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Title: RAFT RIVER PUMP SELECTION ANALYSIS

Organization: Geothermal Technical Development
Conversion Technology & Engineering Branch

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PREFACE

This report was originally written to provide an optimum selection of downhole pumps for supplying the Raft River Geothermal Facility, based on plant net power considerations. Although the methods reported herein are still applicable, the following recent developments have superseded the pump selections made herein.

1) It has been decided to increase the flow from production wells to the maximum obtainable with catalog - listed submersible pumps. (Pumps in wells RRGP-3 and RRGP-5 will be installed at the lower end of the 13-5/8 inch casing.)

2) Substantial improvement in the Raft River injection well capacity may be forthcoming due to well stimulation experiments and new injection well construction.

For updated recommendations of production pump sizing corresponding to Item 1) above, refer to Geothermal Electric Utilization Branch Engineering Design File EDF Serial No. 89 attached to this report as Appendix F.

1. INTRODUCTION

The following is an analysis investigating the relation between well pumping rates and overall plant power at the 5 MW Raft River geothermal plant #1. Information is generated to allow selection of well pumping rates, pump setting depths, and required characteristics of the supply and injection pumps.

The analysis proceeds with a simple analysis of plant power - flow split relationships from which the conclusion is drawn that the plant power, within certain limits, is insensitive to the flow split between wells.

A more complex analysis is then performed which examines flow split sensitivity with all four wells operating and sensitivity of plant power to supply flow increases. This analysis is summarized by tentative field flow rate selections and a data table. Tentative supply and injection pump selections are made and contingency pumps are discussed.

2. FLOW SPLIT SENSITIVITY STUDY

Curves of well drawdown vs flowrate, plotted from the equations given on page 10 of Appendix E are shown on Figures 1, 2, and 3. Wellhead temperatures used in this analysis for production wells are as follows:

Well	Wellhead Temp, °F
1	274
2	282
3	295
5	268

In appendix A the temperature loss in each supply line to the plant is calculated from an experimentally determined soil heat transfer conductivity of 0.25 Btu/hr-ft-°F, Reported in TREE-1114, Asbestos Cement Pipeline Experience at Raft River, by Miller, Kunze and Sanders, April 1977. The temperature loss in each supply pipe is given below:

	Flow Rate (gpm)	Q loss Btu/hr	Temperature drop, °F
Well 1 to plant	1000	1.2×10^5	0.27
Well 2 to plant	800	5.64×10^5	1.46
Well 3 to plant	800	5.30×10^5	1.42
Well 5 to plant	600	1.15×10^5	0.41

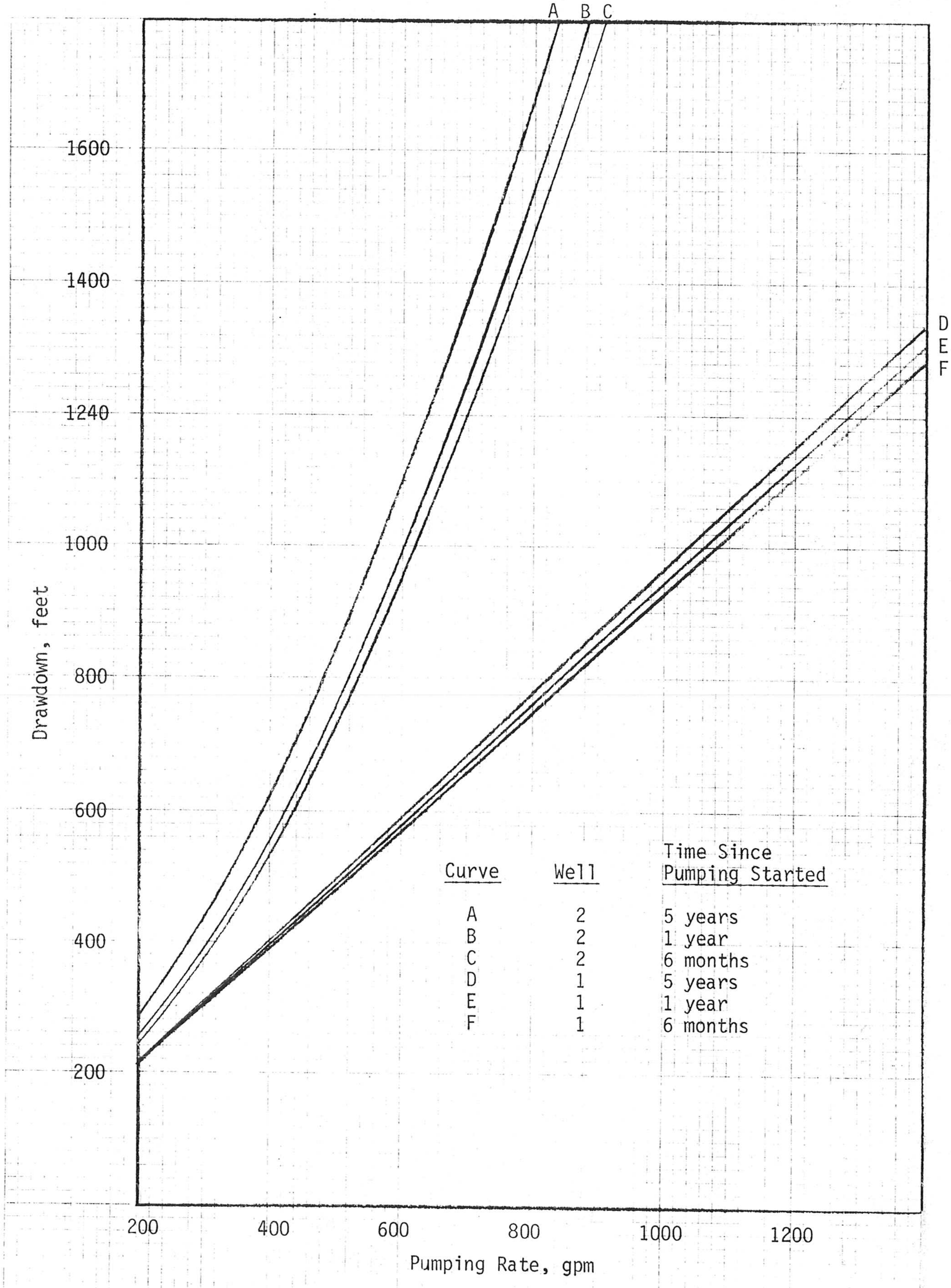

Figure 1. Well 1 and Well 2 Drawdown Characteristic

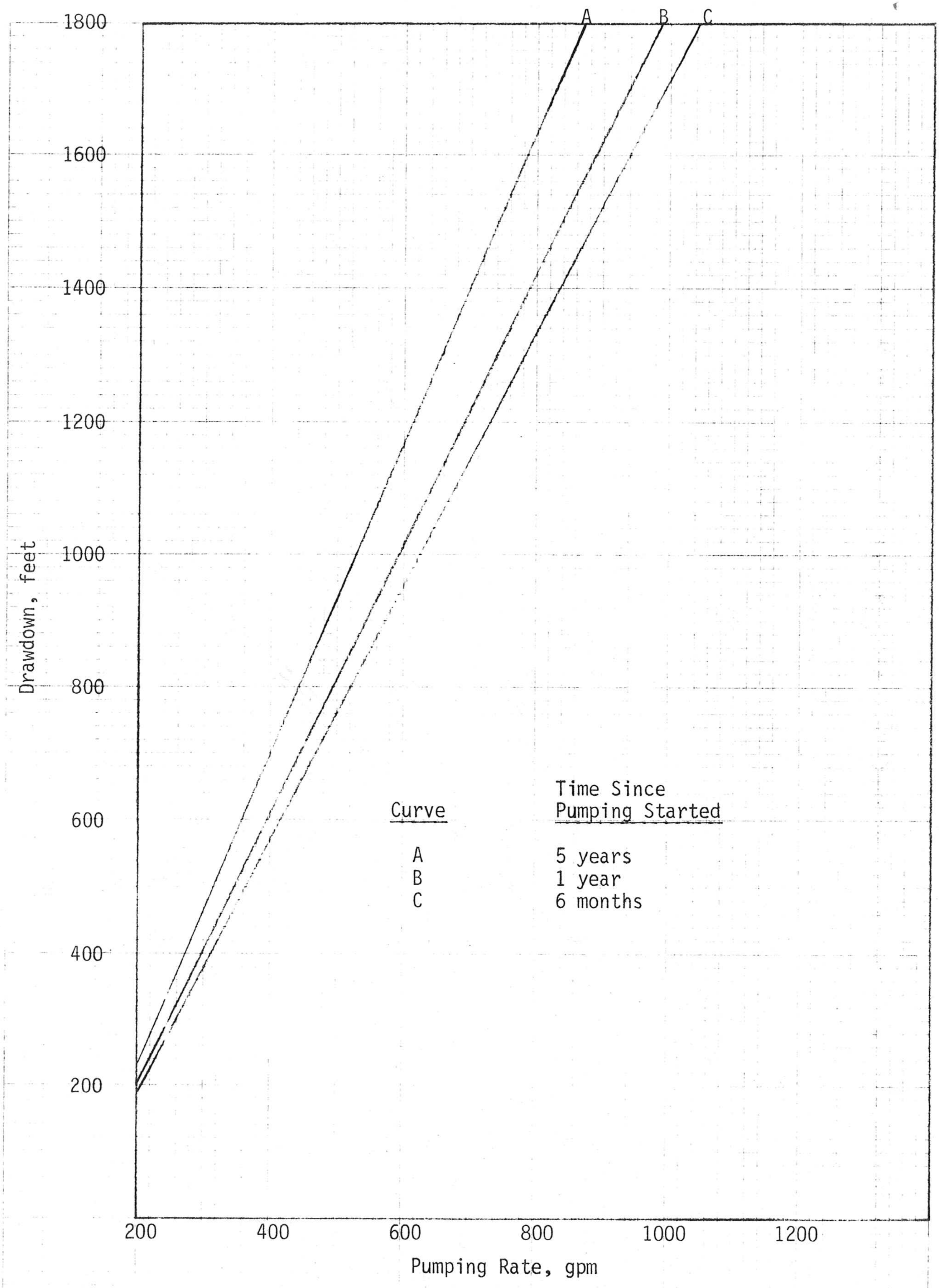

Figure 2. Well 3 Drawdown Characteristic

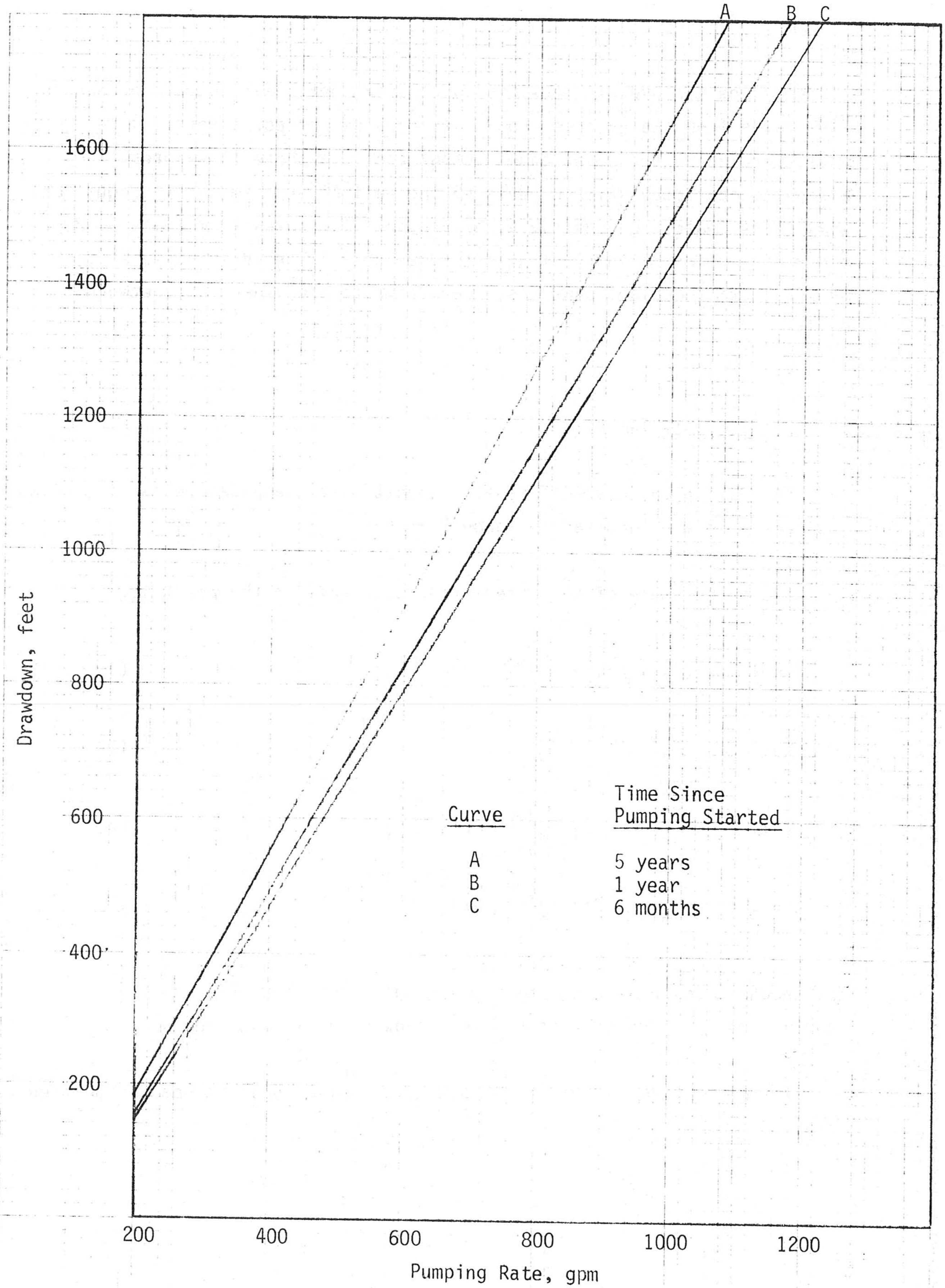

Figure 3. Well 5 Drawdown Characteristic

To determine the overall sensitivity of plant net power output to changing flow rates from the various supply wells, a set of equations will be written relating the plant power output (net) to these flow rates. Since the characteristics of Well #5 and Well #1 are similar the equations will investigate the sensitivity of varying flow rates from Wells 1, 2, and 3 only. The validity of this assumption will be verified later by showing that the plant power is insensitive to the flow split between wells.

2.1 Plant Supply Temperature

The variation in specific heat capacity with temperature is considered negligible in the temperature range 268-295°F.

The temperature of the stream from each well at the plant is:

Well 1 $$T_1 = 274 - \frac{1000}{W_1} (.27) \qquad (1)$$

Well 2 $$T_2 = 282 - \frac{800}{W_2} (1.46) \qquad (2)$$

Well 3 $$T_3 = 295 - \frac{800}{W_3} (1.42) \qquad (3)$$

Well 5 $$T_5 = 268 - \frac{600}{W_5} (0.41) \qquad (4)$$

The second term in each equation gives the temperature loss in the supply line as a function of the well flow rates w_1, w_2, and w_3.

The mixed temperature at the plant, assuming constant heat capacities, then, is:

$$T = [W_1(274 - \frac{100}{W_1}(0.27)) + W_2(282 - \frac{800}{W_2}(1.46))$$

$$+ W_3(295 - \frac{800}{W_3}(1.42)) + W_5(268 - \frac{600}{W_5}(0.41))]/(W_1 + W_2 + W_3 + W_5)$$

Plant Power

Calculations performed by R. W. Snyder reported in a letter from R. W. Snyder to O. J. Demuth, Snyd-3-78, July 7, 1978 are shown in Appendix B. These calculations determined the gross and net power values of the Raft River 5 MW plant as a function of brine supply temperature and flow rate. For our application, it was necessary to add the supply and injection system pumping power back into the net power values reported in the referenced letter so that the plant net power, before supplying well pumps is the result.

An examination of the model used in the referenced analysis revealed that the well pumping power was calculated in Snyder's model by the following equation:

$$Q_{sup} = [324.6\ WB + \frac{(WB - WEV)^2}{290 - WEV}(324.6)]\ 1.055 \times 10^{-3},$$

Where WB is the brine supply flow (lb/sec) and WEV is the cooling tower evaporation in lb/sec. Values of WEV for each run were supplied by personal communication from Snyder and are shown on Table I and Table II, following two pages. Values of Q_{sup} and the plant net power (before supplying well pumps) were then calculated for each run via the above equation and tabulated as shown on the tables. The resulting power values are plotted in Figures 4A and 4B which follow.

For plant design conditions (wet bulb temperature of 68°F) and at design supply flow, the plant net power shown in Figure 4A is well represented by the following:

TABLE I

BRINE FLOW AND TEMPERATURE MAPPING -- $T_{AIR\,WET} = 8°F$

Computer Runs: SNY6TK4 and SNY6TLE $T_{DRY} = 8°F$

Temp Brine In (°F)	Flow Brine (lbs/sec)	Power Net (MWE)	Power (ADJ) (MWE)	Power Gross (MWE)	Efficiency Net (%)	WEV (lbs/sec)	Temp Brine Out (°F)	Pinch Point ΔT_{Lb} (°F)	QSUP (KW)
290.	288.8	4.24	5.069	6.48	8.48	21.36	125.9	2.7	828.6
300.	288.8	4.74	5.566	6.97	8.90	23.16	125.3	2.7	825.9
300.	260.	4.41	5.115	6.52	8.86	21.26	118.4	2.6	704.7
300.	231.	4.06	4.652	6.03	8.79	19.40	110.6	2.7	591.9
290.	231.	3.68	4.274	5.66	8.44	18.23	111.1	2.7	593.5
280.	231.	3.30	3.895	5.29	8.03	17.10	111.2	2.8	595.1
270.	231.	2.94	3.537	4.93	7.62	15.97	111.4	2.9	596.8
270.	260.	3.16	3.871	5.28	7.63	17.25	118.9	2.9	710.7
280.	260.	3.57	4.279	5.67	8.08	18.48	119.0	2.8	708.9
280.	260.	3.77	4.601	6.02	8.06	19.72	126.2	2.7	831.1
270.	260.	3.34	4.173	5.59	7.60	18.37	125.9	2.8	833.1
270.	317.6	3.48	4.445	5.87	5.87	19.39	132.3	2.9	964.7
270.	346.5	3.59	4.696	6.13	7.45	20.32	138.3	2.9	1106.3
280.	346.5	4.13	5.233	6.66	7.98	22.32	138.5	2.7	1103.4
280.	317.6	3.97	4.932	6.35	8.02	21.03	132.5	2.8	962.3
290.	317.6	4.48	5.440	6.86	8.49	22.95	132.3	2.7	959.5
290.	346.5	4.68	5.780	7.21	8.46	24.35	138.5	2.7	1100.5

NOTE: Narrow pinch points are due to 10% fouling; design point pinch points are 10°F.

Fouling = 10%

Adjusted power is plant net power before supplying supply and injection pumps.

TABLE II

BRINE FLOW AND TEMPERATURE MAPPING -- $T_{\substack{\cancel{AIR}\\ WET}}$ = 65°F

Computer Runs: SNY6TVM and SNY6TKI T_{DRY} = 92°F

Temp Brine In	Flow Brine	Power Net	Power (ADJ)	Power Gross	Efficiency Net	WEV (lbs/sec)	Temp Brine Out	Pinch Points ΔT_{LB}	Pinch Points ΔT_{HB}	QSUP (KW)
(°F)	(lbs/sec)	(MWE)		(MWE)	(%)		(°F)	(°F)	(°F)	
290.	288.8	2.86	3.661	5.06	6.29	39.67	140.9	2.62	1.30	801.3
300.	288.8	3.35	4.148	5.54	6.91	41.59	140.8	2.55	0.97	798.4
300.	260.9	3.02	3.697	5.08	6.68	39.55	135.0	2.57	0.96	677.8
300.	231.8	2.66	3.226	4.59	6.38	37.31	128.8	2.57	0.39	566.5
290.	231.8	2.26	2.829	4.19	5.77	35.74	129.1	2.61	1.01	568.7
280.	231.8	1.87	2.440	3.80	5.07	34.22	129.1	2.67	1.31	570.8
270.	231.8	1.48	2.023	3.42	4.31	32.72	128.9	2.74	1.58	543.2
270.	260.9	1.73	2.415	3.79	4.65	34.45	134.7	2.77	1.76	685.3
280.	260.9	2.15	2.832	4.22	5.41	36.10	135.1	2.69	1.54	682.9
280.	288.8	2.39	3.194	4.59	5.64	37.77	140.8	2.70	1.60	804.1
270.	288.8	1.93	2.736	4.13	4.88	35.95	140.3	2.79	1.86	806.8
270.	317.6	2.10	3.038	4.44	5.04	37.30	145.6	2.81	1.96	938.3
270.	346.5	2.23	3.310	4.72	5.12	38.51	150.7	2.84	2.03	1080.3
280.	346.5	2.76	3.837	5.24	5.86	40.64	151.4	2.72	1.69	1077.4
280.	317.6	2.59	3.525	4.93	5.79	39.29	146.1	2.71	1.65	935.4
290.	317.6	3.11	4.042	5.44	6.46	41.33	146.5	2.62	1.32	932.4
290.	346.5	3.31	4.384	5.78	6.54	42.79	151.9	2.63	1.29	1074.3

Fouling = 10% Nominal all points

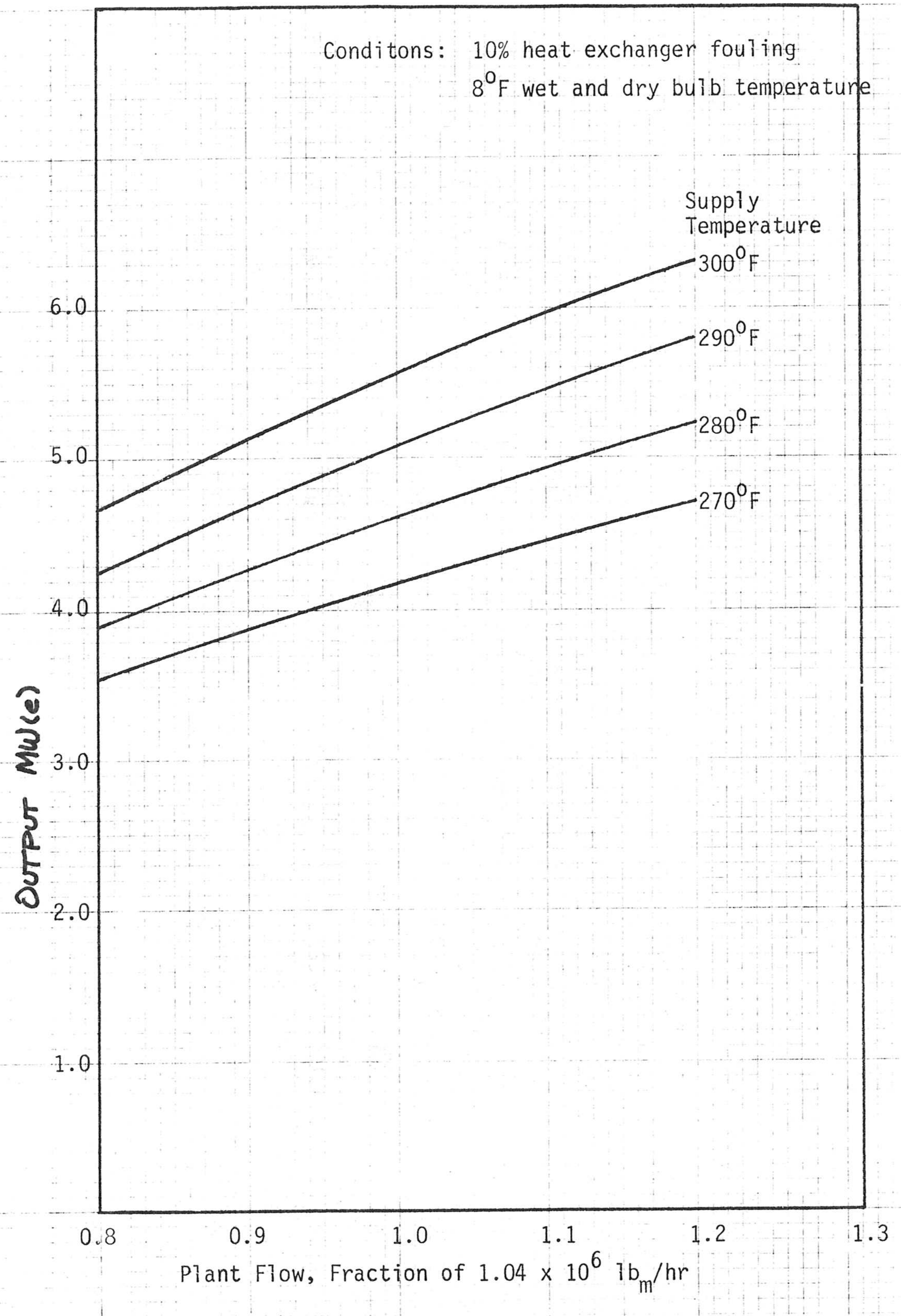

Figure 4A Plant output before supplying well pumps, winter conditions

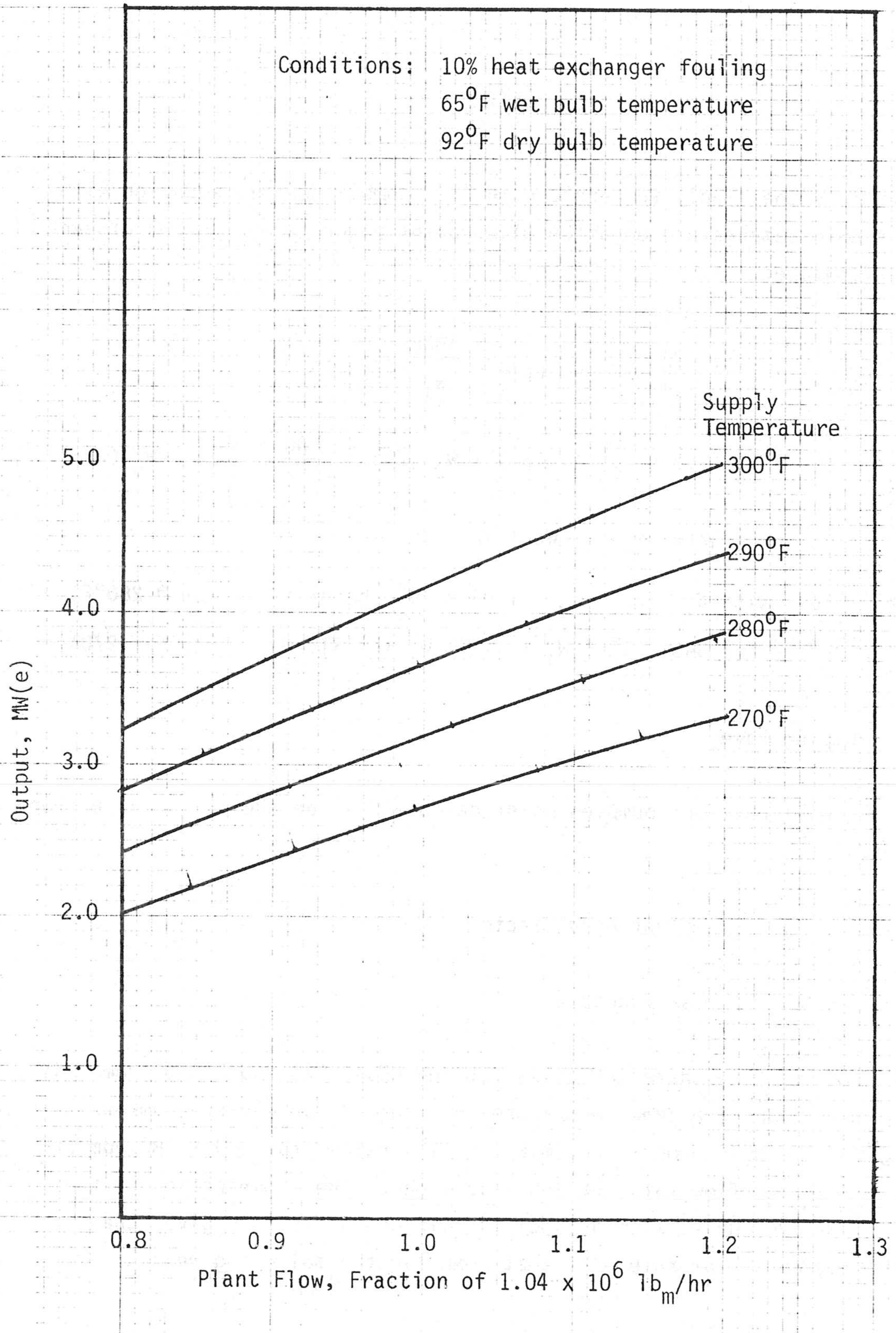

Figure 4B Plant output before supplying well pumps, summer conditions

$$Q_{plant} = 2.74 + 0.46 \left(\frac{T-270}{10}\right), \qquad (7)$$

where T is the supply temperature in °F. Combining this equation with the supply temperature equation gives plant power as a function of each well flowrate:

$$Q_{plant} = 2.74 + 0.046 \; [W_1 \; (274 - \frac{1000}{W_1} \; (0.27))$$

$$+ W_2 \; (282 - \frac{800}{W_2} \; (1.46)) + W_3 \; (295 - \frac{800}{W_3} \; (1.42) + W_5 \; (268 - \frac{600}{W_5} \quad (0.41)$$

$$- 270]/(W_1 + W_2 + W_3 + W_5$$

Simplifying, with $W_1 + W_2 + W_3 = 1.04 \times 10^6$ lbm/hr (2237 gpm @ 280°F) and $W_5 = 0$

$$Q_{plant} = 2.74 + 0.046 \; (.1225 \; W_1 + .1261 \; W_2 + .1319 \; W_3 - 1.1506 - 270)$$

2.2 Pumping Power

We will base our pumping power calculations on the following assumptions:

1) 85% plant usage factor

2) 5 year drawdown

Head vs flow characteristics for the REDA M675 and N1050 submergible deep well pumps are shown on Figures 5, 6 and 7 for various numbers of stages. The M675 pump is optimum for flow rates from 600 - 880 gpm and the N-1050 for flow rates of 900 - 1315 gpm. The intersection of the well drawdown curves with a specific pump characteristic gives the operating well flow rate with that pump for the following reason:

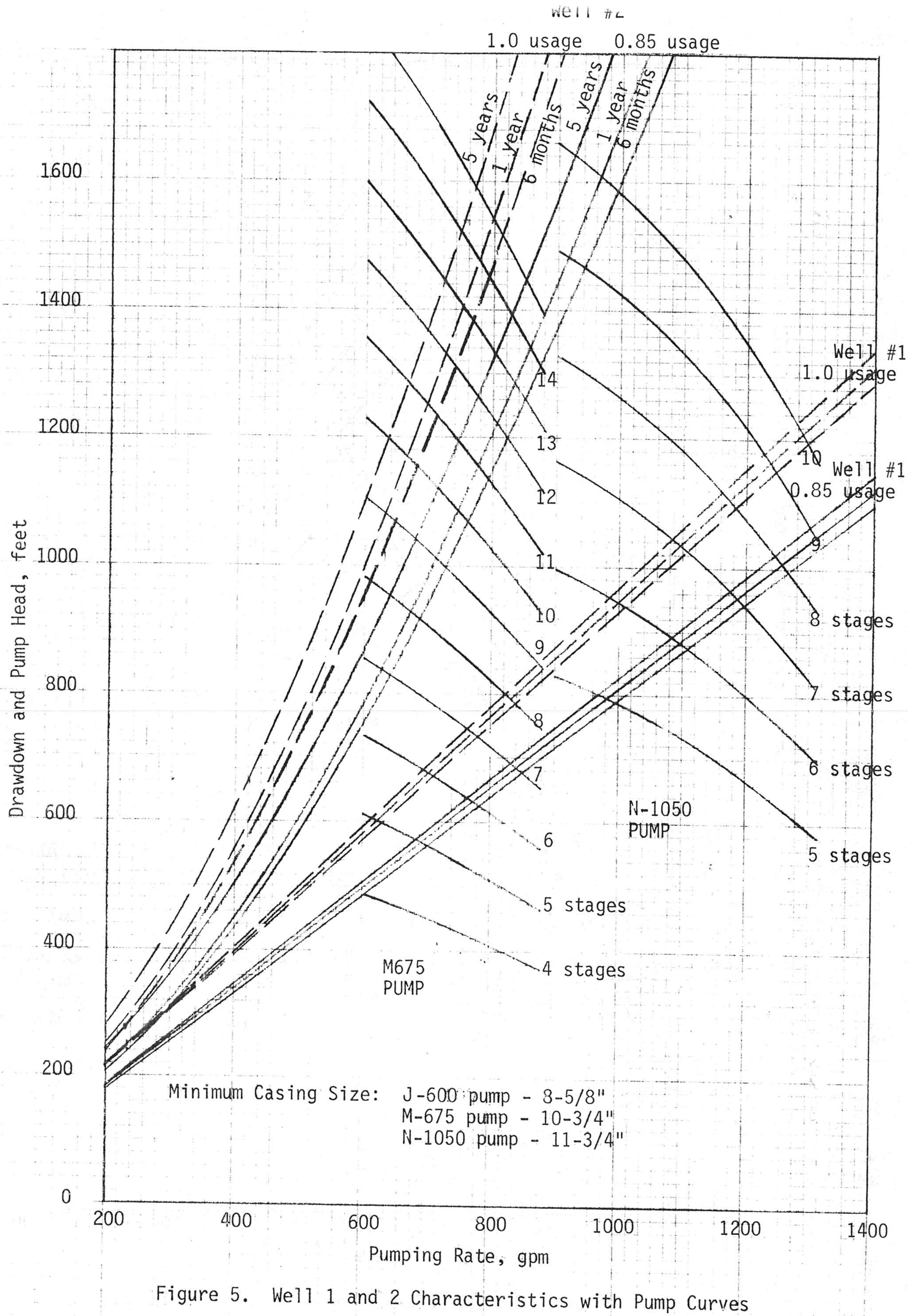

Figure 5. Well 1 and 2 Characteristics with Pump Curves

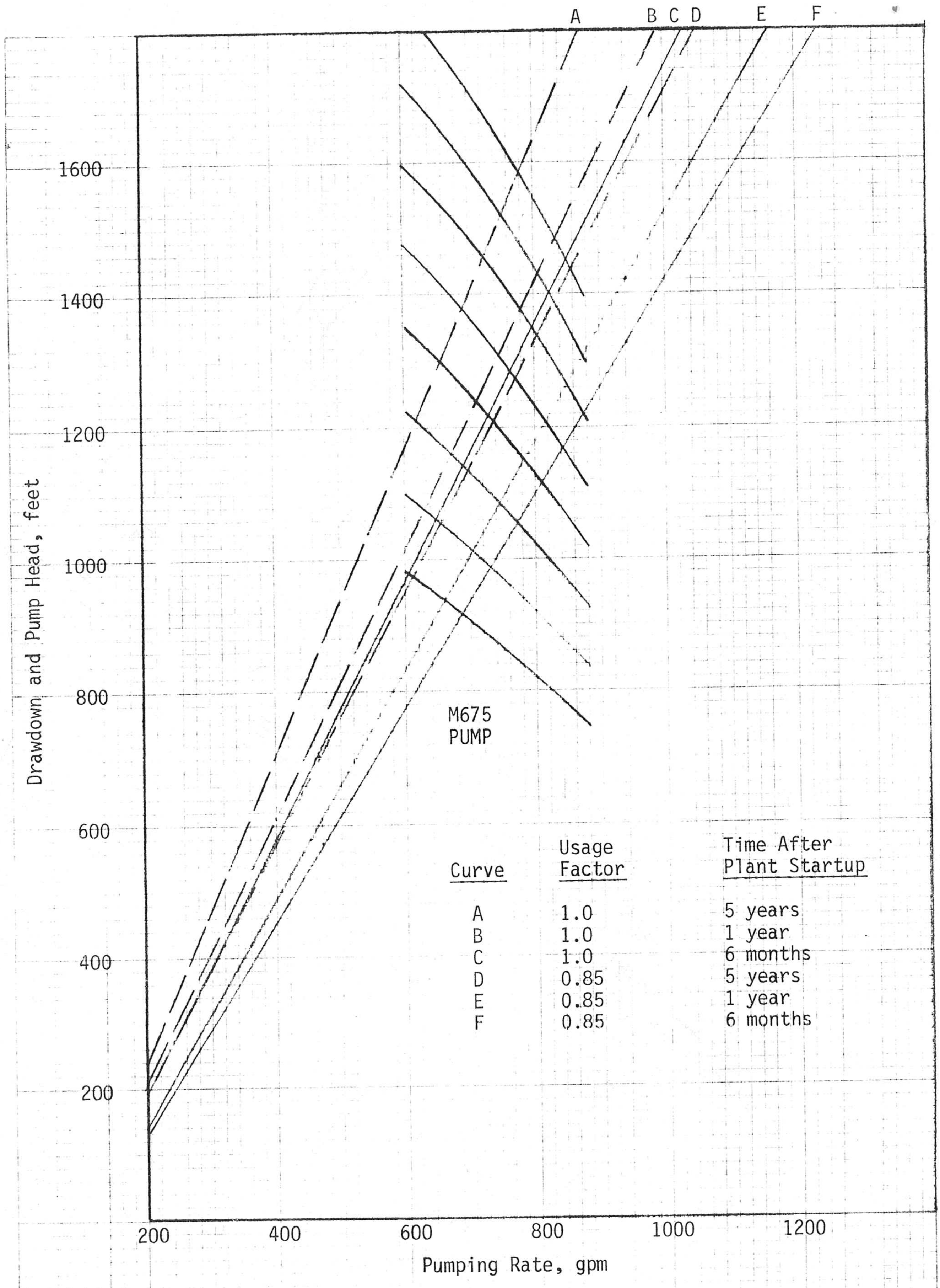

Figure 6. Well 3 Characteristics with M-675 Pump Curves

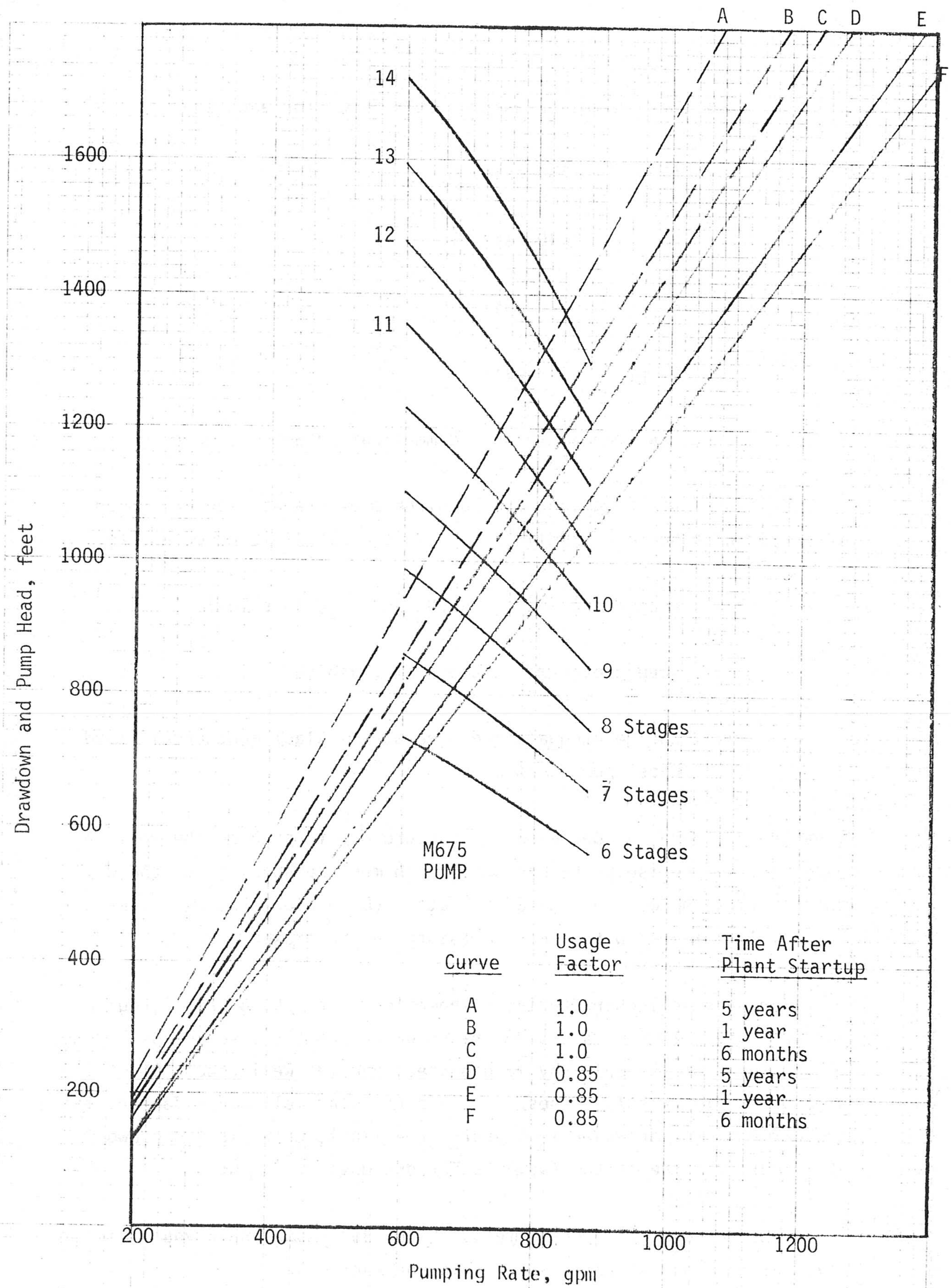

Figure 7. Well 5 Characteristics with M-675 Pump Curves

The shut in well pressure (zero flow) for each well is:

#1	140 psia
#2	140 psia
#3	130 psia
#5	135 psia

(Reference personal communication with D. Goldman)

During plant operation, the required pressure at each well head is in the neighborhood of 130-140 psia. This pressure is necessary to:

1) keep dissolved gases (N_2 and CO_2) in solution

2) keep geothermal fluid from flashing

3) Insure adequate pressure at the plant geothermal fluid boost pump suction.

Thus the drawdown, or decrease in pressure due to pumping the well in question, is precisely the pressure which must be supplied by the well pump to flow the well at the given rate. (Borehole friction losses are negligible compared with the uncertainty in the drawdown data).

For each well characteristic shown in Figures 5, 6, and 7, curves for well usage 100% of the time are shown by short dashes,for well usage 95% of the time are shown by long dashes, and for well usage 85% of the time are shown by solid lines. For a particular well usage factor, the top curve is the drawdown at 5 years, the middle curve is for drawdown at 1 year, and the bottom curve is for drawdown at 6 months.

Thus the operating characteristic for 85% usage and 5 years time is given by the topmost solid line curve for each well.

Initially, suppose for example, the following pumps were chosen for each well:

	Stages	Type	Flow rate (gpm)	5 yr, 85% usage drawdown (ft)
Well #1	6	M675	760	640'
Well #2	11	M675	722	1225'
Well #3	12	M675	755	1292'
Well #5	9	M675	732	990'

Figure 8 gives the motor load horsepower, per stage for the M-675 pump. Converting gpm to M^3/day

$$\left(\frac{gal}{min}\right) 5.451 = \frac{M^3}{day}$$

$$(760 \text{ gpm})\ 5.451 = 4143\ M^3/\text{day}$$

$$(722 \text{ gpm})\ 5.451 = 3935\ M^3/\text{day}$$

$$(755 \text{ gpm})\ 5.451 = 4115\ M^3/\text{day}$$

$$(732 \text{ gpm})\ 5.451 = 3990\ M^3/\text{day}$$

The horsepower for each well is (A cut impeller)

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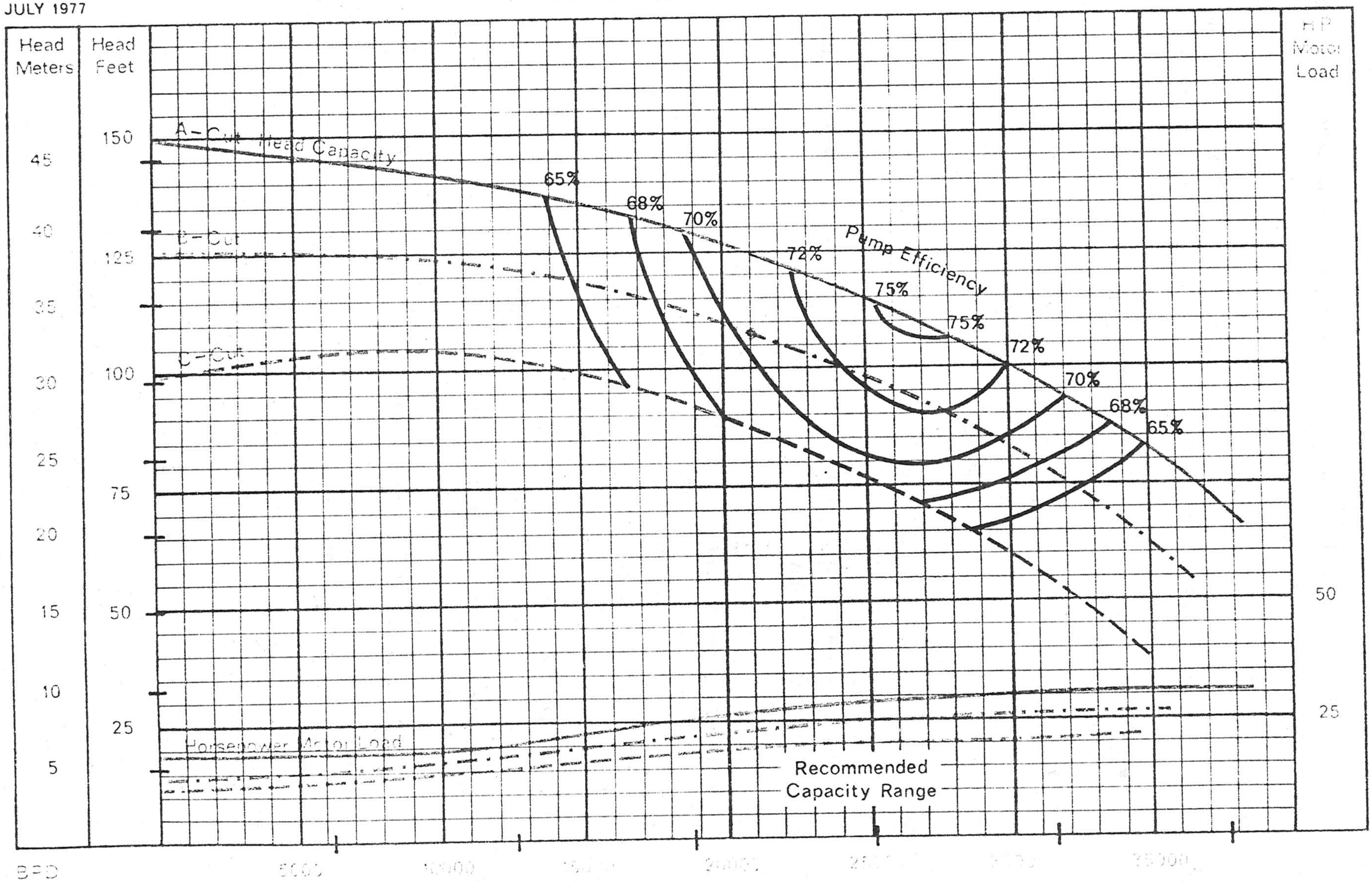
BARTLESVILLE, OKLAHOMA 74003
JULY 1977

Figure 8 —
Reda Pump Performance Curve
One Stage–M 675–60 Hz
862 Series – 3500 RPM

Minimum Casing Size
Check Clearances



Type M675

	Uncorrected hp/stage	Stages	Uncorrected overall hp	Corrected by 0.93 specific gravity @ 280°F
Well #1	28.5	6	171	159 hp
Well #2	28	11	308	286 hp
Well #3	28.5	12	342	318 hp
Well #5	28.8	9	259	241 hp

Assuming that one can create a pump or find a pump which will operate at an efficiency equal to the M675 at another set of head - flow conditions, the pumping power at a different set of flow rate and head values is related to an original set of head and flow rate values by

$$HP_2 = \left(\frac{gpm_2}{gpm_1}\right)\left(\frac{head_2}{head_1}\right) HP_1$$

where the subscript 1 refers to the original set of conditions and 2 refers to the new set. What this equation says, in effect, is that pumping power is proportional to the product of the volumetric flow rate and the pressure rise, at a given efficiency. For a given flow rate for Wells 1, 2, 3 and 5 of W_1, W_2, W_3, and W_5, then the pump horsepower for each well is (assuming constant efficiency):

<u>Well 1</u>

$$HP_1 = 159 \left(\frac{W_1}{760}\right)\left(\frac{\text{new head at flow } W_1}{640}\right)$$

Well 2

$$HP_2 = 286 \left(\frac{W_2}{722}\right) \left(\frac{\text{new head at flow } W_2}{1225}\right)$$

Well 3

$$HP_3 = 318 \left(\frac{W_3}{755}\right) \left(\frac{\text{new head at flow } W_3}{1292}\right)$$

Well 5

$$HP_5 = 241 \left(\frac{W_5}{732}\right) \left(\frac{\text{new head at flow } W_5}{990'}\right)$$

Referring again to the well drawdown characteristics at 5 yrs. and 85% usage on Figures 5, 6, and 7, note that the drawdown curves are linear for Wells 1 and 3. Also for Well 2 the curve can be well approximated by a linear fit in the 600-880 gpm range. The slope of each well characteristic curve is:

$$\text{Well 1} \quad \frac{200 \text{ ft}}{240 \text{ gpm}} = 0.833 \frac{\text{ft}}{\text{gpm}}$$

$$\text{Well 2} \quad \frac{540 \text{ ft}}{200 \text{ gpm}} = 2.7 \frac{\text{ft}}{\text{gpm}}$$

$$\text{Well 3} \quad \frac{405 \text{ ft}}{200 \text{ gpm}} = 2.025 \frac{\text{ft}}{\text{gpm}}$$

$$\text{Well 5} \quad \frac{316 \text{ ft}}{200 \text{ gpm}} = 1.58 \frac{\text{ft}}{\text{gpm}}$$

The drawdown in Well 1 at a new flow rate W_1 is:

$$\text{new head at flow } W_1 = 640 + 0.833\ (W_1 - 760)$$

Similarly for Wells 2, 3, and 5,

$$\text{new head at flow } W_2 = 1225 + 2.7\ (W_2 - 722)$$

$$\text{new head at flow } W_3 = 1292 + 2.025\ (W_3 - 755)$$

$$\text{new head at flow } W_5 = 990 + 1.58\ (W_5 - 732)$$

and the total supply well pumping power, operating Wells 1, 2, 3 and 5 is:

$$HP_{total} = HP_1 + HP_2 + HP_3 + HP_5, \text{ where}$$

$$HP_1 = 159\ \left(\frac{W_1}{760}\right)\ \left(\frac{640 + 0.833\ (W_1 - 760)}{640}\right)$$

$$HP_2 = 286\ \left(\frac{W_2}{722}\right)\ \left(\frac{1225 + 2.7\ (W_2 - 722)}{1225}\right)$$

$$HP_3 = 318\ \left(\frac{W_3}{755}\right)\ \left(\frac{1292 + 2.025\ (W_3 - 755)}{1292}\right)$$

$$HP_5 = 241\ \left(\frac{W_5}{732}\right)\ \left(\frac{990 + 1.58\ (W_5 - 732)}{990}\right)$$

Simplifying the total;

$$HP_{total} = \frac{159}{760} W_1 \left(1 + \frac{.833}{640} (W_1 - 760)\right) + \frac{286}{722} W_2 \left(1 + \frac{2.7}{1225} (W_2 - 722)\right)$$

$$+ \frac{318}{755} W_3 \left(1 + \frac{2.025}{1292} (W_3 - 755)\right) + \frac{241}{732} W_5 \left(1 + \frac{1.58}{990} (W_5 - 732)\right).$$

Changing into kilowatts (multiplying by 0.7452),

$$KW_{total} = .1559\, W_1\, [1 + .001302\, (W_1 - 760)]$$

$$+ .2952\, W_2\, [1 + .002204\, (W_2 - 722)]$$

$$+ .3138\, W_3\, [1 + .001567\, (W_3 - 755)]$$

$$+ .2453\, W_5\, [1 + .0016\, (W_5 - 732)].$$

Using this equation for pumping power, and

$$Q_{plant} = 2.74 + 0.046\, (.1225\, W_1 + .1262\, W_2 + .1319\, W_3 - 1.1506 - 270)$$

for the plant net power before supplying well pumps, the plant power and well pumping power are now calculated for various well flow rates which result in 2237 gpm total flow. The results are tabulated in Table 3, along with the mixed mean plant inlet temperature for several flow combinations.

Examination of Table 3 makes it abundantly clear that <u>THE PLANT NET POWER IS INSENSITIVE TO THE FLOW SPLIT BETWEEN WELLS</u>.

TABLE III

PLANT POWER WELL FLOW SENSITIVITY

Well flow, gpm 1	2	3	Plant Power before supplying supply pumps MW_e	Mixed Supply Temperature °F	Supply Pump Power MW_e	Net Power (less injection pumps) (MW_e)
760	722	755	3.319	282.58	.569	2.750
800	702	735	3.307	282.32	.553	2.754
840	682	715	3.295	282.05	.538	2.757
880	662	695	3.283	281.80	.526	2.757
920	642	675	3.271	281.54	.515	2.756
960	622	655	3.259	281.28	.505	2.754
1000	602	635	3.247	281.02	.497	2.750
1040	582	615	3.235	280.76	.491	2.744
1080	562	595	3.223	280.50	.486	2.737
1120	542	575	3.211	280.24	.483	2.728
740	702	795	3.333	282.88	.576	2.757
720	682	835	3.347	283.18	.585	2.762
700	662	875	3.361	283.49	.596	2.765
680	642	915	3.375	283.79	.610	2.765
660	622	955	3.389	284.09	.626	2.763
880	642	715	3.288	281.91	.525	2.763
880	622	735	3.293	282.03	.525	2.768
880	602	755	3.299	282.15	.526	2.773
880	582	775	3.304	282.26	.528	2.776
880	562	795	3.309	282.38	.531	2.778
880	542	815	3.315	282.49	.535	2.780
880	522	835	3.320	282.61	.540	2.780
880	502	855	3.325	282.73	.545	2.780
880	482	875	3.331	282.84	.552	2.779
880	462	895	3.336	282.96	.559	2.777
880	442	915	3.341	283.07	.568	2.773
920	522	795	3.303	282.23	.525	2.778
880	662	695	3.283	281.80	.526	2.757
880	682	675	3.277	281.69	.527	2.750
880	702	655	3.272	281.57	.530	2.742
880	722	635	3.267	281.45	.534	2.733
720	742	775	3.331	282.84	.586	2.745
680	762	795	3.343	283.10	.605	2.738
640	782	815	3.354	283.36	.625	2.729
600	802	835	3.366	283.62	.647	2.719
560	822	855	3.378	283.88	.671	2.707
0	1100	1137	3.546	287.52	1.165	2.381

This indicates that the pumping rates should be selected with the capability of running the plant on any three wells, so that if one well is down for maintenance the plant can be continued in useful operation.

3. OVERALL FIELD FLOW RATE OPTIMIZATION

The next portion of this analysis deals with optimizing the overall field flow rate, given the fact that the plant power is relatively insensitive to the particular flow split chosen.

Again a set of equations will be written to calculate the plant power and pumping power. In this case however injection pumping power will need to be calculated also.

3.1 Injection Pump Power

The injection pump power depends on the injection well characteristics shown in Appendices C and D. Present injection capacity is predicted in these appendices to be 400 gpm in Well #7 and 1250 gpm in Well #6 at 700 psi wellhead injection pressure with 5 years continuous pumping. Assuming 85% usage factor, $\frac{1250 + 400}{0.85} = 1950$ gpm can be injected with our present injection wells.

(If the injection rate is 1950 gpm and the usage factor is 85%, this means we are injecting at 1950 gpm 85% of the time and zero gpm 15% of the time. The average injection rate is then 0.85 x 1950, or 1650 gpm. This allows us to draw injection well characteristic curves where the pressure buildup at 1950 gpm with 85% usage is equal (on the average) to the pressure buildup at 1650 gpm continuous injection flow.)

The reason for limiting injection pressure to 700 psi at the wellhead is discussed in Appendix D. Basically, the limit is imposed to guard against upward fracturing of rock formations at the bottom of the well casing. These fractures could result in contamination of the near ground surface aquifers and necessitate abondonment of the affected well.

The injection pumping arrangement postulated at this point, for calculating a baseline injection pumping power value, consists of a total of five 7 stage Johnson Model 9DHC vertical turbine pumps, three of which will be located at Well #6, and two located at Well #7. The 9DHC pump is designed for a flowrate of about 500 gpm, and 3 pumps will give an injection capacity of about 1500 gpm at Well #6. The extra pump located at Well #7 will be located there in anticipation of possible well stimulation. The head/flow characteristic curve for a single stage 9DHC pump is shown on Figure 9. Horsepower per stage is 30.8 at a flow rate of 500 gpm. Note that since approximately 100 psia will be available at the injection pump suction as a result of the brine boost pumps in the power plant, only 600 psi head will be required from the injection pumps. In feet of 140°F injected water, this amounts to:

$$\frac{600\ lb_f/in^2}{61.39\ lb_m/ft^3} \quad \frac{144\ in^2}{ft^2} = 1407\ ft.$$

This head requires a 7 stage pump (see Figure 9). Total horsepower for 7 stages at 30.8 horsepower per stage is 215.6 hp/pump. Correcting for 140°F water, HP = $215.6\ \frac{61.39}{62.4} = 212.11$ hp. In KW, this is 0.7452 (212.11) = 158 KW, and for 2500 gpm (5 pumps) the total injection pumping power is:

$$5(158) = 790\ Kw.$$

Another consideration in optimizing the overall field flow rate is flow requirements for other experiments located at the Raft River Site. A compilation of experimental requirements was made by R. C. Schmitt and is shown in Table 4. Schmitt also noted that the aquaculture, agriculture (irrigation), and heat dissipation - soil warming experiments could use power plant discharge water at 140-150°F. The remaining requirements;

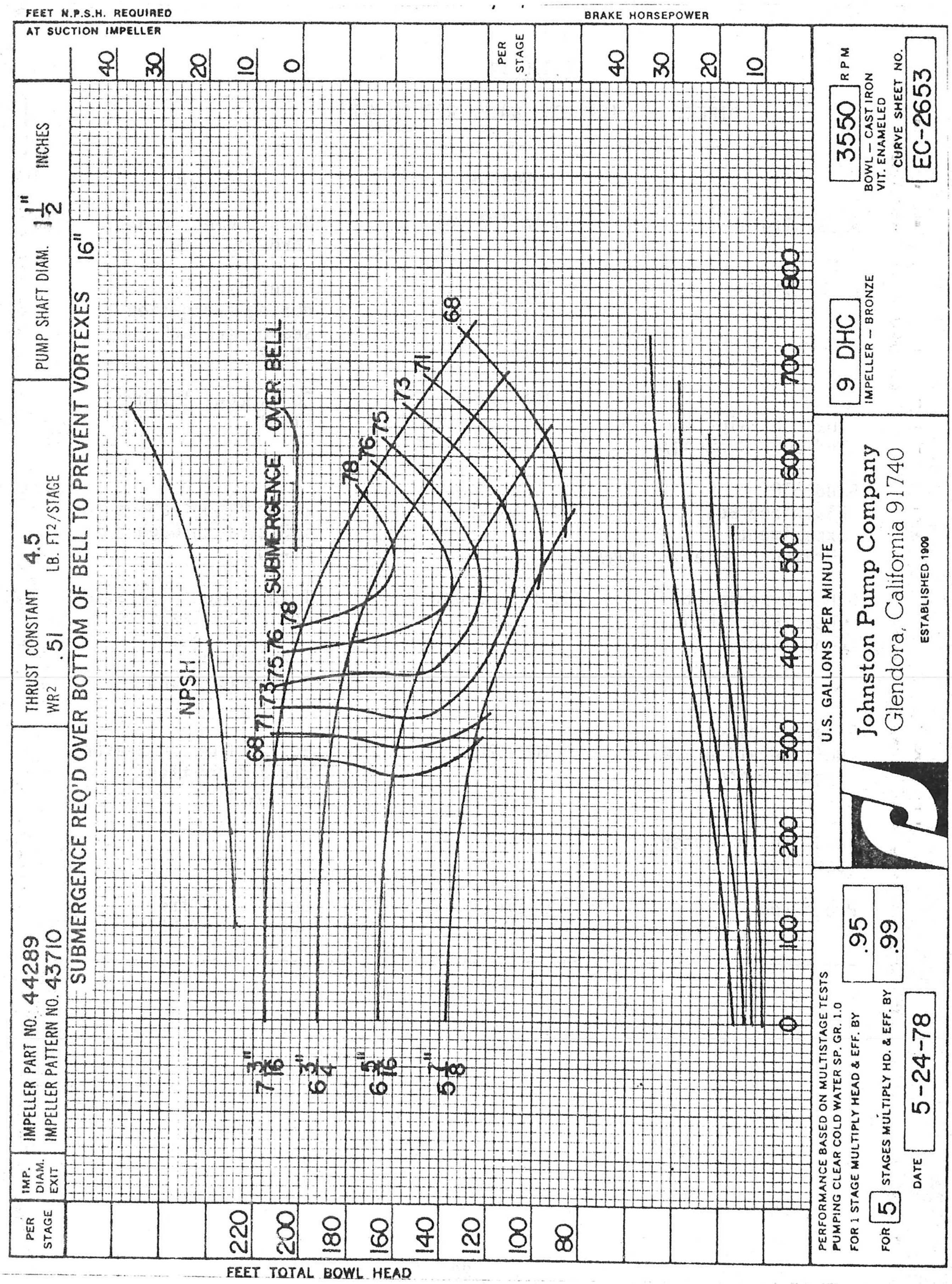


FIGURE 9 JOHNSTON 9DHC PUMP PERFORMANCE

TABLE IV

DIRECT APPLICATIONS WATER REQUIREMENTS

	Volume	Duration
Aquaculture	Up to 130 gpm	Mostly Continuous through FY-79
Agriculture	∿ 180 gpm	About 1/2 time during irrigation season through FY-82
HD-SW (Heat Dissipation and Soil Warming)	∿ 100 gpm	Continuous through FY-81
Bldg 610- Fluidized Bed Experiments (Drying, Space Heating)	20 - 80 gpm	Intermittent about 1/3 time through FY-80
Other Experiments (Heat Pump, Biomass Conversion, etc.)	Up to 100 gpm	Intermittent Operation less than 1/2 times Start about Mid FY-80 through FY-83
Site Buildings- Refrigeration - Air Conditicning	∿ 10 - 20 gpm	Mostly Cooling Season and Intermittent FY-79, 80
(Heating In Winter) (Same Requirement)		
Prototype	120 gpm	Continuous from June 1 FY-83

60 KW Prototype	120 gpm
Site Heating & A.C.	15 gpm
Heat Pump & Biomass Converter	50 gpm
Fluidized Bed Dryer	20 gpm
Total	200 gpm

add up to about 200 gpm (on a continuous basis). No allowance is made for the 500 KW direct contact plant at this point since it is assumed that other supply and injection flow requirements will be reduced accordingly when the 500 KW plant is in operation or a spare well will be used to supply the 500 KW plant. Note also that irrigation water will not be reinjected (180 gpm) but this is a summer savings in injection flow only.

Table 5 indicates the reinjection requirements as a function of overall field and plant flow rates, taking into account cooling tower evaporation losses, irrigation flow., and shrinkage due to cooling. A good approximation to the cooling tower evaporation losses calculated by Snyder's 5 MW plant model was found to be 140 gpm at 8°F wet bulb and 300 gpm at 68°F wet bulb, and 2250 gpm plant flow, adjusted proportionally to the actual plant flow.

Summer evaporation, gpm = 300 (W/2250)

Winter evaporation, gpm = 140 (W/2250),

W = plant flow rate, gpm

As shown previously, our present injection capacity at 85% usage is 1940 gpm at 700 psi wellhead pressure,

$$\frac{1250 + 400}{.85} \cong 1940,$$

of which capacity 1470 gpm is in Well #6 and 470 is in Well #7. If Well #7 can be stimulated to approximately 1000 gpm capacity at 700 psia

TABLE V

INJECTION FLOW RATES

Plant Flow (gpm)	Field Flow (gpm)	Experiment flow (gpm)	Cooling Tower Evap & Drift (gpm) Summer	Cooling Tower Evap & Drift (gpm) Winter	Irrigation Experiment (Summer only)	Shrinkage (5.6%) Gpm	Injection Flow, gpm Summer	Injection Flow, gpm Winter
2050	2250	200	273.3	126	180	115	1682	2009
2150	2350	200	286.6	133	180	120	1763	2097
2250	2450	200	300	140	180	126	1844	2184
2350	2550	200	313.33	146.22	180	132	1924	2271
2450	2650	200	326.66	152.44	180	137	2006	2360
2550	2750	200	340.00	158.66	180	143	2087	2448
2650	2850	200	353.33	164.88	180	149	2167	2536
2750	2950	200	366.66	171.10	180	154	2249	2624
2850	3050	200	380.00	177.33	180	160	2330	2712
2950	3150	200	393.33	183.55	180	166	2410	2800
3050	3250	200	406.66	189.77	180	171	2492	2889
3150	3350	200	419.99	196.80	180	177	2573	2977
3250	3450	200	433.33	202.22	180	183	2653	3064
3350	3550	200	446.66	208.44	180	188	2735	3153
3450	3650	200	459.99	214.66	180	194	2816	3241
3550	3750	200	473.33	220.88	180	200	2896	3329
3650	3850	200	486.66	227.10	180	205	2978	3418
3750	3950	200	500.00	233.33	180	211	3059	3506
3850	4050	200	513.33	239.55	180	217	3139	3593
3950	4150	200	526.66	245.77	180	222	3221	3682

then the overall capacity would be 2470 gpm. Our best estimate of expected performance from new injection wells, if added, would be to average the performance, as is, of Wells 6 and 7;

$$\frac{1940}{2} \sim 1000 \text{ gpm}$$

So a new injection well in combination with stimulation of Well #7 could reasonably be expected to increase our injection capacity to 3470 gpm at 700 psi injection pressure.

These possible injection scenarios are compiled in Table 6.

We have previously shown injection power required at 2500 gpm injection flow to be 790 KW. Figure 9, however shows the head per stage to be 186 feet. Seven stages provide 1302 feet of head. 600 psi head is required from the injection pumps (100 psi suction pressure is supplied by the brine boost pumps in the plant)

$$600 \text{ psi} \times \frac{144 \quad in^2/ft^2}{61.39 \quad lb_m/ft^3} = 1407 \text{ feet.}$$

Assuming pumps can be found which operate at the same efficiency as the 9DHC at 500 gpm, the KW required at 2470 gpm 600 psi head is:

$$KW = 790 \; \frac{1407 \text{ ft}}{1302 \text{ ft}} \; \frac{2470 \text{ gpm}}{2500 \text{ gpm}} = 843 \text{ KW}$$

at 1940 gpm, with no injection stimulation and 200 psia injection pressure,

$$KW = \frac{1940}{2470} (843) = 662 \text{ KW, and}$$

TABLE VI

POSSIBLE INJECTION SCENARIOS

Case #1 Injection as is @ #6, #7	Case #2 Stimulate #7	Case #3 Stimulate #7, and add new injection well
Capacity:	Capacity:	Capacity:
1940 gpm @ 700 psi	2470 gpm @ 700 psi	3470 gpm @ 700 psi

at 3470 gpm

$$KW = \frac{3470}{2470} (843) = 1184 \text{ KW}$$

The wellhead pressure for Well #6 is predicted by Figure 3 of Appendix C to be 120 psi at 5 years continuous injection due to interference and static wellhead pressure. If Well #7 and any other new injection wells behave similarly, and no reason is seen to believe that they won't, the head required from the injection pumps at any reasonably constant injection flow rate chosen will be zero at zero flow and $\sim$ 600 psi at the 700 psi injection pressure limit and will vary proportional to the flow between these values as shown by Figure 3 of Appendix C. In other words, the head required from the injection pumps will be approximately equal to the pressure buildup at the injection wellhead at the injection flowrate chosen.

Using the equation:

$$KW_2 = KW_1 \frac{\text{Head}_2}{\text{Head}_1} \frac{\text{flow}_2}{\text{flow}_1} \text{ (at constant pump efficiency)}$$

where subscript 2 refers to the new set of head-flow conditions and subscript 1 refers to the original set, the injection pumping powers for each injection scenario are:

<u>Case 1</u>: (700 psi injection limit reached at 1940 gpm)

$$KW_2 = 662 \left(\frac{\text{flow}_2}{1940}\right) \left(\frac{\text{flow}_2}{1940}\right)$$

Note that the ratio $\frac{\text{Head}_2}{\text{Head}_1}$ is equal to $\frac{\text{flow}_2}{1940}$ as explained in the previous paragraph.

Similarly for Cases #2 and #3

Case 2: (700 psi injection limit reached at 2470 gpm)

$$KW_2 = 843 \left(\frac{flow_2}{2470}\right) \left(\frac{flow_2}{2470}\right), \text{ and}$$

Case 3: (700 psi injection limit reached at 3470 gpm)

$$KW_2 = 1184 \left(\frac{flow_2}{3470}\right) \left(\frac{flow_2}{3470}\right)$$

Values of injection power for each injection scenario are tabulated in Table 7.

Note that the injection pressure limit of 700 psi is reached at 2150 gpm plant flow in the summer and at 1850 gpm plant flow in the winter with injection as is (1940 gpm injection capacity).

Taking into account evaporation and drift, the irrigation flows, and 5.6% shrinkage the equations for injection power during the winter are:

8°F wet bulb

Case #1: (injection wells "as is")

$$KW = 662 \; \frac{W - 140 \left(\frac{W-200}{2250}\right) (0.944)^2}{1940}$$

TABLE VII

INJECTION POWER FOR VARIOUS INJECTION SCENARIOS

	Case #1 Inject as is		Case #2 Stimulate #7		Case #3 Stimulate #7 and #8 drilled	
Field Flow	Summer	Winter	Summer	Winter	Summer	Winter
2250	.567	.651	.445	.623	.317	.443
2350	.623	.715	.490	.679	.348	.483
2450			.536	.737	.381	.524
2550			.584	.798	.415	.568
2650			.634	.843	.451	.613
2750			.687	.853	.488	.660
2850			.741		.527	.708
2950			.798		.567	.759
3050					.609	.811
3150					.652	.865
3250					.697	.920
3350					.743	.978
3450					.790	1.036
3550					.840	1.097
3650					.890	1.160

NOTE: that the injection pressure limit of 700 psi is reached at 2150 gpm plant flow in the summer and at 1850 gpm plant flow in the winter with injection as is (1940 gpm injection capacity).

Case #2: (Well #7 stimulated)

$$KW = 843 \frac{W - 140 (\frac{W-200}{2250})(0.944)^{2}}{2470}$$

Case #3: (Well #7 stimulated injection Well #8 added)

$$KW = 1184 \frac{W - 140 \frac{(W-200)}{2250} (0.944)^{2}}{3470}$$

and for 68°F wet bulb (summer conditions)

Case #1

$$KW = 662 \frac{(W - 180 - 140 (\frac{W-200}{2250}) (0.944)^{2}}{1940}$$

Case #2

$$KW = 843 \frac{(W - 180 - 140 (\frac{W-200}{2250})) (0.944)^{2}}{2470}$$

Case #3

$$KW = 1184 \frac{W - 180 - 140 (\frac{W-200}{2250})) (0.944)^{2}}{3470}$$

(W = field total flow rate)

3.2 Plant Power Equation

Now that we have equations for supply and injection pumping power, if we can get an equation for the plant net power before supplying well pumps in summer and winter we can optimize the overall field flow.

Going back to Figure 4A, the data is well fitted by the following:

$$KW = 2,025 + 0.37 \left(\frac{W-2000}{225}\right) - 0.2 \left(\frac{W-2000}{900}\right)^2$$

$$+ 0.4 \left(\frac{T-270}{10}\right) + 0.033 \left(\frac{W-2000}{900}\right) \frac{T-270}{10}$$

Where W = total field flow and total power plant flow = W-200

For winter conditions (Figure 4B) the data is fitted by:

$$KW = 3.55 + 0.34 \left(\frac{W-2000}{225}\right) - 0.2 \left(\frac{W-2000}{900}\right)^2$$

$$+ 0.365 \left(\frac{T-270}{10}\right) + 0.042 \left(\frac{W-2000}{225}\right) \left(\frac{T-270}{10}\right)$$

For flow from all four wells the mixed plant inlet temperature is:

$$T = [W_1 [274 - \frac{1000}{W_1} (.27)] + W_2 (282 - \frac{800}{W_2} (1.46)) + W_3 (295 - \frac{800}{W_3} (1.42))$$

$$+ W_5 (268 - \frac{600}{W_5} (1.41))]/W_1 + W_2 + W_3 + W_5$$

$$= \frac{274\ W_1 - 270 + 282\ W_2 - 1168 + 295\ W_3 - 1136 + 268\ W_5 - 246}{W_1 + W_2 + W_3 + W_5}$$

$$= 274\ W_1 + 282\ W_2 + 295\ W_3 + 268\ W_5 - 2820\ /\ W_1 + W_2 + W_3 + W_5$$

3.3 Field Flow and Plant Power Data; Flow Optimization

Using the preceeding equations for plant power, supply pumping power, and injection pumping power, the data in Table 8 were calculated and tabulated.

Note that in Case #1 with injection Wells 6 and 7 operating "as is", we are limited by injection capacity to a total field production rate of 2100 gpm. Any higher flow rate causes injection wellhead pressure to exceed 700 psi. Similarly in Case #2, the highest production flow possible is about 2700 gpm and in Case #3 the highest production flow possible is about 3800 gpm.

Thus, in Case #1 the highest net plant power possible is injection capacity limited to 2.336 MW_e, and in Case #2 the highest net plant power possible is 2.799 MW_e. For injection Case #3 the highest net plant power is realized at a production flow of about 3350 gpm, of which 3150 gpm goes to the power plant. Net yearly averaged power at this flow is 3.204 MW_e.

The various cases looked at in Table 8 indicated two superior choices in selection of pumping rates for Wells 1, 2, 3 and 5, within the injection capacity and 700 psi injection pressure constraints:

	Well #1 flow gpm	#2	#3	#5
Choice #1	1200	650	650	Standby (650 gpm pump installed)
Choice #2	650	650	650	650

TABLE 8

PLANT NET POWER AS A FUNCTION OF OVERALL FLOW

Flow Rates, gpm					Net Power (Before Supplying Well Pumps (MWe)		Injection pump Power (MWe)			Supply Pump Power (MWe)	PLANT OVERALL NET POWER								
							Case #1	Case #2	Case #3		Case #1 Injection As Is			Case #2 Stimulate #7			Case #3 Stimulate #7 and Add New Injection Well		
Total	Well 1	Well 2	Well 3	Well 5	68°F W.B.	8°F W.B.	Injection Wells 6 and 7 (as is)	With Well #7 Stimulated	Well #7 Stimulated and new injection well added		65° W.B.	8° W.B.	AVE	65° W.B.	8° W.B.	AVE	65° W.B.	8° W.B.	AVE
1600	400	400	400	400	1.600	3.138	0.353	0.277	0.197	0.169	1.078	2.616	1.847	1.154	2.692	1.923	1.234	2.772	2.003
1700	425	425	425	425	1.797	3.324	0.398	0.313	0.222	0.198	1.202	2.728	1.965	1.286	2.813	2.050	1.377	2.904	2.141
1800	450	450	450	450	1.990	3.506	0.440	0.350	0.250	0.229	1.315	2.831	2.073	1.411	2.927	2.169	1.511	2.027	2.269
1900	475	475	475	475	2.177	3.683	0.497	0.391	0.278	0.762	1.418	2.924	2.171	1.524	3.030	2.277	1.637	3.143	2.390
2000	500	500	500	500	2.359	3.854	0.551	0.433	0.308	0.248	1.510	3.005	2.258	1.628	3.123	2.323	1.715	3.210	2.463
2100	525	525	525	525	2.536	4.021	0.608	0.478	0.340	0.335	1.593	3.078	2.336 (1)	1.723	3.208	2.466	1.861	3.346	2.604
2200	550	550	550	550	2.708	4.183		0.524	0.373	0.375				1.809	3.284	2.547	1.960	3.435	2.698
2300	575	575	575	575	2.875	4.340		0.573	0.407	0.417				1.885	3.350	2.619	2.051	3.516	2.784
2400	600	600	600	600	3.037	4.492		0.624	0.444	0.462				1.451	3.406	2.679	2.131	3.586	2.859
2500	625	625	625	625	3.194	4.639		0.676	0.481	0.508				2.010	3.455	2.733	2.205	3.650	2.929
2600	650	650	650	650	3.346	4.781		0.732	0.521	0.557				2.057	3.492	2.774	2.268	3.703	2.986
2700	675	675	675	675	3.491	4.916		0.797	0.568	0.608				2.086	3.511	2.799 (2)	2.371	3.745	3.033
2800	700	700	700	700	3.635	5.051			0.604	0.660							2.371	3.787	3.079
3000	750	750	750	750	3.904	5.300			0.693	0.773							2.438	3.834	3.135
2500	650	600	650	600	3.203	4.648		0.676	0.481	0.502				2.025	3.470	2.748	2.220	3.665	2.943
2500	675	575	675	600	3.212	4.656		0.676	0.481	0.499				2.037	3.482	2.754	2.232	3.676	2.954
2500	700	550	700	550	3.221	4.665		0.676	0.481	0.497				2.048	3.492	2.770	2.243	3.687	2.965
2500	725	525	725	525	3.230	4.674		0.676	0.481	0.498				2.056	3.500	2.778	2.251	3.695	2.973
2500	750	500	750	500	3.239	4.683		0.676	0.481	0.501				2.062	3.506	2.784	2.257	3.701	2.479
2500	775	475	775	475	3.248	4.691		0.676	0.481	0.506				2.066	3.509	2.788	2.261	3.704	2.983
2500	800	450	800	450	3.257	4.700		0.676	0.481	0.513				2.068	3.511	2.790	2.263	3.706	2.985
2500	825	425	825	425	3.266	4.709		0.676	0.481	0.523				2.067	3.510	2.789	2.262	3.705	2.984
2500	850	400	850	400	3.275	4.717		0.676	0.481	0.534				2.065	3.507	2.786	2.260	3.702	2.981
2500	875	375	875	375	3.284	4.726		0.676	0.481	0.548				2.060	3.502	2.781	2.255	3.697	2.976
2500	900	350	900	350	3.293	4.735		0.676	0.481	0.564				2.053	3.495	2.779	2.248	3.690	2.969
3050	800	750	750	750	3.963	5.354			0.716	0.789							2.458	3.849	3.154
3100	850	750	750	750	4.021	5.407			0.741	0.805							2.475	3.861	3.168
3150	900	750	750	750	4.078	5.459			0.765	0.823							2.490	3.871	3.181
3200	950	750	750	750	4.133	5.509			0.790	0.842							2.501	3.877	3.189
3250	1000	750	750	750	4.187	5.558			0.814	0.862							2.511	3.882	3.197
3300	1050	750	750	750	4.240	5.606			0.839	0.883							2.516	3.884	3.201
3350	1100	750	750	750	4.292	5.653			0.864	0.905							2.523	3.884	3.204 (3)
3400	1150	750	750	750	4.342	5.698			0.891	0.928							2.523	3.879	3.201
3450	1200	750	750	750	4.392	5.742			0.917	0.952							2.523	3.873	3.195
2500	1200	650	650		3.278	4.721		0.676	0.481	0.626				1.976	3.419	2.698	2.171	3.614	3.893
2400	1100	650	650		3.133	4.584		0.624	0.444	0.579				1.930	3.381	2.656	2.110	3.566	2.841
2500	1100	700	700		3.306	4.748		0.676	0.481	0.644				2.986	3.428	2.757	2.181	3.623	3.902
2550	1050	750	750		3.404	4.841		0.703	0.501	0.694				2.007	3.444	2.726	2.209	3.645	2.928
3130	1230	630	625	645	4.001	5.383			0.755	0.749							2.497	3.879	3.188

(1) Optimum power case (injection case #1)
(2) Optimum power case (injection case #2)
(3) Optimum power case (injection case #3)

Plant yearly averaged net powers for these choices are:

	Choice #1	Choice #2	Optimum
1940 gpm injection capacity	2.336 MW_e	2.336 MW_e	2.336 MW_e
2470 gpm injection capacity	2.698 MW_e	2.774 MW_e	2.799 MW_e
3470 gpm injection capacity	2.893 MW_e (3.188)*	2.986 MW_e	3.204 MW_e

Additional consideration in selecting these two choices were:

1) Failure of either Well #2 or Well #3 in Choice #1 would result in very minor flow perturbation when Wells #2, 3, and #5 have similar flow rates.

2) Changing the flow split between wells was found to have little effect on plant power.

3) The head/flow curves for the REDA J-600 pump (which has maximum efficiency at about 600-650 gpm) are much steeper than the curves for the M-675. (Compare Figure 5 and Figure 10.) This selection of the 650 gpm flow rate and the J-600 pump provides "insurance" that any errors in predicted well characteristics will not be so likely to require changing out the pump for that particular well. Also note that the head/flow curve for the N-1050 pump is steeper for Well #1 at 1200 gpm than the M-675 curve for Well #1 at 750 gpm.

---

* (3.188) If standby well #5 is operated in choice #1 (3130 gpm overall field flow)

4) 650 gpm is about the upper limit for production in Wells #2 and #3 unless the packers in these two wells are drilled out. The packers are presently located at 1224 feet in Well #2 and 1175 feet in Well #3. (See Table 9, Figure 5, and Figure 6.) Well #2 should be able to produce about 690 gpm and Well #3 about 670 gpm with the present packer settings (Maintains > 90 psi above pump bowls at 5 years).

5) 9-5/8 inch casing begins at about 1188 feet in Well #3, and 1284 feet in Well #5. For any production rate greater than 700 gpm in Well #3, the drawdown is predicted by Figure 6 to exceed 1188 feet. The pump must be set at or near the drawdown level (e.g., if drawdown is 1188 feet, then the original wellhead pressure of 130-140 psi is still above the pump bowls).

   If Well #3 were to drawdown more than predicted, the pump would need to be set even deeper. This situation indicates selection of a pump for Well #3 that will fit inside the 9-5/8 inch casing so that it can be set as deep as necessary. Note that the maximum flow attainable with the 9-5/8 inch J-600 pump is about 700 gpm at a pump speed of 3500 Hz.

6) The plant yearly averaged net power for these two flow combinations would be within 16 KW of the optimum power case for Choice #1 and within 218 KW for Choice #2, in the event that Well #7 is stimulated and a new injection well is added. (Optimum case net power is 3.204 MW_e and is designated (3) in Table 8.)

7) The plant net power is within 101 KW of the optimum for Choice #1 and 25 KW for Choice #2 in the event that Well #7 is stimulated to twice its present capacity. Optimum case net power is 2.799 MW_e and is designated (2) in Table 8.

   Choice #1 has the disadvantages of requiring drillout of the packer located at 850 feet in Well #1, and slightly lower potential for maximizing the overall plant net power if a new injection well is added. It has the advantage, however, of providing a spare well.

TABLE 9

WELL	Packer Setting Depth, ft
#1	850
#2	1224
#3	1175

Note that in Choice #2, if <u>any</u> well goes out there will be a net flow decrease of 650 gpm.

4. PUMP SELECTION

Based on flow rates of 650 gpm for wells #2, #3, and #5 the following pumps are recommended, according to the best estimate well characterestics:

Well #2 (See Figure 11)

21 Stage I-600 pump

Provides 655 gpm @ 1 yr and 630 gpm @ 5 yrs

Well #3

21 Stage J-600 pump (See Figure 12)

Provides 660 gpm @ 1 yr and 625 gpm @ 5 yrs

Well #1

Case 1 - 1200 gpm capability (See Figure 5)

8 Stage N - 1050 pump

Provides 1240 gpm @ 1 yr and 1230 gpm @ 5 yrs

Case 2 - 650 gpm capability (See Figure 10)

12 Stage J-600 pump

Provides 670 gpm @ 1 yr and 660 gpm @ 5 yrs

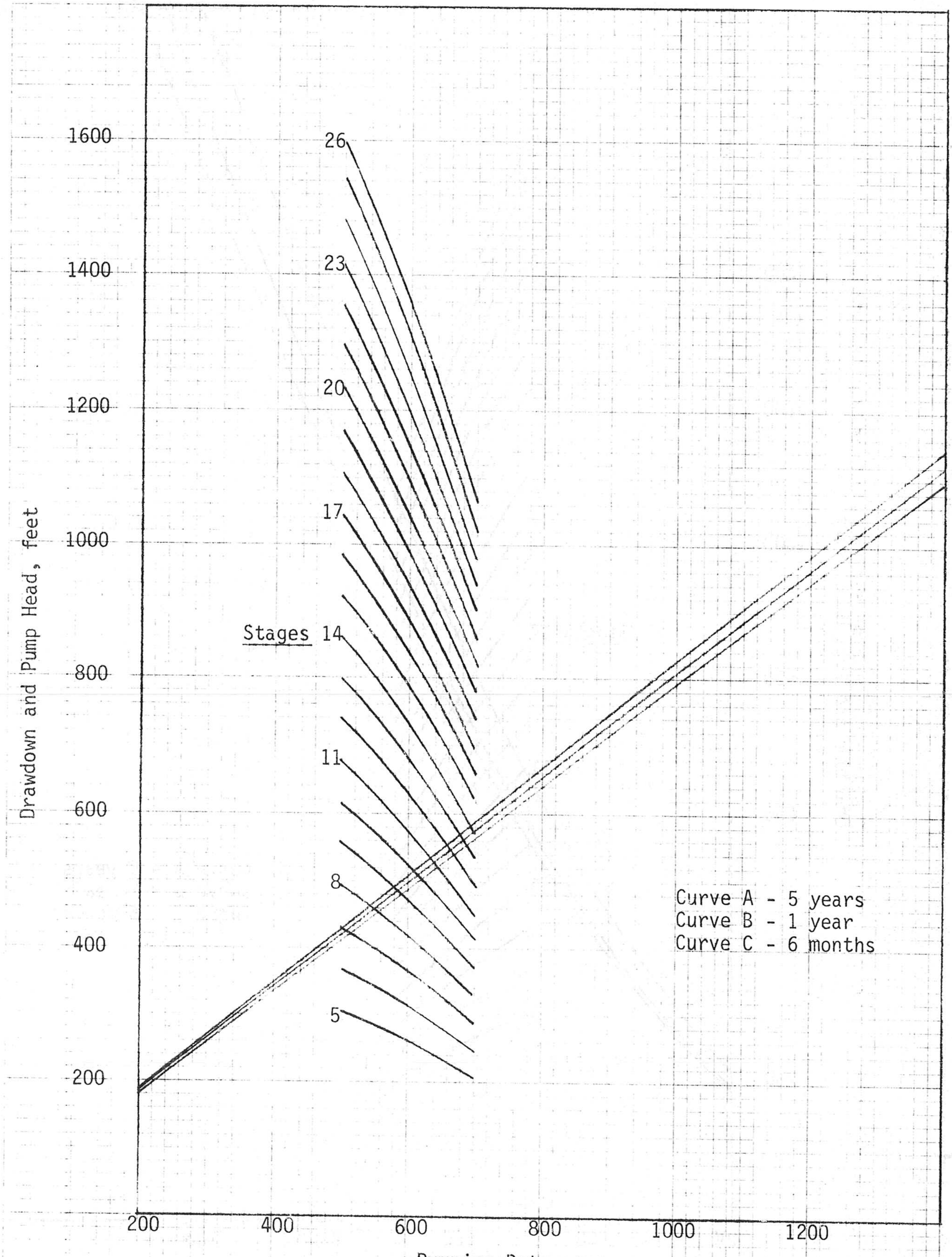


Figure 10. Well 1 with J-600 Pump, 0.85 Usage Factor

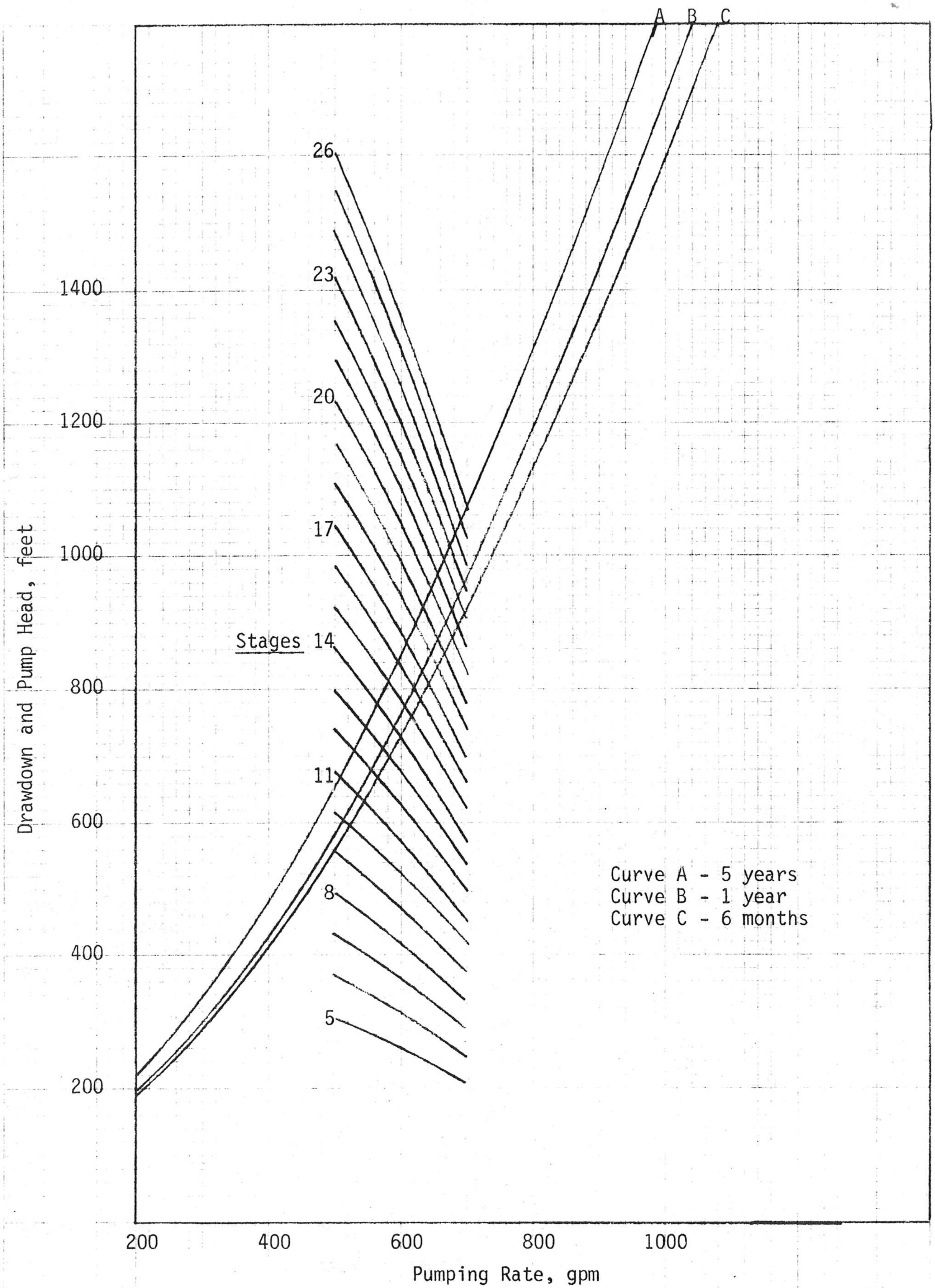


Figure 11. Well 2 with J-600 Pump, 0.85 Usage Factor

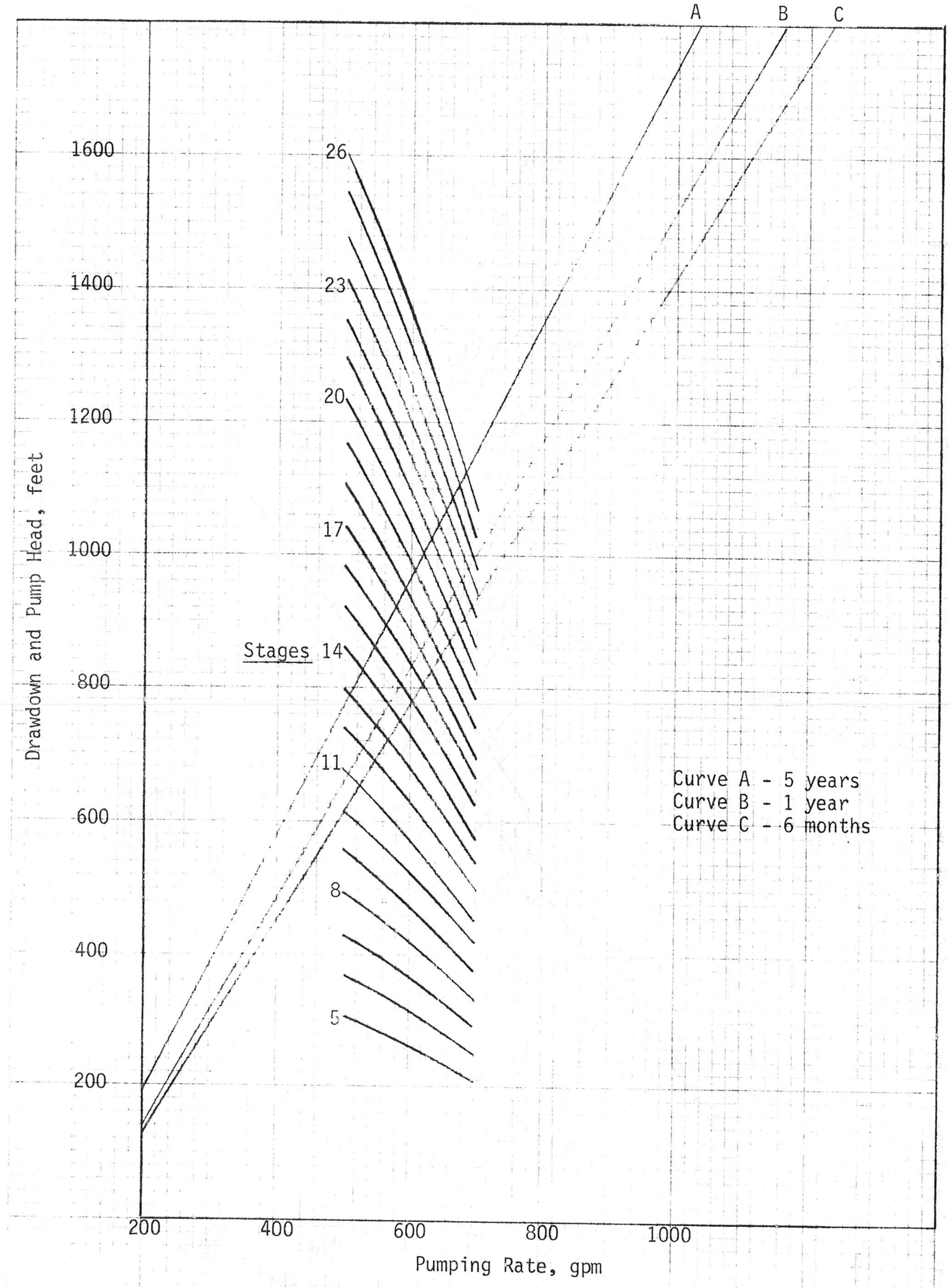


Figure 12. Well 3 with J-600 Pump, 0.85 Usage Factor

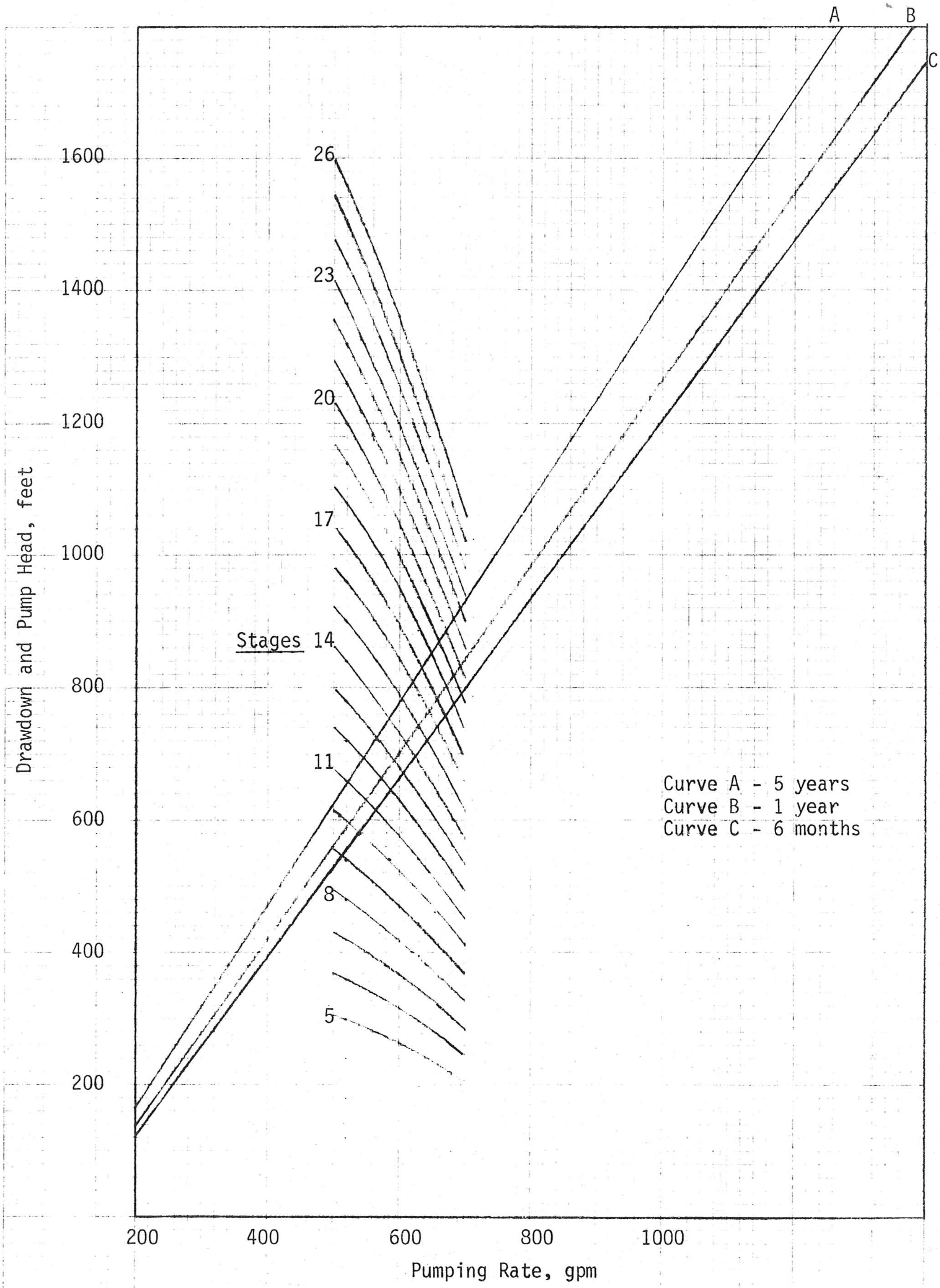


Figure 13. Well 5 with J-600 Pump, 0.85 Usage Factor

Well #5 650 gpm capability

Case 1 - 1200 gpm from well #1

In this case well #5 will be operated as a standby well, and should be capable of providing 100% flow for 6 months

18 stage J-600 pump

Provides 680 gpm continuously for 18 days and 645 gpm continously for 6 months.

Case 2 - 650 gpm from well #1

Also requires an 18 stage J-600 pump which provides 670 gpm for 1 yr and 645 for 5 yrs

4.1 Contingency Supply Pumps

It is recommended that contingency pumps be purchased for each well, in case the well turns out to draw down greater than anticipated. These contingency pumps should be chosen to provide 650 gpm at a head equal to the head where the original pump flow has decreased to 550 gpm, (1250 to 1050 on well #1 for case #1)

For each well these contingency pumps are:

Well #1 contingency pump

Case #1 10 stage N-1050 pump

Case #2 15 stage J-600 pump

Well #2 contingency pump

26 stage J-600 pump

Well #3 contingency pump

26 stage J-600 pump

Well #5 contingency pump

23 stage J-600 pump

4.2 Supply Pump Motors

For case #2, in order to simplify the purchase of spares, it is recommended that identical motors be perchased for all wells, able to power the highest head pump which is to purchased in the J-600 series. This pump is the 26 stage J-600 contingency pump for wells #2 and #3. Referring to Figure 14, the horsepower for 100 stages pumping water at 62.4 lb_m/ft^3 is 1140 hp.

For 27 stages, the horsepower required would be .27 (1140) = 307 hp for water @ 280° the load is 284 hp.

The 340 horsepower REDA 738 series motor would be adequate for any well and pump combination. Note that the purchase of identical motors for each well also allows the purchase of identical power transformers for each pump as each pump will use the same supply voltage.

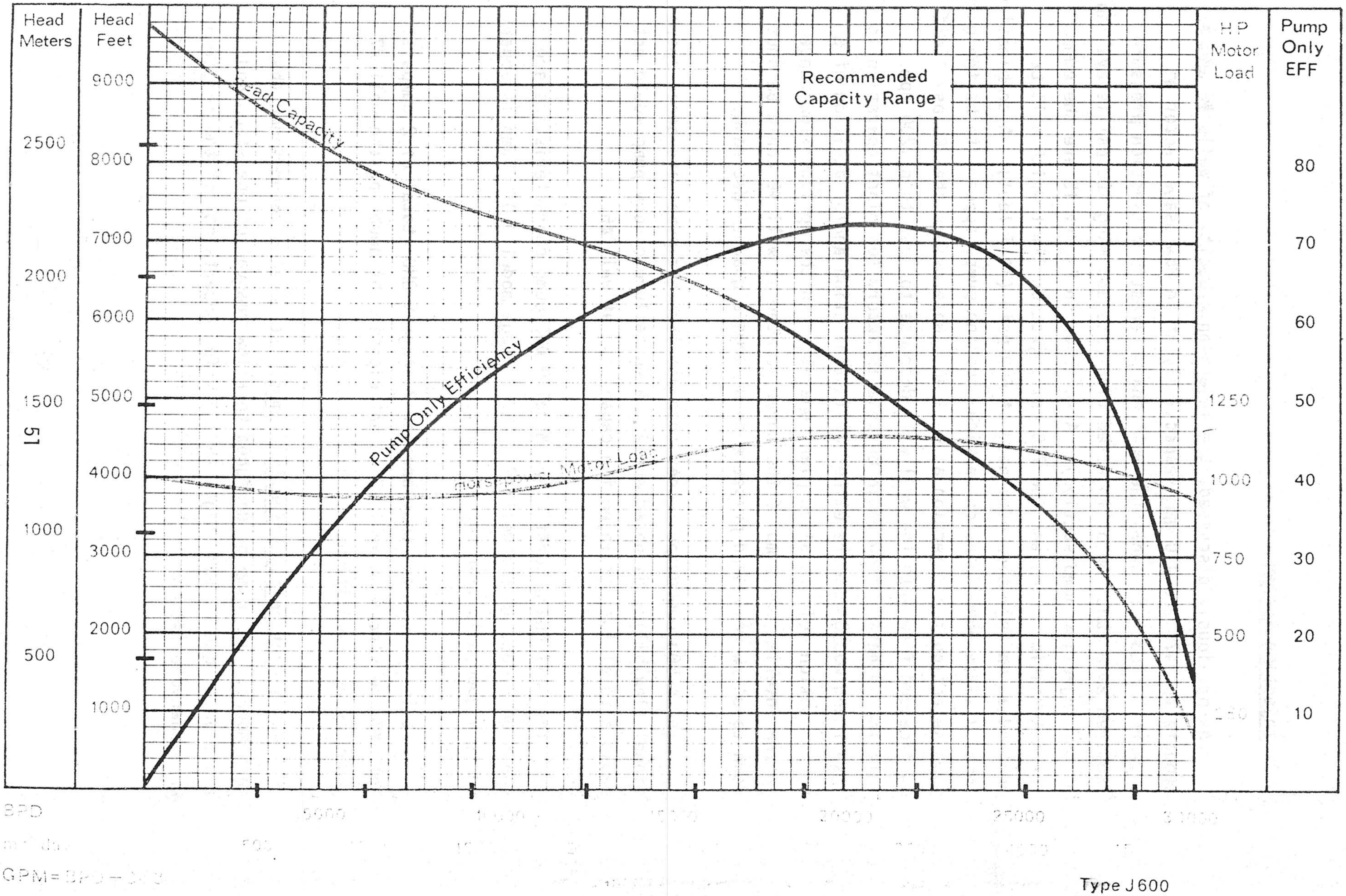
Using larger motors than required costs very little in the way of energy consumption since the power drawn by the pump motor is almost entirely determined by the pump characteristics and not the motor size. Increased motor horsepower above the required horsepower to drive the pump is essentially "in reserve".

TRW REDA PUMP DIVISION
BARTLESVILLE, OKLAHOMA 74003
JULY 1977

FIGURE 14

Reda Pump Performance Curve
100 Stage – J600 – 60 Hz
675 Series – 3500 RPM

Minimum Casing Size
8 5/8 IN OD
Check Clearances



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4.3 Injection System

As previously discussed, the injection capacity of wells #6 and #7 amounts to 1470 and 470 gpm respectively at an 85% usage factor at 5 years. Figure 15 shows the well characterestic (injection pressure required as a function of injected flow rate assuming 100 psi is available at the injection pump suction). Also shown on Figure 15 are the pump characteristic curves and the 700 psi injection limit which will be reached at an injection pump head of 600 psid (1417 feet). A combination of three 7 stage 9DHC Johnston vertical turbine pumps appears to be the optimum pump selection for injection at well #6. Note before the 700 psi limit is exceeded flow into the well will decrease to less than 1200 gpm. This low injection flow would be unsatisfactory for plant operation in itself and would require either well stimilation and/or addition of a new injection well to allow plant operation in the optimum flow range. In the interim, one pump of the three located at well #6 could be shut down to allow well head pressure to undergo a gradual decrease.

Three 500 gpm pumps rather than one 1500 gpm pump give added operational flexibility as noted above. Also failure of one pump would not cause a total loss of injection capability at well #6.

The well characterstic and Model 9 DHC pump characteristics are shown on Figure 16 for well #7. The 7 stage model 9 DHC pump is apparently a good selection for well #7.

It is recommended that another 7 stage 9 DHC (total of 2 pumps at well #7) be placed at well #7 in anticipation of doubling the well #7 capacity by stimulation.

4.3.1 Contingency Injection Pumps. It is also recommended that each Model 9 DHC pump be designed to allow removal of one stage and addition of one or two stages to allow for uncertainty in the injection well characteristics.

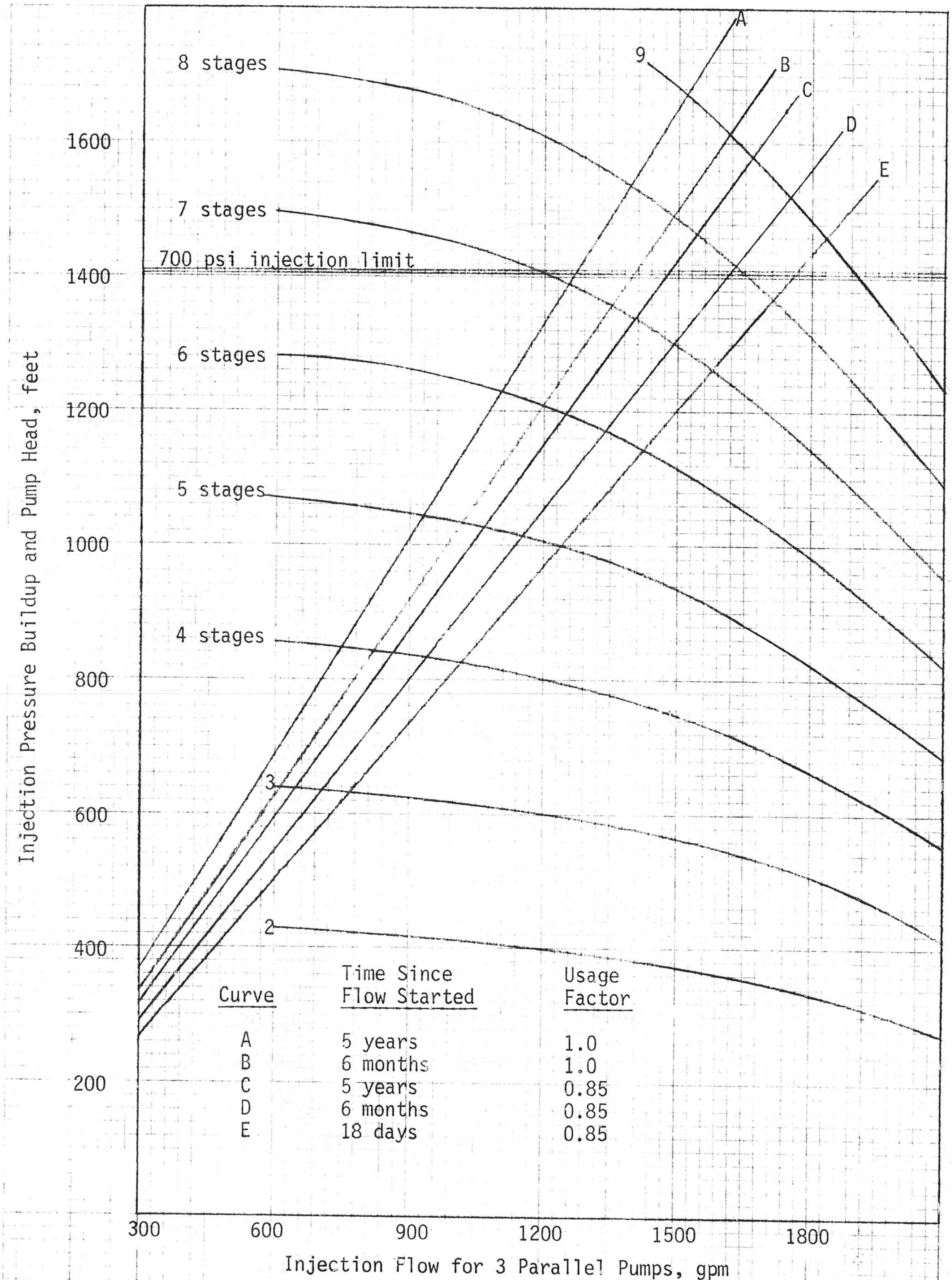

Figure 15. Injection Characteristics of Well 6 with Three Model 9DHC Pumps

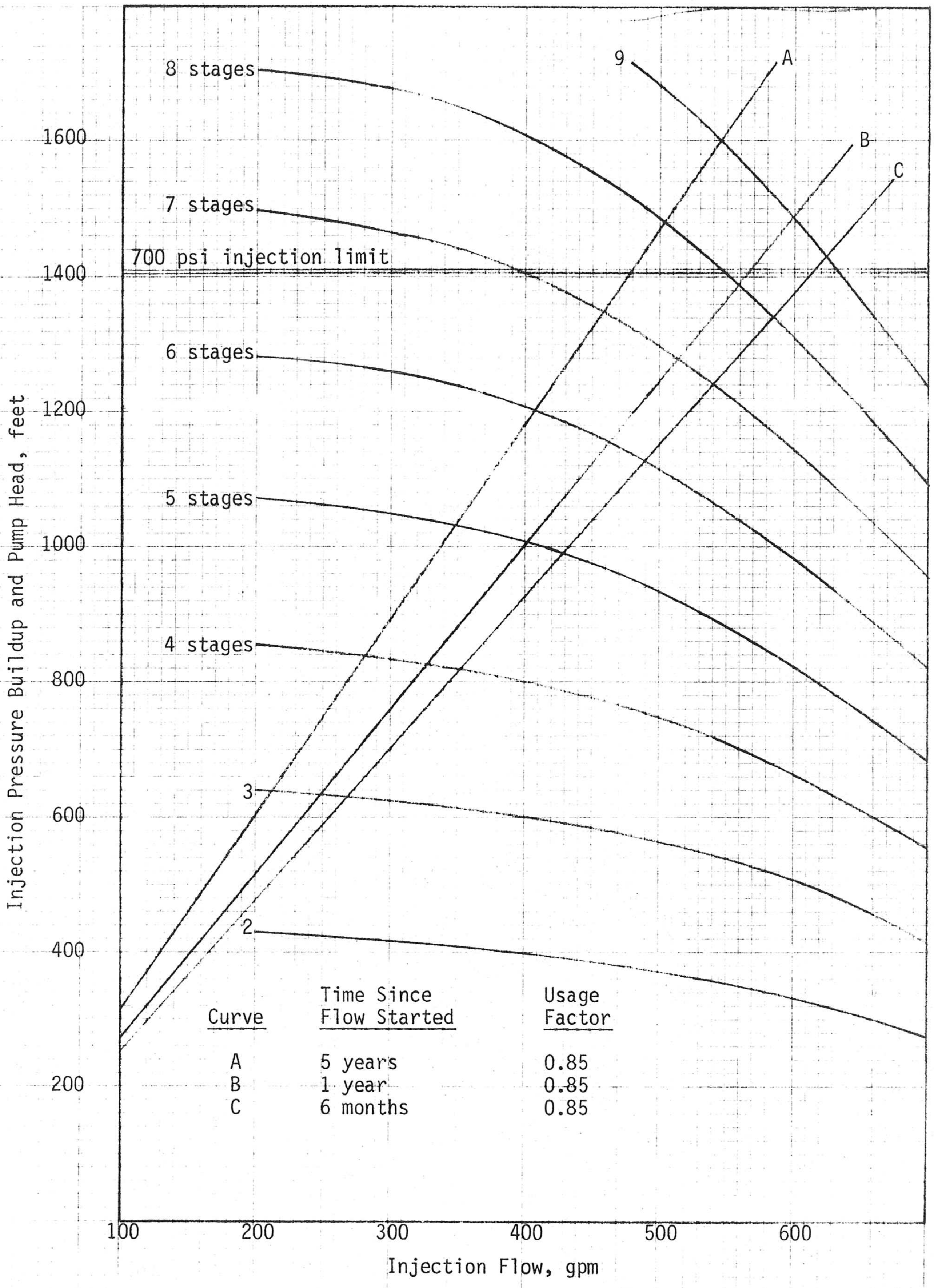

Figure 16. Injection Characteristic of Well 7 with Model 9 DHC Pump

APPENDIX A

CALCULATION OF HEAT LOSSES IN RAFT RIVER TRANSITE PIPE

APPENDIX A

CALCULATION OF HEAT LOSSES IN RAFT RIVER TRANSITE PIPE

BASIC DATA

Well 3 to Plant

Length = 7476 feet
Depth = 3.0 feet to Pipe Centerline
Dia = 10"
1" Insulation

Well 1 to Plant

Length = 1707 feet
Depth = 3.0 feet to Pipe Centerline
Dia = 12"
1" Insulation

Well 5 to Plant

Length = 1804 feet
Depth = 4 feet
Dia = 10"
1" Insulation

Well 2 to Well 1

Length = 3865 feet
Depth = 8.0 feet
Dia = 12"
No Insulation

RESISTANCE OF SOIL

From Reference TREE-1114, Asbestos cement pipeline experience at Raft River, Miller, Kunze, and Sanders, April 1977.

$$R_{soil} = \frac{\ln \dfrac{2 \text{ x depth of soil to pipe centerline}}{\text{radius of pipe + insulation}}}{2 \pi k}$$

k experimental for Raft River Soil is 0.25 Btu/hr-ft-°F

k urethane foam = 0.012 Btu/hr-ft-°F

$$R \text{ insulation and pipe} = \frac{\ln [Ro/Ri]}{2 \quad k}$$

Ro = outside radius
Ri = inside radius

Well 3 to Plant

$$R_{soil} = \frac{\ln \frac{2x3}{7/12}}{2 \quad (.25) \ \frac{Btu}{hr\text{-}ft\text{-}^{o}F}} = 1.484 \ (\frac{Btu}{hr\text{-}ft\text{-}^{o}F})^{-1}$$

$$R_{insulation} = \frac{\ln \quad 7''/6''}{2 \quad (.012)} = 2.044 \ (\frac{Btu}{hr\text{-}ft\text{-}^{o}F})^{-1}$$

$$R_{total} = 1.484 + 2.044 = 3.528 \ (\frac{Btu}{hr\text{-}ft\text{-}^{o}F})^{-1}$$

$$Q = \frac{250^{o}F}{3.528(Btu/hr\text{-}ft\text{-}^{o}F)^{-1}} = 70.86 \ Btu/hr\text{-}ft$$

$$Q_{loss} = (70.86 \ Btu/hr\text{-}ft)_{x} \ (7476 \ feet) = 5.30 \times 10^{5} \ Btu/hr$$

Based on the following flow rates

Well 1. 1000 gpm ($.463 \times 10^{6}$ lb_m/hr)

Well 2. 800 gpm ($.371 \times 10^{6}$ lb_m/hr)

Well 3. 800 gpm ($.371 \times 10^{6}$ lb_m/hr)

Well 5. 600 gpm ($.278 \times 10^{6}$ lb_m/hr)

$$\Delta T_{line\ 3} = 5.30 \times 10^5 \frac{Btu}{hr} \times \frac{hr}{.371 \times 10^6\ lb_m} \times \frac{lb_m\text{-}°F}{1.0\ Btu} = 1.42°F$$

For Well 1 to Plant

Same depth, diameter, composition as #3, so

$$\Delta T = \left(\frac{1707\ feet}{7476\ feet}\right) 1.42°F \left(\frac{800}{1000}\right) = 0.265°F$$

$$Q_{loss} = \left(\frac{1707}{7476}\right) \left(5.3 \times 10^5 \frac{Btu}{hr}\right) = 1.21 \times 10^5 \frac{Btu}{hr}$$

From Well #5 to Plant (10" Pipe)

$$R_{soil} = \frac{\ln \dfrac{2 \times 4}{(5/12)}}{2\ \ (0.25)} = \frac{\ln 19.2}{1/2} = 1.88\ (Btu/hr\text{-}ft\text{-}°F)^{-1}$$

$$R_{insulation} = \frac{\ln \dfrac{7''}{6''}}{2\ \ (.012)} = 2.04\ (Btu/hr\text{-}ft\text{-}°F)^{-1}$$

$$R_{total} = 3.92\ (Btu/hr\text{-}ft\text{-}°F)^{-1}$$

$$Q = \frac{250°}{3.92} = 63.77\ Btu/hr\text{-}ft$$

$$Q_{loss} = 63.77\ Btu/hr\text{-}ft \times 1804\ ft = 1.15 \times 10^5 \frac{Btu}{hr}$$

$$\Delta T = \frac{1.15 \times 10^5\ Btu/hr}{.278 \times 10^6\ lb_m/hr} \ \frac{lb_m - °F}{1.0\ Btu} = 0.41°F$$

From Well #2 to Well #1 (Uninsulated Pipe)

$$R_{soil} = \frac{\ln \frac{2 \times 8}{0.5}}{2 \quad (0.25)} = 2.209 \text{ (Btu/hr-ft-°F)}^{-1}$$

$$Q = \frac{250°F}{2.25 \text{ (Btu/hr-ft-°F)}^{-1}} = 113.17 \text{ Btu/hr-ft}$$

$$Q_{loss} = (113.17 \text{ Btu/hr-ft}) \ (3865 \text{ ft}) = 4.37 \times 10^5 \ \frac{\text{Btu}}{\text{hr}}$$

$$\Delta T = \frac{4.37 \times 10^5}{0.371 \times 10^6} = 1.18°F$$

For the other 1707 feet to the plant, the losses are the same as well 1 to plant, specifically $\Delta T = 0.28°F$ $Q_{loss} = 1.27 \times 10^5 \ \frac{\text{Btu}}{\text{hr}}$

Total, well 2 to plant

$$\Delta T = 1.15 + 0.28 = 1.46°F$$

$$Q_{loss} = (4.37 + 1.27) \times 10^5 = 5.64 \times 10^5 \ \frac{\text{Btu}}{\text{hr}}$$

Tabulation

gpm		Q_{loss} (Btu/hr)	ΔT °F
1000	Well 1.	1.21×10^5	0.27°F
800	Well 2.	5.64×10^5	1.46°F
800	Well 3.	5.30×10^5	1.42°F
600	Well 5.	1.15×10^5	0.41°F

TREE-1114

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ASBESTOS-CEMENT PIPELINE EXPERIENCE
AT THE
RAFT RIVER GEOTHERMAL PROJECT

L. G. Miller

J. F. Kunze

R. D. Sanders

Date Published - April 1977

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B. PIPELINE AND SOIL TEMPERATURES B-1

VIII. HEAT LOSS FROM BURIED TRANSITE PIPE

Heat loss from the pipeline is rather critical when attempting to use these moderate temperature waters for generating electricity. For instance, given a fixed size of heat exchangers and condensers, and geothermal input at 290°F, each loss of 1°F costs nearly 1% in power output from a turbine. Balancing such a loss is the cost of a pipeline. For initial considerations, the following table lists the approximate cost allocations for a buried Transite pipeline, in normal sedimentary top soil and fine gravel conditions.

APPROXIMATE COSTS PER MILE

10 IN. BURIED TRANSITE PIPELINE

Transite pipe, purchase price, including couplings	$ 35,000
Excavation and backfill for 30 in. burial* depth	40,000
(for 48 in. depth = $65,000)	
(for 24 in. depth = $30,000)	
Installation of pipe into trench	20,000
Insulation - 1 in. sprayed urethane, low flame spread type ($1.25/lb material cost, typically 3 lb/ft^3 density. 2 in. thickness applied is approximately 55¢/ft^2 or $1.60/ft	8,000
Contingency	10,000
Approximate Total	$ 113,000 = 23/ft

*Burial depths quoted for total trench depth to bottom of pipe.

The above analysis indicates minor cost sensitivity to depth of burial. However, if trench depth exceeds nominally 4 ft, mechanical shoring of the sidewalls of the trench will be required, adding substantially to the cost. Since a pipeline should be laid as uniformly straight (or level) as possible, to minimize the strain on the gasket couplings, an uneven terrain may require shoring in certain sections, none in others. A 30-inch burial depth leaves nearly 2 ft contingency for terrain unevenness before shoring is required. The following analyses assume a 2 to 3 ft burial depth.

Material	k in $\frac{Btu}{hr\text{-}ft^2\ °F/ft}$	Comments
Transite Pipe	0.49	Wet
Water	0.38	
Dry Soil and Sand	0.18	
Sand and Gravel Mix	0.9	Dry
Styrofoam Beads	0.020	Service Temp 180°F
Rock Wool Fibre	0.026	Dry
Fibreglas	0.033	Dry
Urethane Foam (3 lb/ft^2)	0.012	Service temp >300°F

In actual use, the soil will often be wet, but there is the tendency for it to bake and dry out near the pipe. The effective heat transfer coefficient will probably average 0.3 to 0.4, for typical soil conditions to be encountered in the northwest.

For insulation material, sprayed on polyurethane coating has been selected as the most practical and relatively inexpensive material. Its choice was dictated, in part, by recent experience in a number of applications on 300°F piping, and others at higher temperatures, to as high as 700°F (where some loss of adhesion occurred with time).* Recent tests at Raft River, on piping that has routinely seen 275°F for three months, (to date) showed extremely firm adhesion of the foam to the pipe surface (in this case mild steel pipe) and no noticeable deterioration of the foam with time.

Thermal resistances to the transfer of heat from the pipeline are listed in the following table, for 10 in. diameter transite pipe buried in soil with insulation. The soil results are a "half space" solution, for steady state conditions in which all heat transmission is away from the center of the earth. Resistances refer to each foot of pipe length.

*Private communication from urethane foam supplier.

Material	Resistance in $\left(\frac{\text{Btu}}{\text{hr}^\circ\text{F/ft}}\right)^{-1}$ **
Transite pipe, wet, 10 in. diameter by 1 in thick wall	0.059
Urethane foam, 1 in. thick	2.0
Wet soil 24 in. depth to pipe centerline	1.11
k = 0.3 30 in. depth to pipe centerline	1.22
36 in. depth to pipe centerline	1.32
Dry soil 30 in. depth to pipe centerline	2.0
Dry soil 60 in. depth to pipe centerline	2.65
Wet soil 60 in. depth to pipe centerline	1.59

$$** \quad R = \frac{\ln\left[\frac{2 \times \text{depth of soil to pipe centerline}}{\text{radius of pipe}}\right]}{2\pi K}$$

for the "half space" soil situation, all conduction upward

$$* \quad \frac{\ln Ro/Ri}{2\pi K}$$

for full radial conduction, such as pipe wall and insulation

The use of urethane insulation, 1-inch thick, for pipe buried 3 ft will effectively reduce the heat loss by a factor of at least two, even more for conditions of wet soil. One inch of urethane is as effective an insulator as 5 ft of typical soil. Whether more than 1-inch thickness of urethane is appropriate should depend on a cost/benefit ratio, of lost power from the electric generating plant due to the reduced temperature. For purposes of analysis, a resistance of

$$R = 1.0 \left(\frac{\text{Btu}}{\text{hr}^\circ\text{F/ft}}\right)^{-1}$$

and

1. a temperature difference of 250°F between the fluid in the pipe and the outside air temperature.

2. a flow of 1000 gallons/minute through the 10 in. Transite pipe (4.8×10^5 lb/hr).

results in the following

Heat loss per mile of pipeline = 1.32×10^6 Btu/hr (equivalent to 48 kW of electricity at 12-1/2% conversion efficiency)

Fluid temperature loss per mile of pipeline - 2.75°F

The use of urethane foam, 1-inch thick, gives a thermal resistance for the pipeline exceeding 2, and thus temperature loses are less than half this amount. The addition of an extra inch of urethane thickness would reduce the net power loss by about 16 kW, equivalent to $2900 worth of electricity/year at a bus bar rating of 25 mills/kW-hr. Thus, 2-inches of urethane can be justified on a cost-benefit basis for most pipelines. The value of the lost energy in direct heat (non-electric) applications is generally less, and more difficult to assign a precise value, because of varying plant capacity factors and generally lower price assigned to thermal energy. In that case, 1-inch of urethane may be the optimum thickness for cost effectiveness.

Experience with the present pipeline between wells No. 1 and No. 2 for heat loss and soil temperature measurements is summarized in Appendix B. Measured heat loss compares closely with the above listed thermal conductivities and resistances. The results indicate that the average thermal resistance for the pipeline, buried a minimum of 5 ft, is 1.9 $(\text{Btu/hr-ft-°F})^{-1}$ (+5%, -40%) for each foot of pipe. This result corresponds to an average thermal conductivity for the soil of 0.25 Btu/hr-ft-°F (+40%, -5%).

Pipeline and Soil Temperatures

The pipeline was instrumented, as shown in Figure B-1, in a region of typical Raft River region soil, with thermocouples to measure the temperature gradient in the soil. The fluid temperature loss from one end to the other of the pipeline was also measured. These measurements began a week after cold winter weather set in. The results of these measurements are shown in Figure B-2. The pipeline carried 235 gpm for the first 2-1/2 weeks, but equilibrium temperature conditions had not been reached when the flow was reduced to 65 gpm. During the next 6 weeks, the temperatures stabilized, allowing an estimate of heat loss to be made and average soil resistance/conductivity computed. At that time temperature drop of the fluid from one end to the other end (4000 ft away) on the pipeline was 13°. For 65 gpm flow, this gives a loss of 405,000 Btu/hr, leading to the following result, in $(\text{Btu/hr-°F})^{-1}$ for R.

Total R/ft of pipeline = 1.97

R for soil/ft of pipeline = 1.92

$$k_{avg} \text{ for soil} = 0.25 \ \frac{\text{Btu}}{\text{hr-ft}^2\text{-°F/ft}}$$

The earlier results from the higher flow rates, approaching but not yet reaching equilibrium temperatures, gave conductivities substantially higher. The longer term results, however, agree closely with partially wet, sandy soil conductivities, and hence appear to be reasonable values to use in future design.

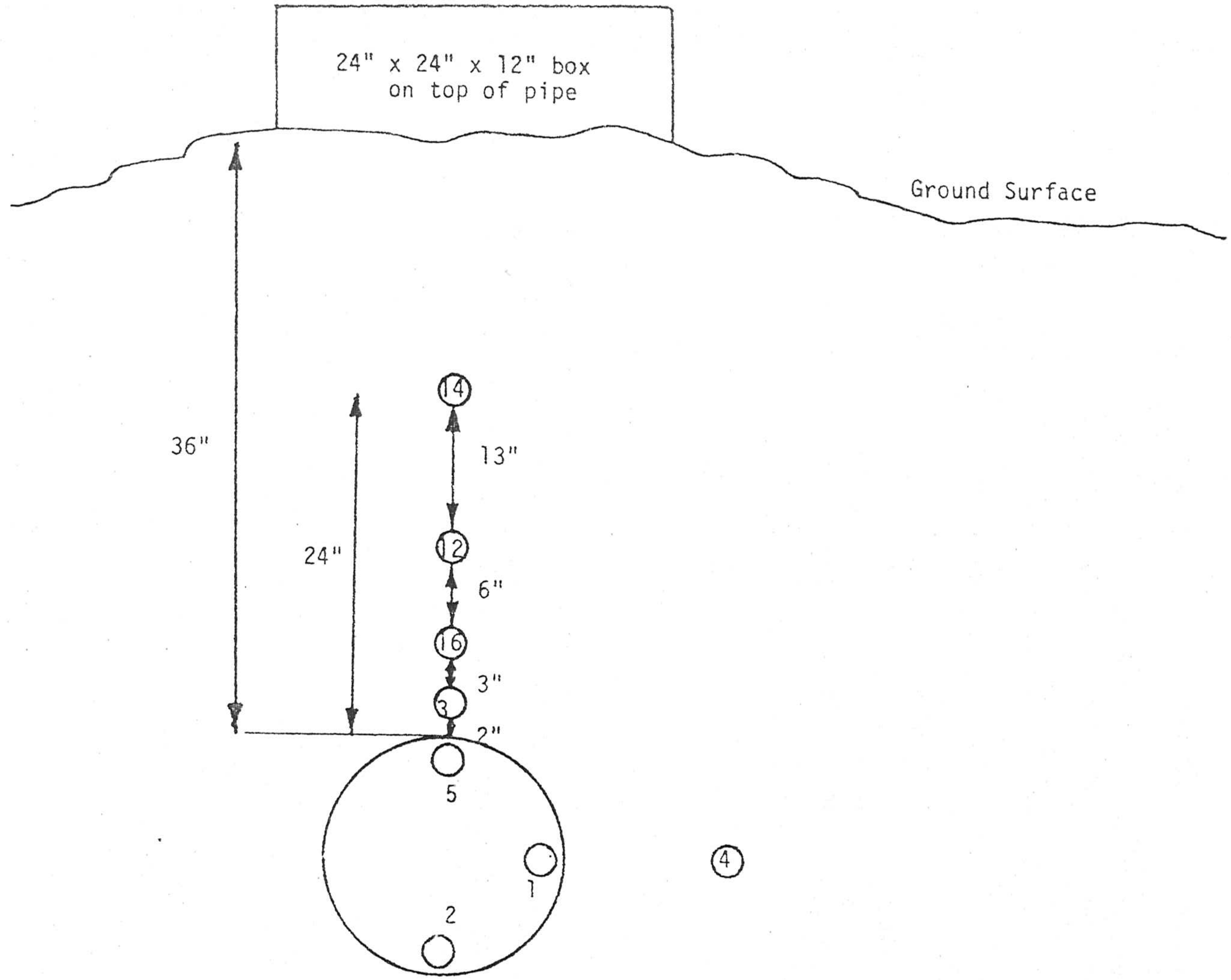


Figure B-1

Physical location of monitoring thermocouples placed in soil around 12-inch dia Transite pipeline. Measurement location was near the RRGE No. 1 security force.

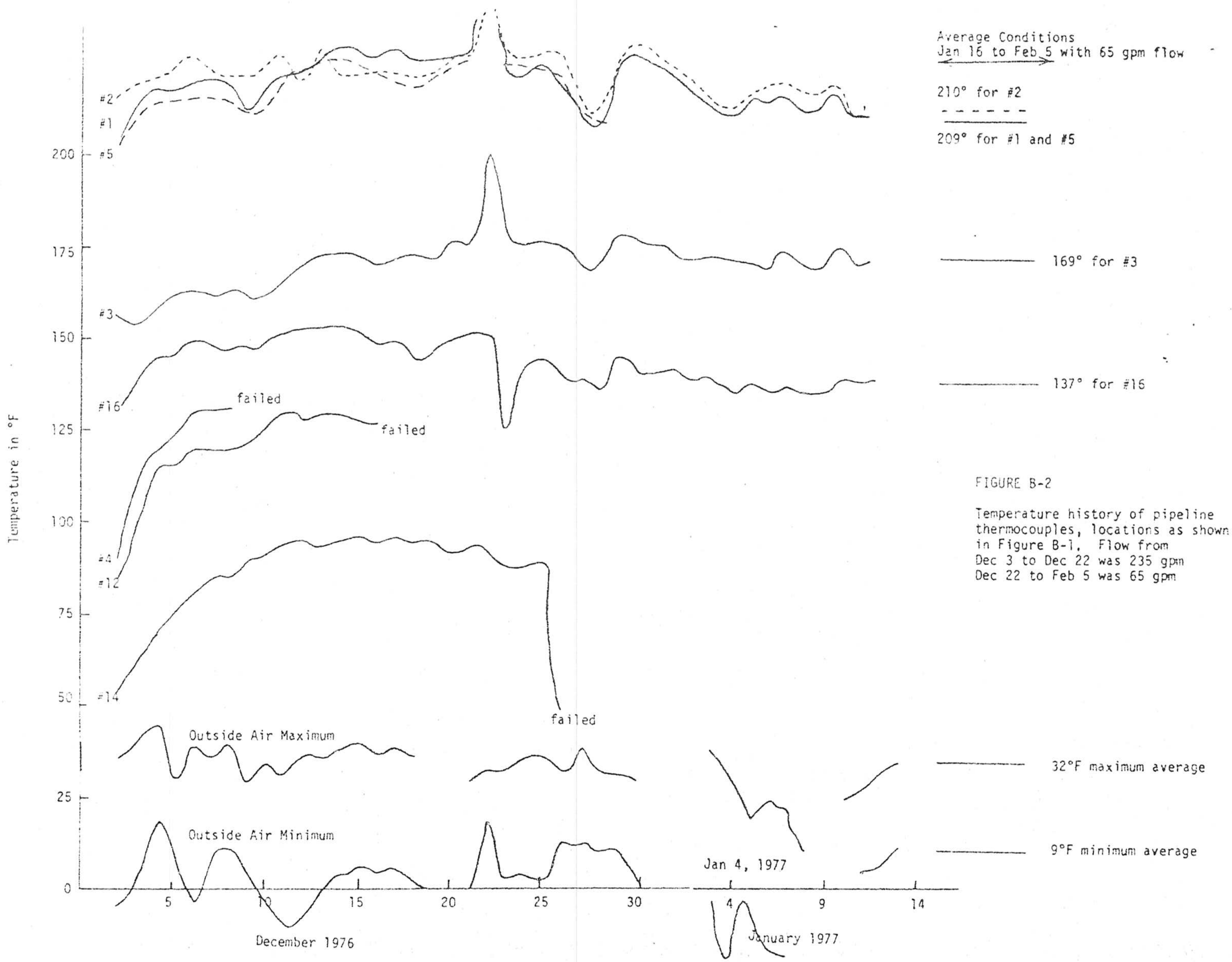


FIGURE B-2

Temperature history of pipeline thermocouples, locations as shown in Figure B-1. Flow from Dec 3 to Dec 22 was 235 gpm Dec 22 to Feb 5 was 65 gpm

APPENDIX B

5 MW PLANT POWER PRODUCTION STUDY

EG&G Idaho

INTEROFFICE CORRESPONDENCE

date July 7, 1978

to O. J. Demuth

from R. W. Snyder RWS

subject GEOTHERMAL ELECTRIC PLANT POWER TRADE-OFF BETWEEN BRINE SUPPLY TEMPERATURE AND BRINE SUPPLY FLOW - Snyd-3-78

Ref: TAF Computer Listings: SNY6TKI, SNY6TVM, SNY6TK4, and SNY6TLE

The Geothermal Electric Plant Model was exercised to study the effects on plant performance of varying brine supply temperature and brine flowrate. The study was performed to determine the trade off between high-flow cooler brine versus low-flow hotter brine. All runs were performed with the following fixed conditions: fouling was set to 10% of design maximum, Isobutane boost pump head rise was set to 110% of design, the turbine was assumed installed, and the low preheater was bypassed by 10% of isobutane flow.

Figure 1 shows the effect on Net Plant Power (in megawatts electrical) of varying brine temperature and brine flowrate. The ambient air temperature was selected to be the cold extreme (T wet bulb = 8°F and T dry bulb = 8°F). Figure 2 shows Gross Plant Power for the same conditions. Figure 3 and 4 are a repeat of figures 1 and 2 except that the ambient air temperature was changed to the hot extreme condition (T wet bulb = 65°F and T dry bulb = 92°). Sample partial derivitives $\frac{\partial \text{ (brine flow)}}{\partial \text{ (brine temp)}}$ at constant power are calculated on Figures 1 and 3. These partials give the amount that brine flow can be reduced for each degree farenheit the brine supply temperature is increased and still maintain plant power constant. Since the partial varies markedly at various operating points the power trade-off will not be a constant. Instead the trade-off (brine flowrate vs brine temperature) will be affected by fouling, ambient air conditions, brine temperature, and brine flowrate.

Tables I and II give the tabulated data used for the figures. In addition, five other parameters of interest are tabulated: net efficiency, brine temperature leaving the plant, the pinch points in the high and low boilers, and the isobutane boiling temperature in the high boiler.

jm

Attachment:
As Stated

FORM EG&G-954
(Rev. 2-77)

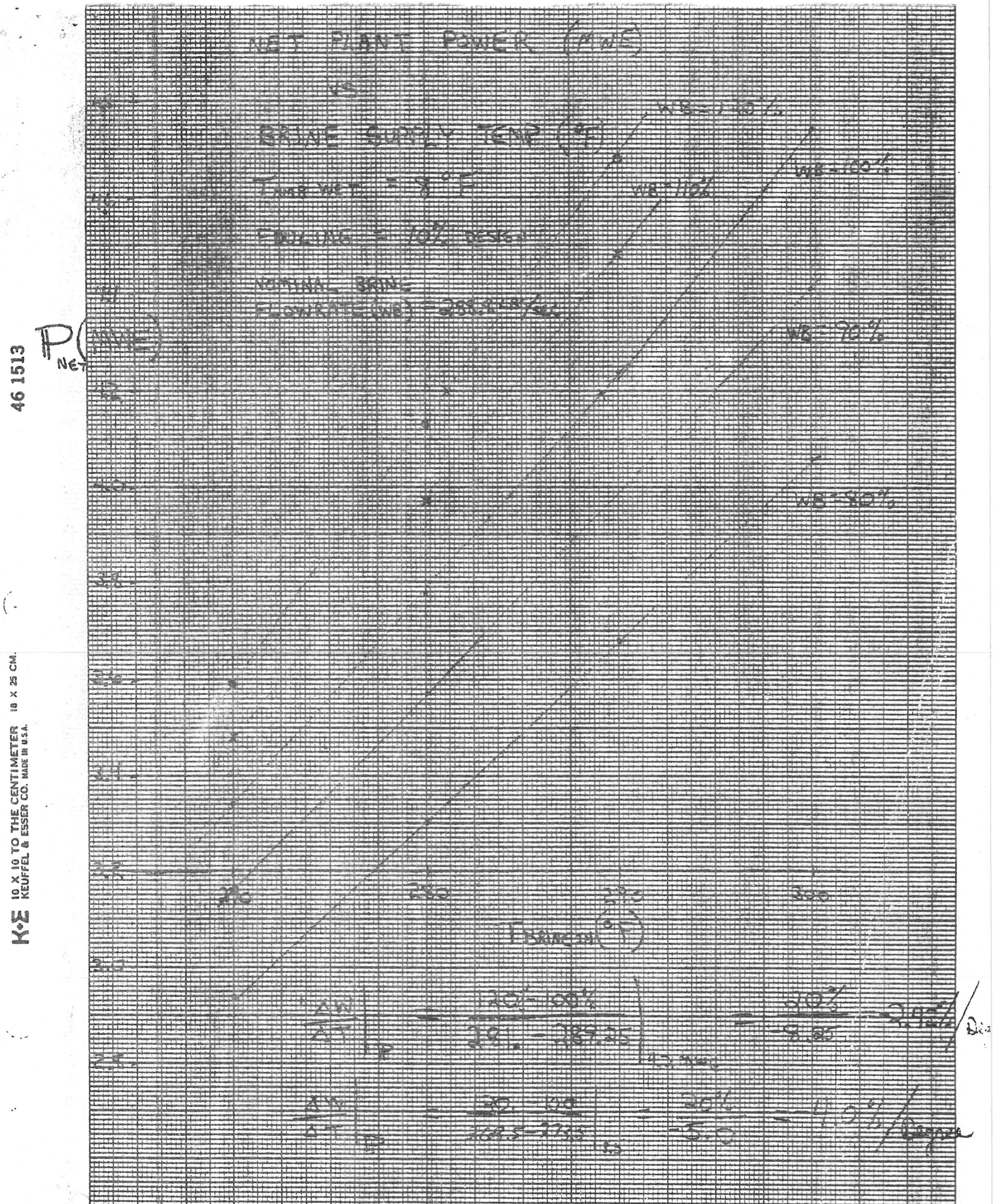
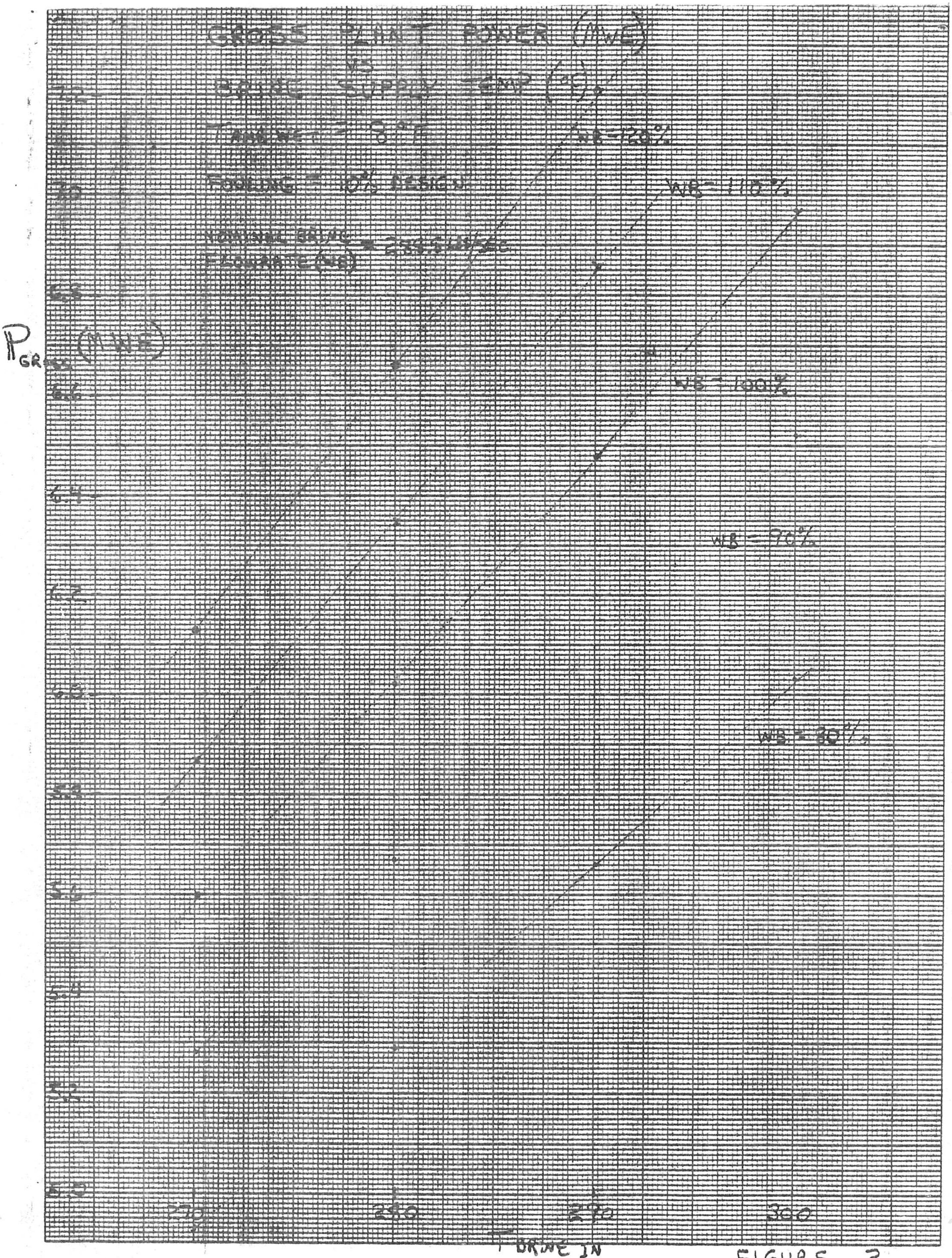

NET PLANT POWER (MWE)
VS.
BRINE SUPPLY TEMP (°F)
WB = 110%
WB = 100%
WB = 90%
WB = 80%
P NET (MWE)
270
280
290
300
T BRINE IN (°F)

FIGURE 1

B-3



GROSS PLANT POWER (MWE)
VS
BRINE SUPPLY TEMP (°F)
FOULING = 10% DESIGN
WB = 120%
WB = 110%
WB = 100%
WB = 90%
WB = 80%
7.2
7.0
6.8
6.6
6.4
6.2
6.0
5.8
5.6
5.4
5.2
5.0
P GROSS (MWE)
270
280
290
300
T BRINE IN

FIGURE 2

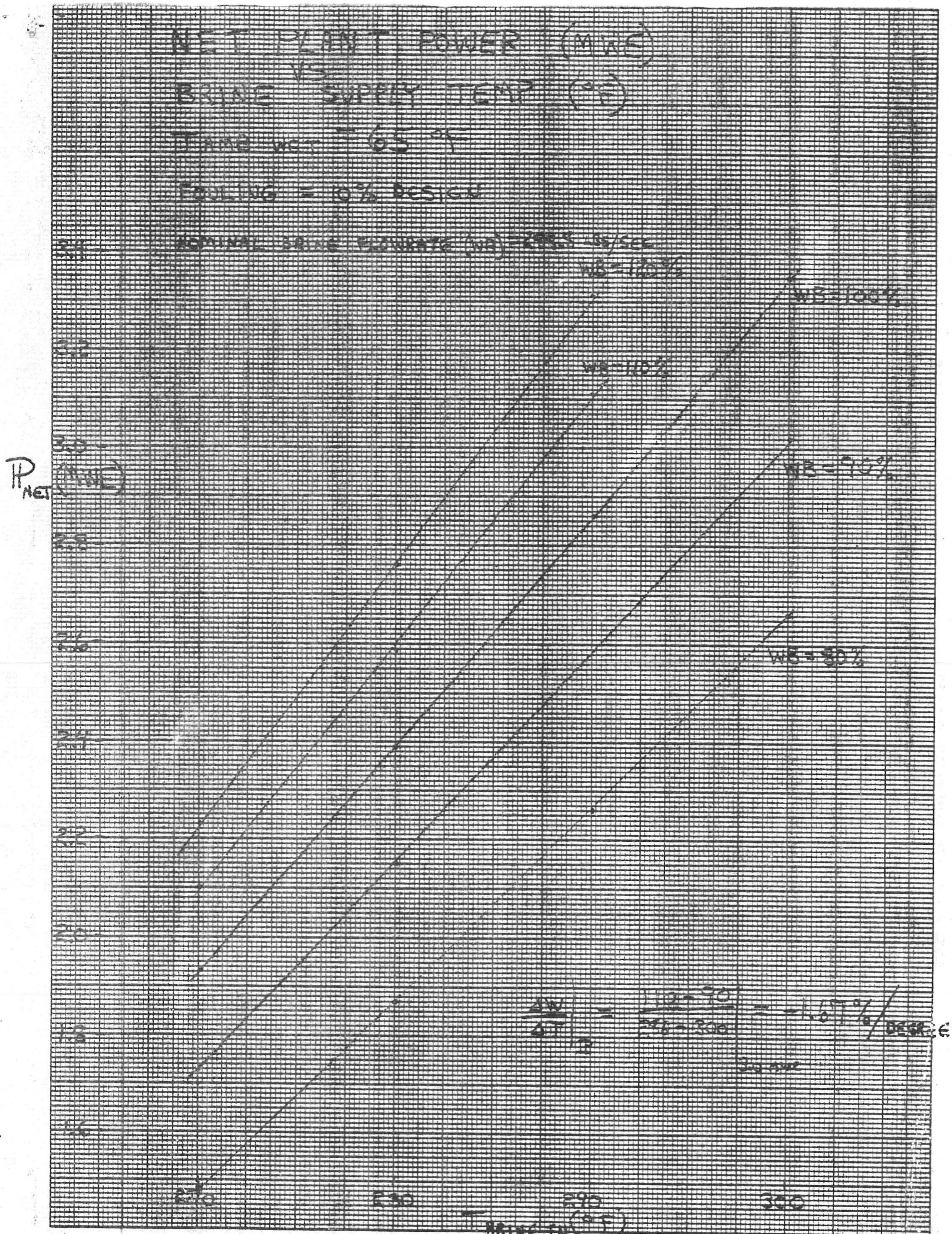

NET PLANT POWER (MWE)
VS
BRINE SUPPLY TEMP (°F)
FOULING = 10% DESIGN
WB=120%
WB=110%
WB=100%
WB=90%
WB=80%
3.4
3.2
3.0
2.8
2.6
2.4
2.2
2.0
1.8
1.6
P_{NET} (MWE)
270
280
290
300
$T_{BRINE\ IN}$ (°F)
DEGREE

FIGURE 3

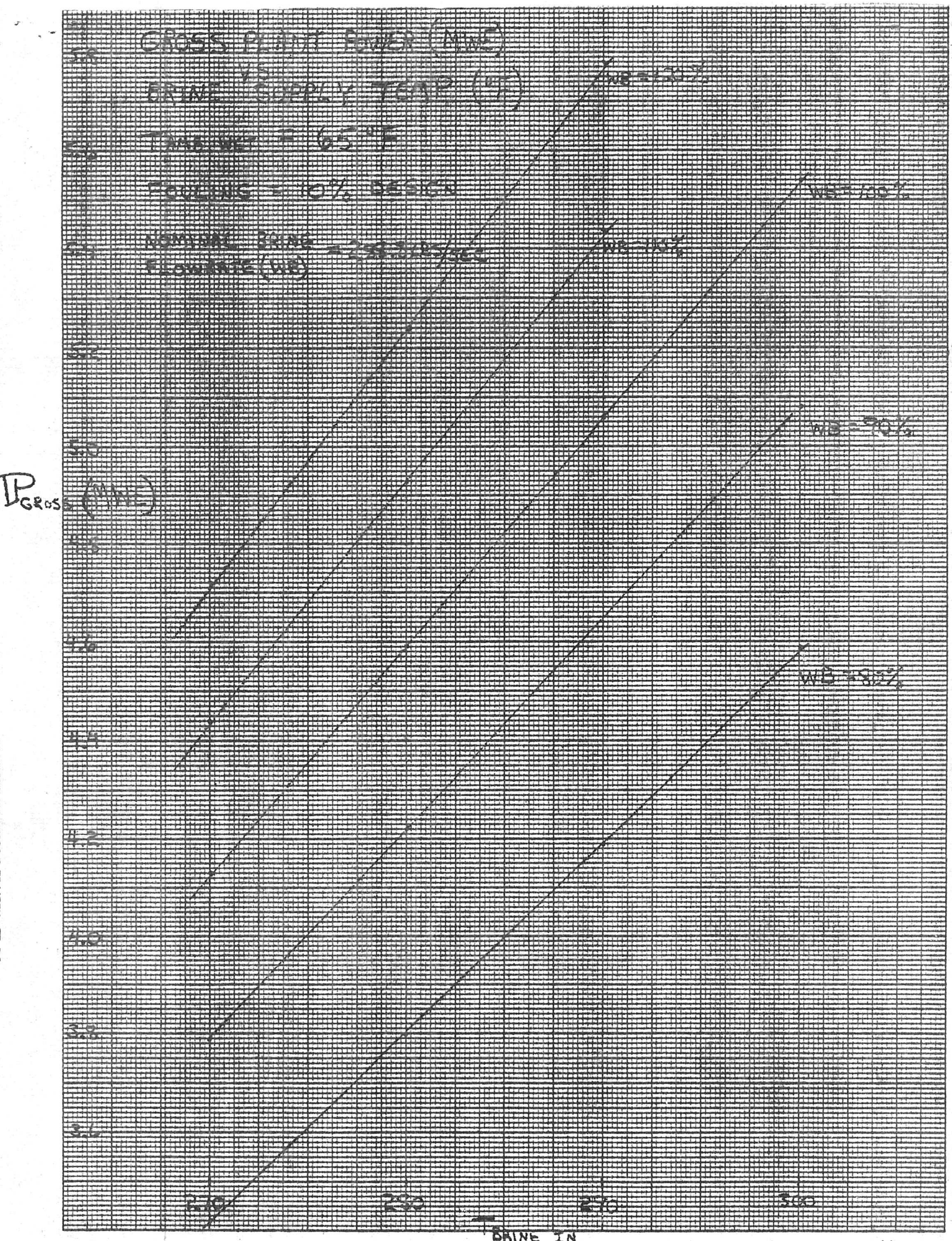

GROSS PLANT POWER (MWe)
VS
BRINE SUPPLY TEMP (°F)
T AMB, WET = 65°F
FOULING = 10% DESIGN
NOMINAL BRINE FLOWRATE (WB)
WB = 120%
WB = 110%
WB = 100%
WB = 90%
WB = 80%
5.6
5.4
5.2
5.0
4.8
4.6
4.4
4.2
4.0
3.8
3.6
P GROSS (MWe)
210
240
270
300
T BRINE IN

FIGURE 4

6/28/78

TABLE I -- BRINE FLOW + TEMPERATURE MAPPING -- $T_{AIR\ WET} = 8°F$

Computer Runs: SNY6TK4 and SNY6TLE

TEMP BRINE IN (°F)	FLOW BRINE (LBS/SEC)	POWER NET (MWE)	POWER GROSS (MWE)	EFFICIENCY NET (%)	TEMP BRINE OUT (°F)	PINCH POINT ΔT_{LB} (°F)	PINCH POINT ΔT_{HB} (°F)	T ISO H. B. (°F)
290.	288.8	4.24	6.48	8.48	125.9	2.7	1.3	241.8
300.	"	4.74	6.97	8.90	125.3	2.7	1.0	251.8
"	260.	4.41	6.52	8.86	118.4	2.6	1.2	245.3
"	231.	4.06	6.03	8.79	110.6	2.7	0.4	238.1
290.	"	3.68	5.66	8.44	111.1	2.7	1.0	229.9
280.	"	3.30	5.29	8.03	111.2	2.8	1.3	221.6
270.	"	2.94	4.93	7.62	111.4	2.9	1.6	213.8
"	260.	3.16	5.28	7.63	118.9	2.9	1.8	219.0
280.	"	3.57	5.67	8.08	119.0	2.8	1.5	227.5
290.	288.8	4.24	6.48	8.48	125.9	2.7	1.3	241.8
280.	"	3.77	6.02	8.06	126.2	2.7	1.6	232.5
270.	"	3.34	5.59	7.60	125.9	2.8	1.9	223.5
"	317.6	3.48	5.87	7.55	132.3	2.9	1.9	227.4
"	346.5	3.59	6.13	7.45	138.3	2.9	2.0	230.9
280.	"	4.13	6.66	7.98	138.5	2.7	1.7	240.6
"	317.6	3.97	6.35	8.02	132.5	2.8	1.7	236.8
290.	"	4.48	6.86	8.49	132.3	2.7	1.3	246.8
"	346.5	4.68	7.21	8.46	138.5	2.7	1.3	251.2

NOTE: Narrow pinch points are due to 10% fouling; design point pinch points are 10 °F.

TABLE II -- BRINE FLOW + TEMPERATURE MAPPING -- $T_{AIR_{WET}} = 65°F$

Computer Runs: SNY6TVM and SNY6T

TEMP BRINE IN (°F)	FLOW BRINE (LBS/SEC)	POWER NET (MWE)	POWER GROSS (MWE)	EFFICIENCY NET (%)	TEMP BRINE OUT (°F)	PINCH POINTS ΔT_{LB} (°F)	PINCH POINTS ΔT_{HB} (°F)	T_{ISO} H.B.
270.	288.8	2.86	5.06	6.29	140.9	2.62	1.30	242.1
300.	"	3.35	5.54	6.91	140.8	2.55	0.97	252.3
"	260.	3.02	5.08	6.68	135.0	2.57	0.96	245.7
"	231.	2.66	4.59	6.38	128.8	2.57	0.39	238.6
290.	"	2.26	4.19	5.77	129.1	2.61	1.01	230.2
280.	"	1.87	3.80	5.07	129.1	2.67	1.31	221.9
270.	"	1.48	3.42	4.31	128.9	2.74	1.58	213.9
"	260.	1.73	3.79	4.65	134.7	2.77	1.76	219.2
280.	"	2.15	4.22	5.41	135.1	2.69	1.54	227.7
280.	288.8	2.39	4.59	5.64	140.8	2.70	1.60	232.7
270.	"	1.93	4.13	4.88	140.3	2.79	1.86	223.6
"	317.6	2.10	4.44	5.04	145.6	2.81	1.96	227.6
"	346.5	2.23	4.72	5.12	150.7	2.84	2.03	231.0
280.	"	2.76	5.24	5.86	151.4	2.72	1.69	240.8
"	317.6	2.59	4.93	5.79	146.1	2.71	1.65	237.0
290.	"	3.11	5.44	6.46	146.5	2.62	1.32	247.1
"	346.5	3.31	5.78	6.54	151.9	2.63	1.29	251.5

EG&G Idaho

INTEROFFICE CORRESPONDENCE

date September 27, 1978

to J. H. Ramsthaler

from R. C. Stoker RCStoker

subject RRGI-6 INJECTION RATE ESTIMATES - RCSt-52-78

Attached is a paper concerning the data derived from the 800 gpm injection test conducted at RRGI-6 on May 1, 1978. The data is of very short duration (310 minutes or 5.17 hours) when compared to the time desired for estimates (5 years). The test data, and thus the estimates, are subject to change depending on the influence of any undetected hydrologic boundaries which extended testing will detect. The presence of boundaries will generally have an adverse effect on well performance.

Based on the limited test data presented in the attached paper, the following represents the injectability of RRGI-6:

Injection Rate (gpm)	*Wellhead Pressure (after 5 years) (psi)
200	213
300	258
400	305
500	350
600	395
700	440
800	485
900	530
1,000	575
1,100	620
1,200	665

*Add shutin pressure (~ 17 psi) to get gauge reading (psig) at wellhead.

la

Attachment:
As Stated

cc: C. A. Allen
D. W. Allman
H. M. Burton
M. R. Dolenc
D. Goldman
T. W. Lawford
G. M. Millar
L. B. Nelson
W. L. Niemi
R. D. Sanders
S. G. Spencer
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RRGI-6 INJECTION TEST

D. W. Allman

A 3-step injection test and a 310-minute duration injection test was conducted on May 1, 1978. The 3-step injection test data do not yield creditable results and thus will not be discussed in this paper.

The 310-minute duration flow test was conducted at a rate of 800 gpm (Figure 1). A short 6-minute pump failure resulted in a slight deviation of the data collected after 48-minutes of pumping from the linear portion of the data plot beginning at approximately 5 minutes ($u < .01$ after ~ 0.04 minutes). Data toward the end of the test also declined below the preceding linear trend. The reason(s) for this latter departure is not known.

The 110°F temperature of the injected water was lower than the 150°F temperature of the injection zone and resulted in a problem estimating a value for kh. The calculated value for kh is dependent on the viscosity of the waters in the reservoir and the borehole. The viscosity of water at 110°F and 150°F is 0.6145 cp. and 0.4239 cp., respectively. Since the viscosity at 110°F is 45% higher than at 150°F, errors up to 45% in calculated kh values can result because of uncertainties in the viscosity of the waters causing the observed pressure buildup during injection. The temperature distribution of the water in the borehole and in the vicinity of the uncased borehole throughout the injection test is not known, but can be expected to change. This change will result in temporally dependent: (a) well borehole friction losses; (b) turbulent friction losses in the overall receiving reservoir in the immediate vicinity of the borehole; (c) presumed laminar friction losses in the receiving reservoir invaded by the lower temperature injected water; and (d) flow velocities in the wellbore because of

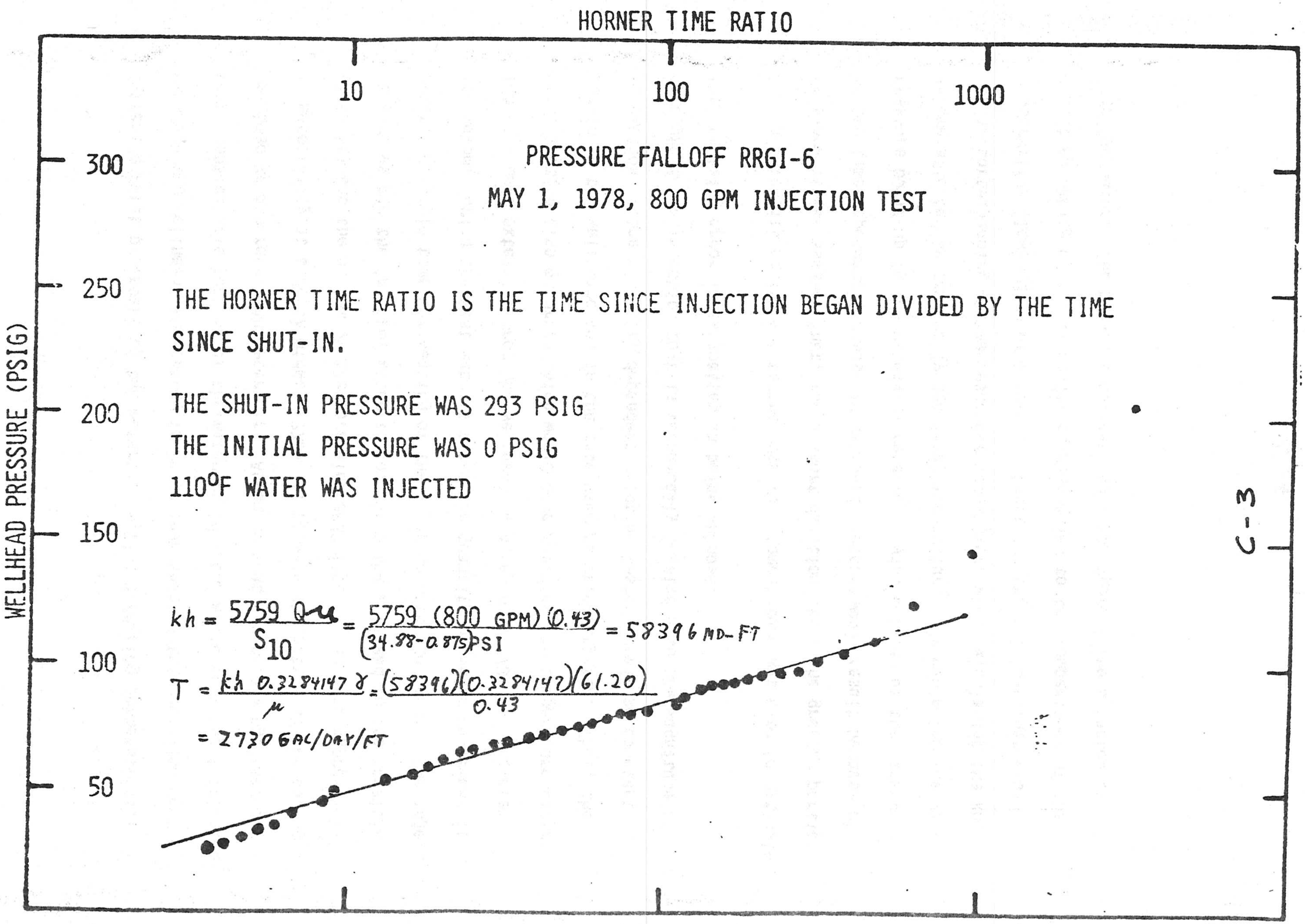

HORNER TIME RATIO
10
100
1000
PRESSURE FALLOFF RRGI-6
MAY 1, 1978, 800 GPM INJECTION TEST
THE HORNER TIME RATIO IS THE TIME SINCE INJECTION BEGAN DIVIDED BY THE TIME SINCE SHUT-IN.
THE SHUT-IN PRESSURE WAS 293 PSIG
THE INITIAL PRESSURE WAS 0 PSIG
110^{o}F WATER WAS INJECTED
$kh = \frac{5759\ Q\mu}{S_{10}} = \frac{5759\ (800\ \text{GPM})(0.43)}{(34.88-0.875)\text{PSI}} = 58396$ MD-FT
$T = \frac{kh\ 0.3284147\ \gamma}{\mu} = \frac{(58396)(0.3284147)(61.20)}{0.43}$
$= 2730$ GAL/DAY/FT
WELLHEAD PRESSURE (PSIG)
300
250
200
150
100
50

FIGURE 2

differing rates of uptake by the materials having differing permeabilities. Although the wellhead temperature is lower than that in the receiving reservoir, considerable heating of the water would occur while in transit from the wellhead to the receiving reservoir. Assuming that the receiving reservoir is essentially at a depth midway (2786 ft) between the bottom of the casing (1700 ft) and the bottom of the borehole (3872 ft), it requires approximately 22 minutes for the injected water to move from the wellhead to the receiving reservoir, ample time for heating of the injected water to occur. The injected volume during the test was ~14 times the quantity of water contained in the well bore extending from the wellhead to a depth of 2786 ft. However, prior testing also occurred which would have modified the temperature distribution in the well bore and in the receiving reservoir system. Thus, the assumption of the viscosity dependent friction losses remaining constant throughout the injection test is technically invalid with the magnitude of the resulting error in estimating kh being unknown.

A viscosity equivalent to the reservoir temperature was used to estimate kh since it was assumed that, for a short duration test, the greater portion of the time-dependent increase in wellhead pressure would result because of pressure build-up in the receiving reservoir lying outside of the reservoir volume affected by temporally declining temperature. By employing the viscosity corresponding to the reservoir temperature when calculating the kh, conservative (low) values will result compared to those values that would result by employing the viscosity corresponding to the temperature of the injected water. The pressure build-up data in Figure 1 are affected by previous step injection tests which terminated two hours prior to beginning injection at 800 gpm. The pressure build-up curve in Figure 1 would have a slope ~5 psi/log cycle higher than the 22 psi/log cycle observed if there had been no prior injection. The resulting kh is ~73,400 md-ft.

Pressure fall off or recovery data were also collected (Figure 2). A viscosity corresponding to 150°F was also used in the equation to calculate kh. The slope of the linear regression extending from a Horner time rate of 500 to 10 would be ~0.875 psi/log cycle less than the 34.88 psi/log cycle observed if there had been no previous step injection testing. The resulting kh obtained from the pressure recovery data is estimated to be 58,400 md-ft. The log mean kh for the pressure build-up and recovery data is 65,500 md-ft, or a T (coefficient of transmissivity) of 3060 gal/d/ft assuming a temperature of 150°F.

The pressure build-up after injecting for 5 years was obtained by graphical extrapolation using the data plotted on Figure 1. It was assumed that the linear portion of the pressure build-up curve had a wellhead pressure of 275 psi after injecting for 10 min and increased at the rate of 27 psi/log cycle thereafter. No hydrologic boundary effects were assumed to influence the data. After 5 years of injecting at 800 gpm, the calculated pressure would be 421.3 psi at the wellhead. The difference in the specific weights of the water in the well bore during the test (conservatively assumed to be 110°F) and during power plant operation (assumed to be 150°F) would result in a wellhead pressure of 12.4 psi greater than that obtained by graphical extrapolation.

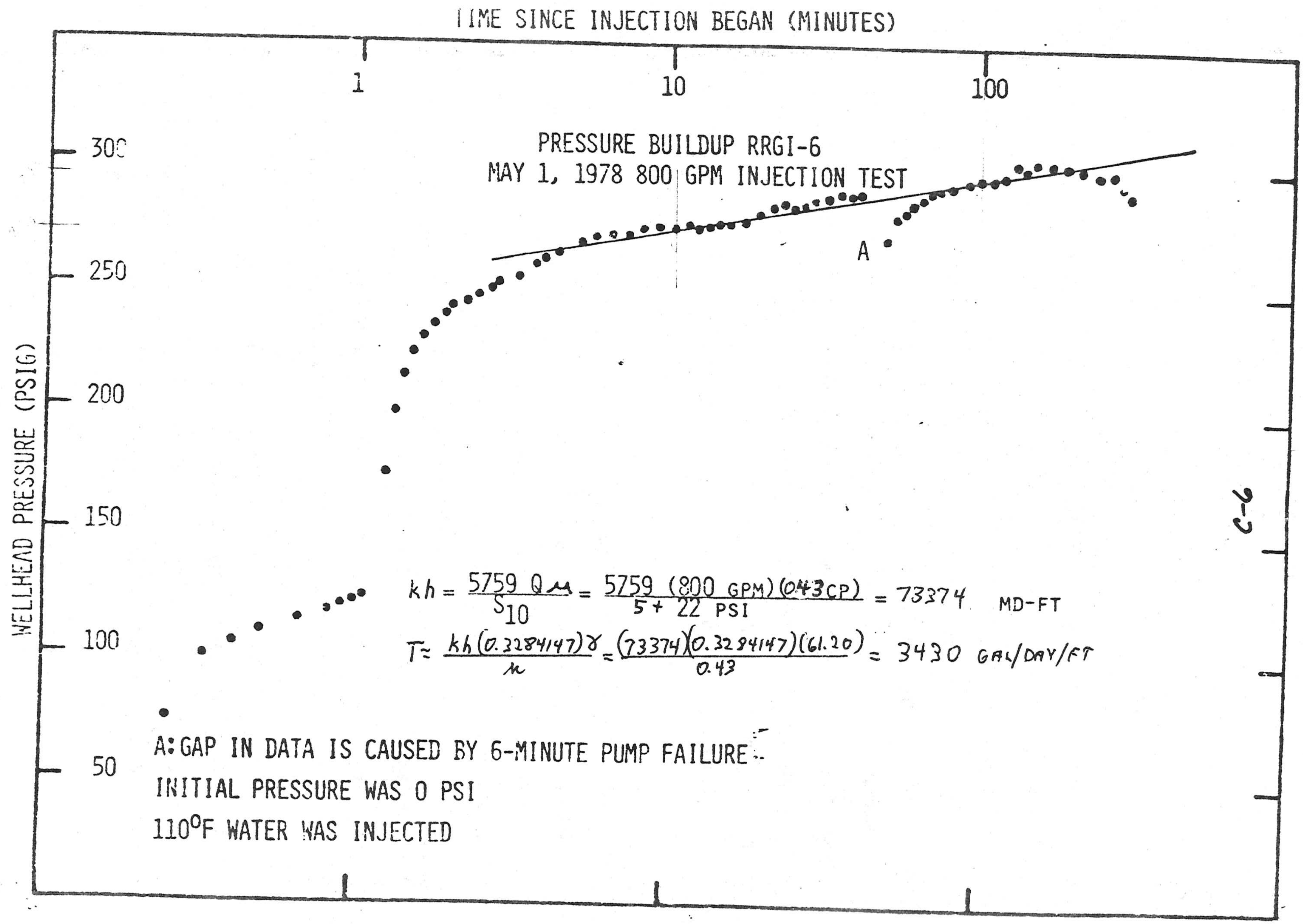

TIME SINCE INJECTION BEGAN (MINUTES)
1
10
100
WELLHEAD PRESSURE (PSIG)
300
250
200
150
100
50
PRESSURE BUILDUP RRGI-6
MAY 1, 1978 800 GPM INJECTION TEST
A
kh = 5759 Qμ / S10 = 5759 (800 GPM)(0.43 CP) / 5 + 22 PSI = 73374 MD-FT
T ≈ kh(0.3284147)γ / μ = (73374)(0.3284147)(61.20) / 0.43 = 3430 GAL/DAY/FT
A: GAP IN DATA IS CAUSED BY 6-MINUTE PUMP FAILURE
INITIAL PRESSURE WAS 0 PSI
110°F WATER WAS INJECTED
C-6

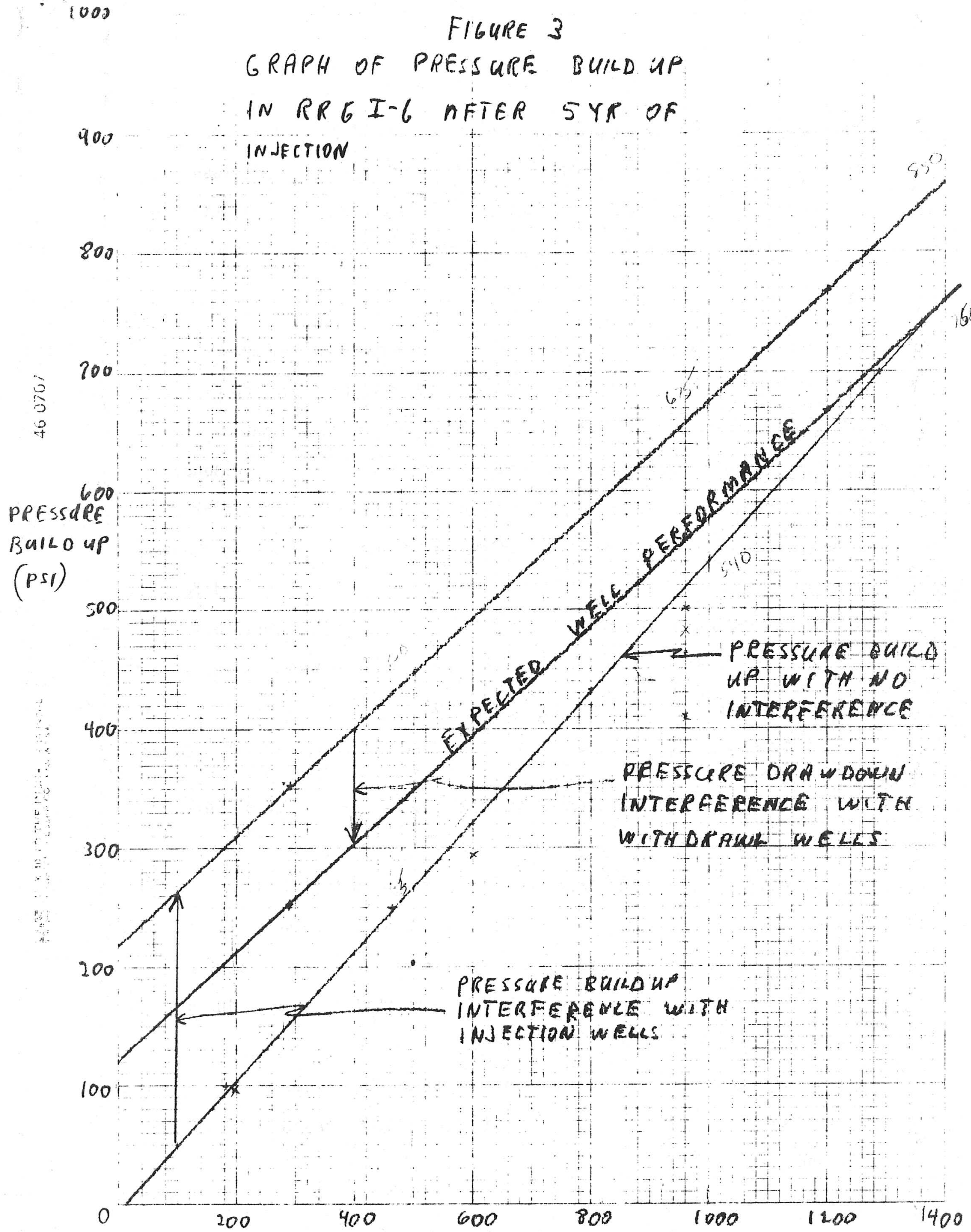
FIGURE 1

The net resulting wellhead pressure would then be 434 psi. The pressure build-up after five years of injection as a function of injection rate assuming no well interference affects, is indicated in Figure 3. This relationship was calculated assuming pressure build-up to be directly proportional to the injection rate.

Pressure build-up interference will occur between RRGI-6 and other injection wells. To simplify calculations, the remaining portion of the 2500 gpm not injected into RRGI-6 was assumed to be injected into wells at a radius of 2500 ft from RRGI-6. This assumption may not be unreasonable since the radii from RRGI-6 and RRGI-7 and RRGE-3 are ~2500 ft and ~2600 ft respectively. The interference was calculated assuming a kh of 75,000 md-ft, a reservoir temperature of 150°F, and consequently, a T of 3506 gpd/ft. The storage coefficient was assumed to be 5×10^{-4} with interferences being calculated after operating the system for five years or 1825 days. The pressure build-up considering the interference with other injection wells as a function of injection rate is indicated by the upper linear sloping line in Figure 3.

Additional drawdown interference results with the withdrawal wells. To simplify calculations, the withdrawal wells were assumed to be at a radius of 8800 ft which is the approximate distance from RRGI-6 to RRGE-1. The interference was calculated assuming a kh of 75,000 md-ft., a reservoir temperature of 200°F, and a T of 4936 gpd/ft. The storage coefficient was assumed to be 5×10^{-4}. After five years pressure drawdown at RRGI-6 would be 103 psi because of the pumping wells. This pressure drawdown is probably too large because of the higher T in the vicinity of the production wells. The expected well performance curve in Figure 3 considers the interference with both injection and pumping wells.

FIGURE 3
GRAPH OF PRESSURE BUILD UP
IN RRGI-6 AFTER 5YR OF
INJECTION



By limiting wellhead pressure to 250 psi, and assuming a pressure build-up of 200 psi and a pressure drawdown of 103 psi, a wellhead pressure build-up of 154 psi would result from injection at the rate of 285 gpm at RRGI-6. Reduced pressure drawdown interference at RRGI-6 would result in an injection rate less than 285 gpm.

EG&G Idaho

INTEROFFICE CORRESPONDENCE

date September 22, 1978

to H. M. Burton

from M. R. Dolenc MRD

subject RRGI-7 INJECTION CAPABILITIES - MRD-30-78

As we have expressed verbally, Reservoir Engineering recommends injection pressures less than 700 psi for the RRGI-7 test. Limited data gathered during the 56-minute injection test carried out after well completion, suggests very low permeability in the injection zone. This short test limits detailed quantitative analysis, but does create the following concerns to our Reservoir & Environmental groups.

(1) The injection formation (2044' - 3858') has low permeability with a Kh = 7500 md-ft;

(2) Preliminary pressure projections based on the 56-minute test supplied by David Allman (see Table I), show that an 800 gpm injection test may exceed breakdown (or fracture initiation) pressure after 5 years;

(3) It is difficult to predict actual breakdown pressures on an untested rock; however, Roger Stoker calculates an average range of 700-1400 psi on other wells. I calculate 800-1200 psi on the data on well number 7;

(4) David Allman's preliminary curve (Figure I) suggests that a barrier may have been detected toward the end of the test. If this barrier exists, pressure requirements for injection will increase over that indicated in Table I;

(5) If the well fractures during open-hole injection tests, vertical fractures are probable which will create a direct conduit into the upper aquifer. Environmental constraints could then eliminate the use of this well for injection;

(6) A sandy water bearing zone which resulted in the loss of about 250 barrels of water during RRGI-3 drilling from 1930-1950 feet, was observed in RRGI-6 and RRGI-7 drilling. This zone in number 7 lies from 1910-1950 feet (only 94 feet above casing point).

Our conclusion is that the limited RRGI-7 data suggests a tight injection section exists and a barrier may exist which will increase injection pressure within a few hours of injection startup. Such a barrier means

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that at flow rates of 400-600 GPM, pressures approaching breakdown (or fracture initiation) may be reached. If the fracture does start, one might expect vertical connection with an aquifer at 1910-1950, which may affect shallow water systems. Therefore, we recommend:

(1) Proceeding with the RRGI-7 injection test, but limit injection pressures to less than 700 psi.

(2) Considering the possibility of a designed fracture test to increase the injectability of RRGI-7.

la

cc: C. A. Allen
D. W. Allman
J. E. Driscoll
D. Goldman
T. W. Lawford
L. B. Nelson
W. L. Niemi
J. H. Ramsthaler
S. G. Spencer
R. R. Stiger
R. C. Stoker
J. F. Whitbeck
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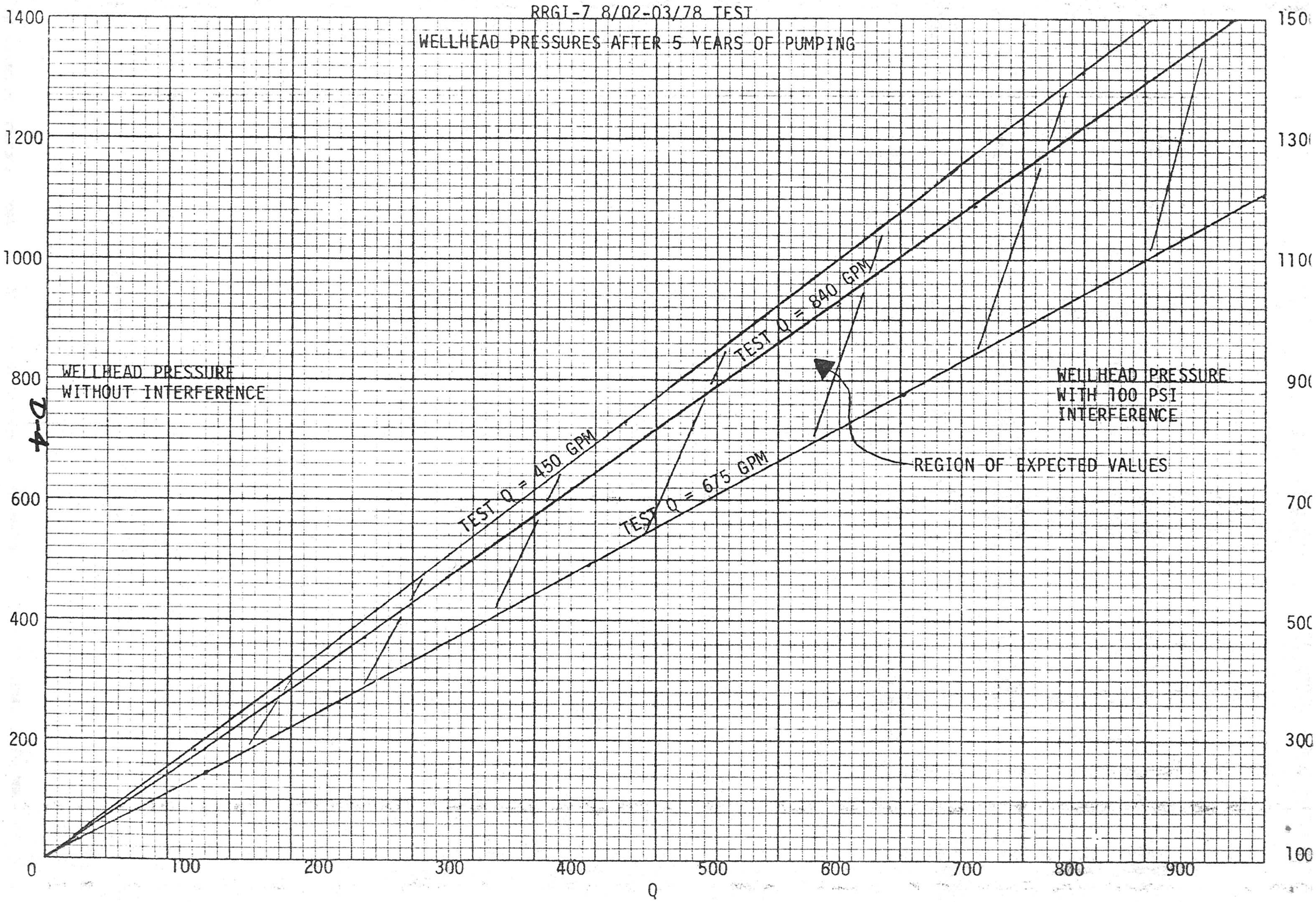
TABLE I

WELLHEAD PRESSURE RESPONSE

Q	No Boundary 10 Day Pressure	20 Day Pressure	Barrier @ 200 Minutes 10 Day Pressure	20 Day Pressure
200	193	209	290	322
400	362	394	556	619
600	530	579	820	916
800	699	763	1085	1214
1000	867	948	1351	1512

FIGURE I


RRGI-7 8/02-03/78 TEST
WELLHEAD PRESSURES AFTER 5 YEARS OF PUMPING
1400
1200
1000
800
600
400
200
0
1500
1300
1100
900
700
500
300
100
100
200
300
400
500
600
700
800
900
Q
WELLHEAD PRESSURE
WITHOUT INTERFERENCE
WELLHEAD PRESSURE
WITH 100 PSI
INTERFERENCE
TEST Q = 450 GPM
TEST Q = 840 GPM
TEST Q = 675 GPM
REGION OF EXPECTED VALUES

D-4

APPENDIX E

DRAWNDOWN CALCULATIONS ON PRODUCTION

C. J. Bliem

DRAWNDOWN CALCULATIONS ON PRODUCTION WELLS

The drawdown characteristics of each well will be considered in three parts:

(1) Drawdown with no interference, ΔP_1

(2) Production well interference, ΔP_2

(3) Injection well interference, ΔP_3

The drawdown, ΔP_1 will be the sum of these components

$$\Delta Pd = \Delta P_1 + \Delta P_2 + \Delta P_3$$

Information is taken from the following references:

1. RRGE - #1: Ltr R. C. Stoker to J. H. Ramsthaler, RRGE-1 Production Estimates, RCSt-45-78, 7-27-78

2. RRGE - #2: Ltr R. C. Stoker to J. H. Ramsthaler, RRGE-2 Testing and Production Estimates, RCSt-51-78, 9-19-78

3. RRGE - #3: D. W. Allman, Summary of Pump Testing on RRGE-3 (Rough Draft)

4. RRGE - #5: S. Watson, Interprectation of RRGP-5 72-hour Flow Test November 1-7, 1978 Test Plan FET-14A-78 (Rough Draft 1-11-79)

1. DRAWDOWN WITH NO INTERFERENCE

RRGE-1:

Reference 1 projects a 5 year drawdown of 330 psi at a flowrate of 880 gpm. If the drawdown is proportional to flowrate, then at 5 yrs:

$$\Delta P_1 = \frac{330 \text{ psi}}{880 \text{ gpm}} \; Q = 0.375 \; Q_1$$

Test results reported in reference 1 Figure 1 indicate that from approximately 2 hours to 99 hours of a pumped flow test on RRGE-1., the change in drawdown was

$$\Delta P_1 / \log \, t_2/t_1 = 12.5 \text{ psi} / \log \text{ cycle time}$$

Therefore, extrapolating the 5 year result back to 1 year and 6 months gives

at 880 gpm

1 year: $\Delta P_1 = 330 \text{ psi} - 12.5 \text{ psi} \log (5/1)$

$= 321.3$ psi

or

$$\Delta P_1 = 0.365 \; Q_1$$

6 months $\Delta P_1 = 330 - 12.5 \text{ psi} \log (5/1/2)$

$= 317.5$ psi

or

$$\Delta P_1 = 0.361 \; Q_1$$

RRGE-2:

Test results from Reference 2 are listed in the table below for drawdown at 333 min along with changes in drawdown with time at the end of the testing. Note that the drawdown - flowrate relation is not linear for this well. The 6 month, 1 year and 5 year drawdown values are obtained by extrapolating from the 333 minute value assuming the rate of drawdown with log time remains constant. That is, no additional boundaries are encountered.

	Ref 2		Extrapolation ΔP_1		
Flow Rate (gpm)	ΔP_1 @ 333 min (psi)	(psi/log cycle time)	t = 6 month (psi)	1 year (psi)	5 years (psi)
200	27.5	12.5	63.7	67.5	76.2
225	30.0	20.0	87.9	94.0	107.9
250	43.6	18.2	96.3	101.8	114.5
300	59.7	22.8	125.8	132.6	162.3
350	73.4	28.5	156.0	164.5	184.5
400	92.2	34.0	190.7	200.9	224.7
740	275.0	74.0	489.4	511.7	563.4
800	344.0	80.0	575.8	599.9	655.8

Fitting the data above with a quadratic equation using least-squares criteria gives.

6 month: $\Delta P_1 = -1.0 + 0.2406\ Q_2 + 0.000588\ Q_2^2$

1 year: $= -1.6 + 0.2631\ Q_2 + 0.000599\ Q_2^2$

5 year: $= -7.3 + 0.3496\ Q_2 + 0.000587\ Q_2^2$

The maximum difference between the equations above and the data in the table is 11.9 psi. Half the values are within $\pm$ 5 psi of the table values.

RRGE-3:

Reference 3 gives the best estimate of 5 year drawdown at well 3 to be.

$$\Delta P_1 = 0.9329\ Q_3$$

To extrapolate this result back to 1 year and 6 months the following test data was used:

In the region beyond 4000 seconds (after the recharge boundary had been encountered) the following:

$$Q/\Delta P_2 - \Delta P_1/\ln\ (t_2/t_1)$$

Date	(P) Production (R) Recovery	
7-6-77	P	5.15
	R	5.36
11-17-77	P	6.15
	R	7.18
1-31-78		5.33
mean value	=	5.83 gpm/psi/log cycle t

Then:

1 year: $\Delta P_1 = 0.9329\ Q_3 - \dfrac{Q_3}{5.83}\ (\log_{10}\ {}^{5}/_{1})$

$= 0.813\ Q_3$

6 months $\Delta P_1 = 0.9329\ Q_3 = \dfrac{Q_3}{5.83}\ (\log_{10}\ {}^{5}/_{1/2})$

$= 0.761\ Q_3$

RRGE-5:

Reference 4 gives the best estimate of 20 day performance as being that with one recharge and two barrier boundaries (Fig. 14)

$$\Delta P_1 = 0.556\ Q_5 - 82.5$$

Seventy two hour test results give the following for $Q/\Delta(\Delta P_1)/\ln(t_2/t_1)$:

Q (gpm)	Production or Recovery	$\Delta(\Delta P_1)/\ln(t_2/t_1)$ (psi/log cycle)	$[\Delta(\Delta P_1)/\ln(t_2/t_1)]/Q$ (psi/log cycle/gpm)
40	P	3.0	0.0750
40	R	7.0	0.1750
140	P	11.5	0.0821
140	R	----	------
190	P	19.4	0.1021
190	R	16.5	0.0868
300	P	26.0	0.0867
300	R	23.9	0.0797

The mean value of this set of results after rejecting 40R by Chauvenet's criteria is

$$[\Delta(\Delta P_1)/\ln(t_2/t_1]/Q = 0.0854$$

Then:

$$\Delta P_1 = (0.5562 + .0854\ (\ln(t/20\ \text{days}))Q - 82.5$$

6 mo = 182.5 days $\quad \Delta P_1 = 0.6382\ Q_5 - 82.5$

1 yr = 365 days $\quad \Delta P_1 = 0.6639\ Q_5 - 82.5$

5 yr = 1825 days $\quad \Delta P_1 = 0.7236\ Q_5 - 82.5$

2. PRODUCTION AND INJECTION INTERFERENCE

RRGE-1:

Reference 1 indicates that the combined production and injection interference for flow rates of 800 and 1000 gpm for well 1 and the remainder of 2500 gpm being produced by the other wells and injection is:

at 5 years:

$$Q = 800 \text{ gpm} \quad \Delta P_1 + \Delta P_2 + \Delta P_3 = 340 \text{ psi}$$

$$Q = 1000 \text{ gpm} \quad \Delta P_1 + \Delta P_2 + \Delta P_3 = 410 \text{ psi}$$

Now from Section 1:

	800 gpm	1000 gpm
$\Delta P_1 =$	300 psi	375 psi
$\Delta P_2 + \Delta P_3 =$	40 psi	35 psi

Now $\Delta P_2 = K_1(2500 - Q_1)$ at $\Delta P_3 = - K_2\ (2500)$

or

$$40 = K_1\ (1700) - K_2\ (2500)$$

$$35 = K_1\ (1500) - K_2\ (2500)$$

giving $K_1 = 0.025$, $K_2 = 0.001$

Assuming that production from 2 and 5 influence 1 but 3 does not

5 years $\Delta P_2 = 0.025\ (Q_2 + Q_5)$

and $\Delta P_3 = - 0.001\ (Q_{inj})$

Assuming that these vary with time in the same manner as ΔP_1

$$\frac{\Delta P_{1\ yr}}{\Delta P_{5\ yr}} = \frac{\Delta P_{1\ 1\ yr}}{\Delta P_{5\ 1\ yr}} = \frac{0.365\ Q_1}{0.375\ Q_1} = 0.973$$

$$\frac{\Delta P_{6\ mo}}{\Delta P_{5\ yr}} = \frac{0.361\ Q_1}{0.375\ Q_1} = 0.962$$

therefore:

6 months: $\Delta P_2 = 0.024\ (Q_2 + Q_5)$

$\Delta P_3 = -0.00096\ Q\ inj$

1 year: $\Delta P_2 = 0.024\ (Q_2 + Q_5)$

$\Delta P_3 = -0.00097\ Q\ inj$

RRGE-2:

Reference 2 states that at 5 years the effect of pumping all other wells at a total of 2500 gpm without pumping #2 will give a drawdown in well #2 of 66.68 psi,

5 years $\Delta P_2 = \frac{66.68\ psi}{2500\ gpm}\ (Q_1 + Q_5) = 0.0267\ (Q_1 + Q_5)$

assuming that well #3 does not effect #2.

Similarly injecting 2500 gpm will produce an interference on well #2 of -20 psi or

5 years $\Delta P_3 = \frac{-20}{2500}\ Qinj = -0.008\ Qinj.$

Note the ΔP_2 relation compares favorably with that of RRGE-1 and the ΔP_3 relation compares fairly well.

Using the same type of extrapolation to 1 year and 6 months as was done with RRGE-1:

Flow (gpm)	$\frac{\Delta P_1 \text{ (1 yr)}}{\Delta P_1 \text{ (5 yr)}}$	$\frac{\Delta P_1 \text{ (6 mos)}}{\Delta P_1 \text{ (5 yr)}}$
200	0.886	0.836
225	0.871	0.815
250	0.889	0.841
300	0.817	0.775
350	0.892	0.846
400	0.894	0.849
740	0.908	0.869
800	0.915	0.878

	1 yr		6 mos	
$\bar{x}$ =	0.884		0.839	
σ =	.030		.032	
d_{max} =	.055	.940 / .828	.060	.899 / .779
$\bar{x}_{cor}$ =	0.894		.848	

Then

6 mo $\quad \Delta P_2 = 0.0226 \ (Q_1 + Q_5)$

1 yr $\quad = 0.0238 \ (Q_1 + Q_5)$

5 yr $\quad = 0.0267 \ (Q_1 + Q_5)$

and

6 mo $\quad \Delta P_3 = -.0069 \ Qinj$

1 yr $\quad -.0072 \ Qinj$

5 yr $\quad -.0080 \ Qinj$

RRGE-3:

It is assumed that there will be no interaction between wells 1,2,5 and well 3

$$\Delta P_2 = 0$$

Reference 3 given for 5 years, injecting 2500 gpm an interference of - 100 psi

$$\text{5 years} \quad \Delta P_3 = -\frac{100}{2500}\,\text{Qinj} = -0.04\ \text{Qinj}$$

Extrapolating:

$$\frac{\Delta P_{1\ yr}}{\Delta P_{5\ yr}} = \frac{\Delta P_{1\ 1\ yr}}{\Delta P_{1\ 5\ yr}} = \frac{0.8130}{0.9329} = 0.871$$

$$\frac{\Delta P_{6\ mos}}{\Delta P_{5\ yr}} = \frac{0.7614}{0.9329} = 0.816$$

Therefore:

6 month: $\Delta P_3 = -0.033$ Qinj

1 year: $= -0.035$ Qinj

5 year: $= -0.040$ Qinj

RRGE-5:

Nothing definitive is given in Reference 4 about interaction. It is therefore assumed that it will be similar to wells 1 and 2.

	#1	#2
6 mo	$\Delta P_2 = 0.024\ (Q_2 + Q_5)$	$= 0.023\ (Q_1 + Q_5)$
1 yr	$= 0.024\ (Q_2 + Q_5)$	$= 0.024\ (Q_1 + Q_5)$
5 yr	$= 0.025\ (Q_2 + Q_5)$	$= 0.027\ (Q_1 = Q_5)$

Averaging these results to give well 5 results:

6 mo $\Delta P_2 = 0.023\ (Q_1 + Q_2)$

1 yr $\Delta P_2 = 0.024\ (Q_1 + Q_2)$

5 yr $\Delta P_2 = 0.026\ (Q_1 + Q_2)$

Similarly using well #2 data and replacing it also for well #1

6 mo $\Delta P_3 = -0.0069\ Qinj$

1 yr $-0.0072\ Qinj$

5 yr $-0.0080\ Qinj$

Summarizing the Results: $\begin{matrix}\text{6 mo}\\\text{1 yr}\\\text{5 yr}\end{matrix}$ Numbers

RRGE-1:

$$\Delta P_d = \begin{matrix}0.361\\0.365\\0.375\end{matrix} Q_1 + \begin{matrix}0.023\\0.024\\0.025\end{matrix} (Q_2 + Q_5) - \begin{matrix}0.0069\\0.0072\\0.0080\end{matrix} Qinj$$

RRGE-2:

$$\Delta P_d = - \begin{matrix}1.0\\1.6\\7.3\end{matrix} + \begin{matrix}0.241\\0.263\\0.350\end{matrix} Q_2 + \begin{matrix}0.000588\\0.000599\\0.000587\end{matrix} Q_2^2$$

$$+ \begin{matrix}0.023\\0.024\\0.025\end{matrix} (Q_1 + Q_5) - \begin{matrix}0.0064\\0.0072\\0.0080\end{matrix} Qinj$$

RRGE-3:

$$\Delta P_d = \begin{matrix}0.761\\0.813\\0.933\end{matrix} Q_3 - \begin{matrix}0.033\\0.035\\0.040\end{matrix} Qinj$$

RRGE-5:

$$\Delta P_d = - 82.5 + \begin{matrix}0.638\\0.664\\0.724\end{matrix} Q_5 + \begin{matrix}0.023\\0.024\\0.025\end{matrix} (Q_1 + Q_2)$$

$$- \begin{matrix}0.0069\\0.0072\\0.0080\end{matrix} Qinj$$

From D. Goldman 1-30-79

Well	Well head Pressure (psi)	Depth of Casing (ft)	At Casing Depth Temperature (F)	At Casing Depth Pressure (psi)	Well head Elevation (ft)
RRGE-1	140	3600	280	1588	4835
2	140	4200	280	1830	4845
3	130	4227	290	1822	4860
5	135	3408	270	1513	4888

EG&G Idaho

INTEROFFICE CORRESPONDENCE

date July 27, 1978

to J. H. Ramsthaler

from R. C. Stoker

subject RRGE-1 PRODUCTION ESTIMATES - RCSt-45-78

Attached is a paper concerning the data derived from reservoir tests conducted at RRGE-1. The data is of short duration (98.67 hours or 4.11 days) when compared to the expected operating time (5 years). However, projections based on these type of time differentials are considered normal for standard well hydrology interpretation. Undetected hydrologic boundaries present the greatest hazard in extrapolating the data over a five year period. A major boundary would cause the well to be even less productive than estimated in the attached paper.

la

Attachment: as stated

cc: D. W. Allman
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FORM EG&G-954
(Rev. 2-77)

W. L. Niemi
July 13, 1978

RRGE-1 PRODUCTION CAPABILITY

This paper is transmitted in response to personal communication with Ray Sanders concerning the rate at which well RRGE-1 can be constantly produced over a five-year period. It is emphasized that figures presented here are only estimates and are subject to change as more information concerning the Raft River Geothermal Reservoir is obtained.

Some qualifying assumptions must be taken into account in estimating a five year (43,800 hours) production rate for RRGE-1. The drawdown in well head pressure at RRGE-1 was based upon a 99 hour pump test conducted between February 2 and 6, 1976. It is assumed first, that a constant drawdown was attained before RRGE-1 was shut-in. It is assumed next, that a barrier boundary resulting in a constant doubling of drawdown would be experienced after 100 hours of production. The initial well head pressure before production begins is assumed to be 160 pounds per square inch (psi). The ability of the reservoir to transmit water between wells RRGE-1, RRGE-2, RRGP-4 and RRGP-5 is assumed to be 33% higher than the reservoir's ability to transmit water between RRGE-1 and the injection wells in the vicinity of RRGE-3. The assumed reservoir temperature is 290°F. Drawdown well loss, due to head losses caused by turbulent flow in the well, is not considered. Drawdown caused by the wells being open to different portions of the reservoir is assumed negligible. Interference drawdown caused by the pumpage of wells RRGE-2, RRGP-4 and RRGP-5, is calculated by use of the Theis Nonequilibrium Formula, and reservoir characteristics based upon current data. Interference build up caused by the injection of 2500 gallons per minute (gpm) into wells in the vicinity of RRGE-3, RRGI-6 and RRGI-7 is estimated to be equal to that caused by pumpage of RRGP-4.

Table 1 shows the drawdown in well head pressure acceptable for different pump bowl depths. It is assumed that 90 psia (90 - P_{vapor} = 46.7 117' water) must be maintained above the pump bowls. The columns on the table represent: depth to pump bowls (Depth); initial well head pressure (WHP); total pressure above pump bowls (Pressure); acceptable drawdown after five years of pumpage (Drawdown).

TABLE 1

Depth	WHP	Pressure	Drawdown
650 ft.	160 psi	420 psi	330 psi
700 ft.	160 psi	440 psi	350 psi
750 ft.	160 psi	460 psi	370 psi
800 ft.	160 psi	480 psi	390 psi
850 ft.	160 psi	500 psi	410 psi

Table II estimates the drawdown to be expected at RRGE-1 for different pumping rates and reservoir conditions. The drawdown includes estimates of interference caused by production and injection wells. Columns in the table represent: production rate at RRGE-1 (Q); was the effect of a boundary assumed in the analysis (Boundary); the drawdown at RRGE-1 to be expected after five years of continuous pumpage (Drawdown); production rate at RRGE-2 (RRGE-2); production at RRGP-4 (RRGP-4); and production rate at RRGP-5 (RRGP-5).

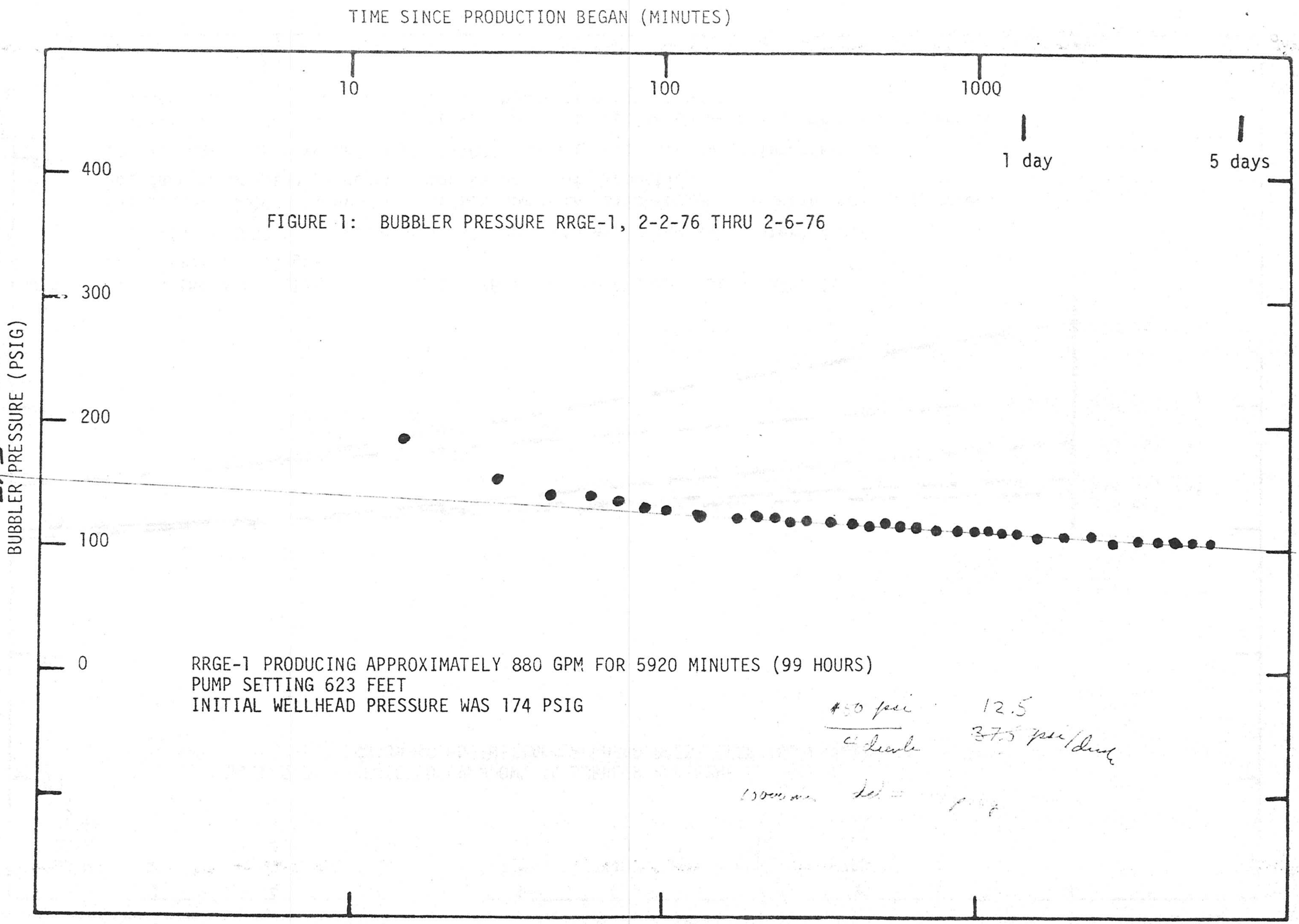
TABLE II

Q	Boundary	Drawdown	RRGE-2	RRGP-4	RRGP-5
800 gpm	No	340 psi	400 gpm	650 gpm	650 gpm
800 gpm	Yes	370 psi	400 gpm	650 gpm	650 gpm
1000 gpm	No	410 psi	400 gpm	550 gpm	550 gpm
1000 gpm	Yes	470 psi	400 gpm	550 gpm	550 gpm

RRGE-1 currently appears capable of producing between 800 and 1000 gpm for five years and maintaining a 90 psi (117 feet of water) over the pump bowls. This prediction of production capability is subject to change as the reservoir characteristics are further defined by testing of RRGP-4 and RRGP-5. The prediction of RRGE-1 productivity becomes more reliable as additional information is obtained. Any increased production from wells No. 2, 4 or 5 above that assumed in Table II, will cause increased drawdown at RRGE-1. Encountering additional major undetected boundaries will also cause detrimental effects on RRGE-1 production estimates.

Conclusions drawn in this paper are based upon the pump test presented in Figure 1. Figure 1 is a semi-log graph of bubbler pressure versus time of production. Figure 2 presents the extrapolation of data over 5 years, again on a semi-log graph.

An assumed production rate from RRGE-1 of 800 gpm at a pump setting depth of 800 feet (considering one possible boundary) is the best estimate for planning purposes available at this time.


TIME SINCE PRODUCTION BEGAN (MINUTES)
10
100
1000
1 day
5 days
400
300
200
100
0
BUBBLER PRESSURE (PSIG)
FIGURE 1: BUBBLER PRESSURE RRGE-1, 2-2-76 THRU 2-6-76
RRGE-1 PRODUCING APPROXIMATELY 880 GPM FOR 5920 MINUTES (99 HOURS)
PUMP SETTING 623 FEET
INITIAL WELLHEAD PRESSURE WAS 174 PSIG
12.5

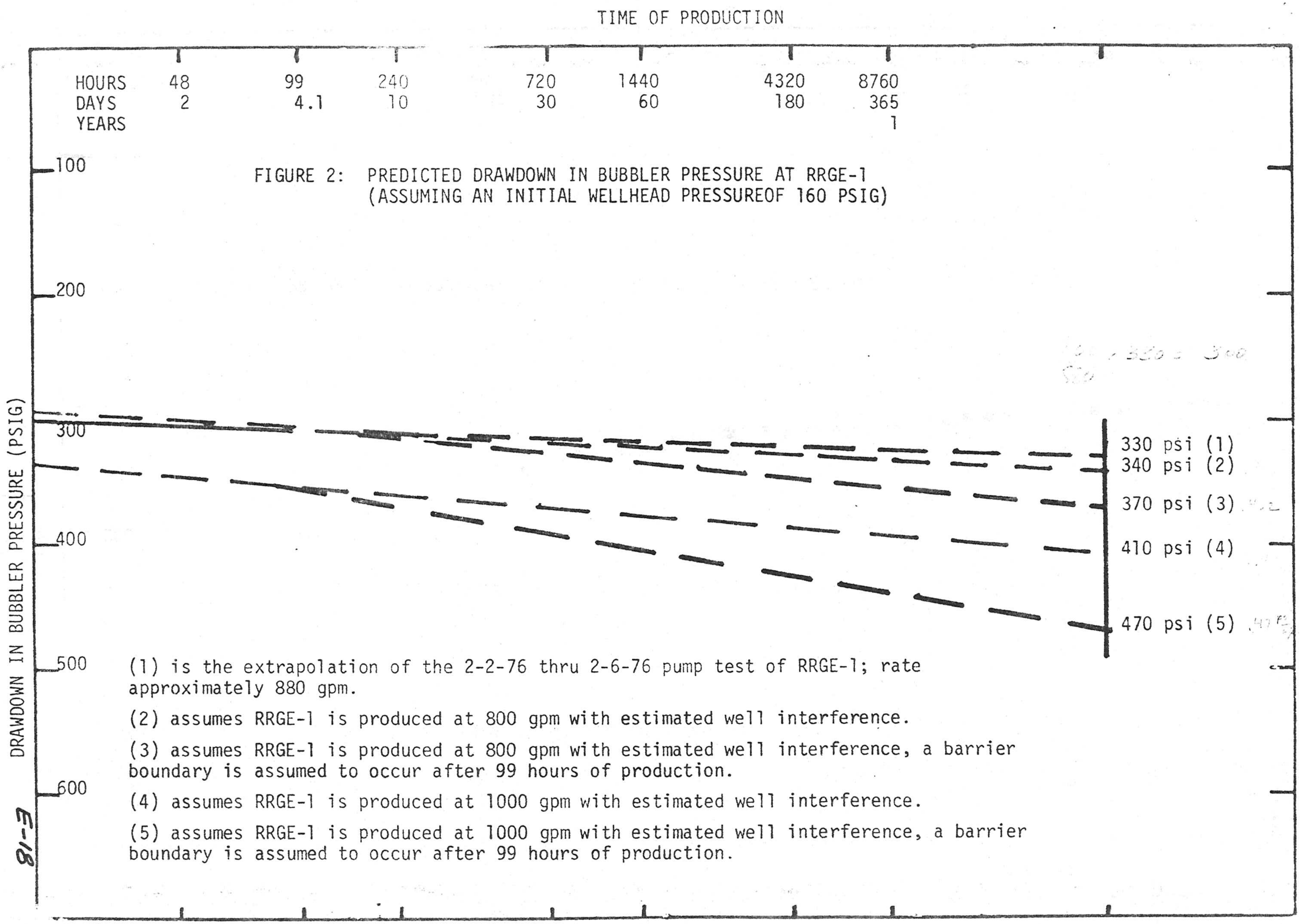


FIGURE 2: PREDICTED DRAWDOWN IN BUBBLER PRESSURE AT RRGE-1
(ASSUMING AN INITIAL WELLHEAD PRESSUREOF 160 PSIG)

(1) is the extrapolation of the 2-2-76 thru 2-6-76 pump test of RRGE-1; rate approximately 880 gpm.

(2) assumes RRGE-1 is produced at 800 gpm with estimated well interference.

(3) assumes RRGE-1 is produced at 800 gpm with estimated well interference, a barrier boundary is assumed to occur after 99 hours of production.

(4) assumes RRGE-1 is produced at 1000 gpm with estimated well interference.

(5) assumes RRGE-1 is produced at 1000 gpm with estimated well interference, a barrier boundary is assumed to occur after 99 hours of production.

EG&G Idaho

INTEROFFICE CORRESPONDENCE

date September 19, 1978

to J. H. Ramsthaler

from R. C. Stoker

subject RRGE-2 TESTING AND PRODUCTION ESTIMATES - RCSt-51-78

Attached is a paper concerning the data derived from reservoir tests conducted at RRGE-2.

With the current pump inlet setting depth of 800 feet (a bubbler setting of 790 feet), a well shut-in bubbler pressure of 450 psi, and a minimum pump inlet pressure of 52 psi; the maximum predicted well pumping rate is 540 gpm. This estimate is based on the data (Figure 9) presented in the attached paper. It considers interference from other wells and two detected hydrologic boundaries. Undetected hydrologic boundaries present the greatest hazard in extrapolating the data over a five year period. A major undetected boundary would cause the well to be less productive than estimated here.

la

Attachment:
As Stated

cc: D. W. Allman
H. M. Burton
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FORM EG&G-954
(Rev. 2-77)

SUMMARY OF PUMP TEST RESULTS ON RRGE-2

AS OF AUGUST 16, 1978

David W. Allman

Several production tests have been performed on RRGE-2. One of the most significant tests was performed at a steady production rate of 225 gpm on September 12 and 13, 1975, during which the H-P downhole pressure probe was used. The use of this probe results in accurate drawdown data. The data can be interpreted as implying the presence of barrier boundaries near the well as indicated by the straight line segmented nature of the drawdown data (Figure 1). The first break in slope, after approximately 15 minutes (900 seconds) of pumping results in a straight-line segment having a slope approximately double that of data prior to 15 minutes. This can be interpreted as indicating the presence of a linear impermeable barrier boundry located 50 feet from RRGE-2. The affects on the potentiometric head in RRGE-2 of a linear impermeable barrier boundry can be mathematically modeled using an imaginary pumping well at a distance of 100 feet from RRGE-2, pumping at the same rate as RRGE-2. The mathematical model would result in a doubling of the slope as observed.

The third linear segment of the drawdown plot begins at approximately 333 minutes (20,000 seconds). The slope of this segment is approximately 4 times greater than the linear segment prior to 15 minutes. This can be interpreted as another linear impermeable barrier boundry perpendicular to the first hypothesized barrier boundry. This second barrier boundry is estimated to be 275 feet from RRGE-2. The influence on RRGE-2 potentiometric heads of the impermeable barrier boundry can be mathematically represented by 2 pumping image wells at distances of 550 feet and 559 feet from RRGE-2. Because the image wells have near identical radii from RRGE-2, the impact of these two image wells on the potentiometric head in RRGE-2 occurs at essentially the same time. As result, the third straight line segment of the drawdown data plot has a slope approximately four times greater than the initial slope.

The expected relationships between drawdown after five years of pumping with and without interference with surrounding wells as a function of pumping rate are plotted in Figure 2. This plot results from extrapolating the September 12 and 13 data. The lower sloping line is the drawdown pumping rate relationship that would result with no well interference using the drawdown of 30 psi at 333 minutes and a Q/ΔS/ per cycle time of 11.25. The upper sloping line is the drawdown pumping rate relationship that would result from interference with the pumping wells. This interference was calculated assuming a reservoir kh of 100,000 md-ft, an S (storage coefficient) of 0.0005, a temperature of 300°F, equal production rates for RRGE-1, RRGE-4 and RRGE-5, a combined production rate of 2500 gpm, and radii from RRGE-2 of 3918 feet, 5280 feet, and 6160 feet for RRGE-1, RRGE-4 and RRGE-5 respectively. With no withdrawals from RRGE-2, interference of 66.68 psi would result because of pumping. The central line which depicts the expected well performance considers both the interference with the pumping wells and an estimated 20 psi of interference with the injection wells.

A series of relatively short drawdown tests of approximately one day duration have also been conducted RRGE-2. The results of these tests are plotted in Figure 3. The pressure declines are measured at the well head. As a result, considerable errors result in absolute drawdown. The changing specific gravity of the water in the wellbore as the temperature of the water in the wellbore increases as a result of discharging the well, can result in absolute drawdowns up to approximately 35 psi greater than those indicated in Figure 3. However, once thermal equilibrium is reached in the wellbore, relative temporally dependent declines in drawdown data can be determined with what is believed to be an acceptable degree of accuracy. However, it must be recognized that it may be possible that all the parameters describing these plots have errors of such a magnitude that the conclusions based on these data are completely erroneous.

The data in Figure 3 exhibits some non-ideal characteristics. The data from the time pumping began to approximately 333 minutes appear to have significant errors because of temporally dependent borehold fluid density changes as suggested by the lack of distinct changes in slope of the data as presumed boundary affects influence the drawdown data. Since the data collected after approximately 333 minutes exhibits well defined linear trends for approximately 0.64 of a log cycle, some credence can be placed on the wellhead drawdown data being indicative of the drawdowns occurring in the wellbore fluid adjacent to the production zone(s). The slopes expressed as psi/log cycle of time (ΔS/log cycle time), of the linear trend from approximately 333 minutes until termination of the test are listed in Table 1 as a function of the flow rate used during the test. In addition, the value of the ratio Q/ΔS/log cycle time is also listed in Table 1 along with the observed drawdown after flowing the well for 333 minutes.

Data for two additional tests at 800 and 740 gpm (Figure 4 and 5), have also been examined. The drawdown data for the 800 gpm test do not exhibit a distinct change in slope over the 725 minutes of pumping. However, the drawdown data for the 740 gpm test exhibit an abrupt change in slope after pumping 500 minutes. The reason for the absence of a slope change in Figure 4 is not known. The drawdown after pumping 333 minutes as well as the slope of the drawdown data after 333 minutes are listed in Table 1.

The estimated drawdowns after pumping 333 minutes appear to be predictable. Figure 6 is a plot of the drawdown versus Q for the data listed in Table 1. The coefficient of determination r^2, indicates that 98.5% of the variation in the drawdown after pumping 333 minutes is accounted for by the regression.

Contrary to that which would result with an ideal well, the value of $Q/\Delta S$/log cycle time is dependent on Q. Figure 7 is a plot of ΔS/log cycle time versus Q. The best fitting linear regression between these variables indicates that the rates of $Q/\Delta S$ log cycle time is not a constant since there is a non zero interrupt. Figure 8 is a graph of $Q/\Delta S$/log cycle time versus Q. The non-linearity of this relationship is readily apparent. An ideal well would have a $Q/\Delta S$/log cycle time value independent of Q. The dashed line is the relationship between these two variables as obtained from the best fitting linear regression based on the data plotted in Figure 6.

The dependent relationship between the ratio $Q/\Delta S$/log cycle time and Q is significant in that it indicates the greater the rate of withdrawal from the wall, the poorer the well performs. This dependent relationship also indicates that significant errors in predicting drawdown can be expected unless: (a) the test pumping rate is fortuitously close to the pumping rate being used for projection purposes, (b) the ratio $Q/\Delta S$/log cycle time is not dependent on Q, or (c) the relationship between $Q/\Delta S$/log cycle time and Q can be defined.

The expected relationships between drawdown after five years of pumping with and without interference with surrounding wells as a function of pumping rate Q are plotted in Figure 9. The lower sloping solid line is the drawdown pumping rate relationship that would result with no well interference using the drawdown at 333 minutes as obtained from the relationship in Figure 6 and the values for ΔS/log cycle time as obtained from the linear relationship in Figure 7. The upper sloping solid line is the drawdown-pumping rate relationship that would result from interference with the pumping wells. This interference was calculated using identical assumptions as those used for Figure 2. The central solid line depicts the expected well performance with both injection well and pumping well interference.

The comparison of the drawdown-pumping rate relationship using the 225 gpm test data only and all the available data indicates that above approximately 280 gpm, the data based on the 225 gpm test underestimate the resulting drawdowns. For convenience, the dashed line in Figure 9 is the expected well performance based on the 225 gpm test data as per Figure 2. Below approximately 280 gpm, the data based on the 225 gpm test overestimate the resulting drawdowns. Based on these results, the projection of drawdown-pumping rate relationships beyond the range of pumping rate data available can result in rather larger errors in estimated drawdown.

CONCLUSION:

(1) To eliminate the significant affects of temporally dependent borehole fluid density changes on the hypothesized drawdown data, drawdown data should be collected with a downhole pressure probe.

(2) Based on the 225 gpm test, the drawdown data can apparently be duplicated by assuming one real pumping well and 3 pumping image wells.

(3) Estimated drawdowns after pumping 333 minutes are apparently not linearly dependent on the pumping rate.

(4) The changes in drawdown (ΔS) per log cycle time appear to be linearly dependent on the pumping rate.

(5) The ratio of pumping rate (Q) to the change in drawdown (ΔS) per log cycle time is not linearly dependent on Q as would be the case for an ideal well exhibiting constant values for kh and T.

Table 1

Selected Parameter Response Obtained From Withdrawal Tests On RRGE-2.

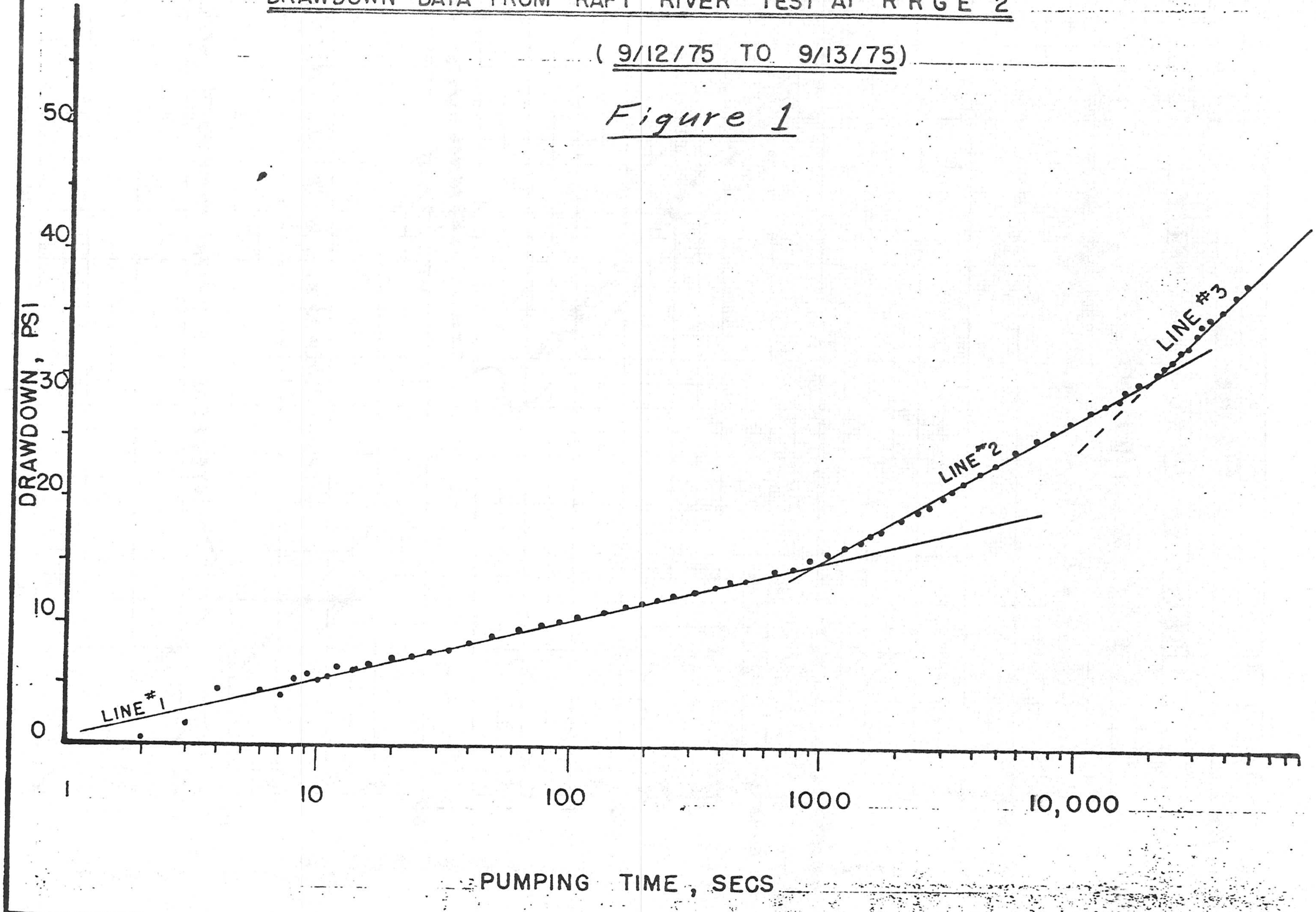
Pump Rate (9pm)	Drawdown at 333 min. (psi)	ΔS/Log Cycle Time (psi)	Q/ΔS/Log Cycle Time (9pm/psi)
200	27.5	12.5	16.0
225	30.0	20.0	11.3
250	43.6	18.2	13.7
300	59.7	22.8	13.2
350	73.4	28.5	12.3
400	92.2	34.0	11.8
740	275.0	74.0	10.0
800	344.0	80.0	10.0

8/16/78

DRAWDOWN DATA FROM RAFT RIVER TEST AT RRGE#2

(9/12/75 TO 9/13/75)

Figure 1



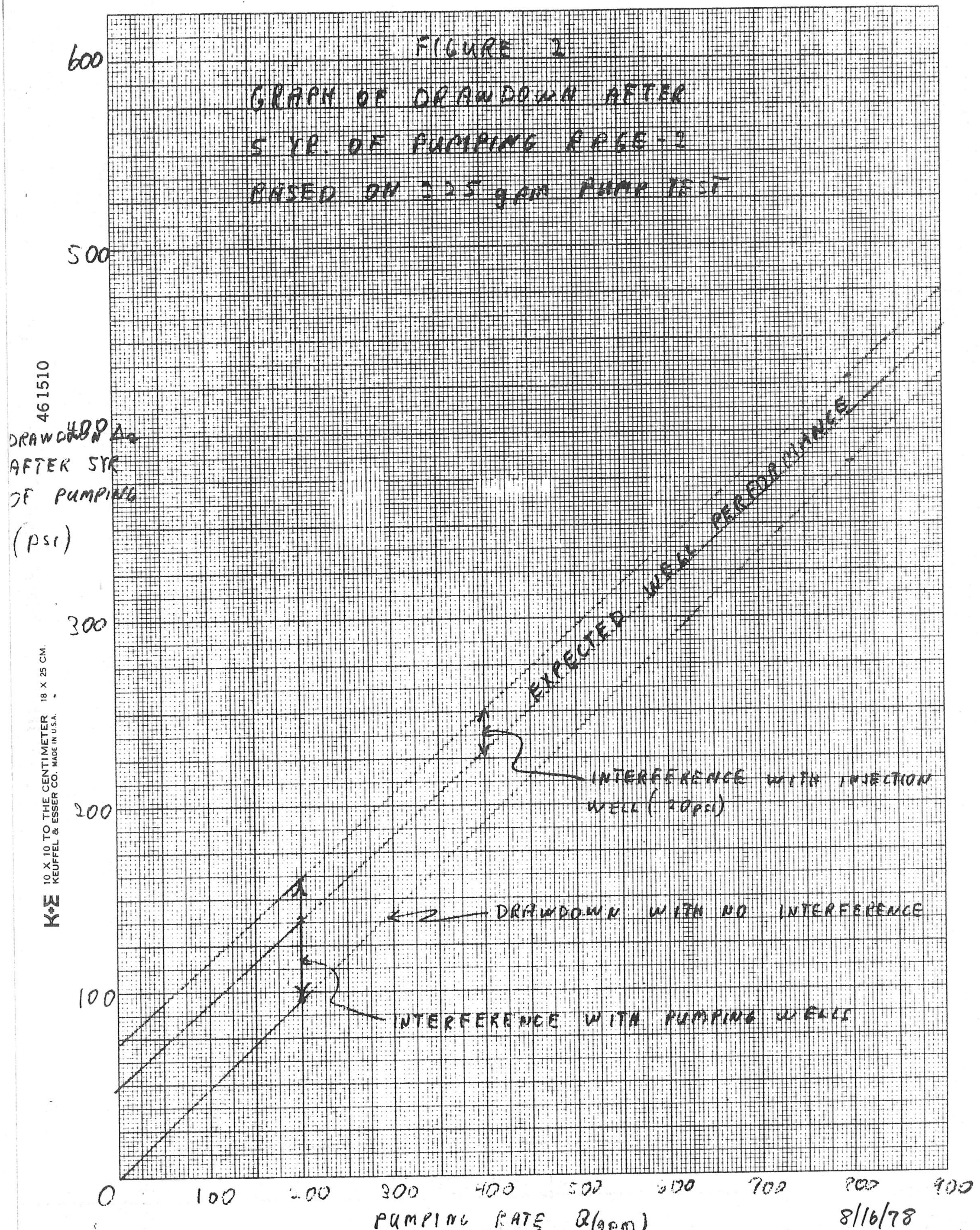
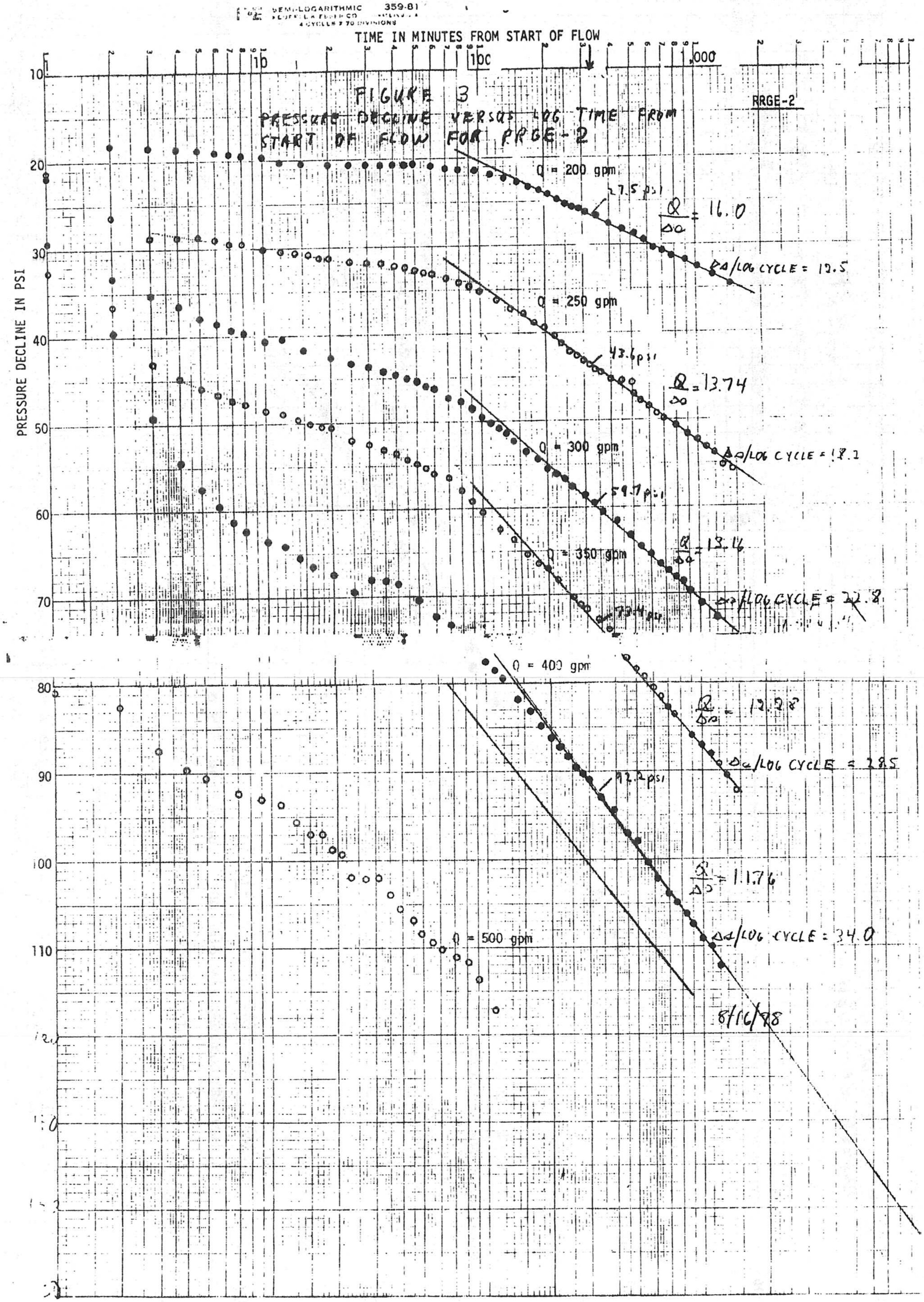
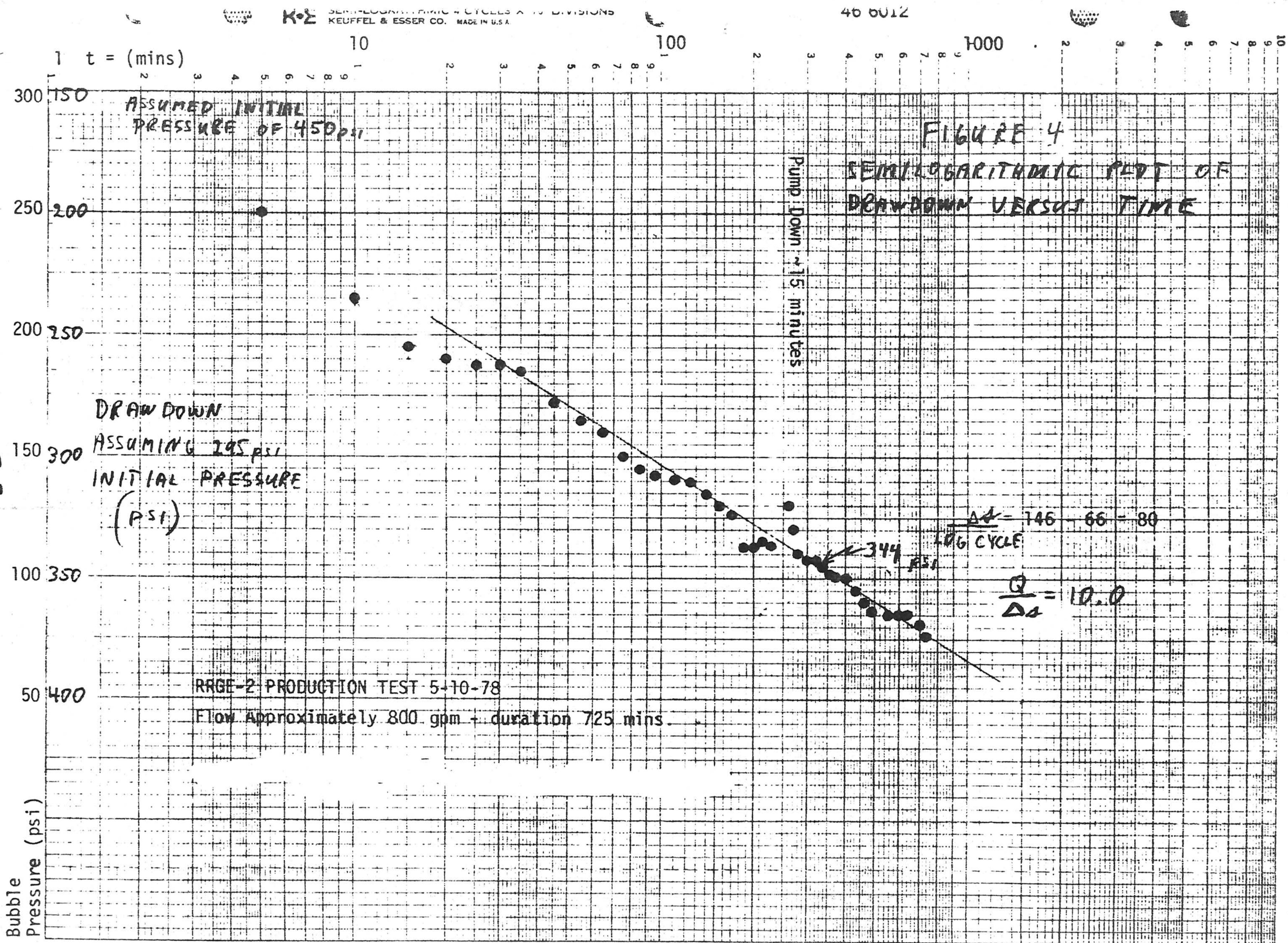


FIGURE 2
GRAPH OF DRAWDOWN AFTER
5 YR. OF PUMPING RRGE-2
BASED ON 225 gpm PUMP TEST
600
500
400
300
200
100
0
DRAWDOWN Δp
AFTER 5YR
OF PUMPING
(psi)
EXPECTED WELL PERFORMANCE
INTERFERENCE WITH INJECTION WELL (20psi)
DRAWDOWN WITH NO INTERFERENCE
INTERFERENCE WITH PUMPING WELLS
100
200
300
400
500
600
700
800
900
PUMPING RATE Q(gpm)
8/16/78
461510
K+E 10 X 10 TO THE CENTIMETER 18 X 25 CM.
KEUFFEL & ESSER CO. MADE IN U.S.A.

E-28

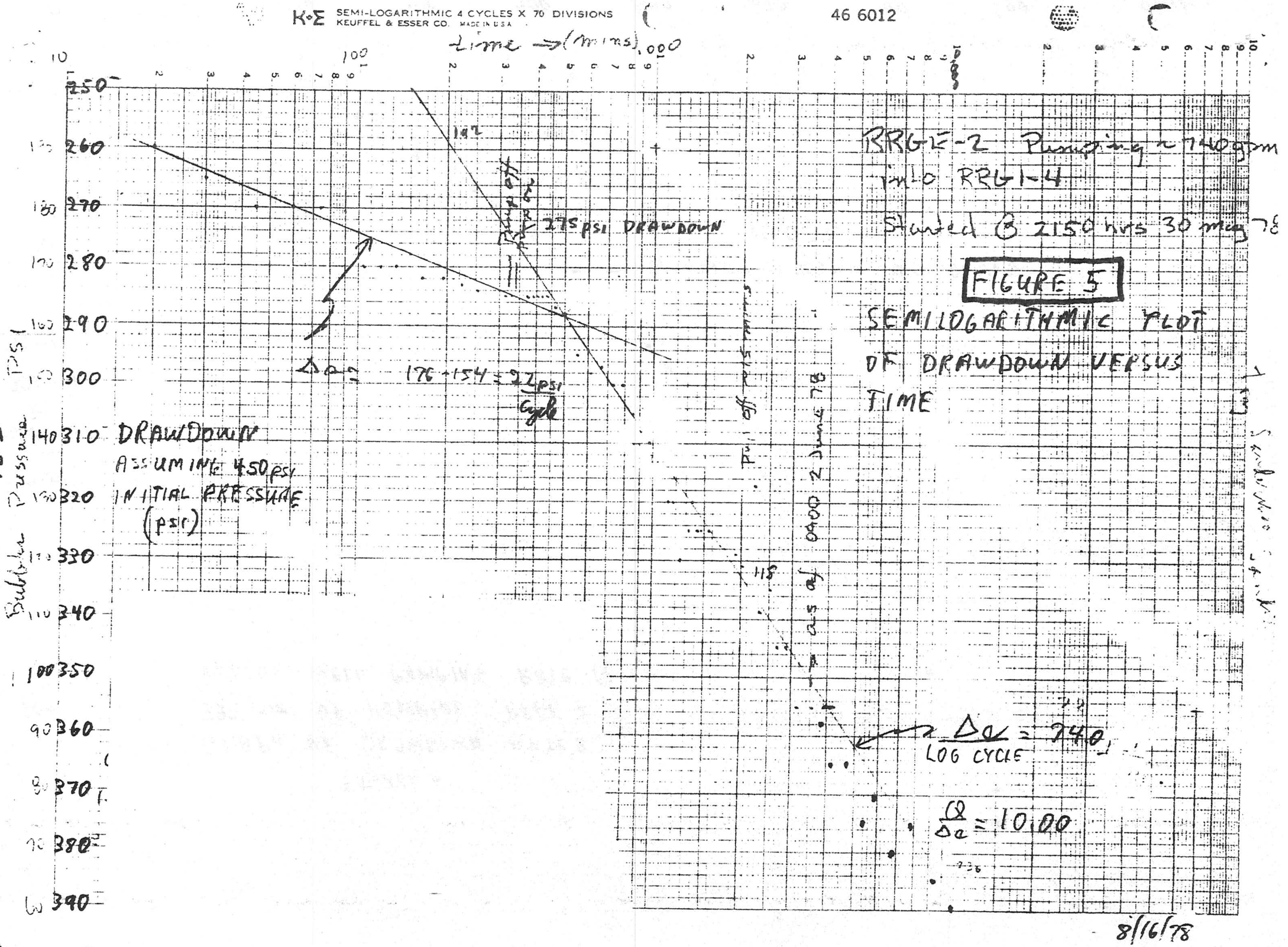

SEMI-LOGARITHMIC 359-81
4 CYCLES X 70 DIVISIONS
TIME IN MINUTES FROM START OF FLOW
10
100
1,000
FIGURE 3
PRESSURE DECLINE VERSUS LOG TIME FROM START OF FLOW FOR RRGE-2
RRGE-2
PRESSURE DECLINE IN PSI
10
20
30
40
50
60
70
80
90
100
110
Q = 200 gpm
27.5 psi
Q/Δσ = 16.0
Δσ/LOG CYCLE = 12.5
Q = 250 gpm
43.6 psi
Q/Δσ = 13.74
Δσ/LOG CYCLE = 18.2
Q = 300 gpm
59.7 psi
Q/Δσ = 13.4
Δσ/LOG CYCLE = 22.8
Q = 350 gpm
Q = 400 gpm
Q/Δσ = 12.28
Δσ/LOG CYCLE = 28.5
92.2 psi
Q/Δσ = 1.176
Δσ/LOG CYCLE = 34.0
Q = 500 gpm
8/16/78



K•E SEMI-LOGARITHMIC 4 CYCLES X 10 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.
46 6012
t = (mins)
1
10
100
1000
Bubble Pressure (psi)
300
250
200
150
100
50
150
200
250
300
350
400
ASSUMED INITIAL PRESSURE OF 450 psi
DRAW DOWN ASSUMING 295 psi INITIAL PRESSURE (psi)
FIGURE 4
SEMILOGARITHMIC PLOT OF DRAWDOWN VERSUS TIME
Pump Down ~15 minutes
Δs / LOG CYCLE = 146 - 66 = 80
344 psi
Q / Δs = 10.0
RRGE-2 PRODUCTION TEST 5-10-78
Flow Approximately 800 gpm - duration 725 mins.

8/16/78

E-30



K+E SEMI-LOGARITHMIC 4 CYCLES X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.
46 6012
Time → (mins)
RRGE-2 Pumping ~740 gpm
into RRGI-4
Started @ 2150 hrs 30 May 78
FIGURE 5
SEMILOGARITHMIC PLOT
OF DRAWDOWN VERSUS
TIME
275 psi DRAWDOWN
Δa = 176 - 154 = 22 psi/cycle
DRAWDOWN
ASSUMING 450 psi
INITIAL PRESSURE
(psi)
Bubbler Pressure PSI
Pull off 5 1/2 " line
as of 0900 2 June 78
Δa / LOG CYCLE = 740
Q / Δa = 10.00
8/16/78

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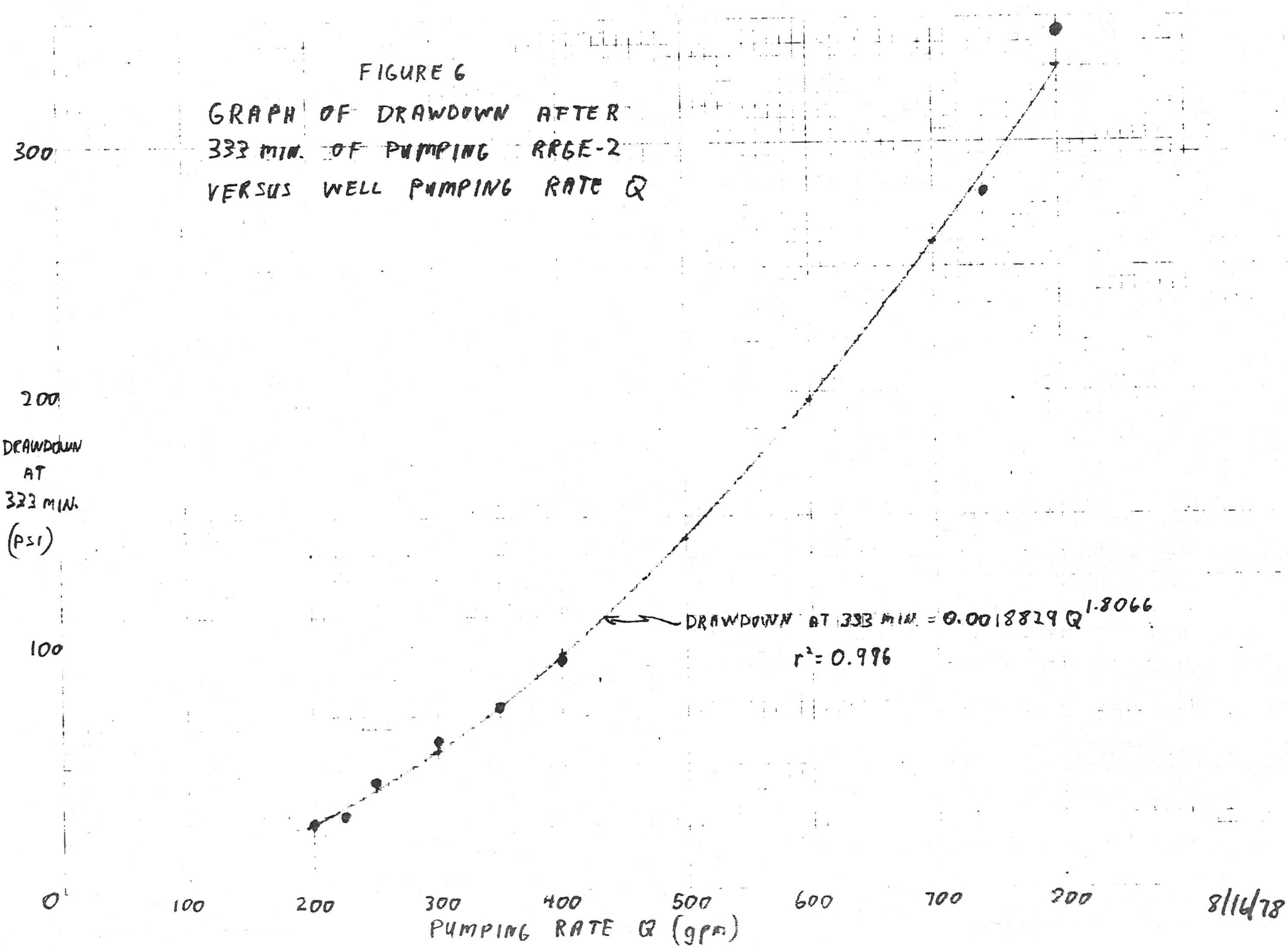


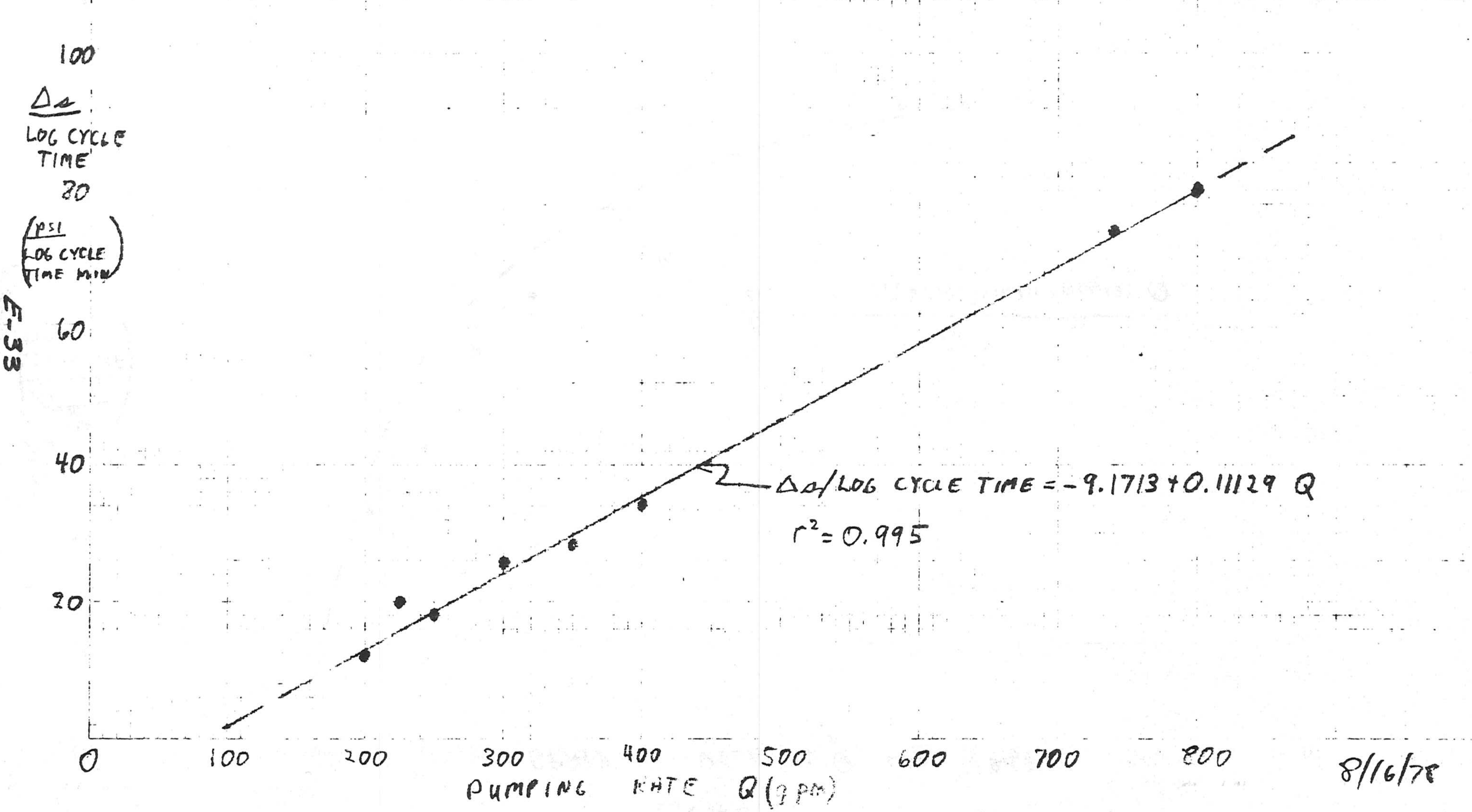
FIGURE 6

GRAPH OF DRAWDOWN AFTER 333 MIN. OF PUMPING RRGE-2 VERSUS WELL PUMPING RATE Q

8/16/78

FIGURE 7

GRAPH OF Δs/LOG CYCLE TIME VERSUS Q FOR RRGE-2



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RRGE 2

FIGURE 8

GRAPH OF Q/Δs vs Q FOR RRGE-2

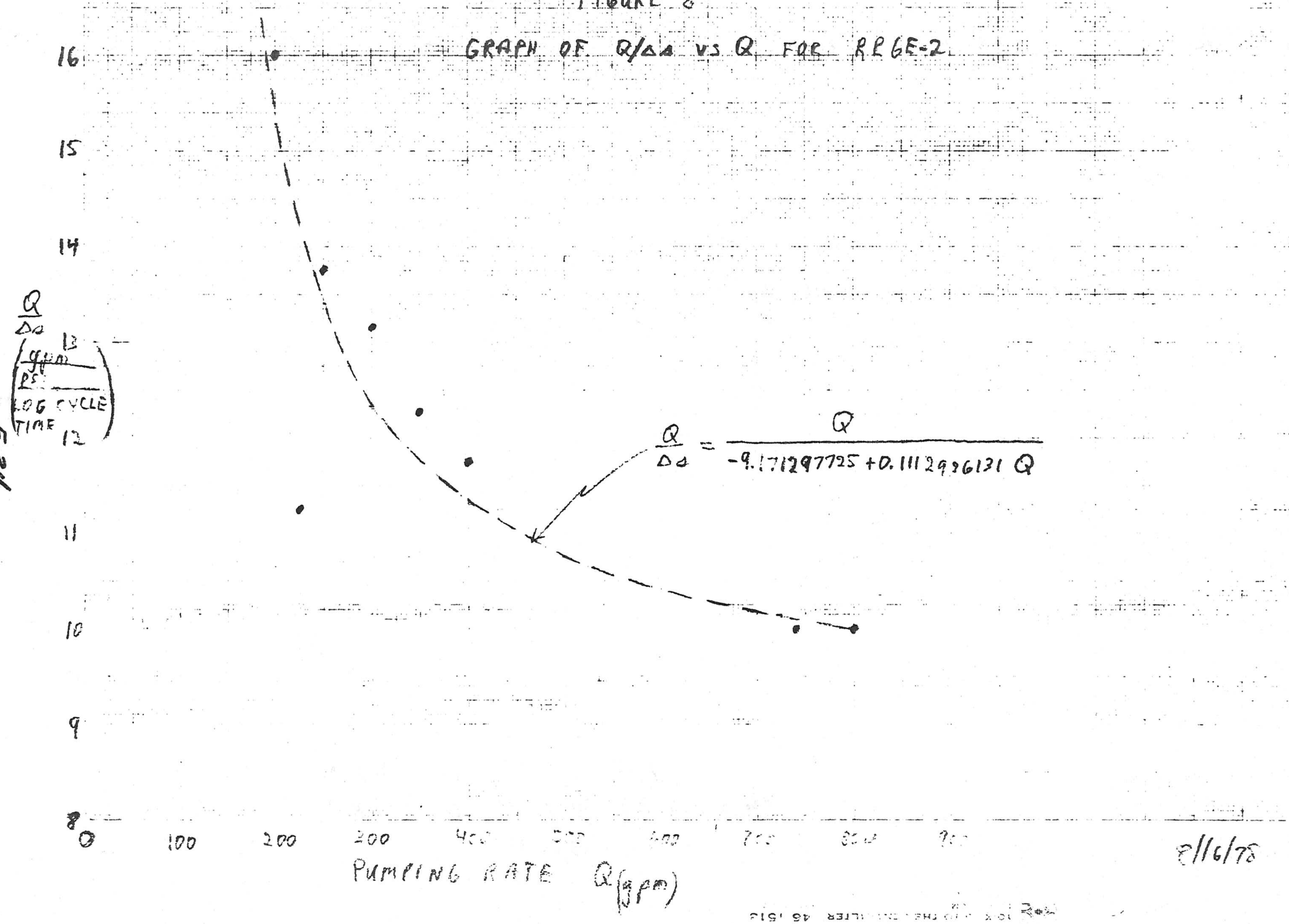

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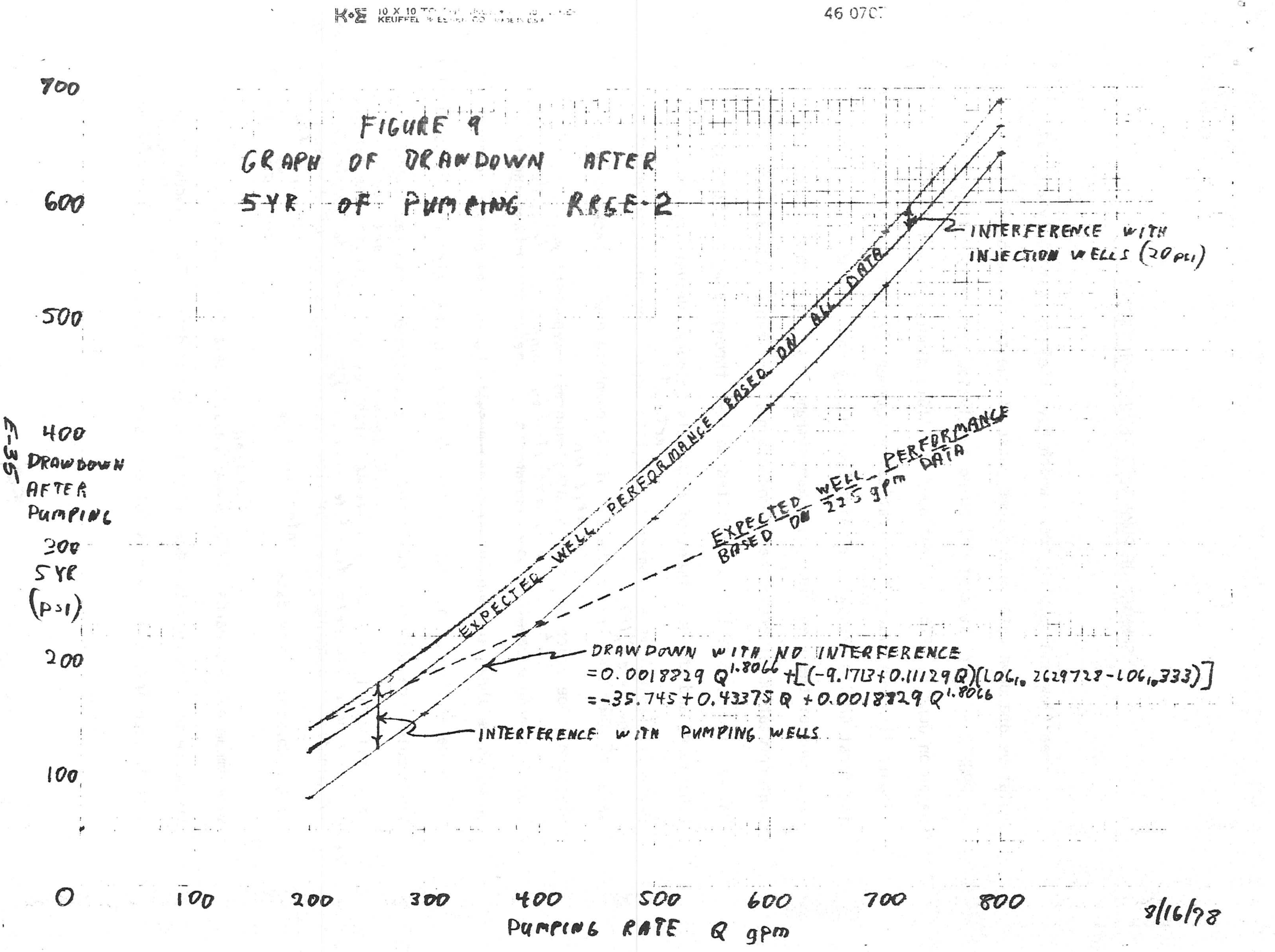
FIGURE 9
GRAPH OF DRAWDOWN AFTER
5YR OF PUMPING RRGE-2



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D. W. Allman
Rough Draft

SUMMARY OF PUMP TEST RESULTS ON RRGE-3

Six free flow and pumping tests which have yielded reasonably accurate relative drawdown data during some phase of the test have been conducted on RRGE-3. The first test following completion of the well in May 1976 began on June 8, 1976 and continued for 11610 minutes at a flow rate (Figure 1) which fluctuated erratically between 152 gpm and 120 gpm during the first 4800 minutes (80 hr) but remained relatively constant at ~137 gpm for the remainder of the free flow test (Narasimham, T.N., McEdwards, D.G., "Interpretation of Preliminary Production-Interference RRGE-3, Raft River Valley, Idaho, June 1976", submitted to EG&G through Lawrence Berkeley Laboratory and the Department of Materials Science, University of California, Berkeley). Table 1 is a summary of the pertinent test data. The unique potential value of ~~this~~ the June 8, 1976 test lay in the use of the downhole Hewlett-Packard (HP) pressure probe which would eliminate reliance on ~~temporally dependent~~ wellhead and bubbler pressure data which is affected by temporally dependent ~~baseline no drawdown data. The drift in baseline no drawdown wellhead and bubbler pressure results because of~~ density changes of the water and the nitrogen in the borehole and the "air" line respectively during te[st]. The bubbler pressure data collected during subsequent pump tests appear to be significantly affected by ~~unstable~~ temporally dependent borehole temperature and density profiles for the first 900 minutes of pumping. Thus, it is necessary to have accurate downhole pressure fluid ~~data~~ in order to quantatively analyze [data] collected during the initial 90 min. of a test. Unfortunately, the poor flow control negated much of the usefulness of the downhole probe data.

Narasimham and McEdwards (1976) ~~used~~ employed computer data generated using a variable discharge program to match ~~the~~ observed drawdown data. The drawdown data were divided into two segments for analysis. The data for the first 1080 min. (18 hours) of production were analyzed since the probability of hydrologic boundaries affecting the data is minimal at the beginning of production. Figure 2 is a log-log plot of the observed and computed drawdown data versus time. The sensitivity of the computed drawdown values to changes in the assumed kh value of 12 000 md-ft is not known. Since the observed and computed data match appears to be poor for a log-log plot, the accuracy of the reported kh is somewhat suspect. As a result, the results of this analyses were not used in summarizing computations.

The second segment analyzed included all of the drawdown and part of the recovery data (Figure 3). The computed data were calculated assuming a kh of 6400 md-ft, which for the purpose of comparison with latter pumping test data, would, on a semilogarithmic plot of drawdown or bubbler pressure
in psi per log cycle time
versus time, result in a ratio of $Q/\Delta s_1$ of 6.01 ~~gpm/psi~~/log cycle time assuming
where Δs_1 is the slope of the linear data segment +
a discharge rate, Q, of 135 gpm and a reservoir temperature of 300°F. The match
would result on a semilogarithmic drawdown plot prior to boundary
between the observed and computed drawdowns is unacceptable prior to ~ 4800 affects, any.
minutes (80 hours) while the flow rate was fluctuating, but after 80 hours of flowing, the match appears to be acceptable. Based on the data for the entire test, it appears that the better estimate for the reservoir kh is the 6400 md-ft ($Q/\Delta s_1$ = 6.01 gpm/psi/log cycle time) value.

Recovery or pressure buildup data ~~were~~ collected following well shut-in were analyzed separately. The buildup due to injection, referred to as ΔP injection is the difference between the observed pressure and the extrapolated production pressure as indicated in Figure 4. Conventional curve matching techniques for the pressure buildup data plotted in Figure 5 result in a calculated kh of 5448 md-ft or a ratio of $Q/\Delta s_1$ of 5.12 gpm/psi/log cycle time. The similar values further support th contentio

for kh determined from the recovery and the entire drawdown data ~~suggest~~ that the computed kh value of 12000 md-ft based on the initial 18 hours of production is not valid. Based on the flow test beginning June 8, 1976, it is concluded that the ratio of $Q/\Delta s$, can be expected to be in the range of 5 to 6 gpm/psi/log cycle at a flow rate of 135 gpm. In addition, the close fit of the type c to the data figure 5 im it ~~appears~~ is unlikely that significant hydrologic boundaries were encountered during the initial ~~6000~~ minutes of recovery.

he relatively close values of $Q/\Delta s$, for drawdown (6.01 gpm/psi/log cycle) and recovery
5.12 gpm/psi/log cycle) ...lly during the 1700 min. o drawdown and recovery. suggest no significant hydrologic boundaries were enc...

The next test resulting in interpretable data began pumping at 788 gpm on June 29, 1977 and continued for 1440 minutes (Table 1). Figure 6 is a semilogarithmic graph of bubbler pressure versus time. The data appear to plot as a linear trend having a slope Δs, of 186 psi/log cycle time from approximately 450 minutes after pumping began to approximately 1250 minutes. The reason for the deviation of the data collected after 1250 minutes from the linear trend of the preceeding data is not known. The ratio of $Q/\Delta s$, is 4.24 gpm/psi/log cycle and is entered in Table 1 as a value for the first linear segment observed for the drawdown data. The following is an equation that can be used to predict bubbler pressure:

$$\text{Bubbler Pressure} = 177 - 186\,(\log t - 3)$$

where: bubbler pressure is in psi

t is the time since pumping began in minutes

No recovery data were collected. The bubbler pressure data for this test appear to provide a valid estimate of the well performance from approximately 400 to 1200 minutes after beginning pumping.

On July 6, 1977, ~~RRGE-3~~ pumping of RRGE-3 began at a rate of 592 gpm. Bubbler pressure data were collected for 18 255 minutes (Figure 7). The bubbler pressure data followed two linear trends: one from approximately 650 minutes to 3325 minutes and the other extending from 3325 to 14500 minutes. The slopes Δs_1 ~~/log cycle~~ and Δs_2 ~~/log cycle~~ for the first and second linear segments, respectively are 161 and 115 psi/log cycle, ~~respectively~~. The ratio of ~~the slope Δs/log cycle~~ $\Delta s_2/\Delta s_1$ of the second linear segment relative to that of the first segment is 0.714. Since this ratio indicates that the slopes of the second linear segments is not one half that of the first segment, the recharge boundary encountered is not an ideal linear constant head boundary. This conclusion assumes that no boundary affects were manifested prior to 3325 minutes. Type curve solutions for a boundary having these characteristics are not available. The ratios of $Q/\Delta s_1$ ~~/log cycle~~ and $Q/\Delta s_2$ for the first and second linear segments are 3.68 and 5.15 gpm/psi/log cycle respectively (Figure 7). Based on the similar values for the June 8, 1976 recovery test $Q/\Delta s_1$ ratio and those for the first linear segments of subsequent tests (Table 1), this assumption appears to be valid, but without additional HP borehole pressure data, it is not conclusively known whether this assumption is valid. The equations for predicting the bubbler pressures for the first and second linear segments of the data in Figure 7 are:

Bubbler Pressure = 252 - 161 (log t - 3)

and

Bubbler Pressure = 113 - 115 (log t - 4)

respectively.

Where: Bubbler Pressure is in psi

t is time since pumping began in minutes

Based on the bubbler pressure drawdown data for the July 6, 1977 test, a recharge boundary which does not produce the effects of a linear constant

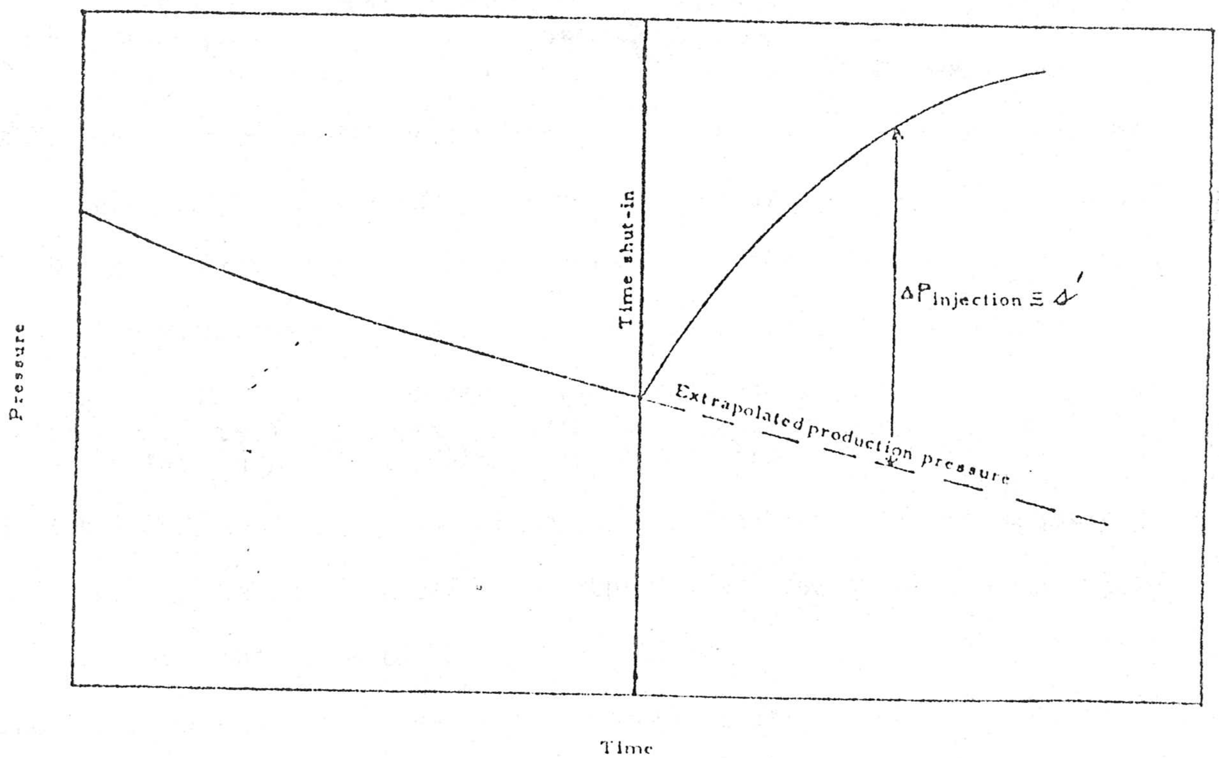

Fig.3 RRGE 3 Buildup analysis - schematic definition of $\Delta P_{injection}$

head boundary affected the bubbler pressure data after 3325 minutes of pumping.

Recovery data were collected beginning at 2865 minutes following well shutin and continu~~ing~~ed until 11325 minutes. Figure 8 is a graph of calculated recovery, s', versus time since the well was shut in. The value s' is defined as the difference between the calculated bubble pressure that would have resulted had the pressure continued to decline as defined by the equation for the second linear segment in Figure 7, minus the observed wellhead pressure. The value for t' is the time in minutes since the well was shut-in. Conceptually, s' is equivalent to ΔP injection in figure 3. A linear regression through the data plotted in Figure 8 for t' > 3800 minutes has a ~~shape~~ slope of 110.4 psi/log cycle t' which results in a $Q/\Delta s_2'$ value of 5.36 psi/log cycle t'. These values are surprisingly similar to those for the second segment of the drawdown data plotted in Figure 7. This similarity of the $Q/\Delta s_2$ and the $Q/\Delta s_2'$ values suggest that no additional hydrologic boundaries were encountered between approximately 3325 minutes and 29 580 minutes. The recovery data for the July 6, 1977 pump test support the $Q/\Delta s_2$ value obtained for the second linear segment of the drawdown data (Figure 7) and furthermore suggest that no additional hydrologic boundary effects were encountered between approximately 3325 minutes and 29580 minutes after pumping began.

A test beginning November 17, 1977 pumped water from RRGE-3 at 603 gpm for 1440 minutes. Figure 9 is a semilogarithmic plot of bubbler pressure versus time. A linear regression passing through the data when t > 600 minutes has a slope Δs_1 of 125.0 psi/log cycle time which results in a $Q/\Delta s_1$ ratio of 4.82 gpm/psi/log cycle. Th~~is~~e value for $Q/\Delta s_1$ is the largest calculated for pump tests with the discharge rate greater than 590 gpm, but the data appear to be valid.

The equation for the bubbler pressure is as follows (figure 9):

Bubbler pressure = 264 − 125.0 (log t − 3)

A pump test which began on November 28, 1977 maintained a discharge rate of 603 gpm for 34,185 minutes. Figure 10 is a graph of bubbler pressure versus time. The slope Δs_1 of the first linear segment beginning at approximately 750 minutes after pumping began and ending at 3899 minutes is 142.0 psi/log cycle which results in a ~~ratio of~~ value for $Q/\Delta s_1$ of 4.25 gpm/psi/log cycle. The following is the equation defining the bubbler pressure:

Bubbler Pressure = 257 - 142 (log t - 3)

Where: Bubbler Pressure is in psi

t is time since pumping began in minutes

The second linear segment of the data plotted in figure 10 extends from 3899 minutes to 22560 minutes after which the data ~~are invalid~~ contain an apparent error of 10 psi because of recalibration of the gage. ~~which resulted in an apparent 10 psi error~~. The slope of the bubbler pressure data, Δs_2 for the second segment is 98.0 psi/log cycle with a ratio of $Q/\Delta s_2$ of 6.15 gpm/psi/log cycle. The equation for the bubbler pressure from 3899 minutes to 22560 minutes is as follows:

Bubbler Pressure = 133 - 98 (log t - 4)

Where: Bubbler Pressure is in psi

t is time since pumping began in minutes

The following is the equation for the bubbler pressure from 22560 minutes to 34185 minutes:

Bubbler Pressure = 143 - 98 (log t - 4)

The ratio of the slope Δs_2 of the second linear segment relative to that, Δs_1, of the first segment is 0.691 which is ~~approximately~~ essentially equal to the mean of 0.690 (table 1). The values for $Q/\Delta s_1$ and $Q/\Delta s_2$ of 4.25 and 6.15 gpm/psi/log cycle for the first and second linear segments respectively appear to be valid.

Recovery data were collected for the pump test beginning November 28, 1977 using the bubbler and a wellhead pressure gage. Figure 11 is a graph of the bubbler pressure recovery s' versus time, t', ~~since well shutin~~. Bubbler pressure recovery s' is equivalent to Δp injection in Figure 3. The first linear segment which extends from 300 minutes to 1369 minutes has a slope $\Delta s'_1$ of 128.0 psi/log cycle which results in a ratio of $Q/\Delta s'_1$ of 4.71 gpm/psi/log cycle. This ratio which is slightly higher than the log mean of 4.51 gpm/psi/log cycle ~~the second highest value observed (Table 1)~~, table 1, ~~but still~~ appears to a ~~be within~~ reasonable value ~~limits~~. The following is the equation for bubbler pressure recovery for the first segment:

$$\text{Bubbler Pressure} = 198 + 128\,(\log t' - 3)$$

The second linear segment which extends from 1369 minutes to 6570 minutes has a slope $\Delta s'_2$ of 84.0 psi/log cycle. The ~~which results in a~~ ratio of $Q/\Delta s'_2$ has a value of 7.18 gpm/psi/log cycle. This value for the ratio is larger than the mean excluding value of 7.18 gpm/psi/log cycle ~~next largest recorded value~~ by 1.70 ~~1.03~~ (Table 1). Or ~~Because of this large difference relative~~ the stand deviation, the ~~thus, there is some suspicion~~ is considerable suspicion regarding the validity of the value of 7.18. The following equation defines the bubbler pressure for this second linear segment:

$$\text{Bubbler Pressure} = 288 + 84\,(\log t' - 4)$$

The ratio $\Delta s_2/\Delta s_1$ has a value of ~~of the slopes $\Delta s'$ of the second segment to the first segment is~~ 0.656 which is considerably ~~somewhat~~ lower than other values calculated from these tests (table 1). The values for $Q/\Delta s_2$, $\Delta s_2/\Delta s_1$, and the intersection time of 1369, for the 2 linear segments all suggest that second linear segment for the data in figure 11 are atypical, and as such were not used in calculating means for the various statistics.

Data collected after 6570 minutes exhibit unexplained abrupt pressure changes. Figure 12 is a graph of the bubbler pressure versus wellhead pressure during recovery. Abrupt changes in the relationship between bubbler pressure and wellhead pressure occur for bubbler pressures greater than 335 psi, ~~when the wellhead pressure is both psig and psia~~. These errors may result because of errors in reading the gages. The unit slope ~~of~~ when the bubbler pressures are between 300 and 335 psi suggest that the bubbler pressure data and the wellhead pressure data are equally valid or invalid as the case may be. ~~are not significantly affected by borehole fluid temperature changes, although this is not conclusive evidence.~~ The wellhead data for pressures greater than 340 psi appear to be approximately 7 psi too great relative to the trend from 300 to 335 psi (figure 12). The increased slope of the data for bubbler pressures greater than 352 psi is [illegible] the bubbler tube and the water

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in the wellbore surrounding the bubbler tube. The relationship between bubbler pressures and wellhead pressures suggests a cautious approach when using pressure data not collected near the producing zone(s) during the recovery phase of a discharge test on a geothermal well.

The final pump test began January 31, 1978 and continued pumping at 650 gpm for 13085 minutes (figure 13). The first linear segment extends from 1085 to 3375 minutes after pumping began and has a slope Δs_1 of 175.0 psi/log cycle and a resulting ratio of $Q/\Delta s_1$ of 3.71 gpm/psi/log cycle. The following is the equation for the bubbler pressure:

$$\text{Bubbler Pressure} = 252 - 175 (\log t - 3)$$

The second linear segment extends from 3375 to 13085 minutes after pumping began. The slope Δs_2 is 122 psi/log cycle with a resulting $Q/\Delta s_2$ ratio of 5.33 gpm/psi/log cycle. The equation for the bubbler pressure after 3375 minutes is:

$$\text{Bubbler Pressure} = 102 - 122 (\log t - 4)$$

The ratio of the slopes of the second linear segment relative to the first segment is 0.697 (Table 1) which is approximately equal to the mean of 0.701 ~~0.690~~. This similarity tends to substantiate the validity of the data for the test of January 31, 1978.

SUMMARY COMPILATION

The summary of the data collected during testing is necessary because of the different discharge rates employed and the variable durations of the tests. Table 2 lists the drawdown equations for the first and second linear segments noted on the semilogarithmic plots of bubbler pressure versus drawdown and bubbler pressure recovery versus drawdown (Figures 6, 7, 9, 10, 11, 13), assuming an initial effective bubbler shutin pressure of 420 psi. These equations have been derived from those contained in the preceeding text. As indicated in Table 1, the logarithmic ~~arithmetic~~ mean is 3533 ~~2995~~ minutes for the intersection of the first and second linear trending segments of the semilogarithmic plots excluding the intersection time of 1309 min obtained from the recovery data of the 11/15/7 test. Values for the ratio of the rate of withdrawal from the well during testing, Q, relative to drawdowns (at a time of 3533 ~~2998~~ minutes) calculated for the Q/s ratio is 1.8833 gpm/psi omitting the recovery value of 2.967 gpm/psi for the November 28, 1977 test which was so large with respect to. The other values are to be considered erroneous. The following equation was used to calculate the drawdown after five years:

$$\text{Drawdown} = \frac{Q}{2.420} + \frac{Q}{1.925} = 0.9327\,Q$$

Where: Drawdown is in psi

Q is pumping rate in gpm

The predicted drawdowns for various pumping rates are plotted in Figure 13 assuming no interference with other wells and no additional boundary effects.

The relationship between predicted drawdown after five years of continuous pumping versus pumping rate is indicated in Figure 14 assuming no interference with other wells and 100 psi of net interference with other wells. The 100 psi of interference is a very crude estimate and thus should not be considered to be an unalterable value. The yield from RRGE-3 with 400 psi of drawdown after pumping five years can be expected to be between 435 to 540 gpm. This is slightly less than RRGE-2 (RCSt-51-78) which is expected to yield 540 gpm with a similar drawdown. However, the higher wellhead temperature of 295° ± 4°F at RRGE-3 as compared to an estimated 282°F for RRGE-2 provides water of greater economic value per unit volume, and thus, RRGE-3 should be operated with greater drawdowns than other wells yielding colder waters.

using the equations defining the first linear segments (Table 2), are also listed in Table 2. These values which are the specific capacities after pumping ~~2998~~ 3533 minutes exhibit no dependency on the pumping rate within the range tested. In addition, the specific capacity of 2.249 gpm/psi for the recovery data (November 28, 1978) is quite similar to those values obtained from pumping test data. (i) These relationships suggest negligible "well losses" due to non-Darcy flow and a ratio of $Q/\Delta s$ which is independent of Q.

The drawdown data listed in Table 2 were projected for a five-year period (Figure 13) assuming no interference with other wells, and no additional hydrologic boundary effects. In Figure 13, the solid lines are observed drawdowns assuming a shut-in pressure of 420 psi with the dashed values extrapolated. After five years, the estimated drawdowns ranged from 490 psi to 613 psi. The July 6, 1977 test where pumping was at a rate of 592 gpm had a predicted drawdown of 585 psi whereas the November 28, 1977 test where pumping was at a higher rate of 603 gpm had only 524 psi of drawdown. This implies errors in predicted drawdowns after five years can be at least 70 psi, based on extrapolation of the observed drawdowns.

An equation was also derived for predicting drawdown by averaging all the test data listed in Table 2. The ratios of Q/s at 2998 minutes after pumping started are listed in Table 2 for each of the five tests with the average being 2.5293 gpm/psi. The additional drawdown resulting from 2990 minutes until five years can be calculated using the values listed in the last column of Table 2. The average for the additional component

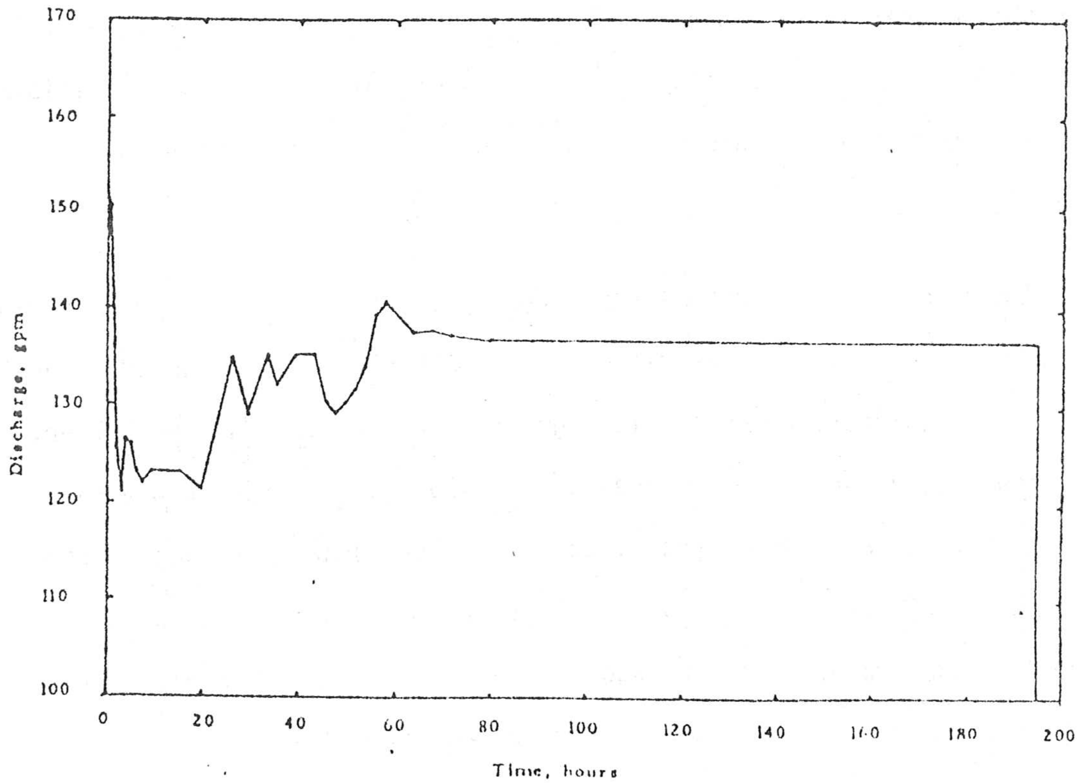


Fig. 1 RRGE 3 DISCHARGE RATE FOR TEST BEGINNING JUNE 5, 197

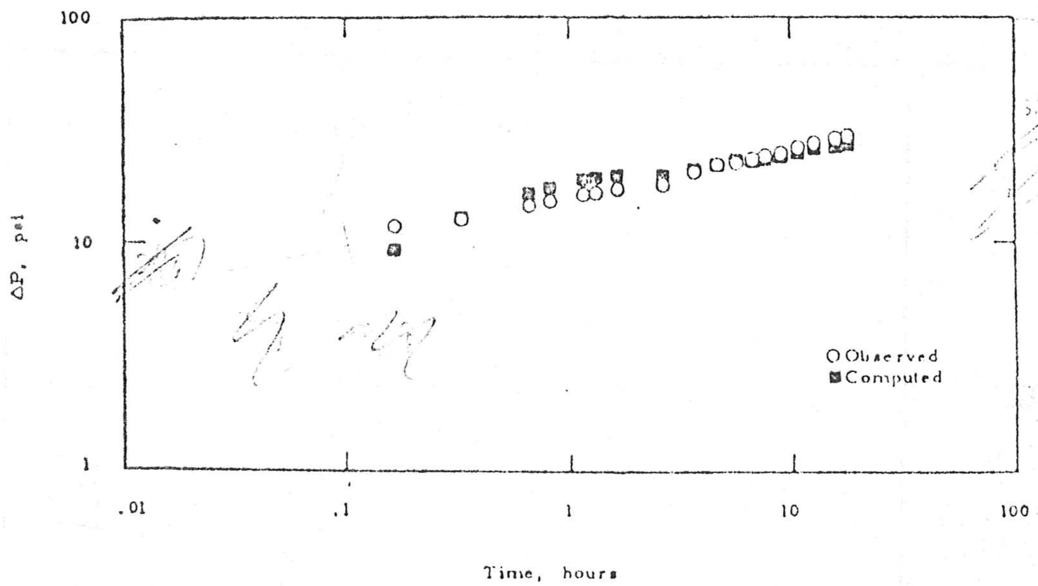


Fig. 2 RRGE 3 Production test - drawdown analysis by variable discharge method

Figure 2

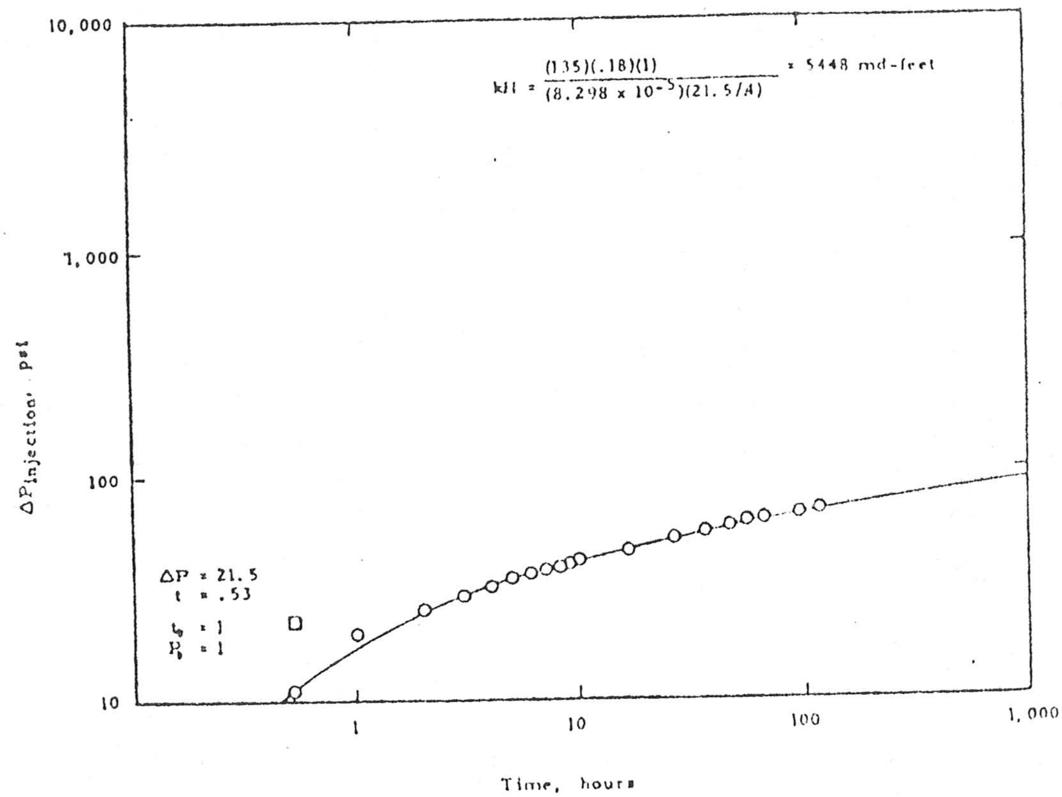


Fig. 4   RRGE 3 Production test - buildup analysis

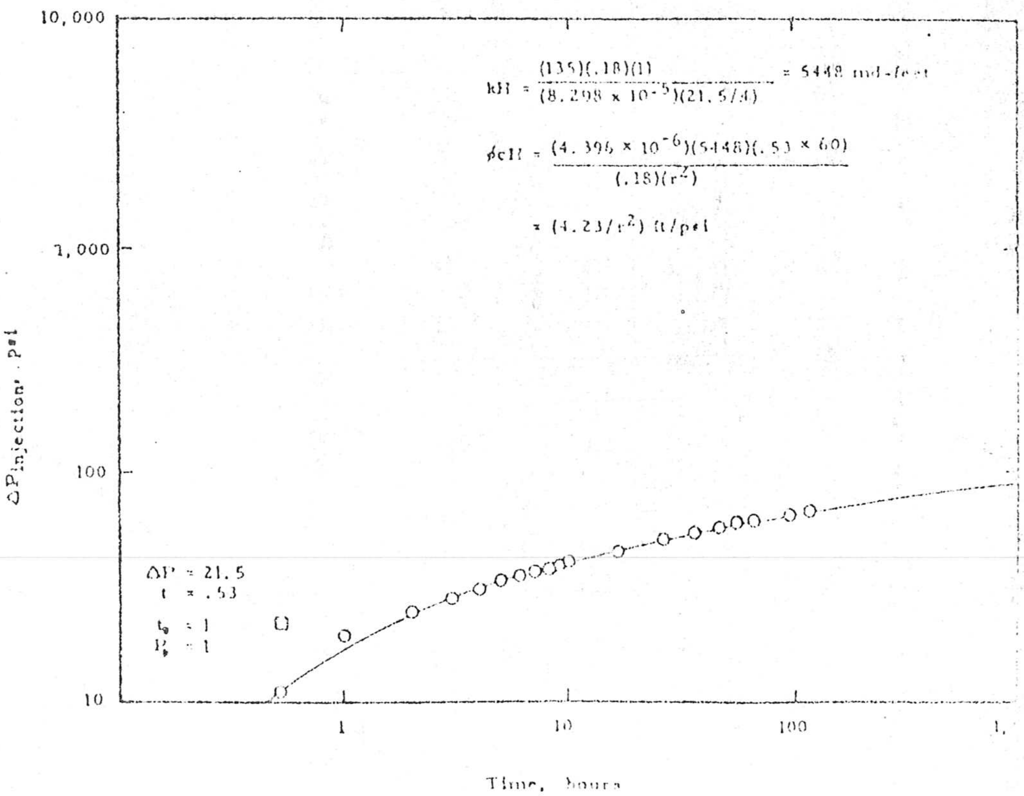


Fig. 5   RRGE 3 Production test - buildup analysis

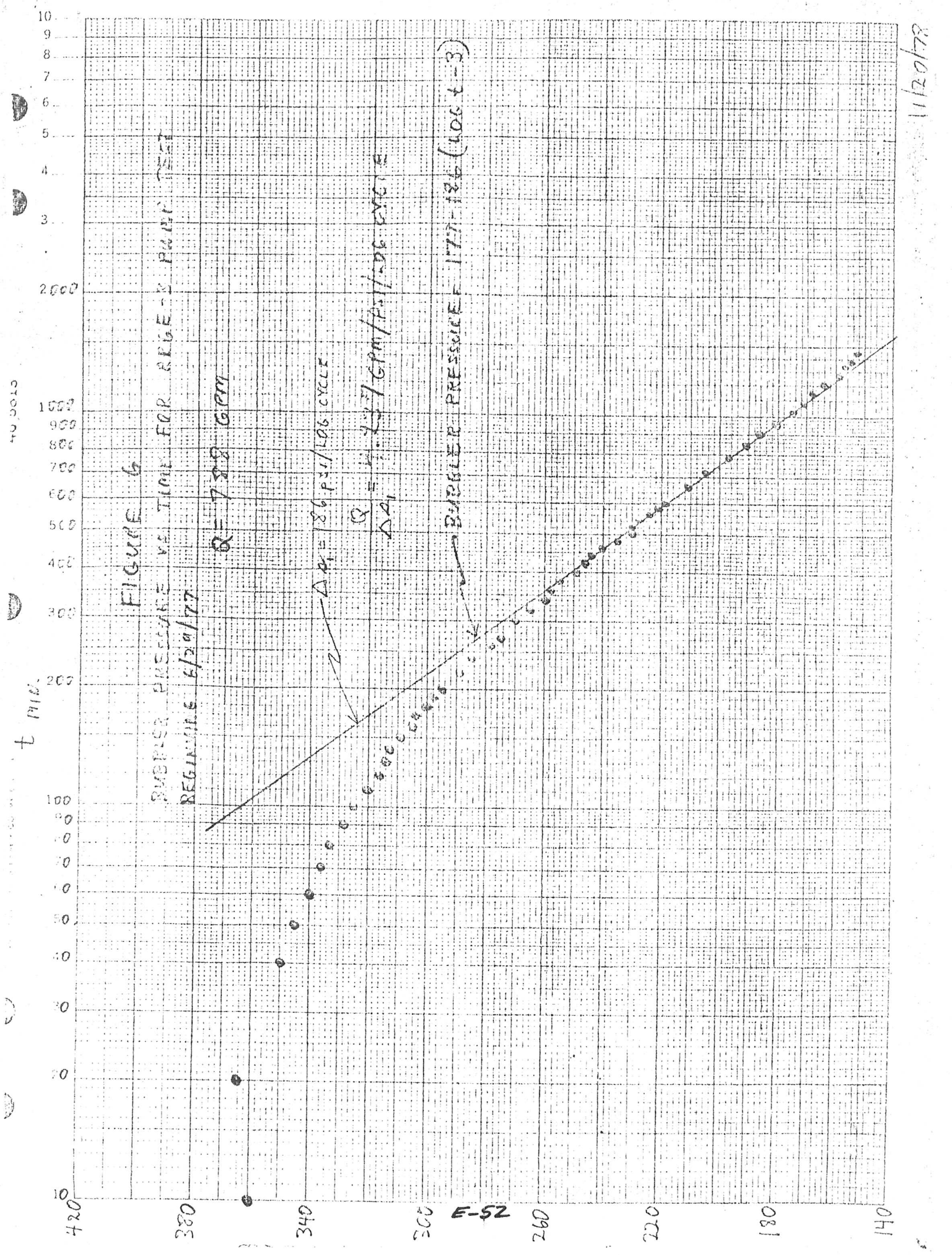
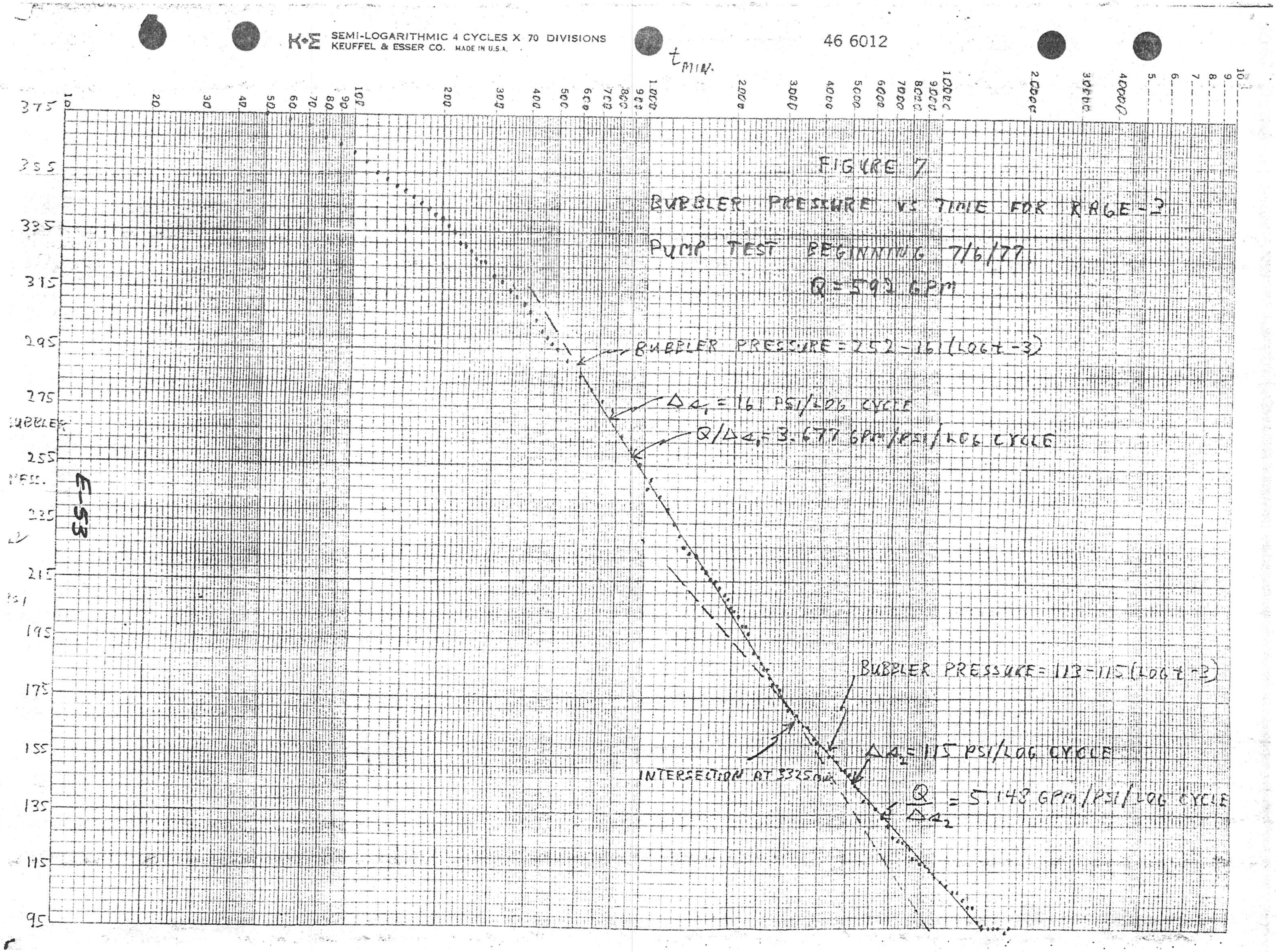


FIGURE 6
BUBBLER PRESSURE VS TIME FOR RRGE-3 PUMP TEST
BEGINNING 6/29/77
Q = 730 GPM
ΔP1 = 126 PSI/LOG CYCLE
Q/ΔP1 = 5.79 GPM/PSI/LOG CYCLE
BUBBLER PRESSURE = 177-126 (LOG t - 3)
t min
11/20/78
10
9
8
7
6
5
4
3
2000
1000
900
800
700
600
500
400
300
200
100
90
80
70
60
50
40
30
20
10
420
380
340
300
260
220
180
140


K+E SEMI-LOGARITHMIC 4 CYCLES X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.
46 6012
t_{MIN}
FIGURE 7
BUBBLER PRESSURE VS TIME FOR RAGE-2
PUMP TEST BEGINNING 7/6/77
Q = 592 GPM
BUBBLER PRESSURE = 252 - 161 (LOG t - 3)
Δs_1 = 161 PSI/LOG CYCLE
$Q/\Delta s_1$ = 3.677 GPM/PSI/LOG CYCLE
BUBBLER PRESSURE = 113 - 115 (LOG t - 3)
Δs_2 = 115 PSI/LOG CYCLE
$\frac{Q}{\Delta s_2}$ = 5.148 GPM/PSI/LOG CYCLE
INTERSECTION AT 3325 min
BUBBLER PRESS. PSI
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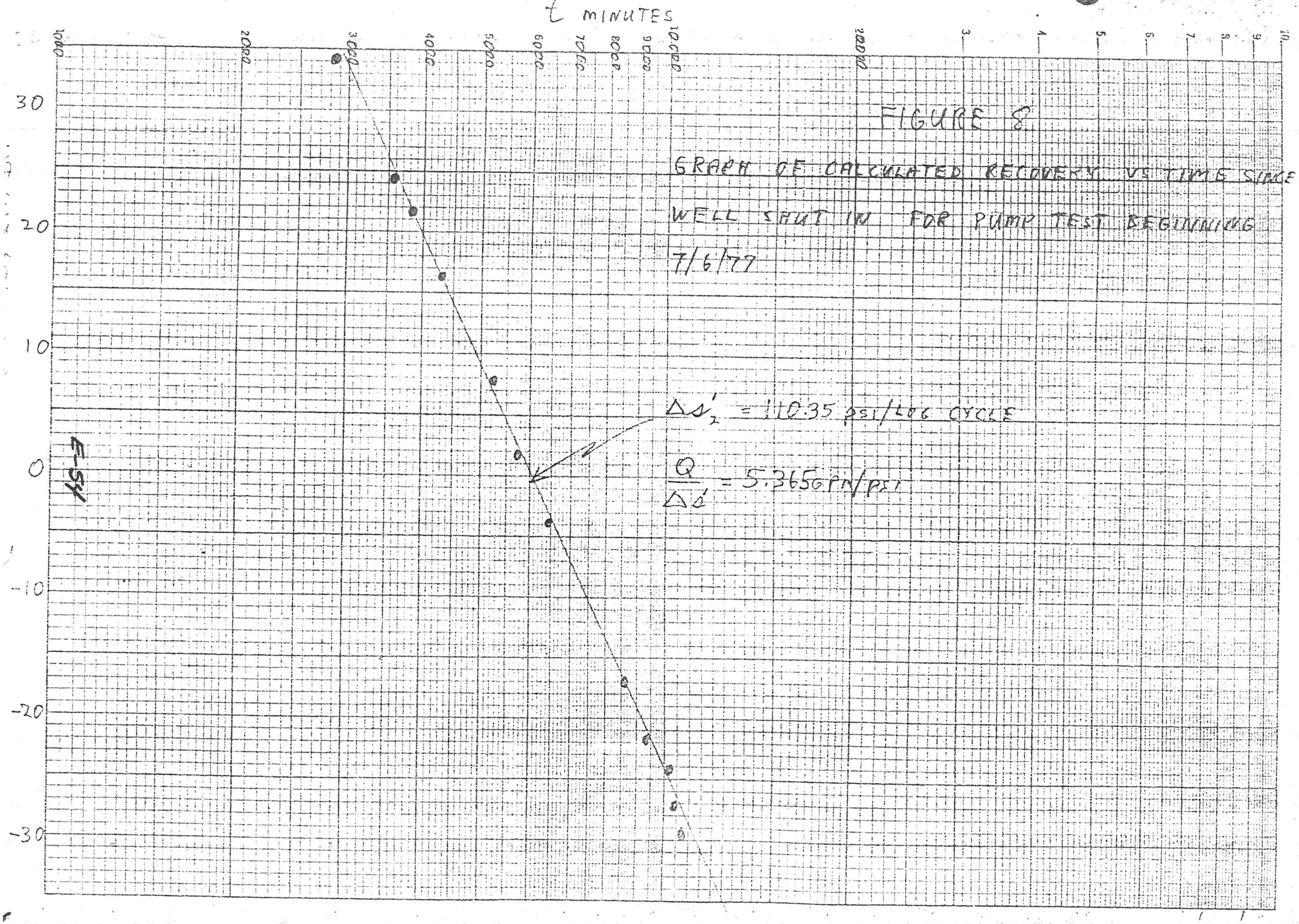
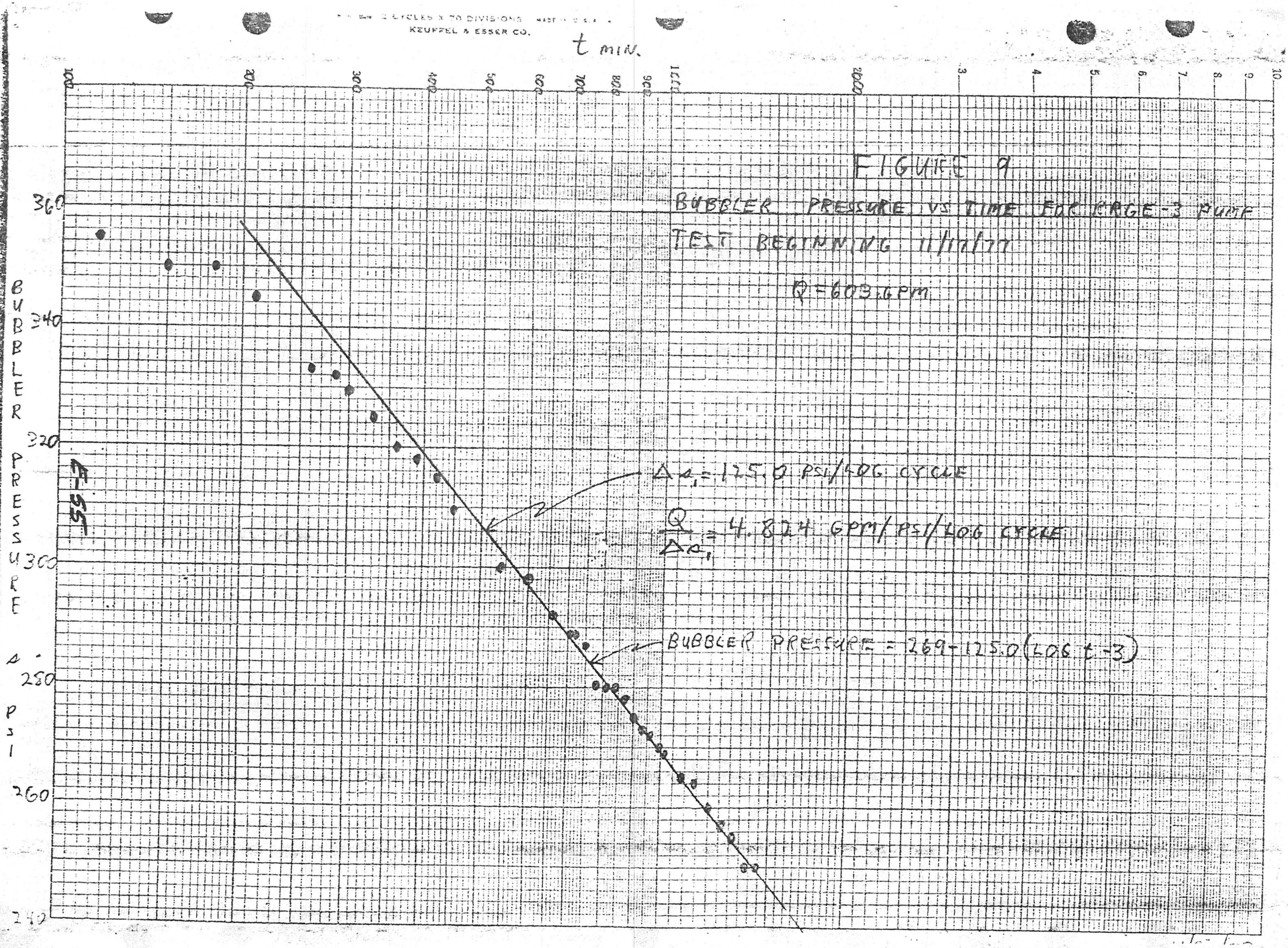
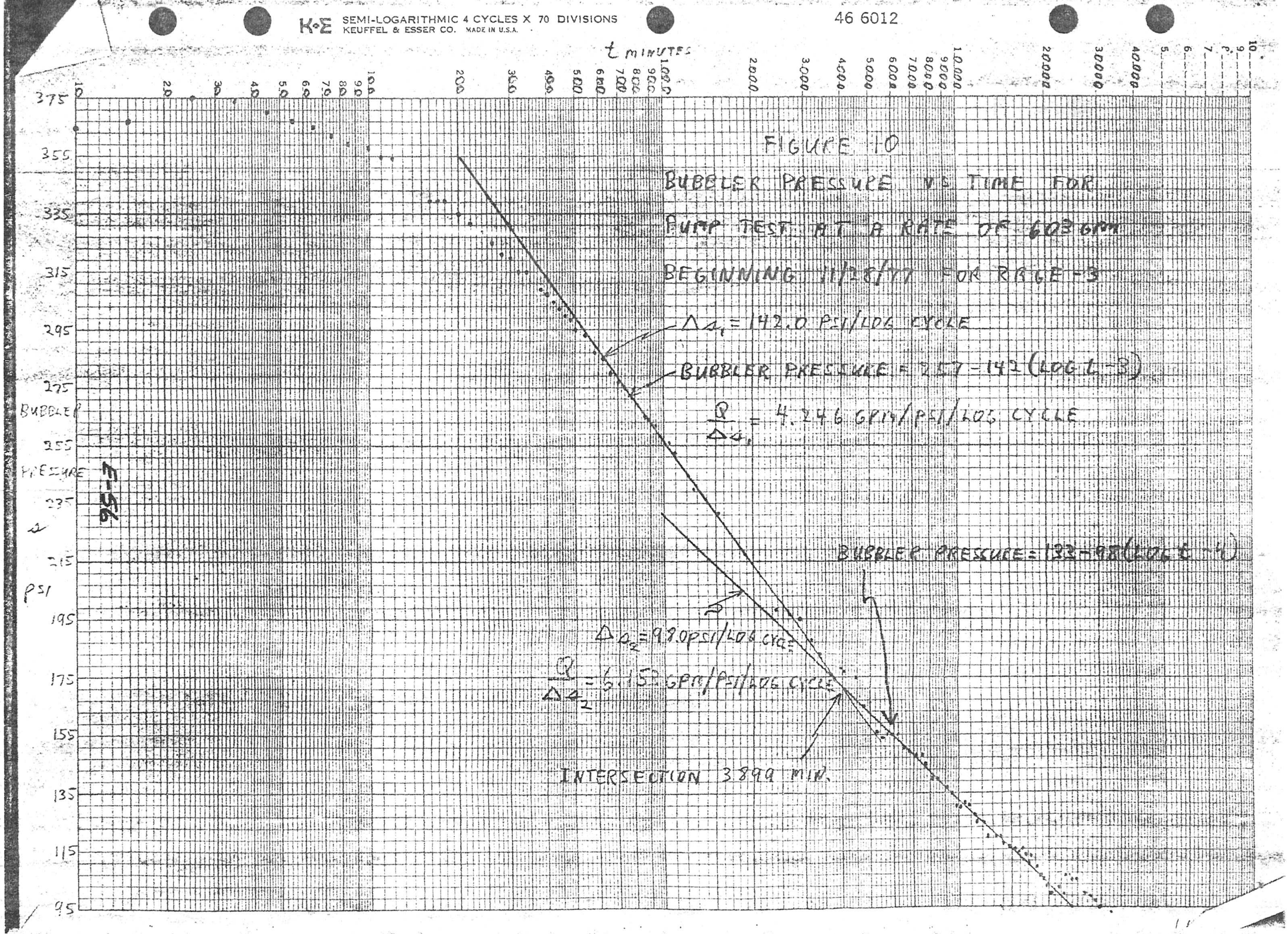


t' MINUTES
1000
2000
3000
4000
5000
6000
7000
8000
9000
10,000
20000
30
20
10
0
-10
-20
-30
FIGURE 8
GRAPH OF CALCULATED RECOVERY VS TIME SINCE WELL SHUT IN FOR PUMP TEST BEGINNING 7/6/79
$\Delta s'_2$ = 110.35 PSI/LOG CYCLE
$\frac{Q}{\Delta s'}$ = 5.365 GPM/PSI


KEUFFEL & ESSER CO.
t MIN.
FIGURE 9
BUBBLER PRESSURE VS TIME FOR CRGE-3 PUMP
TEST BEGINNING 11/17/77
Q = 603 GPM
$\Delta s_1 = 125.0$ PSI/LOG CYCLE
$\frac{Q}{\Delta s_1} = 4.824$ GPM/PSI/LOG CYCLE
BUBBLER PRESSURE = 269 - 125.0 (LOG t - 3)
BUBBLER PRESSURE s PSI


K+E SEMI-LOGARITHMIC 4 CYCLES X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.
46 6012
t MINUTES
BUBBLER PRESSURE PSI
FIGURE 10
BUBBLER PRESSURE VS TIME FOR
PUMP TEST AT A RATE OF 603 GPM
BEGINNING 11/28/77 FOR RRGE-3
Δs₁ = 142.0 PSI/LOG CYCLE
BUBBLER PRESSURE = 257 - 142 (LOG t - 3)
Q/Δs₁ = 4.246 GPM/PSI/LOG CYCLE
BUBBLER PRESSURE = 133 - 98 (LOG t - 4)
Δs₂ = 98.0 PSI/LOG CYCLE
Q/Δs₂ = 6.153 GPM/PSI/LOG CYCLE
INTERSECTION 3899 MIN.

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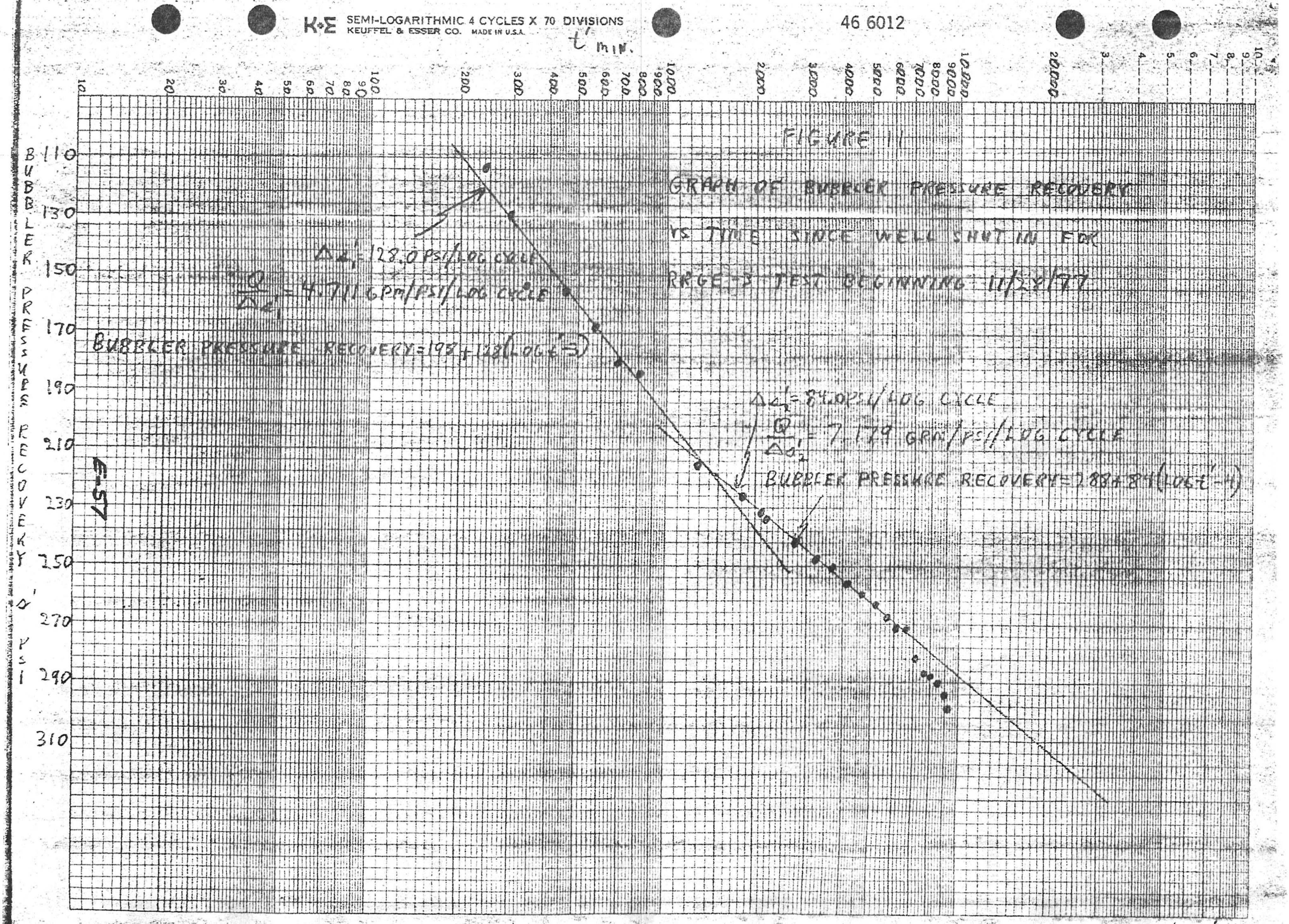
K+E SEMI-LOGARITHMIC 4 CYCLES X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.
46 6012
t' MIN.
FIGURE 11
GRAPH OF BUBBLER PRESSURE RECOVERY
VS TIME SINCE WELL SHUT IN FOR
RRGE-3 TEST BEGINNING 11/29/77
Δ∆'₁ = 128.0 PSI/LOG CYCLE
Q/Δ∆'₁ = 4.711 GPM/PSI/LOG CYCLE
BUBBLER PRESSURE RECOVERY = 193 + 128(LOG t' − 3)
Δ∆'₂ = 84.0 PSI/LOG CYCLE
Q/Δ∆'₂ = 7.179 GPM/PSI/LOG CYCLE
BUBBLER PRESSURE RECOVERY = 288 + 84(LOG t' − 4)
BUBBLER PRESSURE RECOVERY Δ' PSI
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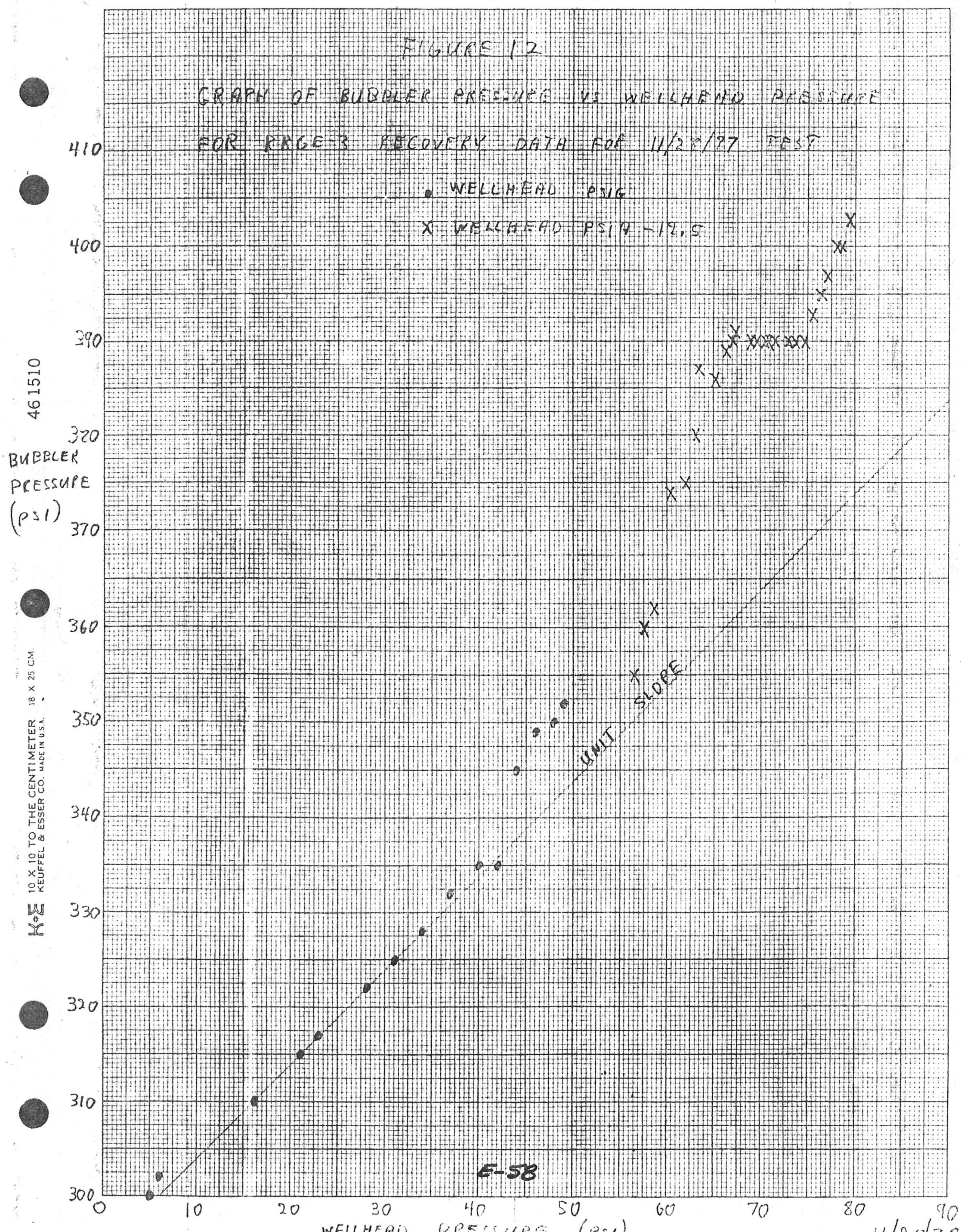

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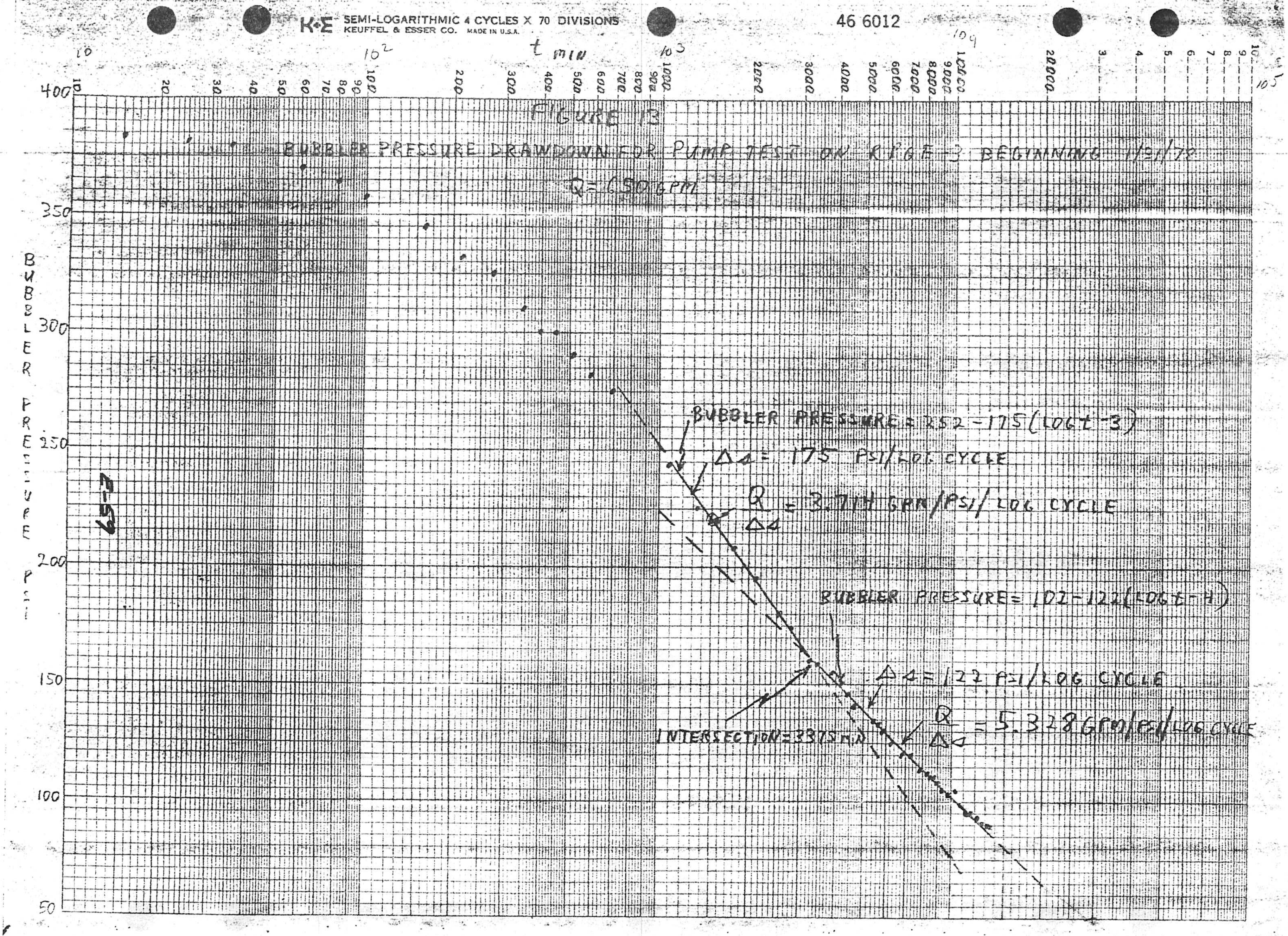
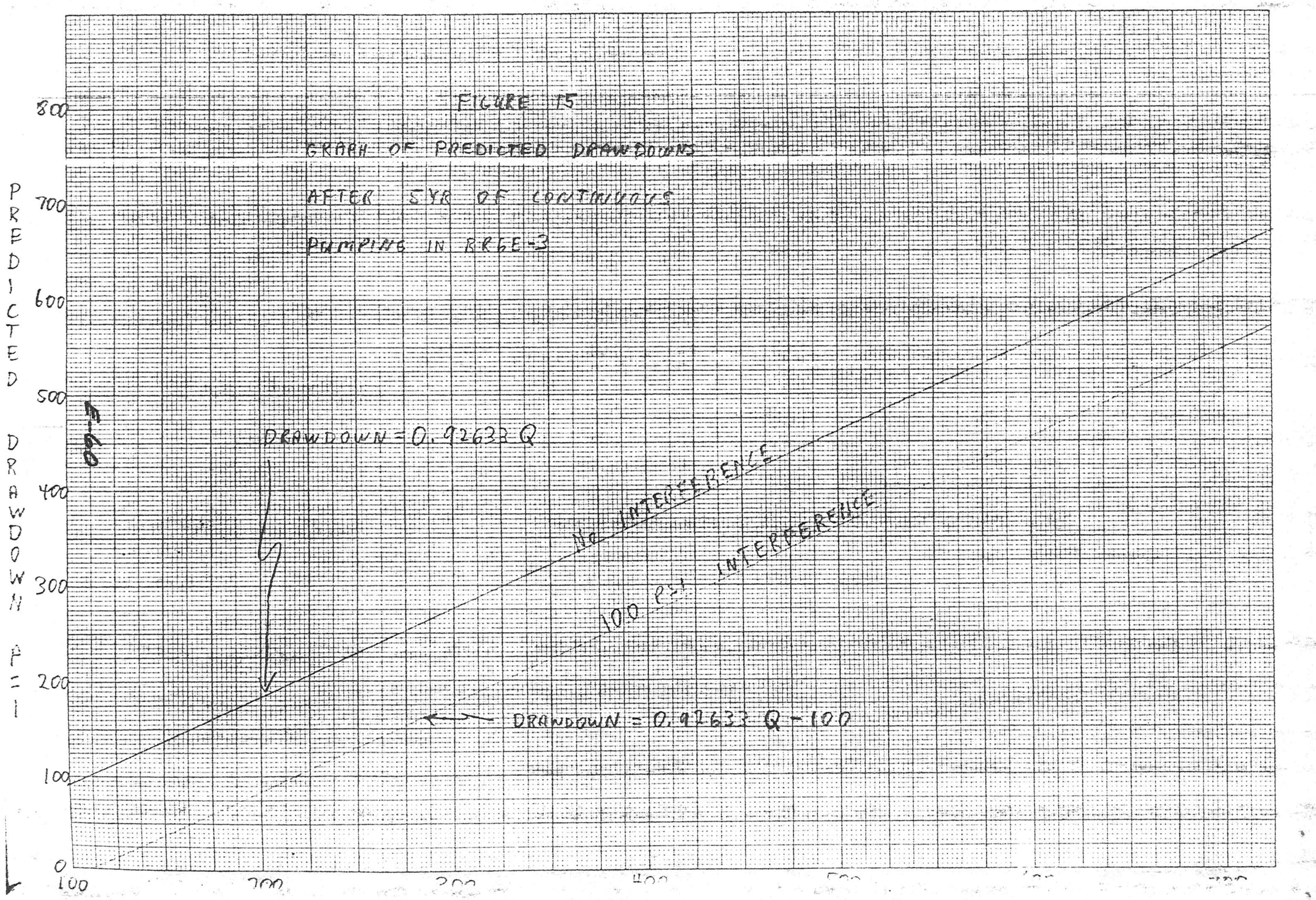

K+E SEMI-LOGARITHMIC 4 CYCLES X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.
46 6012
t min
FIGURE 13
BUBBLER PRESSURE DRAWDOWN FOR PUMP TEST ON RRGE-3 BEGINNING 1/21/79
Q = 650 GPM
BUBBLER PRESSURE = 252 - 175 (LOG t - 3)
Δs = 175 PSI/LOG CYCLE
Q/Δs = 3.714 GPM/PSI/LOG CYCLE
BUBBLER PRESSURE = 102 - 122 (LOG t - 4)
Δs = 122 PSI/LOG CYCLE
Q/Δs = 5.328 GPM/PSI/LOG CYCLE
INTERSECTION = 3375 MIN
BUBBLER PRESSURE PSI
E-59

K+E 10 X 10 TO THE CENTIMETER 18 X 25 CM.
KEUFFEL & ESSER CO. MADE IN U.S.A.

46 1510



ROUGH DRAFT
1/11/79
S. Watson

INTERPRETATION OF RRGP-5 72-HOUR FLOW TEST
NOVEMBER 1-7, 1978
TEST PLAN FET-14A-78

OBJECTIVES

The objectives of the test reported herein include the determination and/or estimation of:

1. local intrinsic transmissivity (kh)
2. local boundaries
3. borehole flow characteristics
4. pump setting for long-range test.

SUMMARY OF RESULTS

Local intrinsic transmissivities could not be calculated due to thermally affected data. The wellhead pressure data is suggestive of a recharge type boundary. Well loss and/or skin effects appear to be negligible at rates lower than ~~18~~ 17.7 litres per second (l/s) [~~300~~ 280 gallons per minute (gpm)]. Additional ~~production~~ pump tests ~~utilizing a pump~~ should be performed. The highest well-head temperature recorded during the 72-hour production test was 124°C (255°F)

EXPERIMENTAL PROCEDURE

The 72-hour test was composed of three one-hour constant-rate pulse tests and a 72-hour constant-rate production test. The pulse and production tests consisted of allowing RRGP-5B to artesian flow at a constant rate while monitoring wellhead pressure and temperature at RRGP-5B and wellhead pressure at RRGE-1, RRGE-2, USGS-3, and MW-1. The discharge rate was held constant by ~~utilization of a manometer tube and~~ manual control at the RRGP-5B well. [illegible] ~~The~~ manometer adequately ~~met Reservoir Engineering~~ requirements, and was relatively easy to monitor. The 3/4-inch water sampling line, ~~used for water sampling,~~ used to control ~~made slight adjustments in~~ discharge. ~~manageable.~~ The discharge varied within ±3%. Recovery data was collected after each pulse test, but was not obtained after the production test due to the failure of recording instruments.

Well RRGP-5B was preheated by artesian flow at approximately 13 l/s (200 gpm) for approximately 30 minutes in an attempt to thoroughly heat the wellbore. ~~The~~ Preheating is a procedure to establish isothermal wellbore conditions at aquifer temperatures. The well was held at 1.3 l/s (20 gpm) to maintain thermal quasi-equilibrium, once the temperature of discharge water stabilized. RRGP-5B was then discharged at approximately 3.8 l/s (60 gpm) for five minutes, prior to the start of testing. The unscheduled short-duration pulse at 3.8 l/s (60 gpm) discharge was caused by a faulty valve. (Figure 1). ~~The~~ Pulse tests were conducted at ~~2.52l/s~~ 2.52 l/s (40 gpm), 12.0 l/s (190 gpm), and ~~19.1 l/s (300 gpm)~~ 17.7 lps (280 gpm). The production test was conducted at 8.83l/s (140 gpm). The preheating and (attempt to maintain ~~maintenance of~~ thermal quasi-equilibrium did not prevent the data produced by the two high-rate pulse tests from being thermally affected. It is not evident, but is assumed, that the low-rate pulse and production tests were affected thermally. The preheat and postheat procedures ~~do~~ did keep thermal effects to a minimum.

DATA EVALUATION

A modified nonequilibrium analysis of the ~~2.52l/s~~ 2.52 l/s (40 gpm) and the 12.0 l/s (190 gpm) pulse tests possibly suggests a recharge boundary (Figure 2).

The 2.5 l/s (40 gpm) pulse test did not stress the aquifer sufficiently to produce adequate pressure drawdown for quantitative hydrogeologic analysis. The displacement of the 2.5 l/s (40 gpm) pulse test data after 15 minutes was apparently related to human error. The ~~19 l/s (300 gpm)~~ 17.7 lps (280 gpm) pulse test "stressed" the borehole artesian capacity of RRGP-5B, as shown by the inability to maintain constant discharge. This was indicated by the appearance of steps in the data. The first 60 minutes of the production test were ~~utilized~~ used as a fourth pulse test. The production test data is also suggestive of a recharge boundary (Figure 3). The data after 42 minutes ~~was~~ were not obtained due to instrument failure (Gould, 1978); therefore, a possible boundary cannot be confirmed.

The ~~12~~ 12.0 l/s (190 gpm) and ~~19 l/s (300 gpm)~~ 17.7 lps (280 gpm) pulse test data are thermally affected for at least the initial minute. It is assumed from experience that the other tests were also thermally affected, although this is not obvious from the data. It has been shown (Niemi, 1978) that such uncorrected data are useless for quantitative evaluation. Reliable early-time data must be collected in order to determine aquifer characteristics. Reliable early-time data can apparently only be collected within the wellbore at the production face.

Well losses, ~~utilizing~~ using Jacob's formula (Walton, 1970), of 0.17 sec^2/m^5 (63 sec^2/ft^5) for the initial pulse, 0.2 sec^2/m^5 (8.6 sec^2/ft^5) for the second pulse, and 0.06 sec^2/m^5 (24 sec^2/ft^5) for the final pulse were estimated. Well losses of less than 0.01 sec^2/m^5 (5 sec^2/ft^5) are indicative of an efficient well and well losses greater than 0.03 sec^2/m^5 (10 sec^2/ft^5) are indicative of a clogged well (Walton, 1962). The well loss data estimated by Jacob's formula does not provide conclusive results concerning RRGP-5B borehole flow conditions. A general linear productivity relationship is suggested by the specific capacity (s_c) data (Figure 4) if the 17.7 lps (280 gpm) ~~19 l/s (300 gpm)~~ pulse test is disregarded. It is possible that the 17.7 lps (280 gpm) ~~19 l/s (300 gpm)~~ pulse test does not lie on the apparent linear trend, as the "high" production rate may have induced lower partial pressure water into the well and/or control of discharge rate was poor. Figure 4 may suggest that the well losses within RRGP-5B are insignificant at low rates.

RRGP-5B recovered to the initial wellhead pressure in less than 7 percent of the production time, following the 2.52 l/s (40 gpm) and 12.0 ~~12~~ l/s (190 gpm) pulse tests. The well was fully recovered before the initial recovery data was collected following the 72-hour production test (one hour after shut-in). Rapid recovery is usually indicative of an ineffective and poorly constructed well. RRGP-5B recovered in approximately the same time that it was produced following the 17.7 lps (280 gpm) ~~19 l/s (300 gpm)~~ pulse test.

The production and recovery portions of an equilibrium test ~~the flow or pulse test~~ (Figure 5) should theoretically overlie each other. However, the difference between production and recovery data is approximately 21 kilo Pascals (kPa) 3 psi [pounds per square inch (psi)] for each test. The difference can be caused by a combination of factors, most probably variations in discharge rate, instrument error, and/or well losses. Figure 5 may indicate that well losses are insignificant within RRGP-5B at low discharge rates. Note that production data was graphed in psia and recovery data in psi, a difference of approximately 88.3 kPa (12.8 psi). This 88.3 kPa (12.8 psi) was taken into account when graphing the corrected recovery data.

The discharge rate divided by drawdown per log cycle (Q/s_{10}) of an ideal well is constant, independent of discharge rate (Q). Figure 6 indicates no relationship between Q/s_{10} and Q, but Q/s_{10} changes. If the 2.52 ~~2.5~~ l/s (40 gpm) recovery, 12.0 ~~12~~ l/s (190 gpm) production, and 17.7 lps (280 gpm) ~~[illegible]~~ production data points are disregarded (38 percent of the data), due to large errors related to thermal effects, a linear trend can be approximated. Figure 6 suggests that RRGP-5B was not performing ideally, perhaps due to fracture-controlled groundwater flow, in comparison to the theoretical flow through a porous medium.

~~The~~ Recovery data at RRGP-5B (Figure ~~6~~ 7) may suggest a recharge boundary during the 2.5 l/s (40 gpm) and the 12 l/s (190 gpm) pulse tests. ~~However,~~ however, the break in slope should occur at the same time on both production and recovery data. The failure of the suggested boundary to occur at concurrent times implies that the suggested boundary is: ~~either~~ (1) a nonideal or a leaky boundary, (2) that an aquifer(s) is nonhomogenous, or (3) that no recharge boundary exists. The data may appear as a recharge boundary due to instrument error. The recovery data from the 17.7 l/s (280 gpm) ~~[illegible]~~ pulse test is not suggestive of a recharge boundary. Future tests ~~should~~ will assist in interpreting the suggested boundary.

It is assumed, but not apparent, that all recovery data were thermally affected. The effect of ~~the cooling of the~~ wellbore cooling would be to decrease the slope of data plotted as corrected recovery. Table I lists the slopes of drawdown and recovery per log cycle (s_{10}) of the 72-hour test. Flatter slopes apparently occurred during recovery than during production. Pressure changes must be measured within the wellbore for reliable data collection.

The production data at RRGP-5B (Figure 3) may suggest a recharge boundary after 30 minutes, but missing data and lack of quality control qualify the results. The data after 160 minutes may also suggest a recharge boundary. ~~However,~~ The data is impossible to interpret, as it is theoretically inconceivable for the wellhead pressure to rise as more water is discharged from the aquifer(s). The failure of the digiquartz and Heise wellhead pressure to differ by assumed atmospheric pressure, 88.3 kPa (12.8 psi), once Heise pressures were recorded on November 4, 1978, adds to the difficulty in interpreting the data. ~~The~~ production data from 30 to 160 minutes ~~is~~ are missing due to failure of recording instruments. The initial recovery data, collected after one hour of shut-in time, showed that the well had fully recovered.

Table I lists the drawdown per log cycle of the initial linear trend of the results of the 72-hour test. The u condition was satisfied in less than a quarter of a minute ~~by the RRGP-5B data~~. The results could not be used in calculating the intrinsic transmissivity of the aquifer(s) penetrated as the data was thermally affected. ~~The Hewlett-Packard~~ An adequate downhole temperature-pressure probe is necessary to produce data which can be quantitatively analyzed.

Observation Well Response

Wells RRGE-1, RRGE-2, MW-1, and USGS-3 were used as observation wells during the 72-hour test. Digiquartz pressure transducers were used to measure wellhead pressures. Geologic relationships indicate the RRGP-5B, RRGE-1, and RRGE-2 penetrate the same fault zone and perhaps the same aquifer(s).

The wellhead pressure of RRGE-1 and RRGE-2 for November 1-7, 1978 (Figure 8) reveals declining pressure at RRGE-2, believed to be a seasonal trend. If RRGE-1 and RRGE-2 penetrate the same or similar aquifers, an analogous trend should be apparent in the RRGE-1 data. Figure 8 shows the irregular nature of RRGE-1 data. This indicates that the discharge rate at RRGE-1 was not maintained constant. No quantitative analysis can be made of the RRGE-1 data unless the discharge is maintained constant. The effect of RRGE-1 nonuniform discharge on RRGE-2 and RRGP-5B cannot be evaluated.

TABLE I

Test Results 72-Hour Test RRGP-5B

Test	$s_{10}^{\dagger}$ kPa/cycle	psi/cycle	$Q/s_{10}^{\ddagger}$ l/s/kPa/cycle	gpm/psi/cycle
2.5 lps (40 gpm) production	20.7	(3)	0.1209	(0.28)
2.5 lps (40 gpm) recovery	48.3	(7.01)	0.0518	(0.12)
8.8 lps (140 gp,) production	79.3	(11.50)	0.1110	(0.26)
8.8 lps (140 gpm) recovery	--	--	--	--
12 lps (190 gpm) production	134	(19.44)	0.0892	(0.21)
12 lps (190 gpm) recovery	114	(16.53)	0.1055	(0.24)
19 lps (300 gpm) production	179	(25.96)	0.1060	(0.24)
19 lps (300 gpm) recovery	165	(23.93)	0.1148	(0.26)

Drawdown in RRGE-1 (Figure 9) appears to have occurred after 140 minutes of production. The apparent drawdown may be related to RRGP-5B production or a seasonal trend occurring within the aquifer(s). The data points occurring above the apparent trend after 2800 minutes are related to poor control of RRGE-1 discharge rates. Data indicate that the u assumption was satisfied after 3600 minutes of production, after which a modified nonequilibrium analysis could be employed. A nonequilibrium analysis (Figure 10) does not match any recognizable type curve, but reveals the apparent inconsistent ~~due~~ RRGE-1 discharge.

A semi-log plot of wellhead pressure at RRGE-2 (Figure 1~~0~~) begins to decline after approximately 120 minutes of production. Data suggest that RRGP-5B would have to be produced for 8900 minutes (6.15 days) before the u assumption would be satisfied. The data cannot, therefore, be analyzed with the modified nonequilibrium method. ~~A log-log plot of the~~ data (Figure ~~11~~); The nonequilibrium method (Fig 12) does not graph as ~~suggests the pressure begins to decline after 60 minutes. However, a plot of wellhead pressure change (Figure 12) is not~~ a recognizable type curve. It is questioned that the pressure decline in RRGE-2 was related to RRGP-5B, as the apparent decline appears sooner and of greater magnitude than RRGE-1, which is physically closer to RRGP-5B. However, it is possible, with fracture-controlled flow, for distant wells to show greater response than nearby wells (Niemi and Nelson, 1978). It is believed that the pressure decline at RRGE-2 is related to a seasonal trend and/or cooling from a previous test. The effect of nonconstant discharge from RRGE-1 on RRGE-2 cannot be evaluated at this time.

Pressure changes greater than 0.7 Pa (0.1 psia) were not observed at MW-1 or USGS-3 during the pulse or 72-hour test. It is concluded that RRGP-5B did not affect MW-1 or USGS-3.

<u>CONCLUSIONS</u>

RRGP-5B is not capable of producing artesian flow greater than 19 l/s (300 gpm) for extended periods. RRGP-5B did not have sufficient wellhead pressure to maintain the 17.7 lps (280 gpm) pulse for greater than 45 minutes. ~~60 minute [illegible] pulse test.~~

The test data may suggest a recharge boundary. This boundary is, perhaps, the same recharge boundary implied by the testing of RRGE-1 (Allman, 1978). Additional testing of RRGP-5B must be conducted before confirming the existence of a recharge boundary.

The local intrinsic transmissivity of the aquifer(s) penetrated by RRGP-5B could not be calculated due to the inability to obtain pressure data which was not thermally effected. ~~within the well bore.~~ Future tests must be conducted with the a ~~Hewlett-Packard~~ down-hole temperature-pressure probe within the well.

~~The~~ Well losses within RRGP-5B appear to be insignificant at rates less than 12.0 12 l/s (190 gpm). ~~The~~ Well losses at rates higher than 17.7 lps (280 gpm) ~~[illegible]~~ cannot be estimated at this time.

The effect of producing RRGP-5B on RRGE-1 and RRGE-2 could not be quantitatively determined. Discharge from RRGE-1 was apparently not maintained constant. It is of prime importance in predicting aquifer and well performance, over the life of the project, that the effects of one well on another (interference) be established. The production of acceptable interference data requires that RRGE-1 be produced at a constant (±3%) rate. The RRGP-5B testing did not affect MW-1 or USGS-3.

Additional production tests using ~~utilizing~~ a pump should be performed at RRGP-5B. A long-term (20 days) test at 38 l/s (600 gpm) should be conducted. This production rate will provide a rigorous basis for evaluating productivity predictions. Pulse tests should be conducted in conjunction with the long-term test. ~~The pulse tests should be conducted in conjunction with the long-term test.~~ The pulse tests will provide additional information on the performance of RRGP-5B. The pulse and long-term tests must be conducted with a Hewlett-Packard or equivalent downhole temperature-pressure probe in RRGP-5B. Temperature-depth profiles should be plotted in RRGP-5B during additional tests of the well. The temperature profiles may supply additional information concerning the recharge boundary suggested by the 72-hour test. Future well and aquifer tests should not be terminated and the well shut-in until arrangements for the collection of recovery (falloff) data have been established.

Figures 13 and 14 are predictions of pump-setting depth versus production rate for the proposed 20-day production test of RRGP-5B. The predictions are based upon the 8.8 l/s (140 gpm) 72-hour constant rate production test. The graph simulating a recharge boundary and 2-barrier boundaries best replicates current well performance. The 2-barrier boundaries are not directly seen in the data but are interpolated due to experience.

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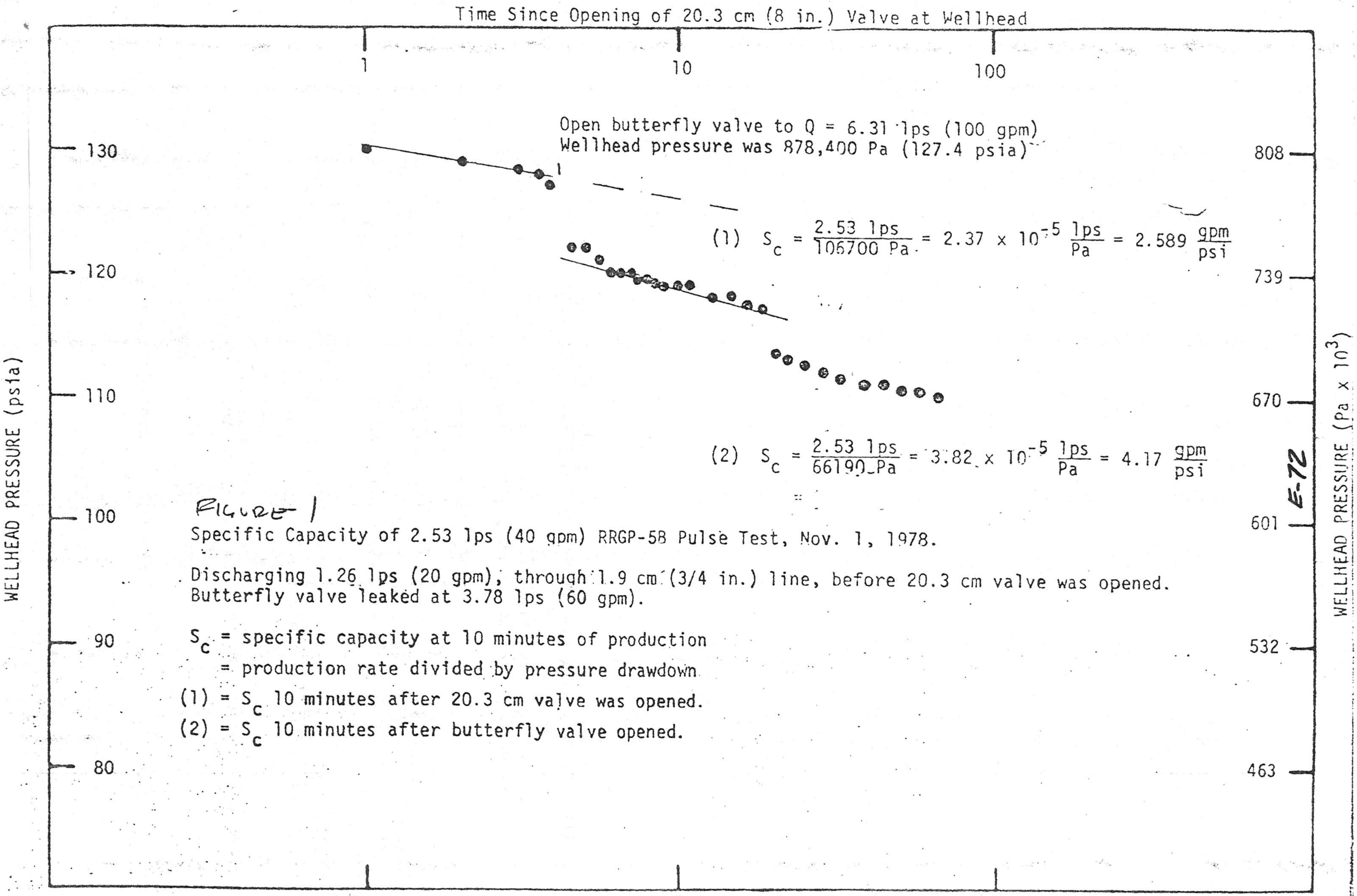
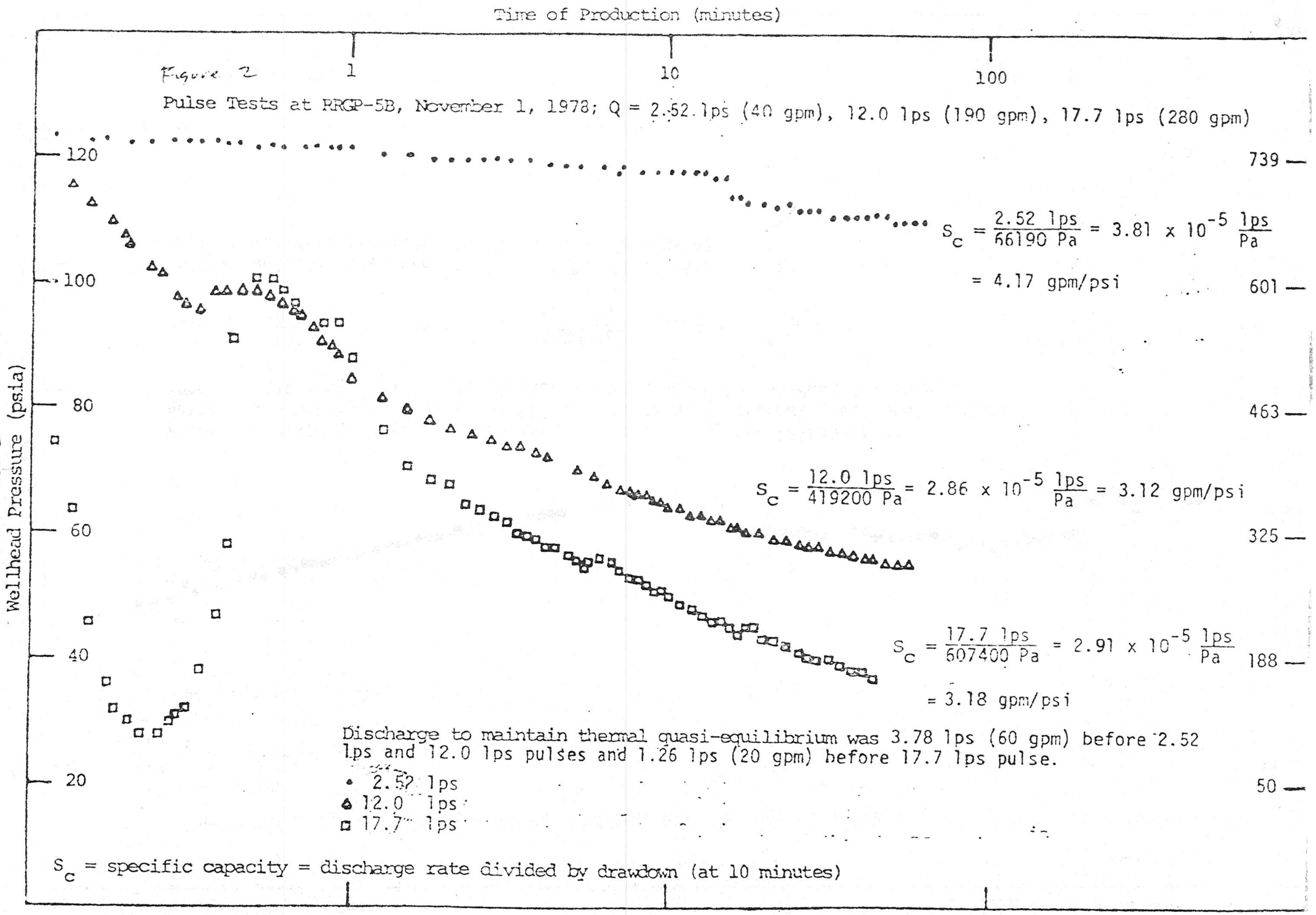


Figure 1

Specific Capacity of 2.53 lps (40 gpm) RRGP-5B Pulse Test, Nov. 1, 1978.

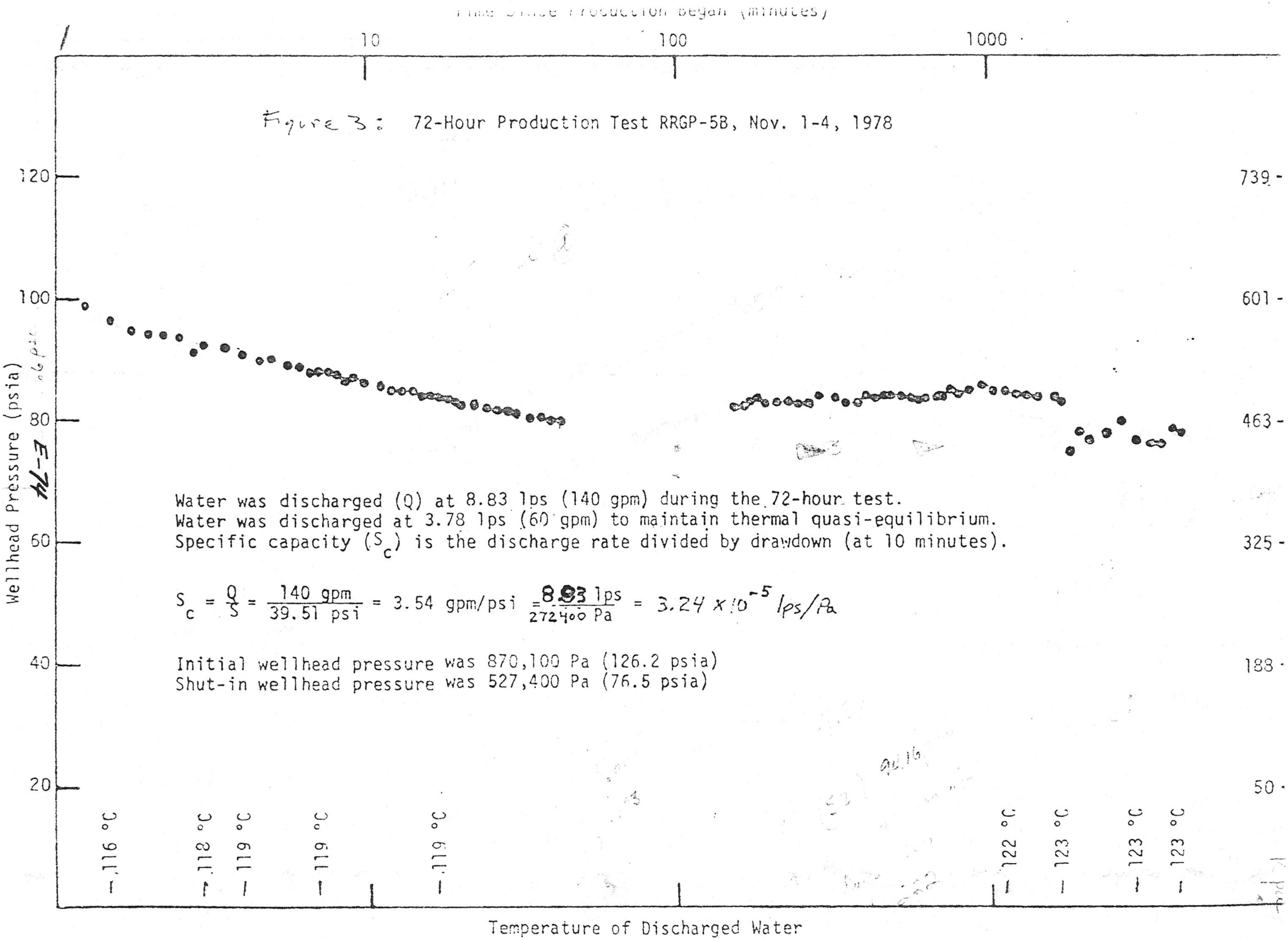
Discharging 1.26 lps (20 gpm), through 1.9 cm (3/4 in.) line, before 20.3 cm valve was opened. Butterfly valve leaked at 3.78 lps (60 gpm).

S_c = specific capacity at 10 minutes of production
= production rate divided by pressure drawdown
(1) = S_c 10 minutes after 20.3 cm valve was opened.
(2) = S_c 10 minutes after butterfly valve opened.



Time of Production (minutes)
Figure 2
Pulse Tests at RRGP-5B, November 1, 1978; Q = 2.52 lps (40 gpm), 12.0 lps (190 gpm), 17.7 lps (280 gpm)
1
10
100
Wellhead Pressure (psia)
120
100
80
60
40
20
739
601
463
325
188
50
$S_c = \frac{2.52 \text{ lps}}{66190 \text{ Pa}} = 3.81 \times 10^{-5} \frac{\text{lps}}{\text{Pa}}$
$= 4.17$ gpm/psi
$S_c = \frac{12.0 \text{ lps}}{419200 \text{ Pa}} = 2.86 \times 10^{-5} \frac{\text{lps}}{\text{Pa}} = 3.12$ gpm/psi
$S_c = \frac{17.7 \text{ lps}}{607400 \text{ Pa}} = 2.91 \times 10^{-5} \frac{\text{lps}}{\text{Pa}}$
$= 3.18$ gpm/psi
Discharge to maintain thermal quasi-equilibrium was 3.78 lps (60 gpm) before 2.52 lps and 12.0 lps pulses and 1.26 lps (20 gpm) before 17.7 lps pulse.
• 2.52 lps
△ 12.0 lps
□ 17.7 lps
S_c = specific capacity = discharge rate divided by drawdown (at 10 minutes)

Figure 3: 72-Hour Production Test RRGP-5B, Nov. 1-4, 1978



Water was discharged (Q) at 8.83 lps (140 gpm) during the 72-hour test.
Water was discharged at 3.78 lps (60 gpm) to maintain thermal quasi-equilibrium.
Specific capacity (S_c) is the discharge rate divided by drawdown (at 10 minutes).

$$S_c = \frac{Q}{S} = \frac{140 \text{ gpm}}{39.51 \text{ psi}} = 3.54 \text{ gpm/psi} = \frac{8.83 \text{ lps}}{272400 \text{ Pa}} = 3.24 \times 10^{-5} \text{ lps/Pa}$$

Initial wellhead pressure was 870,100 Pa (126.2 psia)
Shut-in wellhead pressure was 527,400 Pa (76.5 psia)

E-74

Figure 4

RRGP-5B Specific Capacity (s_c) vs Discharge Rate (Q)

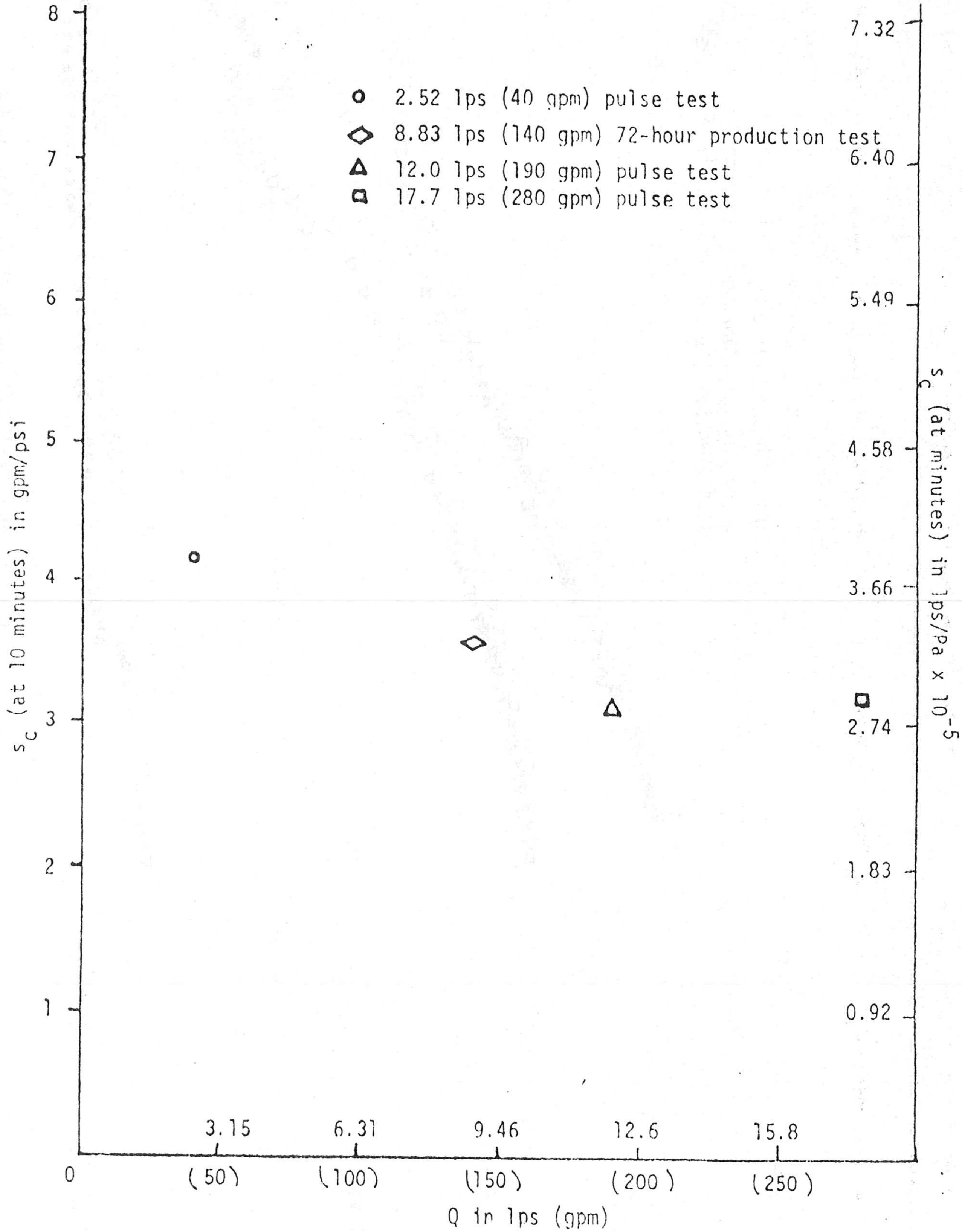


Figure 5

PULSE TEST DRAWDOWN AND RECOVERY, RRGP-5B, NOV. 1, 1978

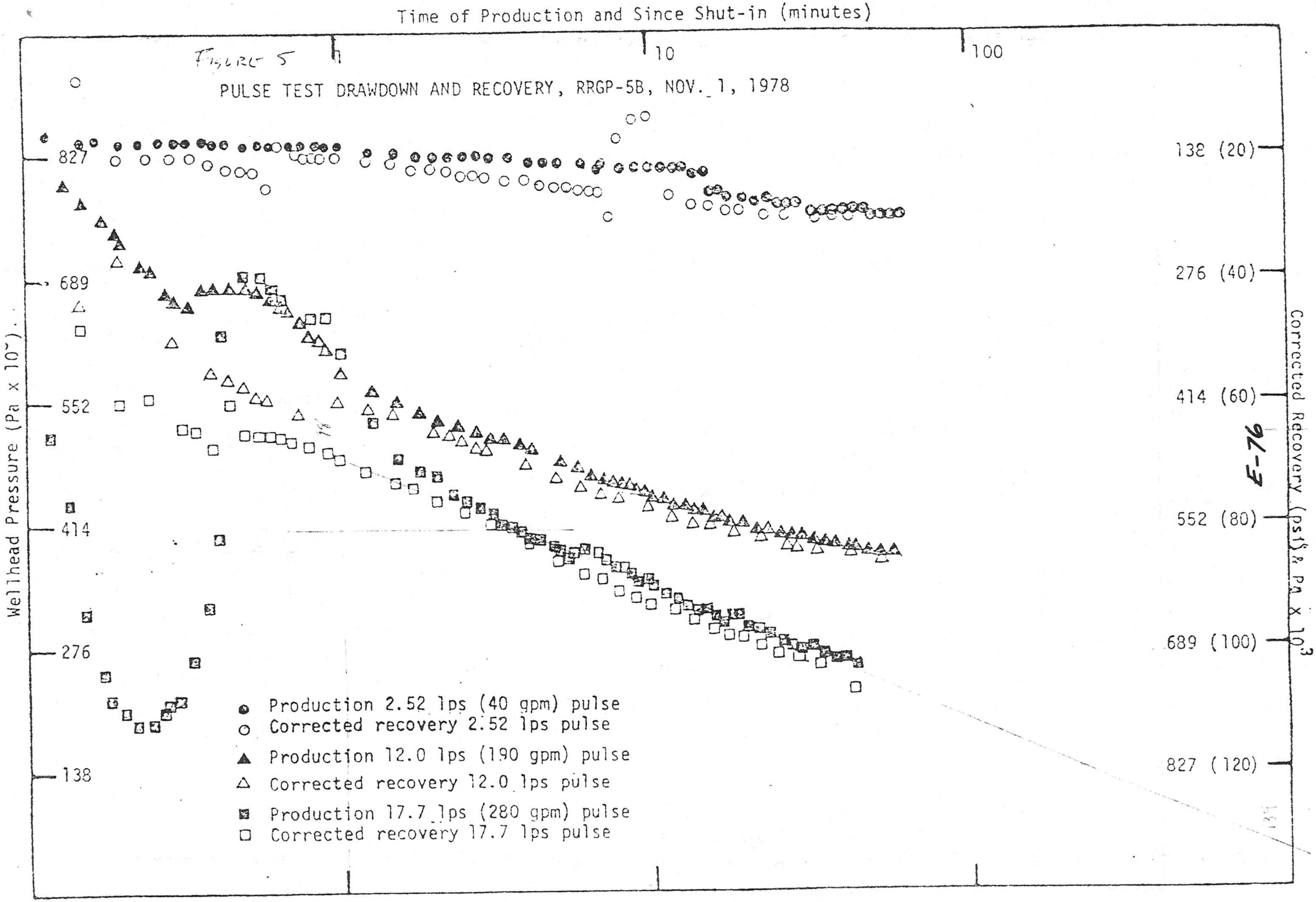
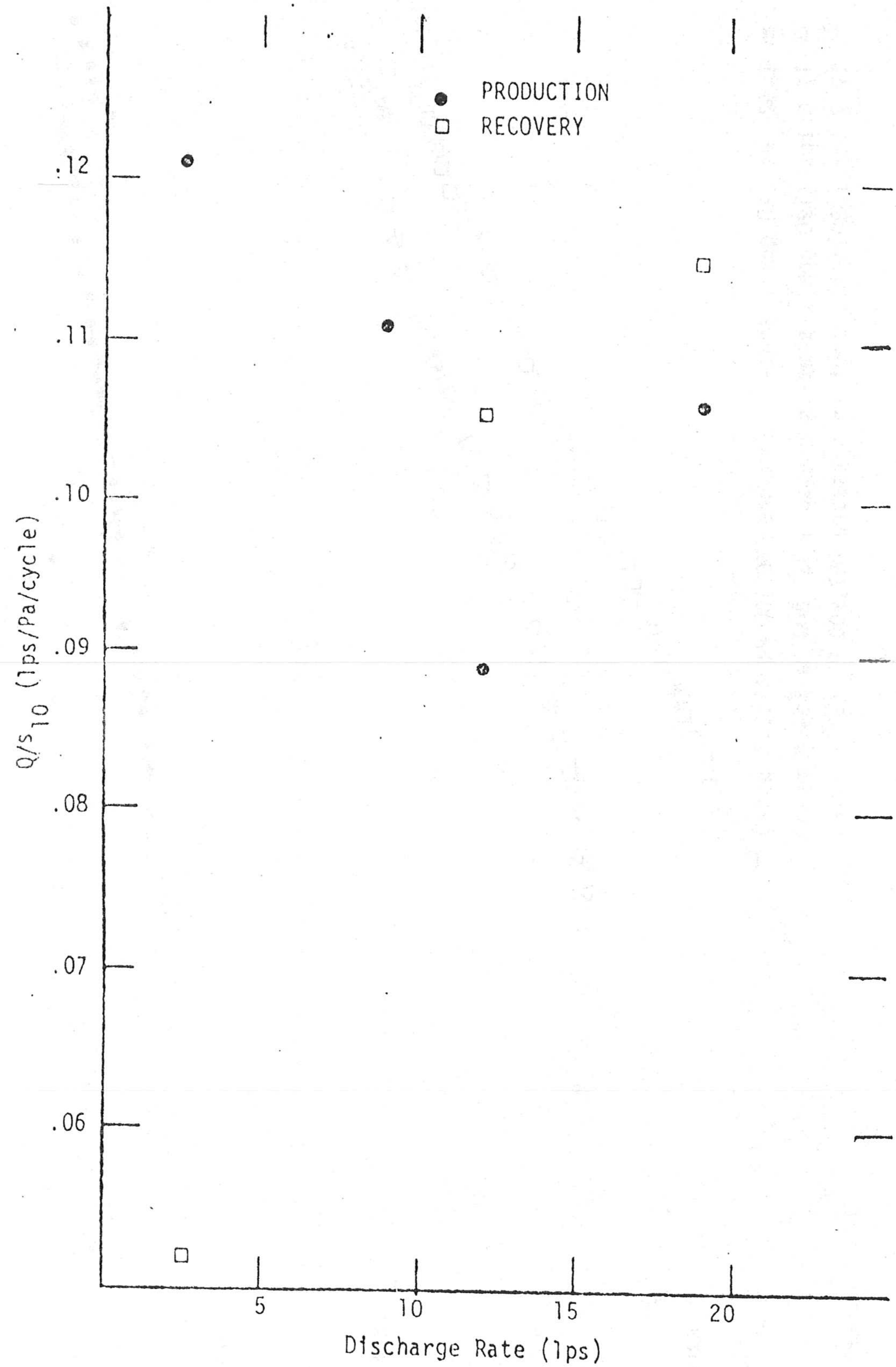


Figure 6

GRAPH COMPARING DISCHARGE RATE DIVIDED BY DRAWDOWN PER LOG CYCLE VS DISCHARGE RATE



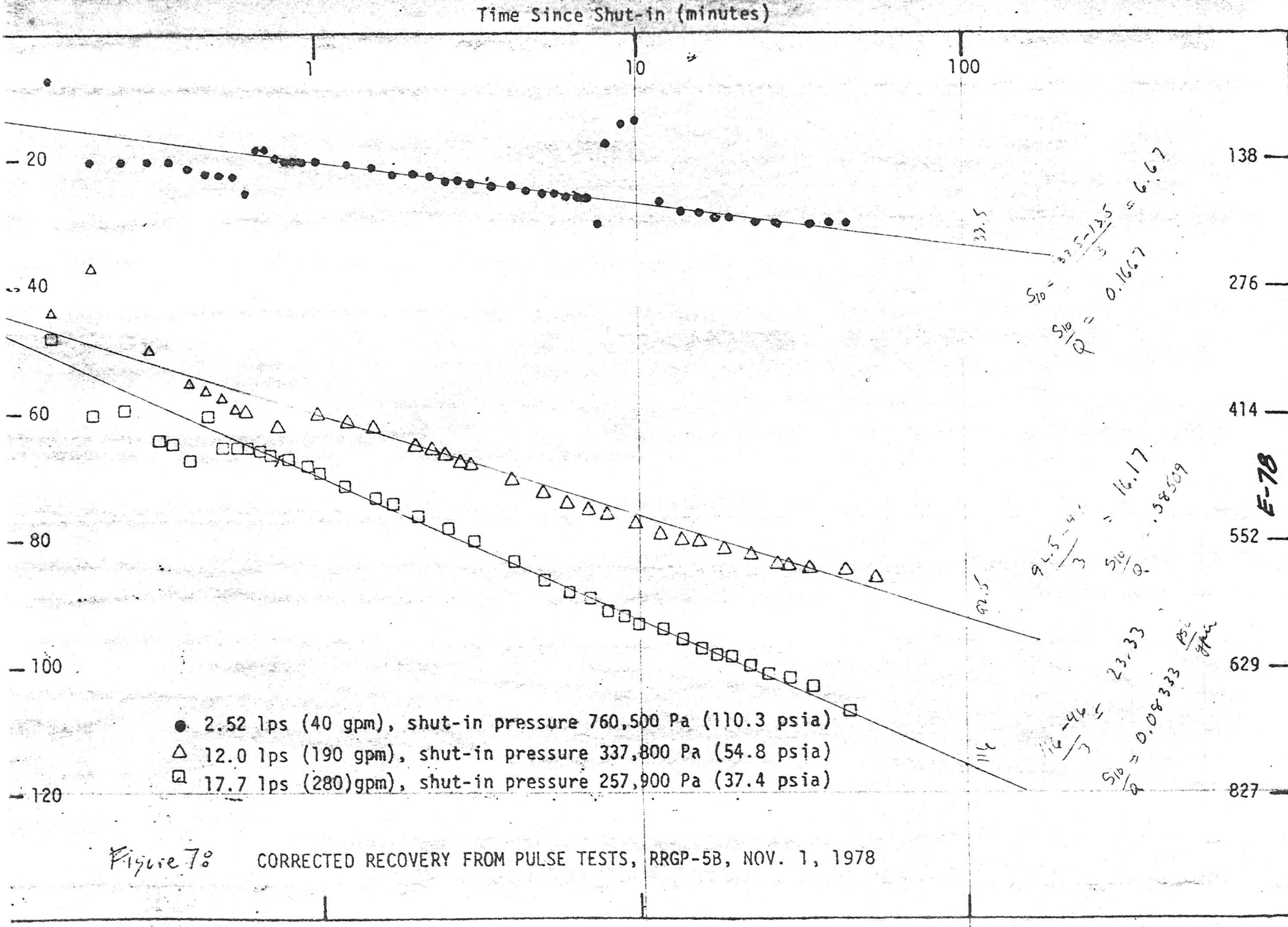


Figure 7: CORRECTED RECOVERY FROM PULSE TESTS, RRGP-5B, NOV. 1, 1978

E-78

Figure 8

WELLHEAD PRESSURE RRGE-1 AND RRGE-2, NOVEMBER 1 THRU NOVEMBER 7, 1978

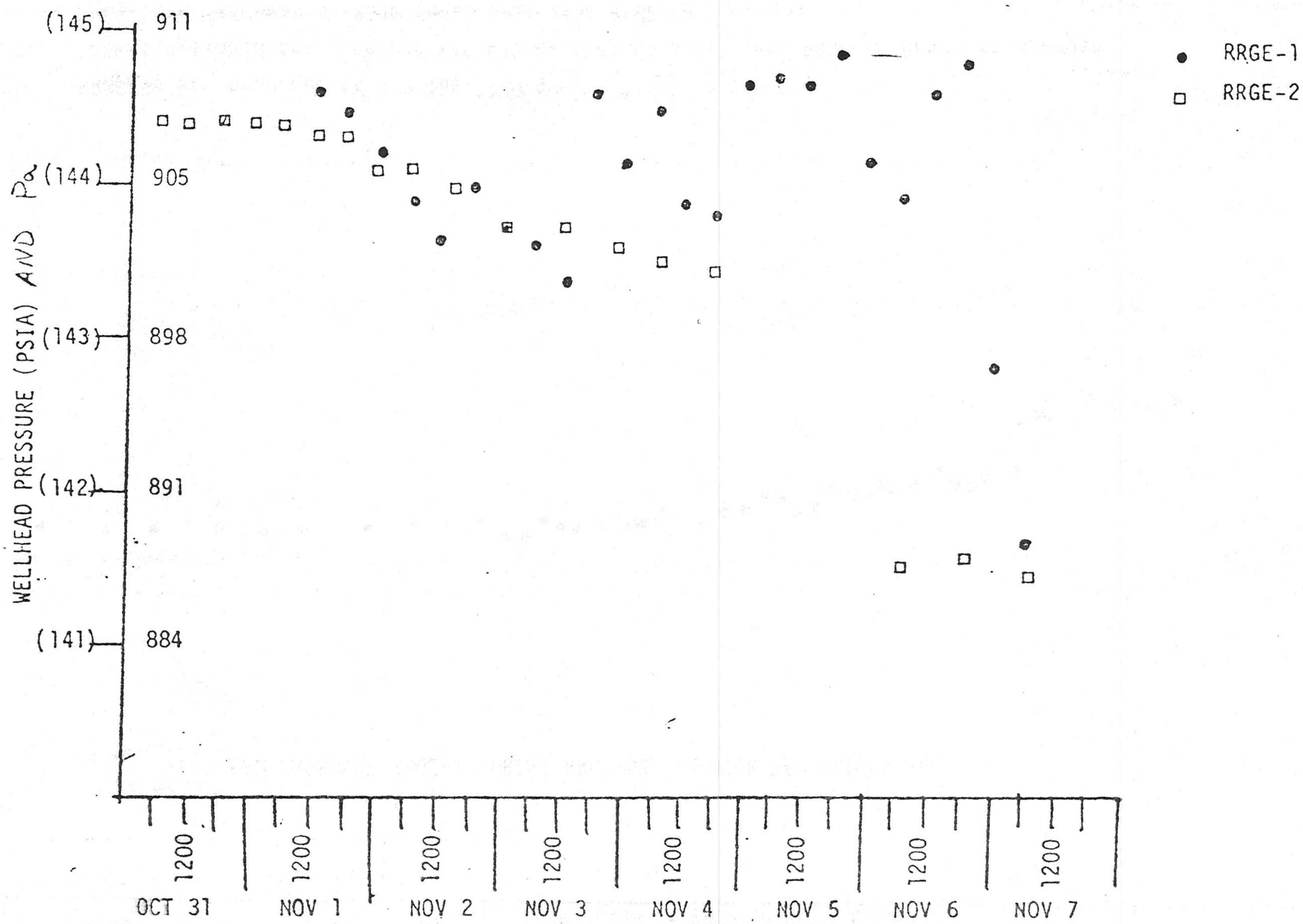
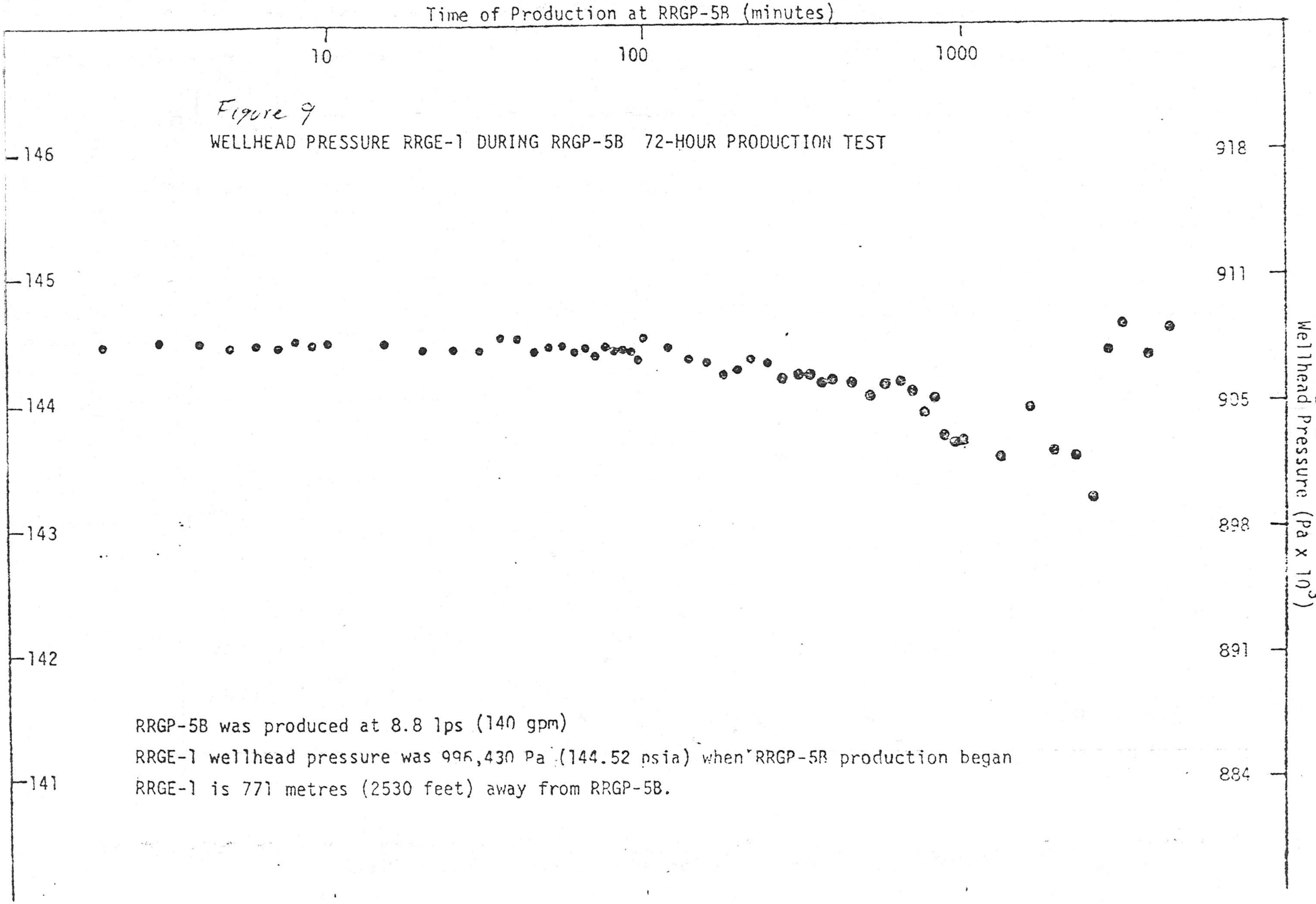


Figure 9

WELLHEAD PRESSURE RRGE-1 DURING RRGP-5B 72-HOUR PRODUCTION TEST



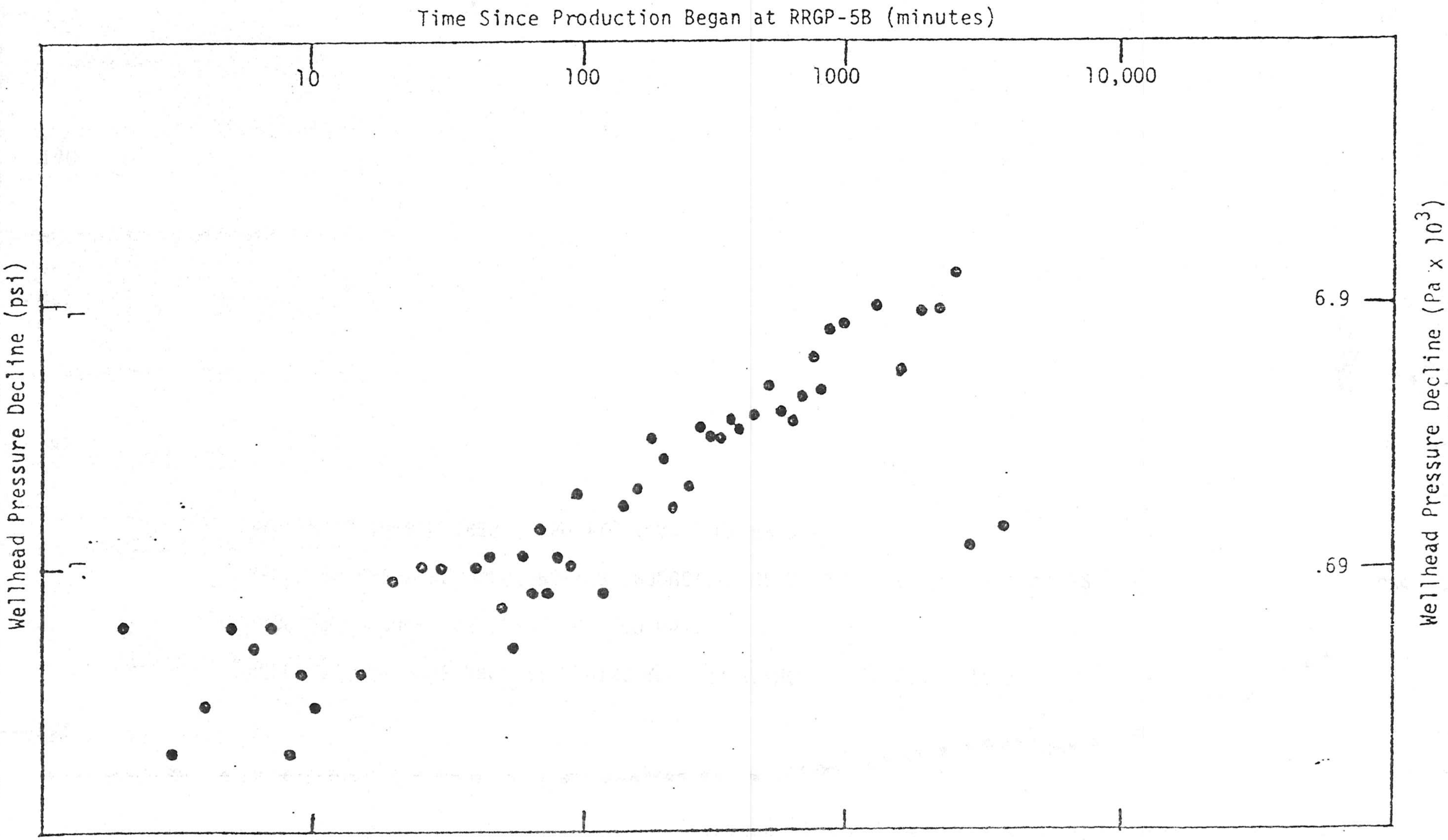
RRGP-5B was produced at 8.8 lps (140 gpm)

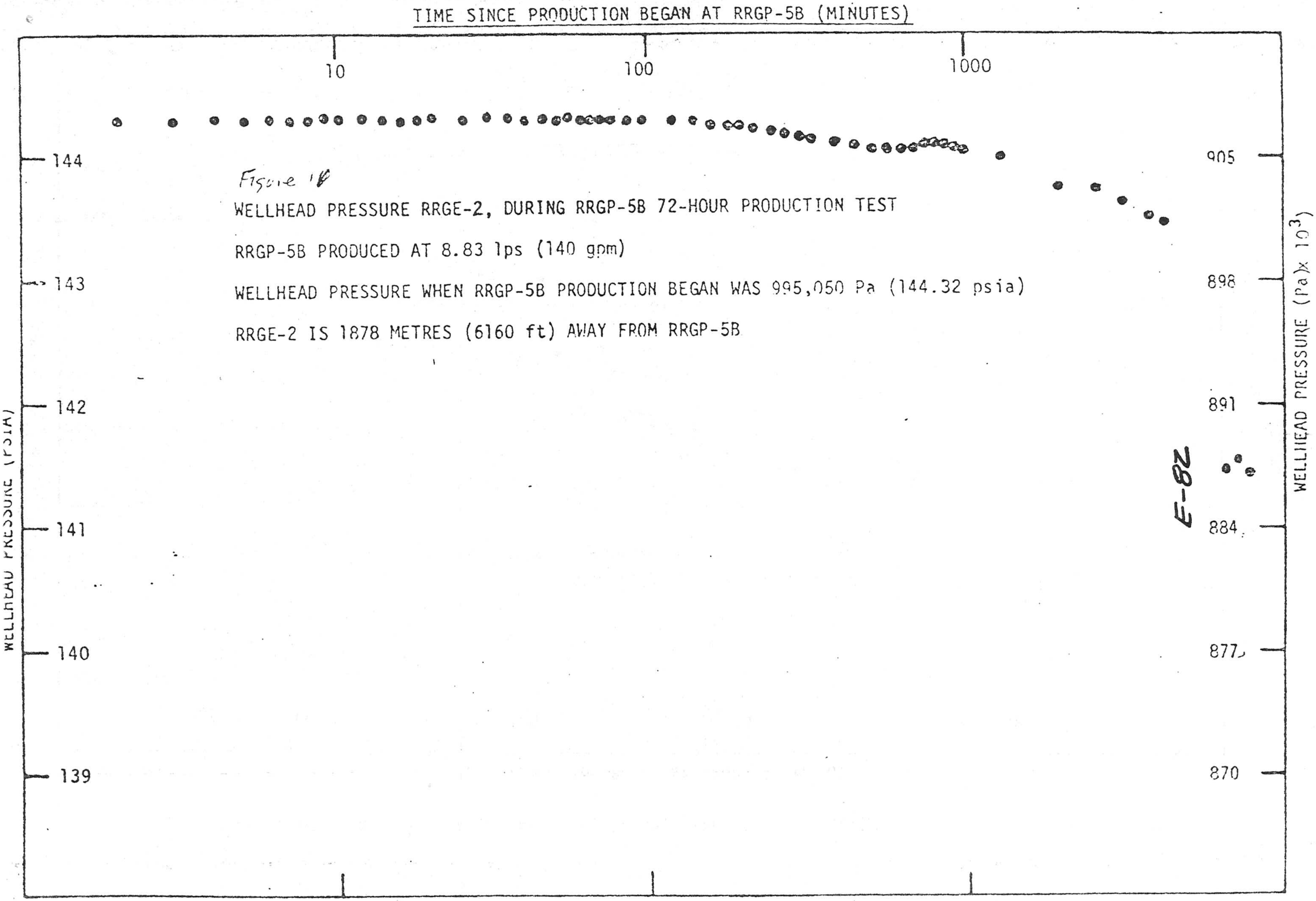
RRGE-1 wellhead pressure was 996,430 Pa (144.52 psia) when RRGP-5B production began

RRGE-1 is 771 metres (2530 feet) away from RRGP-5B.

Figure 12

LOG-LOG GRAPH OF WELLHEAD PRESSURE CHANGE RRGE-1, NOV. 1-4, 1978; RRGP-5B PRODUCING 8.83 lps (140 gpm)





TIME SINCE PRODUCTION BEGAN AT RRGP-5B (MINUTES)
10
100
1000
WELLHEAD PRESSURE (PSIA)
144
143
142
141
140
139
WELLHEAD PRESSURE (Pa)x 10^3
905
898
891
884
877
870
Figure 18
WELLHEAD PRESSURE RRGE-2, DURING RRGP-5B 72-HOUR PRODUCTION TEST
RRGP-5B PRODUCED AT 8.83 lps (140 gpm)
WELLHEAD PRESSURE WHEN RRGP-5B PRODUCTION BEGAN WAS 995,050 Pa (144.32 psia)
RRGE-2 IS 1878 METRES (6160 ft) AWAY FROM RRGP-5B

E-82

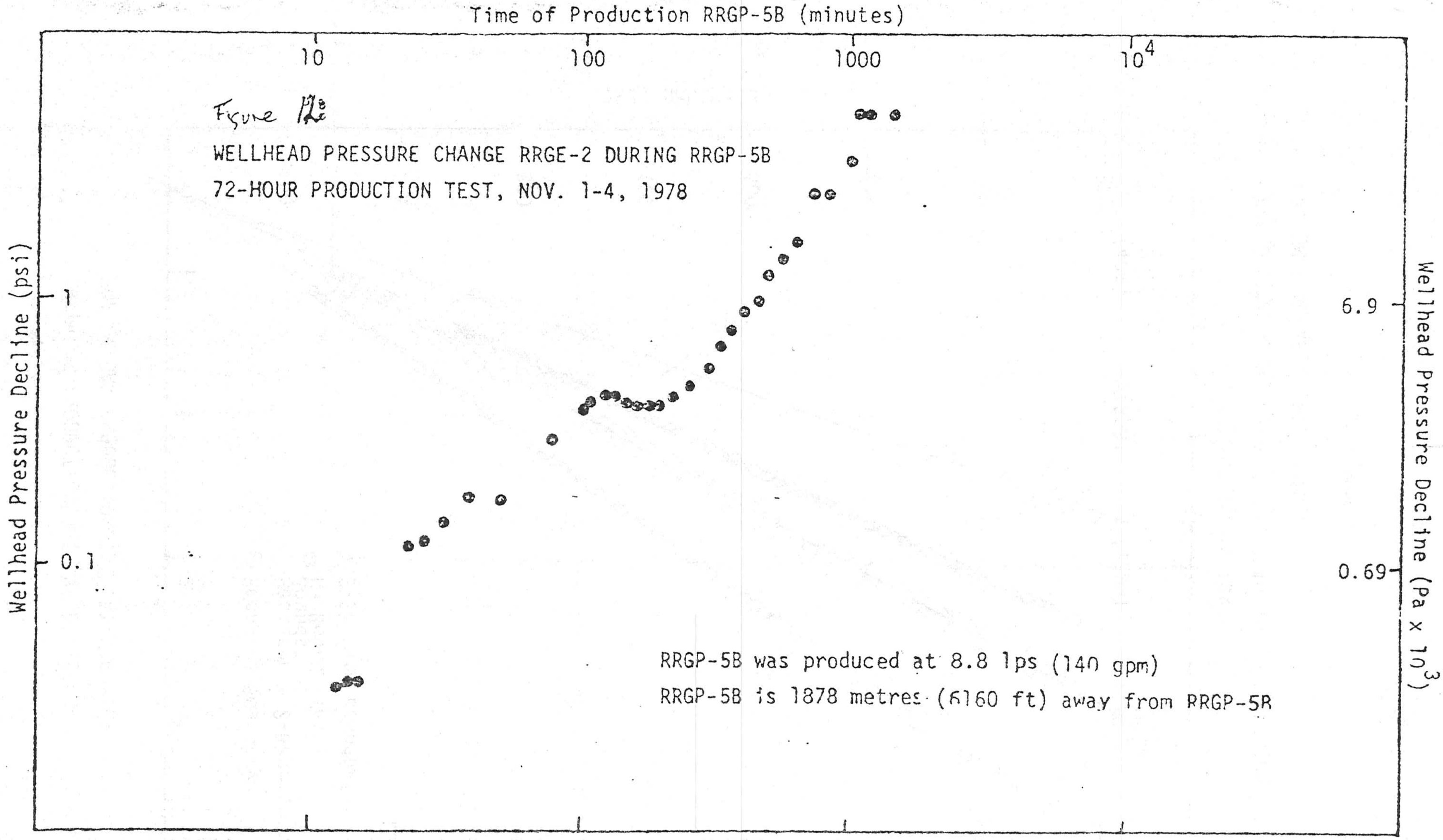
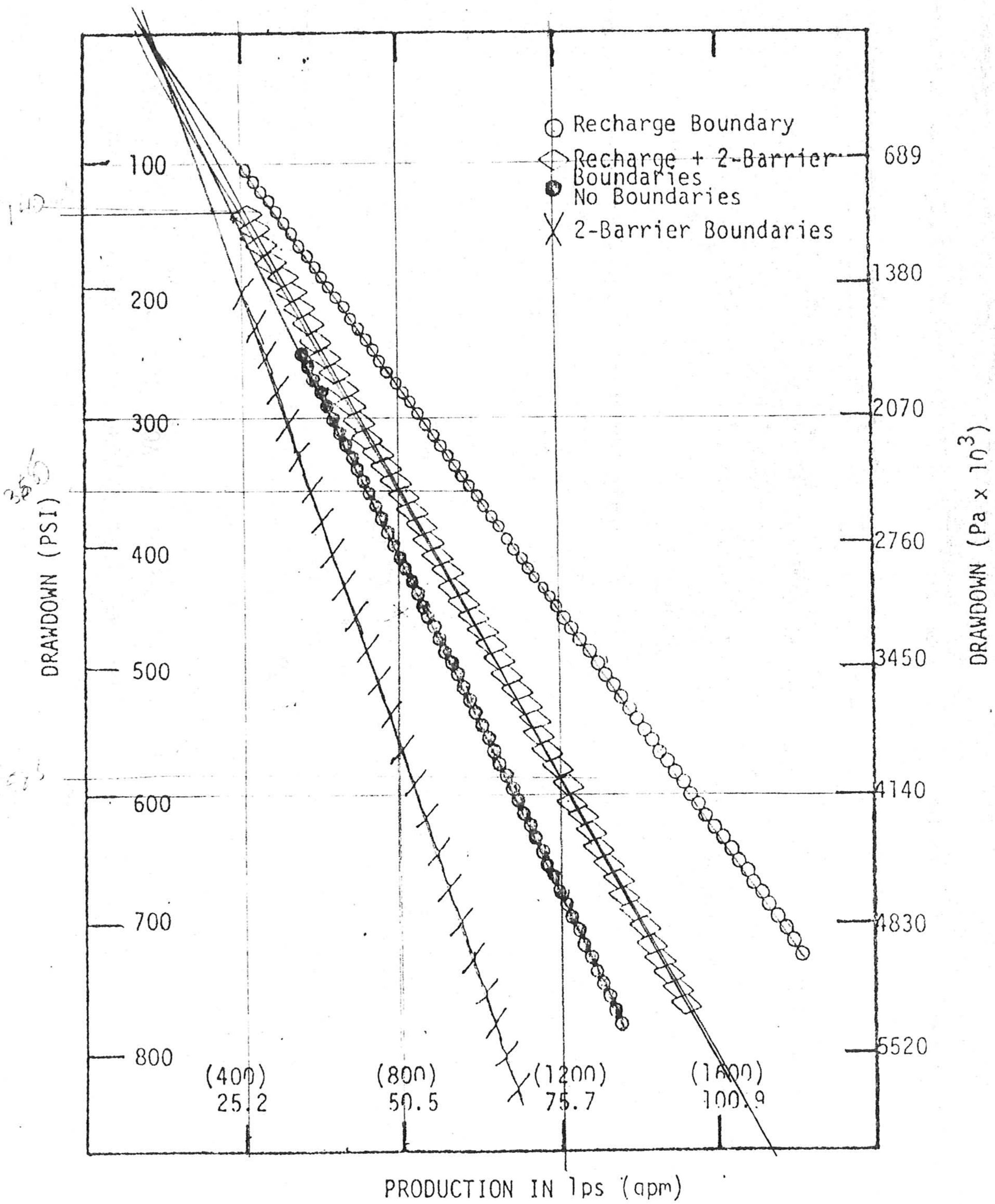


Figure 12

WELLHEAD PRESSURE CHANGE RRGE-2 DURING RRGP-5B
72-HOUR PRODUCTION TEST, NOV. 1-4, 1978

FIGURE 14:

GRAPH OF PRODUCTION RATE VS DRAWDOWN
FOR 20-DAY PRODUCTION TEST AT RRGP-5B

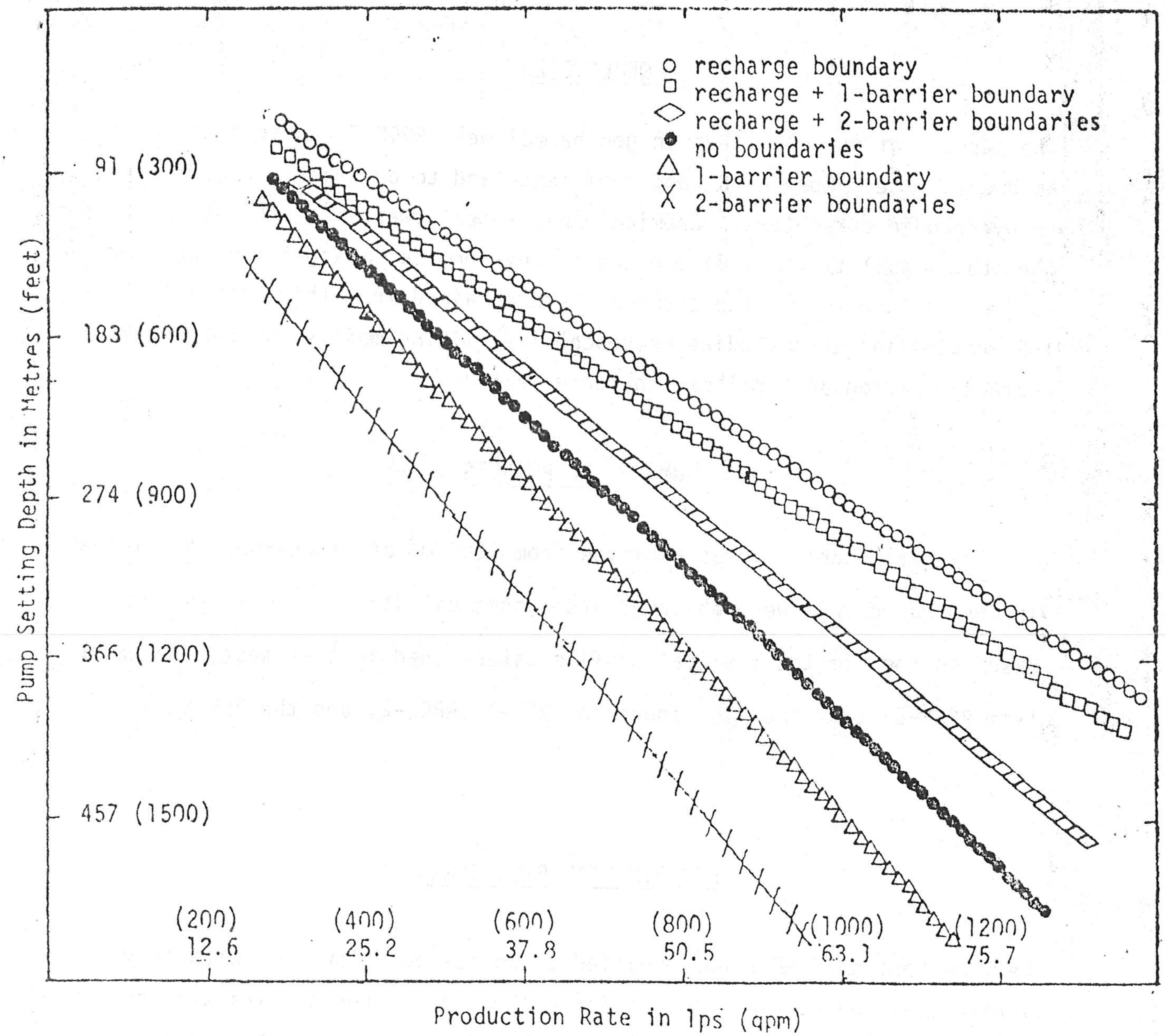


BASED UPON 72-HOUR, 8.83 lps (140 gpm) PRODUCTION TEST (Nov. 1-4, 1978

ASSUMES NO WELL INTERFERENCE

Figure 13

GRAPH OF PUMP SETTING DEPTH VS PRODUCTION RATE
FOR 20-DAY PRODUCTION TEST AT RRGP-5B



Based upon 72-hour, 8.83 lps (140 gpm) production test (Nov. 1-4, 1978)

Assumptions:
1) no well interference
2) 620,000 Pa (90 psi) must be maintained above pump bowls
3) an initial wellhead pressure of 793,000 Pa (115 psi)
4) 135 °C (275 °F) aquifer temperature

RESULTS, CHEMICAL DATA COLLECTED DURING THE 18-HOUR FLOW TEST OF RRGP-5, FET-14A-78

OBJECTIVES

The purpose of the flow test on geothermal well RRGP-5 was to test wellhead hardware, site pumps for a long-term test, and to determine or estimate geohydrologic parameters. Chemical measurements were made to determine when chemical stability was achieved and if any chemical changes were apparent during the flow test. The chemical data obtained from this test will have application in later studies on geochemical mixing models for reservoir characterization and wellbore characterization.

SUMMARY OF RESULTS

Chemical stability was achieved from 1200 m^3 of discharge. No trends in chemical change were observed after chemical stability was reached. Based on the limited chemical profile established in this test, the water from RRGP-5 is of the type found in RRGE-1, RRGE-2, and the BLM well.

EXPERIMENTAL PROCEDURE

The flow test on RRGP-5 was modified to an 18-hour flow test with only hydrological and chemical data being collected. Water samples were collected every 30 minutes. All samples were analyzed for conductivity and pH. Samples collected at ≈ 8-hour intervals were analyzed for pH, conductivity, Na^+, Cl^-, $CaCO_3$, and alkalinity. In addition to these chemical measurements, the conductivity was monitored by an in-line monitor for the duration of the test. A pH probe was installed for in-line monitoring but failed at the beginning of the test.

DATA EVALUATION

Table I shows the chemical analysis of the samples collected during the 18-hour flow test of RRGP-5. The flowrate was ≈ 1100 lpm for a total volume of ≈ 1200 m^3. The volume of the wellbore is ≈ 200 m^3. The rule-of-thumb for flushing the wellbore, such that chemical stability will be achieved, is ≈ 3 times the wellbore volume. This volume of water had flowed from the well between the start of flow at 9:00 AM and 6:30 PM. The conductivity measurements in Table I indicate chemical stability at ≈ 5:00 PM. Table II shows the chemical data for the 8-hour analysis. The mean concentration ($\bar{X}$), standard deviation (S_c), and percent standard deviation ($\%S_1$) values determined excluded the first two values for each species. These are values for each species after well RRGP-5 reached chemical equilibrium. The concentration values in Tables I and II do not indicate a trend in chemical change during the flow period after chemical stability is reached. The in-line conductivity probe chart showed no indication of chemical change. Table I compares conductivity readings of the two methods. The conductivity of the water samples is ≈ 400 μs higher than the in-line probe. This difference is due to the high pressure, high temperature environment of the in-line probe.

CONCLUSIONS

1. The 18-hour flow test of geothermal well RRGP-5 resulted in the discharge of 1200 m^3 of water. This was adequate to insure chemical stability. No trends in chemical change were observed after chemical stability was reached.

2. Based on the limited chemical profile established in this test, the water from RRGP-5 is of the type found in RRGE-1, RRGE-2, and the BLM well. This was expected from its location.

TABLE I

Flow Test of RRGP-5, November 1, 1978
Test Plan FET 14A-78

Time	pH	Conduct. (in-line)	Conduct.	Time	pH	Conduct. (in-line)	Conduct.
09:00	7.2	2000	2500	01:00	7.5	2400	2750
10:30	7.4	2300	2500	01:30	7.5	2400	2700
11:00	7.5	2100	2600	02:00	7.5	2200	2700
11:30	7.5	2050	2550	02:30	7.4	2200	2700
12:00	7.6	--	2600	03:00	7.3	2200	2700
12:30	7.5		2600	03:30	7.2	2400	2700
13:00	7.4		2600	04:00	7.4	2200	2750
13:30	7.2	2100	2600	04:30	7.5	2100	2700
14:00	7.3	2400	2700	05:00	7.6	2100	2750
15:30	7.2	1950	2600	05:30	7.5	2100	2750
16:00	7.4	1950	2600	06:00	7.5	2100	2700
17:00	7.4	--	2700	06:30	7.5	2200	2700
17:30	7.6	--	2700	07:00	7.5	2200	2700
18:00	7.5	2350	2700	07:30	7.5	2200	2700
18:30	7.6	2000	2700	08:00	7.5	2400	2750
19:00	7.5	--	2700	08:30	7.5	2400	2700
19:30	7.6	2450	2700	09:00	7.6	2400	2750
20:00	7.6	2450	2700	09:30	7.4	2400	2700
20:30	7.5	2400	2700	10:00	7.5	2400	2700
21:00	7.5	2475	2700	10:30	7.5	2400	2700
21:30	7.5	2475	2700	11:00	7.5	2400	2750
22:00	7.8	2300	2700	11:30	7.5	2400	2700
22:30	7.5	2450	2700	12:00	7.5	2450	2700
23:00	7.5	2400	2700	12:30	7.5	2400	2700
23:30	7.5	2400	2700	13:00	7.5	2400	2700
24:00	7.8	2300	2700	13:30	7.2	2400	2750
24:30	7.6	2200	2700				

Conductivity values are μs

TABLE II

8-Hr Analysis of RRGP Flow Test

Time	pH	Conduct.	Na^+	Cl^-	$CaCO_3$	Alkalinity
09:00	7.2	2500	479	754	124	35.2
13:30	7.2	2600	493	715	118	34.2
24:00	7.8	2700	477	822	130	33.2
08:00	7.5	2750	562	737	120	34.8
13:30	7.2	2750	527	802	126	35.0
24:00	7.1	2800	520	911	124	37.3
08:00	7.0	2700	532	863	126	37.5
13:30	7.3	2700	585	802	120	37.6
24:00	7.1	2800	520	822	140	39.2
08:00	7.2	2800	554	699	130	37.8
13:30	7.3	2800	520	828	128	37.6
17:15	7.2	2800	528	791	122	37.0
$\bar{X}$	7.3	2760	533	818	127	36.7
S_i	±0.2	∓46	±29	±70	±6.0	±1.8
$\%S_i$	±3.2	±1.7	±5.5	±8.5	±4.7	±4.9

Concentration values are μg/ml

Conductivity values are μs

FORM INEL-2631
(Rev. 2-76)

IDAHO NATIONAL ENGINEERING
AEROJET NUCLEAR COMPANY

ENGINEERING DESIGN FILE

FILE NO.
EDF SERIAL NO. 89
GWA NO. 64A1153A2
DATE 5/31/79

TASK SUPPLY AND INJECTION SYSTEM

SUBJECT

RAFT RIVER PRODUCTION PUMP SIZING, RRGE-1, 2, and 3

ABSTRACT

Pump Selection Summary - RRGE-1, 2, and 3

	RRGE-1	RRGE-2	RRGE-3
Pump Manu.	REDA	REDA	Centrilift
Size	N-1500	N-1050	IA-600
Stages	10	17	12
Impeller Cut	A	B	Std.
Motor H.P.	720	720	250
Pump H.P.	642	696	221
kW Load*	500	550	175
Flow 100%, 6 mo.	1510 gpm	1010 gpm	660 gpm
Flow 100%, 1 yr.	1500 gpm	990 gpm	640 gpm
Flow 85%, 1 yr.	1610 gpm	1100 gpm	685 gpm
Flow 85%, 5 yr.	1590 gpm	1070 gpm	650 gpm
Flow 85%, 30 yr.	1575 gpm	1035 gpm	620 gpm
Pump Set Depth	1630 ft.	2432 ft.	As deep as possible in 13-5/8 casing. (~1150 ft.)

*Assumes 95% efficient motor

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AUTHOR	DEPT.	REVIEWED	DATE	APPROVED	DATE
J. K. Jacoby	Geothermal Test & Anal.	M. R. Berglund	5/31/79	R R Piscitella	6-5-79

APPENDIX F

GP-04, Raft River Pump Selection Analysis, develops and explains the method for selection of production pumps in wells RRGE-1, 2, 3, and RRGP-5. New pumps for RRGE-1 and 2 will be selected herein; the pump for RRGP-5 will be respecified following the current 20 day production test of RRGP-5.

For wells RRGE-1 and 2, the pumps will be selected to provide the greatest possible flow. The upper limit on flow is established by the largest motor available for submersible pumps, which is rated at 720 HP. (REDA) For wells RRGE-3 and RRGP-5 the basis for pump selection is established by the location of the transition between 13-5/8 and 9-5/8 inch casing, which occurs at 1188 feet below ground level in Well 3 and 1284 feet in Well 5.

For these two wells the largest possible capacity pump will be selected, compatible with a pump setting depth (and drawdown) which are at the bottom of the 13-5/8 inch casing.

As will be seen from the results of this analysis, the pumps selected will provide an excess of about 1000 gpm over and above the 2850 gpm specified in the Project Management Plan for the Raft River 5 Megawatt (electric) Pilot Geothermal Power Plant. This excess capacity provides for maximum flexibility in production field operation and will allow expansion for yet undefined applications.

Appendix E of GP-04 developed a set of equations for drawdown in Raft River production wells RRGE-1, 2, 3, and RRGP-5. For RRGE-1, 2, and 3 these equations are:

RRGE-1

$$\Delta P_1 = \begin{Bmatrix} 0.361 \\ 0.365 \\ 0.375 \end{Bmatrix} Q_1 + \begin{Bmatrix} 0.023 \\ 0.024 \\ 0.025 \end{Bmatrix} (Q_2 + Q_5) - \begin{Bmatrix} 0.0069 \\ 0.0072 \\ 0.0080 \end{Bmatrix} Q_{inj}$$

Where: ΔP_d = drawdown in psi

Q_1 = production rate (gpm) for Well #1

$Q_2 + Q_5$ = combined production (gpm) for Wells 2 and 5

Q_{inj} = injection rate in field (gpm)

For calculating interference effects in this equation and the following equations;

Q_1 was assumed to be (on the average) 1275 gpm

Q_2 (average) = 825 gpm

Q_5 (average) = 550 gpm

Q_{inj} (average) = 2000 gpm

In the brackets: $\begin{Bmatrix} \text{6 month drawdown coefficient} \\ \text{1 year drawdown coefficient} \\ \text{5 year drawdown coefficient} \end{Bmatrix}$

RRGE-2

$$\Delta P_2 = - \begin{Bmatrix} 1.0 \\ 1.6 \\ 7.3 \end{Bmatrix} + \begin{Bmatrix} 0.241 \\ 0.263 \\ 0.350 \end{Bmatrix} Q_2 + \begin{Bmatrix} 0.000588 \\ 0.000599 \\ 0.000587 \end{Bmatrix} Q_2^2$$

$$+ \begin{Bmatrix} 0.023 \\ 0.024 \\ 0.025 \end{Bmatrix} (Q_1 + Q_5) - \begin{Bmatrix} 0.0069 \\ 0.0072 \\ 0.0080 \end{Bmatrix} Q_{inj}$$

RRGE-3

$$\Delta P_3 = \begin{Bmatrix} 0.761 \\ 0.813 \\ 0.933 \end{Bmatrix} Q_3 - \begin{Bmatrix} 0.033 \\ 0.035 \\ 0.040 \end{Bmatrix} Q_{inj}$$

Substituting various values for production flows into each equation yields:

Production capacity (gpm)	average flow 100% of capacity (100% usage factor) 6 months drawdown (ft)	1 year drawdown (ft)	average flow 85% of capacity (85% usage factor) 6 months drawdown (ft)	1 year drawdown (ft)	5 year drawdown (ft)
Well RRGE-1:					
200	223.4	227.3	196.5	200.1	203.8
1600	1478.2	1496.0	1263.0	1278.5	1311.7
Well RRGE-2:					
200	247.9	259.0	213.8	222.9	245.2
400	542.8	568.1	442.0	462.8	519.2
600	854.4	996.1	754.7	788.7	877.6
800	1482.8	1543.1	1151.8	1200.6	1320.0
1000	2128.1	2209.1	1633.2	1698.2	1846.9
1100	2494.5	2586.7	1905.6	1979.6	2141.9
Well RRGE-3:					
200	214.0	229.9	157.3	169.3	195.2
800	1347.6	1441.0	1120.9	1198.8	1376.5

Note that few points are required for RRGE-1 and 3 because the relations are linear with production. Figures 1 and 2 show the above relations plotted in combination with the head versus flow relations for the applicable REDA pumps. Figure 3 shows the drawdown curve for Well 3 in combination with the Centrilift I-600 submersible pump.

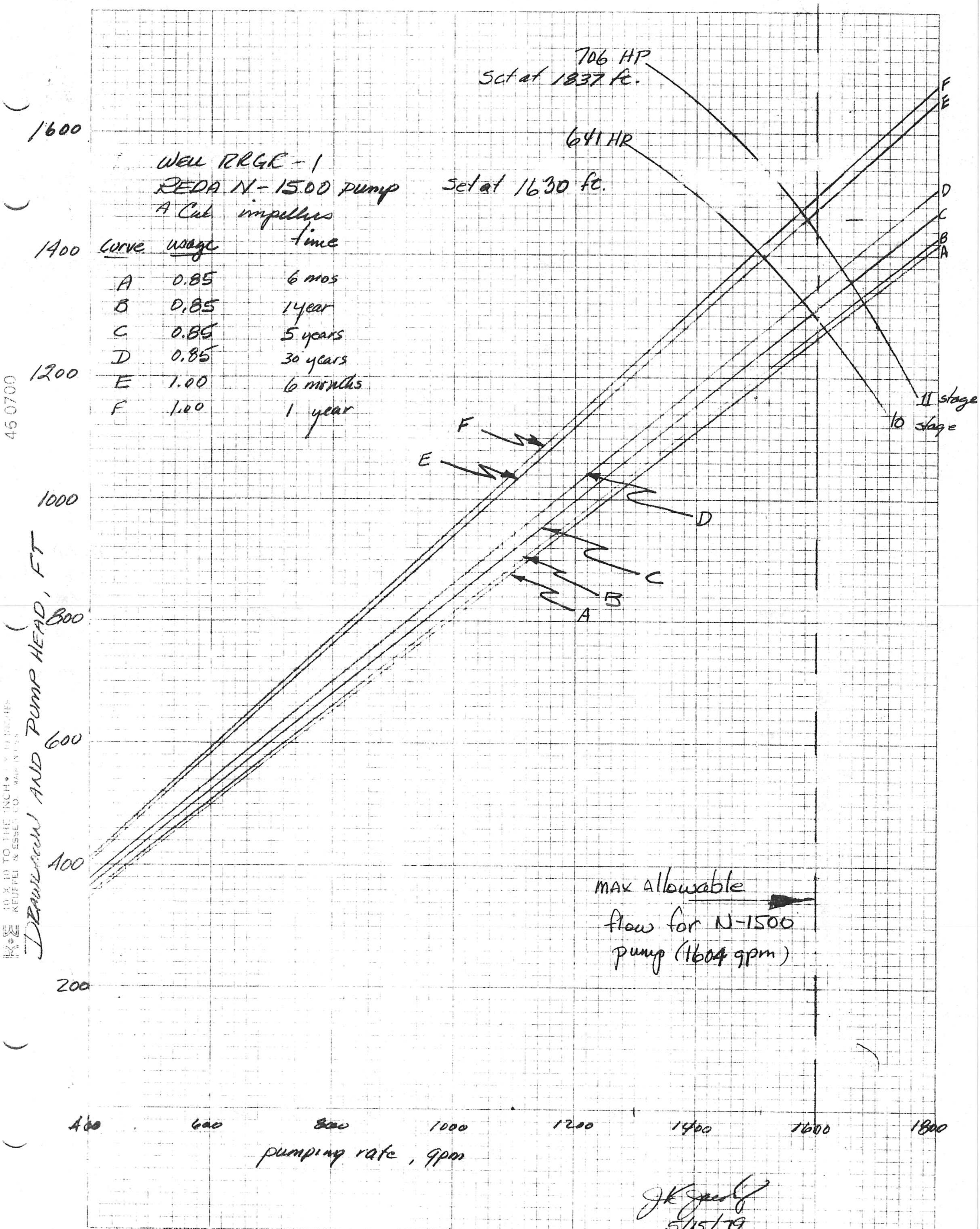
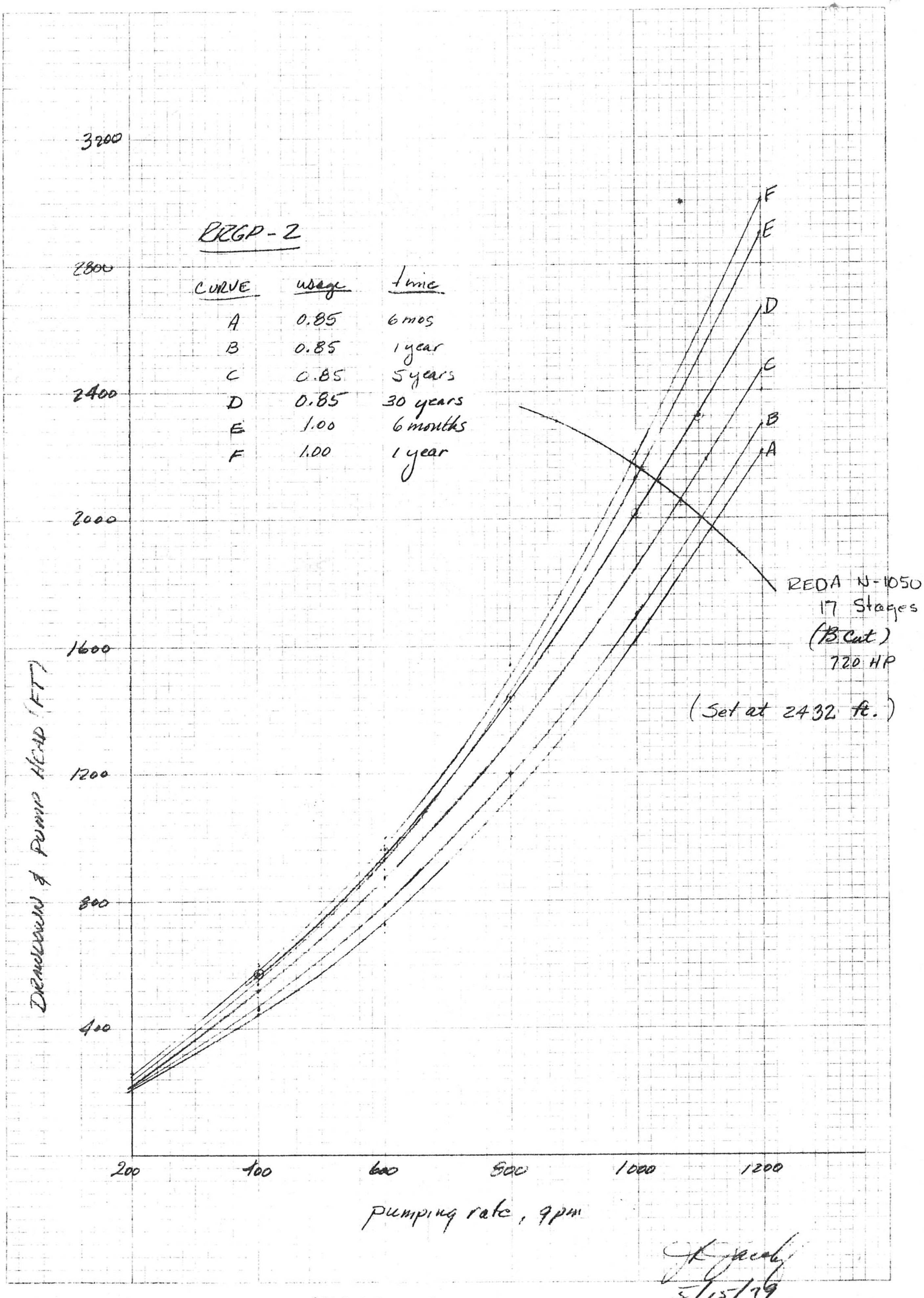

706 HP
Set at 1837 ft.
641 HP
Set at 1630 ft.
WELL RRGE-1
REDA N-1500 pump
A Cut impellers
Curve usage time
A 0.85 6 mos
B 0.85 1 year
C 0.85 5 years
D 0.85 30 years
E 1.00 6 months
F 1.00 1 year
A
B
C
D
E
F
11 stage
10 stage
MAX Allowable flow for N-1500 pump (1604 gpm)
DRAWDOWN AND PUMP HEAD, FT
200
400
600
800
1000
1200
1400
1600
400
600
800
1000
1200
1400
1600
1800
pumping rate, gpm
5/15/79

FIGURE I

E-5



RRGP - 2
CURVE usage time
A 0.85 6 mos
B 0.85 1 year
C 0.85 5 years
D 0.85 30 years
E 1.00 6 months
F 1.00 1 year
REDA N-1050
17 Stages
(B Cut)
720 HP
(Set at 2432 ft.)
Drawdown & Pump Head (FT)
pumping rate, gpm

FIGURE 2
F-6

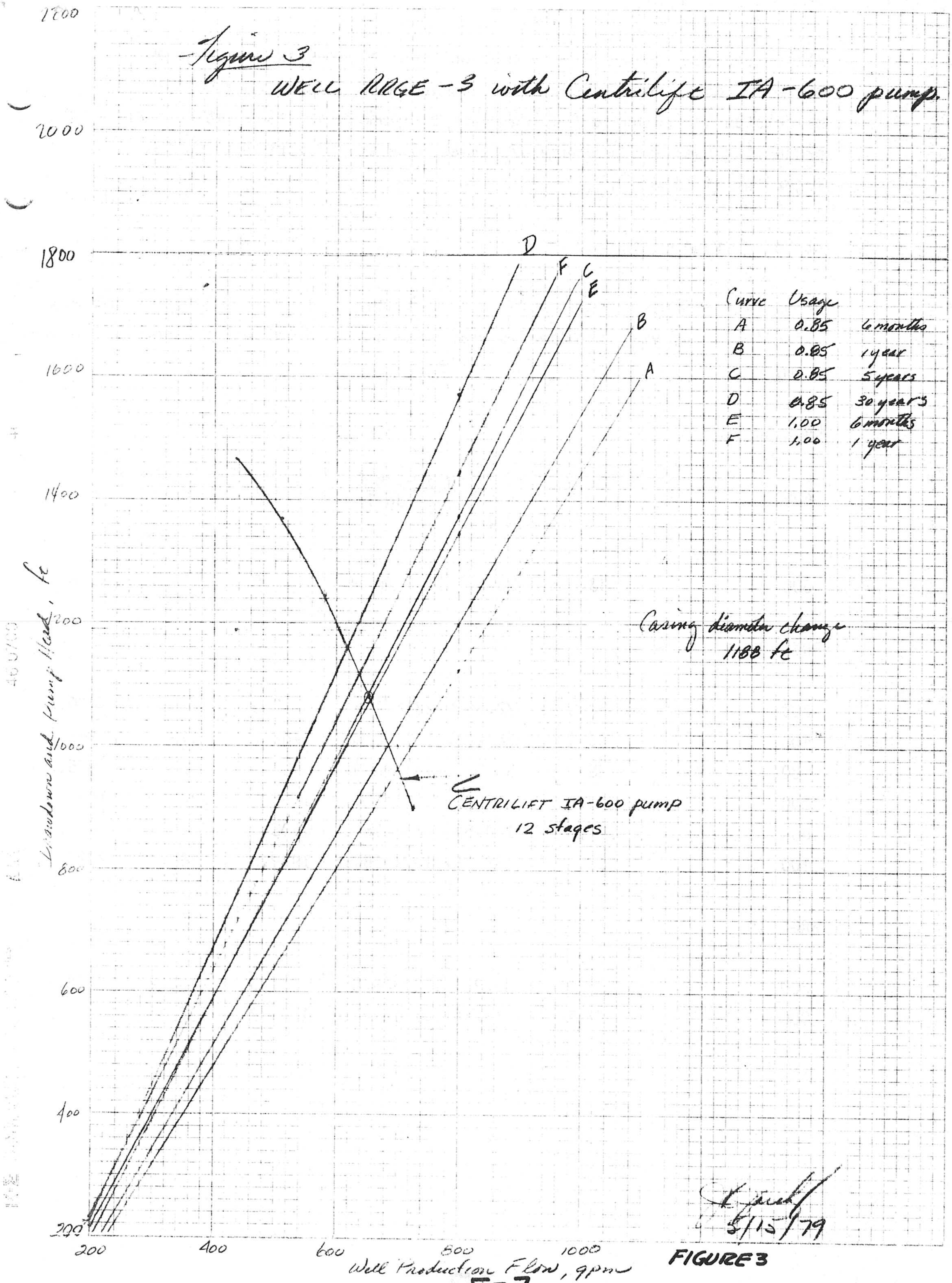


Figure 3
WELL RRGE-3 with Centrilift IA-600 pump.
D
F
C
E
B
A
Curve Usage
A 0.85 6 months
B 0.85 1 year
C 0.85 5 years
D 0.85 30 years
E 1.00 6 months
F 1.00 1 year
Casing diameter change
1188 ft
CENTRILIFT IA-600 pump
12 stages
Drawdown and Pump Head, ft
2000
1800
1600
1400
1200
1000
800
600
400
200
200
400
600
800
1000
Well Production Flow, gpm
5/15/79

FIGURE 3

Also, note that curves are plotted on these figures for drawdown at 30 years, 85% usage factor. These curves were plotted from points calculated according to the logarithmic drawdown relation (at constant production wellhead pressure decreases directly proportional to the logarithm of time).

At 85% average production:

Production capacity (gpm)	5 year drawdown -1 year drawdown (ft)	30 year drawdown -5 year drawdown (ft)	1 year drawdown (ft)	5 year drawdown (ft)	30 year drawdown (ft)
RRGE-1:					
200	3.7	$3.7 \frac{\log 30-\log 5}{\log 5-\log 1}$ = 4.12	200.1	203.8	207.92
1600	33.2	33.2(1.113)=36.96	1278.5	1311.7	1348.7
RRGE-2					
200	22.3	22.3(1.113)=24.8	222.9	245.2	270.0
400	56.4	56.4(1.113)=62.8	462.8	519.2	582.0
600	88.9	88.9(1.113)=98.9	788.7	877.6	976.5
800	119.4	119.4(1.113)=132.9	1200.6	1320.0	1452.9
1000	148.5	148.5(1.113)=165.3	1698.4	1846.9	2012.2
1100	162.3	162.3(1.113)=180.6	1979.6	2141.9	2322.5
RRGE-3:					
200	25.9	25.9(1.113)=28.8	169.3	195.2	224.0
800	177.7	177.7(1.113)=197.8	1198.8	1376.5	1574.3

Based on the 720 HP maximum power limitation for REDA pumps, we will now calculate the number of stages allowable for the N-1500 pump in Well #1 and the N-1050 pump in Well #2. Referring to Figure 1, the intersection of the drawdown curve with the pump head-flow curve, determines the operating flowrate for the following reasons:

1) The shutin wellhead pressure for each well at Raft River is:

RRGE-1	-	140 psig
RRGE-2	-	140 psig
RRGE-3	-	130 psig
RRGP-5	-	135 psig

2) During well operation the required pressure at each wellhead is near 130-140 psig. This pressure is necessary to:

   a) keep dissolved gases in solution,
   b) keep geothermal fluid from flashing, and
   c) insure adequate pressure at the 5 MW plant geothermal fluid boost pump suction.

Therefore, the drawdown, which is, by definintion the decrease in pressure due to flowing the well in question, is precisely the pressure which must be supplied by the well pump to flow the well at the given rate. Borehole friction losses are negligible compared with the uncertainty in the drawdown data.

Figure 1 shows that the operating flowrate at 6 months with an 11 stage pump running 100% of the time is predicted to be 1580 gpm. If the pump is operated less than 100% of the time, the flow would be even higher. The maximum allowable flowrate for the N-1500 pump is 1604 gpm.

To reduce the risk of having to throttle the Well #1 discharge to 1600 gpm the 10 (a-cut impeller) stage N-1500 pump is recommended. This pump is predicted to supply 1510 gpm continuously for 6 months and $\sim$ 1600 gpm if used only 85% of the time.

Horsepower per stage for the a-cut impeller is 69 HP (see Figure 4). For 10 stages the HP is 690. Pumping water with a specific gravity of 0.93 the horsepower is 0.93(690) = 641.7 HP. The minimum recommended flow for the N-1500 pump with a-cut impellers is 1166 gpm.

At this flow, the pump head is 168 feet per stage. For 10 stages the head would be 1680 feet (at minimum recommended flow). At a minimum recommended pump suction pressure of 90 psig (223.4 ft.) and a desired minimum discharge pressure at the surface of 110 psig (273.1 ft.), the pump suction should be set at 1680 ft. - (273.1 - 223.4) ft. = 1630 ft.

For well RRGE-2 with an N-1050 REDA pump (see Figures 2 and 5), the horsepower per stage (b-cut impeller) is 44. The maximum REDA pump motor size is 720 HP. The maximum allowable number of stages is therefore 720/44(.93) = 17.6 stages, (.93 = SP.gr. at 280^{o}F). Rounding down to 17 stages, the motor load will be (44)(.93)(17) = 696 H.P. The pump suction should be set at (17)(146) - (273.1 223.4)ft. = 2432 ft. (146 feet is the head per stage at minimum recommended flow for the N-1050 b-cut impeller).

For well RRGE-3, the maximum pumping rate is realized when the well is drawn down such that the minimum allowed pressure of 90 psi remains above the pump bowls with the pump set as deep as possible in the 13-5/8 inch casing. Referring to Figure 3, it is seen that the Centrilift IA-600 pump with 12 stages provides a good match with predicted well characteristics as the drawdown at 1 years continuous operation is 1120 feet, approaching the depth of the casing diameter change, 1188 feet. Thus the pump would have only 130-140 psi (shut in well pressure) remaining above the pump bowls if the pump suction were set at 1188 feet below ground level. Since the pump suction would have to be 30-50 feet above the transition (motor extends below pump suction) the margin is further reduced to 110-120 psi. Note that if the well drawdown is greater than expected, pump discharge flow can be throttled by control valves at the surface.

Table 1 summarizes flows, pump selections, and pump setting depths recommended for wells RRGE-1, 2, and 3. Data for well RRGP-5 will be compiled and pump recommendations made by June 7, 1979 following the present 20 day test at 625 gpm.

Table 1

Pump Selection Summary - RRGE-1, 2, and 3

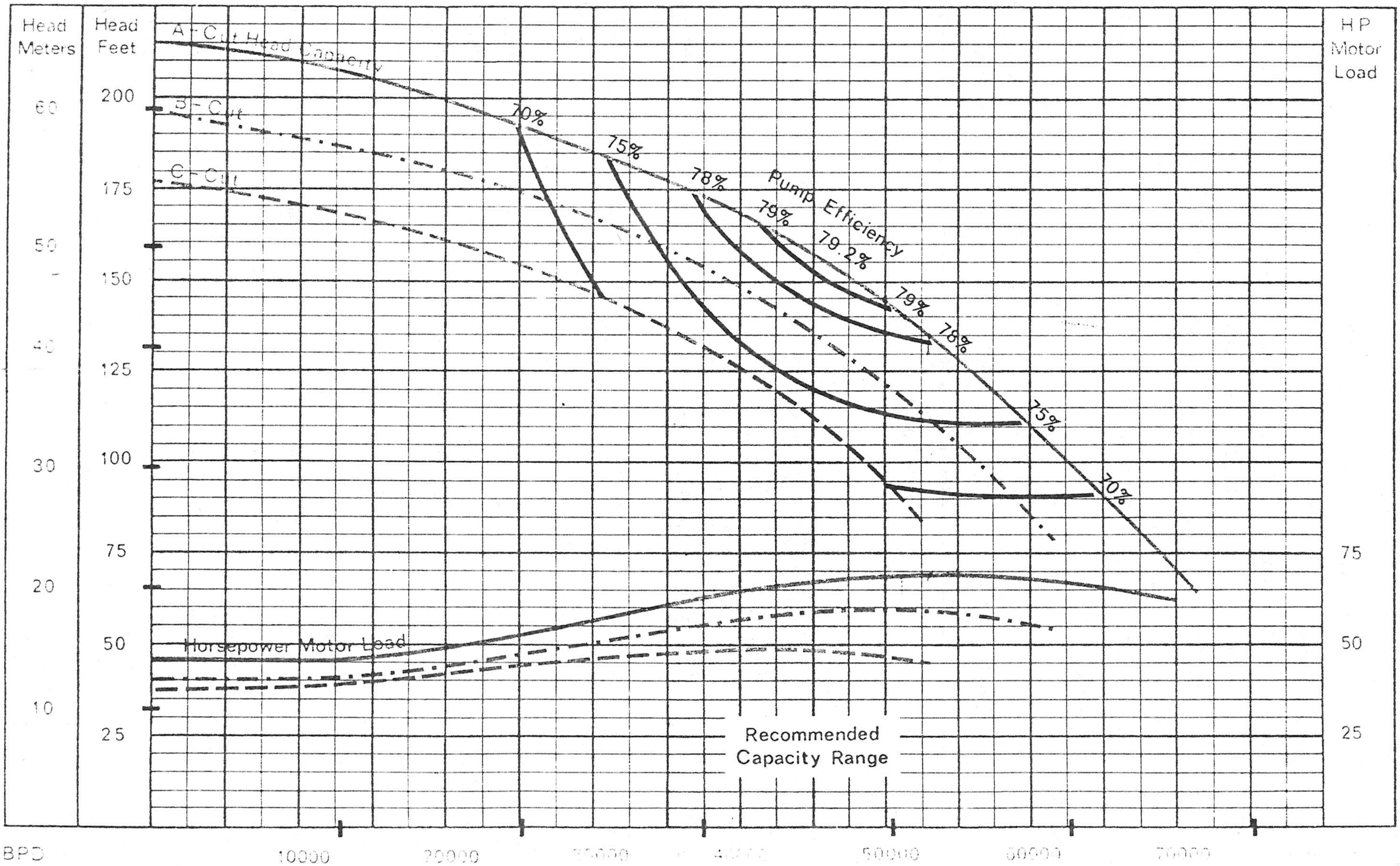
	RRGE-1	RRGE-2	RRGE-3
Pump Manu.	REDA	REDA	Centrilift
Size	N-1500	N-1050	IA-600
Stages	10	17	12
Impeller Cut	A	B	Std.
Motor H.P.	720	720	240
Pump H.P.	642	696	221
kW Load	500	550	175
Flow 100%, 6 mo.	1510 gpm	1010 gpm	660 gpm
Flow 100%, 1 yr.	1500 gpm	990 gpm	640 gpm
Flow 85%, 1 yr.	1610 gpm	1100 gpm	685 gpm
Flow 85%, 5 yr.	1590 gpm	1070 gpm	650 gpm
Flow 85%, 30 yr.	1575 gpm	1035 gpm	620 gpm
Pump Set Depth	1630 ft.	2432 ft.	As deep as possible in 13-5/8 casing.

TRW REDA PUMP DIVISION
BARTLESVILLE, OKLAHOMA 74003
JULY 1977

FIGURE 4

Reda Pump Performance Curve
One Stage–N1500 – 60 Hz
1000 Series – 3500 RPM

Minimum Casing Size
11¾IN OD
Check Clearances



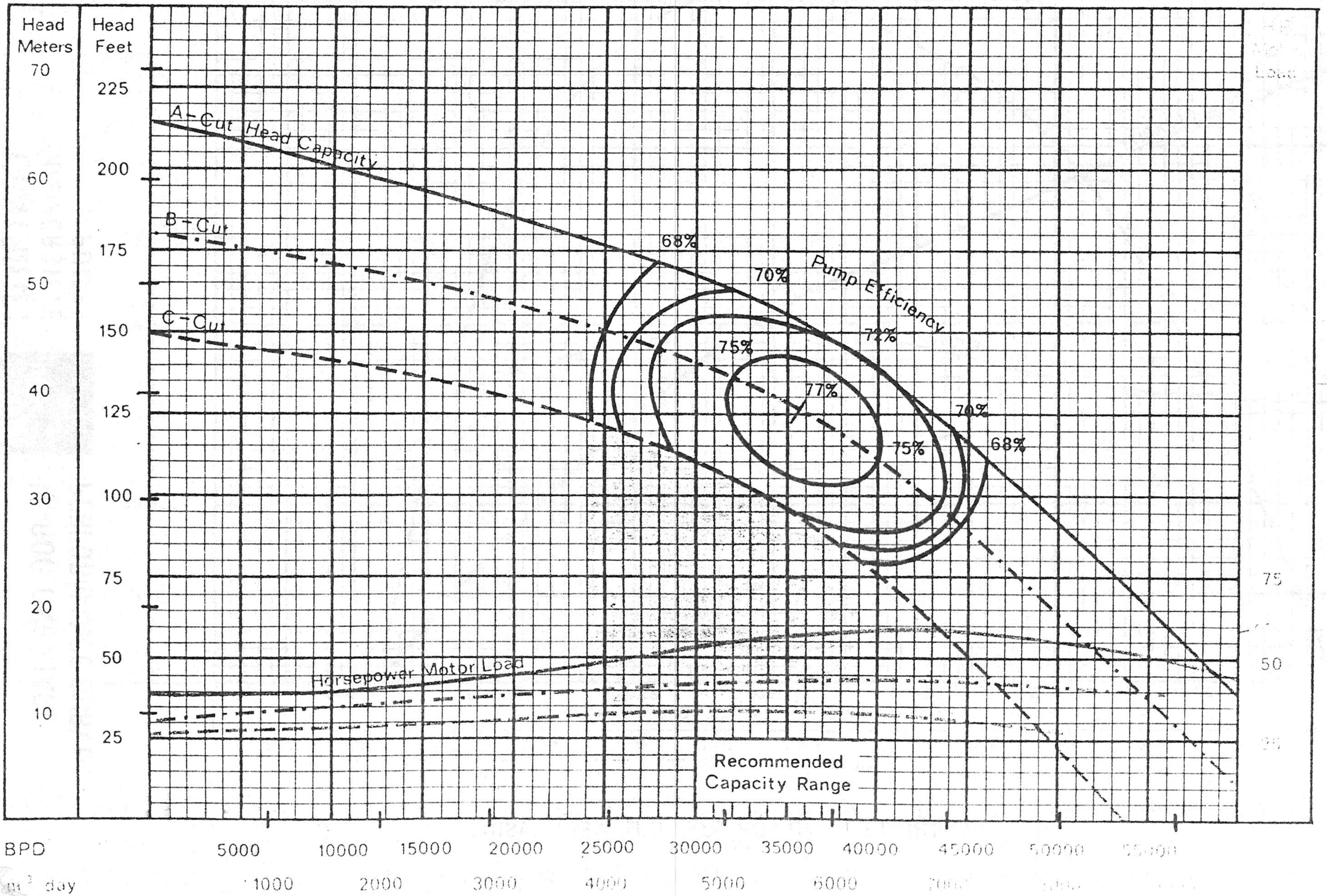
Type N1500

F-12

FIGURE 5

TRW REDA PUMP CO.
Bartlesville, Oklahoma
April 1977

Reda Pump Performance Curve
One Stage – N1050 – 60 Hz
950 Series – 3500 RPM

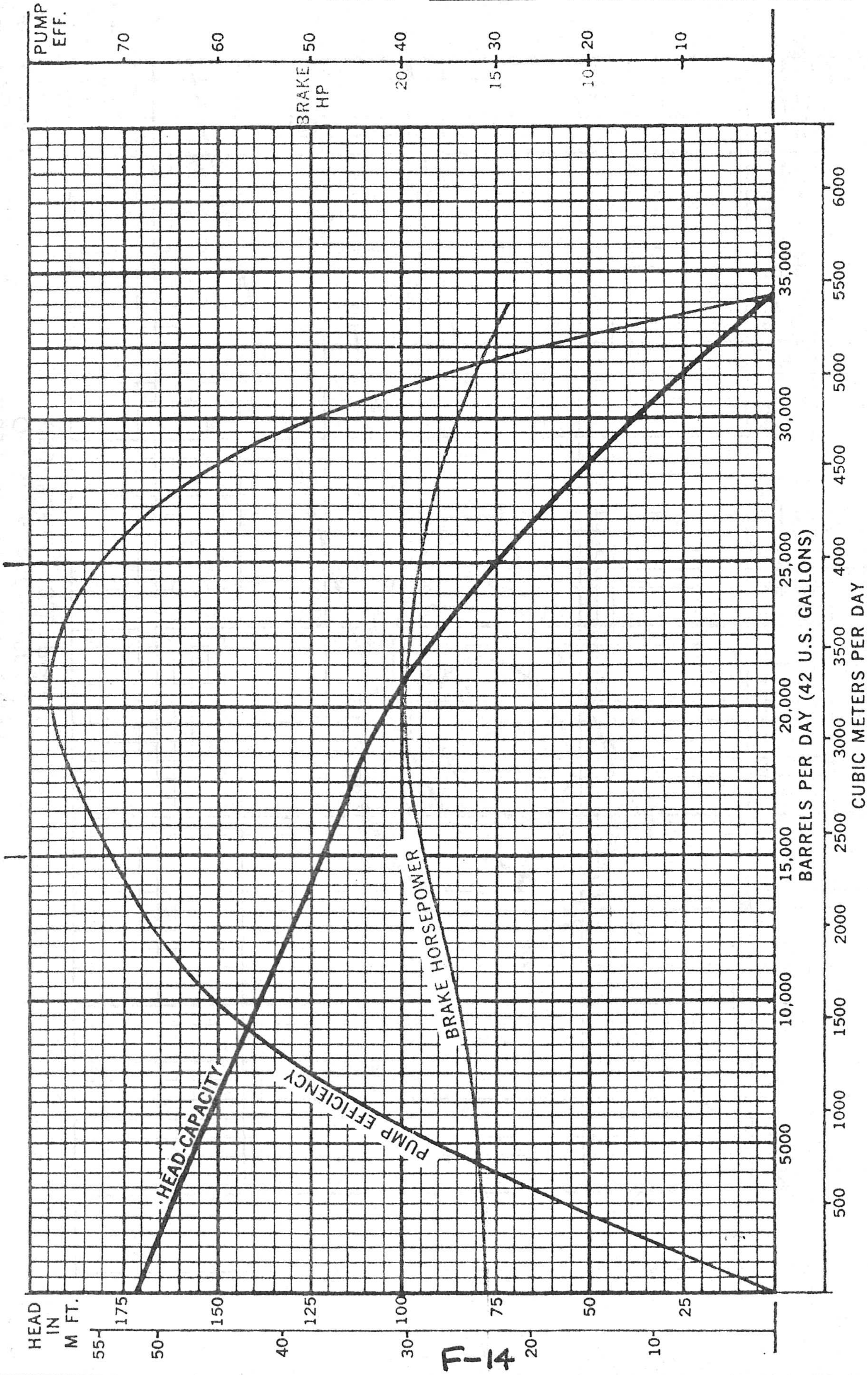


Type N1050

CENTRILIFT®
SUBMERSIBLE PUMPS

IA-600 ONE STAGE PERFORMANCE CURVE

FIGURE 6



F-14

IA-600 CENTRILIFT PUMP FOR 10¾" O.D. WELL CASING

SERIES 875 | WATER TEST 3475 R.P.M. | NO. 110-9-78 | SPECIFIC GRAVITY 1.0

EB-21.1

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