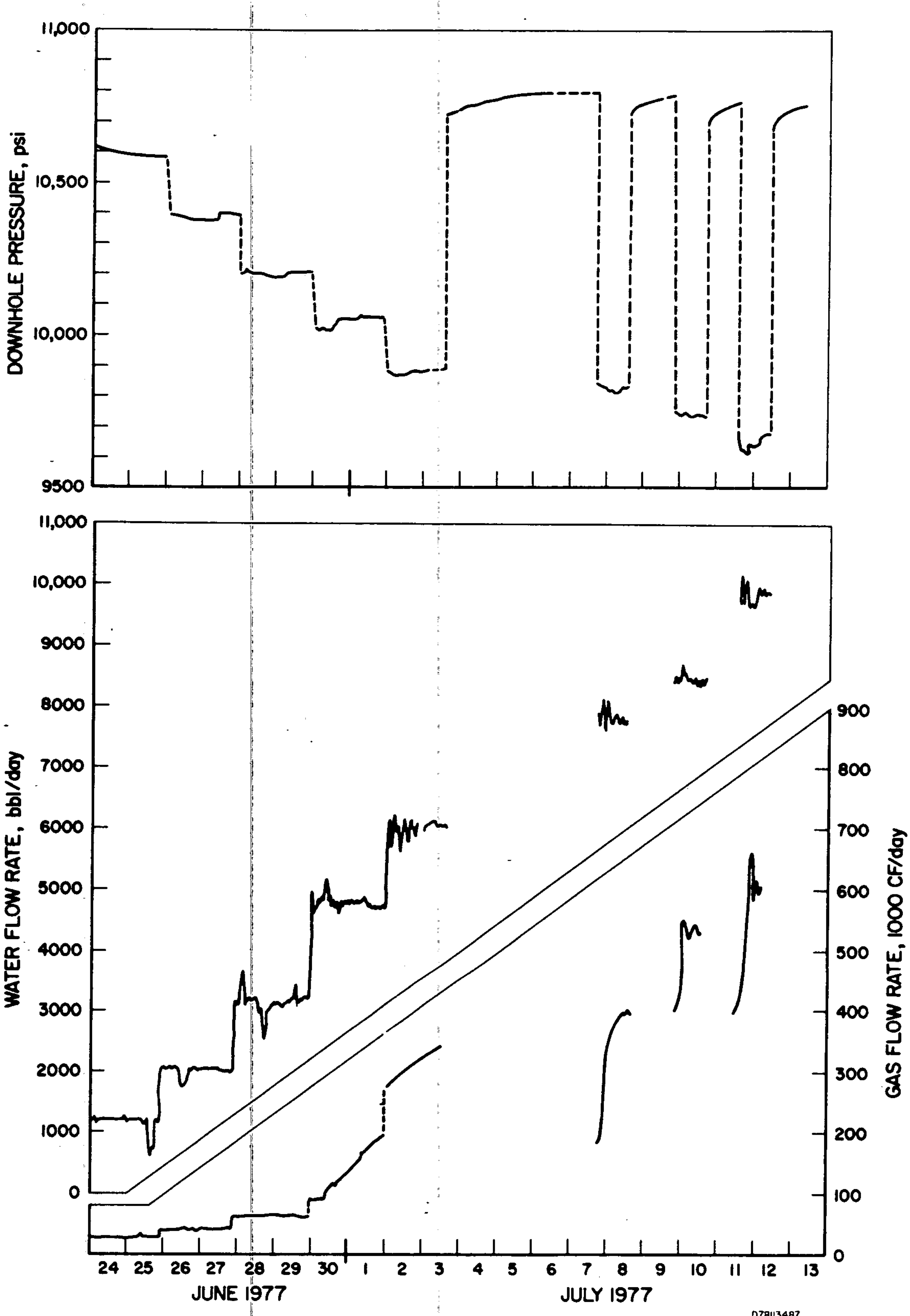

Figure 1. WELL TEST DATA FOR DELCAMBRE NO. 1 SAND NO. 1

The theory behind multiple flow rate analysis is given in reference 2. The equation that relates the down-hole well bore pressure to flow rate and time is —

$$\frac{P_t - P_o}{q_n} = \frac{162.2\nu B}{kh}\left[\sum_{j=1}^{n} \frac{(q_j - q_{j-1})}{q_n} \log (t - t_{j-1}) + \overline{S}\right] \quad (1)$$

where

P_t = well bore pressure at time t (psi)

P_o = initial well bore pressure (psi)

q_n = flow rate for nth increment (bbl/day)

t = time (hours)

B = volume factor (vol/vol)

$\overline{S}$ = composite skin factor (dimensionless)

h = height (ft)

k = permeability

ν = viscosity (cP)

j (subscript) = number of flow increment.

So long as the composite skin factor ($\overline{S}$) and the permeability-thickness (kh) remain constant for a large reservoir, it is seen that a plot of $(P_t - P_o)/q_n$ versus the summation term in the square brackets will give a straight line with slope (m') and intercept (b') of —

$$m' = \frac{162.2\nu B}{kh}$$

$$b' = m'\overline{S}$$

The data for the June 23 — July 3 tests used to make this analysis are given in Table 1 and the resulting plot is seen on Figure 2. In Figure 2, it is clearly seen that the data do not form a straight line as prescribed by the theory. The immediate conclusion is that either kh, or $\overline{S}$, or both kh and $\overline{S}$ are not constant throughout the test.

Osborn et al.[1,3] reported kh (and other parameters) based on this superposition equation and the use of a mathematical procedure (regression analysis) to fit selected data segments. The values they reported are summarized in Table 2. It is observed in Table 2 that the reported kh values generally

Table 1. DELCAMBRE NO. 1 SAND NO. 1 MULTIPOINT FLOW TEST ANALYSES

Time Point	Time (hr)	$\bar{q}$* (bbl/day)	$\bar{P}_w$* psi	$\left(\frac{P_i - P_w}{q_n}\right)$	$\sum_{j=1}^{n} \frac{(q_j - q_{j-1})}{q_n} \log (t - t_{j-1})$
t_0	0		10,820	--	--
t_1	50	1163	10,590	0.198	1.699
t_2	98	1988	10,390	0.216	1.863
t_3	146	3094	10,200	0.200	1.943
t_4	194	4707	10,050	0.164	1.986
t_5		5951	9,880	0.160	2.031

* $\bar{q}$ and $\bar{P}_w$ are approximate averages for the flow and pressure during the flow periods.

Table 2. PERMEABILITIES-THICKNESS (kh) VALUES BY OSBORN *ET AL.*[1,3] DELCAMBRE NO. 1 WELL SAND NO. 1 TEST SERIES

Test Sequence Number	Date	Type Test	kh (md-ft)	$\bar{S}$
1	6/23-6/25	Drawdown	2,939 4,524	0.11 4.13
2	6/26-6/27	Drawdown	5,878	11.79
3	6/28-6/29	Drawdown	5,095	5.18
4	6/30-7/1	Drawdown	--	
5	7/ 2-7/3	Drawdown	1,406 2,716 5,181	-5.74 -2.64 3.68
6	7/ 3-7/7	Buildup	8,697 8,840	12.96 13.31
7	7/ 7-7/8	Drawdown	6,181	5.06
8	7/ 8-7/9	Buildup	11,677 12,206	17.85 18.91
9	7/ 9-7/10	Drawdown	6,666	5.42
10	7/10-7/11	Buildup	11,417	15.42
11	7/11-7/12	Drawdown	6,830	4.98
12	7/12-7/13	Buildup	11,926	14.89

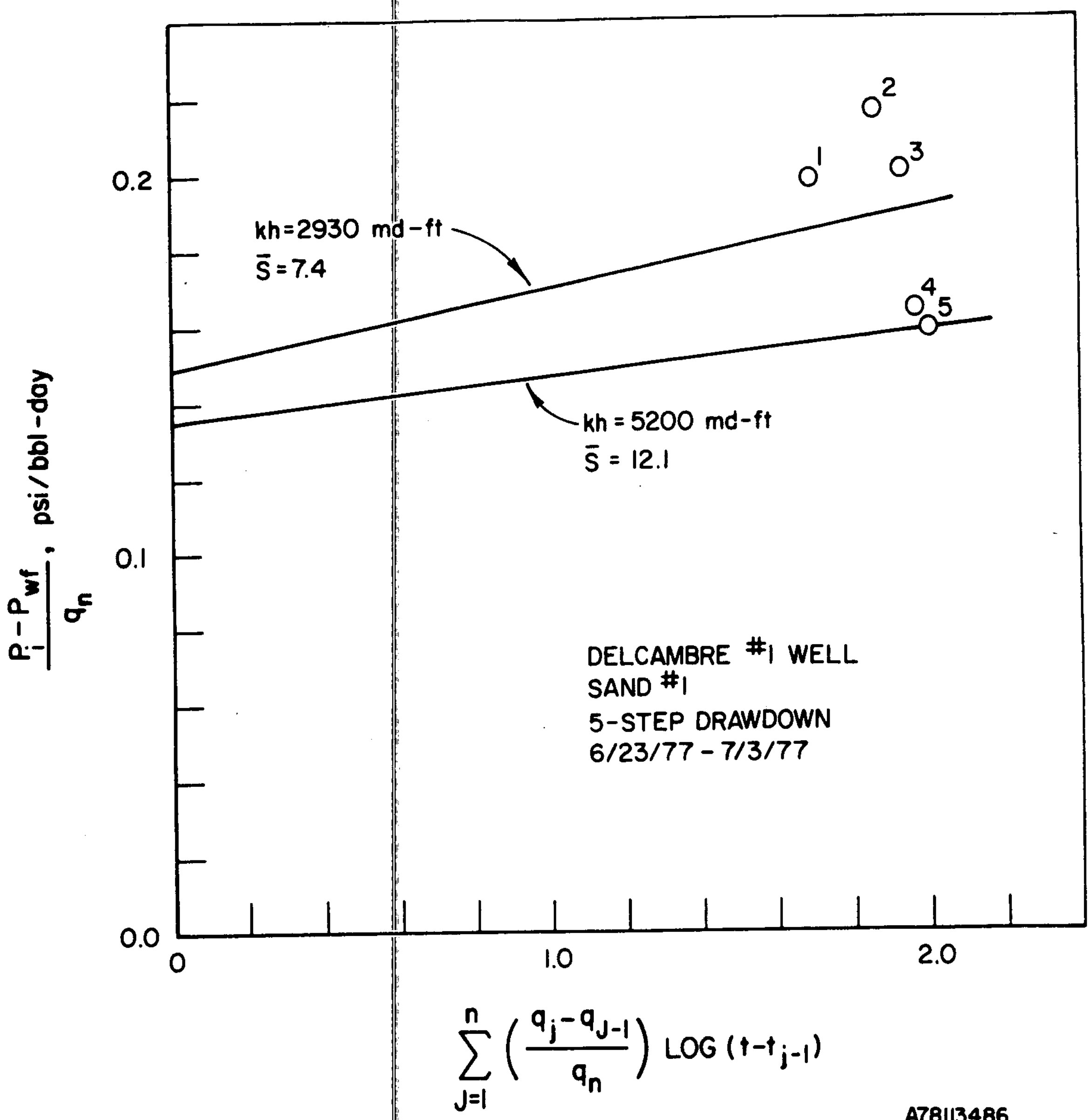

Figure 2. SAND NO. 1 DRAWDOWN ANALYSIS RESULTS

increase with time but contain large fluctuations. It is also noted that there is a considerable difference between the results, depending on whether they are from drawdown data or buildup data. There is almost a factor of 2 between the kh's for adjacent drawdown and buildup analyses. As is apparent in Table 2, reported values for the composite skin factor ($\overline{S}$) contain large fluctuations which do not seem physically possible.

In the transmittal letter of the Otis report,[1] the analysts (John S. Rodgers and J. S. Mokha) attribute the differences between drawdown and buildup kh values to "the concept of gradient permeability discontinuities caused by rock deformation." Since there is no experimental data on the compressibility or pressure dependence of permeability for the reservoir rock, the concept of rock deformation from pore volume relaxation cannot be verified. Laboratory studies of other sandstones suggest it is unlikely, however, that the 5% to 7% change in reservoir pressure would cause the permeability to change to half of its original value and then rapidly restore on shut-in for buildup.

The first drawdown step pressure data was plotted in Figure 3. It is noted in Equation 1 that when $n = 1$, a plot of pressure versus logarithm of time should give a straight line with slope $m = 162.2\nu Bq/kh$ and an intercept (at $t = 1$ hr) of $b = P_w - m\overline{S}$. The data did plot a straight line quite well, and for a viscosity of $\nu = 0.36$ cP and volume factor $B = 1.0$, the permeability-thickness value is kh = 2930 millidarcys-ft with the composite skin factor of $\overline{S} = 7.4$. This value of kh is close to the first value reported by Osborn <u>et al</u>., in Table 2, but this value of $\overline{S}$ is much larger than that reported (7.4 versus 0.11).

To better define the starting parameters for the Intercomp simulation model, additional analyses were made using the superposition equation and a programmable desk calculator (Hewlett Packard Model 97). Equation 1 was programmed so that for a series of flow rates and times, the resulting pressure could be calculated. With this program, the required kh's and skin factors to match the down-hole pressure could be estimated by trial and error as guided by the reported drawdown and buildup analyses.

The programmable calculator was then used to obtain a combination of kh and $\overline{S}$ which would match the last step in the first drawdown series and the following first buildup test. Trial and error found that kh = 5200 millidarcys-ft

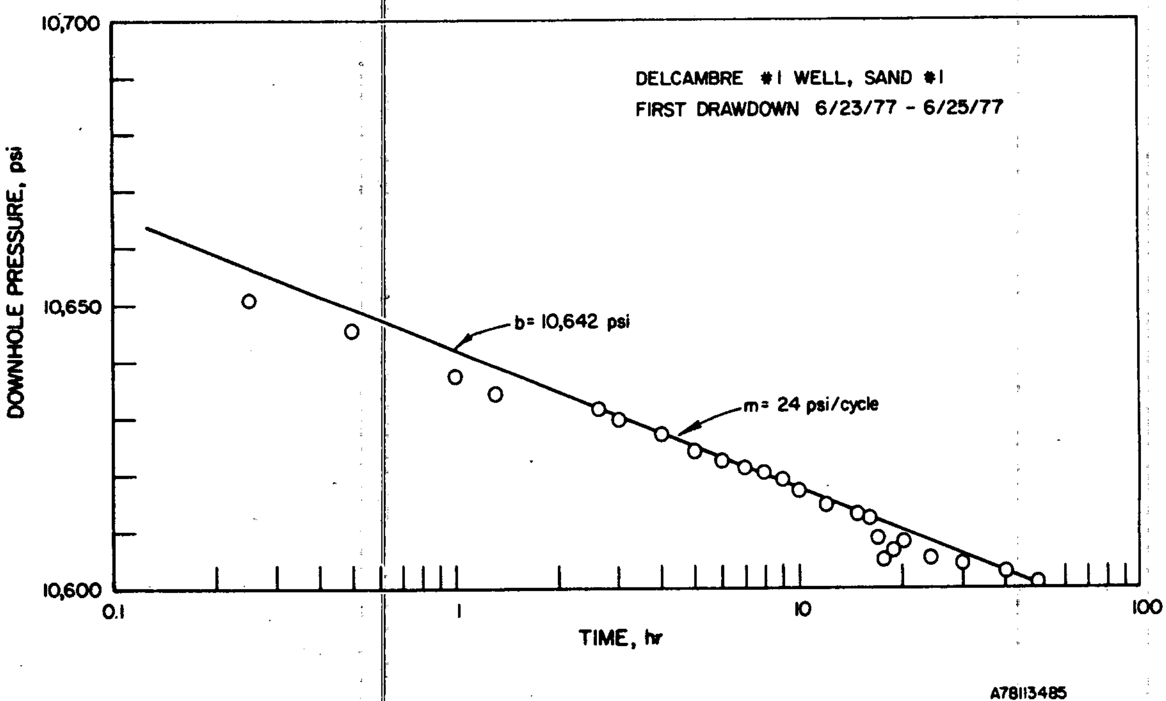

Figure 3. ANALYSIS OF FIRST DRAWDOWN OF SAND NO. 1

and $\overline{S}$ = 12.1 had a good fit to the data from June 30 to July 7. These kh and $\overline{S}$ values are almost twice those for the first step of the drawdown test of June 23 to June 26 discussed above. The equivalent slopes and intercepts for the multiple flow rate test analyses for this and the first step analyses were calculated and plotted on Figure 2. The reason that the upper line does not pass through the point for the first drawdown is that the point was calculated from the end of the drawdown, whereas the line is a best fit to all data points. This difference suggests that kh or $\overline{S}$ or both may be changing during the first drawdown, rather than both being constant as assumed in the analysis.

These simple analyses suggest that kh and $\overline{S}$ increase with time through the five steps of the first drawdown series. There can be several reasons for the increase in kh, and several speculations, suggested by available well log information and theory, were explored by adjusting k and h and $\overline{S}$ to various values to fit the data. One possibility is that some of the perforations were not producing in the first step of the drawdown but suddenly opened up in the second, third, and fourth drawdown steps. This is suggested by the sudden increases found in the down-hole pressure without a corresponding change in the water flow rate.

Using the reasoning that these sudden pressure increases represent the addition of more producing horizons to the well, it can also be argued that the sudden influx of excess gas that begins on June 20 is the result of a gas-rich zone suddenly breaking through the flow barrier so as to begin production. This in turn suggests that a multilayer model be used for the Intercomp reservoir simulator wherein some of the layers contain only gas-saturated brine and at least one layer contains excess gas. Arguments can be made for considering the excess gas either as a free cap or as dispersed bubbles. Several different models are suggested, which can be run on the simulator. It should be noted that all of the analyses discussed above assume the both kh and $\overline{S}$ are constant over the time interval spanned by each calculation.

In looking at the gas production in Figure 1, it is observed that the rate of excess gas produced between June 30 and July 3 is constantly increasing. This suggests cleanup of a damaged production point or some other mechanism where prior gas production enhances further production. In terms of conventional analysis, none of the gas production is constant enough for the usual reservoir analysis. The later portions of the July 7-July 13 drawdown tests do suggest that more constant production was being established. Using these three tests, an approximate back-pressure plot of excess gas production versus p^2 was made. In this plot, the intercept is considerably below the initial reservoir pressure, which indicates that there is a skin effect or a relative permeability threshold effect that has a major influence on the production.

Further Drawdown Test Analysis

It was discussed above how the five-step multirate drawdown test of the No. 1 sand showed that the permeability thickness (kh) and skin effect (S) were changing during the test. This was the case for the first three steps of the drawdown even before the excess gas started to flow. To further understand this behavior, the data for pressures and flow rates were placed in the Tektronix computer and the multistep flow test analysis performed on the data. A similar analysis was reported by Osborn et al., where they utilized Otis Engineering Services to perform the analysis. This analysis consists of plotting pressure against a summation function of the flow rate and time. The kh value is then determined from the slope of the plot by the equation —

$$kh = \frac{162.6 \nu B}{m}$$

where ν = viscosity (.36 cP for this analysis)

B = volumetric factor (1.0 for this analysis)

m = slope of pressure versus summation function.

If kh is constant, then a plot of pressure versus the summation function for the five-step drawdown of the No. 1 sand should have straight-line plots with the slopes of the five steps equal to each other. The resulting plot is shown in Figure 4. Note in this figure that, besides there being a number of sudden offsets, the slopes of the various segments differ from one another. Also note that the slopes tend to become less with time, indicating an increased kh with time. Figure 4 is useful in giving a view of the difficulties to be encountered in interpreting the data.

In reanalyzing the detailed data, several things were noted which have an effect on the interpretation. The first of these things was that the flow rate for the first 1.75 hours was not recorded. The pressure data were nicely

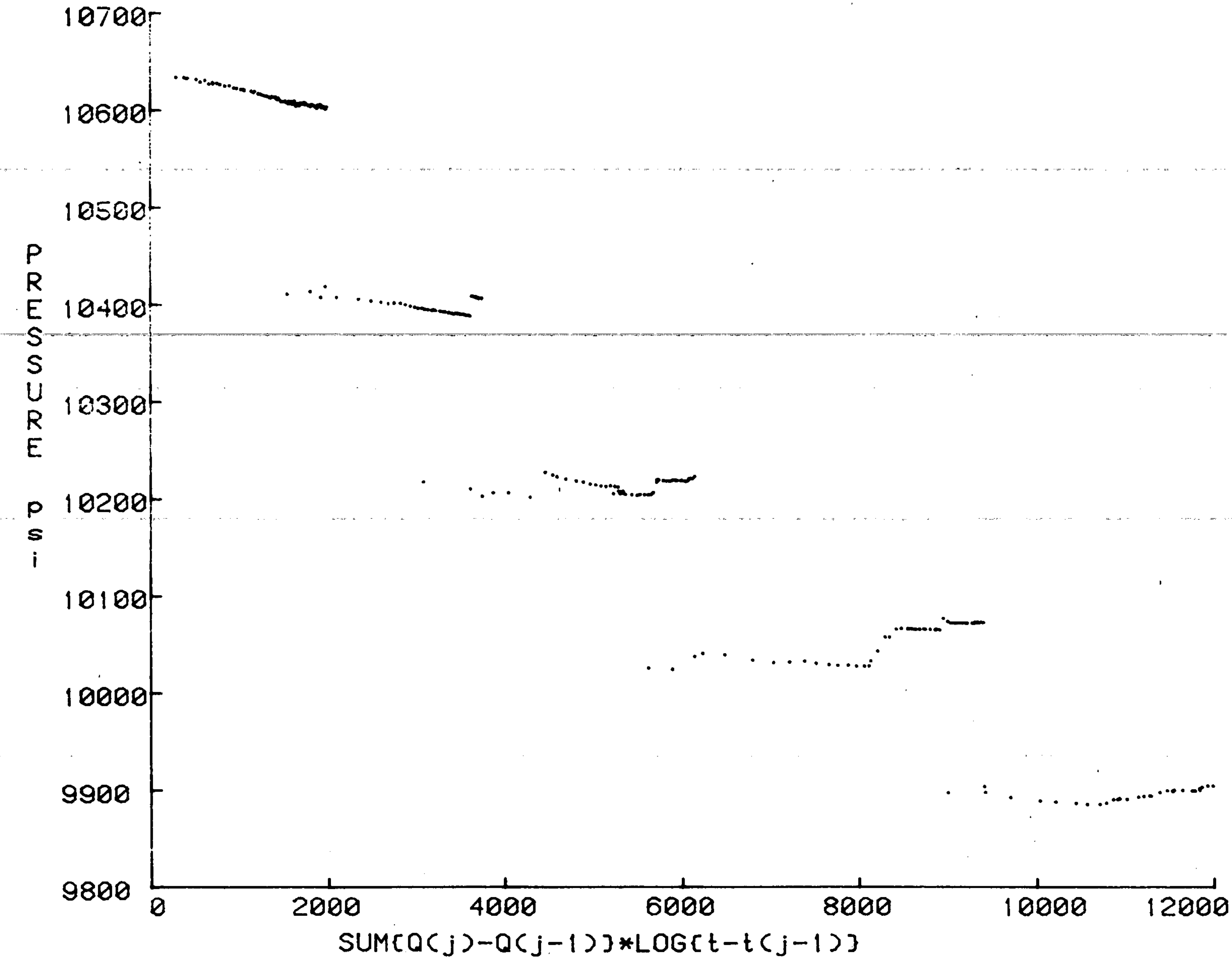

Figure 4. PLOT OF BOTTOM HOLE PRESSURE VS. THE SUPERPOSITION FUNCTION OF TIME FOR THE FIVE STEPS IN THE MULTIRATE DRAWDOWN TEST

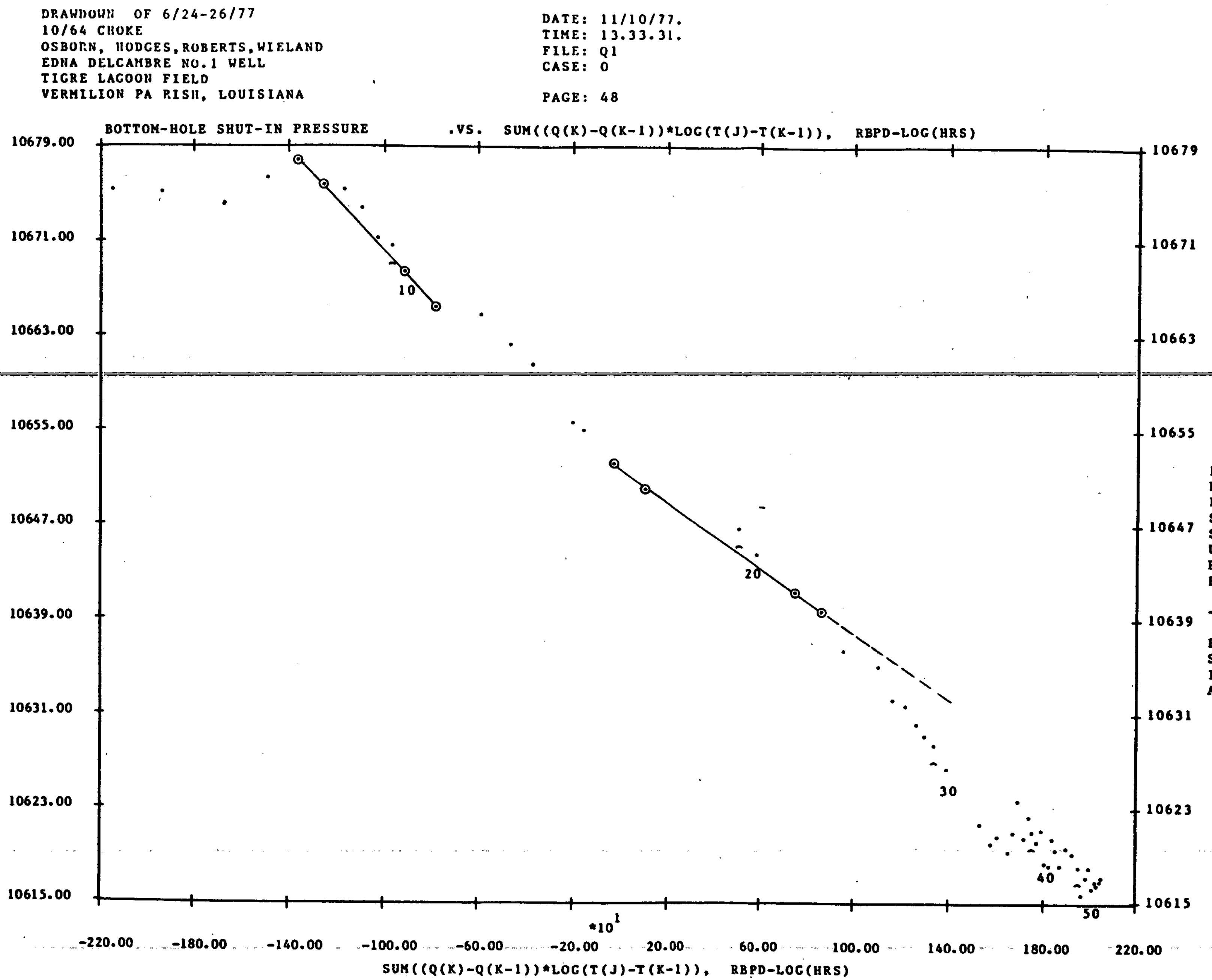

Figure 5. PLOT BY OTIS SERVICES OF THE BOTTOM HOLE PRESSURE VS. THE SUPERPOSITION TIME FUNCTION FOR THE FIRST STEP OF THE MULTISTEP DRAWDOWN TEST

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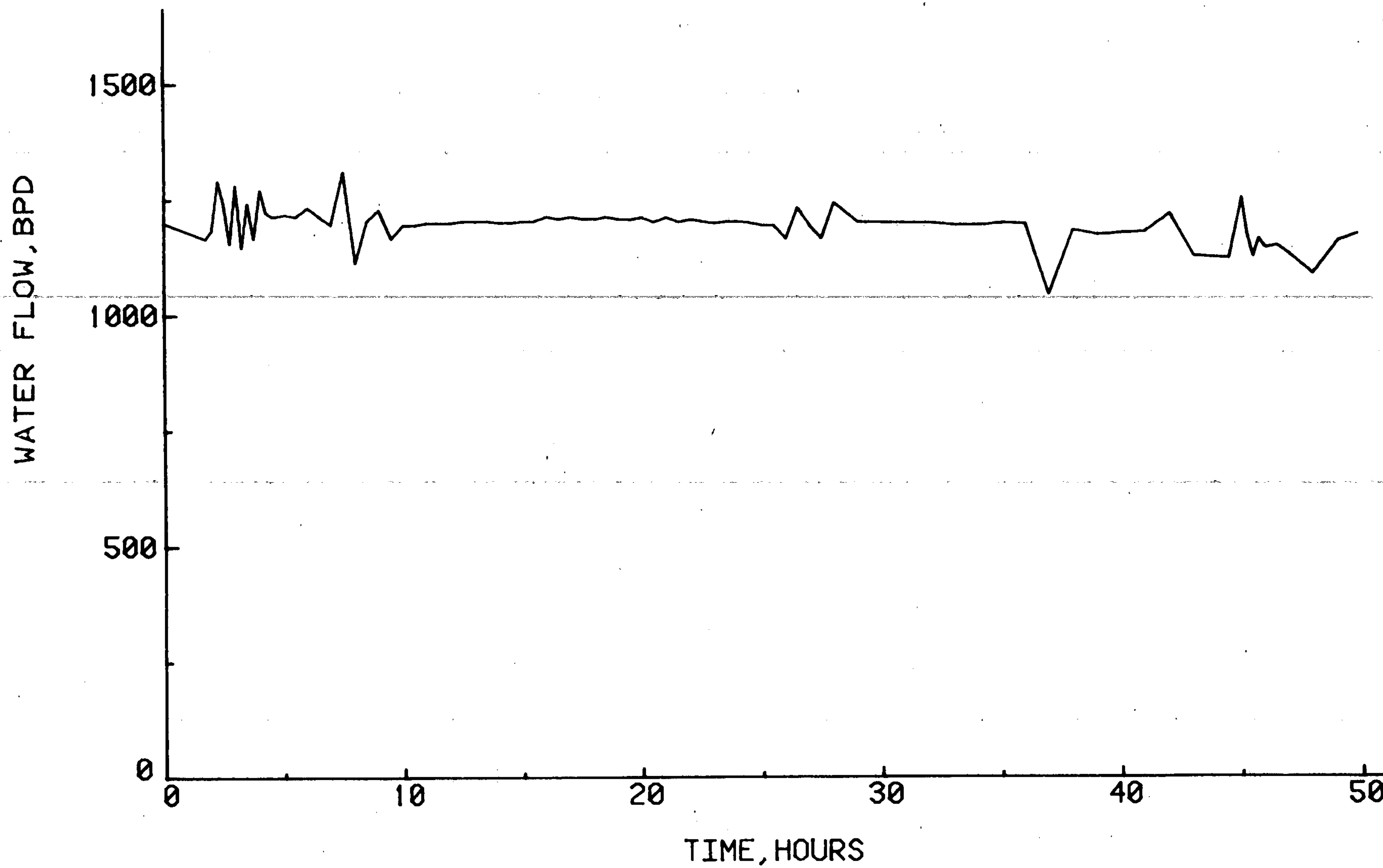

Figure 6. MEASURED BRINE FLOW-RATE FOR THE FIRST STEP IN THE MULTIRATE DRAWDOWN TEST

recorded for this time, but there is no indication of how steady the corresponding flow was. These initial pressure and flow data are important in an analysis for flow boundaries or nearby faults that affect the production geometry. The initial flow should be as steady as possible so that plots of pressure versus log time can be examined for inflections that indicate changes in production flow patterns. Also, if the flow rate fluctuates, the changing flow will have an effect on the summation function in the multipoint analysis.

The Otis analysis was made with the flow part of the summation function set at the approximate average for the flow period. This ignores the way in which the short-time flow fluctuations affect the pressure. Then, when they examined the plot for straight-line segments, they looked only for short-time linearities. Consequently, the segments they chose to fit could have been significantly influenced by the short-time fluctuations; this might have caused an erroneous choice for the slope. Since they used an average flow over the entire step of the test, they should have obtained a corresponding average fit over the same period. An example will illustrate this point.

Figure 5 shows the Otis plot for the first drawdown step of the No. 1 sand. For this plot, they used a constant flow rate of 1207 bbl/day. Then, from this plot, two straight-line segments were determined by selecting four points each to represent the straight-line fit to the data. The first fit (with "10" by the line) is for times only a few minutes after the start of the test and during the period when the flow was not reported. The second fit (with "20" by the line) is for times from about 1 hour to about 4 hours. During this time the reported flow was oscillating somewhat as shown in Figure 6, which plots the reported flow data for the first drawdown step. These two fits to the data are thus made for times when there is high possibility for error and the actual short-term flow may be different from the average 1207 bbl/day. Also, it is difficult to see why the particular points used for the fits were selected and the others ignored.

There would be expected changes in slope of the data when flow boundaries are encountered by the effective drainage radius of flow, but in Figure 7 there is enough scatter in the data that any change in slope for the first 40 hours of flow is hard to identify. Thus, it seems that a better interpretation of this initial flow data is to fit the data between a few minutes (to get past the start-up transient) and about 40 hours with a single straight

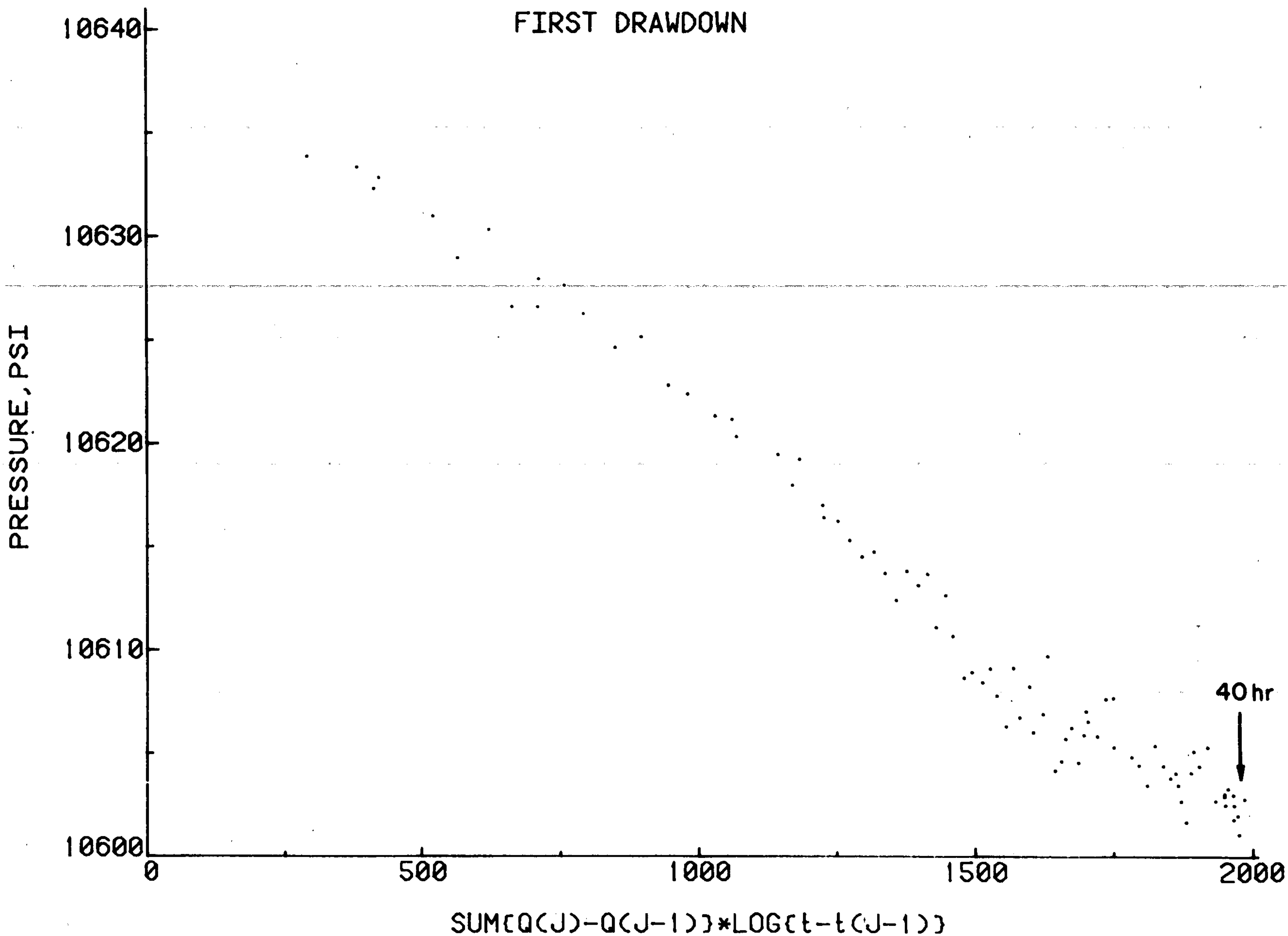

Figure 7. PLOT OF PRESSURE VS. THE SUPERPOSITION FUNCTION OF TIME FOR THE FIRST STEP OF THE DRAWDOWN TEST

line. Analysis of the buildup data indicates a flow discontinuity, but it is small enough that it isn't readily identifiable on Figure 7. A single straight-line fit to the data up to about 40 hours in Figure 7 gives a kh of about 3280 millidarcys-ft, compared to the values of 2939 and 4524 millidarcys-ft for the two fits by Otis.

When the pressure is plotted versus logarithm time for this first drawdown, the data indicate a straight-line fit as shown in Figure 8. Note that in Figure 8 there is a small offset in the data at about 2 hours and that slightly different slopes are found when the early time data (Figure 9) and mid-time data (Figure 10) are plotted. This small offset may be instrument-related rather than reservoir-related. It might be the result of a small shift in position of the pressure gauge, or it might be a sudden slight decrease in the effective skin factor for the producing perforations. This shift is slight and is only noticeable because of the use of the high-sensitivity Hewlett Packard down-hole gauge. The kh for the fit in Figure 9 is not calculated since the flow data are missing for this time. For the fit in Figure 10, the average flow for the time considered is 1207 bbl/day so the kh is 2825 millidarcys-ft, which is within 15% of the kh obtained from the fit to data in Figure 7.

The data between 41 and 50 hours in this first flow test were not used in the analysis because of their unusual behavior. While both the water flow rate and pressure indicate decreases during this time, the gas flow rate remained steady. This raises some question as to the validity of the data for this period since it is believed that only solution gas was being produced at this time.

Next, attention can be directed to the second step in the drawdown test. For this step, the plot and indicated fit to the data by Otis are shown in Figure 11. Again, as in Figure 5, it is not obvious why the particular three points were selected in Figure 11 to represent the fit to the data. For this plot, a constant flow of 2058 bbl/day was used. It appears that the data in Figure 11 could be reasonably fitted with three straight lines: one line for the early time data indicated by the "10" and "20"; another for the later data indicated by the "30"; and a final line for the offset data indicated by the "40." The latter two lines would be parallel to each other and simply offset from each other to accommodate the offset in the pressure data. The change

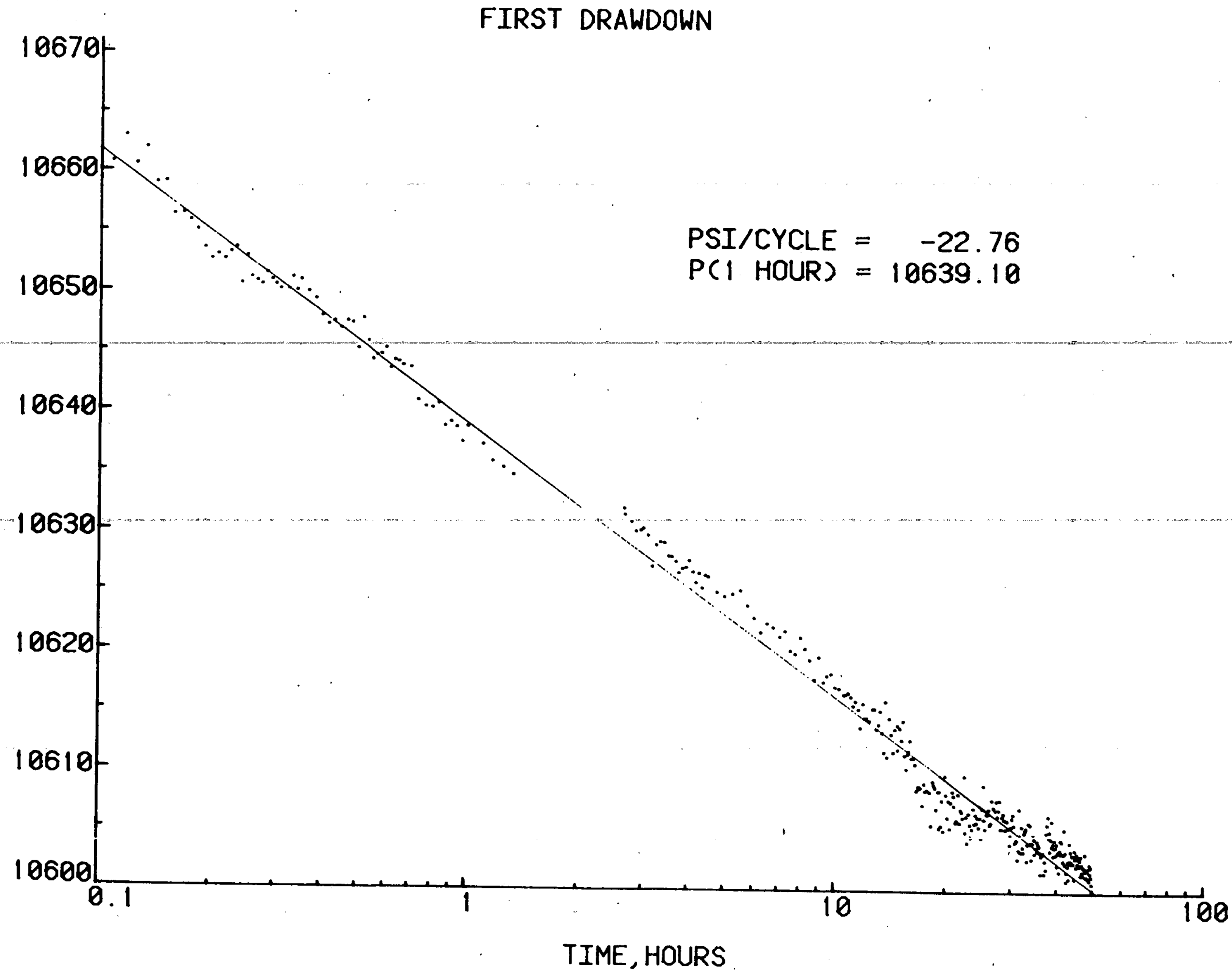

Figure 8. PLOT OF BOTTOM HOLE PRESSURE VS. LOGARITHM OF TIME FOR THE FIRST STEP OF THE MULTIRATE DRAWDOWN TEST

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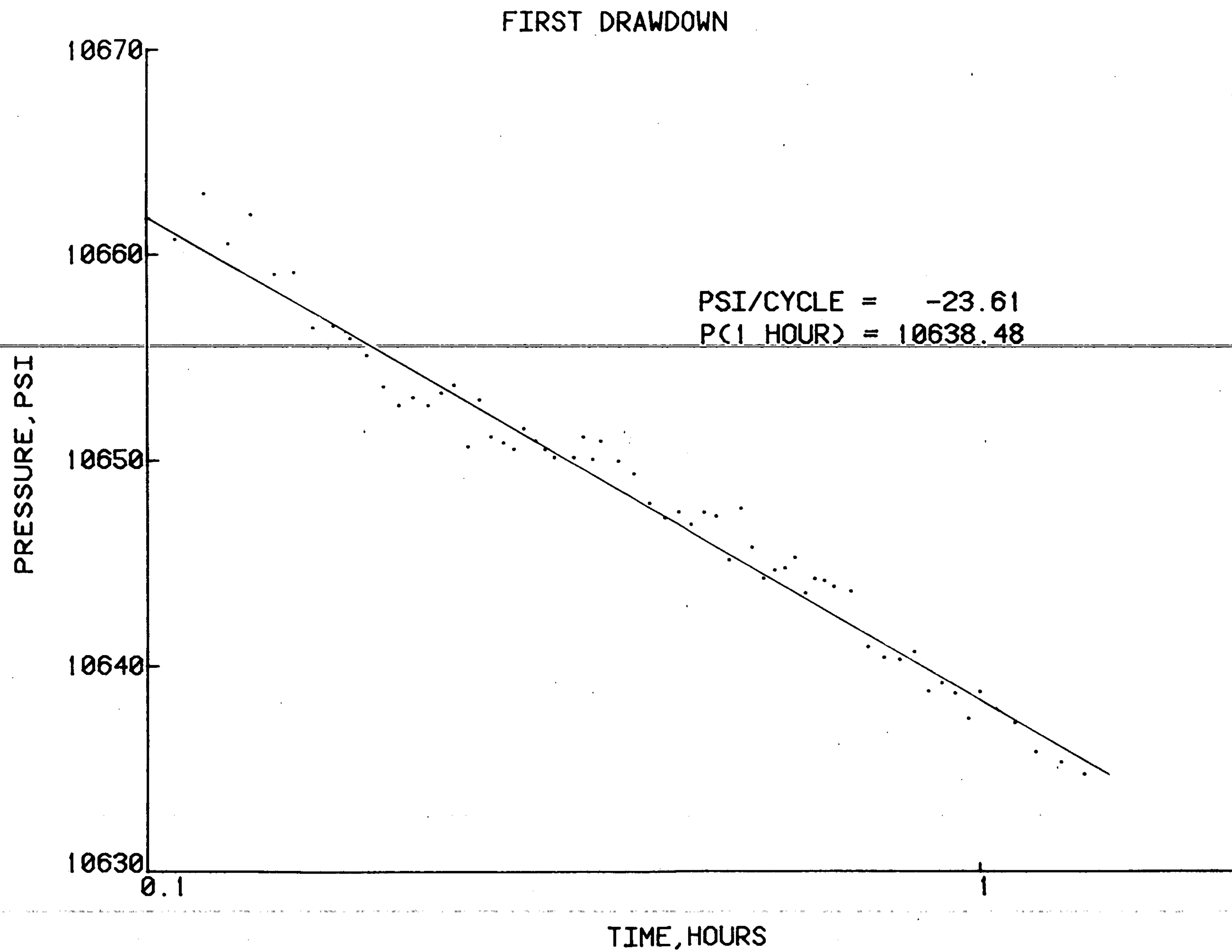

Figure 9. PLOT OF BOTTOM HOLE PRESSURE VS. THE LOGARITHM OF TIME FOR THE FIRST 1.4 HOURS OF THE FIRST DRAWDOWN TEST

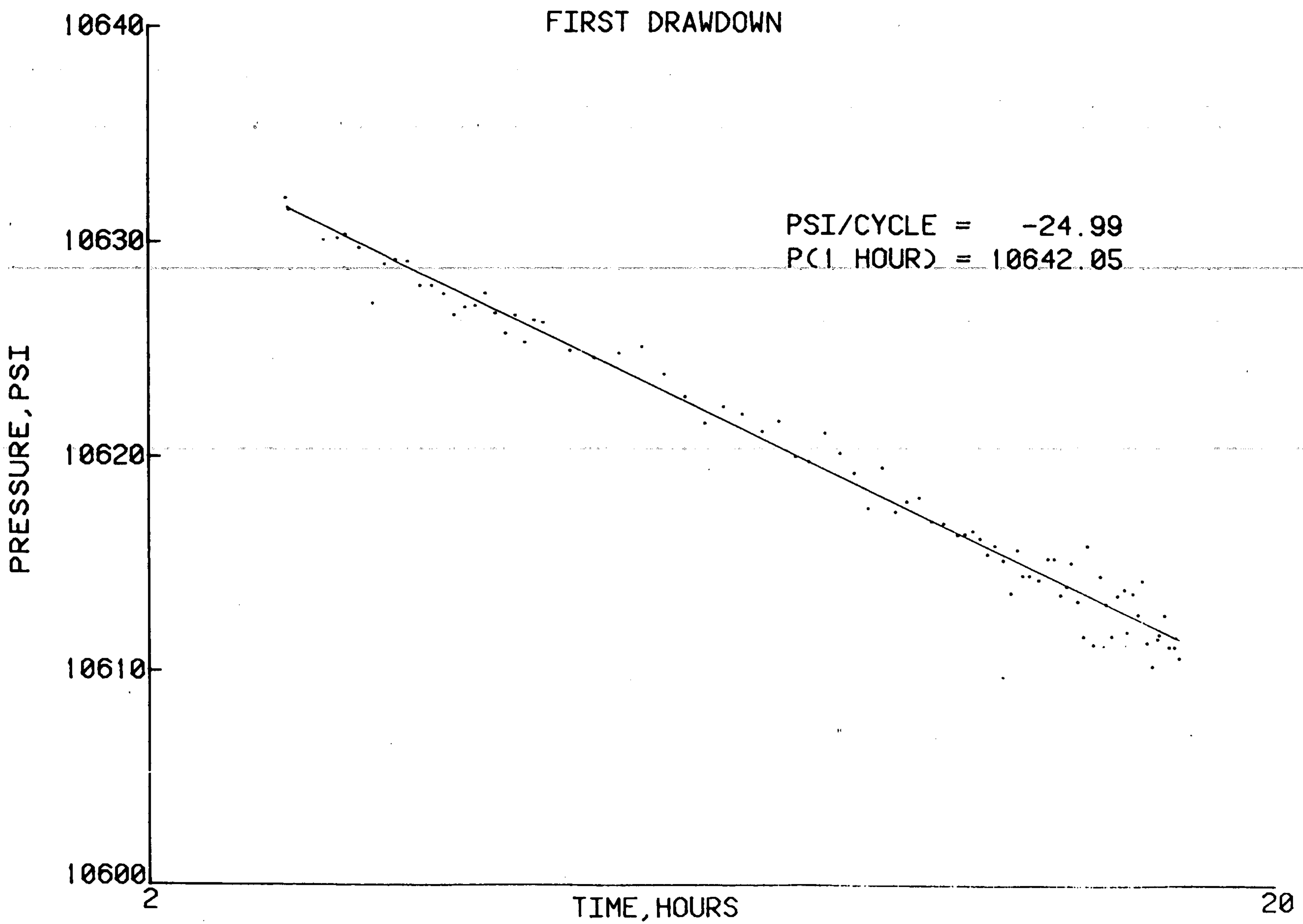

Figure 10. BOTTOM HOLE PRESSURE VS. LOGARITHM OF TIME FOR THE TIME 2.6 TO 16.5 HOURS OF THE FIRST DRAWDOWN TEST

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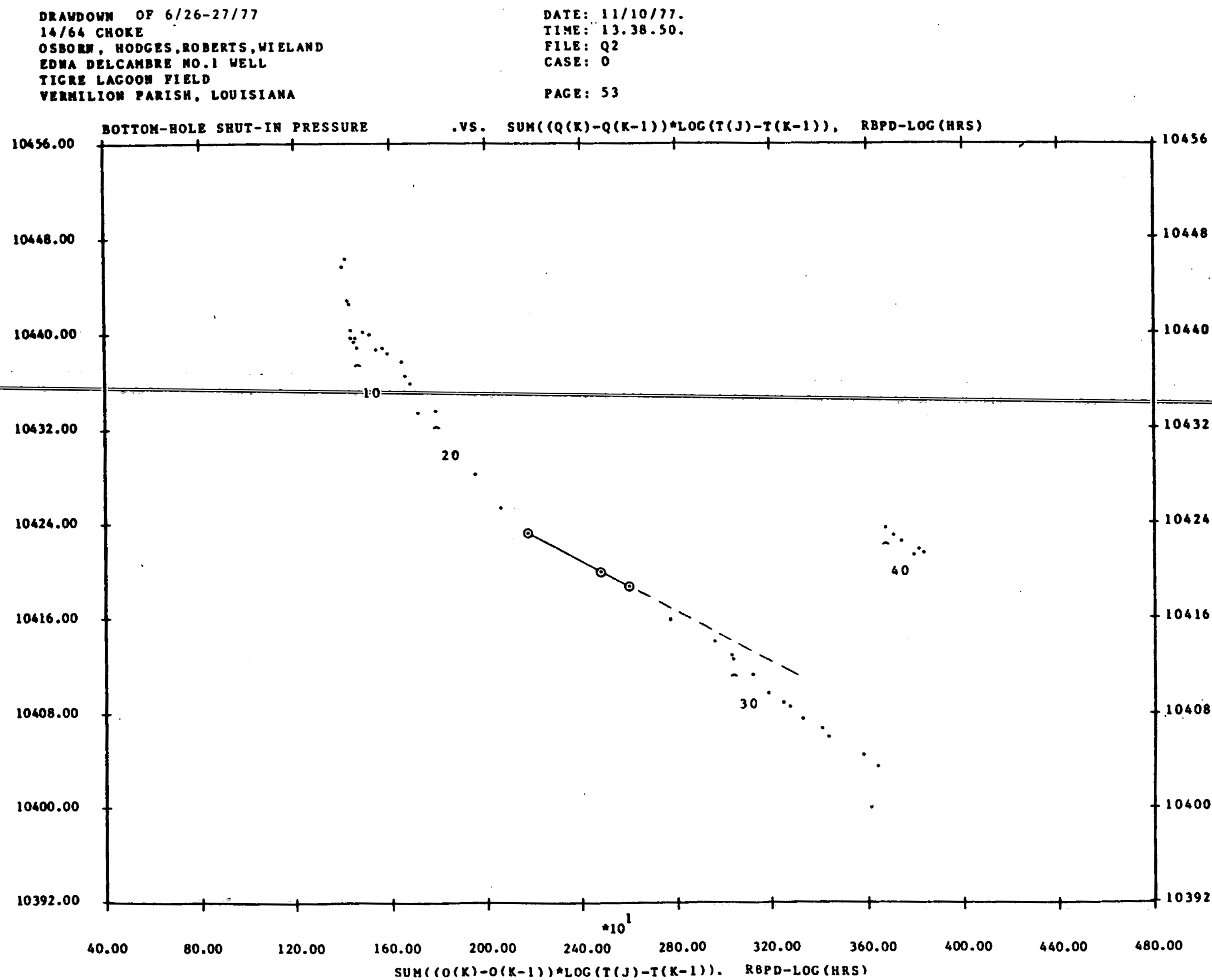

Figure 11. PLOT BY OTIS ENGINEERING OF THE BOTTOM HOLE PRESSURE VS. THE SUPERPOSITION FUNCTION OF TIME FOR THE FIRST DRAWDOWN TEST

in slope between the first two lines would indicate a change in the effective kh while the offset between the latter two lines indicates a change in the skin factor.

Three offsets can be seen in the pressure data for this second step of the drawdown in Figure 12. Two small offsets are at about 52 to 58 hours and a large offset is at about 86 hours. These offsets appear to be the result of the removal of skin damage at the producing zone and an increase in the effective kh. If a straight-line fit is made in Figure 12 to the data for about 60 hours to 85 hours, the resulting kh is 4170 millidarcys-ft. This same value is a reasonable fit to the 85-98 hour data.

The third step in the drawdown, plotted in Figure 13, shows even more offsets. No fits to the data were made in the Otis report, but it can be seen in the figure that a series of three parallel lines through the segments "10", "20", and "30" can be made. When this is done, the resulting kh is about 3270 millidarcys-ft. This agrees reasonably well with the previous values and indicates further changes in the effective skin factor and kh. The corresponding pressure-time plot for this step is shown in Figure 14.

The fourth drawdown step is when excess or free gas began to flow. The pressure-time plot for this step is given in Figure 15. The excess gas began at about 157 hours and is associated with the offsets and change in slopes seen in this figure. The multiflow analysis plot by Otis is shown in Figure 16, with a fit to the data as shown in the figure. In view of the continual shifting of the pressure as seen by the offsets, the validity of this fit is questionable, as are the similar fits to the other pressure plots. The analysis is not continued past the onset of the excess gas at this time since the free gas complicates the interpretation.

Summary of Brine-Only Flow Period

Detailed analysis of the pressure and flow data for the first four drawdown steps of the flow test of the No. 1 sand suggests that the mechanical conditions at the well bore producing zone kept changing. The many shifts and changes in slopes of the data plots indicate that there were many changes in the production pattern from the sands into the well bore. This could result from intermittent opening and closing of certain flow channels as material lodged and dislodged with production. The values of kh and the skin

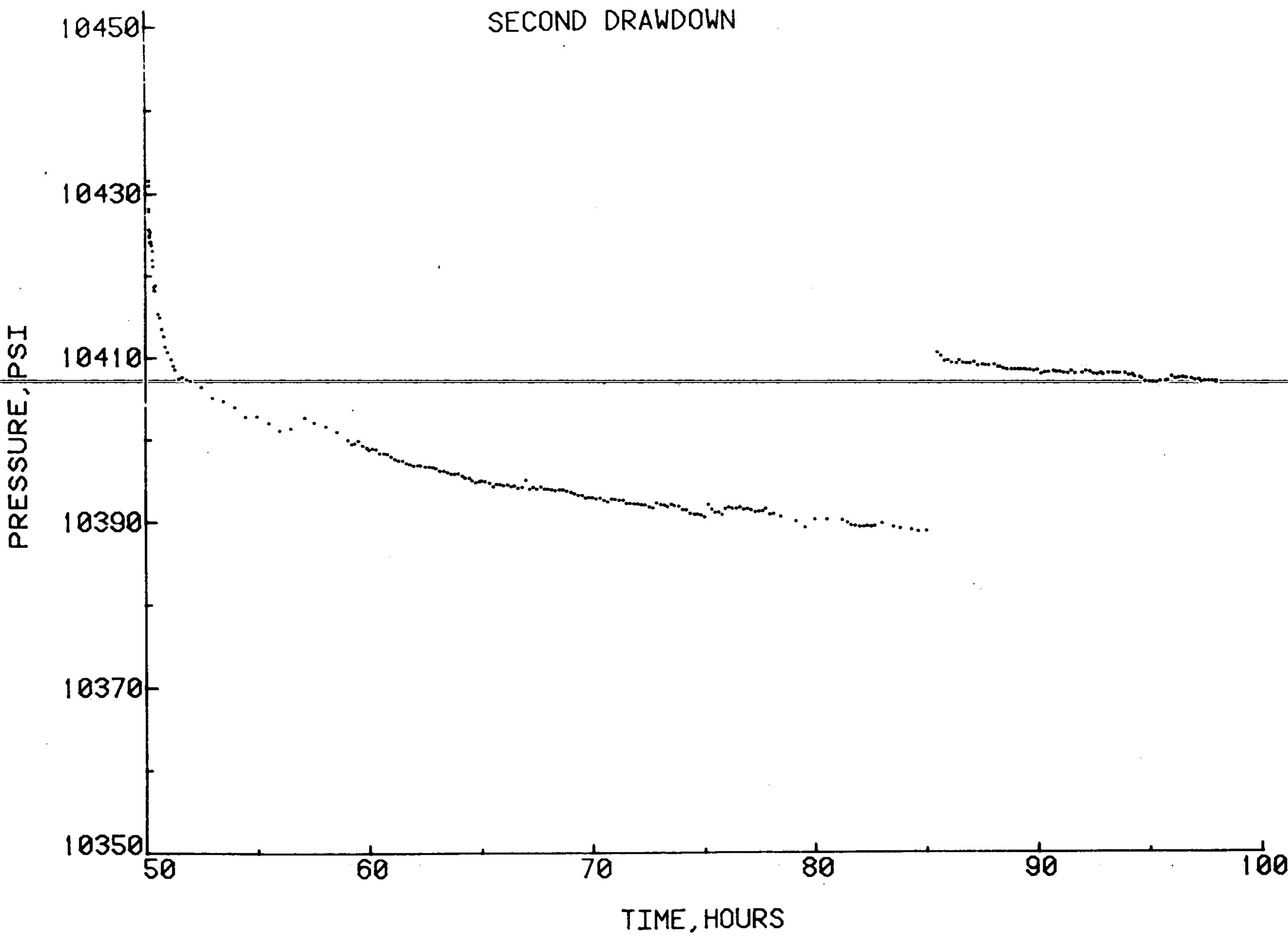

Figure 12. PLOT OF BOTTOM HOLE PRESSURE VS. TIME FOR THE SECOND STEP AT THE MULTISTEP DRAWDOWN TEST

DRAWDOWN OF 6/27-29/77
18/64 CHOKE
OSBORN, HODGES, ROBERTS, WIELAND
EDNA DELCAMBRE NO.1 WELL
TIGRE LAGOON FIELD
VERMILION PARISH, LOUISIANA

DATE: 11/10/77.
TIME: 13.39.40.
FILE: Q3
CASE: 0

PAGE: 58

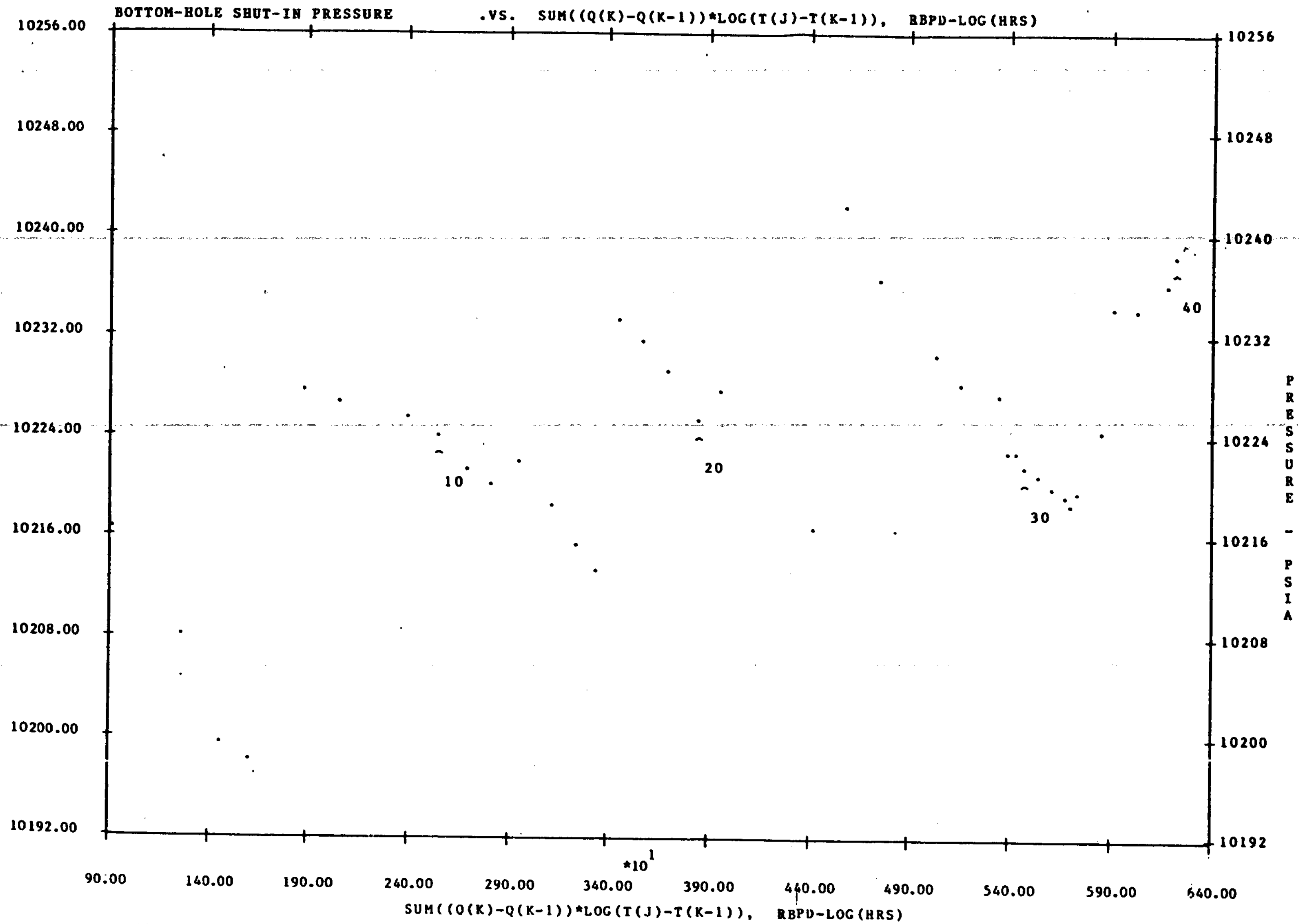

Figure 13. OTIS ENGINEERING PLOT OF BOTTOM HOLE PRESSURE VS. THE SUMMATION FUNCTION OF TIME FOR THE THIRD STEP OF THE MULTIRATE DRAWDOWN TEST

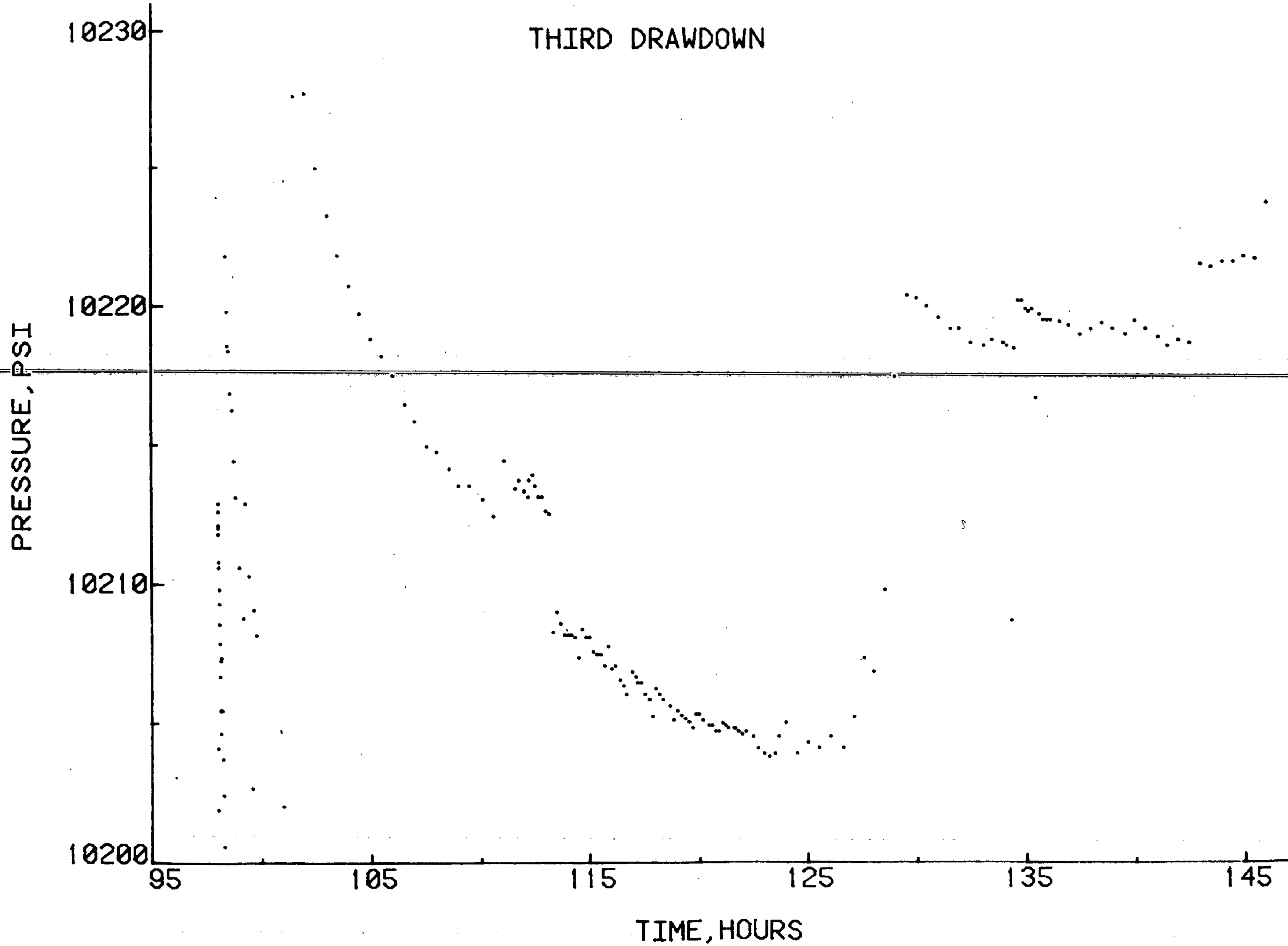

Figure 14. PLOT OF BOTTOM HOLE PRESSURE VS. TIME FOR THE THIRD STEP OF THE MULTIRATE DRAWDOWN TEST

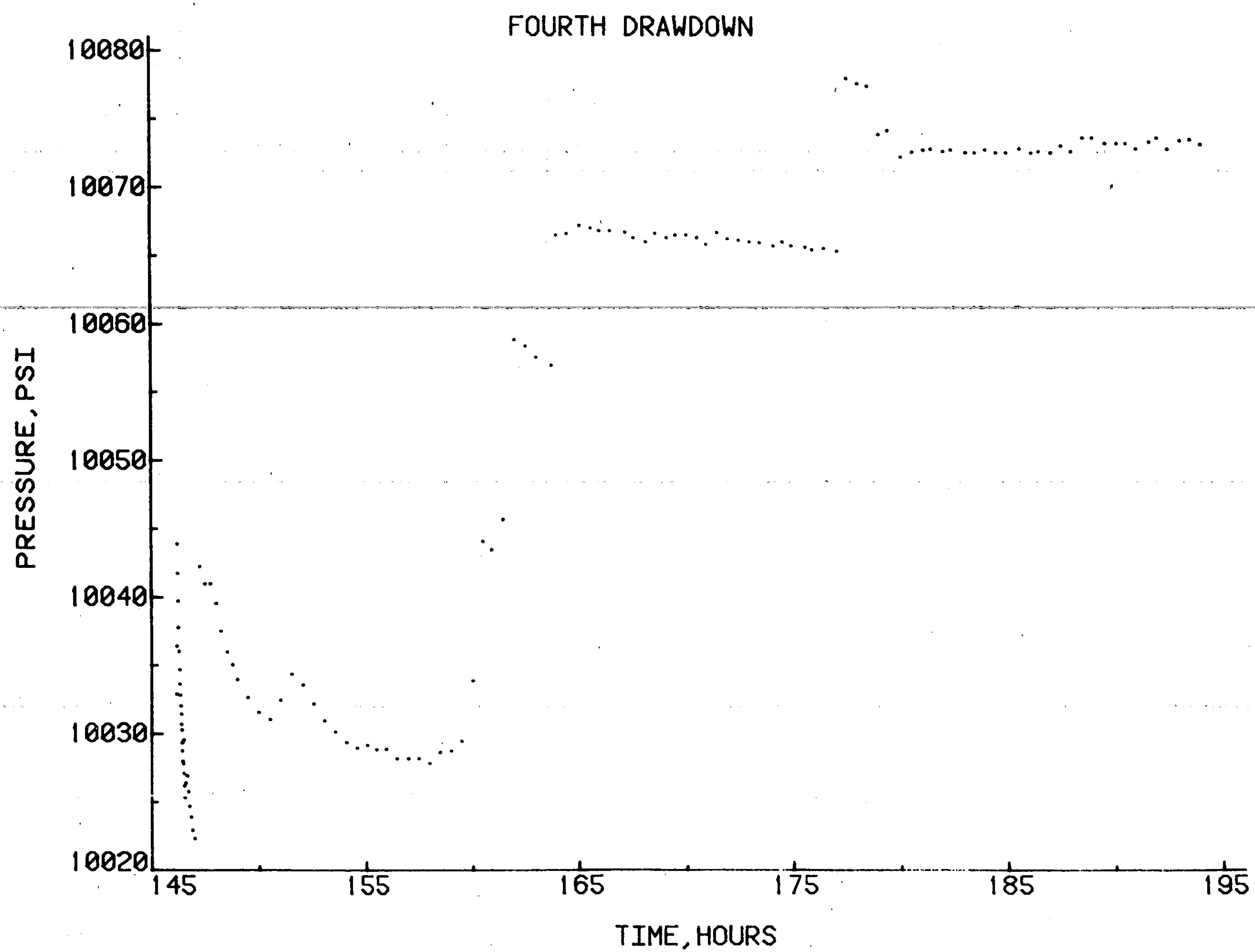

Figure 15. PLOT OF BOTTOM HOLE PRESSURE VS. TIME FOR THE FOURTH STEP OF THE MULTIRATE DRAWDOWN TEST

2/80
61025

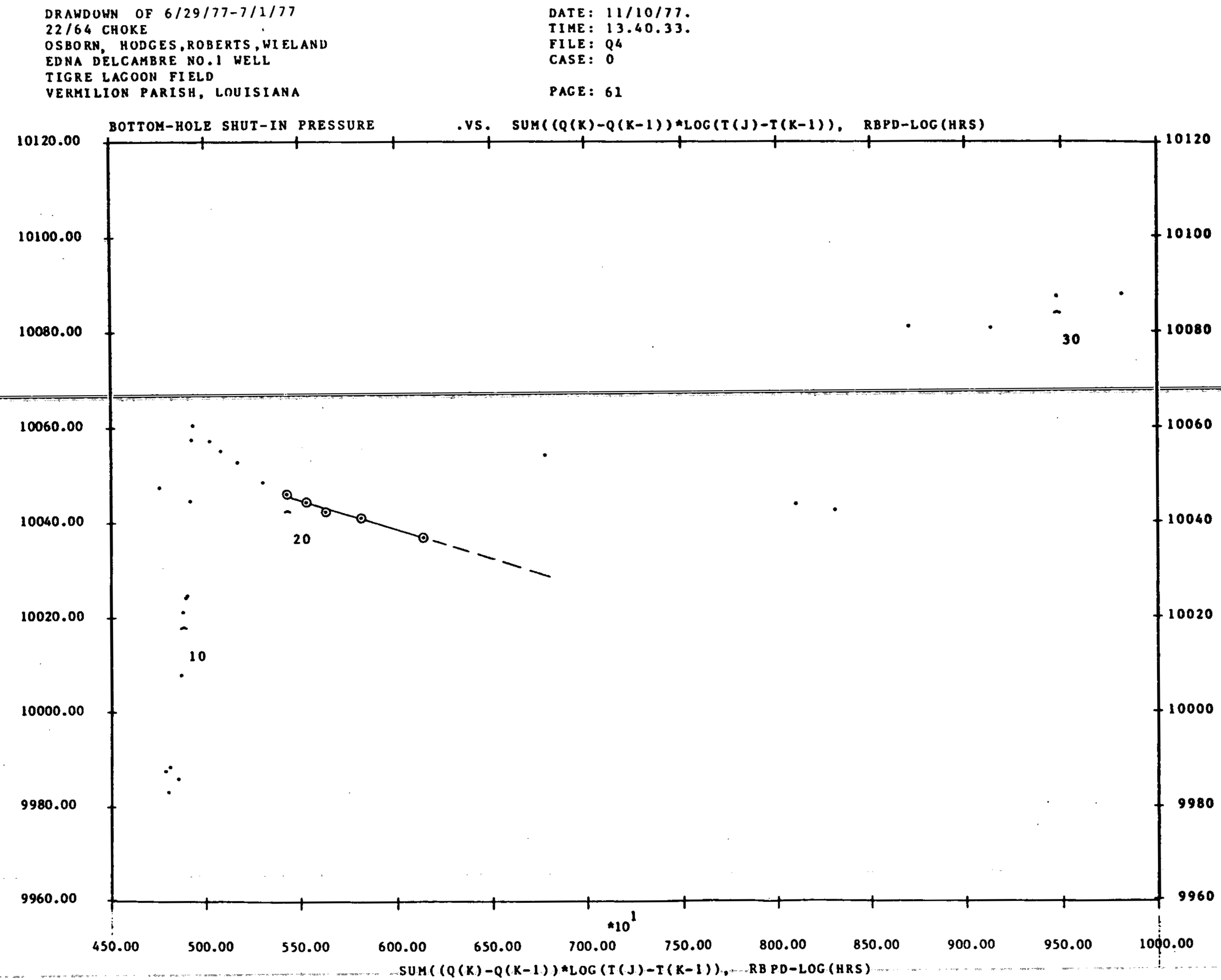

Figure 16. OTIS ENGINEERING PLOT OF BOTTOM HOLE PRESSURE VS. THE SUMMATION FUNCTION OF TIME FOR THE FOURTH STEP OF THE MULTIRATE DRAWDOWN TEST

factor would thus change with these fluctuating mechanical conditions and their values would depend on which flow channels or sands were open and which were blocked at any given time.

How a changing flow condition could occur is not readily evident. The total amount of sand produced throughout the test was only about 500 cm^3. therefore sand production would not be expected to have had a significant effect. The changes may be due to occurrences in the cement around the casing or shifts of the casing on rock associated with the pressure differentials created by the drawdowns. Small movements could result in opening or closing of flow channels or alter the permeability of the zone adjacent to the well bore.

Buildup Test Analysis

The pressure buildup for the No. 1 sand is plotted in Figure 17. The plots in Figure 17 indicate three regions in the buildup. First, there is the after-flow period which is dominated by early time well bore effects and the reservoir characteristics near the well bore and perforations. Following this after-flow period, there is a period labeled "A" on Figure 17 which is nearly linear on the semilog plot. Then there are small breaks in the curves followed by a final period labeled "B" which is also approximately linear but with a steeper slope than the "A" period. Table 3 summarizes the results of this analysis.

It is noted in the test data that for the first buildup the early time data is missing so that no "A" region is seen, and in the second buildup no break is observed like those found in the third and fourth tests. It is also noted that the time for the break is longer in the fourth test than in the third test. This might be interpreted as the result of recompression of the excess free gas in the formation near the well bore and/or the effects of two or more independent zones producing to the well instead of a sealing fault. Table 2 also gives the apparent distance to a discontinuity on the assumption that the change in slope is the result of a sealing fault.

Because of the complication of the excess free gas it is expected that the usual reservoir engineering procedure to obtain kh from the slope of the pressure versus logarithm of time may not be correct. The calculated values in Table 2 are labeled "apparent" because of this possible incorrect interpretation.

Table 3. SUMMARY OF BUILDUP DATA FOR SAND No. 1, EDNA DELCAMBRE No. 1 WELL

Buildup Test No.	q Prior Flow b/day	m "A" Slope psi/cycle	Apparent "A" kh md-ft*	Time of Slope Change hours	"B" Slope psi/cycle	Apparent Distance to Barrier ft**
1	5950	--	--	--	52.0	--
2	7750	37.0	12,200		37.0	
3	8450	44.4	11,090	4.4	53.0	1820
4	9850	49.6	11,590	6.0	62.5	2170

* $kh = 162.6 \frac{qB\mu}{m} \approx 58.3 \frac{q}{m}$

** $r_e = \sqrt{\frac{kt}{.04\mu C_e \phi}} \approx 1430 \sqrt{kt}$

$h \approx 30$ feet

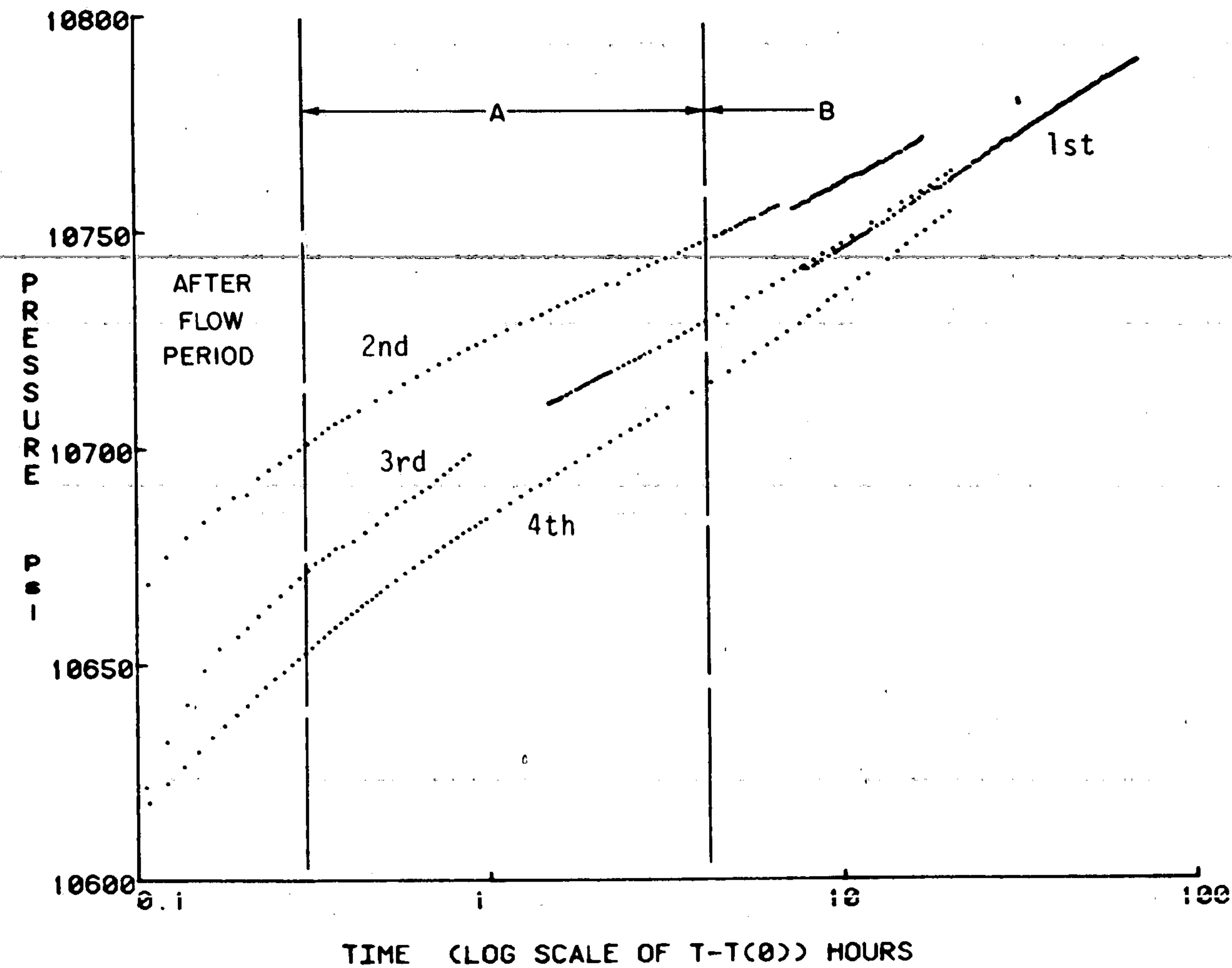

Figure 17. PRESSURE VERSUS LOGARITHM OF TIME FOR THE FOUR BUILDUP TESTS

Gas/Water Ratio

A recheck of the gas/water ratio was made for the first four drawdown steps up to the time of the sudden influx of excess gas. By considering the more steady parts of the production data rather than the gross averages of each step, it is found that the gas/water ratio is nearly constant at 19.0 to 19.5 SCF/bbl. This value does not include the residual gas still dissolved in the brine at the separator pressure and temperature. For these first drawdown steps, the separator was apparently operated at a temperature of about 150°F and a pressure of about 300 psi so the brine would still retain about 0.8 SCF/bbl of natural gas (using 133,000 ppm dissolved solids). This total saturation value of approximately 20.5 SCF/bbl is close to the 22.8 SCF/bbl reported by McNeese University[4] from recombination analysis. The McNeese report suggests that the aquifers might not be saturated, but it is difficult to imagine how there can be free gas in the reservoir without the water which is in contact with the gas being saturated.

Geochemical Thermometer Temperatures

To look for things that correlated with the onset of the excess gas, we examined the chemical composition of the produced brine for possible changes with time. While doing this the *in situ* brine temperature was calculated using a geothermometer equation which uses the concentrations of the sodium, potassium, and calcium ions. These data and resulting temperatures are tabulated in Table 4. No changes in composition or temperature beyond the statistical scatter were noted. The geothermometer equation used is

$$t(°C) = \frac{1647}{2.740 + \log\left(\frac{Na}{K}\right) + \beta \log\left(\frac{\sqrt{Ca}}{Na}\right)} - 273$$

where Na, K, and Ca are in moles/liter

$\beta = 1/3$ for temperatures above 100°C.

Gas Composition Changes

To further determine the source of the excess free gas produced from the No. 1 sand, the composition of the produced gas was examined. Figure 18 plots percent composition of three of the minor constituents throughout the test period reported by Hankins and Karkolits.[5] These are ethane, propane, and carbon dioxide. Note that when the free gas begins to be produced, the amount

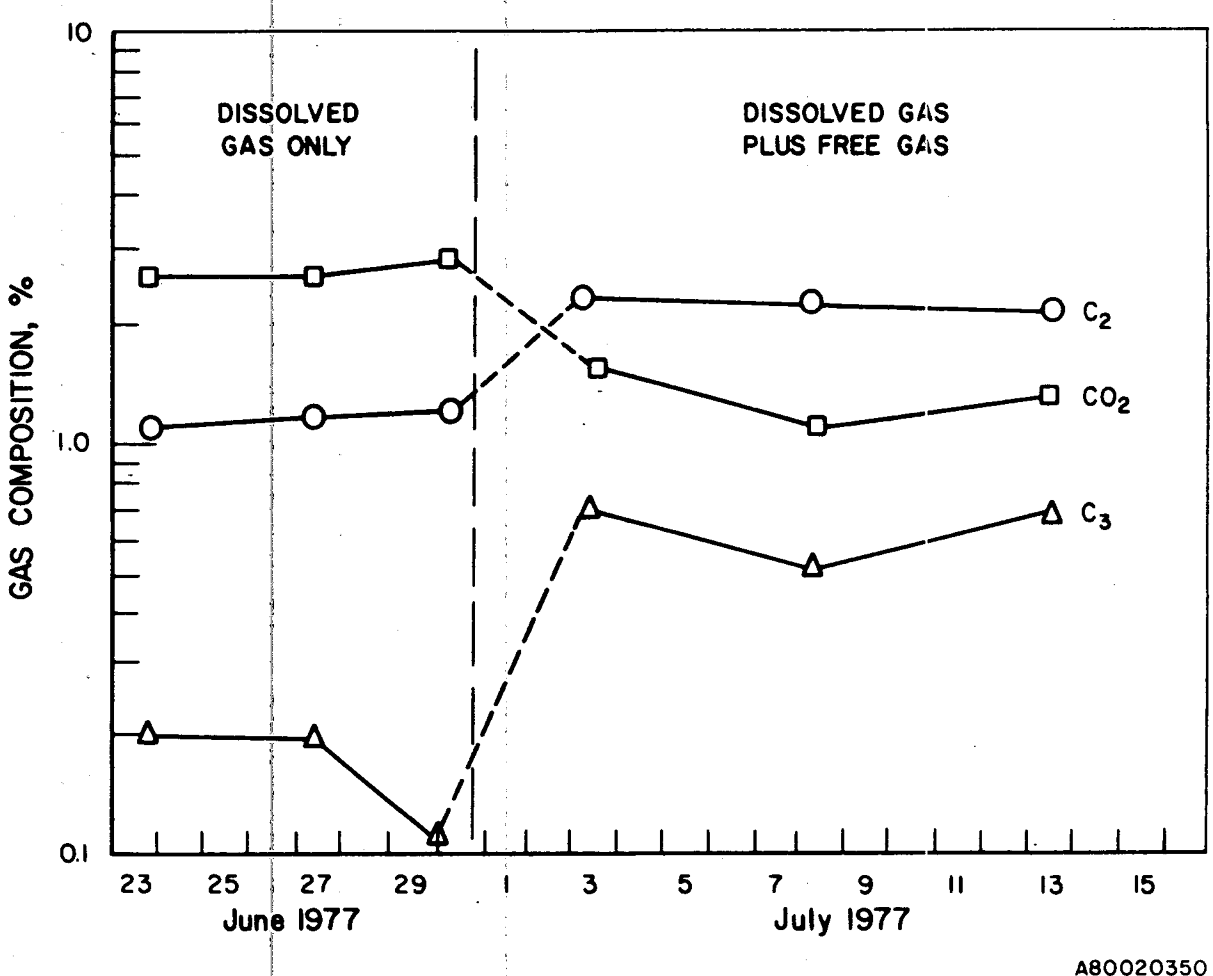

Figure 18. COMPOSITION OF ETHANE (C_2), PROPANE (C_3) AND CARBON DIOXIDE (CO_2) IN THE NATURAL GAS PRODUCED FROM THE EDNA DELCAMBRE NO. 1 WELL, SAND NO. 1 TEST

of C_2 (ethane) and C_3 (propane) increases significantly. At the same time the percentage of carbon dioxide decreases. These data are consistent with the fact that the ethane and propane are less soluble in water than methane. If there is free gas in contact with water, the heavier hydrocarbons will preferentially concentrate in the gas phase. Also, carbon dioxide would preferentially concentrate in the water, as was observed.

These data are evidence that the excess gas originated from free gas, or a different gas source than the dissolved gas. It does not answer whether the free gas was in the form of a cap or whether it was in dispersed bubbles, but it does argue against the "champagne bottle" model of exsolved gas proposed by Jones. If the excess gas was exsolved from the water, then the gas composition would be expected to remain constant. Whether the composition of gas that might be in the hypothesized dispersed gas bubbles would be the same as in a free gas cap is not yet determined, but the observed changes in composition are consistent with the gas cap model or the existence of a leaky adjacent well — the conclusion reached for the technical report given in the Appendix.

Dispersed Gas Model

In this dispersed gas model, it is assumed that the free gas is trapped in the matrix in discontinuous small bubbles or pockets and will not initially flow because its saturation is small and is above the relative permeability cutoff point. When water is produced, the water saturation decreases until the point is reached where gas can be produced. For this model to give an explanation of the excess free gas, it is necessary to find a plausible combination of the right amount of free gas and a suitable relative permeability curve.

The permeability and relative permeabilities for gas and liquid when two-phase flow occurs are not known for the test data on the Delcambre No. 1 well. Without direct measurements it is necessary to use the production test results and some theory to construct the relative permeabilities. As a first attempt to determine the relative permeability curves, the results in the Otis report[3] were compared to different theoretical curves.

The theoretical equations for relative permeability which were considered were the Corey equation,[6] the Pirson equation,[7] and the Otis modification to the Pirson equation.[1] They are as follows:

Table 4. EDNA DELCAMBRE No. 1 WELL
Na-K-Ca GEOTHERMOMETER TEMPERATURES
SAND No. 1

Depth 12,573 — 12,605

Sample No.	Time	Ca	Na	K	Geothermometer t, °C
		ppm	ppm	ppm	
1F	6-23 PM				
2	6-23 PM	2030	46,000	290	105
3	6-24 AM	2100	47,000	280	103
4	6-24 PM	2000	45,000	280	105
5	6-25 AM	2030	46,000	270	103
6	6-25 PM	2070	46,000	290	105
7	6-26 AM	2070	47,000	290	105
8	6-26 PM	1770	45,000	280	105
9	6-27 AM	2030	47,000	280	103
10	6-27 PM	2100	45,000	290	106
11	6-28 AM	2070	50,000	270	100
12	6-28 PM	1970	42,000	290	108
13	6-29 AM	2030	45,000	290	106
14	6-29 PM	1970	46,000	280	104
15	6-30 AM	1930	47,000	300	106
16	6-30 PM	2070	50,000	290	103
17	7- 1 AM	2070	45,000	290	106
18	7- 1 PM	2030	45,000	290	106
19	7- 2 AM	2100	43,000	290	107
20	7- 2 PM	2070	43,000	290	107
21	7- 3 AM	2070	45,000	290	106
22	7- 7 PM	2070	48,000	290	104
23	7- 8 AM	2030	44,000	280	105
24	7-10 AM	2100	46,000	290	105
25	7-10 PM	2100	46,000	290	105
26	7-11 PM	2100	47,000	260	100
27	7-12 AM	2130	45,000	290	106
28	7-13 AM	2070	47,000	300	106
29	7-13 PM	2100	43,000	280	105
	Averages	2045.7	45,710	285.7	104.86
		= 0.0511 M/ℓ	=1.987 M/ℓ	=0.00731 M/ℓ	= 220.75°F

Corey

$$k_{rw} = \left(\frac{S - S_r}{1 - S_r}\right)^4 \quad (2)$$

$$k_{rg} = \left[1 - \left(\frac{S - S_r}{S_m - S_r}\right)\right]^2 \left[1 - \left(\frac{S - S_r}{1 - S_r}\right)^2\right] \quad (3)$$

Pirson

$$k_{rw} = \left(\frac{S - S_r}{1 - S_r}\right)^{1/2} S^3 \quad (4)$$

$$k_{rg} = \left[1 - \left(\frac{S - S_r}{1 - S_r}\right)\right] \left[1 - \left(\frac{S - S_r}{1 - S_r}\right)^{1/4} S^{1/2}\right]^{1/2} \text{ drainage} \quad (5)$$

$$k_{rg} = \left[1 - \left(\frac{S - S_r}{S_m - S_r}\right)\right]^2 \text{ Imbibition} \quad (6)$$

Otis

$$k_{rw} = \left(\frac{S - S_r}{S_m - S_r}\right)^{3/2} S^3 \quad (7)$$

$$k_{rg} = \left[1 - \left(\frac{S - S_r}{S_m - S_r}\right)\right] \left[1 - \left(\frac{S - S_r}{S_m - S_r}\right)^{1/4} S^{1/2}\right]^{1/2} \quad (8)$$

where

k_{rw} = relative saturation to water

k_{rg} = relative saturation to gas

S = saturation (fraction of pore space filled with water)

S_r = residual saturation of water in pores after mobile water is swept away by gas flow

S_m = saturation point at which there is no further continuous flow path to gas.

Figure 19 plots the permeability ratio and saturations of gas in Table 4 along with the theoretical equations for $S_r = 0.2$ and $S_m = 0.98$. These values for S_r and S_m were selected since they are the values reported by Otis in

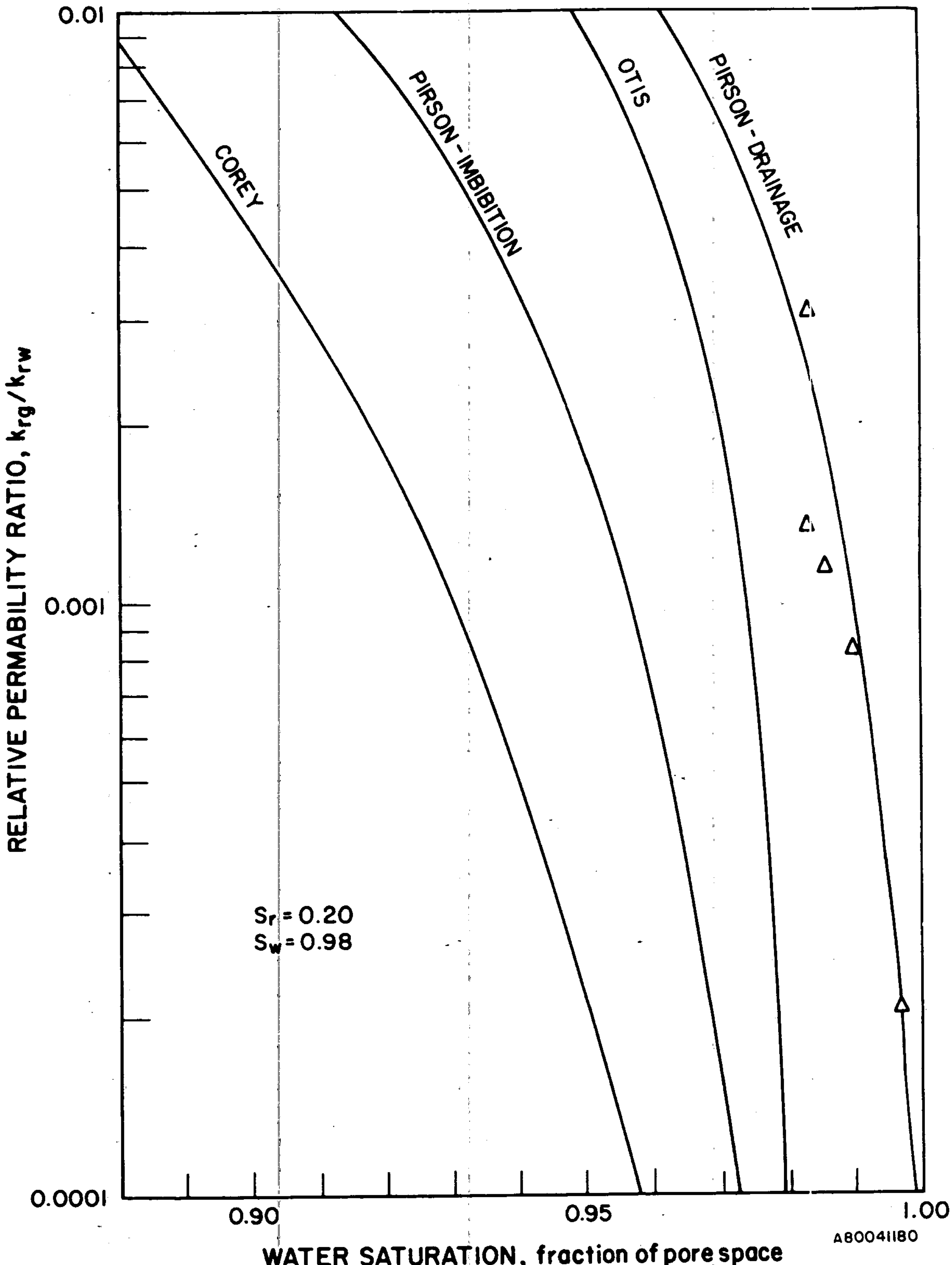

Figure 19. PLOT OF CALCULATED GAS SATURATIONS VS. RELATIVE PERMEABILITY RATIO COMPARED WITH COREY, PIRSON, AND OTIS THEORETICAL PERMEABILITY RATIOS. THE CALCULATED SATURATIONS (triangles) WERE OBTAINED FROM THE DRAWDOWN PRODUCTION TESTS AND THE ASSUMPTION THAT THE RATIO OF GAS/WATER PRODUCTION WAS THE SAME AS THE IN-PLACE GAS/WATER RATIO

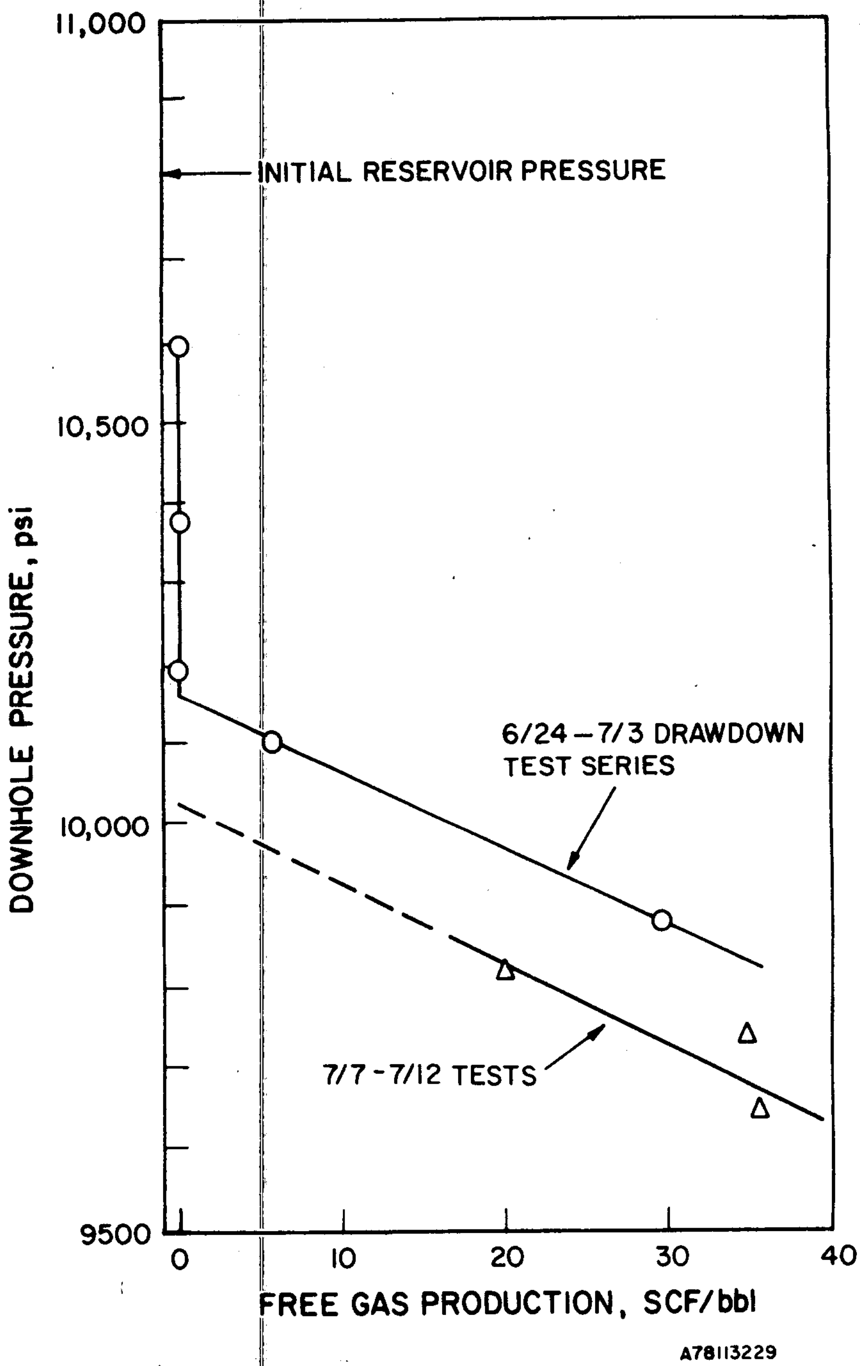

Figure 20. PLOT OF PRODUCTION OF FREE GAS IN EXCESS OF THAT DISSOLVED IN WATER FOR THE 1977 PRODUCTION TESTS OF THE NO. 1 SAND IN THE EDNA DELCAMBRE NO. 1 WELL

their analysis. From Figure 19, it first appears that the Pirson equations may be the best theoretical equations to use. This result is not conclusive, however, since the assumption used to obtain the saturations may not be correct. Also, the pressure effect in gas production as shown in Figure 20 must be considered. And, if S_m is set equal to 1.0 rather than 0.98, the theoretical curves come closer together.

In Table 5, it is observed that for the first three steps in the drawdown sequence, the gas production was essentially equal to the amount of gas dissolved in the produced water. Starting with the fourth test, and on through the remaining production, excess gas is produced. Figure 20 shows that if the data from the first drawdown sequence are compared to the data from the later tests, which were interspersed with buildup tests, there is an apparent relationship between the down-hole well bore back pressure and the gas production rate. These data suggest the possibility of a threshold pressure about 700 psi below the initial reservoir pressure before gas is produced. Several possible physical models can be envisioned to explain this sudden onset of free gas production during the drawdown tests.

Table 5. SELECTED RESULTS FROM THE NO. 1 EDNA DELCAMBRE WELL DRAWDOWN TESTS OF THE SAND NO. 1

Test Date	Total Gas (SCF/bbl)	Dissolved Gas (SCF/bbl)	Excess Gas (SCF/bbl)	Permeability Ratio k_{rg}/k_{rw}	Pressure (psi)	Saturation of Gas*
6/24-6/26	23.7	23.0	--	--	10,600	---
6/26-6/27	20.8	22.9	--	--	10,380	---
6/27-6/29	21.0	22.8	--	--	10,200	---
6/29-7/1	28.2	22.7	5.5	0.00021	10,100	0.003
7/ 1-7/3	52.0	22.7	29.3	0.00116	9,880	0.014
7/ 7-7/8	42.9	22.7	20.2	0.00083	9,820	0.010
7/ 9-7/10	57.7	22.6	35.1	0.00138	9,740	0.017
7/11-7/12	58.8	22.6	36.2	0.00309	9,650	0.017

* Saturation is calculated on the assumption that the gas and water production are in the same proportions as the in-place water and gas near the well. This assumption is true only for one specific saturation which is dependent on the relative permeabilities. In general, this assumption will not be true, and either more water or more gas will be produced compared to the *in situ* gas/water proportions.

From the initial evaluation of the Corey and Pirson relative permeability equations, the Pirson-drainage curve appeared to be the most correct for the No. 1 sand case. Also, the amount of free gas appeared to be in the 1 to 2% range. To apply this to the dispersed gas model, a calculation was made using Intercomp's two-dimensional radial program with a modified Pirson relative permeability curve. The modification consisted of a sharp cutoff to zero permeability at the point of free gas saturation. This is shown in Figure 21. With this sharp cutoff the relative permeability will rise rapidly to the Pirson value with only a slight decrease in water saturation. This mechanism should then turn on the gas production with water production. For this calculation, the initial saturation (zero permeability) was set at 0.98860 and the initial saturation in the reservoir at 0.98861. The other pertinent input parameters are listed in Tables 6, 7, 8, and 9. The kh was set to match the late-time production value, and the calculation ran on specified water production. There was no attempt to match the well bore skin effect to get a match of the calculated and measured bottom hole pressure.

The calculated gas production is shown in Figure 22. Note in this figure that the calculation does show a slight increase in the gas/water ratio with the increased water production of the five-step drawdown test, but there is no sudden turning on of the gas flow as actually happened in the well. By changing the input parameters around, it may be possible to get the gas to turn on a little faster or slower, but not suddenly as the well actually did. From this calculation, it appears that the proposed model of a sudden flow of gas from a dispersed system will not adequately match the data.

Finding the Right Model

After a considerable amount of work and computer simulator runs with the two-dimensional radial coning model, it became apparent that the dispersed gas phase model was not correct to describe the excess gas in the Delcambre No. 1 sand. The effort was then shifted to evaluation of other proposed models to determine which one might be correct. The best candidate was the free gas cap model, which was discussed in some detail by Charles Matthews, so an effort was started to model this theory. This required the use of Intercomp's three-dimensional simulator, Beta II. This effort came to the conclusion that this model also did not match the experimental data on the excess gas, but that a computer match to the start time occurred when the

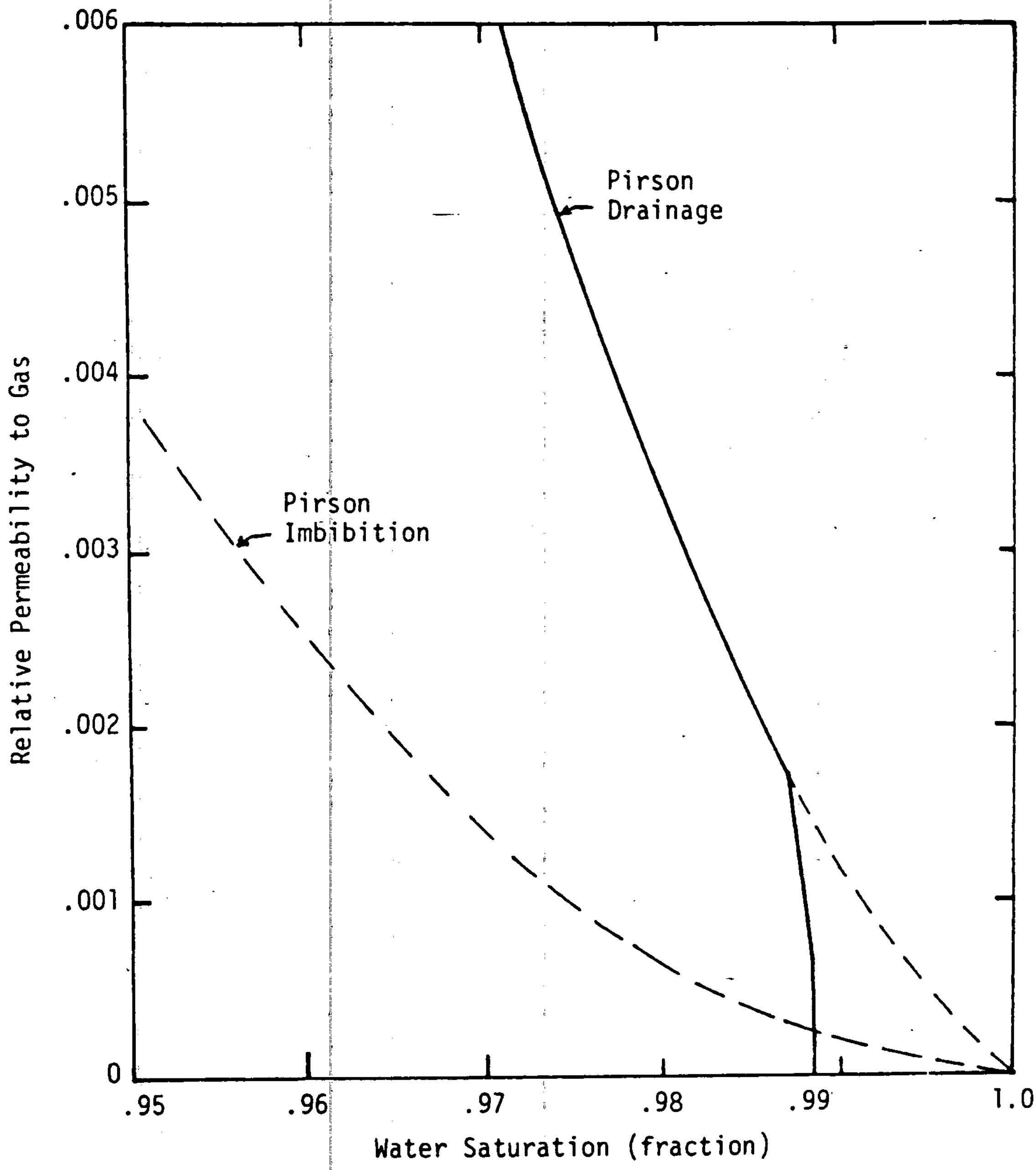

Figure 21. RELATIVE PERMEABILITY CURVE USED FOR DISPERSED GAS — RELATIVE PERMEABILITY TURN-ON MODEL

Table 6. INPUT PARAMETERS FOR DISPERSED-PHASE RELATIVE PERMEABILITY TURN-ON MODEL

Cylindrical Symmetry	
Permeability	396 md
Thickness	30 ft
Porosity	0.293
Initial Pressure	10,868 psi
Total Compressibility	21.7×10^{-6} psi^{-1}
Initial Gas Saturation	20.5 SCF/bbl
Initial Free Gas	0.01139

Table 7. RELATIVE PERMEABILITY TABLE (over range of calculations)

Water Saturation	K_{rg}	K_{rw}
0.9870	0.0018	0.9366
0.9880	0.0012	0.9414
0.9885	0.0006	0.9438
0.9886	0.0000	0.9442
0.9900	0.0000	0.9510

Table 8. P-V DATA (over range of calculations)

Pressure (psi)	Gas Saturation (SCF/STB)	Gas Viscosity (cP)	Water Viscosity (cP)
10,000	20.4	0.0349	0.3605
10,868	20.5	0.0365	0.3664

Table 9. WATER PRODUCTION SCHEDULE

Drawdown Step	Time (hours)	Flow (bbl/day)
1	0-50	1163
2	50-98	1980
3	98-146	3150
4	146-194	4707
5	194-233	5951

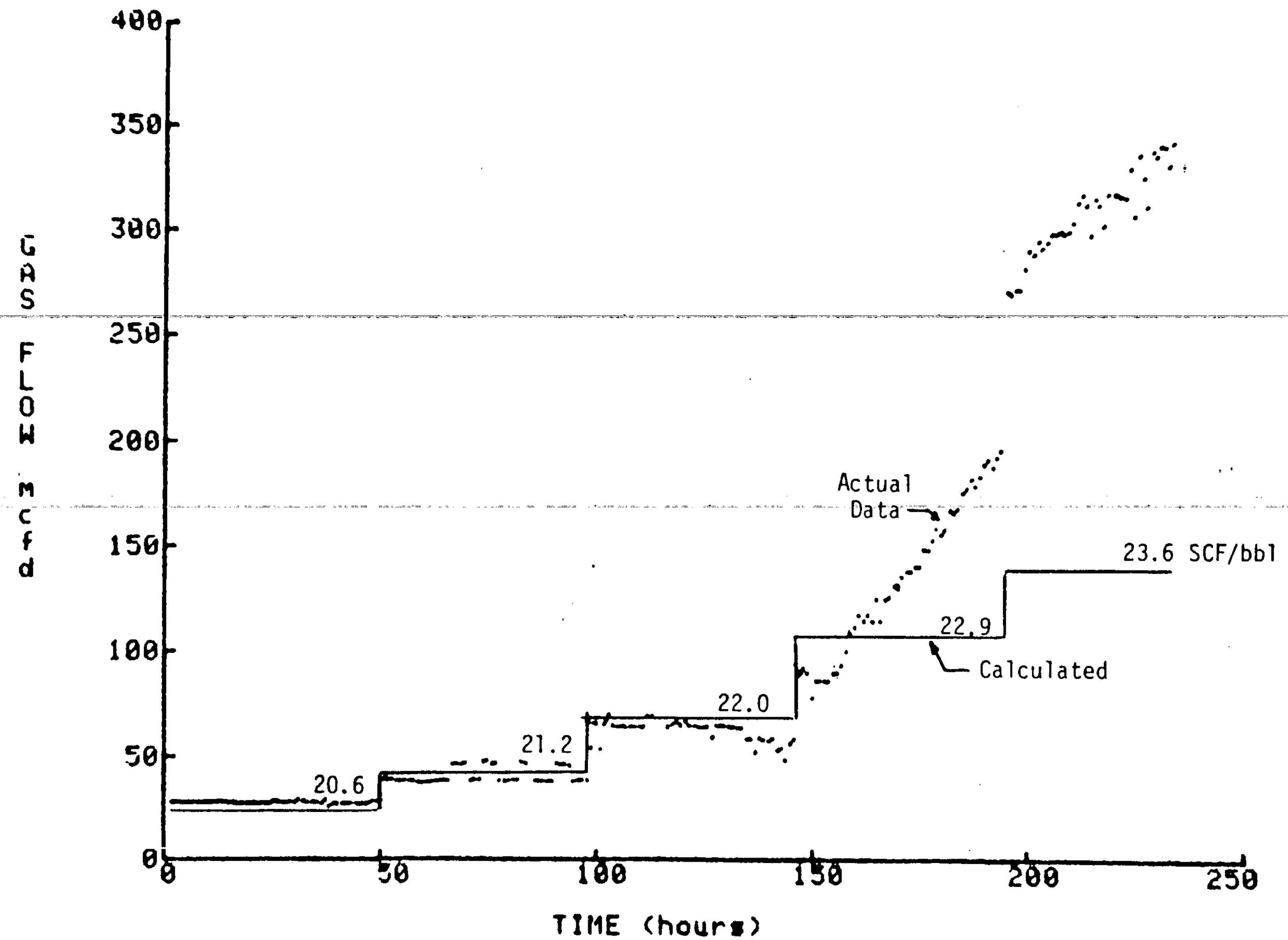

Figure 22. COMPARISON OF ACTUAL GAS FLOW FROM THE EDNA DELCAMBRE NO. 1 SAND WITH THE CALCULATED GAS FLOW USING THE DISPERSED GAS — RELATIVE PERMEABILITY TURN-ON MODEL

edge of the excess free was about 400 ft from the well. This distance matched that to the nearby Delcambre 4 and 4A wells which had a history of difficulties as explained by J. Donald Clark of Union Oil. The data and computer results then all fell in together for the model of a free gas source from some other horizon into the No. 1 sand via a connection along the No. 4 or 4A wells. This appears to have solved the mystery of the occurrence of the excess gas. No new physical phenomona are required. The occurrence of the gas is the result of a downhole mechanical condition. A technical paper was written on this and presented at the fourth U.S.-Gulf Coast Geopressured-Geothermal Energy Conference at the University of Texas at Austin in October. A copy of the paper is included as the Appendix to this report. Additional details concerning the analysis of the data and the models not covered in earlier sections of the report are given in the Appendix technical report.

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APPENDIX A. Ratio of Produced Gas to Produced Water From DOE's Edna Delcambre No. 1 Geopressured-Geothermal Aquifer Gas Well Test

RATIO OF PRODUCED GAS TO PRODUCED WATER FROM DOE'S EDNA DELCAMBRE NO. 1 GEOPRESSURED-GEOTHERMAL AQUIFER GAS WELL TEST

by

Leo A. Rogers
Philip L. Randolph

Paper Presented at the

FOURTH UNITED STATES GULF COAST
GEOPRESSURED-GEOTHERMAL ENERGY CONFERENCE

The University of Texas at Austin
Austin, Texas

October 29-31, 1979

RATIO OF PRODUCED GAS TO PRODUCED WATER FROM DOE'S EDNA DELCAMBRE NO. 1 GEOPRESSURED-GEOTHERMAL AQUIFER GAS WELL TEST

Leo A. Rogers
Philip L. Randolph

Institute of Gas Technology

Abstract

A paper presented by the Institute of Gas Technology (IGT) at the Third Geopressured-Geothermal Energy Conference hypothesized that the high ratio of produced gas to produced water from the No. 1 sand in the Edna Delcambre No. 1 well was due to free gas trapped in pores by imbibition over geological time. This hypothesis was examined in relation to preliminary test data which reported only average gas-to-water ratios over the roughly 2-day steps in flow rate.

Subsequent public release of detailed test data revealed substantial departures from the previously reported computer simulation results. Also, data now in the public domain reveal the existence of a gas cap on the aquifer tested.

This paper describes IGT's efforts to match the observed gas/water production with computer simulation. Two models for the occurrence and production of gas in excess of that dissolved in the brine have been used. One model considers the gas to be dispersed in pores by imbibition, and the other model considers the gas as a nearby free gas cap above the aquifer. The studies revealed that the dispersed gas model characteristically gave the wrong shape to plots of gas production on the gas/water ratio plots, and no reasonable match of these plots to the flow data could be achieved. The free gas cap model gave a characteristically better shape to the production plots and could provide an approximate fit to the data if the edge of the free gas cap is only about 400 feet from the well.

Because the geological structure maps indicate the free gas cap to be several thousand feet away and the computer simulation results match the distance to the nearby Delcambre wells 4 and 4A, it appears that the source of the excess free gas in the test of the No. 1 sand may be from these nearby wells. The gas source is probably a separate gas zone and is brought into contact with the No. 1 sand via a conduit around the No. 4 well.

RATIO OF PRODUCED GAS TO PRODUCED WATER FROM DOE'S EDNA DELCAMBRE NO. 1 GEOPRESSURED-GEOTHERMAL AQUIFER GAS WELL TEST

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Introduction

The U.S. Department of Energy (DOE) test of the Edna Delcambre No. 1 well provided some of the first data in relation to the national program of evaluating the potential for obtaining natural gas from geopressured-geothermal aquifers. The reentry and testing of this old well was accomplished in the summer of 1977, and early reports on it were presented at the Third Geopressured-Geothermal Energy Conference in Lafayette, Louisiana, in November 1977.[1]

Two zones were tested in the well: The lower zone designated the No. 3 sand at 12,869-12,911 feet, and the upper zone designated the No. 1 sand at 12,583-12,605 feet. The details of the test procedure, data, and preliminary analysis are contained in a series of reports prepared by the contractors and DOE.[2,3] While both zones produced natural gas in excess of the amount that could be dissolved in the brine, the source of the excess gas in the upper zone was unknown since there was no prior evidence of free gas in the zone. Several speculations were advanced as to the source of this excess gas since the possible production of this excess gas would have significant implications on the economics and viability of this source of natural gas.

One of the theories of the excess gas is that the source was a nearby gas cap which was not initially in contact with the well, but became connected as pressure around the well was lowered during production. The gas would cone down into the well. Another theory is that the excess gas initially exists as a dispersed phase of small-to-microscopic bubbles in the reservoir rock matrix.[3] With this theory, production of the excess, or free gas, would occur as the pressure was lowered around the well such that the expanding small bubbles would increase the gas saturation to the point where the gas would no longer be trapped, but would flow as controlled by the relative permeability. A third theory is that the gas is all initially dissolved, but as the pressure is lowered around the well by rapid production, gas exsolves from the solution and migrates to the top, where it is produced like a gas cap. A fourth theory is that the gas came from a zone above or below the perforated interval, the free gas having moved through a channel in the cement annulus between the well casing and the well bore wall. This could result from a poor cement job. A fifth theory is that the gas came from the nearby Edna Delcambre No. 4 or No. 4A well, which had flow paths in their well bores or annuli.

Of these theories, the first two have been given modest amounts of consideration. Qualitative and semiquantitative plausibility arguments for the first theory — the gas cap theory — have been reported by C. L. Matthews[4] following the Third Geopressured-Geothermal Energy Conference and the introduction of the dispersed-gas-phase theory by Randolph.[1] The purpose of this report is to describe the progress made to date at the Institute of Gas Technology (IGT) to analyze the data concerning the Edna Delcambre No. 1 well test and the gas production in order to determine which model best describes the occurrence of the excess free gas from the No. 1 sand in the Delcambre No. 1 well and evaluate the possible occurrence of such dispersed gas in geopressured aquifers in general.

Production Test Data

The production test of the No. 1 sand consisted of a five-step drawdown test followed by a buildup test and then three additional shorter term flow and shut-in tests. Figure A-1 shows the resulting pressure and production data. Figure A-2 shows the gas/water ratio. Note that the well produced essentially only brine with dissolved gas for the first three steps of the multistep drawdown test. The excess gas did not occur until the fourth step at about 160 hours after the beginning of the test. Once the extra gas began production, it then continued through all the subsequent flow periods.

A Hewlett-Packard down-hole pressure gauge provided bottom-hole pressure for most of the test period. Production was through variable and fixed chokes and a gas/water separator. The produced gas was measured at two points in the separator system: one at "high stage" and one at "low stage." The flow data were obtained and reported by Otis Engineering.[5] Water and gas samples were taken and analyzed by McNeese State University.[6]

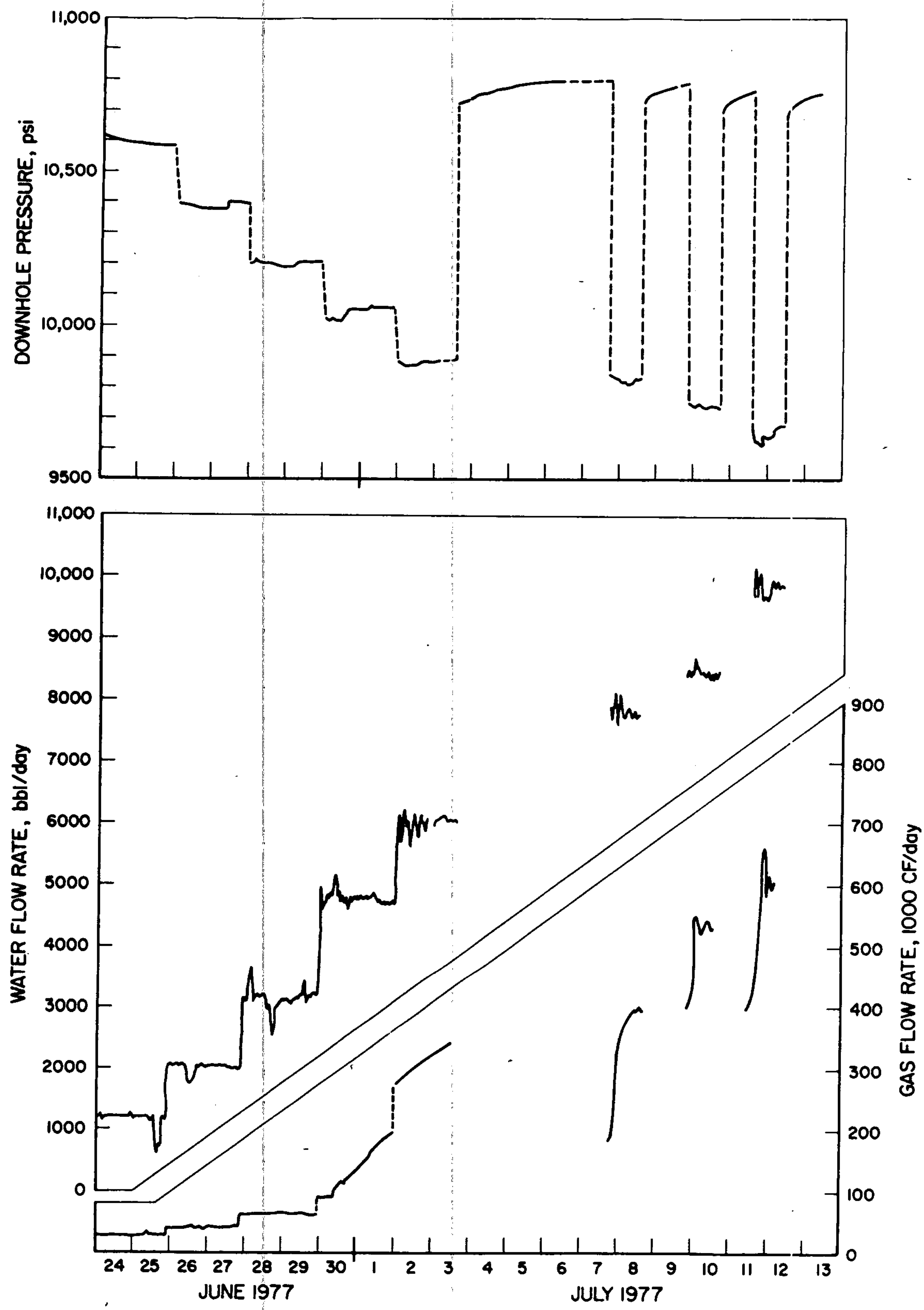

Figure A-1. WELL TEST DATA FOR DELCAMBRE NO. 1, SAND NO. 1

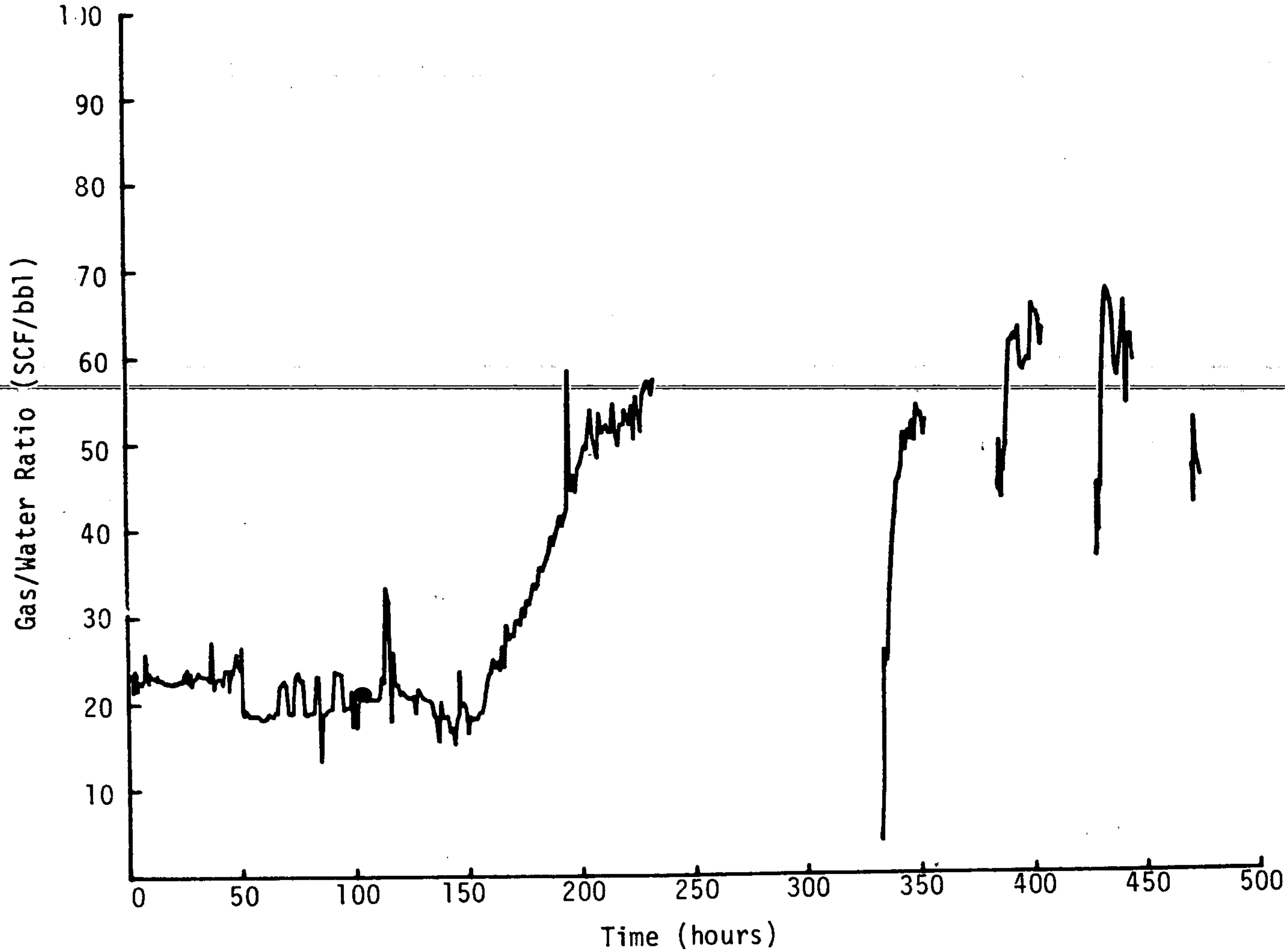

Figure A-2. GAS/WATER RATIO FOR PRODUCTION TEST OF THE NO. 1 SAND

Area Drilling and Production

The Edna Delcambre No. 1 well is in an area which has had considerable exploration and production prior to the DOE test. It is possible that these other activities had an influence on the status of the reservoir around the test well. A summary of the drilling and gas production in the area by Don Clark[7] is a follows:

> "The Planulina sand zone of the Tigre Lagoon Field comprises several defined sand reservoirs of which several have produced gas in commercial quantities over the past 20 years. The Edna Delcambre No. 1 well was drilled by the Coastal States Gas Producing Company and was initially completed in the Planulina 8 geopressured gas sand with perforations between 13,716 feet to 13,726 feet. The initial bottom-hole pressure was measured at 11,736 psi on February 1, 1968. The well produced 5,551,490 MCF of gas before it was recompleted in the Planulina No. 7 sand in March 1970. The well produced 270,491 MCF of gas from the Planulina No. 7 sand.
>
> "The well was recompleted in the Planulina No. 6 gas sand in September 1971 and produced 4,058,307 MCF of gas before depleting the sand in March 1975, at which time it was temporarily abandoned.
>
> "Coastal States drilled the Delcambre No. 4, a 400-foot offset to the Delcambre No. 1 well and completed the well in the Planulina No. 8 sand during December 1969. The well produced 5,217,813 MCF of gas and blew out during a workover and was plugged and abandoned in October 1971.
>
> "The Coastal States E. Delcambre No. 4A was directional drilled to kill the Delcambre No. 4 well which was blowing out underground. This well, after killing the blow out, was completed in the Planulina No. 1 sand in November 1971. This completion produced 3,666,867 MCF of gas before it was junked after killing E. Delcambre No. 4 well a second time. These underground mishaps may have some bearing on future tests conducted on the Delcambre No. 1 in the Planulina sand section.
>
> "Union Oil Company, the offset operator to the Delcambre lease, drilled and completed the E. E. Broussard No. 8 well in the Planulina No. 8 sand in November 1968. This well produced 3,607,836 MCF of gas, 59,897 barrels of condensate, and 524,527 barrels of salt water before watering out in March 1971. The well was recompleted in the upper part of the No. 8 sand and produced 34,625 MCF of gas before sanding up. The well was completed in Planulina No. 7 sand during January 1972.
>
> "The final completion of the well was in the Planulina No. 2 sand where it produced 331,628 MCF of gas and sanded up in 1974.

"Union E. Dugas No. 7 was completed in the Planulina No. 8 sand in April 1969 and, through December 1978, had produced 20,316,137 MCF of gas, 422,769 barrels of condensate, and 3,168,428 barrels of salt water.

"Union E. E. Broussard No. 9 was completed in the Planulina No. 6 sand in March 1969 and, through December 1978, had produced 15,199,921 MCF of gas. The Coastal States No. 4D well was opened in this No. 6 sand in December 1968 and produced 3,803,073 MCF of gas when communication between sand members resulted in the blowout and early abandonment of the well.

"The Planulina No. 1 sand was produced in the Eraste Thibodeaux No. 3 well from February 1967 to January 1969. The total production for this well was 799,229 MCF of gas along with some condensate and water.

"In retrospect, most all the sands in the Planulina Zone have been produced in commercial quantities from wells in the Tigre Lagoon Field. The No. 1 sand, designated by OHRW Engineering and perforated between 12,751 ft. to 12,605 ft., is the same sand designated by Union Oil Company as the Planulina No. 3 Sand. This sand has some 50 ft. of gas saturation in the E. Dugas No. 7 well and will be produced by this well in the very near future.... This sand had not produced commercial gas at the time of the geopressured test of June 1977 in the Delcambre No. 1 well.

"The discussion of the geopressure production behavior of the Delcambre No. 1 well would not be reliable unless the above gas production history of this Planulina age sand section is made known to the reviewer. In other words, one should definitely expect a gas saturated aquifer as well as high possibilities of some minor free gas saturation in the relatively high structural position in the Planulina sands. The effect of the underground blowouts and inter-sand communication could change the normal saturation expected in the general well area."

Figure A-3 is a structure map of the DOE No. 1 sand (the Planulina No. 3 sand) as reported by Matthews,[3] and Figure A-4 is the structure map reported by Clark. There are some differences between these two maps, but the general features are similar. From the well location, there is a major north-south fault to the east and some additional faulting to the south. The zone slopes gently upwards to the north, where there is a gas cap in a structural high.

Wireline Well Logs

Figure A-5 to A-9 show the log data over the interval of the No. 1 sand (Planulina No. 3). Examination of these figures indicates that there are

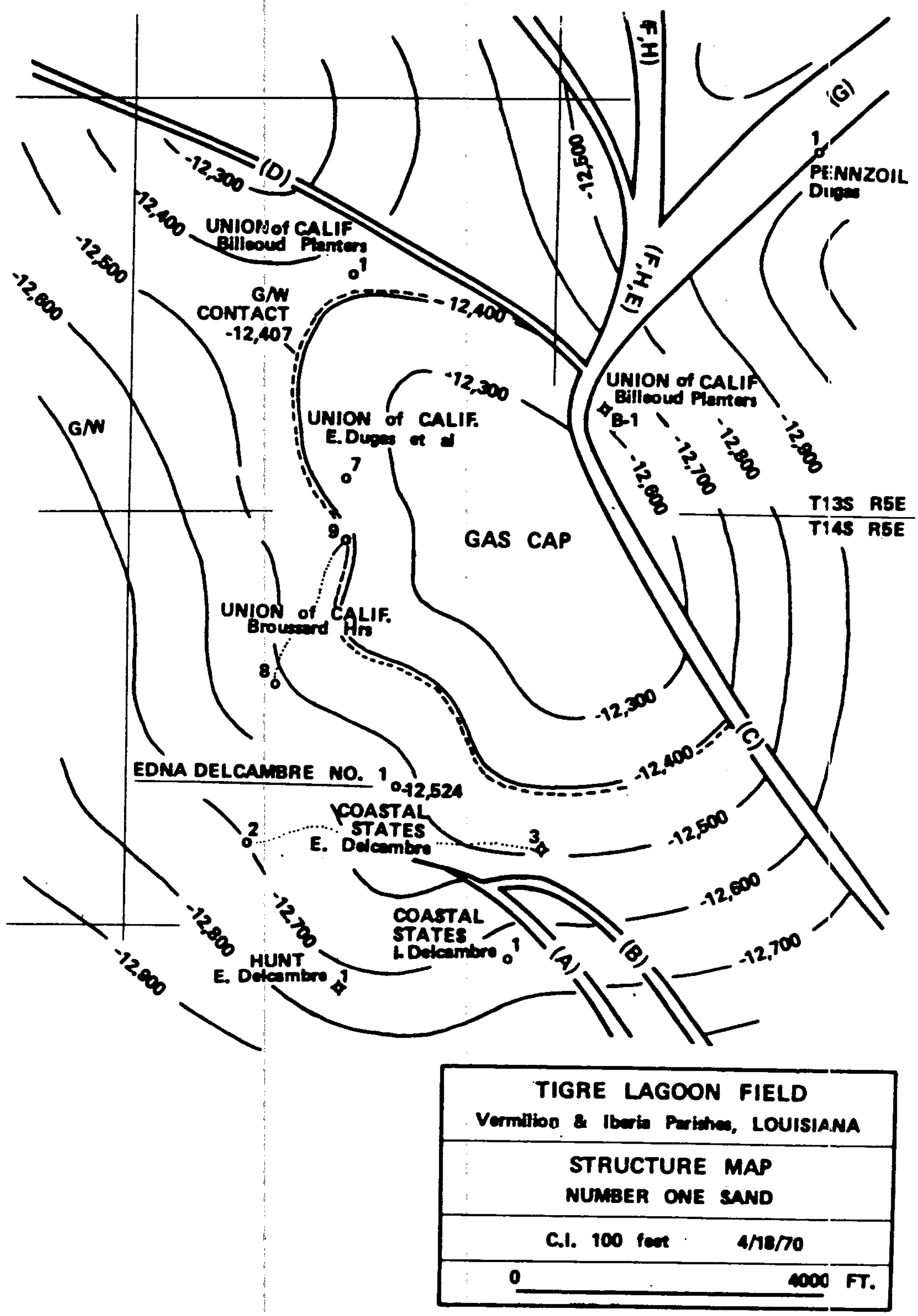

Figure A-3. STRUCTURE MAP AS REPORTED BY MATTHEWS.[3] (Original Source Was an FPC Filing by Coastal States Gas)

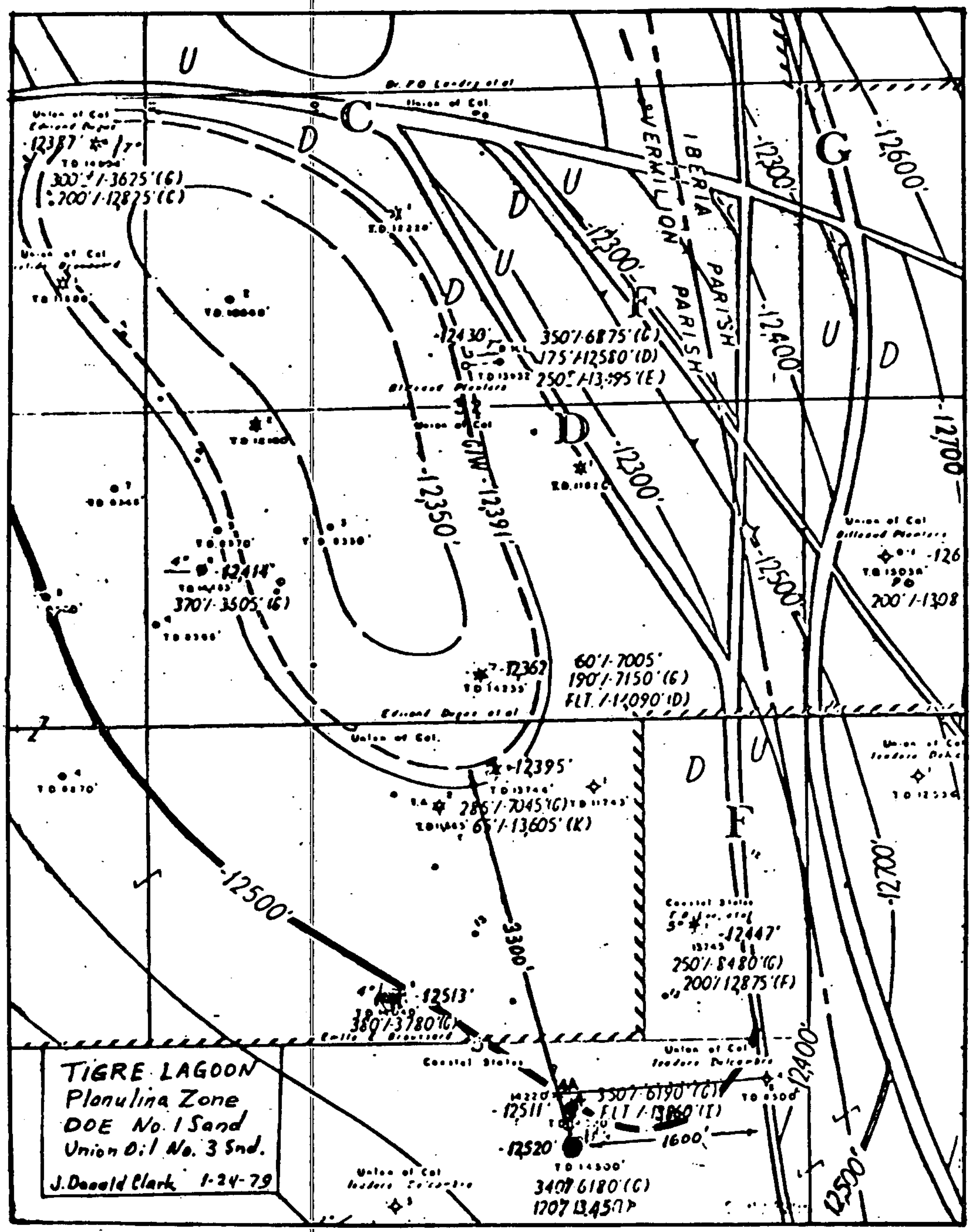

Figure A-4. STRUCTURE MAP AS SUPPLIED BY J. DONALD CLARK

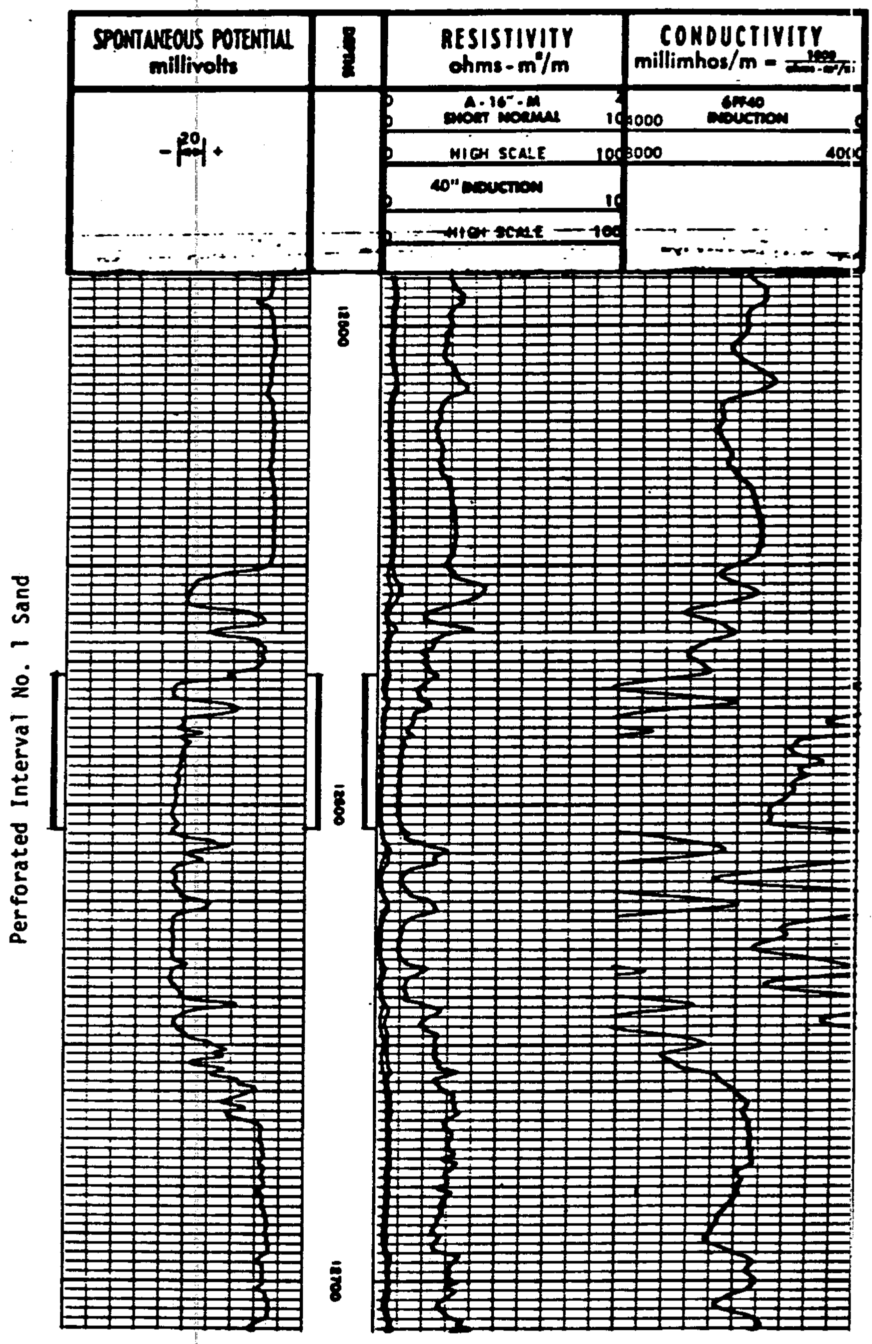

Figure A-5. WELL LOG OF THE NO. 1 SAND

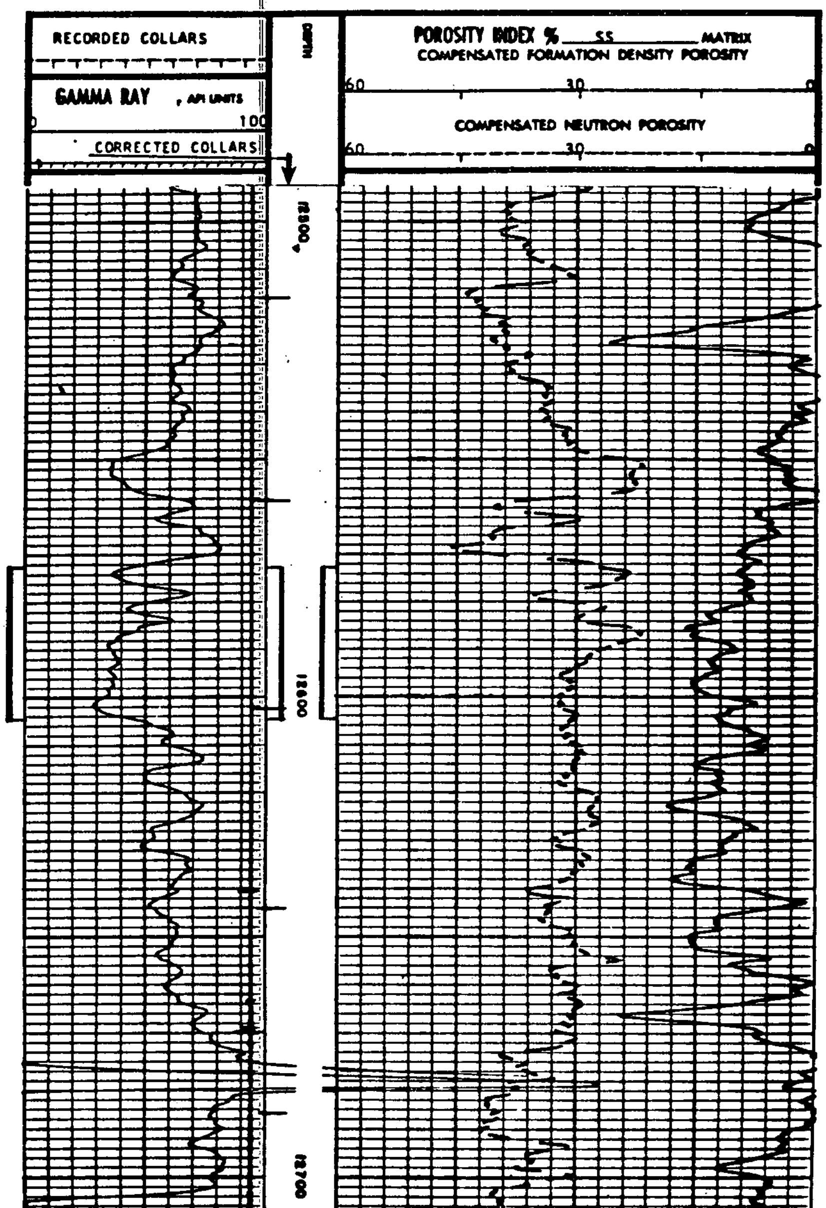

Figure A-6. WELL LOG OF THE NO. 1 SAND

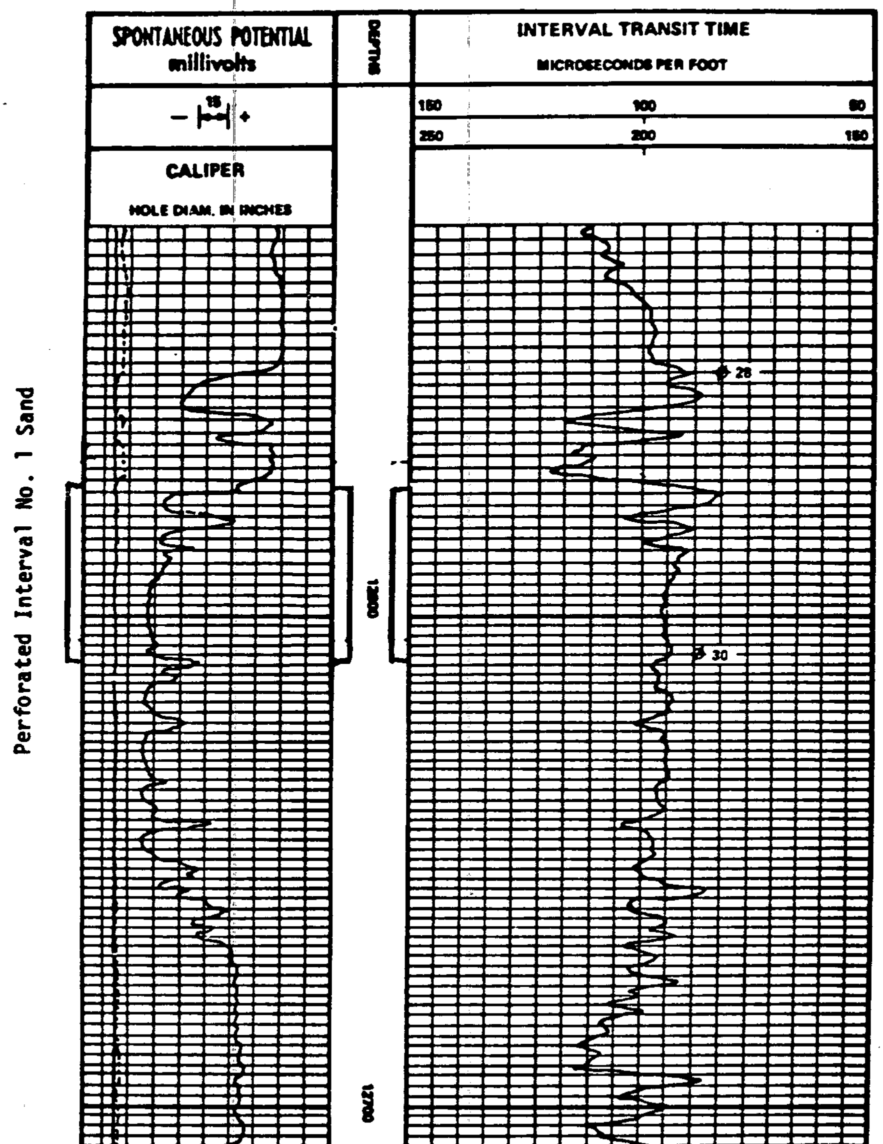

Figure A-7. WELL LOG OF THE NO. 1 SAND

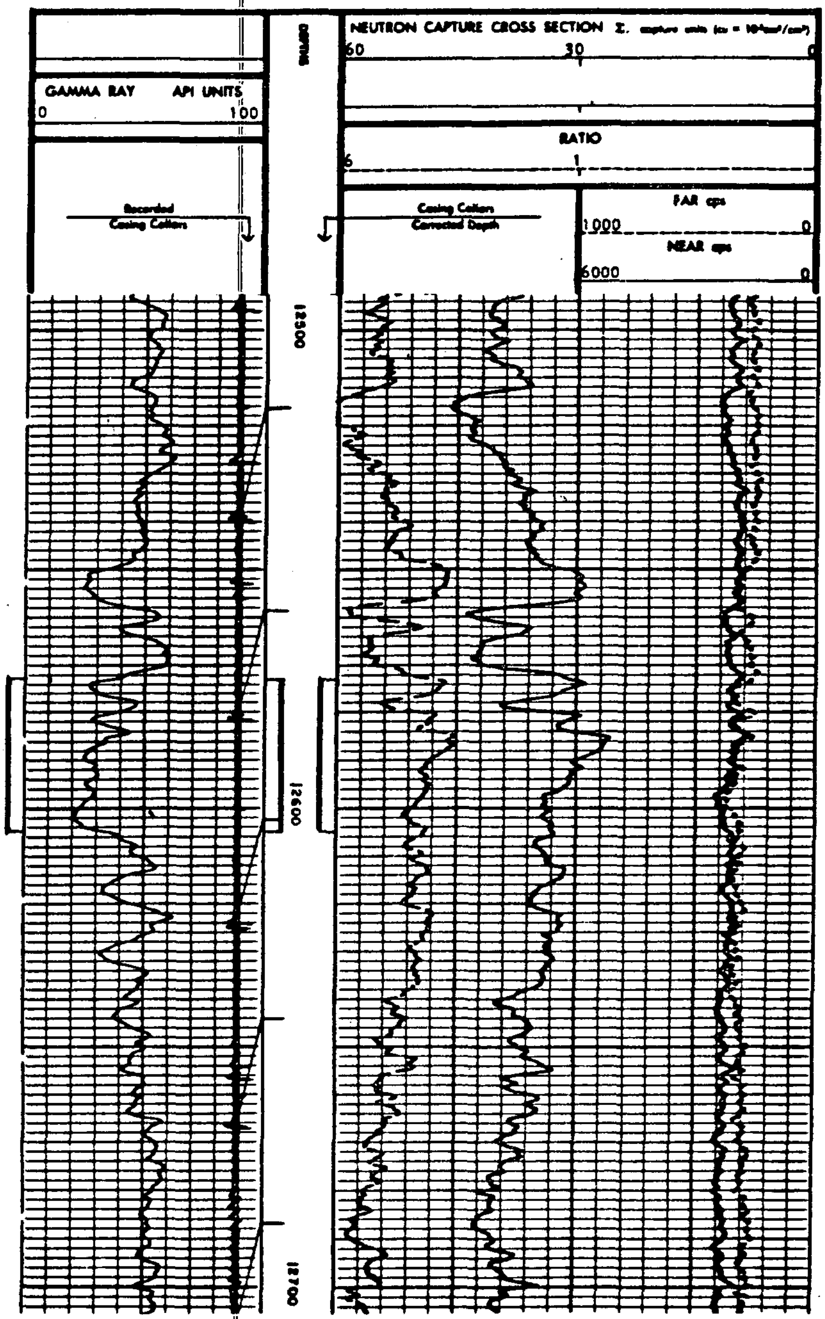

Figure A-8. WELL LOG OF THE NO. 1 SAND

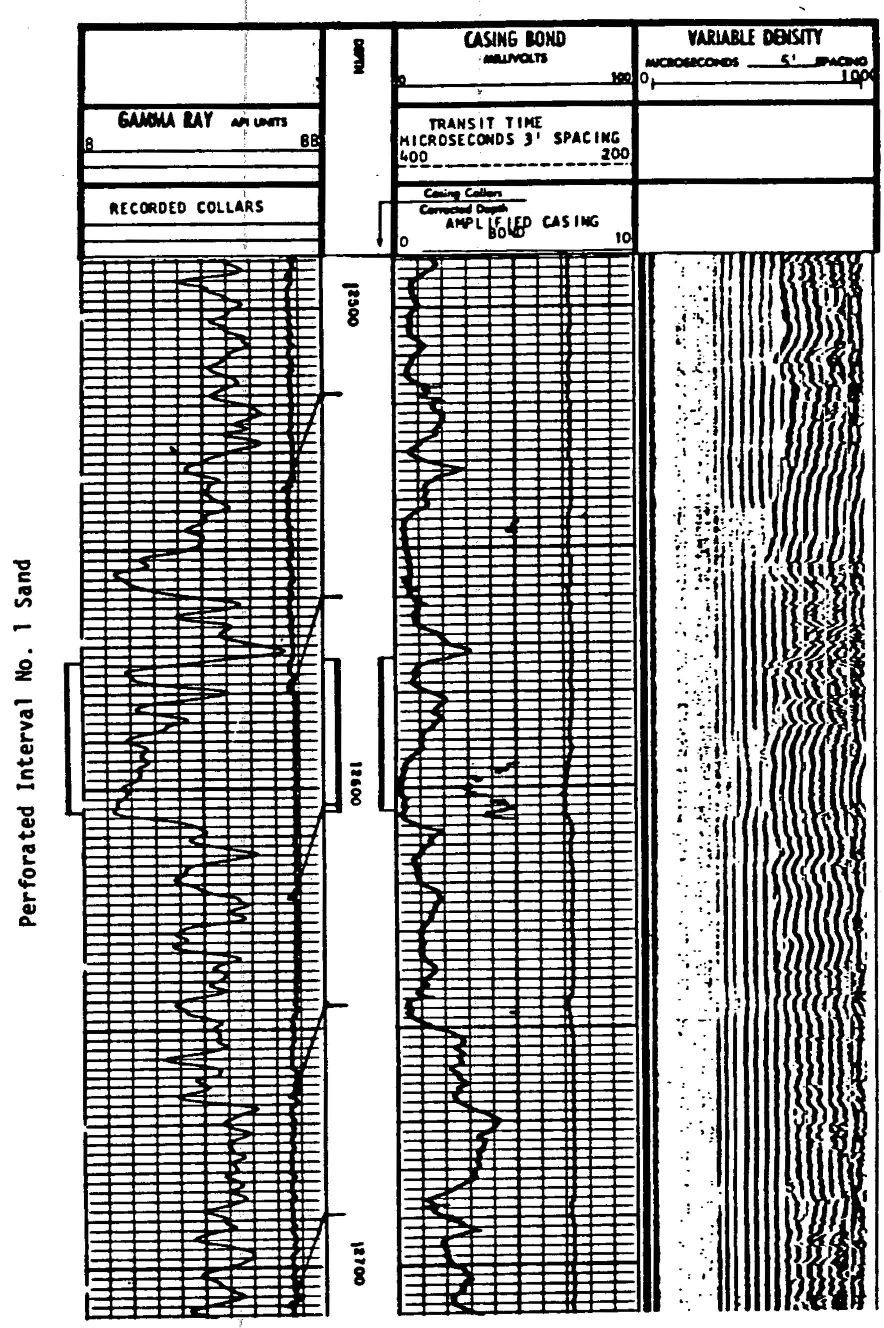

Figure A-9. WELL LOG OF THE NO. 1 SAND

several sand layers or stringers within the perforated interval. Immediately above and below the perforated intervals are layers of shale. These shale layers would normally be expected to be the bounding and confining layers for the producing interval.

Within this perforated interval no free gas could be positively identified from the logs.[9] The statistical nature of the data was not sufficiently accurate to identify free gas of only a few percent. Note, however, that the interval of 12,550-12,565 feet, just above the boundary shale, has indications of a zone that might contain some free gas saturation. Further, the casing bond log indicates a possible poor bond across the shale layer between the top of the perforated interval and this overlying layer, which may contain free gas. This leaves open the speculation that the excess gas produced in the flow test came from these overlying layers via a flow channel through poor-quality cement in the well-bore annulus. Also, since the Edna Delcambre No. 4 well, which was drilled only a few hundred feet away, had an underground blowout, there is the additional possibility that some of these normally water-saturated layers had some gas forced into them from the No. 4 well.

Analysis of Test Data

The reported test data of pressure and flow of brine and natural gas were examined in some detail at IGT. Graphs were made of pressure versus the logarithm of time and other factors for multistep drawdown analysis. The plots of pressure versus the logarithm of time were studied in particular for straight-line segments and breaks in the curves which would indicate pressure wave reflections from boundaries or flow discontinuities at some distance from the well.

The early time analyses were questionable since the brine flow rate for the first hour of the first drawdown test was missing, and the first 2 hours of pressure data for the first shut-in were missing. The use of the down-hole Hewlett-Packard pressure gauge, however, provided reasonably good bottom-hole pressure data. There were significant differences in the amount of gas measured between the high and low stages of the separator, and some judgment was required to determine which data were most accurate.

Figure A-10 plots the pressure data for the first step of the multistep drawdown test. Note that the data can reasonably be fitted with several

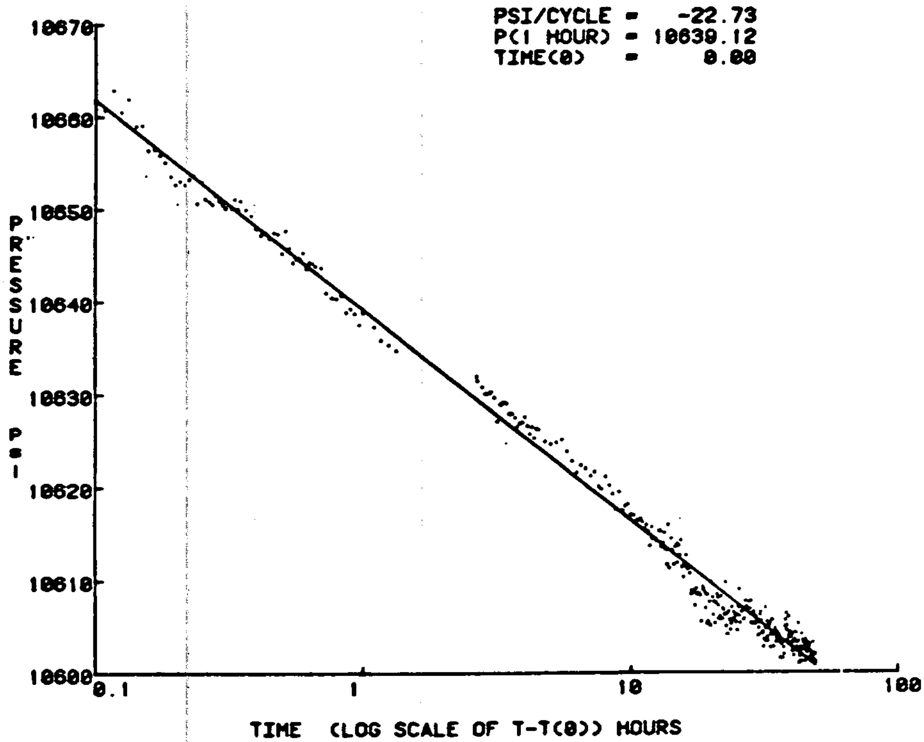

Figure A-10. PLOT OF PRESSURE VERSUS LOG TIME FOR FIRST DRAWDOWN

straight-line segments. From the slopes and intercepts of these straight-line segments, the permeability thickness is calculated to be about 3,000 millidarcys-ft. If an estimate is made for the missing brine flow data and this pressure is plotted against the summation function for the multistep analysis based on supposition (see reference 8), then the results are seen in Figure A-11. This plot has sufficient scatter that it is difficult to determine where straight-line segments should be fitted. The plot also shows that there are probably some inaccuracies so that caution is indicated in analyzing the data.

The pressure build-up data for the shut-in periods are plotted in Figure A-12. Although the first few hours of the first test are missing, the four plots are similar in shape and show the existence of a change in slope at about 5 hours. This corresponds to an apparent distance of about 1900 feet to a flow barrier. This distance is in general agreement with the geology of the area, which shows a major north-south fault about this distance from the well at the No. 1 sand horizon.

An analysis of these pressure data was also made by J. Donald Clark.[7] In his analysis, given in Table A-1, he notes additional barriers both closer

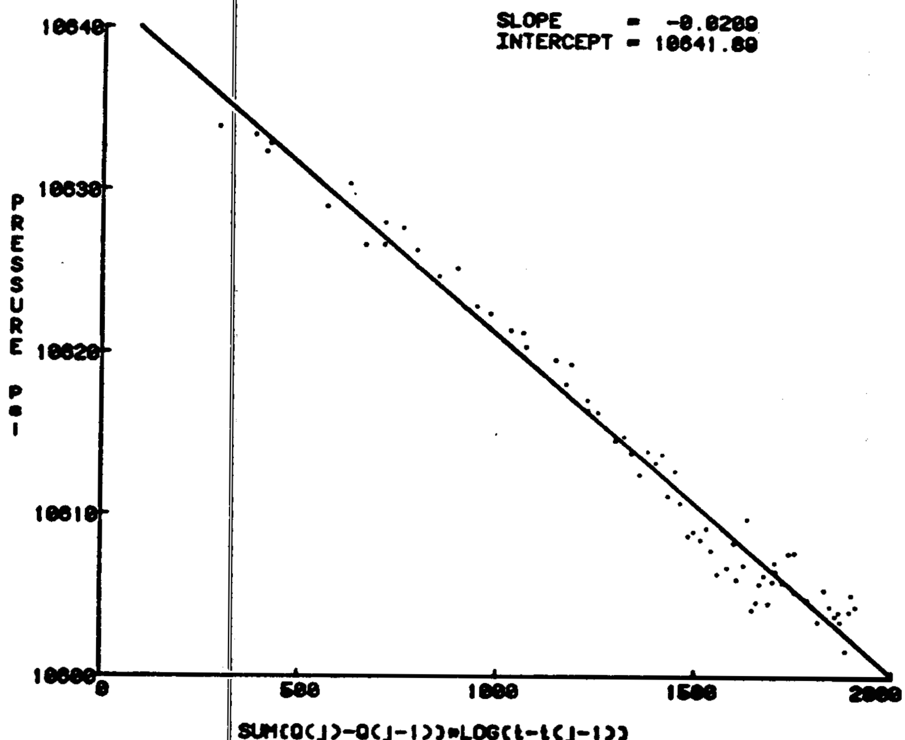

Figure A-11. PLOT OF PRESSURE VERSUS THE SUMMATION FUNCTION FOR MULTIRATE TESTS (See Appdenix B.)

and more distant than 1900 feet. His analysis is based on data from nearby wells in addition to the DOE Delcambre No. 1 well. His analysis theorizes existence of a second sealing fault at an angle of about 60 degrees to the first fault and a third fault that cuts off the tip of the 60-degree pie-shaped producing area. Other flow boundaries are to the south and west of the well, such that the well is producing from inside the pie-shaped sector. Figure A-13 is his analysis of the fault locations from the reservoir limit test analysis.

The many jogs in the pressure and flow data during the production periods indicate that there may have been occasional slugging of gas and brine into the well from the surrounding reservoir. The five-step drawdown sequence could be approximately matched using a value of about 3,000 millidarcys-ft for the first two steps and about 5,000 millidarcys-ft for the last two steps after the onset of the excess gas. The first increase occurred at about 85 hours in the latter part of the second step. It is also possible, from the complexity of the pressure data and the multiplicity of sands as evidenced by the well logs, that various layers could begin production at different times.

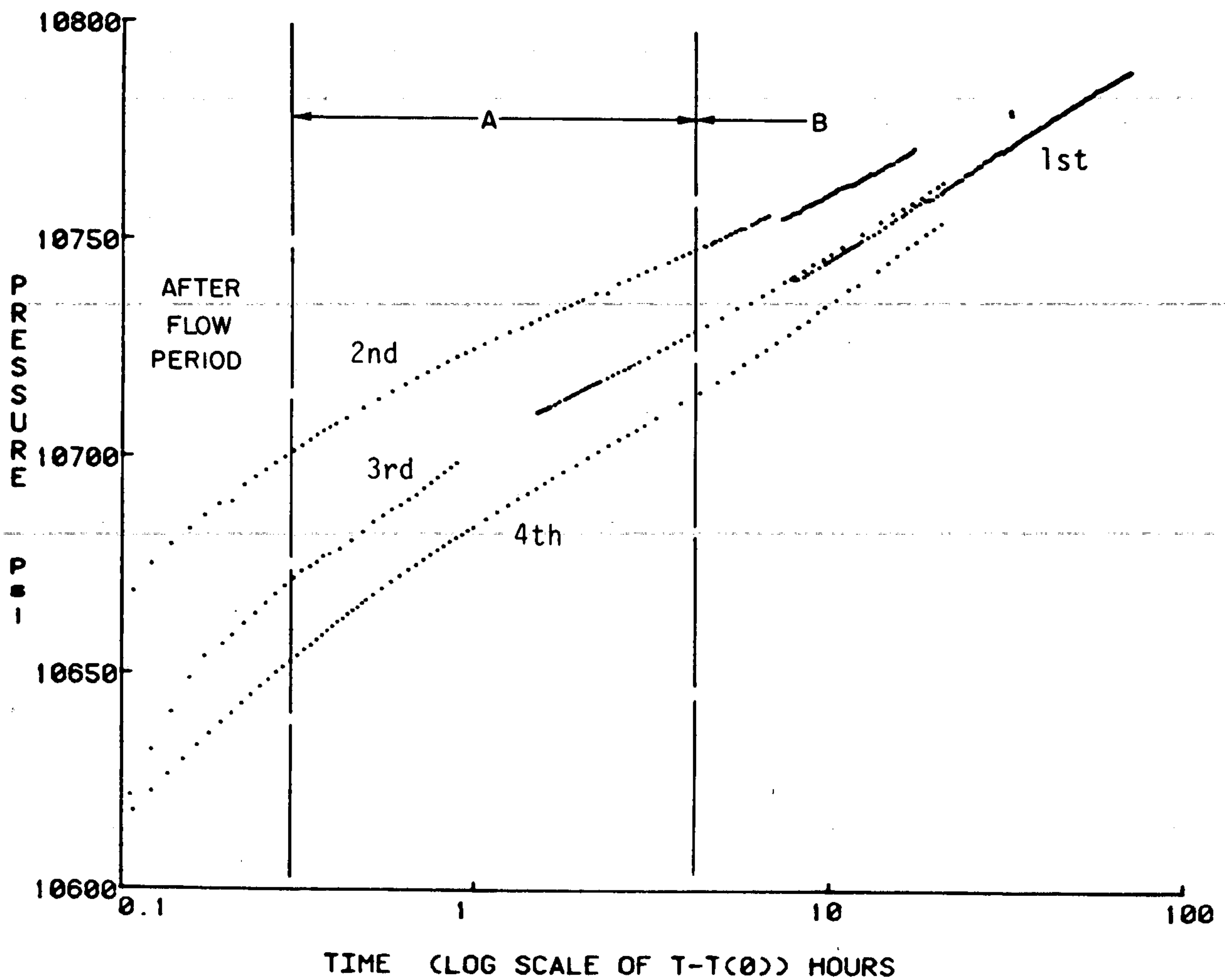

Figure A-12. PRESSURE VERSUS LOGARITHM OF TIME FOR THE FOUR BUILDUP TESTS

Table A-1. DELCAMBRE NO. 1 WELL NO. 1 SAND RESERVOIR LIMIT TEST*

Time, days	Distance, ft	Plot Slope, psi/cycle	Flow Angle, degrees
0.004	154	24.5	360
0.600	1886	49.0	180
0.770	2137	12.5	Gas zone
2.083	35.5		

* Analysis by J. Donald Clark based on first drawdown test (June 23-24, 1977), of plot of pressure versus log time and the following data:

Assumed constant flow rate = 1163 bbl/day

Porosity = 0.293

Viscosity = 0.386

Height = 30 ft

Water volume factor = 1.04 Reservoir bbl/bbl

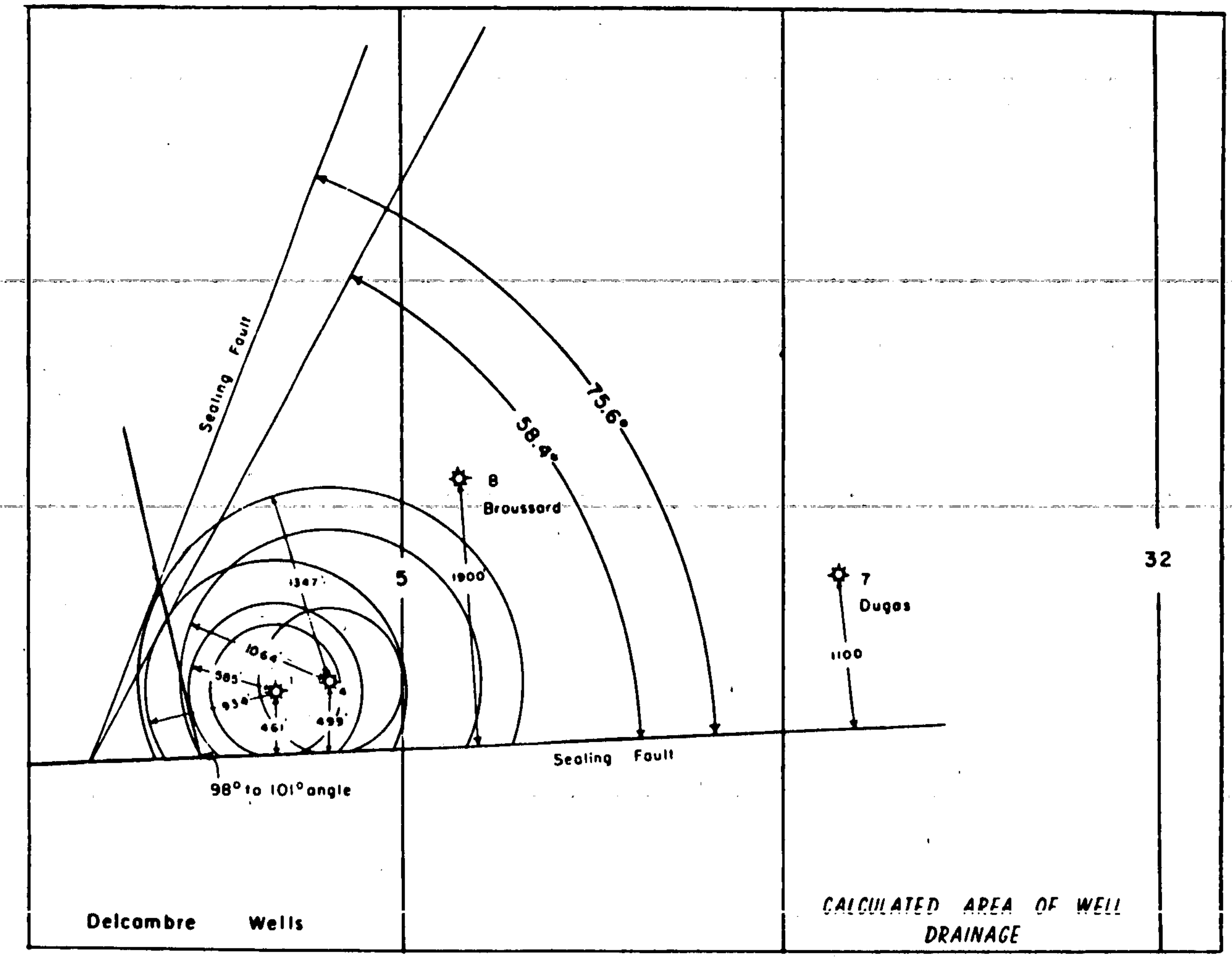

Figure A-13. RESERVOIR LIMIT TEST ANALYSIS BY J. DONALD CLARK

A tabulation of the various values for kh obtained from application of the multirate theory is given in Table A-2. A tabulation of the data and plots of the data segments used for the piecewise analysis are given in Appendix B.

Water and Gas Composition

Both brine and gas samples were analyzed for their chemical constituents by McNeese State University. These reported analyses were evaluated for changes which would be associated with the onset of free gas. The brine data showed no observable change in the ion concentrations throughout the test. The composition of the minor constituents in the natural gas, however, showed a significant change associated with the onset of the free gas. Figure A-14 plots the percentage of ethane, butane, and carbon dioxide over the test period. Note that when the excess gas was produced, the percentages of ethane and butane approximately doubled, while the percentage of carbon dioxide was reduced almost by half. This is convincing evidence that the excess gas had a different composition and probably came from free gas in contact with the brine. Ethane and butane, being less soluble in water than methane, would preferentially concentrate in the free gas cap, and carbon dioxide would be concentrated in the brine rather than the gas cap. This difference in composition could also result if the gas was from a previously disconnected source.

Gas Solubility and Saturation

Analysis of the gas and water flow rates during the first two steps of the drawdown test, before the excess gas began, gave the value of about 20.5 SCF/bbl (including the gas still dissolved in the brine at the separator temperature and pressure). The recombination studies by McNeese State University reported solubilities of 22.8 to 24.0 SCF/bbl to be fully saturated, and the authors of the report suggested that the aquifer might not be fully saturated. Methane solubility in brine was also recently reported by Blount.[12] For the conditions of the No. 1 sand (13.3% salt, 10,830 psi, 378°K), the methane solubility, according to his equation, is 25.4 SCF/bbl. The Delcambre brine is about 89% NaCl, 5% other chlorides, and 6% other dissolved solids. The gas composition is 90+% methane. Blount's equation for methane in NaCl brine should, therefore, be reasonably close for the Delcambre gas solubility. The results of Blount and the McNeese researchers agree with each other and

Table A-2B. PERMEABILITIES-THICKNESS (kh) VALUES BY OTIS ENGINEERING
DELCAMBRE NO. 1 WELL, SAND NO. 1 TEST SERIES
(See Appendix B.)

Test Sequence Number	Date	Type Test	kh (md-ft)	$\overline{S}$
1	6/23-6/25	Drawdown	2,939	0.11
			4,524	4.13
2	6/26-6/27	Drawdown	5,878	11.79
3	6/28-6/29	Drawdown	5,095	5.18
4	6/30-7/1	Drawdown	--	
5	7/ 2-7/3	Drawdown	1,406	-5.74
			2,716	-2.64
			5,181	3.68
6	7/ 3-7/7	Buildup	8,697	12.96
			8,840	13.31
7	7/ 7-7/8	Drawdown	6,181	5.06
8	7/ 8-7/9	Buildup	11,677	17.85
			12,206	18.91
9	7/ 9-7/10	Drawdown	6,666	5.42
10	7/10-7/11	Buildup	11,417	15.42
11	7/11-7/12	Drawdown	6,830	4.98
12	7/12-7/13	Buildup	11,926	14.89

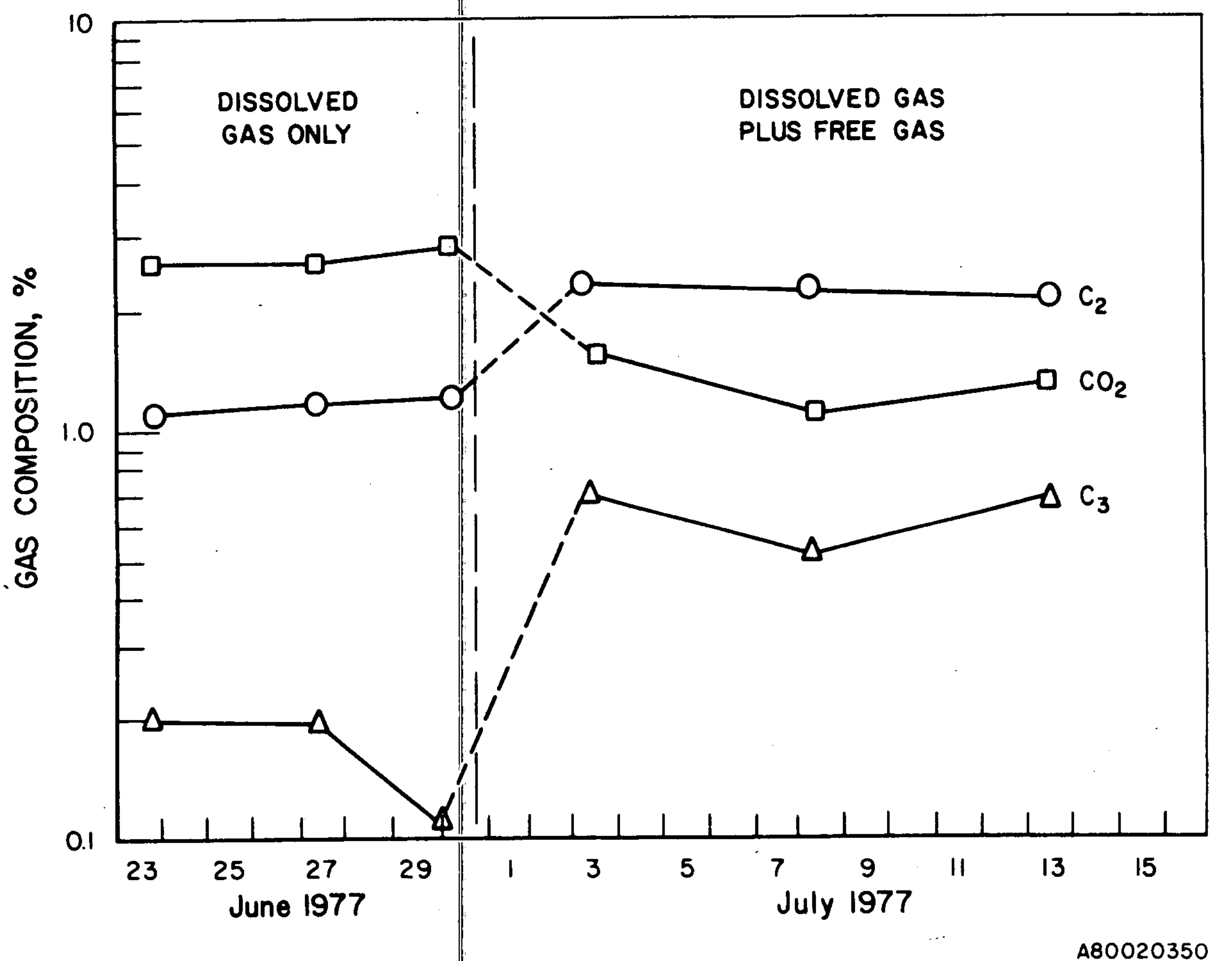

Figure A-14. COMPOSITION OF ETHANE (C_2), PROPANE (C_3), AND CARBON DIOXIDE (CO_2) IN THE NATURAL GAS PRODUCED FROM THE EDNA DELCAMBRE NO. 1 WELL, SAND NO. 1 TEST predict a higher gas solubility in the Delcambre brine than was found from the well test. The conclusion is that the Delcambre No. 1 brine was slightly undersaturated, assuming the gas and water flow measurements were accurate. This argues against the possible existence of a dispersed free gas phase (or even a free gas cap) in the main brine-producing zones in the No. 1 sand.

Modeling the Dispersed Gas Phase Hypothesis

The occurrence of a dispersed gas phase of small bubbles trapped within the rock matrix was postulated on the basis of discontinuous cycles of pressurization and pressure release of growth faults in reservoir (Randolph[1]). On each cycle of pressure release, additional amounts of natural gas are postulated to be released and remain as free gas. During repressurization, additional gas migrates in with the inflowing saturated brine, so that the now free and trapped gas does not redissolve. The free gas does not flow because its concentration is below the critical saturation point. Through repeated cycles of fault leakage and repressurization as saturated brine migrated through, the postulated dispersed gas phase would be developed.

An argument against the occurrence of a dispersed gas phase has been given by C. Matthews,[4] in which he presents plausibly analyses to show that migrating gas in the brine, or released from the brine, would move to the upper part of the reservoir layer and would not remain dispersed through the matrix, capillary and diffusion forces being fast enough during geological time for reservoir formation and gas migration to cause gas movement to the top of the sands and updip.

To model the dispersed gas phase hypothesis with computer reservoir simulators, the relative permeability equations by Corey and Pirson[12,13] were considered, but with a modification at the critical gas saturation point. The modification, shown in Figure A-15, is where the relative permeability to gas drops rapidly to zero rather than curving smoothly to zero, as given by the Corey equation. The initial amount of free gas in the dispersed phase is then placed at a value between this cutoff and full water saturation. With this initial condition the free gas is not initially produced with the brine, but as the pressure decreases in the reservoir near the well and the gas saturation increases, the critical saturation point is reached. When this occurs, the free gas begins to be produced.

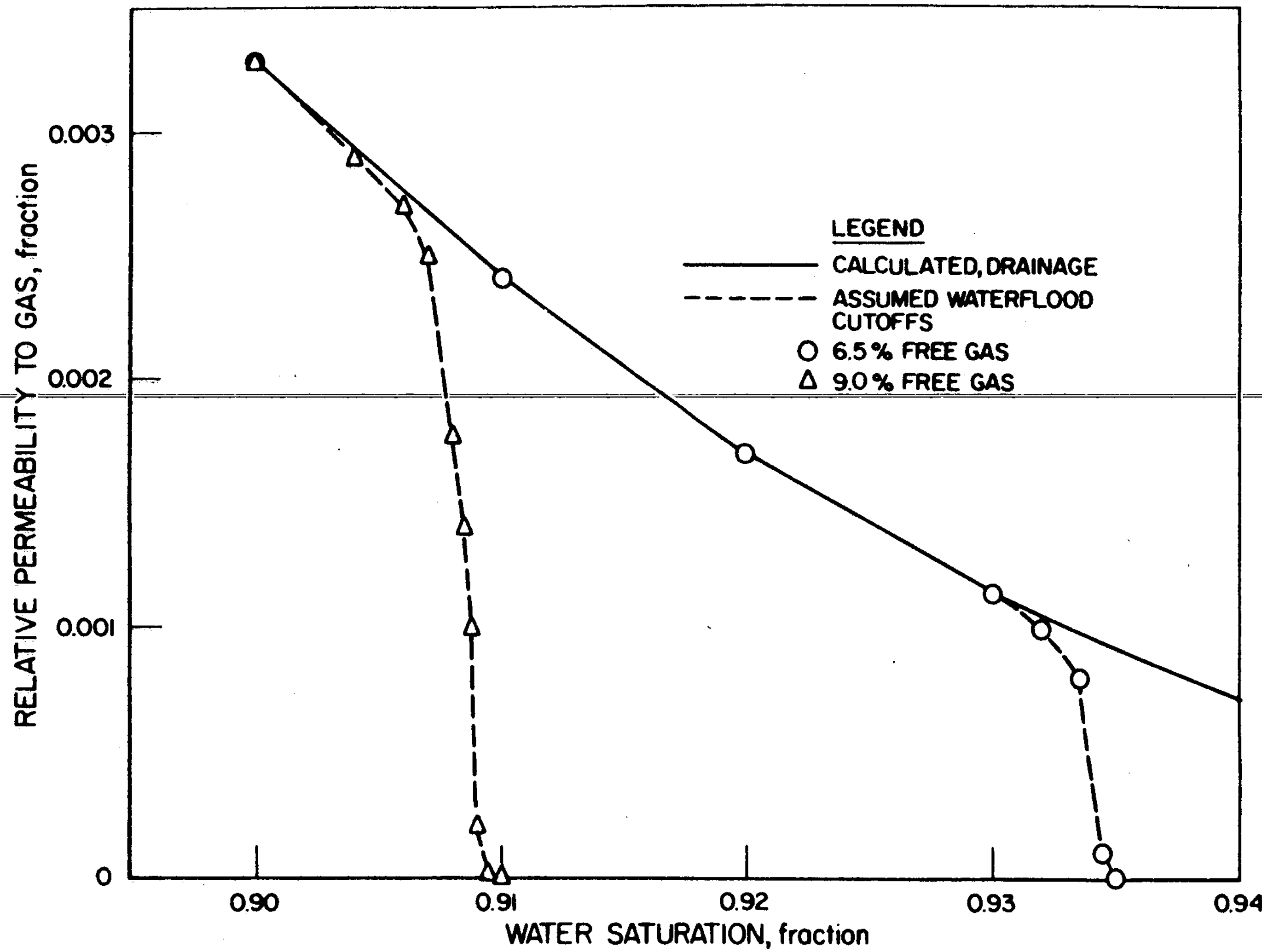

Figure A-15. WATERFLOOD CUTOFFS OF CALCULATED DRAINAGE AND RELATIVE PERMEABILITY TO GAS

For the reservoir simulator, input values for the relative permeabilities and saturations were adjusted by trial and error in an attempt to have the free gas begin at the time observed in the field test and to approximate the produced gas with time. The computer simulator used was Intercomp's two-dimensional radial coning model.

Some of the earlier calculations, as reported by Randolph,[3] indicated that the free gas required to match the hypothesis needed to be about 6.5%, or 5 times the amount of gas dissolved in the brine. This amount of free gas was not observed from analysis of the well logs. The well log analysis by Henry Dunlap[9] indicated possible 100% water saturation. The analysis of the data in the Otis Engineering report[5] indicated a possible gas saturation of 2% to 4% based on their modifications of the relative permeability curves and estimated values for the critical saturation. This was a calculated value rather than a measured value, however, and dependent on the theory.

Figures A-16 and A-17 show representative results of the trial-and-error matching attempts using modified Pirson and Corey relative permeability curves and various initial dispersed free gas saturations. A good fit to the data was not obtained. Further, the general shapes of the plots for gas production or the gas/water ratio are systematically at variance with the observed data. In the well test, the gas continually increases throughout the fourth and fifth steps of the drawdown test. The computer calculations of the dispersed gas model, however, indicate that a sharp increase in gas was followed by a tailing off to give a "sawtooth" appearance to the plot of the gas/water ratio. Since the theoretical model of the dispersed gas phase yields a characteristically different pattern for the gas/water ratio through a multistep drawdown test, a good fit to the data cannot be expected. It was possible, however, to get larger amounts of free gas to be produced in the computer calculation during the fourth and fifth drawdown steps by judicious selection of the initial gas saturation and shape of the relative permeability to gas curve. Because of the characteristically different shapes of the plots of the data and theoretical computer calculations, it is clear that the theoretical model does not fit these data.

A study of expected gas production from aquifers containing initial immobile free gas was recently reported by John C. Martin.[10] His study was directed to the question of how to identify such gas in addition to predicting

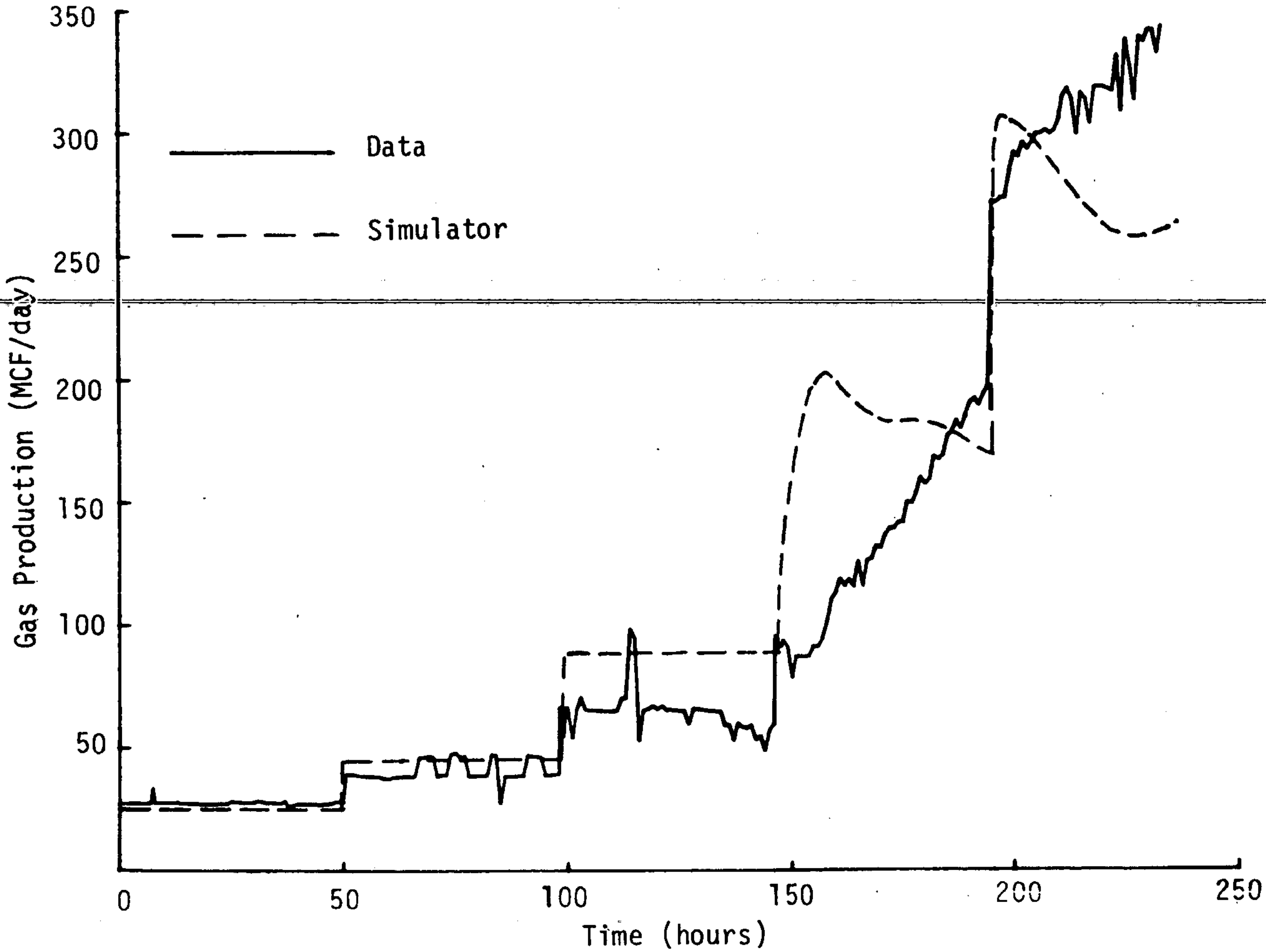

Figure A-16. COMPUTER SIMULATOR MATCH TO GAS PRODUCTION FOR DISPERSED GAS PHASE MODEL

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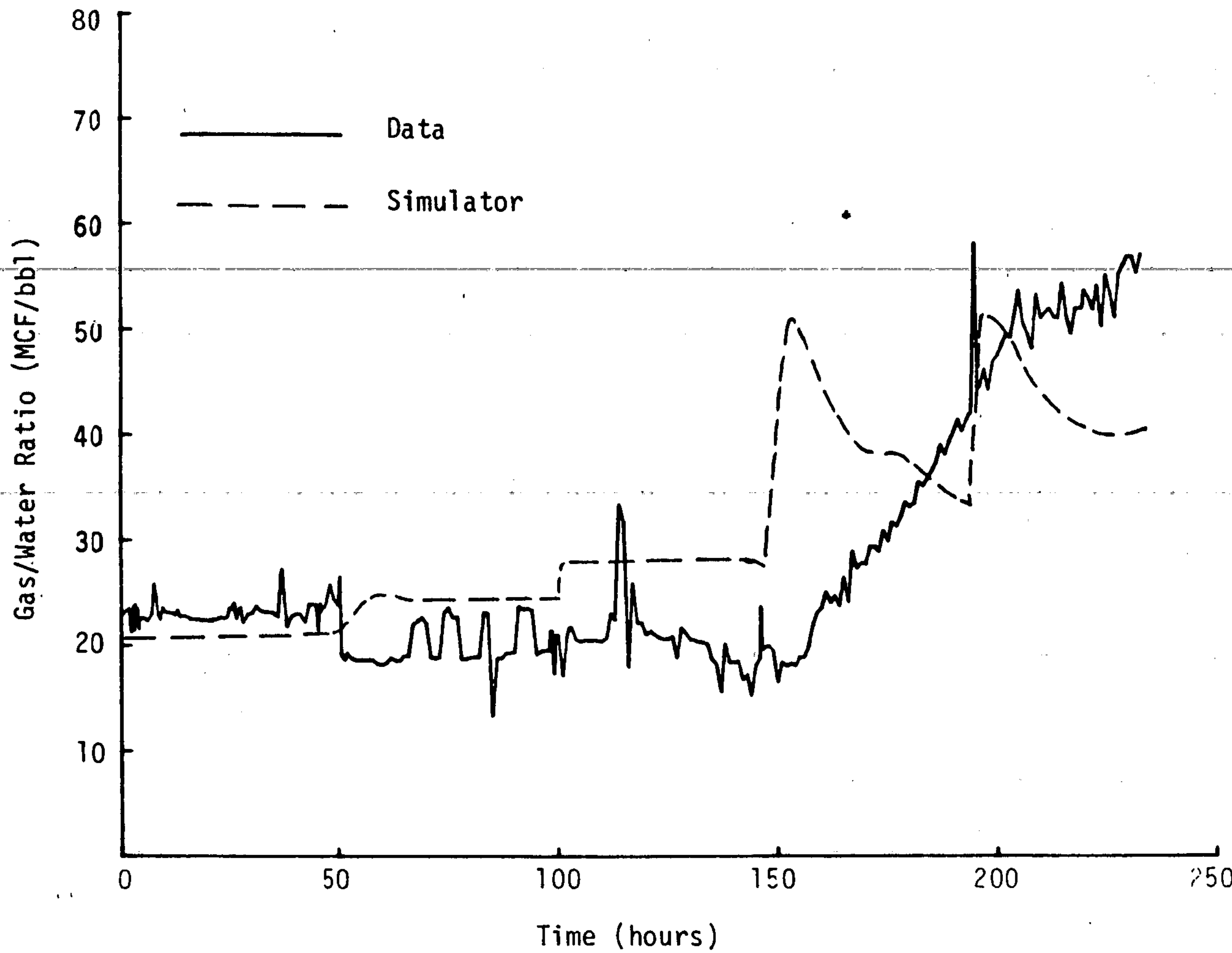

Figure A-17. COMPUTER SIMULATOR MATCH TO GAS/WATER RATIO FOR DISPERSED GAS PHASE MODEL

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the expected production. The study consisted of a computer simulation study where the key parameters were varied over a range of typical values to represent geopressured-geothermal aquifers. His results also indicated the sawtooth shape in the gas/water ratio plots for multistep flow tests, which suggested that such a shape on the gas/water ratio plot would be evidence of the postulated immobile free gas.

This study also shows that a sawtooth shape to a plot of the gas/water ratio may result from a multirate drawdown test if the reservoir and test conditions are right. This condition occurred for the cases of a sharp cutoff of the curve of relative permeability to gas that Randolph previously used as well as the smooth relative permeability curves that Martin used as long as the initial gas saturation was close enough to the critical gas saturation value.

Modeling the Free Gas Cap Hypothesis

Modeling the free gas cap hypothesis was done using Intercomp's Beta II reservoir simulator. This model allows full three-dimensional simulation of the reservoir including dip angles to the grid block system. The program was used in the radial flow mode with the well in the center. The angle of dip was approximately 3° with the grid block mesh being 15 horizontal, 5 vertical, and 3 angular for 180°. This grid was rather coarse, but adequate to calculate the general features of a gas cap and its coning down into the producing well. Based on the structure maps shown in Figures A-3 and A-4, the formation slopes upward to the north, and the major fault at about 1900 feet, as deduced by the geology and reservoir limit test, is to the east.

The distance from the well to the edge of the free gas cap was determined by adjusting the gas/water contact elevation in several computer runs until the free gas broke through to the well bore at the right time of about 160 hours. Using a permeability of about 100 millidarcys and a height of 30 ft to match the 300 millidarcys-ft-kh deduced from the reservoir engineering analysis of the data, the resulting distance to the edge of the free gas was in the range of about 400 ft. An exact distance cannot be stated because of the coarseness of the grid in the computer model, the effect of capillary pressure spreading out the contact zone, and the uncertainty in the assumptions of the reservoir physical properties. This result is judged accurate enough to state that the free gas source, assuming a free gas cap model, is only a few hundred feet from the well and not thousands of feet as indicated in the geological structure maps.

The discrepancy between the computer match of only a few hundred feet to the free gas source and the geological structure maps, which show the caps to be thousands of feet away, raises the possibility that the source of the free gas is not the gas cap, but rather the Edna Delcambre No. 4 well, which is only about 400 feet away and had a history of gas production and trouble with underground blowouts. There is the distinct possibility that the free gas originated from some other zone and its flow path was up, or down, the well casing or annulus of well No. 4 or 4A and then into the No. 1 sand when the pressure in the No. 1 sand was lowered during the test. This possibility is also in agreement with the fact that the water composition remains constant, but the gas chemical composition changes when the excess free gas breaks through.

Figures A-18 and A-19 show the gas production and gas/water ratios obtained from the free gas cap model computer runs made to this report date. This is an early match since by the time of the deadline for submittal of this report the necessary number of trial and error runs had not been made to get a more precise match. From the few runs made, however, it was evident that the free gas cap, or source, a few hundred feet away from the well gave the characteristically better shape to the plots of gas production for reservoir parameters, and are in the range as determined by reservoir engineering analysis of the test production data. Additional computer runs are needed to get a better match to the data for the gas cap hypothesis and to determine whether computer simulation can adequately distinguish between the gas cap hypothesis and the No. 4 well source hypothesis.

Conclusions

Since the Edna Delcambre No. 1 well was the first DOE well tested under the Geopressured-Geothermal Gas program, there was considerable interest in its results. When the well unexpectedly produced natural gas in quantities above the amount dissolved in the brine, there was a lively concern as to the origin of the gas and whether it was a general phenomenon that could be expected in other geothermal wells. The possible occurrence of extra gas has a strong influence on the economics of the resource.

The test data have now been analyzed by several groups or persons. It is found that the geological structure near the well is complex, including nearby

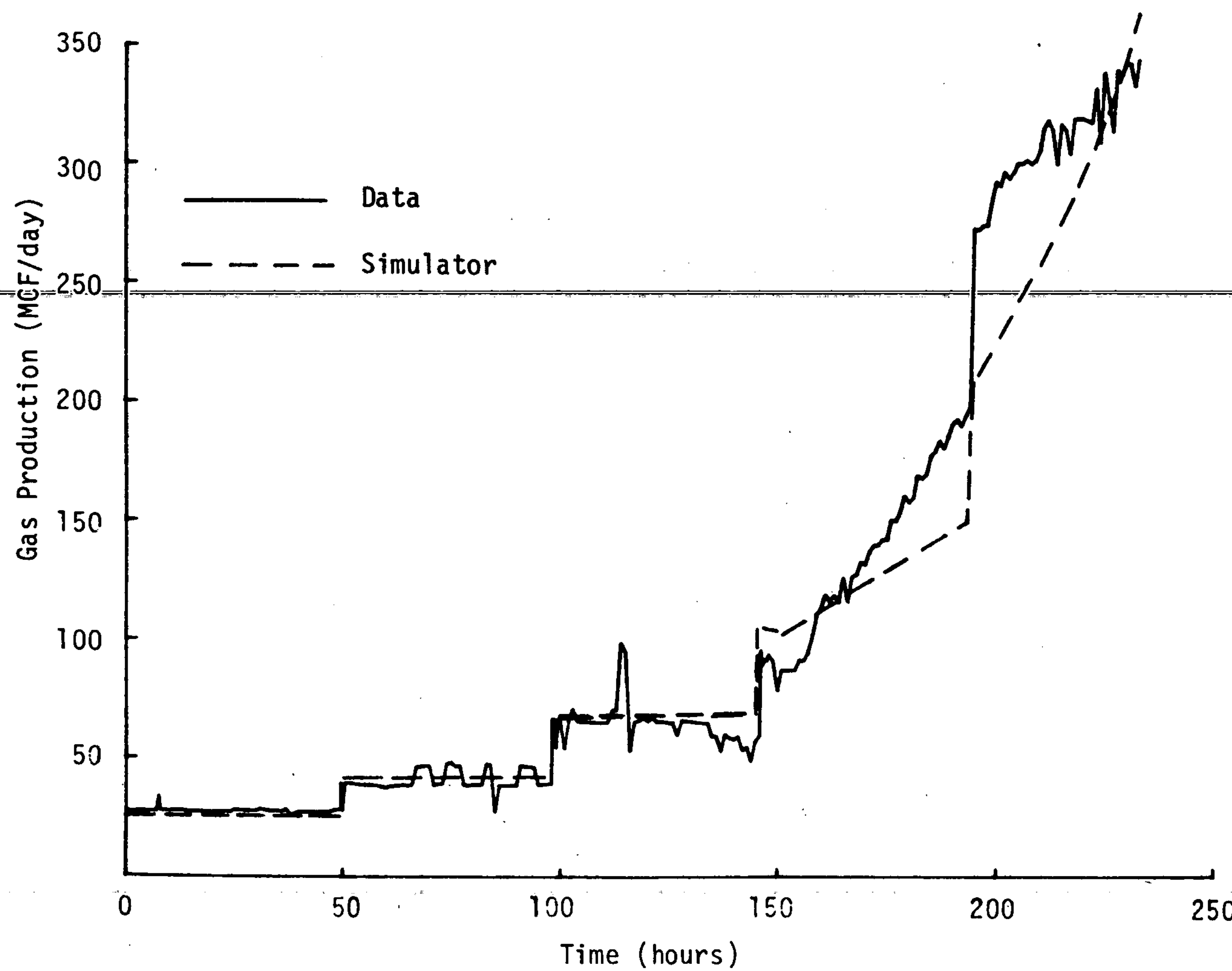

Figure A-18. COMPUTER SIMULATOR MATCH TO GAS PRODUCTION FOR FREE GAS CAP MODEL

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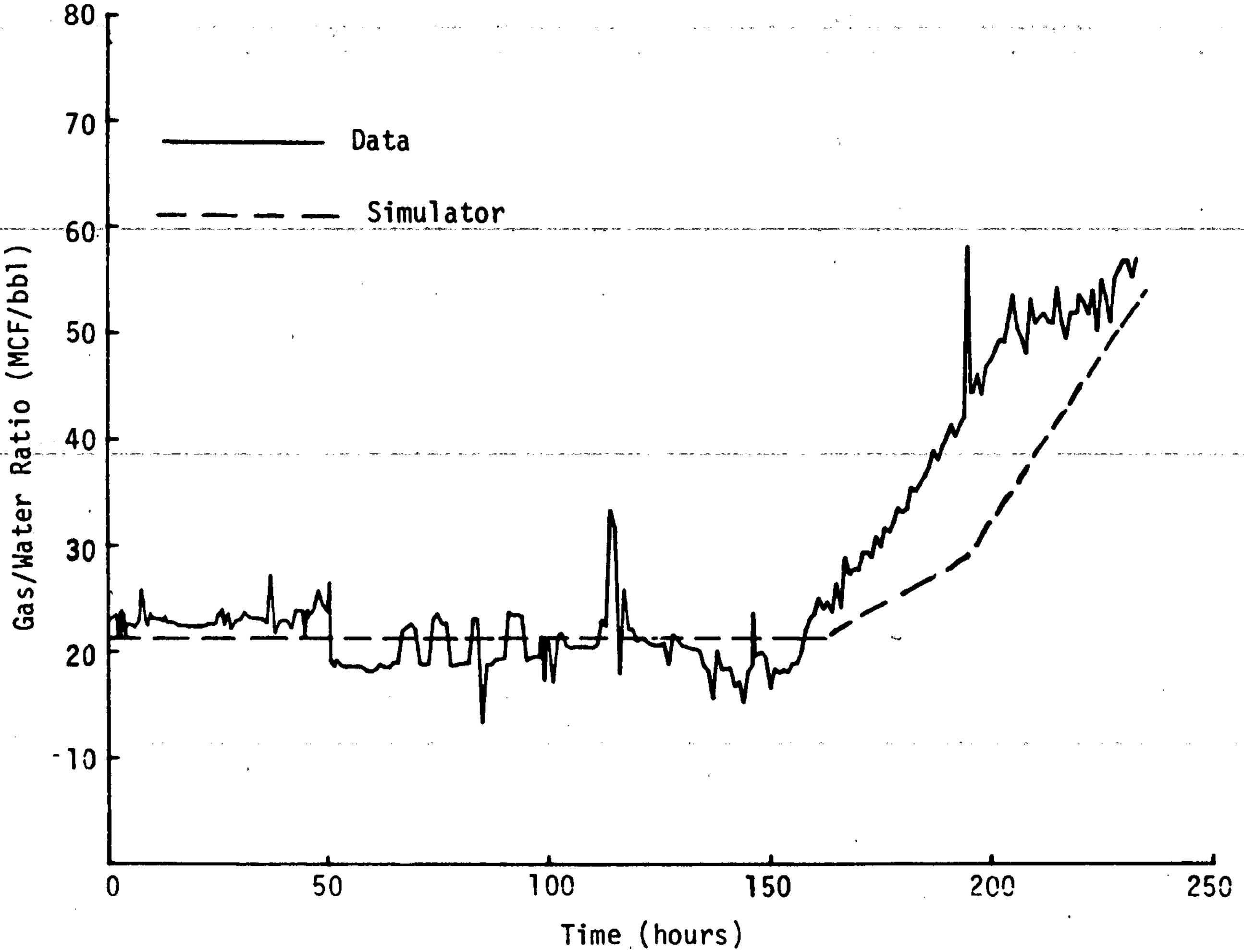

Figure A-19. COMPUTER SIMULATOR MATCH TO GAS/WATER RATIO FOR FREE GAS CAP MODEL

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faults and gas caps. The flow tests first successfully produced brine and dissolved gas from which important engineering parameters such as dissolved gas content and reservoir characteristics were obtained. The subsequent production of the excess gas complicated the test and raised technical issues of whether the extra gas might be from a dispersed phase throughout the reservoir matrix or whether it was from a free gas cap. Other suggested possibilities were that the extra gas exsolved from solution as the water level was lowered through production, or that it came from another zone via a channel around the well casing in the nearby No. 4 well.

Detailed examination of the data by usual reservoir engineering techniques and computer modeling to simulate the observed pressure and flow data indicate the permeability-thickness of the No. 1 sand interval to be initially about 3000 millidarcys-ft. The effective permeability-thickness then increased during the test. There are numerous breaks and offsets in the pressure data which both indicate the erratic behavior of the flow and complicate the analysis using routine analytic reservoir engineering methods.

Computer modeling was performed to test both the theory of a dispersed, but originally immobile, free gas phase and the theory of a nearby free gas cap or zone. These studies indicated that plots of the gas/water ratio versus time would yield stair-step or sawtooth-shaped curves which were characteristically the wrong shape to match the experimental data from the production test of the No. 1 sand in the Edna Delcambre No. 1 well. Computer results for the free gas cap model gave gas production and gas/water ratio values which were characteristically a better shape to match the experimental data. By judicious selection of the various reservoir parameters based on reservoir engineering analyses of test data, it was possible to get an approximate match of the computed gas production to the measured gas production. The computed fit did not determine a unique solution to the problem, but it did provide a consistent set of reservoir parameters which were in line with the measured values. In this study, the postulated free gas cap was required to have its edge about 400 ft from the well.

For these computer studies, it is apparent that the initially dispersed but immobile gas model is not correct for the No. 1 sand in the Edna Delcambre No. 1 well. The free gas cap model is more consistent with the data, but in view of the computer simulation studies along with the data, this model does not appear to be correct either. The most likely source of the excess gas now appears to be from a yet undetermined gas zone which became connected to the No. 1 sand via a conduit around the No. 4 or No. 4A well.

Because the dispersed but immobile free gas model produces characteristic stair-step and sawtooth gas/water ratio plots for multiple rate drawdown tests, it may be possible to identify such reservoirs by a multiple rate test. The authors are not aware of any such test data, but it might be found in tests of abandoned watered-out geopressured gas wells where flooding of the gas cap creates a dispersed free gas phase by imbibitions, and capillary effects trap free gas in the pores of the rock. Such reservoirs may not be found where they were formed over geologic time periods, and equilibrium thermodynamic principles apply. They may, however, be left behind from production of gas caps on top of aquifers which were recently flooded by intrusion of water, or in the upper edge of an aquifer where the capillary pressures spread the gas out like a transition zone.

Finally, the Department of Energy program of completing both old and new geopressured-geothermal aquifers should provide additional data, detailed analysis of which should give better understanding of the physical mechanisms which control production. As these physical parameters become better understood, improved production and economic projections can be made.

Acknowledgment

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APPENDIX B. Multirate Test Analysis

The theory behind multiple flow rate analysis is given in Reference 8. The equation that relates the down-hole well bore pressure to flow rate and time is —

$$\frac{P_t - P_o}{q_n} = \frac{162.2\nu B}{kh} \left[\sum_{j=1}^{n} \frac{(q_j - q_{j-1})}{q_n} \log (t - t_j - 1) + \overline{S} \right] \quad \text{(B-1)}$$

where:

P_t = well bore pressure at time t (psi)

P_o = initial well bore pressure (psi)

q_n = flow rate for nth increment (bbl/day)

t = time (hours)

B = volume factor (vol/vol)

$\overline{S}$ = composite skin factor (dimensionless)

h = height (ft)

k = permeability

ν = viscosity (cP)

j (subscript) = number of flow increment.

So long as the composite skin factor ($\overline{S}$) and the permeability-thickness (kh) remain constant for a large reservoir, it is seen that a plot of $(P_t - P_o)/q_n$ versus the summation term in the square brackets will give a straight line with slope (m') and intercept (b') of —

$$m' = \frac{162.2\nu B}{kh}$$

$$b' = m'\overline{S}$$

A tabulation of the data taken from the well test reports for the Edna Delcambre No. 1 sand is given in Table B-1. Also included in the table are the cumulative gas production, cumulative brine production, and the summation function in Equation B-1 excluding $\overline{S}$. The pressure is plotted versus the sum (q,t) function in Figure B-1. If the data were ideal and met the conditions of the theory used to obtain Equation B-1, then a series of parallel straight line segments would have resulted. Note in Figure B-1, however, that there

Table B-1, Part 1. TABULATION OF MULTIRATE FLOW TEST DATA
FOR THE DOE EDNA DELCAMBRE NO. 1 WELL, SAND NO. 1
(Time zero is at 20:00 hours on June 23, 1977)

HOURS	BBLS/DAY	MCF/DAY	P(psi)	SUM BBLS	SUM MCF	SUM(e*t)
0.000	1200.00	27.40	10818.43	0.00	0.00	0.00
1.750	1163.64	27.40	10633.86	86.17	2.00	291.65
2.000	1183.03	27.40	10633.34	98.40	2.28	383.13
2.250	1289.70	27.40	10632.82	111.28	2.57	421.89
2.500	1241.21	27.40	10632.30	124.46	2.85	412.01
2.750	1153.94	27.40	10631.00	136.93	3.14	521.86
3.000	1280.00	27.40	10630.33	149.61	3.43	622.83
3.250	1144.24	27.40	10628.95	162.24	3.71	566.17
3.500	1241.21	27.40	10627.96	174.66	4.00	712.49
3.750	1163.64	27.40	10626.59	187.18	4.28	663.43
4.000	1270.30	27.40	10627.65	199.86	4.57	758.91
4.250	1221.82	27.40	10626.60	212.84	4.85	710.62
4.500	1212.12	27.40	10626.28	225.52	5.14	793.17
5.000	1216.97	27.40	10624.65	250.82	5.71	849.72
5.500	1212.12	27.40	10625.17	276.12	6.28	896.55
6.000	1231.51	27.40	10622.81	301.58	6.85	944.63
6.500	1212.12	27.40	10622.37	327.03	7.42	980.04
7.000	1192.73	27.40	10621.33	352.08	7.99	1030.35
7.500	1309.09	33.82	10620.31	378.14	8.63	1069.87
8.000	1110.30	27.52	10621.18	403.35	9.27	1061.87
8.500	1202.42	27.55	10619.24	427.44	9.84	1184.63
9.000	1226.67	27.55	10619.50	452.74	10.42	1144.82
9.500	1163.64	27.58	10618.00	477.64	10.99	1171.10
10.000	1192.73	27.64	10617.01	502.18	11.57	1225.32
10.500	1192.73	27.64	10616.41	527.03	12.14	1227.56
11.000	1197.57	27.64	10616.24	551.93	12.72	1252.48
11.500	1197.57	27.58	10615.31	576.88	13.29	1273.67
12.000	1197.57	27.58	10614.49	601.83	13.87	1296.62
12.500	1202.42	27.49	10614.76	626.83	14.44	1318.05
13.000	1202.42	28.11	10613.70	651.88	15.02	1336.99
13.500	1202.42	27.35	10612.39	676.93	15.60	1357.99
14.000	1197.57	27.29	10613.83	701.93	16.17	1377.63
14.500	1197.57	27.35	10613.13	726.88	16.74	1397.81
15.000	1202.42	27.35	10613.66	751.88	17.31	1414.31
15.500	1202.42	27.26	10611.10	776.93	17.87	1429.29
16.000	1212.12	27.26	10612.64	802.08	18.44	1446.85
16.500	1207.27	27.16	10610.67	827.28	19.01	1460.47
17.000	1212.12	27.19	10608.66	852.49	19.58	1480.72
17.500	1207.27	27.16	10608.92	877.69	20.14	1494.84
18.000	1207.27	27.16	10608.42	902.84	20.71	1512.96
18.500	1212.12	27.03	10609.12	928.04	21.27	1527.09
19.000	1207.27	27.03	10607.77	953.24	21.83	1539.68
19.500	1207.27	27.02	10606.31	978.40	22.40	1556.35
20.000	1212.12	27.02	10609.12	1003.60	22.96	1569.16
20.500	1202.42	27.02	10606.73	1028.75	23.52	1580.54
21.000	1212.12	27.03	10608.24	1053.90	24.09	1597.55
21.500	1202.42	27.03	10606.00	1079.05	24.65	1604.93
22.000	1207.27	27.03	10606.89	1104.15	25.21	1621.77
22.500	1202.42	27.16	10609.72	1129.25	25.78	1630.19
23.000	1197.57	27.16	10604.13	1154.25	26.34	1643.64
23.500	1202.42	27.16	10604.62	1179.25	26.91	1655.11
24.000	1202.42	27.16	10605.72	1204.30	27.47	1662.49
24.500	1197.57	27.16	10606.25	1229.30	28.04	1673.39
25.000	1192.73	28.05	10604.54	1254.20	28.62	1685.29
25.500	1192.73	27.94	10605.90	1279.05	29.20	1695.48
26.000	1163.64	27.94	10606.54	1303.60	29.78	1703.17
26.500	1231.51	27.72	10605.83	1328.55	30.36	1720.28
27.000	1192.73	27.72	10607.06	1353.80	30.94	1699.66
27.500	1163.64	27.49	10607.64	1378.34	31.51	1735.26
28.000	1241.21	27.49	10607.69	1403.39	32.09	1749.26
29.000	1200.00	27.49	10605.26	1454.25	33.23	1750.66
30.000	1197.57	27.58	10604.79	1504.20	34.38	1783.68
31.000	1197.57	28.44	10604.38	1554.10	35.55	1796.69
32.000	1197.57	27.87	10603.41	1604.00	36.72	1810.92
33.000	1192.73	27.64	10605.38	1653.80	37.88	1825.67
34.000	1192.73	27.64	10604.35	1703.49	39.03	1840.36
35.000	1197.57	27.64	10603.75	1753.29	40.18	1853.38
36.000	1195.15	27.15	10603.42	1803.14	41.32	1866.71
37.000	1044.85	28.43	10601.63	1849.81	42.48	1881.44
38.000	1183.03	25.73	10605.09	1896.22	43.61	1894.65
39.000	1173.33	26.70	10604.01	1945.31	44.70	1862.44
40.000	1178.18	27.10	10604.05	1994.30	45.82	1890.35
41.000	1180.60	27.10	10604.36	2043.44	46.95	1905.49
42.000	1219.39	27.07	10605.29	2093.44	48.08	1920.18
43.000	1127.27	26.94	10602.66	2142.33	49.20	1934.01
44.500	1123.64	26.88	10602.46	2212.67	50.88	1951.99
45.000	1253.33	26.94	10603.00	2237.43	51.45	1950.58
45.250	1175.76	26.94	10602.63	2250.09	51.73	1871.42
45.500	1127.27	27.02	10603.27	2262.08	52.01	1956.63
45.750	1166.06	27.02	10602.77	2274.02	52.29	1985.18
46.000	1146.67	27.07	10602.87	2286.07	52.57	1949.93
46.500	1151.51	27.15	10602.96	2310.01	53.13	1966.29
47.000	1132.12	27.21	10601.75	2333.80	53.70	1965.54
48.000	1088.48	28.02	10601.94	2380.06	54.85	1973.21
49.000	1158.79	28.17	10601.05	2426.88	56.02	1975.35
50.000	1175.76	28.00	10602.46	2475.51	57.19	1966.98
50.500	1469.09	39.00	10418.23	2503.06	57.89	1972.85
50.750	2055.76	39.35	10413.50	2521.42	58.30	1803.63
51.000	2065.45	39.31	10410.66	2542.89	58.71	1544.79
51.500	2109.09	39.27	10407.39	2586.37	59.53	1920.12
52.000	2036.36	39.27	10407.09	2629.55	60.34	2100.11
53.000	2067.88	38.83	10405.04	2715.06	61.97	2352.95
54.000	2072.73	38.43	10403.88	2801.32	63.58	2491.39
55.000	2063.03	38.43	10402.70	2887.48	65.18	2607.34
56.000	2072.73	38.43	10401.03	2973.65	66.78	2700.97
57.000	2058.18	38.35	10402.28	3059.71	68.38	2776.14
58.000	2067.88	38.35	10401.51	3145.67	69.98	2844.80
59.000	2070.30	37.68	10399.99	3231.88	71.57	2900.51
60.000	2056.45	37.28	10398.60	3317.85	73.13	2954.68
61.000	2075.15	38.05	10397.79	3403.93	74.70	3004.20
62.000	2019.39	38.05	10396.69	3489.23	76.28	3045.17
63.000	2062.42	38.30	10396.38	3574.27	77.87	3090.06
64.000	2089.09	38.67	10395.77	3660.76	79.48	3113.69
65.000	2020.60	38.39	10394.87	3746.38	81.08	3154.24
66.000	2020.60	38.28	10394.27	3830.57	82.68	3197.92
67.000	2107.88	46.34	10394.96	3916.58	84.44	3215.02
68.000	2080.00	46.34	10393.85	4003.82	86.37	3237.37
69.000	2055.76	46.57	10393.46	4089.99	88.31	3287.15
70.000	2118.79	46.81	10392.84	4176.96	90.25	3317.71
71.000	2031.51	38.32	10392.54	4263.42	92.03	3339.67
72.000	2077.57	39.02	10392.02	4349.03	93.64	3382.12
73.000	2063.03	39.02	10391.94	4435.29	95.26	3390.34

Table B-1, Part 2. TABULATION OF MULTIRATE FLOW TEST DATA
FOR THE DOE EDNA DELCAMBRE NO. 1 WELL, SAND NO. 1
(Time zero is at 20:00 hours on June 23, 1977)

HOURS	BBLS/DAY	MCF/DAY	P(psi)	SUM BBLS	SUM MCF	SUM(e,t)
74.000	2065.45	47.67	10391.31	4521.30	97.07	3419.64
75.000	2043.63	48.15	10390.43	4606.91	99.07	3440.92
76.000	2058.18	46.51	10391.43	4692.36	101.04	3463.12
77.000	2060.00	46.85	10391.43	4778.15	102.98	3478.08
78.000	2063.03	38.52	10390.72	4864.05	104.76	3499.53
79.000	2063.03	38.60	10390.02	4950.01	106.37	3520.25
80.000	2048.48	38.71	10390.12	5035.67	107.98	3540.97
81.000	2050.91	38.75	10390.05	5121.07	109.59	3560.69
82.000	2050.91	38.83	10389.22	5206.53	111.21	3575.33
83.000	2048.48	47.39	10389.61	5291.93	113.01	3591.96
84.000	2048.48	47.29	10388.93	5377.28	114.98	3608.54
85.000	2048.48	27.35	10388.70	5462.64	116.53	3624.21
86.000	2050.91	38.60	10409.30	5548.04	117.91	3639.95
87.000	2048.48	38.56	10408.91	5633.44	119.51	3655.56
88.000	1997.57	38.52	10408.78	5717.74	121.12	3671.70
89.000	1995.15	38.52	10408.20	5800.92	122.73	3686.57
90.000	1983.03	38.48	10408.10	5883.80	124.33	3686.05
91.000	1975.76	46.92	10407.80	5966.27	126.11	3690.98
92.000	1978.18	46.39	10407.70	6048.65	128.05	3694.95
93.000	1973.33	46.39	10407.55	6130.97	129.99	3699.56
94.000	1978.18	46.14	10407.49	6213.29	131.91	3707.18
95.000	2007.27	38.48	10406.57	6296.32	133.48	3714.19
96.000	2000.00	38.91	10407.24	6379.81	135.29	3723.82
97.000	1997.57	39.03	10406.78	6463.09	136.91	3742.21
98.000	2000.00	39.03	10406.69	6546.37	138.54	3754.91
98.250	3100.00	66.52	10203.05	6572.94	139.09	3756.30
98.500	3122.42	66.52	10218.34	6605.34	139.78	3097.64
99.000	3141.82	54.43	10210.56	6670.60	141.04	3622.21
99.500	3156.36	66.32	10206.34	6734.20	142.30	3873.30
100.000	3151.51	66.19	10206,95	6801.91	143.68	4045.44
101.000	3149.09	54.00	10202.01	6933.17	146.18	4290.79
102.000	3129.69	65.87	10227.61	7063.98	148.68	4458.81
102.583	3130.28	68.00	10224.64	7140.01	150.31	4542.23
103.000	3246.90	70.59	10223.30	7195.41	151.51	4588.11
104.000	3166.01	65.23	10220.71	7329.02	154.34	4689.25
105.000	3199.84	65.11	10218.74	7461.64	157.06	4812.17
106.000	3170.84	65.04	10217.44	7594.36	159.77	4885.84
107.000	3175.68	64.92	10215.81	7726.58	162.47	4965.80
108.000	3166.01	64.92	10214.70	7858.70	165.18	5027.28
109.000	3173.26	64.74	10213.49	7990.77	167.88	5087.11
110.000	3175.68	64.68	10213.07	8123.04	170.58	5139.66
111.000	3139.42	64.92	10214.02	8254.60	173.28	5191.88
112.000	3047.58	70.12	10213.30	8383.50	176.09	5241.20
113.000	3129.76	70.12	10212.58	8512.19	179.01	5276.41
114.000	2953.33	98.38	10208.14	8638.92	182.52	5285.90
115.000	2984.75	94.33	10208.04	8762.63	186.54	5331.21
116.000	2960.58	53.12	10206.93	8886.49	189.61	5316.88
117.000	2513.47	65.11	10206.75	9000.54	192.07	5331.30
118.000	2984.75	65.78	10206.22	9115.08	194.80	5341.74
119.000	3033.08	67.08	10205.42	9240.45	197.57	5222.51
120.000	3124.92	65.55	10205.28	9368.75	200.33	5303.26
121.000	3141.84	66.95	10204.83	9499.30	203.09	5363.72
122.000	3110.42	65.23	10204.61	9629.56	205.84	5434.85
123.000	3151.51	65.29	10203.90	9760.02	208.56	5492.14
124.000	3166.01	65.04	10205.01	9891.63	211.28	5529.02
125.000	3150.00	64.80	10204.30	10023.21	213.98	5576.12

HOURS	BBLS/DAY	MCF/DAY	P(psi)	SUM BBLS	SUM MCF	SUM(e,t)
126.000	3117.67	44.80	10204.48	10153.79	216.68	5620.09
127.000	3168.42	59.55	10205.01	10284.75	219.27	5653.38
128.000	3045.17	65.67	10206.92	10414.20	221.88	5675.45
129.000	3103.17	65.55	10217.43	10542.29	224.62	5715.19
130.000	3182.93	65.36	10220.26	10673.25	227.34	5711.70
131.000	3170.84	64.86	10219.55	10805.62	230.06	5738.14
132.000	3187.76	64.68	10219.11	10938.09	232.76	5785.72
133.000	3187.76	64.56	10218.56	11070.92	235.45	5818.74
134.000	3214.34	64.50	10218.64	11204.29	238.14	5853.66
135.000	3168.42	59.04	10219.85	11337.27	240.71	5884.35
136.000	3245.76	59.04	10219.45	11470.90	243.17	5920.63
137.000	3383.52	52.87	10219.25	11609.01	245.50	5938.10
138.000	2975.08	59.83	10219.14	11741.48	247.85	5981.94
139.000	3180.51	58.34	10219.14	11869.72	250.31	6058.16
140.000	3158.76	57.86	10219.45	12001.79	252.73	5990.19
141.000	3192.59	59.10	10218.87	12134.11	255.17	6025.61
142.000	3187.76	53.27	10218.74	12267.03	257.51	6044.13
143.000	3185.34	54.67	10221.35	12399.80	259.76	6072.72
144.000	3190.18	48.51	10221.57	12532.63	261.91	6095.48
145.000	3158.76	57.08	10221.77	12664.90	264.11	6116.21
146.000	3173.26	59.43	10223.69	12796.81	266.54	6137.81
146.250	4040.89	95.49	10037.78	12834.39	267.34	6131.23
146.500	4562.92	88.94	10026.10	12879.20	268.30	5615.88
147.000	4610.94	91.22	10024.51	12974.76	270.18	5883.25
147.500	4596.75	91.05	10040.93	13070.67	272.08	6227.87
148.000	4669.26	93.34	10039.58	13167.19	274.00	6474.41
149.000	4681.34	90.87	10033.94	13362.00	277.84	6786.01
150.000	4751.43	78.62	10031.54	13558.51	281.37	7023.74
151.000	4724.84	86.92	10032.49	13755.94	284.82	7207.30
152.000	4828.77	86.92	10033.66	13954.97	288.44	7377.11
153.000	4761.10	86.92	10031.09	14154.76	292.06	7507.53
154.000	4823.93	86.92	10029.43	14354.45	295.68	7652.93
155.000	4823.93	90.95	10029.10	14555.44	299.39	7752.37
156.000	4819.10	90.78	10028.83	14756.34	303.17	7864.01
157.000	4741.76	94.14	10028.12	14955.52	307.03	7960.45
158.000	4604.36	100.85	10027.81	15150.24	311.09	8045.80
159.000	4751.43	109.99	10028.72	15345.15	315.48	8101.24
160.000	4809.43	112.80	10033.72	15544.33	320.12	8119.41
161.000	4736.93	118.59	10043.72	15743.21	324.94	8198.29
162.000	4814.27	115.73	10058.46	15942.20	329.83	8281.43
163.000	4800.00	118.49	10057.62	16142.50	334.70	8329.71
164.000	4861.21	115.42	10066.55	16343.77	339.58	8403.57
165.000	4765.93	125.91	10067.17	16544.34	344.61	8462.60
166.000	4807.02	115.73	10066.85	16743.77	349.64	8536.43
167.000	4359.91	126.13	10066.78	16934.75	354.68	8570.93
168.000	4662.01	127.13	10066.13	17122.71	359.95	8624.07
169.000	4761.10	132.21	10066.44	17319.02	365.36	8538.48
170.000	4749.01	131.27	10066.55	17517.15	370.85	8597.28
171.000	4652.34	136.59	10065.90	17713.01	376.43	8669.14
172.000	4744.18	139.26	10066.25	17908.77	382.17	8720.43
173.000	4838.43	139.39	10066.05	18108.41	387.98	8737.05
174.000	4596.75	141.77	10065.79	18304.97	393.84	8790.02
175.000	4746.60	141.77	10065.74	18499.63	399.74	8862.52
176.000	4739.34	150.14	10065.45	18697.25	405.83	8846.73
177.000	4780.43	149.48	10065.36	18895.58	412.07	8899.13
178.000	4770.76	153.82	10077.59	19094.56	418.39	8938.49

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Table B-1, Part 3. TABULATION OF MULTIRATE FLOW TEST DATA
FOR THE DOE EDNA DELCAMBRE NO. 1 WELL, SAND NO. 1
(Time zero is at 20:00 hours on June 23, 1977.)

HOURS	BBLS/DAY	MCF/DAY	P(psi)	SUM BBLS	SUM MCF	SUM(a,t)
179.000	4775.60	160.11	10073.99	19293.45	424.93	8987.63
180.000	4756.26	157.35	10072.38	19492.03	431.54	9026.71
181.000	4763.51	159.41	10072.68	19690.35	438.14	9065.04
182.000	4751.43	168.68	10072.62	19888.58	444.97	9095.23
183.000	4768.35	167.40	10072.53	20086.91	451.98	9128.41
184.000	4722.43	169.34	10072.71	20284.64	458.99	9156.77
185.000	4836.02	176.88	10072.52	20483.77	464.20	9190.85
186.000	4785.26	178.72	10072.58	20684.21	473.61	9208.83
187.000	4698.26	183.13	10072.51	20881.79	481.15	9265.50
188.000	4722.43	179.82	10072.64	21078.05	488.71	9294.14
189.000	4703.09	184.93	10073.58	21274.42	496.31	9297.65
190.000	4727.26	190.20	10073.21	21470.88	504.13	9318.86
191.000	4642.67	192.26	10072.84	21666.09	512.10	9335.04
192.000	4705.51	189.40	10073.61	21860.84	520.05	9361.48
193.000	4683.76	193.95	10073.35	22056.45	528.03	9360.68
194.000	4683.76	197.45	10073.11	22251.61	536.19	9388.75
195.000	4678.92	272.49	9903.69	22446.67	545.98	9406.37
195.500	6119.34	271.80	9897.45	22559.15	551.65	9417.31
196.000	6104.84	271.57	9897.09	22686.48	557.31	8991.94
197.000	5923.58	273.51	9892.51	22937.07	568.66	9697.48
198.000	6194.26	273.74	9889.05	23189.53	580.06	10031.82
199.000	6051.67	283.87	9887.74	23444.65	591.68	10204.69
200.000	6158.01	292.32	9886.44	23699.02	603.68	10429.30
201.000	6003.33	290.26	9885.50	23952.38	615.82	10555.21
202.000	6003.33	296.51	9885.21	24202.52	628.05	10701.39
203.000	5969.50	293.57	9886.97	24451.96	640.34	10775.76
204.000	5773.74	296.46	9890.57	24696.61	652.63	10854.24
205.000	5592.48	299.95	9890.92	24933.40	665.06	10919.58
206.000	5938.08	299.95	9891.47	25173.62	677.56	10926.20
207.000	6097.59	301.61	9890.53	25424.37	690.09	10900.51
208.000	6232.93	299.95	9890.46	25681.25	702.62	11008.86
209.000	5652.90	301.25	9892.93	25928.87	715.15	11134.18
210.000	5993.66	305.65	9893.89	26171.51	727.79	11268.72
211.000	6112.09	315.02	9893.59	26423.71	740.72	11197.23
212.000	6124.17	318.40	9893.82	26678.63	753.92	11285.15
213.000	6143.51	313.88	9897.55	26934.21	767.09	11386.03
214.000	5875.24	299.69	9899.85	27184.60	779.87	11467.68
215.000	5829.32	317.01	9900.16	27428.45	792.72	11543.10
216.000	6148.34	314.12	9898.53	27677.98	805.87	11528.33
217.000	6147.00	304.21	9899.54	27934.13	818.75	11527.44
218.000	6147.00	319.30	9899.88	28190.26	831.74	11637.88
219.500	6146.19	319.30	9898.89	28574.42	851.70	11747.84
220.000	5955.00	319.30	9899.33	28700.48	858.35	11779.02
221.000	6000.00	318.02	9900.30	28949.54	871.62	11835.72
222.000	6116.92	317.32	9901.71	29201.97	884.86	11830.51
223.000	6138.67	332.10	9903.25	29457.30	898.39	11859.49
224.000	6153.17	309.06	9904.47	29713.38	911.75	11925.29
225.000	6145.92	338.57	9904.07	29969.61	925.24	11984.01
226.000	6129.00	327.51	9902.71	30225.34	939.12	12038.77
227.000	6131.42	313.56	9904.74	30480.76	952.47	12085.17
228.000	6145.92	339.84	9905.42	30736.54	966.09	12123.79
229.000	6017.83	337.55	9905.61	30989.95	980.20	12163.10
230.000	6017.83	342.60	9962.05	31240.69	994.37	12205.63
231.000	6020.25	342.29	10035.27	31491.49	1008.64	12206.69
232.000	6017.83	332.85	10108.49	31742.28	1022.70	12222.02
233.000	6022.67	344.15	10181.71	31993.13	1036.81	12243.30
233.010	0.00	0.00		31994.38	1036.88	12233.84
235.000	0.00	0.00		31994.38	1036.88	10491.82
240.000	0.00	0.00		31994.38	1036.88	7335.39
245.000	0.00	0.00	10750.43	31994.38	1036.88	6050.42
250.000	0.00	0.00	10758.69	31994.38	1036.88	5259.22
255.000	0.00	0.00	10764.22	31994.38	1036.88	4698.90
260.000	0.00	0.00	10769.44	31994.38	1036.88	4271.78
265.000	0.00	0.00	10773.14	31994.38	1036.88	3930.85
270.000	0.00	0.00	10776.51	31994.38	1036.88	3649.92
275.000	0.00	0.00	10779.57	31994.38	1036.88	3412.97
280.000	0.00	0.00	10782.10	31994.38	1036.88	3209.51
285.000	0.00	0.00	10784.29	31994.38	1036.88	3032.29
290.000	0.00	0.00	10786.25	31994.38	1036.88	2876.13
295.000	0.00	0.00	10788.06	31994.38	1036.88	2737.19
300.000	0.00	0.00	10789.67	31994.38	1036.88	2612.55
305.000	0.00	0.00	10790.91	31994.38	1036.88	2499.96
310.000	0.00	0.00	10792.16	31994.38	1036.88	2397.62
315.000	0.00	0.00	10793.41	31994.38	1036.88	2304.11
320.000	0.00	0.00	10794.66	31994.38	1036.88	2218.26
325.000	0.00	0.00	10795.91	31994.38	1036.88	2139.10
330.000	0.00	0.00	10797.16	31994.38	1036.88	2065.85
332.490	0.00	0.00	10797.79	31994.38	1036.88	2031.35
332.500	7890.00	30.00	10797.79	31996.02	1036.88	2031.22
333.500	7895.17	82.46	9865.83	32324.88	1039.23	2017.71
333.750	7132.03	183.24	9859.59	32403.15	1040.61	2775.87
334.000	7650.21	182.15	9876.58	32480.14	1042.51	3858.29
334.500	7951.70	198.56	9846.86	32642.66	1046.48	4318.89
335.000	7226.24	181.25	9843.40	32800.76	1050.44	4973.76
335.500	8083.60	197.59	9844.65	32960.24	1054.38	5881.48
336.500	7348.72	239.71	9843.78	33281.75	1063.49	6565.00
337.000	7532.44	257.86	9844.90	33436.76	1068.68	7258.98
337.500	7588.97	278.23	9844.29	33594.27	1074.26	7385.37
338.000	7725.58	300.53	9842.38	33753.80	1080.29	7649.18
339.000	7245.09	299.97	9841.51	34065.69	1092.80	8176.54
340.000	7447.65	335.58	9839.25	34371.79	1106.04	8666.36
341.000	7459.43	339.22	9837.13	34682.35	1120.10	8938.47
342.000	7548.93	353.74	9836.13	34995.03	1134.53	9280.84
343.000	7322.81	371.02	9831.69	35304.85	1149.63	9586.96
344.000	7584.26	369.67	9830.44	35615.42	1165.06	9890.28
345.000	7421.74	377.98	9827.52	35928.04	1180.64	10090.70
346.000	7563.06	377.98	9820.99	36240.23	1196.39	10373.71
347.000	7391.12	384.47	9820.51	36551.77	1212.27	10567.24
348.000	7424.09	369.33	9840.56	36860.42	1227.98	10800.30
349.000	7445.29	401.52	9837.96	37170.20	1244.04	10954.97
350.000	7442.94	392.30	9836.41	37480.37	1260.58	11124.32
351.000	7405.25	391.95	9834.26	37789.71	1276.91	11291.74
352.000	7471.20	377.25	9834.88	38099.64	1292.94	11448.08
353.070	7470.00	390.00	9874.82	38432.70	1310.04	11596.47
353.100	0.00	0.00	10656.77	38437.37	1310.29	11603.17
355.000	0.00	0.00	10736.66	38437.37	1310.29	9797.94
360.000	0.00	0.00	10755.57	38437.37	1310.29	6219.19
365.000	0.00	0.00	10764.73	38437.37	1310.29	4945.71
370.000	0.00	0.00	10772.16	38437.37	1310.29	4226.95
375.000	0.00	0.00	10775.22	38437.37	1310.29	3749.64
380.000	0.00	0.00	10778.29	38437.37	1310.29	3403.13
384.500	0.00	0.00	10781.04	38437.37	1310.29	3160.59

Table B-1, Part 4. TABULATION OF MULTIRATE FLOW TEST DATA
FOR THE DOE EDNA DELCAMBRE NO. 1 WELL, SAND NO. 1
(Time zero is at 20:00 hours on June 23, 1977.)

HOURS	BBLS/DAY	MCF/DAY	P(psi)	SUM BBLS	SUM MCF	SUM(a*t)
384.590	8000.00	360.00	9957.08	38452.37	1310.96	3156.25
385.000	8319.89	366.18	9792.31	38591.77	1317.16	38.94
385.250	8233.35	409.42	9777.72	38677.98	1321.20	1488.66
385.500	8430.05	378.43	9769.75	38764.77	1325.31	2741.41
386.000	8678.27	374.84	9758.91	38942.98	1333.15	4235.72
386.500	8528.40	395.27	9750.74	39122.22	1341.18	5289.45
387.000	8528.40	394.08	9752.85	39299.89	1349.40	6257.17
387.500	8495.62	409.55	9752.86	39477.23	1357.77	6935.41
388.000	8504.98	417.83	9750.33	39654.32	1366.39	7516.58
389.000	8512.01	474.21	9749.32	40008.84	1384.97	8421.07
390.000	8423.02	515.06	9750.09	40361.65	1405.58	9140.09
391.000	8399.61	514.60	9748.22	40712.12	1427.03	9733.52
392.000	8430.05	522.52	9756.12	41062.74	1448.64	10209.07
393.000	8394.92	515.23	9753.58	41413.26	1470.26	10621.29
394.000	8425.36	529.79	9750.19	41763.68	1492.03	10998.27
395.000	8561.18	499.46	9745.66	42117.57	1513.47	11323.40
396.000	8364.48	484.22	9742.18	42470.19	1533.97	11629.33
397.000	8469.86	496.76	9743.74	42820.90	1554.40	11947.14
398.000	8385.56	496.76	9746.69	43172.06	1575.10	12165.48
399.000	8444.10	497.65	9744.99	43522.67	1595.82	12413.59
400.000	8248.40	539.97	9753.42	43870.43	1617.44	12612.60
401.000	8364.48	539.97	9754.02	44216.54	1639.93	12822.89
402.000	8341.06	538.03	9750.73	44564.57	1662.39	12957.33
403.000	8343.41	532.27	9751.31	44912.16	1684.69	13138.54
404.000	8446.44	512.25	9749.87	45261.95	1706.45	13297.53
404.800	8446.44	530.00	9748.36	45543.50	1723.82	13410.39
404.900	0.00	0.00	10599.42	45561.10	1724.93	13430.68
405.000	0.00	0.00	10657.60	45561.10	1724.93	21896.78
410.000	0.00	0.00	10733.82	45561.10	1724.93	8220.60
415.000	0.00	0.00	10748.17	45561.10	1724.93	6285.14
420.000	0.00	0.00	10757.49	45561.10	1724.93	5284.92
427.000	0.00	0.00	10731.98	45561.10	1724.93	4443.77
427.900	0.00	0.00	10716.18	45561.10	1724.93	4361.69
427.950	9900.00	360.00	9776.57	45571.41	1725.30	4357.25
428.250	10000.00	370.34	9694.19	45695.78	1729.87	-845.57
428.500	9868.94	441.87	9667.73	45799.27	1734.10	1678.72
428.750	9980.00	403.03	9652.72	45902.65	1738.50	3377.45
429.000	9970.00	391.51	9644.65	46006.55	1742.64	4436.94
429.250	9950.00	435.70	9643.27	46110.30	1746.94	5363.38
429.500	9934.61	434.09	9638.29	46213.87	1751.47	6121.13
430.000	9873.63	437.77	9633.87	46420.20	1760.56	7291.48
431.000	9791.54	555.45	9639.84	46829.90	1781.25	8924.08
432.000	9634.41	615.81	9642.69	47234.60	1805.65	10055.02
433.000	9690.70	652.05	9652.09	47637.21	1832.06	10901.75
434.000	9662.55	643.50	9657.86	48040.40	1859.05	11545.52
435.000	9791.54	643.50	9655.45	48445.70	1885.87	12115.42
436.000	9704.77	620.33	9651.98	48831.87	1912.20	12596.41
437.000	9728.22	568.50	9645.73	49256.72	1936.96	13059.01
438.000	9953.37	568.50	9649.37	49666.76	1960.65	13433.02
439.000	9826.72	580.82	9663.71	50078.84	1984.59	13780.54
440.000	9843.14	612.39	9663.11	50488.63	2009.45	14162.46
441.000	9864.25	648.84	9662.55	50899.20	2035.73	14450.84
442.000	9749.33	525.33	9680.53	51307.82	2060.19	14725.51
443.000	9894.74	611.83	9689.55	51717.07	2083.88	14985.01
444.000	9885.36	611.27	9691.61	52129.15	2109.36	15189.00
445.000	9843.14	579.69	9690.15	52540.16	2134.15	15434.26
446.010	0.00	0.00	9688.79	52747.28	2146.33	15651.88
450.000	0.00	0.00	10712.48	52747.28	2146.33	10436.69
466.300	0.00	0.00	10754.62	52747.28	2146.33	5395.81

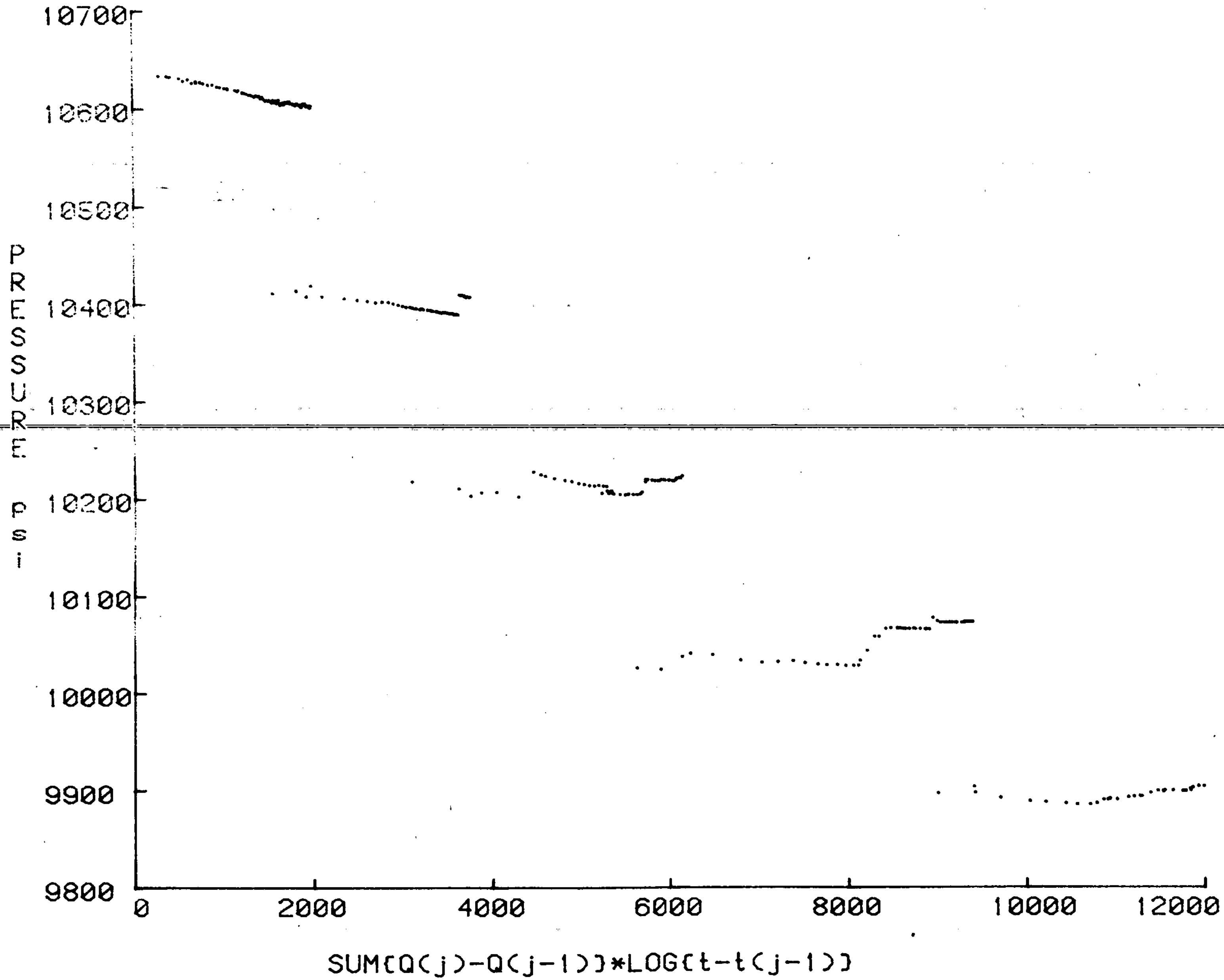

Figure B-1. PLOT OF PRESSURE VERSUS THE FIVE STEPS OF THE MULTIRATE DRAWDOWN TEST. DATA FROM TABLE B-1.

are jogs and offsets in the data, and that the various segments of the plot are not parallel to each other. The pieces of the data that do yield straight-line plots give a variety of slopes and hence kh values. Figure A-11 shows a plot of the data for the first drawdown test and the resulting least-squares fit to the data. Table A-2A gives the results of making such plots for the drawdown and buildup tests using the data in Table B-1.

A similar multirate analysis was performed by Otis Engineering in their well test report. Their analysis was different, however, in that for their summation function they made all the qj's constant and equal to the average flow rate over the plot interval. They then selected small segments out of the plots from which to get the kh. The results they reported are given in Table A-2B. In examining the fits they selected to obtain the reported kh's, we are uncertain as to how the segments were selected for the straight-line fits.

CONCLUSIONS

This annual report concentrates primarily on the technical aspects of the proposed models to explain the excess free gas that occurred during the flow tests of the No. 1 sand in the Edna Delcambre No. 1 geopressured-geothermal well. Since this was the first well tested under the Department of Energy geopressured-geothermal gas program, there was considerable interest in its results. When the well unexpectedly produced natural gas in quantities in excess of the amount dissolved in the brine, there was significant interest in its origin. There was some speculation as to whether this might be a general phenomenon that could be expected in other geopressured-geothermal wells. Several theories were proposed to explain the source of the excess gas, and the Department of Energy funded several studies to further understand the matter. The work funded at IGT was to analyze the data and perform computer simulation modeling of the theories. In particular, the dispersed gas phase model was to be evaluated.

Reservoir engineering analysis of the flow test data provided a basic description of the usual parameters such as pay thickness, porosity, permeability, etc. Some geological structure maps provided a general description of the area around the wells. All of this provided a starting set of data to run numerical reservoir simulator models. With this basic set of data, computer simulation of the hypothesized dispersed gas phase was accomplished by judiciously selecting the initial free gas saturation to a small fraction and composing a relative permeability table with the appropriate shape and cutoff. An attempt was made to simulate the situation where the dispersed gas was initially trapped within the sandstone matrix, but would then begin to be produced as the pressure drawdown around the well bore allowed expansion of the trapped small bubbles to exceed the critical saturation point and then flow as a free gas phase.

The numerical reservoir simulator used for this study was initially the 2D Radial Coning model from Intercomp Inc., Houston, Texas. A telephone data communications link was established so that input and output could be made from Chicago and the problems run on the computer in Houston. There was considerable difficulty in getting both the simulator and the communications link between computers to work, but they eventually worked satisfactorily.

The dispersed gas phase model was initially proposed on the basis of the preliminary test data reported at the Third Geopressured-Geothermal Energy Conference. The model was proposed in a paper given at the conference based on certain assumptions about how such an initial dispersed gas phase might be obtained and how relative permeabilities need to behave to produce the excess gas. Subsequent evaluation of the data and work by others questioned the validity of these assumptions. Further, after a dozen or so computer runs with the reservoir simulator, it became apparent that the dispersed gas phase model was not satisfactory for explaining the occurrence of the excess free gas that began at about 160 hours into the test and in the fourth step of a five-step isochronal drawdown test.

Because the dispersed gas phase model would not satisfactorily explain the occurrence of the excess gas, other models were considered. One was the "champagne bottle" model (by Paul H. Jones) which presumes that rapid production of the brine will lower the water level and pressure around the well bore such that the dissolved gas efervesces from the brine like bubbles in a champagne bottle. This model was quickly determined not to be applicable in the Delcambre well because the pressure gradients and relative permeability effects to create such a phenomenon would be physically impossible in the time frame of the test period in this well. No computer calculations were atempted for this model.

The most likely theoretical model to explain the free gas after the two above models are eliminated is the nearby free gas cap model. Arguments for this model were given by Charles Matthews in a separate DOE report. IGT then attempted to model this free gas hypothesis using the Intercomp Beta II reservoir simulator. This simulator is a full 3-dimensional simulator that would approximately allow for inclusion of the faults and tilt to the reservoir sandstone layer. The manner in which the grid blocks and well bore effects were handled in the computer program left much to be desired. Nevertheless, an approximation to the free gas cap model was set up and run. By adjusting the edge of the free gas cap updip away from the well bore to various distances, it was possible to get a calculated production of excess free gas to match the onset time and approximately the production quantities. A characteristically more correct gas/water ratio plot was obtained. This model fit the flow data better, but did not match the geologic picture. The geologic structure map indicated the nearest gas cap to be about 3000 feet away, whereas the required distance to the free gas cap was about 400 feet.

A different model then became apparent in light of these computer runs, analysis of the gas chemistry data, and additional information about the history of the wells in the area. In an unpublished report by J. Donald Clark of Union Oil, it was noted that the Delcambre No. 4 and No. 4A wells, which were about 400 feet from the subject well, had a history of underground blowouts and mechanical problems which might have resulted in gas from different horizons being brought in contact with the No. 1 sand of the DOE test. Further, the chemical analysis of the gas composition from tests on samples taken during the test showed significant changes in composition with the onset of excess free gas. This effectively confirmed that the excess gas was from a source different than the dissolved gas in the No. 1 sand. These pieces of evidence thus dictated the model of gas from some unknown horizon coming into the test horizon via a pathway along the No. 4 or No. 4A wells and then channeling over to the test well.

This leaky nearby well model is the model believed by IGT at this time to be the most correct model. This model best fits the available experimental data. Further, no new or unusual mechanisms of gas trapping mechanisms or relative permeabilities need to be involved. At the end of this report period, some consideration had been given towards a full 3D computer simulation of the leaky well model, but an adequate way to set up the problem had not been devised. As work continues into the next year of the contract, further consideration will be given to making this computer simulation, along with the economics and evaluations of other wells of interest to DOE.

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