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Analysis of Flow Data from The DOW/DOE L. R. Sweezy No. 1 Well

TOPICAL REPORT

S.K. GARG and T.D. RINEY

MARCH 1984

**Work Performed Under Contract
DE-AC08-80-AV10150**

**Prepared for
Department of Energy
Nevada Operations Office**

MASTER

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ABSTRACT

This topical report presents the results of S-CUBED's work to-date on the analysis and simulation of flow and pressure data from the testing of the L. R. Sweezy No. 1 well. Analysis of drawdown data indicates a formation permeability of around 126 md, and a flow-rate dependent skin. The conventional analysis techniques were, however, found to be inadequate for analyzing the buildup data. The formation properties inferred from the drawdown were used together with the CHARGR simulator to simulate the production history of the Sweezy well. The calculated drawdown response displays excellent agreement with the measured data; such agreement was, however, not obtained for the buildup phase of the tests. Parametric calculations designed to investigate the anomalous buildup response suggest that this behavior may be the result of stress-induced hysteresis in formation properties, shale recharge, and long-term formation creep. A research program to further characterize the observed pressure response is outlined.

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I. INTRODUCTION

Since 1975, the U.S. Department of Energy (DOE) has funded an extensive deep drilling and well testing program to evaluate the geopressured geothermal resource underlying the Gulf Coast region of the United States. As part of the DOE Geopressured Geothermal Design Wells Program, the Dow Chemical Company (DOW) undertook the drilling, completion and testing of one geopressured production well (i.e., DOW/DOE L. R. Sweezy No. 1) and one brine disposal well in the Parcperdue Field. This field, consisting of a small confined geopressured reservoir, is located in Vermilion Parish, Louisiana. A description of the geology of the field, well completion, log data, core data and the test plan is given in a report by DOW [1982].

The well test program for the L. R. Sweezy design well was planned with the primary objective of determining the production characteristics of a well-defined geopressured reservoir from initial fluid withdrawal to final depletion. Secondary objectives included observations of the changes in the nature of the fluids as production proceeded, and evaluation of the reservoir mechanisms producing the fluids. To reach these objectives, DOW planned to produce the reservoir through a series of short-term drawdown and buildup tests followed by long-term production testing. The well was to have been flowed at 20,000 to 25,000 bbls/day to obtain sufficient data within six to nine months to permit extrapolation of the reservoir depletion curve. It became apparent during the early tests, however, that production had to be kept below ~10,000 bbls/day to avoid excessive sand production. Sand production ranged from 200 lbs/day to as much as 27,000 lbs/day. It was not possible to unambiguously define the depletion behavior of the reservoir prior to the time that the well was shut down as a consequence of sand production problems.

S-CUBED received the DOW Daily Reports on the L. R. Sweezy well and the relevant flow rate/bottom hole pressure data from Otis Engineering Corporation. Otis performed the wellsite reservoir analysis under a subcontract with DOW. S-CUBED performed independent analysis of the well test data and performed numerical reservoir simulations of the tests under a direct contract with DOE. This report summarizes the S-CUBED analysis of the L. R. Sweezy design well flow tests.

It is appropriate to briefly outline here the contents of the rest of this report. The well geology and test instrumentation are described in Section II. The well test data are discussed next (Section III). In Section IV, we utilize conventional petroleum engineering/hydrology techniques to analyze pressure transient data. The buildup data from the Sweezy well exhibit an anomalous behavior, and it is impossible to identify proper straight line segment(s) on the Horner plot(s). The available drawdown data from early flow tests were, therefore, used to estimate formation permeability, skin factor, and indications of flow barriers. The reservoir depletion behavior was obtained by extrapolating the buildup data to infinite shutin time. The estimated parameters from the analysis of Section IV were used in a geopressured-geothermal reservoir simulator to perform calculations to history-match the observed drawdown/buildup pressures and flow rates (Section V). The calculated drawdown pressures display an excellent agreement with the observations. The computed buildup pressures on the other hand generally lie below the data. The reasons for disagreement between the observed and computed buildup pressures are explored in Section VI; it is suggested that the anomalous buildup response is due to the nonlinear nature of the reservoir diffusivity. The diffusivity appears to much larger during buildup than during drawdown. The physical mechanism(s) responsible for this apparent change in diffusivity are at present not fully clear. Finally in Section VII, a research program for future data gathering and analysis is outlined.

II. BACKGROUND

The fault block penetrated by the L. R. Sweezy No. 1 design well (see Figure 1) was mapped by DOW on the basis of data from seven seismic lines that traversed the area and information from eight nearby wells. The total area of the fault block was estimated by DOW to be ~ 939 acres. The objective sand, identified as the Cib Jeff sand, occurs at a depth of ~ 13,340 ft within the upper Frio formation. The net sand thickness in the fault block varies from 20 ft in the northeast to 80 ft toward the southwest with an average value of ~ 50 ft (Figure 2):

The DOW/DOE L. R. Sweezy No. 1 geopressured geothermal production well was spudded on January 5, 1981, drilled to a total depth of 13,600 ft and logged on April 12, 1981. The entire section below 11,800 ft is shale with the exception of three sands, each 100 ft or less in thickness, occurring at depths of 11,920 ft, 12,305 ft and the objective sand at 13,341 ft. Figure 3 shows the log of the Cib Jeff sand interval that was run in the open hole. Subsequent to logging the well, mechanical problems required that the original hole be sidetracked from 12,721 ft to a total depth of 13,612 ft. This hole was cased to a depth of 13,534 ft and perforated from 13,349 ft to 13,388 ft and from 13,395 ft to 13,406 ft (Figure 4).

Two 60 ft x 4 in. conventional cores were obtained from the well at a depth of 13,340 ft to 13,460 ft. Conventional porosity and permeability measurements performed by Core Laboratories gave an average porosity of 0.28 (but 0.27 over the perforated sand interval) and an average Bench Air Permeability of 3700 md.

Figure 1. Structure Map of Parcperdue Area (Dow [1982])

Figure 2. Net Sand Isopach of Parcperdue Area (Dow [1982])

Figure 3. ISF Log of C1b Jeff Sand (Dow [1982])

DOV CHEMICAL/D.O.E.
L. R. SWEETZ NO. 1
GRAVEL-PACK AND COMPLETION DETAIL

ITEM	DESCRIPTION	O.D. (IN)	I.D. (IN)	LENGTH (FT)	TOP (FT)
TUBING					
Elevation (Rotary to THF)				20.75	00
1	FHC 9' x 5 1/2" TCN Tubing Hanger			.88	20.75
2	1 Jt. 5 1/2", 23#/ft. S-95, LT&C Mod. Tbg. Internally coated w/TK-2C	5.50	4.54 (drift)	99.80	21.63
	5 Pcs Jts., 5 1/2", 23#/ft. S-95, Mod. Tbg. Internally coated w/TK-2C	5.50	4.54	10.05	61.43
				8.09	
				6.07	
				4.10	
				2.52	
	7 Jts. 5 1/2" tbg. as above	5.50	4.54	281.13	92.26
3	Otis Flow Coupling 5 1/2", EXS LT&C Mod.	6.10	4.78	10.00	373.39
4	Otis 'R' Landing Nipple, PXP	5.50	4.313	1.03	383.39
5	254 Jts., 5 1/2" Tbg. as above			10,049.42	324.42
6	Otis Flow Coupling, 5 1/2", EXS LT&C Mod	6.10	4.78	9.98	10,433.74
7	Otis 'RN' Landing Nipple	5.50	3.986	1.15	10,443.72
	T.I.W. Seal Ass. Serial No. 14553				
8	Locator	7.00		1.02	10,444.87
9	Spacer	5.50		3.43	10,448.89
10	Seals-T.I.W. Riton Packing (15 units)	6.75		25.90	10,449.32
11	Mule Shoe	6.68	4.68	1.40	10,475.22
	End of Tubing				10,476.62

NOTE: Locator is spaced-out 5' above PBR.

12	8 5/8", 44#/ft. P-110, FL-4S casing surface to 10,450.89'.				
	T.I.W. Polished Bore Receptical Serial No. 14812				
13	X-Over 8 5/8", 44#, FL-4S x 7 5/8", LT&C PIN.	8.625	6.81	4.25	10,450.89
14	Polished Bore Receptical	8.00	6.75	27.64	10,455.14
15	Extension 7 5/8" LT&C	8.25	6.75	1.40	10,482.78
16	7 5/8", 39#/ft. C-95 & P-110, LT&C Csg 10,484.18' to 13,608.96'.				

GRAVEL-PACK

17	Dowell Model 16 GP Packer w/port- closing sleeve	6.437	3.25	8.03	13,143.16
18	6 Jts. 4", 13.40 #/ft blank w/weld-on centralizers each 15'.	4.00	3.428	28.23	13,151.19
				28.28	
				28.71	
				28.72	
				27.36	
				28.75	
19	3 Jts. 4", .012 gauge Stainless Steel All-welded screen (Howard Smith) w/ weld-on Centralizers each 15'.	4.545	3.428	29.80	13,321.44
				29.94	
				29.72	
20	Wash Pipe Seal Bore Sub	4.75	2.78	1.30	13,410.90
21	Tattle-Tale screen 4", .012 gauge Stainless Steel All-Welded	4.545	3.428	8.52	13,412.20
22	X-Over 4", NU x 2 7/8, SRD	4.47	2.44	.58	13,420.72
23	Locator		2.44	.70	13,421.30
24	Collect/Seal Assembly (4 seal units)	3.25		3.54	13,422.00
25	X-Over 2 7/8 FL x 2 7/8 OSS-MT	3.22	2.44	.50	13,425.54
26	1 Jt., 2 7/8", 6.92#/ft. OSS-MT Tubing	3.22	2.44	32.69	13,426.04
27	Otis 'XN' Landing Nipple 2 7/8", OSS-MT, BXP	3.22	2.205	.93	13,458.73
28	Production Tube w/mule shoe	3.22	2.44	3.90	13,459.66
	End of Tubing				13,463.56
29	T.I.W. Model 'SS' Packer		3.25	3.00	13,422.00

'C188 JEFF' SAND - Perforated 13,349'-138' & 13,395' - 406' OIL Run 5 dated 6-22-81
w/12 SPF w/ 4" Big Hole Jet. Gravel-Packed w/ 20/40 Mesh Sand -- 1330 lb. in
formation & 3040 lb. in Annulus

Final Completion & Packer Fluid -- 17.2 ppg @ 60°F CaBr₂/ZnBr₂

Minimum Restrictions: Tubing - 'RN' Nipple @ 10,444' - 3.986"
Gravel-Pack - 'XN' Nipple @ 13,453' - 2.205"

NOTE: Tubing has 4.313" 'OR' Plug set @ 383' and a 5" BPV set @ surface.

CAS 9/5/81

Figure 4. Gravel-Pack and Completion Detail of L. R. Sweezy No. 1 Well (Dow [1982])

Measurements on the cores at simulated reservoir conditions (prior to fluid production) by Terra Tek, Inc. gave permeabilities in the range of 6-1526 md (Sinha, et al [1981] and Smith and Cooley [1983]). Because of the large variation in measured permeabilities, it is not meaningful to quote an "average permeability value". Under uniaxial compaction conditions (conditions roughly corresponding to those obtained during reservoir production), permeability declined by ~ 30 to ~ 90 percent as the pore pressure was reduced to the reservoir abandonment pressure (~ 6,000 psi).

The sand interval may be separated into two distinct zones, upper and lower. The lower sand interval (13,391 - 13,424 ft) exhibits sand grains that are commonly subangular, fair to poorly sorted, and average 0.15 mm in size. The upper sand interval (13,343 - 13,391 ft) exhibits larger grain size (average 0.3 mm), improved sorting, rounded grains and a greatly reduced clay matrix fraction. Terra Tek reports that this sand is generally friable and in some sections, totalling approximately 5 ft, is practically unconsolidated. The upper sand permeabilities as reported by Terra Tek are generally higher than those of the lower sand.

Terra Tek, Inc. has completed a limited number of tests designed to measure the deformation characteristics of laboratory samples cut from recovered Cib Jeff cores (Sinha et al, 1981; Smith and Cooley, 1983). Uniaxial compaction tests indicate that for the pore pressure range from 11,400 psia to 8,000 psia, the pore volume compressibility during pressure drawdown is essentially constant and is approximately equal to the pore volume compressibility during pressure buildup. The cores exhibit yielding and very large drawdown compressibilities for pore pressures less than 8,000 psia; however, it is to be noted that pore pressures below 8,000 psia were not attained during flow testing of the Sweezy well. The uniaxial

compaction tests were performed at relatively high strain-rates (test time from a few minutes to an hour or two). To characterize formation compaction behavior on the time scales of interest in modeling reservoir response (weeks to months), Terra Tek performed both short term (test time of the order of 1 - 2 hours) and long term (several days) hydrostatic compression tests. In these tests, pore pressure was kept constant and only the confining (and hence effective) pressure was changed. Comparison of short-term and long-term tests showed that formation material undergoes significant creep over a day. The bulk of this creep occurred below effective pressures ($=$ confining pressure - pore pressure) of less than 2,000 psi. The effect of formation creep is to increase the effective drawdown compressibility; the buildup compressibility is presumable unaffected by this phenomenon.

Weatherly Laboratories, Inc. [1982] performed analysis of the chemical and physical characteristics of fluid from the L. R. Sweezy No. 1 well sampled at separator conditions. The following parameters were reported for the fluid recombined at reservoir conditions (237.4°F, 11,408 psia): viscosity = 0.44 centipoise; formation volume factor (reservoir/standard conditions) $\sim$ 1.035; density $\sim$ 1.05 gm/mL; total dissolved solids content of $\sim$ 100,000 mg/L.

The DOW/DOE L. R. Sweezy No. 1 well was completed with a 5-1/2 inch production tubing within a 7-5/8 inch casing. The casing was perforated over the intervals 13,349 - 13,388 ft and 13,395 - 14,406 ft in Cib Jeff sand (Figure 4). The production zone was perforated with 12 shots/foot and then acidized. The Cib Jeff sand was gravel packed with 20/40 mesh Ottawa Sand (1330 lbs in the formation outside the 7-5/8 inch casing and 3040 lbs in the annulus between the screen and the tubing). It is noteworthy that gravel packs have not been used on the other geopressured design wells.

Downhole temperatures and pressures were recorded using a Hewlett-Packard gauge located at the top of the lower perforated section at 13,395 ft. Independent measurements of wellhead pressures and temperatures, gas flows, brine flows, and injection well pressures were also recorded in the DOW Daily Reports. During production the total flow rate was measured using a Halliburton turbine meter placed just upstream of the choke manifold. The well stream from the choke flowed directly into the brine/gas separator system. The liquid brine flow rate was measured by Mock P/D meters; gas flow rate was determined both by a Daniel meter, based on measuring the pressure drop across an orifice plate, and a positive displacement meter.

A downhole temperature of 237°F ($T_0 = 113.9^\circ\text{C}$) was recorded by the H-P gauge at 13,395 ft. Although higher pressures were recorded several times during the test program, the initial reservoir pressure at 13,395 ft is believed to have been about 11,410 psia ($P_0 = 7.867 \times 10^7$ Pa). With these values for the reservoir temperature, pressure and salinity of 100,000 mg/L, the S-CUBED methane/brine equations of state (Pritchett, et al., [1979]) yields a methane mass fraction of 0.00273 at saturation (corresponding to 23.6 SCF/bbl at separator condition of $p = 620$ psig and $T = 120^\circ\text{F}$). The measured gas content at the separator varied widely during the early tests but then settled to values in the range of ~ 17 to 19 cf/bbl (including about 10 percent CO_2); several additional cf/bbl remained in the liquid brine which was reinjected. The methane mass fraction corresponding to this gas/water ratio at reservoir conditions is $\alpha_0 \sim 0.002$ to 0.0025.

Sand production rate was monitored with 1-JMS System sand detectors and examining sand shakeouts which were taken every half hour. The sonic system quantifies sand production by processing of "pinging" signals caused by sand particles in the brine stream striking an acoustical probe inserted in the flow line from the test well.

III. WELL TEST DATA AND OBSERVATIONS

Figure 5 depicts the average production rates and the periods of performance of the twelve flow tests made on the L. R. Sweezy No. 1 well. Short-term tests, Flow Test No. 1 through Flow Test No. 4, were designed to estimate formation properties and for drawdown periods measured in hours. Intermediate-term tests, Flow Test No. 5 through Flow Test No. 8, were for a few days and designed to test for reservoir boundaries. Long-term tests, Flow Test No. 9 through Flow Test No. 12, were designed for drawdown periods of about 60 days in order to examine the depletion behavior of the reservoir. Table 1 provides a more detailed representation of the flow-rate data. In the following, we summarize other pertinent information from the DOW Daily Reports and the pressure/flow-rate data reported by Otis Engineering Corporation.

L. R. Sweezy No. 1 well was opened for Flow Test No. 1 at 17:30 hrs on April 26, 1982 and shut in at 19:53 hrs (cumulative time: $t = 0$, to $t = 2.38$ hrs). Total flow during Flow Test No. 1 was 689 bbl, corresponding to an average flow rate of 6,939 bbl/day. No sand was detected in shake-outs or by the sand detector. Operation of the downhole H-P gauge was intermittent; pressures (at 13,395 ft) as high as 11,423 psia were recorded but are considered unreliable.

The well was opened for Flow Test No. 2 at 10:20 hrs on April 28, 1982 and except for a ten-minute interruption was flowed until 16:12 hrs (cumulative time: $t = 40.626$ to 46.521 hours). The flow rate was increased during this variable-rate test to a final rate of $\sim 14,000$ bbl/day. The choke was badly cut by sand during the flow period and the separator contained ~ 3 gallons of very fine-grained sand at the end of the test. Total flow during Flow Test No. 2 was 2,035 bbl, corresponding to an average flow rate of 8,285 bbl/day.

Figure 5. Average Production Rates and Flow Periods for L. R. Sweezy No. 1 Well Flow Tests

Table 1

Approximate Flow Rate Data (L. R. Sweezy No. 1)

Flow Test	Cumulative Time (hrs)	Average Flow Rate (BPD)	Flow Test	Cumulative Time (hrs)	Average Flow Rate (BPD)
No. 1	0-2.3833 2.3833-40.626	6939 0	No. 10	3037.59-3067.51 3067.51-3212.11 3212.11-3378.91 3378.91-3382.54 3382.54-4527.13 4527.13-4529.28 4529.28-4531.38 4531.38-4537.51 4537.51-4554.93 4554.93-4872.84	8706 0 9221 0 9032 0 5166 0 8754 0
No. 2	40.626-46.521 46.521-195.723	8285 0			
No. 3A	195.723-198.773 198.773-378.273	2172 0			
No. 3	378.273-409.116 409.116-505.790	6455 0			
No. 4	505.790-531.476 531.476-565.821	8615 0	No. 11	4872.84-4886.01 4886.01-4887.59 4887.59-5385.28 5385.28-5387.68 5387.68-5531.34 5531.34-5561.51 5561.51-6376.81 6376.81-6380.76 6380.76-6398.56 6398.56-6404.01 6404.01-6423.93 6423.93-6549.43	4887 0 8101 0 8313 0 8948 0 8290 0 8228 0
No. 5	565.821-691.044 691.044-691.344 691.344-709.837 709.837-886.128	11,000 0 11,000 0			
No. 6	886.128-1055.86 1055.86-1095.88	9060 0			
No. 7	1095.88-1382.49 1382.49-1384.78	9509 0			
No. 8	1384.78-1506.38 1506.38-1696.68	9413 0	No. 12		
No. 9	1696.68-2197.73 2197.73-2205.91 2205.91-2248.09 2248.09-2254.86 2254.86-2925.84 2925.84-2928.49 2928.49-2943.83 2943.83-3037.59	9390 0 9307 0 9496 0 9509 0		6549.43-6830.39	7249

The well was re-opened at 21:13 hrs on May 4, 1982. Problems with the choke caused several false starts and the test was aborted. During Flow Test No. 3A (cumulative time: $t = 195.723$ to 198.773 hrs) a total of 276 bbl was produced, corresponding to an average flow rate of 2,172 bbl/day.

Flow Test No. 3 was the first test in which the flow was sufficiently constant and downhole pressure measurements reliable enough to warrant detailed analysis. The well was opened at 11:54 hrs on May 12 and shut in at 18:48 hrs on May 13, 1982 (cumulative time: $t = 378.273$ to 409.116 hrs). Total flow was 8,295 bbl, corresponding to an average flow rate of 6,455 bbl/day. The pressure recorded at 13,395 ft just prior to opening the well was 11,416 psia.

The well was opened for Flow Test No. 4 at 19:26 hrs on May 16 and shut in at 21:07 hrs on May 17, 1982 (cumulative time: $t = 505.790$ to 531.476 hrs). Some sand was detected in the shake-out 1.5 hrs after starting the test but the flow soon cleaned up and remained clean. The gas/water ratio on the Mock P.D. meter measured GWR ~ 20 SCF/bbl. Total flow was 9,220 bbl, corresponding to an average flow rate of 8,615 bbl/day. The pressure measured at 13,395 ft prior to opening the well was 11,398 psia.

The well was opened for Flow Test No. 5 at 7:28 hrs on May 20 and shut in at 7:30 hrs on May 26, 1982 (cumulative time: $t = 565.821$ to 709.837 hrs). Intermittant production of traces of sand was noted during the first day. Sand production subsequently increased to about 100 lb/day. After shut-in, less than 5 gallons of sand was cleaned out of the separator and top of the sand was tagged at less than 1 ft above bottom of hole. The Mock P.D. meter measured GWR ~ 21 SCF/bbl. Total production during Flow Test No. 5 was 65,871 bbl, corresponding to a total flow rate of 10,977 bbl/day.

The well was flowed intermittantly from 15:47 hrs on June 2 to 17:31 hrs on June 9, 1982 (cumulative time: $t = 886.1281$ to 1055.8594 hrs). The total flow during this period (Flow Test No. 6) was 64,071 bbl, corresponding to a total flow rate of 9,060 bbl/day. Sand production varied up to ~ 300 lbs/day. The downhole pressure data were not recorded for this flow test.

The well was opened for Flow Test No. 7 at 9:32 hrs on June 11 and shut in at 8:09 hrs on June 23, 1982 (cumulative time: $t = 1095.8761$ to 1382.4928 hrs). The total flow during this period was 114,281 bbl, corresponding to an average flow rate of 9,569 bbl/day. No downhole pressure measurements were recorded. Sand production remained low, but the downhole tool tagged the top of sand after shutin of Flow Test No. 7 at 13,472 ft; hence sand fill had been 23 ft in 13 days since tagged at 13,495 ft on June 10, 1982. The DOW Daily Reports speculate that much of this may be from a large sand slug which occurred early in the drawdown period.

The well was opened for Flow Test No. 8 at 10:26 hrs on June 23 and shut in at 12:04 hrs on June 28, 1982 (cumulative time: $t = 1384.7786$ to 1506.3767 hrs). The total flow was 48,091 bbl, corresponding to an average total flow rate of 9,413 bbl/day. The downhole pressure just prior to opening the well was 11,004 psia. The disposal well pressure climbed continuously during the test (~ 30 psia in 4 days) and filters were plugged with very fine sand. On July 6, at the end of buildup following Flow Test No. 8, the top of the sand was tagged at 13,478 ft.

Drawdown for Flow Test No. 9 began at 10:20 hrs on July 6 and ended at 9:29 on August 27, 1982 (cumulative time: $t = 1696.677$ to 2943.826 hrs). The total flow during this long-term test was 483,961 bbl, corresponding to an average flow rate of 9,313 bbl/day. The flow was interrupted briefly three times during the drawdown period. Just prior to the start of drawdown the downhole pressure

was 11,037 psia. The well produced sand throughout the drawdown period; when the choke size was increased from 30/64 inch (~ 9,500 bbl/day) to 32/64 inch (~ 10,050 bbl/day), the sand production rate jumped from ~ 32 lb/day to ~ 800 lb/day. The choke was changed back to 30/64 inch. Serious sanding consistently occurred when the total flow rate reached a critical value between 10,000 and 11,000 bbl/day. Filters then plugged at shorter time intervals. As testing progressed, the problem appeared to be more acute; the flow velocity required to start sanding decreased and the sanding became heavier. At 13:00 hrs on August 8, 1982, a large slug was produced and ~ 25 gallons of sand were removed from the separator.

In Flow Test No. 9 (and the remaining long-term tests) the downhole pressure was not measured during drawdown except for a short flow stabilization period just prior to shutting-in the well to run a 72-hour buildup test.

The well was opened for Flow Test No. 10 on August 31, 1982. After two aborted starts the well was flowed for ~ 30 hrs before being shut in for mechanical reasons at 13:10 hrs on September 1. The total flow during this initial part of Flow Test No. 10 (cumulative time: $t \sim 3037.594$ to 3067.510 hrs) was 10,852 bbl, corresponding to an average flow rate of 8,706 bbl/day. The well was re-opened at 13:46 hrs on September 7 and, except for brief interruptions, was flowed until shut-in at 12:35 hrs on November 2, 1982. The total flow during this major part of Flow Test No. 10 (cumulative time: $t = 3212.110$ to 4554.931 hrs) was 501,624 bbl, corresponding to an average flow rate of 8,965 bbl/day. The average flow rate over the full test period (cumulative time: $t = 3037.594$ to 4554.931 hrs) was 8,106 bbl/day. Sand production rates in excess of 700 lbs/day were measured; carry over of fine particles with the injection stream caused excessive backpressures in the disposal well which in turn required several acidization treatments. On November

5, ~ 100 gallons of sand were cleaned out of the separator and the bottom was tagged at 13,477 ft.

No downhole pressure measurements were made during Flow Test No. 10 drawdown until the well was briefly shut-in on November 1 and the H-P gauge lowered to 13,395 ft. The well was then reopened and the flow stabilized; prior to shut-in the recorded pressure was 9,908 psia. The pressure after ~ 72 hours was 10,210 psia, recorded at the end of the buildup measurements at 13:00 hrs on November 5.

The well was opened for Flow Test No. 11 on November 15, 1982. After two aborted starts the well was flowed for ~ 13 hrs before being shut in to repair a leak at 7:40 hrs on November 16. The total flow during this initial part of the drawdown (cumulative time: $t = 4872.844$ to 4886.011 hrs) was 2,681 bbl, corresponding to an average flow rate of 4,887 bbl/day. At 9:15 hrs on November 16 the well was re-opened and flowed, except for brief interruptions, until shut-in at 9:35 hrs on January 19, 1983. The total flow during this major part of Flow Test No. 11 (cumulative time: $t = 4887.594$ to 6423.932 hrs) was 534,601 bbl, corresponding to an average flow rate of 8,351 bbl/day. The average flow rate over the full drawdown period (cumulative time: $t = 4872.844$ to 6423.932 hrs) was 8,313 bbl/day. Traces of sand were produced throughout the test. Periodic acid treatments of the disposal well were required to control formation plugging by the entrained fine sand particles in the injection stream. After shut-in the bottom of the well was tagged at 13,470 ft.

On January 18, 1983, the well was briefly shut in to run the H-P pressure gauge down the well for bottomhole measurements. The value recorded at 13,395 ft just prior to shut-in was 9,638 psia. The downhole pressures were recorded for ~ 72 hours after shut-in, at which point the pressure had risen to 9,892 psia.

Flow Test No. 12 was started at 15:05 on January 24, 1983. The initial flow rate of ~ 5000 bbl/day was increased by enlarging the choke size to ~ 6000 bbl/day at 15:00 on January 25, to ~ 7,800 bbl/day at 15:10 on January 26, and to ~ 9,500 at 15:15 hrs on January 27. On February 5, 1983 there was a surge in the sand production and the well was shut in at 8:03 hrs. The total fluid produced during the drawdown period (cumulative time: $t = 6549.427$ to 6830.394 hrs) was 84,862 bbl, corresponding to an average flow rate of 7,249 bbl/day. After shut-in the separator and sand filters were found to contain 4 to 5 bbl of fine sand and clay and the disposal well was plugged. The top of the sand in the production well was tagged at 12,999 ft, 350 ft above the top of the perforated interval.

In this report we will need to convert from production rates reported at separator conditions (Table 1) to values at reservoir conditions. For consistency with the reservoir simulation calculations we start with the following values for standard conditions (60°F , 14.7 psia): brine density $\rho \sim 1.063 \text{ gm/cm}^3$; total dissolved solids content ~ 100,900 mg/L. With salinity $S = 0.1009/1.063 = 0.095$, the S-CUBED brine/methane equation-of-state (Pritchett, et al., [1979]) then yields at

reservoir conditions (237°F , 11,410 psia):

$$\rho \sim 1.04966 \text{ gm/cm}^3$$

separator conditions (120°F , 620 psig):

$$\rho \sim 1.05761 \text{ gm/cm}^3$$

The formation factor to convert barrels as measured at the separator to reservoir conditions is therefore

$$B = \frac{1.05761}{1.04966} \sim 1.01$$

To convert volumetric production rates measured at the separator to mass rates required in the numerical simulations we use

$$\rho = 1.05761 \text{ gm/cm}^3 = 1057.61 \frac{\text{kg}}{\text{m}^3} = 168.147 \frac{\text{kg}}{\text{bbt}} .$$

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IV. WELL TEST ANALYSIS

4.1 Multiple-Rate Analysis

Twelve flow tests (see Table 1) were made on the L. R. Sweezy No. 1 well. Short-term tests, Flow Test No. 1 through Flow Test No. 4 were designed to estimate formation properties and were conducted for drawdown periods measured in hours. Intermediate-term tests, Flow Tests No. 5 through Flow Test No. 8, were for a few days and were designed to test for reservoir boundaries. Long-term tests, Flow Test No. 9 through Flow Test No. 12, were designed for drawdown periods of about 60 days in order to examine the depletion behavior of the reservoir.

Flow Test No. 3 was the first test in which the flow was sufficiently constant and downhole pressure measurements reliable enough to warrant detailed analysis. Downhole pressure measurements are also available for Drawdown Test Nos. 4, 5 and 8, and Buildup Test Nos. 3, 4, 5, 8, 9, 10 and 11.

Because of insufficient shutin time between successive flow tests, it is necessary to employ multiple-rate analysis techniques to analyze the pressure transient data for the Sweezy well. A convenient method for analyzing the drawdown data is to plot (Earlougher, [1977]):

$$(p_i - p_{wf})/q_n \quad \text{versus} \quad \sum_{j=1}^n \frac{\Delta q_j}{q_n} \log (t - t_{j-1}) \quad (1)$$

where

- p_i ~ initial reservoir pressure, psi
- p_{wf} ~ flowing pressure at time t , psi
- q_n ~ constant flow rate during n -th flow period
($t_{n-1} \leq t \leq t_n$), bbl/day
- Δq_j ~ $q_j - q_{j-1}$, $2 \leq j \leq n$, bbl/day
- Δq_1 ~ q_1 , bbl/day
- t_{j-1} ~ time at the end of flow period ($j-1$), hours
- t_0 ~ 0 (cumulative time at the start of flow test)

For infinite-acting systems and unfractured wells, the plot should give us a straight line with slope $m' = 162.6 \mu B/kh$ and intercept

$$b' = m' \left[\log \frac{k}{\phi \mu C_T r_w^2} - 3.23 + 0.87 s \right] \quad (2)$$

where

- B ~ formation volume factor, res.bbl/std.bbl
- C_f ~ fluid compressibility, psi^{-1}
- C_m ~ uniaxial formation compressibility, psi^{-1}
- C_T ~ total formation compressibility, psi^{-1} ; equal to
 $[1-\phi/\phi] C_m + C_f$
- h ~ formation thickness, ft.
- k = permeability, md
- r_w ~ well radius, ft
- s ~ skin factor
- ϕ ~ porosity
- μ ~ viscosity, cp

Buildup data from tests with widely varying flow rates prior to shutin can be analyzed by plotting (Earlougher,[1977])

$$p_{ws} \text{ versus } \sum_{j=1}^N (q_j/q_N) \log \left[\frac{t_N - t_{j-1} + \Delta t}{t_N - t_j + \Delta t} \right] \quad (3)$$

where

p_{ws} ~ shutin pressure at time t_N , psi
 q_N ~ final flow rate prior to shutin, bbl/day
 t_N ~ shutin time, hours

The slope of a straight line approximation to the plot provides estimates of the formation parameters

$$k = \frac{162.6 q_N \mu B}{mh} \quad (4)$$

$$s = 1.151 \left[\frac{p_{1hr} - p_{wf}}{m} - \log \frac{k}{\phi \mu C_T r_w^2} + 3.23 \right] \quad (5)$$

where

p_{wf} ~ final flowing pressure before shutin, psi
 p_{1hr} ~ shutin pressure at $\Delta t = 1$ hr extrapolated from straight line, psi

4.2 Drawdown Analysis

Figure 6 is a plot of $\log \Delta p$ (Δp = pressure change = $p_0 - p_f(t)$, where p_0 is the last shutin pressure and p_f is the flowing pressure at time t) versus $\log t$ (t = flowing time) for Flow Test No. 3; it is seen that the early time drawdown data lie on the unit slope line. The presence of a unit slope line (see e.g. Matthews and Russell [1967]) indicates that the well response is controlled by storage effects. The extended duration of the storage effects is caused by wellbore heating during drawdown. A rough rule of thumb is that the semi-log straight line (see section 4.1) starts at a time which is one and one-half log cycles removed from the time at which the pressure data begins to deviate from the unit slope straight line. Using this criterion, it is apparent from Figure 6 that the semi-log behavior should start at about 0.5 hrs. Drawdown Tests No. 4 and No. 5 (see Figures 7 and 8) also exhibit a wellbore storage period similar to that for Flow Test No. 3. The upward bend in the early time drawdown data for Flow Test No. 5 (Figure 8) indicates an apparent decrease in wellbore storage.

Multiple-rate analyses (see subsection 4.1) have been performed for all of the three drawdown tests (i.e. Nos. 3, 4 and 5) for which sufficient downhole pressure data are available. Of the three drawdown tests, Test No. 5 is particularly interesting in that it provides an indication of reservoir boundaries. Figure 9 presents the multi-rate plot for Drawdown Test No. 5. The early straight line portion is fit by a line with slope and intercept given by $m' = 0.0088$ psi/cycle-bbl/day and $b' = 0.0762$ psi/bbl/day. With $q_N = 11,000$ bbl/day, $\mu = 0.33$ cp, $B = 1.01$ and $h = 50$ ft, we obtain

$$k = \frac{162.6 \mu B}{m' h} = \frac{162.6 (0.33) (1.01)}{(0.0088) (50)} = 123 \text{ md}.$$

Figure 6: Flow Test No. 3 Pressure Drawdown Type Curve

Figure 7: Flow Test No. 4 Pressure Drawdown Type Curve

Figure 8: Flow Test No. 5 Pressure Drawdown Type Curve.

Figure 9. Flow Test No. 5 Pressure Drawdown Multi-Rate Plot

The transition of the data from a straight line of slope $m' = 0.0088$ to one of slope $m' = 0.0335$ implies the presence of a reservoir boundary. The flowing time t_1 at which the data begins to deviate from the first slope may be used to estimate the distance to the boundary from the relation

$$r = \left[\frac{0.00105 \, k t_1}{\phi \mu C_T} \right]^{1/2} \quad (6)$$

A second method is based on the time t_2 determined by the intersection of the two straight lines, i.e.,

$$L = 0.01217 \left[\frac{k t_2}{\phi \mu C_T} \right]^{1/2} \quad (7)$$

A critical parameter in either estimation method is the total formation compressibility C_T . We will in fact use the observed indication of a reservoir boundary to estimate the appropriate in situ value for C_T .

We first note that the deviation and intersection times in Figure 9 correspond to the following flowing times

$$\begin{aligned} t_1 &= 577.259 - 565.821 = 11.438 \text{ hrs} \\ t_2 &= 608.702 - 565.821 = 42.881 \text{ hrs} \end{aligned} \quad (8)$$

A preliminary estimate for $C_T \sim 4.9 \times 10^{-6} \text{ psi}^{-1}$ is obtained by setting $C_m \sim 10^{-6} \text{ psi}^{-1}$, $C_f \sim 2.2 \times 10^{-6} \text{ psi}^{-1}$ and $\phi \sim 0.27$. With $k \sim 123 \text{ md}$, $\phi \sim 0.27$, $\mu = 0.33 \text{ cp}$ and C_T tentatively set at $4.9 \times 10^{-6} \text{ psi}^{-1}$, we compute

$$r = \left[\frac{0.00105 (123) (11.438)}{(0.27)(0.33)(4.9 \times 10^{-6})} \right]^{1/2} \sim 1840 \text{ ft}$$

$$L = 0.01217 \left[\frac{(123)(42.881)}{(0.27)(0.33)(4.9 \times 10^{-6})} \right]^{1/2} \sim 1340 \text{ ft}$$

The distance calculated by the two relations is essentially the same when one considers the lack of precision inherent in their derivations.

Thus, the distance to the boundary, based on the tentative value of $C_T = 4.9 \times 10^{-6} \text{ psi}^{-1}$, is $\sim 1600 \text{ ft}$. The well geology (Figure 1) indicates that there are two faults close to the L. R. Sweezy No. 1 well (Fault C at $\sim 600 \text{ ft}$ and Fault A at $\sim 1600 \text{ ft}$) at an average distance of $\sim 1100 \text{ ft}$. If we accept the well geology, then it follows that the formation compressibility must be larger than the tentative value ($4.9 \times 10^{-6} \text{ psi}^{-1}$) used in these computations. We therefore assume that the correct value of C_T is given by

$$C_T = \left(\frac{1600}{1100} \right)^2 (4.9 \times 10^{-6}) \sim 10.4 \times 10^{-6} \text{ psi}^{-1} \quad (9)$$

The values of b' and m' for the first straight line fit to the reduced data (Figure 9) can now be used with the corrected value of C_T , to calculate the skin factor during Flow Test No. 5 drawdown. We obtain

$$s = 1.151 \left[\frac{0.0762}{0.0088} - \log \frac{123 \times 10^6}{(0.27)(0.33)(10.4)(0.3177)^2} \right] + 3.23$$

$$= 3.19$$

Table 2 lists the values of the formation parameters k and s determined by the multi-rate analysis of the drawdown data for Flow Test Nos. 3, 4 and 5. The values for permeability for Flow Test Nos. 3 and 4 are essentially identical to the estimate obtained from Flow Test No. 5. The skin factor, s , is seen to vary linearly (Figure 10) with flow rate indicating the presence of non-Darcy flow in the near wellbore region. The extrapolated skin values are negative for flow rates less than ~ 4500 bbl/day.

It is of interest to note that a similar linear relationship was observed in drawdown data from previously tested geopressed geothermal design wells (Pleasant Bayou No. 2 and Amoco Fee No. 1). Negative values of skin indicating well stimulation were observed for each of these wells.

Downhole drawdown data are not available for Flow Test Nos. 6 and 7. Data for Flow Test No. 8 are available, but the drawdown phase started after a very brief shutin period (~ 2.5 hrs); these drawdown data cannot be used to estimate formation parameters since the presence of the faults is still influencing the reservoir pressure distribution after such a brief shutin period. This point is illustrated by Figure 11 which presents the multi-rate plot of the drawdown data for Flow Test No. 8; the slope of the straight line fit is almost twice that observed during the earlier drawdown tests. None of the remaining tests provide drawdown data useful for interpreting formation parameters.

4.3 Buildup Analysis

Figures 12 through 18 present the multi-rate Horner plot of the buildup data for Flow Test Nos. 3, 4, 5, 8, 9, 10 and 11. For Flow Test Nos. 3, 4, 5 and 8 (Figures 12, 13, 14 and 15), the slope of the buildup data is changing throughout the buildup period, and it is impossible to identify straight line segments of sufficient length (at least one log cycle). These buildup data cannot, therefore, be analyzed by conventional techniques to give formation

Table 2

Results of Multi-Rate Analysis of Drawdown Data and Buildup Data

(a) Drawdown Data (Short-Term Tests)

<u>Flow Test No.</u>	<u>m'</u> <u>psi/cycle-BPD</u>	<u>b'</u> <u>psi/BPD</u>	<u>k</u> <u>md</u>	<u>s</u>
3	0.0084	0.0552	129	0.76
4	0.0087	0.0671	125	2.09
5	0.0088	0.0762	123	3.19

(b) Buildup Data (Long-Term Tests)

<u>Flow Test No.</u>	<u>m₂</u> <u>psi/cycle</u>	<u>k</u> <u>md</u>	<u>Δt₂</u> <u>hrs</u>
9	11.3	912	25
10	12.3	771	17
11	11.6	769	18

Figure 10: Variation of Skin Factor s with Flow-Rate

Figure 11. Flow Test No. 8 Pressure Drawdown Multi-Rate Plot

Figure 12: Flow Test No. 3 Pressure Buildup Multi-Rate Horner Plot

Figure 13: Flow Test No. 4 Pressure Buildup Multi-Rate Horner Plot

Figure 14: Flow Test No. 5 Pressure Buildup Multi-Rate Horner Plot

Figure 15: Flow Test No. 8 Pressure Buildup Multi-Rate Horner Plot

Figure 16: Flow Test No. 9 Pressure Buildup Multi-Rate Horner Plot

Figure 17: Flow Test No. 10 Pressure Buildup Multi-Rate Horner Plot

Figure 18: Flow Test No. 11 Pressure Buildup Multi-Rate Horner Plot

properties. The buildup data (Flow Test Nos. 3, 4, 5 and 8) were replotted in a dimensionless form for comparison purposes (Figure 19).

$$\frac{\Delta p_{\text{buildup}}}{\Delta p_{\text{drawdown}}} = \frac{p_{ws} - p_{wf}}{p_o - p_{wf}} \quad \text{vs} \quad \text{Reduced Time}$$

where

- p_o ~ pressure at start of drawdown period
- p_{wf} ~ pressure at end of drawdown period
- p_{ws} ~ shutin pressure at Δt
- Δt ~ time since well shutin

The resulting dimensionless plots in Figure 19 suggest that, except for the early part of the response for Flow Test No. 4, the buildup data are very compatible. The response for Flow Test No. 8 is affected by the very short shutin subsequent to Flow Test No. 7.

For each of the long-term tests (Flow Test Nos. 9, 10 and 11), the only useful pressure data available are for a 72-hour buildup period after shutin. It is possible to identify three straight line segments (see Figures 16, 17 and 18) on the multi-rate Horner plots for these flow tests. Except for the very early-time buildup data (fit with straight line of slope m_1), the buildup data for Flow Test Nos. 9, 10 and 11 are consistent from test to test.

The buildup data from these long-term flow tests are, however, quite different from those from short-term (Flow Test Nos. 3, 4, 5) and intermediate-term (Flow Test No. 8) flow tests. At present, the reasons for this difference are only poorly understood. The superposition method (subsection 4.1) is based on approximation to the transient linear solution for an infinite reservoir, and is not strictly applicable to a partially-depleted finite reservoir. It can be shown, however, that the slope corresponding to the transient buildup regime can be used to estimate the formation permeability in

Figure 19: Dimensionless Plot of Buildup Data for Indicated Flow Tests

a reservoir for which conventional linear theory is applicable (Appendix).

The line segments with slopes denoted by m_1 in Figures 16, 17 and 18 fit the data only for very short buildup times ($\Delta t < 3$ minutes). The line segments with slopes m_2 appear to represent the transient buildup response of the reservoir subsequent to wellbore effects and prior to the boundaries affecting the sandface pressures. Table 2 lists the values of m_2 for Flow Test Nos. 9, 10 and 11 along with the corresponding values of the formation permeability inferred from Equation (4) using $B = 1.01$, $\mu = 0.33$ cp, $h = 50$ ft and taking q_N to be the value just prior to shutin for each of the three flow tests (Table 1). The average permeability inferred from these late-time buildup tests is about 6.3 times the average permeability calculated using the drawdown data from the early-time tests (Flow Test Nos. 3, 4 and 5).

The conventional method for determining average reservoir pressure ($\bar{p}$) in a finite reservoir involves extrapolating the semi-log straight line on the Horner buildup plot to infinite time to obtain pressure p^* , reading the value of $p^* - \bar{p}$ from a tabulated solution of an approximating reservoir shape, and then obtaining $\bar{p}$ by difference (Matthews and Russell, [1967]). Because of the anomalous behavior of the buildup pressures measured for the L. R. Sweezy No. 1 well, however, there exist no straight lines from which we can extrapolate to estimate the values of p^* for the various tests. This implies that it is not feasible to use the conventional techniques for obtaining $\bar{p}$. For Flow Test Nos. 3, 4, 5 and 8, an approximate estimate for average reservoir pressure can be obtained by extending the late-time part of the Horner plots to infinite time. (In Figures 12 through 18 we have used the symbol $\tilde{p}$ to denote the average reservoir pressure obtained by extending the late-time part of the Horner plot. For the Sweezy well, we have at present no

method for estimating the pressure difference $\tilde{p} - \bar{p}$.) The extrapolation to infinite time (reduced time of zero) to obtain $\tilde{p}$ is very uncertain for all of the long-term flow tests (Flow Test Nos. 9, 10 and 11). First the superposition method is based on an approximation to the transient linear solution for an infinite reservoir. Second, the presence and locations of reservoir boundaries give rise to different slopes which may be extrapolated to different values for $\tilde{p}$ at zero reduced time as illustrated in Figures 17, and 18. Third, the extrapolations of the buildup data are over much greater increments of reduced time than for the earlier tests. Table 3 lists the values for Δt_R (the increment of the reduced time over which the buildup data are extrapolated) and for $\tilde{p}$. For long-term flow tests, the $\tilde{p}$ values are enclosed in parentheses to denote uncertainty. If the shutin periods were carried further in time the buildup data may have undergone further slope change and the associated value for $\tilde{p}$ may be quite different.

4.4 Reservoir Depletion Behavior

If we assume that the three faults (A, B, C) in Figure 1 are sealing faults and ignore possible nonlinear reservoir mechanisms (e.g. shale dewatering, irreversible compressibility, free gas evolution, etc.) then cumulative fluid production, Q , is linearly related to average reservoir pressure, $\bar{p}$.

$$\bar{p} = p_i - \frac{Q}{V\phi C_T}$$

Here p_i is the initial reservoir pressure and V is the reservoir connected-pore volume in barrels. This implies that a plot of $\bar{p}$ versus Q should be a straight line with slope equal to $(1/\phi VC_T)$ and an intercept equal to p_i .

Table 3

Cumulative Production and Extrapolated Reservoir Pressures

<u>Flow Test No.</u>	<u>Q (bbl)</u>	<u>Δt R</u>	<u>p (psia)</u>
3	15,846	0.28	11,401
4	25,066	0.32	11,380
5	90,937	0.44	11,295
8	317,742	0.69	11,064
9	801,703	1.40	(10,518-10,562)
10	1,314,179	1.65	(10,218-10,270)
11	1,851,461	1.85	(9900-9964)
12	1,936,323	--	--

Figure 20 is a plot of estimated average reservoir pressure $\bar{p}$ (cf Table 3) versus cumulative fluid production Q . The data for Flow Test Nos. 3, 4, 5, 8 and 9 are fit by a straight line with intercept p_i equal to 11,410 psi and slope equal to 1.09×10^{-3} psi/bbl. This value for initial reservoir pressure is in good agreement with the value ($\sim 11,400$ psi) measured by Dow. With $\phi \sim 0.27$ and $C_T \sim 10.4 \times 10^{-6}$ psi $^{-1}$, the inferred reservoir volume V is

$$V = \frac{1}{(0.27 \times 10.4 \times 10^{-6}) 1.09 \times 10^{-3}} \text{ bbl} \approx 3.27 \times 10^8 \text{ bbl} \\ \approx 1.835 \times 10^9 \text{ ft}^3$$

Assuming that reservoir thickness $h \approx 50$ ft, we have for reservoir area A

$$A \approx 3.67 \times 10^7 \text{ ft}^2 \approx 840 \text{ acres}$$

The above value for reservoir area is approximately 10 percent less than the estimate (~ 939 acres) obtained by Dow on the basis of available geological and geophysical data (Dow [1982]).

The deviation of data for Flow Test Nos. 10 and 11 from the straight line for the earlier flow tests is apparent in Figure 20. Although it is possible to fit the data for Flow Test Nos. 9, 10 and 11 with another straight line of slope 0.58×10^{-3} psi/bbl, we do not have much confidence in this straight line because of uncertainties in $\bar{p}$ for long-term flow tests. The straight-line fit for long-term flow tests implies that the effective value of (ϕC_T) is increased by the factor 1.88 ($= 1.09/0.58$) during the course of the reservoir depletion. Since the distance from the well to the reservoir boundaries are fixed, we have from Equation (7)

Figure 20: Estimated Average Reservoir Pressure versus Cumulative Fluid Production.

$$\left[\frac{kt_2}{\phi\mu C_T} \right]_{\text{F.T.3,4,5}} = \left[\frac{k\Delta t_2}{\phi\mu C_T} \right]_{\text{F.T.9,10,11}}$$

or, using $t_2 = 42.881$ hours (cf Equation (8)),

$$\begin{aligned} \Delta t_2 &= t_2 \frac{(k/\mu)_{\text{FT 3,4,5}}}{(k/\mu)_{\text{FT 9,10,11}}} \frac{(\phi C_T)_{\text{FT 9,10,11}}}{(\phi C_T)_{\text{FT 3,4,5}}} \\ &= 42.881 (1/6.1) (1.88) = 13.2 \text{ hrs} \end{aligned}$$

This value is of the same order of magnitude as the observed values for Flow Test Nos. 9, 10 and 11 (Table 2).

In any case, it is obvious that $d\bar{p}/dQ$ (reservoir pressure drop per bbl of fluid produced) declines significantly after Flow Test 9. This suggests that some long-term time-dependent processes must be operative in the Parcupdue reservoir tested by the L. R. Sweezy No. 1 well. Examples of these processes are (1) shale water recharge, (2) irreversible compressibility, and (3) formation creep. At the present time, we can only speculate as to which process (or processes) is responsible for the observed depletion behavior; a successful history-match of the available pressure/flow data should be helpful in providing a more definite answer.

4.5 Otis Engineering Reservoir Model

Otis Engineering, under subcontract to Dow, has performed an independent analysis of pressure drawdown and buildup data from the Sweezy well. Since Otis's reservoir model (see Dow Chemical Co. Report [1984]) differs in a fundamental way from the analysis in the preceding sections, we shall now briefly review their model.

For reservoirs with pressure-dependent rock and fluid properties, the radial diffusivity equation may be linearized by introducing the following dimensionless psuedo-time t_D and psuedo-potential m_D functions (see Samaniego, et al., [1977] and Agariwal, [1979]):

$$t_D = \frac{1}{r_w^2} \int_0^t \frac{k(p) dt}{\phi(p) \mu(p) C_T(p)}$$

$$m_D(r_D, t_D) = \frac{2 \pi h (p_i)}{q_i (p_i)} [1 - \phi(p_i)] [m(p_i) - m(r, t)]$$

where

$$m(r, t) = \int_{p_i}^p \frac{k(p)}{\mu(p) [1 - \phi(p)]} dp$$

and

- $C_T(p)$ = pressure-dependent total formation compressibility,
- $k(p)$ = pressure-dependent formation permeability,
- p_i = initial reservoir pressure,
- q_i = fluid volume production rate
- r_D = r/r_w
- r_w = well-bore radius,
- $\phi(p)$ = pressure-dependent formation porosity,
- $\mu(p)$ = pressure-dependent fluid viscosity.
- $\rho(p)$ = pressure-dependent fluid density,

The transient well behavior for flow in a pressure-dependent system can now be expressed by:

$$m_D(1, t_D) = p_D(1, t_D)$$

where p_D is the conventional dimensionless pressure function. The analysis for the pressure-dependent system is subject to the usual assumptions employed in the well-testing theory. For example, it is assumed that we have horizontal flow with no gravity effects, a fully penetrating well, isothermal single-phase fluid obeying Darcy's law, an isotropic and homogeneous formation, and purely elastic rock properties. Hysteresis in system properties with pressure changes is specifically excluded. The conventional application of pseudo-potential function method requires a knowledge of several pressure-dependent properties ($\phi(p)$, $k(p)/k(p_i)$, $C_T(p)$, $\mu(p)$, $\rho(p)$, and $\phi(p)$); the analysis yields initial formation permeability $k(p_i)$ and skin factor, s .

In contrast with the usual application of the pseudo-function analysis method, Otis Engineering simultaneously evaluated several aquifer parameters through a computerized nonlinear regression algorithm. Some pressure-dependent aquifer fluid properties ($\mu(p)$, $\rho(p)$) and rock properties ($k(p)/k(p_i)$, $\phi(p)$) were determined from the laboratory data; the variation in rock compressibility with pressure was, however, one of the unknowns solved for by sequential analyses of the test data.

Otis first analyzed each long-term buildup test (Flow tests 8, 9, 10, 11) separately to simultaneously evaluate permeability-thickness product $k(p_i)h$, skin factor, s , and non-Darcy flow constant, D , hydraulic diffusivity, $k/\phi\mu C_T$, and for boundary distances, d_1 through d_4 , corresponding to a rectangle shape approximation of the aquifer. From these results, the brine-in-place and permeability are estimated to be $\sim 96 \times 10^6$ separator barrels (corresponding to a reservoir area of roughly 880 acres) and 1037 md respectively. The formation compressibility C_T was found to vary from a low of 8.3×10^{-6} for Flow Test 8 to a high of 13.8×10^{-6} psi for Flow Test 11.

Pressure-drawdown data for long-term flow tests were subsequently analyzed for aquifer volume, and formation compressibility. These analyses assumed pseudo-steady state flow in the reservoir. The aquifer volumes obtained were found to agree reasonably well with those given by the buildup analyses. The inferred drawdown formation compressibilities, varying from a low of 21.0×10^{-6} for Flow Test 8 to a high of 38.0×10^{-6} psi^{-1} for Flow Test 11, are, however, at considerable variance with those obtained from the buildup data.

The reservoir analyses performed by Otis Engineering are flawed in several important respects. First, the pseudo-potential method for linearizing diffusivity equations specifically excludes stress-induced hysteresis in formation properties; prediction of different drawdown and buildup compressibilities runs counter to this fundamental requirement. Second, the predicted permeability of 1037 md is based upon the long-term buildup tests (Nos. 9, 10 and 11). Although it is possible to infer permeabilities of this magnitude from the middle straight line segment (slope m_2 in Figures 17, 18 and 19) of these buildup tests (see Table 2), the values inferred from the short-term drawdown tests (Nos. 3, 4 and 5) should be given equal or greater weight. Third, Otis Engineering ascribes the low permeability observed in short-term drawdown tests to the propagation of a compaction front from the wellbore. The pressure-dependent permeability function $k(p)$ used by Otis gives at most a permeability reduction of 30 percent over the bottomhole pressure range (8600 - 11,400 psia) encountered in testing the Sweezy well; this is to be compared with a factor of six or more reduction in permeability implied by short-term drawdown tests. There appears to be no way of reconciling reservoir parameters predicted by Otis with pressure data from short-term and intermediate-term drawdown tests.

Although Otis's reservoir analyses are open to question, it is to be noted that several of the nonlinear mechanisms, invoked by Otis (such as pressure dependent rock properties) may indeed be operating in the Sweezy reservoir (see Section VI of this report). The matter is, however, considerably more complex than implied by the Otis analysis and requires a more fundamental study. We shall return to this question in Section VI of this report.

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V. PRELIMINARY HISTORY-MATCH CALCULATIONS

A preliminary two-dimensional simulation of the Parcperdue geopressed geothermal reservoir was made assuming the formation parameters inferred from the drawdown analyses (Section IV). The calculations were performed with the CHARGR simulator, a successor to the MUSHRM simulator, which embodies the same sophisticated sub-grid treatment for finite-difference zones penetrated by wells (Pritchett, [1980]). The numerical mesh approximating the Parcperdue reservoir consisted of 131 grid blocks (Figure 21); all the boundaries of this stairstep mesh are treated as impermeable and insulated. The L.R. Sweezy No. 1 well is located at the center of the indicated grid block. The well block is square ($\Delta x_1 = \Delta x_2 = 180.45$ ft) as are its neighbors, but the dimensions of the grid blocks increase with distance away from the well. The Cib Jeff reservoir is taken to be flat with uniform thickness $h = 50$ ft. The area of the simulated reservoir is approximately 830 acres.

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

Rock grain density, $\rho_r = 164.4 \text{ lbm/ft}^3$ (2633 kg/m^3)

Initial porosity, $\phi_0 = 0.27$

Thermal conductivity, $c = 3.03 \text{ BTU/hr-ft}^\circ\text{F}$ ($5.25 \text{ w/m-}^\circ\text{C}$)

Rock grain specific heat, $C_{vr} = 0.23 \text{ BTU/lbm}^\circ\text{F}$ ($0.963 \text{ kJ/kg}^\circ\text{C}$)

Initial permeability, $k_0 = 125.6 \text{ md}$ ($124.0 \times 10^{-15} \text{ m}^2$)

Uniaxial formation compressibility C_m :

Figure 21: Numerical Grid Used in Preliminary 2-D Simulation

$$C_m = C_{mL} = 3 \times 10^{-6} \text{ psi}^{-1} (4.35 \times 10^{-10} \text{ Pa}^{-1}) \text{ for } \partial p / \partial t \leq 0$$

$$C_m = C_{mU} = C_{mL} \text{ for } \partial p / \partial t > 0$$

A drop in pore pressure causes a reduction in porosity ϕ and permeability k . The instantaneous porosity ϕ is given by

$$\partial \phi / \partial t = (1 - \phi) C_m \partial p / \partial t$$

The permeability k is, however, assumed to be constant.

Table 4 presents the relative permeabilities for water/gas employed in the CHARGR calculations to treat 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) geopressed wells. Table 4 shows that the gas phase remains essentially immobile for $S_g \leq 0.235$ (~ residual gas saturation), and the liquid-phase relative permeability declines dramatically with small amounts of free gas in the pores.

The reservoir fluid is taken to be a brine with salinity by mass $S = 0.095$, corresponding to a TDS of ~ 100,900 mg/L at standard conditions. The original pore pressure, temperature and methane mass fraction in the reservoir are assumed to be

$$P_o = 11,410 \text{ psia } (7.867 \times 10^7 \text{ Pa})$$

$$T_o = 237^\circ \text{F } (113.9^\circ \text{C})$$

$$\alpha_o = 0.002$$

This value of α_o corresponds to GWR ~ 17.5 cf/bbl at the L.R. Sweezy well separator conditions (~ 620 psig, ~ 120°F), according to the S-CUBED brine/methane equation-of-state (Pritchett, et al., [1979]).

Table 4
Relative Permeabilities

<u>Liquid Relative Permeability (k_{rg})</u>	<u>Free Gas Saturation (S_g)</u>	<u>Gas Relative Permeability (k_{rw})</u>
0	1	0
0.25	0.71	10^{-4}
0.1	0.49	2×10^{-4}
0.235	0.12	5×10^{-4}
1	0	1

The effect of CO₂ content, the presence of entrained methane not separated and inaccuracies in the measurements make the gas content in the reservoir uncertain. A value of $\alpha_o = 0.00273$ corresponds to the brine being saturated with methane at reservoir conditions. The assumed values for the dynamic viscosity and compressibility of the reservoir fluid are also based on the S-CUBED equation-of-state.

$$\mu = 0.33 \text{ cp } (0.33 \times 10^{-3} \text{ Pa-s})$$

$$C_f = 2.69 \times 10^{-6} \text{ psi}^{-1} (3.90 \times 10^{-10} \text{ Pa}^{-1})$$

This value of μ differs from the value of $\mu \sim 0.44$ cp measured by Weatherly Laboratories, Inc. [1982] on a recombined fluid sample using a rolling ball viscometer. Also the values of C_m and C_f yield a total compressibility of

$$C_T = C_f + \frac{1-\phi}{\phi} C_m = 10.8 \times 10^{-6} \text{ psi}^{-1} (15.66 \times 10^{-10} \text{ Pa}^{-1}).$$

which is slightly larger than the value $10.4 \times 10^{-6} \text{ psi}^{-1}$ estimated in Section IV.

In the simulation, the variable rate drawdown and buildup history defined in Table 5 was imposed from the start of Flow Test No. 1 (at cumulative time $t = 0$). The skin factors applied for the various drawdown portions of the well test program were based on the multi-rate Horner analysis of Flow Test Nos. 3, 4 and 5 (Table 2). The apparent variation of these values with flow rate (Figure 10) was used to estimate the appropriate values of s for the other flow tests.

The results for this two-dimensional simulation are compared with the drawdown data for Flow Test Nos. 3, 4 and 5 in Figures 22, 23 and 24, respectively. The match with the drawdown data is

Table 5

Flow Rate History Used in Sweezy Simulation

<u>Flow Test Nos.</u>	<u>Cumulative Time hrs.</u>	<u>Flow Rate (BPD)</u>
No. 1	0 - 2.3833	6,939
	2.3833 - 40.626	0
No. 2	40.626 - 46.521	8,285
	46.521 - 195.723	0
No. 3A	195.723 - 198.773	2,172
	198.773 - 378.273	0
No. 3	378.273 - 409.116	6,455
	409.116 - 505.790	0
No. 4	505.790 - 531.476	8,615
	531.476 - 565.821	0
No. 5	565.821 - 691.044	11,000
	691.044 - 691.344	0
	691.344 - 709.837	11,000
	709.837 - 886.128	0
No. 6	886.128 - 1055.86	9,060
	1055.86 - 1095.88	0
No. 7	1095.88 - 1382.49	9,569
	1382.49 - 1384.78	0
No. 8	1384.78 - 1506.38	9,413
	1506.38 - 1696.68	0
No. 9	1696.68 - 2925.84	9,331
	2925.84 - 2928.49	0
	2928.49 - 2943.83	9,509
	2943.83 - 3037.59	0
No. 10	3037.59 - 3067.51	8,706
	3067.51 - 3212.11	0
	3212.11 - 4531.38	9,010
	4531.38 - 4537.51	0
	4537.51 - 4554.93	8,754
	4554.93 - 4872.84	0
No. 11	4872.84 - 5531.34	8,034
	5531.34 - 5561.51	0
	5561.51 - 6398.56	8,892
	6398.56 - 6404.01	0
	6404.01 - 6423.93	8,228
	6423.93 - 6549.43	0

Figure 22: Comparison of Drawdown Data from Flow Test No. 3 with Simulation

Figure 23: Comparison of Drawdown Data from Flow Test No. 4 with Simulation

Figure 24: Comparison of Drawdown Data from Flow Test No. 5 with Simulation

generally quite good. The agreement with the data for Flow Test No. 5 at late times shows that the combined effects of Fault C at ~ 600 ft and Fault A at ~ 1600 ft on the shape of the drawdown pressure history are satisfactorily reproduced by the simulation.

The comparisons for the buildup phase of various tests do not provide such agreements. The simulated results are compared with the buildup data for Flow Test Nos. 3, 4, 5, 8, 9, 10 and 11 in Figures 25 through 31. In general, the simulation predicts lower buildup pressures than the measured values. To understand the nature of this discrepancy, it is useful to plot (Figures 32 and 33)

$$(P_{\text{measured}} - P_{\text{calculated}}) \frac{10,000 \text{ BPD}}{q_N, \text{ BPD}} \text{ versus shutin time.}$$

The pressure difference is normalized to a flow-rate of 10,000 BPD, and q_N is the last flow-rate prior to shutin. Figures 32 and 33 show that for each buildup test, the normalized pressure difference versus log (shutin time) plot can be approximated by a straight line with slope ω . The slopes for each of the buildup tests are listed in Table 6. This suggests that the pressure discrepancy is due to some diffusive process unaccounted for in our simulation of the buildup response of the Parcperdue reservoir. We also note from Table 6 that the slope ω is essentially the same for buildup test Nos. 3, 4, 5 and 8; this implies that the as yet unknown diffusive process is the same for all these tests. The slope ω for long-term test Nos. 9, 10 and 11 is consistent from test to test; the value of ω for these tests is, however, substantially greater than that for Flow Test Nos. 3, 4, 5 and 8. The different ω values for the short-term and long-term tests suggest that some long-term processes (e.g. shale water recharge, formation creep) are operative in the Parcperdue reservoir. To perform a successful history-match of the available pressure/flow data, it is essential to define the nonlinear diffusive processes that are apparently responsible for the observed buildup response. We examine this problem in some detail in the next section.

Figure 25: Comparison of Buildup Data from Flow Test No. 3 with Simulation

Figure 26: Comparison of Buildup Data from Flow Test No. 4 with Simulation

Figure 27: Comparison of Buildup Data from Flow Test No. 5 with Simulation

Figure 28: Comparison of Buildup Data from Flow Test No. 8 with Simulation

Figure 29: Comparison of Buildup Data from Flow Test No. 9 with Simulation

Figure 30: Comparison of Buildup Data from Flow Test No. 10 with Simulation

Figure 31: Comparison of Buildup Data from Flow Test No. 11 with Simulation

Figure 32: Plot of Pressure Discrepancy versus Shutin Time for Buildup Tests 3, 4, 5 and 8

Figure 33: Plot of Pressure Discrepancy versus Shutin Time for Buildup Test Nos. 9, 10, and 11

**Table 6. Slope of Normalized Pressure Difference Versus
Log (Shutin Time) Plot**

<u>Buildup Test No.</u>	<u>Slope, ω psi/cycle</u>	<u>Comments</u>
3	63	Average value of ω for Test Nos. 3, 4, 5 and 8 = 56 psi/cycle
4	49	
5	57	
8	56	
9	98	Average value of ω for Test Nos. 9, 10 and 11 = 95 psi/cycle
10	95	
11	91	

VI. ANOMALOUS BUILDUP BEHAVIOR

6.1 Introduction

At the present time, it is clear that the Sweezy well exhibits an anomalous buildup behavior. Simply stated, pressure buildup following well shutin is much more rapid than pressure drawdown as a result of fluid production. During Flow Test No. 3, a downhole pressure of 10,970 psia was recorded just prior to shutting-in the well. The first pressure measured after shutin was 11,323 psia, recorded at shutin time $\Delta t = 0.082$ hours. This pressure increase of 363 psi may be compared with a pressure drop of only 235 psi at $t = 0.82$ hours during the drawdown part of Flow Test No. 3. In Section V, it was suggested that this anomalous buildup behavior is most likely the result of some as yet unspecified diffusive process(es). To quantify the effects of various possible mechanisms on buildup response, numerous parametric calculations were performed for Flow Test No. 3. The results of these parametric calculations are briefly described in subsection 6.2. This is followed by a second 2-D simulation of Flow Test Nos. 3, 4 and 5 (subsection 6.3); this simulation is only partially successful in so far as it fails to reproduce the late-time buildup response for Flow Test No. 5. Finally in subsection 6.4, we outline a possible approach for resolving the observed pressure response in the Sweezy well.

6.2 Parametric Studies for Flow Test No. 3

Since the drawdown phase of Flow Test No. 3 is apparently unaffected by reservoir boundaries, it is very likely that the buildup data for small shutin times are not influenced by any reservoir boundaries. The parametric calculations were therefore performed by using the CHARGR simulator in its 1-dimensional radial mode. The reservoir was assumed to be a right circular cylinder with height $h = 50$ ft and radius R chosen sufficiently large that no

signal reaches the outer boundary for the drawdown/buildup times of interest. Because our interest was focused on the anomalous rise in pressures for small shutin times, we first performed a number of calculations in which the finite difference zone size was varied to insure that the numerical resolution was fine enough in the vicinity of the well. The parametric calculations subsequently conducted were designed to investigate the following phenomena:

1. Leakage from overlying/underlying shales
2. Evolution of free gas in the aquifer
3. Wellbore backflow due to sand settling to the bottom of the well upon shutin
4. Two producing zones with different formation properties (compressibility, permeability, skin factor, etc.)
5. Irreversible formation compactions.

As the pressure in the reservoir decreases from its original value p_0 , there will be a vertical pressure gradient $\partial p / \partial z$ induced in the overlaying (underlying) shale layer. The effect of the flow into the reservoir from the shale dewatering may be approximated by a mass source within the reservoir given by

$$\dot{m} = \frac{k' \rho}{h \mu} \frac{\partial p}{\partial z}$$

where k' is the permeability of the shale, h is the reservoir thickness, ρ is the mass density of the recharge fluid and μ is the dynamic viscosity of the recharge fluid. The pressure gradient, $\partial p / \partial z$ may be approximated by $(p_0 - p) / h'$, where h' is the shale thickness. Thus

$$\dot{m} = A (p_0 - p)$$

where

$$A = k' \rho / h h' \mu$$

Calculations made with reasonable values for A (Shale Dewatering Cases) showed that shale recharge has little effect on the calculated buildup response. (This in no way implies that shale recharge may not have a significant effect on the long-term behavior of the reservoirs. See Sections IV and V).

Since there is uncertainty as to the actual gas saturation in the reservoir fluid, several calculations were made to examine the effect of this uncertainty. Calculations were made for $\alpha_0 = 0.002$ (Base Case, see Section V), 0.00273 (Saturation Case) and 0.004 (Free Gas Case). The presence of distributed free gas in the reservoir will decrease the relative permeability of the liquid brine; free gas buildup near the wellbore will increase the apparent skin factor. Since the permeability value inferred from the well test analysis (Section IV) includes the effect of any distributed free gas on the effective permeability, the calculations used input values of k that were increased accordingly. The drawdown and buildup response for the Saturation Case and the Free Gas Case were found to be essentially the same as for the Base Case.

From the large amount of sand produced at the surface it is obvious that the wellbore fluid during drawdown contains entrained particles of sand and silt. When the well is shut in, the entrained solid particles in the wellbore will precipitate downward with the larger particles settling faster than the smaller particles. During this brief precipitation period the effective density of the wellbore fluid at the sandface will be increasing and there may be some backflow into the reservoir. Such a reservoir/wellbore interface phenomenon may be expected to increase the speed of pressure buildup measured after the well is closed. To get a handle on this effect, a step-wise approximation to the pressure buildup history was imposed at the sandface in a calculation (Wellbore Backflow Case) in which the input parameters were otherwise the same as the Base Case (see Section V). It was found that for $0.2 \text{ hr} < \Delta t < 1 \text{ hr}$, injection at a rate as high as $\sim 9 \text{ kg/sec}$ is required to match the buildup response. The total volume injected during this

period (~ 6,400 kg) is about 4 percent of the wellbore volume. This unreasonably large value indicates that backflow from the wellbore after shutin is not the cause of the anomalous buildup behavior.

The sand interval penetrated by the Sweezy well can be separated into two distinct zones, upper and lower (see Section II). The upper sand (13,343 - 13,391 ft) permeabilities as measured by Terra Tek are generally higher than those of the lower sand (13,391 - 13,424 ft). The Sweezy well was cased to a depth of 13,534 ft and perforated from 13,349 to 13,388 ft and from 13,395 ft to 13,406 ft; in other words, the well produces from both the upper and lower sand zones. Numerical calculations (Layered Reservoir Case) show that it is possible to match the observed drawdown/buildup response for Flow Test No. 3 by using two producing zones with no cross-flow and with different formation compressibilities (drawdown phase only) and skin factors (buildup phase only). Furthermore, it is necessary to assume that the formation compacts irreversibly. In any event, it is important to point out that the resulting reservoir model is at best speculative and difficult to envision. It is not considered to be a viable model.

Terra Tek has carried out a limited number of both short-term (test time from a few minutes to an hour or two) and long-term (test time of a few days) tests designed to measure the compressibility of laboratory samples cut from recovered Cib Jeff cores. These tests imply that on the time scales of interest in reservoir response (days to months), the drawdown compressibility may be significantly greater than the buildup compressibility (see also Section II). If this nonlinear effect is present in the in situ formation, it would increase the rate at which the pressure builds up subsequent to shutting-in the well. [The radial diffusivity equation indicates that the pressure change is governed by both permeability k and diffusivity $\eta = k/\phi\mu C_T$.] Since

$$C_T = \frac{1-\phi}{\phi} C_m + C_f$$

the irreversible compaction enters through C_m .

In the following, we shall use subscripts L and U to denote the values of the subscripted variable during loading (increasing effective stress, i.e. $\partial p / \partial t > 0$) respectively. If $C_{mU} < C_{mL}$, then we have:

$$C_{TU} < C_{TL}$$

$$\eta_U > \eta_L$$

If $\eta_U > \eta_L$, then the pressure will increase at a faster rate during buildup than for the constant diffusivity ($\eta_U = \eta_L = \eta$) case. In the Base Case (Section V), C_{mL} and C_f were assumed to be $3 \times 10^{-6} \text{ psi}^{-1}$ and $2.7 \times 10^{-6} \text{ psi}^{-1}$ respectively. These values give for C_{TL} :

$$C_{TL} = \frac{1-\phi}{\phi} C_{mL} + C_f \sim 10.8 \times 10^{-6} \text{ psi}^{-1}$$

Calculations with CHARGR were made (Irreversible Compressibility Case) in which all the input parameters were the same as in the Base Case (Section V) except the uniaxial compressibility during unloading, C_{mU} , is assumed to be smaller than its value during loading, C_{mL} . If $C_{mL}/C_{mU} \sim 100$, then we have:

$$C_{TU} \sim 2.8 \times 10^{-6} \text{ psi}^{-1} \quad \text{and} \quad C_{TL}/C_{TU} \sim 3.9.$$

Although $C_{mL}/C_{mU} \sim 100$ is an extreme case, it was found that even this unrealistic assumption failed to provide the extremely rapid buildup response measured for the Sweezy well.

At this juncture, it is useful to recall that the compressibility value for C_{TL} used in the Base Case was inferred on the basis of the well geology shown in Figure 1. It is possible that the actual well geology (reservoir block volume, distance to

boundaries, etc.) may be substantially different from that shown in Figure 1. A smaller distance to the boundary Faults A and C (Figure 1) would imply a larger value for drawdown formation compressibility C_{TL} . A mean distance to boundaries of 550 ft (as opposed to 1100 ft, Figure 1) gives a C_{TL} of $41.6 \times 10^{-6} \text{ psi}^{-1}$.

Two additional calculations (Additional Irreversible Compressibility Cases) were run with the following values for the formation compressibilities:

$$\begin{aligned} \text{Case 1:} \quad C_{mL} &= 13 \times 10^{-6} \text{ psi}^{-1} \\ C_{mL}/C_{mU} &= 13 \\ C_{TL}/C_{TU} &\sim 7 \end{aligned}$$

$$\begin{aligned} \text{Case 2:} \quad C_{mL} &= 15 \times 10^{-6} \text{ psi}^{-1} \\ C_{mL}/C_{mU} &= 15 \\ C_{TL}/C_{TU} &\sim 8 \end{aligned}$$

All the parameters other than compressibilities and skin factors for these cases are identical with the Base Case. The calculated results are compared with data in Figures 34 and 35. Figure 35 shows that a compressibility ratio C_{TL}/C_{TU} between 7 and 8 (say ~ 7.5) is required to match the early-time buildup data.

6.3 Two-Dimensional History-Match Calculation with Irreversible Formation Compaction

A second two-dimensional simulation of the Parcperdue reservoir was made using the CHARGR simulator in an effort to match the buildup response. The numerical mesh is shown in Figure 36; all the boundaries of this grid are treated as impermeable and insulated. The Sweezy well is located at the center of the indicated grid block. This well block is square ($\Delta x_1 = \Delta x_2 = 164.0 \text{ ft}$) as are its neighbors, but the dimensions of the grid blocks increase with distance away from the well. The reservoir is

Figure 34: Comparison between Calculated and Measured Drawdown Pressures for Flow Test No. 3

Figure 35: Comparison between Calculated and Measured Buildup Pressures for Flow Test No. 3

Figure 36: Numerical Grid used in the Second 2-D Simulation

assumed to be flat with uniform thickness $h = 50$ ft and with an area $A \sim 626$ acres. Note that the upper boundary (corresponding to Fault A, Figure 1) has been moved from a distance of 1600 ft (Figure 1) to a distance of ~ 740 ft from the Sweezy well.

The formation and fluid properties, except for formation compressibility and skin factor, are taken to the same as those for the Base Case (Section V). The formation compressibilities used in this simulation are:

$$C_{TL} \sim 30.4 \times 10^{-6} \text{ psi}^{-1}$$

$$C_{TL}/C_{TU} \sim 7.5$$

The skin factors for Flow Test Nos. 3, 4, and 5 were recomputed using $C_{TL} \sim 30.4 \times 10^{-6} \text{ psi}^{-1}$ and the m' and b' values listed in Table 2.

Figures 34, 35, and 37 to 40 compare the results of this simulation with the drawdown and buildup pressures for Flow Test Nos. 3, 4 and 5. Calculated drawdown pressures (Figures 34, 37 and 39) display a reasonable agreement with data for all the flow tests. Referring to Figure 35, it is seen that the calculated pressures for shutin times less than ~ 1 hour lie far below the data; this is the result of the large size of the well block in the 2-D simulation. (Note that in the 1-D simulations where the near well bore region was finely resolved, the calculated pressure for $\Delta t < 1$ hour lie considerably above those from the 2-D simulation, Figure 35). With this exception, the buildup data from Flow Test Nos. 3 and 4 show good agreement with the calculated values. The comparison for the late-time buildup phase of Flow Test No. 5 does not provide such agreement. The data (Flow Test No. 5) show flattening of the buildup curve for large shutin times; the calculated pressures, however, continue to increase. The simulation gives a much higher average reservoir pressure at the end of Flow Test No. 5 than that inferred from the buildup data (see Table 3).

Figure 37: Comparison between Calculated and Measured Drawdown Pressures for Flow Test No. 4

Figure 38: Comparison between Calculated and Measured Buildup Pressures for Flow Test No. 4

Figure 39: Comparison between Calculated and Measured Drawdown Pressures for Flow Test No. 5

Figure 40: Comparison between Calculated and Measured Buildup Pressures for Flow Test No. 5

6.4 Towards Modeling the Anomalous Buildup Response

The failure to match the late-time buildup data from Flow Test No. 5 implies that the irreversible formation compaction model of subsection 6.3 is deficient. The "irreversible formation compaction" assumption influences the pressure response in two ways. First, it implies that the diffusivity during loading η_L is greater than its value on unloading η_U ; this is apparently necessary to match the sharp rise in buildup pressures at small shutin times. Second, a value of C_{mU} smaller than the value of C_{mL} results in a permanent pore volume compaction as the formation is cycled through a load (pressure drawdown) and unload (pressure buildup) cycle. The permanent decrease in pore volume keeps the average reservoir pressure from falling as low as it would for a purely elastic ($C_{mU} = C_{mL}$) formation. This feature is apparently responsible for the discrepancy between the late-time calculated and measured buildup pressures from Flow Test No. 5 (Figure 40).

Since the "irreversible formation compaction" assumption alone cannot be used to match the observed response of the Sweezy well, we need to examine additional mechanisms. The linearized radial diffusivity equation implies that the pressure response is governed by both permeability k and diffusivity $\eta (=k/\phi\mu C_T)$. This suggests that it may be possible to reproduce the anomalous buildup behavior by using a pressure-dependent (and possibly a history-dependent) permeability. During production, the permeability decreases in the reservoir region experiencing pressure drawdown. The permeability (and hence diffusivity) will increase in the near wellbore region on shutting in the well. Garg et al [1978] report some calculations designed to investigate the effects of irreversible formation compaction, and pressure and history dependent permeability on well response. (In these calculations, permeability was assumed to be a unique function of porosity ϕ . Permanent pore compaction results in irreversible changes in permeability.) Because of the narrow range

of parameter values considered by Garg et al, it is not possible to use their results to analyze the pressure response for the Sweezy well. A more detailed parametric investigation is required to fully characterize the effects of stress-induced hysteresis in formation properties on well response. We believe that such a research program offers at present the best hope for understanding the anomalous buildup data from the short-term and intermediate-term flow tests. Modeling of long-term flow tests will probably require the consideration of additional effects such as shale recharge and long-term (test time of several months) formation creep.

VII. CONCLUDING REMARKS

The pressure buildup response for the Sweezy well remains at present an enigma. It need hardly be stressed that we must have an adequate understanding of this behavior if we are to make a successful prediction of the production capability of geopressed geothermal systems such as the Parcperdue reservoir. The research effort described in the preceding sections suggest some fruitful avenues for future work. Thus, it is likely tha the pressure response from the short-term and intermediate-term flow tests is, primarily, the result of stress-induced hystersis in formation permeability and compressibility. The pressure response from long-term flow tests may involve additional formation drive mechanisms such as shale recharge and formation creep. A combined laboratory and theoretical program is required to make further progress in this matter. A comprehensive laboratory test program on recovered Cib Jeff cores may be especially useful in characterizing stress-induced changes in formation permeability and compressibility, and in understanding the long-term creep behavior of the reservoir rocks. Unfortunately, the very process of coring subjects the recovered cores to a complex loading path, and it may well be impossible to restore these cores to the in situ conditions. The theoretical program should be helpful in elucidating the effects of various phenomena (stress-induced hysteresis in formation properties, shale recharge, etc.) on the well response. Future work planned by S-CUBED includes the application of simulator techniques to characterize more fully the formation properties required to match the observed pressure response from the Sweezy well.

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APPENDIX

Consider a cylindrical reservoir with a no-flow boundary at $r = R$ and a well located at its center. We assume that the well has been produced at constant rate q sufficiently long to establish semi-steady flow conditions in the reservoir. At time $t = t_p$ the well is shut in. The subsequent early-time buildup pressure (p_{ws}) after incremental time Δt is given by superposition of the semi-steady state and transient solutions (Earlougher [1977]):

$$p_i - p_{ws} = (\text{semi-steady state pressure drop caused by rate } q \text{ for time } t_p + \Delta t) + (\text{transient pressure drop caused by rate change } -q \text{ for time } \Delta t)$$

$$= + \frac{q\mu}{4\pi kh} \left[\frac{4k(t_p + \Delta t)}{\phi\mu C_T R^2} + \ln\left(\frac{R}{r_w}\right)^2 - \frac{3}{2} + 2s \right] + \frac{q\mu}{4\pi kh} \left[\ln\left(\frac{\gamma\phi\mu C_T r_w^2}{4k\Delta t}\right) - 2s \right] \quad (A-1)$$

$$= \frac{q\mu}{4\pi kh} \left[\frac{4k}{\phi\mu C_T R^2} (t_p + \Delta t) - \ln\left(\frac{4k\Delta t}{\gamma\phi\mu C_T R^2}\right) + \ln\left(\frac{R}{r_w}\right)^2 - \frac{3}{2} \right] \quad (A-2)$$

For $\Delta t \ll t_p$, Equation (A-2) reduces to

$$p_i - p_{ws} \approx + \frac{q\mu}{4\pi kh} \left[\frac{4kt_p}{\phi\mu C_T R^2} - \ln\Delta t - \ln\left(\frac{4k}{\gamma\phi\mu C_T R^2}\right) + \ln\left(\frac{R}{r_w}\right)^2 - \frac{3}{2} \right] = - \frac{q\mu}{4\pi kh} [\ln\Delta t + \text{constant}]$$

Therefore

$$\frac{q\mu}{4\pi kh} = m \text{ (slope of data on } p_{ws} \text{ vs } \log \Delta t \text{ plot for } \Delta t \ll t_p)$$

(A-3)

Or, since $n(t_p + \Delta t) \sim n t_p = \text{constant}$, we may write

$$\frac{q\mu}{4\pi kh} = m \text{ (slope of data on } p_{ws} \text{ vs } \log \frac{t_p + \Delta t}{\Delta t} \text{ plot for } \Delta t \ll t_p)$$

(A-4)

In practical oilfield units these two relations reduce to the familiar relation

$$k = \frac{162.6 q\mu B}{mh} \quad \text{(A-5)}$$

We have evaluated p_{ws} using the following parameters,

$$\begin{aligned} p_i &= 11,410 \text{ psia } (7.867 \times 10^7 \text{ Pa}) \\ \mu &= 0.33 \text{ cp } (3.3 \times 10^{-4} \text{ Pa} \cdot \text{s}) \\ \phi &= 0.27 \\ C_T &= 10.8 \times 10^{-6} \text{ psi}^{-1} (15.664 \times 10^{-10} \text{ Pa}^{-1}) \\ k &= 125.6 \text{ md } (1.2396 \times 10^{-13} \text{ m}^2) \\ s &= 0 \\ h &= 50 \text{ ft } (15.24 \text{ m}) \\ r_w &= 0.3177 \text{ ft } (0.09683 \text{ m}) \\ R &= 3415 \text{ ft } (1041 \text{ m}) \\ q &= 6872 \text{ bbls/day} \\ t_p &= 6531 \text{ hrs } (2.35118 \times 10^7 \text{ s}) \end{aligned}$$

The fluid/formation parameters are the linear approximation to those used for the base case MUSHRM calculations, R corresponds to the estimated volume of the Parcperdue reservoir block, q is the average flow rate of the L. R. Sweezy No. 1 well over the full 284.6 days of

the test program and t_p is the production time corresponding to the cumulative flow at the end of Flow Test No. 11. The plots corresponding to Equations (A-3) and (A-4) are presented in Figure A-1; both yield slopes which essentially recover the input formation permeability,

$$k = \frac{162.6 (.33) (6872)}{58 (50)} = 127 \text{ md}$$

Figure A-1. Pressure Buildup Subsequent to Semi-Steady State Production for Finite Cylindrical Reservoir.