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DOE/NV/10150--2

DE82 005241

MASTER

ANALYSIS OF INITIAL FLOW DATA FROM MG-T/DOE AMOCO FEE NO. 1 WELL

TOPICAL REPORT

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AUGUST 1981

WORK PERFORMED UNDER CONTRACT
DE-AC08-80-NV10150

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ABSTRACT

Analysis of buildup data from the Initial Flow Test indicates that the MG-T/DOE Amoco Fee No. 1 Well penetrates a zone of relatively high permeability (~ 150 md); this high permeability zone, however, extends to a radius of only about 200 ft from the wellbore. The far field permeability (i.e., for r > 200 ft) appears to be rather low (~ 11 md). No reservoir boundaries can be identified from the Initial flow test. The reservoir simulator MUSHRM together with the formation parameters inferred from the buildup data were employed to history match the observed drawdown/buildup pressures and flow data. The calculated buildup pressures closely agree with the measured values; the rather poor agreement between the measured and calculated drawdown pressures is ascribed to the uncertainties in the flow rate data.

I. INTRODUCTION AND BACKGROUND

Since 1975, the U. S. Department of Energy (DOE) has undertaken an extensive deep drilling and well testing program to help evaluate the geopressured resources underlying the Gulf Coast region of the United States. As part of this program, DOE executed a contract with Magma Gulf-Technadril (MG-T) of Houston, Texas to conduct the drilling, completion and testing of one geopressured - geothermal well (i.e., MG-T/DOE AMOCO Fee No. 1 Well) in Cameron Parish, Louisiana. The subject well is located on a five acre test site approximately 15 miles south of Lake Charles, Louisiana. A description of the geology of the prospect area, well completion, test data on cores obtained from the well, and the test plan is given in a report by Durrett and Durham [1981].

In petroleum engineering and groundwater hydrology, flow testing is conducted routinely to diagnose the well's condition and to estimate formation properties. Flow testing of MG-T/DOE AMOCO Fee No. 1 Well is planned in three separate and distinct phases: (A) Phase I - Initial Flow Test - Reservoir Confirmation, (B) Phase II - Reservoir Limit Determination Test (2-3 weeks), and (C) Phase III - Long Term Demonstration Flow Testing at Commercial Design Rates (~ 6 months). Initial flow testing of the MG-T/DOE AMOCO Fee No. 1 Well was conducted from June 19, 1981 to June 30, 1981 with flow rates upto 4200 Bbl/D in an effort to evaluate formation parameters for the geopressured sand perforated at 15,387 ft to 15,414 ft depth. The relevant data for the Initial Flow Test were supplied to Systems, Science and Software by Mr. Larry Durrett of Magma Gulf-Technadril. The present report is concerned with the analysis of the pressure/flow data obtained during the Initial Flow Test.

The MG-T/DOE AMOCO Fee No. 1 Well has 5-1/2 inch production liner perforated over the interval 15,387 ft - 15,414 ft (mean depth = 15,400.5 ft) in Miogyp sand. Bottom-hole pressure was measured using the Hewlett Packard quartz crystal gauge. Bottom-hole temperature (~ 299°F) was recorded prior to the start of the flow test. Independent surface pressure recording capability was also available. A Halliburton turbine pulse meter was used to record brine flow rates; the turbine flow meter, however, was about 250 B/D off zero, and could not be zeroed (see Appendix for details). The gas production rate was measured by flowing the gas through an orifice plate.

The pressure tool was set at a depth of 15,337 ft. The initial pressure at 15,337 ft datum was measured at 12,053 psi. Assuming a static pressure gradient of 0.46 psi/ft, the initial reservoir pressure (i.e., at 15,400.5 datum) becomes 12,082 psi. The brine produced from this well has a total dissolved solids content of 165,000 ppm (i.e., 0.1487 by mass). With p = 12,082 psi, T = 299°F, and S = 0.1487, the S^3 methane/brine equation-of-state yields a methane content of 23.7 SCF/STB at saturation. The brine produced from the 15,387 - 15,414 ft Miogyp sand is, however, substantially less than saturated with respect to natural gas (i.e., 9-15 SCF/STB rather than 23.7 SCF/STB). In the following, it will be assumed that the methane content of the reservoir fluids is 14.7 SCF/STB.

The main purpose of this report is to analyze pressure drawdown and buildup data to evaluate formation parameters. For purposes of analysis, it is convenient to reduce the brine flow data to standard conditions; the procedures utilized to convert the flow data are discussed in the Appendix. We note here that the indicated changes in flow rate do not correspond to any noticeable changes in the pressure drawdown data. For this reason, we believe that the pressure drawdown data are of limited utility; we will accordingly concentrate on the analysis of the buildup data. It is appropriate to briefly discuss here the contents of the rest of this report. In Section II, we utilize conventional petroleum engineering/hydrology techniques to analyse buildup data to estimate permeability, skin factor and any indications of faults/mobility changes in the perforated zone. Analysis of buildup data indicates that the MG-T/DOE AMOCO Fee No. 1 Well penetrates a zone of relatively high pemeability (~ 150 md); this high permeability zone, however, extends to a radius of only about 200 ft from the well. The far field permeability (i.e., for r > 200 ft) appears to be rather low (~ 11 md). No other reservoir boundaries/mobility changes can be identified from the initial test data. The estimated parameters from the buildup analysis are employed in the S^3 geopressured - geothermal reservoir simulator (MUSHRM) to perform calculations to history match the observed drawdown/buildup pressures and flow rates (Section III). Although the computed final flowing pressure displays excellent agreement with the observed final flowing pressure, the computed drawdown pressures show a generally poor agreement with the observations. This discrepancy between the computed and the observed drawdown pressures can be ascribed to uncertainties in the flow data. The calculated buildup pressures, on the other hand, are in excellent agreement with the observations.

II. ANALYSIS OF BUILDUP DATA

The MG-T/DOE AMOCO Fee No. 1 Well was flowed at varying rates from 18:18 hours on June 19, 1981 to 20:03 hours on June 22, 1981 for a total of 73.75 hours. For purposes of analysis, it is convenient to average the flow rate data over the following two periods (see Appendix):

A. $0 \text{ min} \leq t \leq 3942 \text{ min}$
   $q_c \sim 3420$ STB/D

B. $3942 \text{ min} \leq t \leq 4425 \text{ min}$
   $q_c \sim 2610$ STB/D

Bottom-hole pressures were monitored continuously during the entire flow period. Subsequent to well shutin, pressure buildup was recorded for approximately 184 hours (i.e., from 20:03 hours on June 22, 1981 to 12:13 hours on June 30, 1981). Since the reservoir fluid is undersaturated with respect to natural gas, it is unlikely that the flow stream, at bottom hole conditions, would contain any free gas. Consequently, it is felt that classical single-phase analysis methods should be sufficient for analyzing the pressure buildup data.

Analysis methods for buildup tests with widely varying flow rates before shutin are described by Earlougher [1977]. For infinite - acting systems, a plot of shutin pressure p_{ws} versus a reduced time

$$\sum_{j=1}^{N} (q_j / q_N) \log \frac{t_N - t_{j-1} + \Delta t}{t_N - t_j + \Delta t}$$

should yield a straight line with slope m. Here q_j is the flow rate during the time interval $t_{j-1} < t < t_j$, t_o is 0, q_N is the final flow rate prior to shutin at $t = t_N$, and Δt is the buildup time. Permeability k and skin factor s are given by:

$$\frac{kh}{\mu} = \frac{162.6\ q_N B}{m}$$

$$s = 1.151 \left[\frac{p_{1\ hr} - p_{wf}}{m} - \log \frac{k}{\phi\ \mu\ C_T\ r_w^2} + 3.23 \right]$$

where

B = formation volume factor

h = formation thickness, ft

μ = fluid viscosity, cp

p_{wf} = final pressure before shutin, psi

$p_{1\ hr}$ = shutin pressure at $\Delta t \sim 1$ hour extrapolated from the straight line, psi

ϕ = formation porosity

r_w = well radius, ft

C_T = total formation compressibility (= $((1-\phi)/\phi)\ C_m + C_f$), psi^{-1}

C_m = uniaxial formation compressibility, psi^{-1}

C_f = fluid compressibility, psi^{-1}.

In the absence of measurements, we will assume that the uniaxial formation compressibility is of the order of 1×10^{-6} psi^{-1}. With $C_f \sim 3 \times 10^{-6}$ psi^{-1} and $\phi = 0.22$, we obtain for C_T:

$$C_T = \frac{1 - 0.22}{0.22} 10^{-6} + 3 \times 10^{-6} \sim 6.5 \times 10^{-6} \text{ psi} \quad .$$

The buildup pressure data versus reduced time are plotted in Figures 1 and 2. It can be seen from Figures 1 and 2 that two straight lines can be drawn through the buildup data; these straight lines have slopes of 32.1 psi/cycle and 430.5 psi/cycle respectively. The first straight line segment (slope $\simeq$ 32.1 psi/cycle) yields for near wellbore permeability:

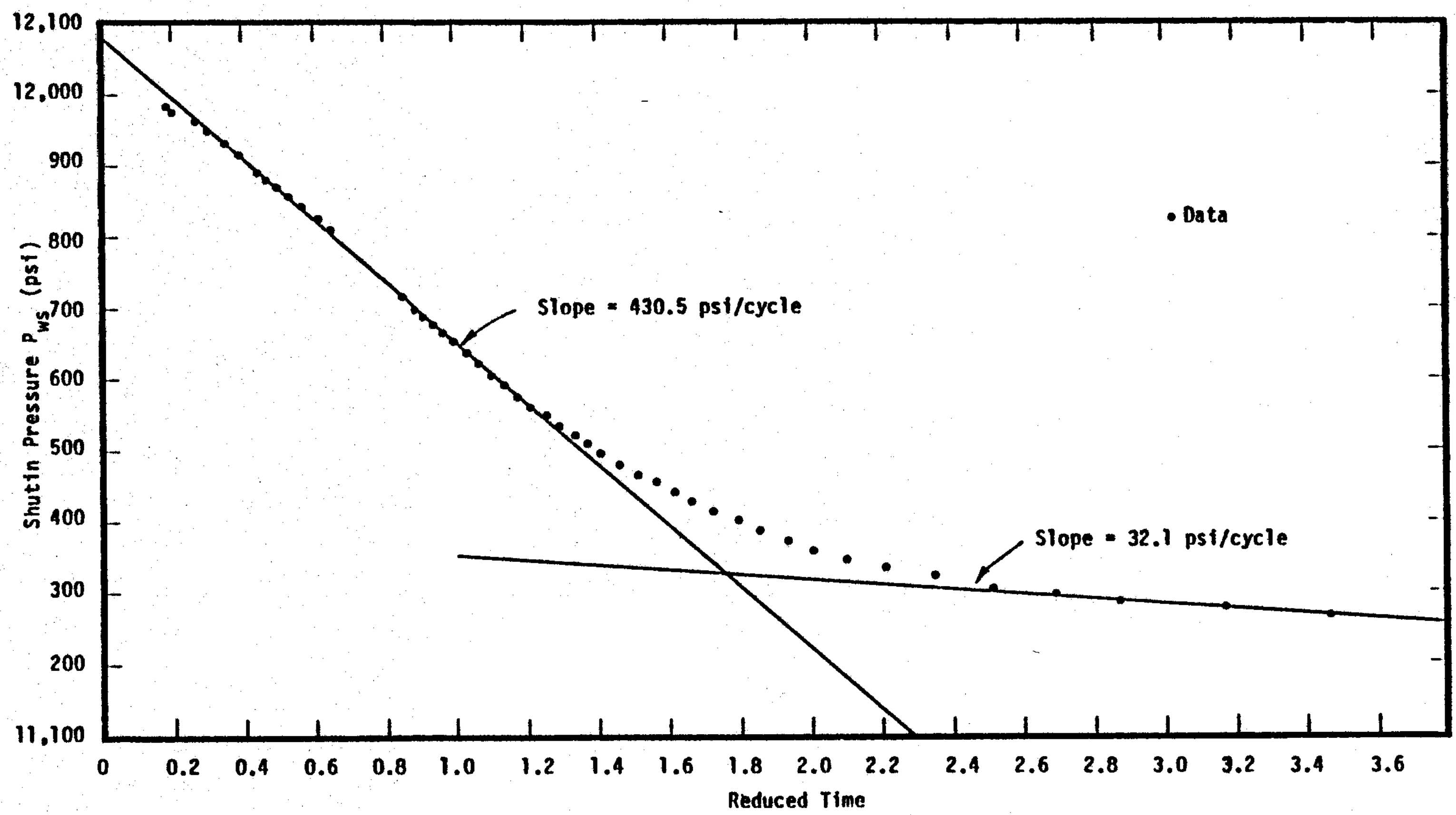

Figure 1. Buildup Data for MG-T/DOE Amoco Fee No. 1 Well (Initial Flow Test).

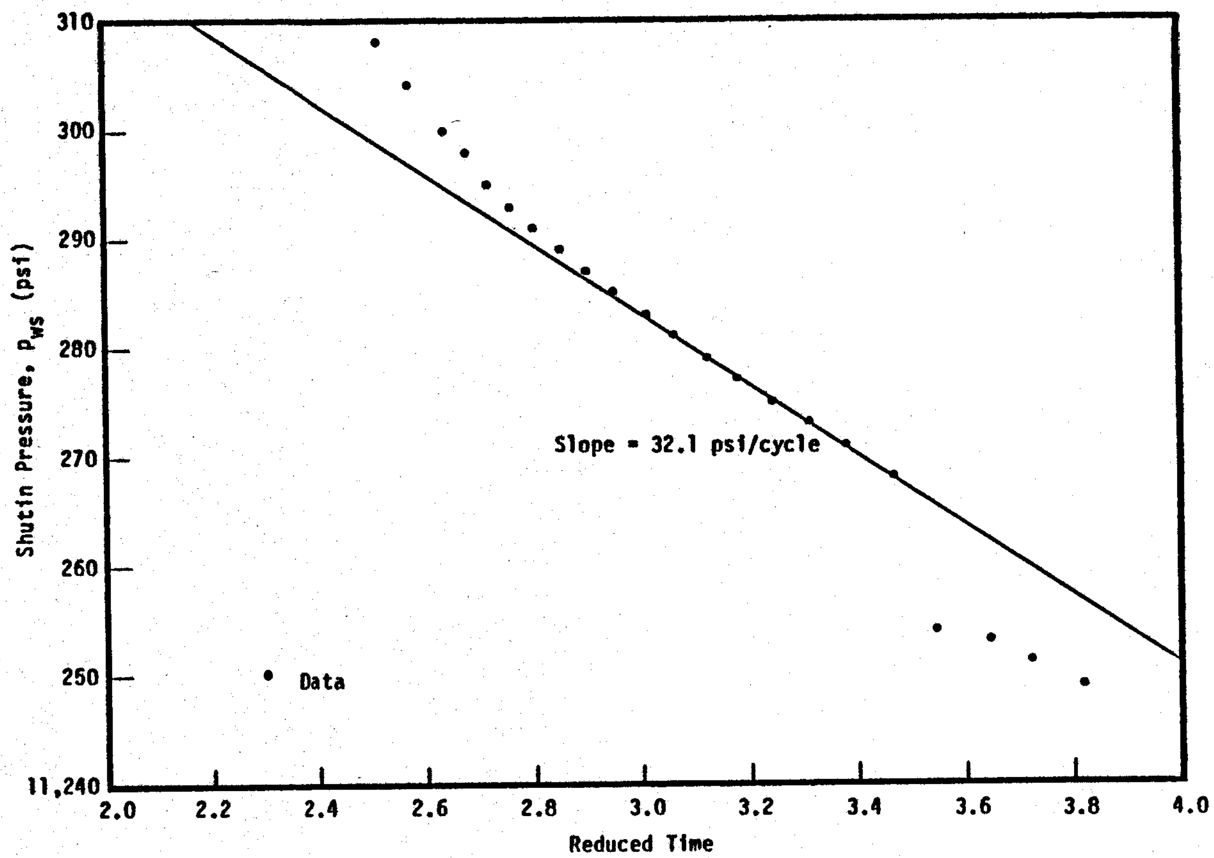

Figure 2. Early-Time Buildup Data for MG-T/DOE Amoco Fee No. 1 Well (Initial Flow Test).

$$\frac{kh}{\mu} = \frac{162.6\ q_N B}{m} = \frac{162.6 \times 2610 \times 1.041}{32.1} \simeq 13,760\ \frac{\text{md ft}}{\text{cp}}$$

$$k = \frac{13760 \times \mu}{h} = \frac{13760 \times 0.296}{27} \simeq 150.9\ \text{md}$$

With $p_{1\ hr}$ = 11,310 psi and p_{wf} = 11,141 psi, we obtain for skin factor s:

$$s = 1.151 \left[\frac{p_{1\ hr} - p_{wf}}{m} - \log \frac{k}{\phi\ \mu\ C_T\ r_w^2} + 3.23\right] \simeq -1.54$$

The pressure buildup data start deviating from the first straight line segment at approximately $\Delta t \simeq 0.15$ hours. The radius investigated by the buildup test at this point in time is approximately given by (see Earlougher [1977]):

$$r_{inv} = \left(\frac{0.00105\ k\ \Delta t}{\phi\ \mu\ C_T}\right)^{1/2} = \left(\frac{0.00105 \times 150.9 \times 0.15}{0.22 \times 0.296 \times 6.5 \times 10^{-6}}\right)^{1/2} \simeq 240\ \text{ft}$$

This implies that the permeability obtained from the first straight line segment applies within a circular region centered at the well of radius (r_{trans}) approximately equal to 240 ft. In the following, we will present an alternative procedure for estimating r_{trans}.

The second straight line segment has a slope of 430.5 psi/cycle. This yields for "far-field" permeability:

$$\frac{kh}{\mu} = \frac{162.6 \times 1.041 \times 2610}{430.5} = 1026\ \frac{\text{md-ft}}{\text{cp}}$$

$$k = \frac{1026 \times 0.296}{27} \simeq 11.25\ \text{md}$$

We will now assert that the effect of the high permeability zone near the wellbore can be represented by an equivalent skin s_{eq}.

With $p_{1\,hr}$ = 11,153 psi (extrapolated from the second straight line segment) and p_{wf} = 11,141 psi, we obtain for s_{eq}:

$$s_{eq} = 1.151 \left[\frac{11,153 - 11,141}{430.5} - \log \frac{11.25}{0.22 \times 0.296 \times 6.5 \times 10^{-6}\,(5.5/24)^2} + 3.23\right] \simeq -6.27$$

The equivalent skin factor is related to "near wellbore" permeability k_1, "far-field" permeability k_2, transition radius r_{trans}, and wellbore radius r_w as follows:

$$\frac{k_2}{k_1} = \frac{s_{eq}}{\ell n \left(\frac{r_{trans}}{r_w}\right)} + 1$$

With k_1 = 150.9 md, k_2 = 11.25 md, s_{eq} = - 6.27 and r_w = (5.5/24 ft), we obtain for r_{trans}:

$$r_{trans} = \exp\left[\frac{s_{eq}}{(k_2/k_1 - 1)} + \ell n\, r_w\right] \simeq 200 \text{ ft} \quad .$$

The above value for r_{trans} (200 ft) is of the same order as that calculated on the basis of the observed pressure deviations from the first straight line segment.

The principal results of the preceding analysis can be summarized as follows:

(i) The near wellbore permeability is about 150 md, and applies within a radius of approximately 200 ft from the wellbore. The far-field permeability (radius > 200 ft) is, however, only about 11 md.

(ii) The well is slightly stimulated (skin factor s = - 1.54). The negative skin factor may represent the presence of a very high permeability zone in the immediate vicinity of the wellbore.

(iii) No reservoir boundaries can be inferred from the initial test.

III. HISTORY - MATCH CALCULATIONS

In this section, we will employ the formation properties derived from the buildup data (Section II) in the reservoir simulator MUSHRM to match the observed drawdown/buildup pressures and flow rates. For simulation purposes, the reservoir is regarded to be a right circular cylinder with height h = 27 ft and radius R = 3,000 ft. The radius R is chosen sufficiently large that no signal reaches the outer boundary of the reservoir for the drawdown/buildup times of interest. [The radius investigated r_{inv} during buildup is approximately given by:

$$r_{inv} = \left(\frac{0.00105\ k\ \Delta t}{\phi\ \mu\ C_T}\right)^{1/2} = \left(\frac{0.00105 \times 11.25 \times 184}{0.22 \times 0.296 \times 6.5 \times 10^{-6}}\right)^{1/2}$$

$$\sim 2270 \text{ ft.}]$$

The reservoir is represented by a 50 zone ($\Delta r_1 = \Delta r_2 = \ldots = \Delta r_{10} = 50$ ft; $\Delta r_{11} = \Delta r_{12} = \ldots = \Delta r_{40} = 60$ ft; $\Delta r_{41} = \Delta r_{42} = \ldots = \Delta r_{50} = 70$ ft) radial grid. The outer boundary is assumed to be impermeable and insulated; this boundary condition does not affect the result. The production well is located at the geometric center of the first grid block.

The reservoir rock is taken to be a sandstone with the following properties:

Rock grain density, ρ_r = 165.4 lbm/ft^3 (= 2.65 x 10^3 kg/m^3)

Initial porosity, ϕ_0 = 0.22

Rock grain specific heat, C_{vr} = 0.23 Btu/lbm°F ($\simeq$ 0.963 kJ/kg°C)

Initial permeability, k_0 =

(i) 150.9 md ($\simeq$ 148.93 x 10^{-15} m^2) for $0 \leq r \leq 200$ ft

(ii) 11.25 md ($\simeq$ 11.10 x 10^{-15} m^2) for 200 ft $< r \leq 3000$ ft.

Uniaxial formation compressibility, C_m = 10^{-6} psi^{-1} (~ 0.145 x 10^{-9} Pa^{-1})

Skin factor, s = - 1.54

A drop in pore pressure causes a reduction in porosity ϕ and the permeability k. The instantaneous porosity ϕ and permeability k are given by the following relations:

$$\frac{\partial \phi}{\partial t} = (1-\phi)\, C_m\, \partial p/\partial t$$

$$k = k_o \left(\frac{\phi}{\phi_o}\right)^3 \left(\frac{1-\phi_o}{1-\phi}\right)^2$$

where

p = fluid pressure,

t = time.

Although in the present case no gas is expected to evolve out of solution, we give in Table 1 relative permeabilities for water/gas to illustrate the effects of the presence of any free gas in the pores. These relative permeabilities are based on measurements reported by Roberts [1980] on several cores obtained from the Pleasant Bayou (Brazoria County, Texas) wells. Table 1 shows that the gas phase remains essentially immobile for $S_g \leq 0.235$ ($\simeq$ residual gas saturation), and the liquid-phase relative permeability declines dramatically with small amounts of free gas in the pores.

Table 1
RELATIVE PERMEABILITIES

Free Gas Saturation (S_g)	Liquid Relative Permeability (k_{rw})	Gas Relative Permeability (k_{rg})
0	1	0
0.005	0.71	10^{-4}
0.1	0.49	2×10^{-4}
0.235	0.12	5×10^{-4}
1	0	1

The reservoir fluid is a partially methane saturated brine with dissolved solids by mass of S = 0.1487. (This corresponds to a TDS of approximately 165,000 ppm at the standard conditions. See Appendix for details.) The initial pore pressure, temperature and methane mass fraction at a depth of 15,400.5 ft are p = 12,082 psi (= 833.02 bars), T = 299°F ($\simeq$ 148.33°C), and C = 0.0016 ($\simeq$ 14.7 SCF/STB). The reservoir is produced by a single 5.5 in well; the production history imposed in the simulation is given in Table A-2 of the Appendix. In the following, all pressures are referred to the 15,337 ft datum; the initial pressure at this datum is 12,053 psi($\simeq$ 831.03 bars).

Figure 3 compares the calculated bottom-hole pressures with observed drawdown pressures. The agreement between the calculated and observed pressures, with the exception of the very early and very late drawdown times, is rather poor. This disagreement between the calculated and the measured drawdown pressures is really not surprising in view of the uncertainties in the flow rate data.

The observed and calculated buildup pressures are compared in Figure 4. In general, there is good agreement between the measured and simulated buildup pressures. The latter observation together

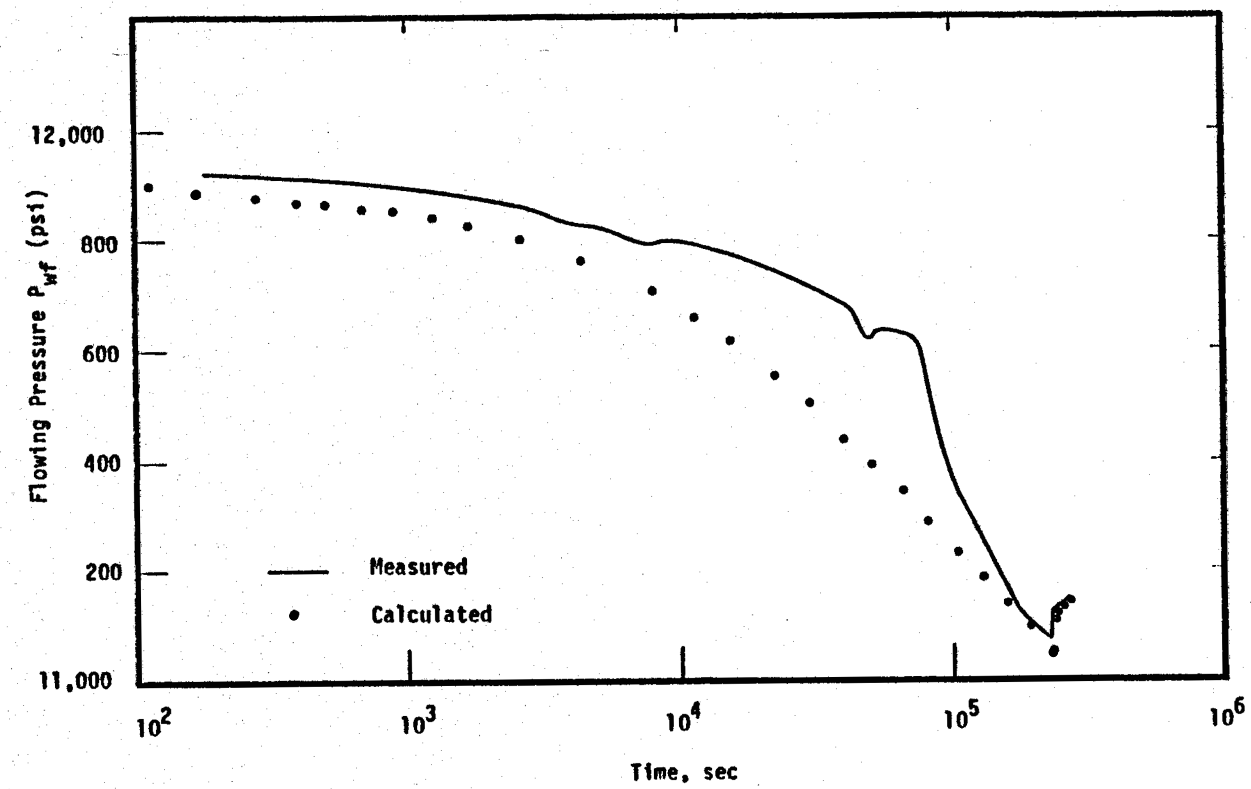

Figure 3. Comparison of Calculated Flowing Pressures with Measured Flowing Pressures for Initial Flow Test of MG-T/DOE Amoco Fee No. 1 Well. Abcissa Denotes Time from the Start of the Flow Test.

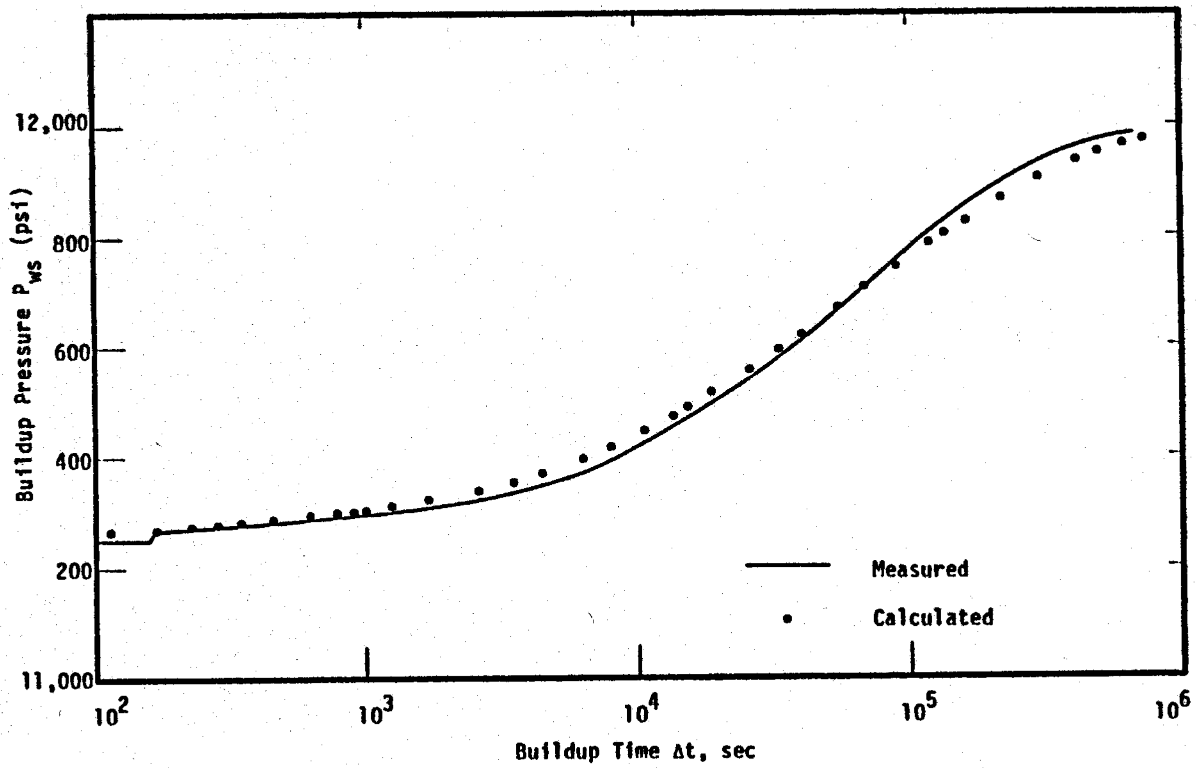

Figure 4. Comparison of Calculated Buildup Pressures with Measured Buildup Pressures for Initial Flow Test of MG-T/DOE Amoco Fee No. 1 Well. Abcissa Denotes Time from the Start of Shutin.

with the good agreement between the calculated and measured pressure data at late drawdown times supports our view that the flow rate data are suspect.

The total calculated brine and methane production during the initial flow test are 1.805×10^6 kg ($\simeq$ 10,239 STB) and 2.893×10^3 kg ($\simeq 1.504 \times 10^5$ SCF) respectively. The calculated brine production is identical with the estimated actual production. The calculated methane content of the produced brine is approximately 14.7 SCF/STB ($\simeq$ assumed methane content of the reservoir fluids).

IV. CONCLUDING REMARKS

Analysis of buildup data from the Initial flow test indicates that the MG-T/DOE AMOCO Fee No. 1 Well penetrates a zone of relatively high permeability (~ 150 md); this high permeability zone, however, extends to a radius of only about 200 ft from the wellbore. The far-field permeability (i.e., for r > 200 ft) appears to be rather low (~ 11 md). No reservoir boundaries can be identified from the Phase I - Initial Flow Test; furthermore, the methane content of the reservoir fluid is somewhat uncertain (9 - 15 SCF/STB). The reservoir simulator MUSHRM together with the formation parameters inferred from the buildup data were employed to history match the observed drawdown/buildup pressure and flow data. The calculated buildup pressures closely agree with the measured values; the rather poor agreement between the measured and calculated drawdown pressures is ascribed to the uncertainties in the flow rate data. Recently, Phase II testing of the subject well has been completed; the data from this test phase should be helpful in identifying atleast some of the reservoir boundaries, and further refining the estimates for formation parameters.

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APPENDIX

INITIAL FLOW TEST DATA NOTES

I. Completed Interval: 15,387 - 15,414 ft
Net Sand Thickness: 27 ft
Mean Reservoir Depth: 15,400.5 ft
Rock Porosity ϕ: 0.22
Well Radius r_w = 2.75 in (0.06985 m)

II. Since all pressures are measured at 15,337 ft datum, this datum is employed in most of the calculations in this report. Pressures at a datum other than 15,337 ft are calculated by using a correction factor of 0.46 psi/ft.

III. Initial Pressure Data:

p_i (15,387 ft, measured) = 12,053 psi ($\simeq$ 831.03 bars)
p_i (15,400.5 ft, calculated) = 12,082 psi ($\simeq$ 833.02 bars)

IV. Initial Reservoir Conditions (15,400.5 ft, datum):

$p_i \simeq$ 12,082 psi ($\simeq$ 833.02 bars)
T_i (measured) = 299°F ($\simeq$ 148.33°C)
S (salinity by mass) $\simeq$ 0.1487
C (methane content): see below.

V. At standard conditions (p = 14.7 psi, T = 60°F) with S = 0.1487, the S^3 equation-of-state gives

ρ_{Brine} = 1.1088 gm/cm^3 ($\simeq$ 176.287 kg/STB)
Total Dissolved Solids = S $\rho_{Brine} \simeq$ 165,000 ppm
Specific Volume of Methane = 52.0 SCF/kg

VI. Methane Content of Resevoir Fluids

Given p_i, T_i and S (see IV above), the methane mass fraction at saturation α_{sat} may be calculated by using the S^3 equation-of-state data. This yields:

$$\alpha_{sat} \doteq 0.257465 \times 10^{-2}$$

Thus, at saturation we have:

$$\frac{\text{SCF of Methane}}{\text{STB}} \simeq \frac{52.00 \times 0.257465 \times 10^{-2}}{5.6726 \times 10^{-3}(1. - 0.257465 \times 10^{-2})} \doteq 23.7$$

The brine produced during the initial flow test was substantially less than saturated with respect to methane (i.e., 9-15 SCF/STB rather than 23.7 SCF/STB at saturation under initial reservoir conditions). In view of this, we will assume that the methane mass fraction of reservoir fluids C is approximately equal to 0.16×10^{-2} (i.e., ~ 14.7 SCF/STB).

VII. Reservoir Fluid Density, Pressure Gradient and Formation Volume Factor

With p_i = 12,082 psi, T_i = 299°F, S = 0.1487 and C = 0.16×10^{-2}, S^3 equation-of-state data yields:

Initial Fluid Density, ρ_i = 1.0656 gm/cm^3 ($\doteq$ 169.421 kg/bbl)

Pressure Gradient = 0.462 psi/ft

Formation Volume Factor B = 176.287/169.421 $\doteq$ 1.041

VIII. At reservoir conditions, the S^3 equation-of-state gives the following value for fluid viscosity: $\mu = 0.296$ cp

Reduction of Flow Data to Standard Conditions

During the initial flow test, brine flow was recorded by a Halliburton turbine flow meter; the total brine production during the three-day test was 11,324 barrels. However, it should be noted that the flow meter was approximately 250 B/D off zero, and could not be zeroed; the actual brine production is estimated to be 10,573 barrels rather than 11,324 barrels. In the following, the indicated flow rates were accordingly adjusted to give a total brine production of 10,573 barrels. In order to convert the measured barrels Q_{meas} (actually the adjusted brine production) to stock-tank barrels, the following procedure was employed:

1. For a given time interval, select the average pressure P (psi) and temperature T (°F) at which the flow data was recorded. (According to information supplied to us, pressure P and temperature T averaged around 4000 psi and 214°F respectively during the initial flow test.)

2. Given P and T, use the S^3 equation-of-state to calculate the liquid density ρ(kg/bbl), and the mass fraction of the methane (α_s) dissolved in the brine.

3. The mass of the brine M_B (less dissolved methane) is given by Q_{meas} $(1-\alpha_s)\rho$. Given M_B, the brine volume at standard conditions is calculated by dividing M_B by the brine density at standard conditions (~ 176.287 kg/STB).

Table A-1 gives the reduced flow data for the initial flow test.

The pressure drawdown and production rate data are plotted in Figure A-1. It is obvious from Figure A-1 that something is wrong; the indicated changes in flow rate (with the exception of the last change on 6/22/1981 at about 12:00 hours) are not reflected in the pressure response. It, therefore, appears that the flow rate data are of doubtful validity. Accordingly, we will average the flow data of Table A-1 over two time intervals (i.e., 1. From the start of flow test to 12:00 hours on 6/22 and 2. From 12:00 hours on 6/22 to the end of the flow test). Also, we require mass withdrawal rate from the reservoir. Given Q_c (STB) from Table A-1, mass withdrawal rate can be computed as follows:

1. Calculate brine flow rate q_c at standard conditions by dividing Q_c by the time interval (days).

2. Given q_c (STB/D), calculate brine mass flow rate $\dot{M}_B$ by

   $$\dot{M}_B = q_c \times 176.287/(24 \times 3600) \text{ kg/sec}$$

3. To obtain the total flow rate $\dot{M}_T$ (kg/sec) divide $\dot{M}_B$ by (1-C), where C($\simeq$ 0.0016) denotes the mass fraction of methane at reservoir conditions.

Table A-2 gives the averaged mass flow data.

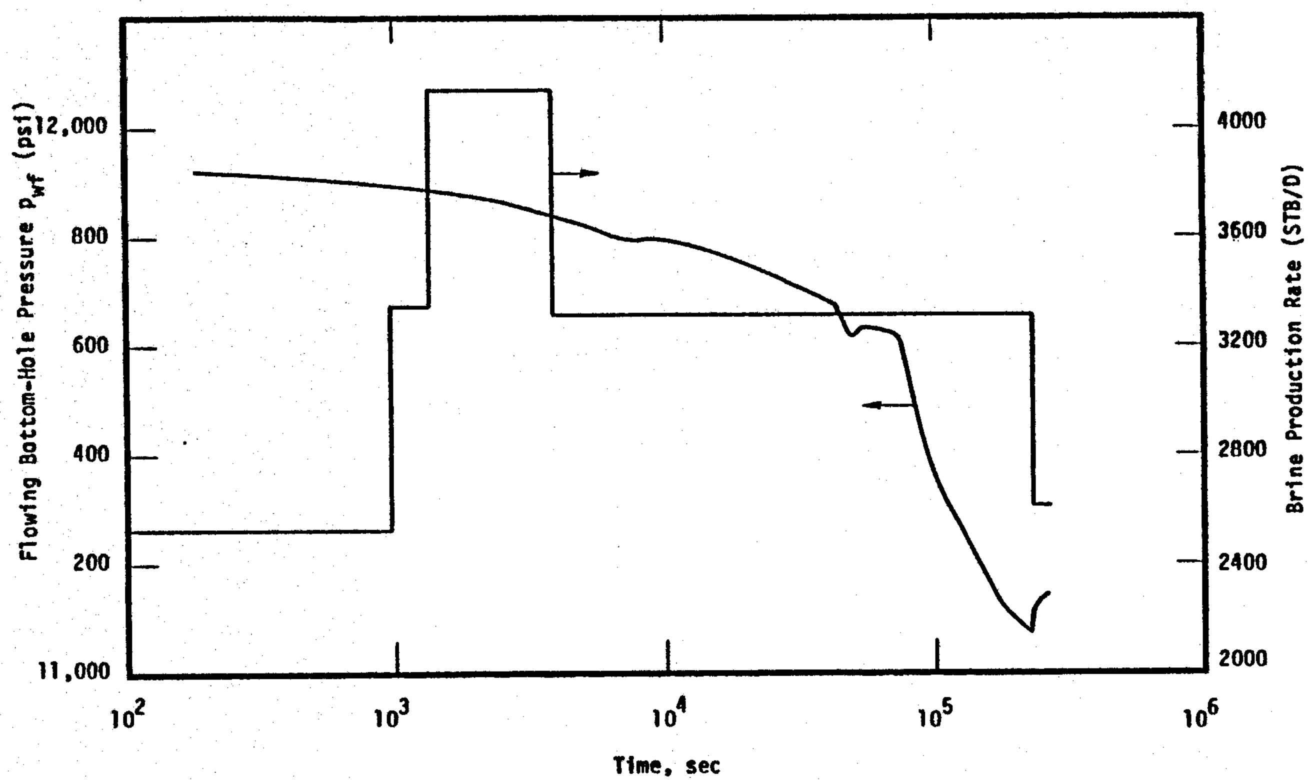

Figure A-1. Pressure Drawdown and Brine Production Rate Data for Initial Flow Test of MG-T/DOE Amoco Fee No. 1 Well. Abcissa Denotes Time from the Start of Flow Test at 18:18 Hours on 6/19/1981.

Table A-1

FLOW DATA FOR INITIAL FLOW TEST

Date/Hours	t, Minutes	Q_{meas} bbl	P(psi) T(°F)	$(1-\alpha_s)\rho$ kg/Bbl	$\dot{M}_B$ kg	Q_c STB	q_c STB/D	$\sum Q_c$
6/19 18:18	0	293	4000	170.717	50,020	284	2522	284
6/19 21:00	162		214					
6/19 21:00	162	144	4000	170.717	24,583	139	3347	423
6/19 22:00	222		214					
6/19 22:00	222	1250	4000	170.717	213,396	1211	4150	1634
6/20 05:00	642		214					
6/20 05:00	642	1835	4000	170.717	313,266	1777	3554	3411
6/20 17:00	1362		214					
6/20 17:00	1362	6147	4000	170.717	1,049,397	5953	3322	9364
6/22 12:00	3942		214					
6/22 12:00	3942	904	4000	170.717	154,328	875	2610	10,239
6/22 20:03	4425		214					
Totals	73.75 hours	10573			1,804,990	10239		10,239

Table A-2

AVERAGED FLOW DATA FOR INITIAL FLOW TEST

Date/Hours	t, min	Q_c, STB	q_c, STB/D	$\dot{M}_B$, kg/s	$\dot{M}_T$, kg/s	$\sum Q_c$
6/19 18:18	0	9364	3420	6.979	6.990	9364
6/22 12:00	3942					
6/22 12:00	3942	875	2610	5.325	5.334	10,239
6/22 20:03	4425					
Totals	73.75 hours	10239				10,239