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GEOTHERMAL PERFORMANCE REPORT
ROOSEVELT HOT SPRINGS UNIT
BEAVER COUNTY, UTAH

PHILLIPS PETROLEUM COMPANY

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GEOTHERMAL PERFORMANCE REPORT

ROOSEVELT HOT SPRINGS UNIT, BEAVER COUNTY, UTAH

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INTRODUCTION

The purpose of this report is to review the results of testing and field operations performed in the Roosevelt Hot Springs Unit (RHS), Beaver County, Utah during the year 1979 and to make recommendations to improve future field operations in RHS and improve testing of all geothermal wells operated by Phillips Petroleum Company. This report contains a brief history of past RHS field tests, presentation and evaluation of 1) data gathered during a flow test of RHS well No. 54-3 during 1979, 2) RHS injectivity step-rate testing, 3) discussion of equipment performance during the flow test of RHS well No. 54-3, and 4) RHS field rate predictions.

SUMMARY

The Roosevelt Hot Springs discovery well, RHS No. 3-1, was drilled in April, 1975 and since then 10 additional wells have been drilled. Thirteen separate flow tests have been conducted within the RHS unit with the last test being Long Term Flow Test No. 2 of RHS well No. 54-3. Phillips Petroleum is the operator with a 74% tentative working interest.

RHS well No. 54-3 flowed for 93 separate days with a total flow time of 88.8 days and averaged 638,441 lbm/hr with a cumulative steam and brine production of 3.92 MM STB. During LTFT No. 2 data obtained satisfied the following test objectives 1) high deliverability 2) measurement of non-condensable gas content of steam 3) verification of brine chemistry 4) field test of a vortex meter 5) testing of scale inhibitor 6) characterization of the wellhead pressure versus flowrate relationship and 7) tracer injectivity study of RHS well No. 82-33. In addition to accomplishing the goals, seven wells were tested by means of an injectivity step-rate program designed to measure wellhead pressure while injection rates were varied between 0.5 and 62 BPM.

Recommendations in this report deal mainly with presenting the results of the LTFT No. 2, evaluation of equipment, suggestions for improving the geothermal testing procedure used by the Salt Lake office, and presenting methods and techniques used in predicting future injection and production performance in the RHS unit. Future work is required by the Salt Lake office in the areas of reservoir engineering, RHS model predictions, brine chemistry analysis, analysis of the step-rate injectivity tests, and tracer study of the disposal system.

CONCLUSIONS

1. Based on production data available total production from RHS unit has been 8,970,170 STBF at 60°F with 7,351,020 STBW reinjected into RHS well No. 82-33.

2. The average flow rate for RHS well No. 54-3 during LTFT No. 2 was 638,441 lbm/hr with 3.92 MM STBF at 60°F cumulative production with 3.55 MM STBW reinjected into RHS well No. 82-33.

3. The kill line from KV-1 was located in a dangerous position.

4. The master valve failure could have been avoided.

5. The average steam ratio (steam to total flow) during the August 22 to November 14 portion of LTFT No. 2 was 8.82%.

6. The steam quality ranged between 92% and 93% during the August 22 to December 5, 1979 LTFT No. 2.

7. All RHS observation wells equipped with subsurface pressure chambers exhibited pressure response during LTFT No. 2 with Getty's RHS well No. 52-21 showing a 32.5 psig change.

8. The subsurface pressure chambers should be removed from the observation wells and checked to avoid future fishing jobs caused by tubing breaks.

9. The vortex meter provided exceptional reliability, and convenience for calculating water flow rates.

10. The Fisher TL101 process controller and 6" Fisher eccentric disc valve controlled the water level in the separator and recovered from system upsets very well.

11. The steam rate can be held constant during commercialization of RHS by controlling the steam pressure off the steam leg of the separator.

12. The WKM safety valve worked throughout the test with only one indication of sticking.

13. The separator control valve (CV-3) was a used valve and probably broken when installed prior to LTFT No. 2 and the bonnet gasket was obsolete.

14. There was no evidence of pipe vibration during LTFT No. 2.

15. The muffler designed by Phillips Petroleum's E & S Group of Bartlesville, was unsatisfactory and did not withstand the high steam flow rates.

16. The two 12.5 Kw generators were of adequate size for the power requirements during LTFT No. 2.

17. The 3 conductor #12 wire used to supply power to the 1/4 HP air compressor in the wash was too small to power a larger compressor,and the drop cords installed for LTFT No. 1 were in poor condition.

18. Four scale inhibitors tested during LTFT No. 2 did control surface equipment scaling.

19. The noncondensable gas (NC) content of the steam measured at RHS well No. 54-3 was 0.581 $\pm$ 0.101 and 0.609 $\pm$ 0.069 (weight basis) to total flow.

20. The sodium iodide tracer survey at RHS well No. 82-33 was inconclusive.

21. Testing of geothermal wells is a complicated task that requires field personnel to be fully aware of the test objectives and equipment used to obtain this data.

22. The injectivity step-rate tests provided useful data for sizing injection equipment.

23. The initial production rates for the existing wells to be used during the 20 megawatt plant development of RHS are as follows:

54-3	800,000 lbm/hr
13-10	600,000 lbm/hr
72-16	800,000 lbm/hr
25-15	400,000 lbm/hr
14-2	500,000 lbm/hr
New Well	700,000 lbm/hr

RECOMMENDATIONS

1. The Bartlesville files of former Phillips employee C. W. Morris should be checked for flow test information on RHS well's No. 12-35 (April 12, 1976) and 54-3 (April 23, 1976) and Thermal Power should be required to furnish the flow information on the April 1977 test of RHS well No. 14-2.

2. Any future testing at RHS well No. 54-3 should be designed for flow rates above 800,000 lbm/hr.

3. Two kill lines on geothermal wells should be connected, and when possible not be located directly in front of the master valve bonnet.

4. A pop-off valve should be installed on all master valves and the master valve should be opened fully then closed 1/4 to 1 turn to allow trapped water in the body a path for expansion into the master valve body.

5. The steam orifice plate should be sized for steam rates large enough to obtain 18 to 20% steam to total flow ratios.

6. Further geothermal tests should be designed to continuously measure the variables needed to calculate steam quality.

7. The RHS model should be rerun using the pressure buildup and drawdown data from LTFT No. 2.

8. Subsurface pressure chambers should be removed when buildup data is sufficient for a match with the reservoir computer model.

9. Further geothermal testing of separated flow should incorporate vortex meters in the steam and water line for metering. The vortex meters should be equipped with strip charts for continuous reading.

10. The separator water level should be controlled by a valve located in the water line downstream of the separator.

11. Further testing of separated flow should incorporate controlling steam rate by steam pressure. The possibility of using electrical controls versus pneumatic should be checked out.

12. The WKM safety valve should be checked for scale in the spring which could cause the valve not to function if used in the future.

13. The temperature and pressure are too high in geothermal well testing to safely use valves that are not specifically designed and selected for each situation. Salvaged valves should be avoided when there is a possibility that the design tolerances will be exceeded.

14. Commercial vibration dampers should be looked into for their possible use when vibration is a problem.

15. Commercial mufflers should be checked for possible uses during commercialization of RHS.

16. The two 12.5 Kw generators should be serviced by a qualified service man, as one generator exhibited valve damages.

17. The wiring at RHS well No. 54-3 should be removed as the installation for LTFT No. 1 did not meet the NEC code.

18. Future test objectives for geothermal wells should include the use of the four scale inhibitors successfully tested at RHS whenever the possibility of scaling exists.

19. The noncondensable gas content of steam should be measured and included in the test objectives for any future geothermal well tests where the total flow is separated into water and steam.

20. Radioactive tracers should be used for determining the patterns of water movement in and around the RHS unit.

21. A field foreman and a field tester should be assigned to the Salt Lake office prior to any more testing of geothermal wells.

22. The injection rates and pressures of the injection wells used during commercialization of RHS should be monitored closely and compared with the injectivity step-rate tests to verify the tests' validity.

23. The rate prediction method used in this report should be verified during commercialization of RHS.

PERTINENT DATA SHEET

Geothermal Performance Report
Roosevelt Hot Springs Unit

General

Date Discovered	April 1975
Type of Accumulation	Highly Faulted
Formation	Wild Horse Canyon/Mineral Range
Total Wells	11
Producers	7
Injectors/Disposal	1
Dry Holes	3
Primary Producing Mechanism	Water Drive
Tentative Working Interest %	74
Interest in Federal Unit %	65.68

Formation Data

Type Pay	Crystalline Igneous & Metamorphic
Average Pay Thickness, Feet	5450 - 9000
Average Porosity, %	2.5
Reservoir Temperature, ^{o}F	500

Producing Data (December 31, 1979)

54-3	STBF*	8,697,154
14-2	STBF	67,758
13-10	STBF	117,858
3-1	STBF	5,175
72-16	STBF	82,225
12-35	STBF**	
Cummulative Prod.	STBF	8,970,170

Injection Data (December 31, 1979)

82-33	STBW	7,351,020
Cumulative	STBW	7,351,020

* No production information available for 4/23/76 test
** No production information available for 4/12/76 test

DISCUSSION

GENERAL HISTORY

The Roosevelt Hot Springs Known Geothermal Resource Area (KGRA) is located in southwestern Utah approximately twelve miles northeast of the town of Milford, Beaver County, Utah (Reference Figure No. 1). The reservoir discovery well was RHS well No. 3-1 (NW SE Sec. 3-27S-9W), which was drilled in April 1975 by Phillips Petroleum Company (Reference Figure No. 2). The well was flow tested for a duration of three hours with an approximate mass flow rate of 600,000 lbm/ hr. Since the discovery well, there have been 10 additional wells drilled, six being producers, three dry hole, and one, RHS well No. 82-33 (NE NE Sec. 33-26S-9W) located outside the reservoir is being used as a disposal well.

Counting the flow test of RHS well No. 3-1 in May 1975, thirteen separate flow tests have been conducted with RHS well No. 54-3 (SW NE Sec. 3-27S-9W) having been tested the most. Total field production of steam and water has been approximately 9.0 MM stock tank barrels (STB) at 60°F with 7.4 MM STBW injected into RHS well No. 82-33. Figure No. 3 is a tabulation of the wells tested, with the dates, flow time, rates, and cumulative production in stock tank barrels @ 60°F. There was no information available in the files on flow tests of RHS wells No. 12-35 (NW NW Sec. 35-26S-9W) on April 12, 1976 and No. 54-3 on April 23, 1976, thus the flow times, rates, and production data have been left blank and the field cumulative production figures do not include production from these two well tests.

The general geologic makeup of the geothermal reservoir is associated with interconnected fractured zones and faults which give the crystalline rock local, highly fractured permeability. The rock encountered during drilling was igneous intrusive rock of the Cenozoic Granitic Pluton or Metamorphic rocks of the Pre-Cambrian age.[1]

In November the Roosevelt Operating Unit was formed with Phillips Petroleum being the operator with a working interest of 74%. Joining this unit were Thermal Power, Amax and O'Brien. Previously Union Oil Company and Superior Oil had formed a unit with Phillips. Phillips has a 65.68% interest within the Federal KGRA Unit. The 74% working interest is tentative and will change as the field is developed and reserves are proven.

Between the conclusion of Long Term Flow Test No. 1 and the first startup of RHS well No. 54-3 for Long Term Flow Test No. 2 the piping system was cleaned and reassembled and the master valves were serviced by WKM. Additional information on work performed in the spring of 1979 covering these areas is contained in a field log book filed in the Salt Lake City Roosevelt Field files.

LONG TERM FLOW TEST NO. 2

Roosevelt Hot Springs well No. 54-3, was flowed between June 8 and December 5, 1979 and averaged 638,441 lbm/hr. This flow period is referred to as Long Term Flow Test No. 2 (LTFT NO. 2) and the flow test conducted between October 7, 1977 and May 31, 1978 is referred to as the Long Term Flow Test No. 1 (LTFT No. 1). Approval for LTFT No. 2 to be conducted was received from the USGS and the State of Utah Water Division because LTFT No. 1 was terminated before completion due to scaling in the wellbore. LTFT No. 2 was considered a continuation of LTFT No. 1 for permitting purposes and obtaining approval to flow Well No. 54-3 and dispose of fluids into Well No. 82-33. The system used to collect and dispose of the fluids during LTFT No. 2 was basically the same system used during the previous test. Changes made in the piping system and separator controls are discussed in the respective topics in the Equipment Performance Section of this report. Figure No. 4 is a piping drawing of well No. 54-3 during the June 8 to 13 portion of the flow test.

During LTFT No. 2 Well No. 54-3 was flowed on 93 separate days with a total flow time of 88.8 days resulting in an average flow rate of 638,441 lbm/hr and 3.92 MM STB - cumulative production of brine and steam. LTFT No. 2 is comprised of two separate flow periods being, 1) June 8 June 13, and 2) August 22 - November 14, and December 3 - December 5. Each period is separately discussed in the following subsections. LTFT No. 2 was designed to meet the objectives outlined in Attachment No. 1. These objectives were successfully achieved prior to the final shut-in on December 5, 1979.

Period 1 (June 8, - June 13, 1979)

The June 8 to June 13 portion of the LTFT No. 2 was terminated due to a master valve failure (MV-1). During the 5 days the well flowed the average rate was approximately 800,000 lbm/hr with total production of 276,000 STBF. Total fluid produced is based on rate calculations made using the wellhead pressure obtained during the failure and techniques developed and discussed in the Rate Prediction Section of this report. Figure No. 5 is a tabulation of wellhead pressure and wellhead temperature data collected during the valve failure from June 8 to commencement of shut-in operations on June 12. Due to the danger involved in obtaining the wellhead pressure and temperature this data is not very extensive.

Following is a day by day discussion of events that transpired during this period beginning with June 8, 1979. Prior to this, the pre-test checklist shown in Figure No. 6 was completed.

June 8, 1979

10:30 Completed pre-startup check list (Reference Figure No. 7). Opened MV-1 first, then MV-2 and had flow to CV-1 which was closed. A leak developed at the top chemical injector located between SV-1 and CV-1. The grease fitting on SV-1 was spraying brine water.

10:35 Shut well in by closing first MV-2 and then MV-1.

While the injector leak was being repaired by removing the injector & rewrapping with teflon tape, WKM was consulted by phone, about the grease fitting on SV-1. Mr. Sug Roberts of WKM's Denver office reported that it was normal for a small amount of leakage through the fitting and that it would seal itself off in a few hours.

12:05 Opened MV-1 & MV-2 and had flow to CV-1. A large amount of steam began coming out of the 13 3/8" - 9 5/8" annulus bleeddown line. A new leak developed around the top of the 2nd injector.

12:15 The well was shut in by closing MV-2 and MV-1. The maximum pressure & temperature recorded at the wellhead was 285 psig and 200°F.

Both chemical injectors were removed and retaped. Shortly after closing both master valves the steam from the 13 3/8" - 9 5/8" annulus bleeddown line decreased and stopped.

12:57 Opened MV-1 and MV-2 and loaded lines to CV-1. There was no sign of leakage around the injectors.

13:05 Opened CV-1 15% and had two phase flow to the pit.

13:25 Start positioning people for diverting flow from the pit and into the separator system.

13:33 A small leak developed around the bonnet on the bottom 10" master valve (MV-1). Before the well could be shut-in the leak increased substantially. There was a separation between the valve body and the bonnet. Also a small leak developed around the stem (Reference Figure No. 8, Photograph A). The valve failure was caused by expansion of water trapped in the valve body. The pressure pop-off valve had been left off the bottom master valve when the master valve was replaced after LTFT No. 1, and was not noticed it was missing.

13:35 A check was made to make sure that everyone was accounted for and safe.

13:40 Opened CV-1 to 100% open to decrease wellhead pressure from 460 psig to 410 psig. Also opened steam control (CV-4) halfway in preparation to use the separator system until the well can be shut-in and controlled. Opened water control valve (CV-6) in wash remotely by means of separator control unit.

13:45 While trying to open chemical test loop control valve (CV-2) it was noticed that the 10" line from the inner pit wall to the muffler was sticking straight up in the air above the pit wall.

13:55 Finally had CV-2 open, and the separator system in operation with no effort to control the separation of steam and brine.

The steam to the pit is discharging to atmosphere through the 10" line that extends through the pit wall (Reference Figure 8, Photograph B). The 40' section that ran from the inner pit wall to the muffler is laying off to the side. The pipe fitting union downstream of BCV-13 and the bonnet of CV-3 also developed small steam leaks. Reference Figure 8 for photographs of these leaks in Photographs C and D respectively.

14:00 The injecton line was checked for leaks with none found and the area was roped off and efforts to remove equipment were begun.

19:30 Installed cap on safety valve (SV-1) so the valve could not close. Wellhead pressure 410 psig and temperature 430°F. Moved office trailer to RHS well No. 3-1 location.

20:30 Dowell arrived on location and ready to start laying lines from pump truck to kill line. Wellhead pressure now 400 psig and temperature 430°F.

22:15 Dowell connected to kill line and valve at end of kill line (KV-3) open. This kill line was located directly in front of the damaged master valve bonnet and would have been useless if the bonnet had pulled out of the body.

June 9, 1979

07:35 Halliburton arrived on location with 1 pump truck and three 500 bbl. frac tanks. Started tearing down Dowell and rigging up Halliburton.

10:00 Water trucks started arriving with 9.99 lb/gal sodium chloride (NaCl).

10:30 Released Dowell to return to Cove Fort as Union Oil had allowed Dowell to standby until Halliburton was on location. Halliburton tied into kill line and KV-3 was opened.

11:30 Halliburton 500 bbl. frac tank was moved from RHS well No. 14-2 and set.

13:30 WKM personnel on location - Mr. Pete Diehl and Jeff Elwood. The opinion of Mr. Diehl was that the master valve failure was caused by expansion of water in the body of the valve. The failure could have been prevented by installation of a pop-off valve or after opening the valve completely, close it 1/4 to 1 turn to allow an expansion path from the body to the main flow channel.

19:00 WKM installed brace consisting of a 2 1/2' circular 1" piece of metal with a hole cut out of the middle. It was slipped over the stem and bolted around the master valve (Reference Figure No. 9, Photograph A).

20:00 Halliburton cement truck on location with 250 sx. Class B cement containing 40% silica flour, 1:1 perlite, 0.4% HR-12, 0.5% CFR-2 (2.32 ft/sx, 13.8 lb/gal, 10.9 gal/sx).

June 10, 1979

10:00 Wellhead pressure 400 psig.

11:00 Sug Roberts of WKM on location. Nowsco arrived on location and held on standby with 1" coiled tubing.

June 11, 1979

15:00 WKM installed 2nd brace on damaged master valve (Reference Figure No. 8, Photographs B and C).

23:00 Tried to begin closing CV-1 by turning hand wheel 1/4 turn every 10 minutes. Figure No. 10 is a tabulation of date, time, CV-1 position and WHP during kill operations.

23:50 Opened CV-1 back open. Had closed valve 10% of way. It was difficult to tell if leak around master valve was increasing. A decision was made to wait until morning when better safety control could be exercised.

June 12, 1979

10:00 Jim Tucker of Otis on location to determine if wellhead design could support a strip in unit and allow stripping in with tubing larger than Nowsco's 1". It was determined that the 3" valve on top of the tree could not support the weight of the unit.

12:00 Began closing CV-1 by turning handle on CV-1 1 1/2 turns every 10 minutes.

17:25 CV-1 66% closed; well left this way overnight with wellhead pressure 463 psig.

June 13, 1979

11:00 A safety meeting with Halliburton was held.

12:21 Pressure tested up to the 3" valve on top of wellhead with 500 psig.

12:24 Opened the 3" valve and started pumping $NaCl_2$ at 1/4 BPM @ 500 psig.

13:00 Closed CV-1 3% to 69% closed. Wellhead pressure 470 psig.

13:05	Closed CV-1 6% to 75% closed. Wellhead pressure remained at 470 psig.
13:10	Closed CV-1 3% to 78% closed. The wellhead pressure is still 470 psig.
13:15	CV-1 completely closed and wellhead pressure is still 470 psig.
13:17	Increase pump rate from 1/4 BPM to 1/2 BPM.
13:25	Increased pump rate to 1 BPM.
14:00	Increased pump rate to 1 1/2 BPM.
14:05	Increased rate to 2 BPM.
14:30	Increased rate to 3 BPM. Well flow starting to shut off.
14:35	Increased rate to 12 BPM. Well on vacuum. Photograph D of Figure No. 9 is a close up of the bonnet separator from the master valve's main body.
15:00	Pumping NaCl at 1 BPM while MV-1 wellhead bolts are being loosened in preparation to change MV-1.
16:00	Replaced MV-1 with another Master valve.
20:00	Released Halliburton. Total volumn NaCl pumped was 943 bbls.

Period 2 (August 22 - December 5, 1979)

RHS well No. 54-3 was opened on August 22 and flowed until November 14, when it was shut-in and then re-opened from December 3 to December 5, 1979. Attachment No. 2 is the procedure followed during the start-up and shut down operations from August 22 on. During these 88 days the well flowed for 81.8 days and the average flow rate was 630,303 lbm/hr with a cumulative production of 3.68 MM STBF and 3.31 MM STBW disposed into well No. 82-33. The average flowing wellhead pressure was 381 psi and average wellhead temperature was 420°F. Attachment No. 3 is a tabulation of the daily WHT, WHP, steam, water and total flow rates. Attachment No. 4 is a computer printout of the daily summation of the field data collected for this period and used in calculating the various flow rates and ratios. The curves of steam, water, and total flow rates, wellhead pressure and wellhead temperature are shown in Figure No. 11.

The steam rate was calculated using the flowing orifice meter equation for a 6" orifice plate in a 10" line with meter constants corresponding to a 1000 psi spring and 200" water column:[2]

$$Qs = C' (hwPf)^{1/2}$$

where

Qs	=	Steam Rate (lbm/hr)
C'	=	(Fb) (Fs) (Fr) (y) (Fa)
hw	=	differential pressure in inches of water
Pf	=	absolute static pressure (psia)
Fb	=	Orifice Factor (7579)
Fs	=	Steam Factor $[1.0618/(Pf\ V)^{1/2}]$
V	=	Specific volume steam, ft^3/lb
Fr	=	Reynold's number factor $[.0263/(hw\ Pf)^{1/2}] + 1$
Y	=	Expansion Factor (1)
Fa	=	Orifice thermal expansion Factor (1)

The water rates were calculated using the water measurements from the vortex meter due to the greater accuracy of a vortex meter versus the orifice meter (Reference Vortex Meter in the Surface Equipment Performance Section). The water rates were calculated using the following equation:

$$Qw = (Kv) (Rv)$$

where

Qw	=	Water rate in lbm/hr
Kv	=	Vortex Meter constant (12910)
Rv	=	Vortex reading

The total flow rate was calculated by summing the steam and water rate for the respective day. The steam ratio was calculated by dividing the steam rate by the total flow rate.

The decision was made to flow the well during December to accommodate a tour of Utah Power and Light representatives and various visiting dignitaries of the Amax, Thermal, O'Brien Unit partners as well as other geothermal industry representatives. The well was opened on December 3 and flowed until December 5. The well was flowed for 48 hrs. and averaged 567,421 lbm/hr and produced 78,304 STB of fluid with 72,397 STBW reinjected into RHS well No. 82-33. The well was subsequently shut-in and the wellhead filled with diesel.

The majority of LTFT No. 2 went very smoothly with only a few minor problems. The general equipment performance has been dealt with separately in this report. The only significant events that affected the test were valve setting changes and the associated changes in the flow rates. From August 22 to October 1 the two phase flow control valve (CV-1) was periodically opened farther to maintain the wellhead pressure in range between 410 - 420 psig. The original setting for CV-1 was 66% open and by September 14 the valve was completely open and BCV-1 was opened to maintain the desired WHP. After October 1 when scale inhibitor injection began, both valves, CV-1 and BCV-1 were opened as far as possible to allow the flow rate to increase near the 750,000 lbm/hr exhibited in the beginning of the test. From October 1 to the end of the test, decreases in flow rate are associated with downhole scaling as the inhibitor injected into the two phase system was very instrumental in controlling surface scale and is discussed in the Scaling Section of this report.

The average steam ratio was 8.82% for the August 22 to November 11, 1979. During the last few days of the test, November 12, 13, and 14, the steam control valve was opened to increase the ratio of steam to total flow and to allow for maximum steam production. The steam increased from 51,356 lbm/hr on 11-11-79 to 64,423, 69,947 and 71,115 lbm/hr from the 12th to 14th respectively.

The limiting factor in obtaining these steam rates was the steam orifice plate, as the steam differential pressure was approaching a reading of 10 on a L-10 chart. These high steam rates resulted in an average steam ratio of 11.6% with a high of 16.5% reached during periods when the L-10 chart read 10. Similarly during December 2-5, 1979 the maximum steam ratio was 16.5% on several occasions.

The steam quality or dryness ranged between 92% and 93% during the August 22 to December 5, 1979 portion of LTFT No. 2. The quality was calculated using the equation below.

$$x = \frac{h - h_1}{h_2}$$

where

x = steam quality

h = enthalpy (BTU/lbm) @ atmospheric pressure

h_1 = enthalpy (BTU/lbm) liquid in equilibrium with vapor @ separator pressure & Tc

h_2 = enthalpy (BTU/lbm) due to change by evaporation @ separator pressure & Tc

Tc = calorimeter temperature

The calorimeter temperature was measured with the same calorimeter used during LTFT No. 1. The calorimeter temperature ranged between 195 and 202°F with 200°F being the average. The average atmospheric pressure was 14.28 psi. The separator pressures fell into the following pressure averages 350, 325, 300 and 210 psig.

OBSERVATION WELLS

During the LTFT No. 2 while RHS well No. 54-3 was being flow tested, RHS well No's 13-10, 3-1, 12-35 and 25-15 as well as Getty's well 52-21 were equipped with subsurface pressure chambers (SPC) connected to Heise gauges and used to monitor subsurface pressure. All the wells except 12-35 and 52-21 were equipped with surface measuring gauges (ie. Heise gauges). During the test the drawdown (Attachment No. 5) data was collected and buildup data is still being collected (Attachment No. 6). There was no builup data collected between June 25 and August 21.

Subsurface Pressure Chambers

The subsurface chambers used have been called bottom-hole pressure chambers in the past, and this nomenclature is incorrect as these devices were not located at the bottom of the well. They were hung anywhere from 1200 to 1460 feet from the surface during LTFT No. 1. Figure No. 12 is a drawing of the subsurface chambers built under the supervision of Dale Javine in the Bartlesville Research Center. The subsurface pressure chambers are lowered into the hole by means of a motor driven pully system that is connected to a nitrogen chamber which purges the system and keeps the 3/32 stainless steel tubing full of nitrogen as it is lowered into the well. The wells, depending on the surface pressure, are equipped with a high pressure lubricator or a low pressure connection. The depths the SPC were hung for each of the well during LTFT No. 1 are as follows:

12-35:	1180'
25-15:	1460'
13-10:	1460'
3-1 :	1460'

In May, 1979 the Getty well was equipped with a SPC @ 1553' and the other observation wells were still equipped with SPC set at the above depths. Prior to the August 22 start-up, leaks developed in the stainless steel tubing in RHS wells No. 12-35 and 13-10. The SPC were pulled and checked during the first week in August and rehung in the wells at the following depths during the remainder of the LTFT No. 2 and are still in the wells:

12-35:	850'
25-15:	1460'
52-21:	1300'
13-10:	1300'
3-1 :	1460'

In addition to the above referenced wells, RHS well No. 82-33 was equipped in May 1979 with 2,000 feet of 3/32 stainless steel tubing and a SPC which was used to measure the pressure as the water was disposed into well 82-33. While RHS well No. 54-3 was being flowed, drawdown data was obtained from the observation well and buildup data collected while RHS well No. 54-3 was shut-in.

Drawdown and Buildup - LTFT No. 2

The Getty well, No. 52-21, did show a drop of 32.5 psi and there is strong evidence that this well could be in the reservoir system as there was similar pressure response (33.3) with RHS well No. 12-35. As of January 20, 1980 the buildup data has been collected and the pressures are building back up.

Figures No. 13-17 are individual well curves containing plots of drawdown, buildup and changes in pressure from June 8 to December 31, 1979. This pressure data will be entered into the reservoir model which was developed by the Research Center and the model will be rerun. Mr. John Baza of this office will perform this work and a report will be issued when the model runs have been completed and an analysis is available.

SURFACE EQUIPMENT PERFORMANCE

The performance of the surface equipment was generally acceptable. This section will discuss the major components/or systems that played a major part in LTFT No. 2.

Vortex Meter

The vortex meter was used for evaluation purposes during the LTFT No. 2. The meter used was an Eastek vortex model No. 2320. It consisted of a three inch wafer made out of 316 stainless steel with a flow element also constructed of 316 stainless steel. It operated off a 115 volt power and supplied a direct read out in percentage of the total water flow to RHS well No. 82-33 in lbm/hr and an accumulation of the total barrels produced. The meter itelf was located in the Negro Mag wash upstream of the 6 inch Fisher valve used to control the water flow. A signal was transmitted from the meter to the flow converter which was located in a meter box next to the separator by a shielded 3 conductor cable. This meter box also housed the separator controls. The flow converter contained the percentage read out in lbm/hr and bbl. accumulator. Based on a comparison of the flows calculated by the vortex and the orifice meter, a percentage difference of 2.5% was observed during the flow test. The equations used for calculating water flow through the 7" orifice plate in a 10" line are as follows:

$$Qw = C' \; hw$$

where

Qw = Water rate lbm/hr
hw = differential pressure in inches of water
C' = (Fb) (K)
Fb = Orifice factor (11394)
K = constant to change to 7.67#/gal. water to lbm/hr (10.84)

A comparison of the water flow calculation is contained in Attachment No. 7 and Figure No. 18 is a graph of each meter's flow rate. It is felt that the vortex meter operated very favorably during the LTFT No. 2 and that its accuracy is greater than that of an orifice meter ($\pm$ .5% vs. $\pm$ 3%). Only once during the test, on September 26, 1979 did the vortex meter fail to function for a few hours. It is possible that a piece of scale was laying across the wafer element. However after a few hours the meter returned to normal operation and this was the only problem encountered.

During a failure of the generators, one of the fuses was blown on the vortex meter and there were no spare fuses of the proper size on location and a larger one was installed while the proper size was received from Salt Lake. During this waiting period another power failure on September 20 by the generator occurred causing the vortex fuse to blow again. However it did not blow in time and the flow counter, total barrels per day, was inoperative from this date on.

Separator Control System

The separator control system consisted of two controls, water level and steam pressure. Both components of the system worked exceptionally well, total recovery time after a drastic change in separator level was between 3 and 5 minutes.

The water level control consisted of a 6" Fisher Type 8500 Eccentric disc control valve (CV-6) with a Fisher Type 3516 rotary pneumatic valve positioner and a Fisher TL101 Process Controller. The water control valve (Reference Figure No. 4) was located in the 10" water line in the bottom of Negro Mag Wash approximately 1/4 mile from the separator. Supply air to drive the pneumatic positioner was furnished by a 1/4 hp. electric air compressor located in the wash. The positioner was set to fail open on an interruption of air or electrical signal from the process controller. The process controller was located next to the separator and was connected to the separator water level indicator by a shielded 2 conductor cable and the valve positioner in the wash also connected to the processor by a shielded 2 conductor cable. The controller had two operating positions, auto and manual. When in manual the valve could be opened or closed from the well site independently of the level in the separator. When in auto, the controller opened and closed the valve as the level in the separator varied in relation to the set point selected by the operator. During the June 8 to June 13, 1979 portion of the LTFT No. 2 the controller was not in operation. The controller was set for a 55% water level in the water portion of the separator during the remainder of LTFT No. 2 from August 22 to December 5.

The steam pressure was controlled by a 8" Fisher cage valve and a pneumatic positioner. The control for the positioner was a Fisher Wizard. Air supply to the wizard and positioner on the steam valve was supplied by an electric air compressor located in a trailer on the well site. The steam pressure was not controlled during the June portion of the test and was varied during the remainder of LTFT No. 2. The static pressure as recorded by the steam orifice meter is an accurate record of the steam pressure settings. The steam pressure setting from August 22 to October 1 was 325 psig and 300 psig from October 1 to November 12, 1979. The settings were varied between 175 and 300 psig from November 12 to the 14 in an effort to monitor the effects of the separator system on the total flow rate.

The valve position was pneumatic fail open type if the air supply was interrupted. As the steam flow rate increased the steam line pressure would increase causing the wizard to send a pneumatic signal that would open the valve. Similarly as the steam rate decreased, the valve would close. The positioner was equipped with a hand wheel for manual operation. This hand wheel had a variable mechanical stop which allowed for an override control on the pneumatic fail open. During the flow test, the mechanical stop was set so if the valve failed open, it would only open a distance equal to approximately a 25 psig decrease in steam pressure.

During the LTFT No. 2 the upsets or changes in separator levels of the separator were of two types. The first could be classified as manual upsets caused by changing control setting and the second as well caused changes in total flow. The manual upsets occurred during interruptions of the electrical system when generators were changed, JPL coming on line and decreasing the flow rate to the disposal system, and changes in the steam pressure setting. Well-caused changes were slugging and decreased flow caused by scaling. Well slugging was not a problem and was only slightly noticeable during startup and the associated wellbore storage effects that accompany startups. Rate decreases caused by scaling occurred throughout the test.

Orifice Meters

Orifice meters were used to measure steam, water and two phase flow during LTFT No. 2. The meters operated satisfactorily with no major problems encountered. For this flow test the general connections from the meter to the flange taps were changed and a different chemical was used in the condensing chambers. These changes allowed for easier daily operations and greater accuracy.

All three meters were bellows type, two being Barton, and one an American Singer. After reviewing a Barton technical manual it was determined all three meters were piped incorrectly for dry gas measurement during LTFT NO. 1 and were repiped as shown in Figure No. 19. In addition to the fact that the piping of the meter to the condensing chambers was wrong, the flange taps were 90° out of phase. Accurate steam measurement requirements call for the taps to be located at either 3 or 9 o'clock when looking at a cross sectional view. Because the flange taps were at 12 o'clock, solving the problems required mounting the condensing chambers above the meter run with the bellows mounted above the meter run but below the condensing chambers.

Also changed was the line size connecting the flange taps to the condensing chamber. During LTFT No. 1, 1/4" copper flex hoses were used. Requirements for accurate measurement of hot water and steam call for 1/2" diameter connections, thus 1/2" teflon flexible hoses were used throughout LTFT No. 2.

The chemical used in the condensing chambers during the LTFT No. 2 was dibutyl phthalate as opposed to ethylene glycol during LTFT No. 1. When ethylene glycol is used the condensation forming in the condensing chamber would be diluted, thus every 3 or 4 days the fluid was changed for accurate measurements. The dibutyl phthalate was never diluted by condensation during the LTFT No. 2, and thus never needed changing.

The meter used to measure the two phase flow was a Barton meter using a 1000 lb. spring and a bellows calibrated for a 25 lb. change. The steam flow was measured with an American meter and the water with a Barton. Both meters used to measure the water and steam were equipped with a 1000 lb. spring and a bellows calibrated to 200" water column. All three meters were calibrated by Stabro Labs of Salt Lake City, Utah in May, 1979. The orifice plates and line sizes used were: two phase - 12" line and 8 1/2" plate; water 10" line with a 7" plate and steam - 12" line with a 7 1/2" plate from June 8 to 13 and 6" plate from August 22 until December 5, 1979.

WKM Safety Valve

The WKM 10 inch safety valve (SV-1) was in complete operation during the LTFT No. 2 and was operative at the end of the flow test. Only one minor problem occurred with the safety valve and that occurred at the end of the test when we were making preparation to open RHS well No. 54-3 on December 3. The valve was sticking a little bit and when a hammer was used on the side of the valve body, it freed the sticking portion and the valve operated normally.

After LTFT No. 1 the valve was locked in the open position with the lockout cap, causing the piston to hold down the closing spring and gate. Prior to starting RHS well No. 54-3 for the LTFT No. 2 the 10 inch valve was checked in May by WKM and it was found that the valve would not close. The valve was sent to Kilgore, Texas to be repaired and it took WKM approximately two weeks to repair the valve. WKM had to tear the valve completely apart, and replace seats, seals, springs and clean scale deposits out of the body. These scale deposits were holding the spring in the depressed position. The valve was returned and installed and the well was operated beginning June 8 through December 5 with the safety valve in service.

The valve operates on the principle of nitrogen being supplied to the valve and this nitrogen causes the piston to hold the gate open. Upon removal of the nitrogen supply the valve will shut-in the well in approximately 30 seconds as the depressed spring forces the gate to close across the flow channel. The valve can be operated manually from a distance of seventy five feet from the wellhead at the control panel. The control panel consisted of an open knob and an emergency shut-in knob. The open knob when pulled out supplies nitrogen to the 10 inch safety valve which depresses the piston and opens the gate. This open knob could be locked open while the nitrogen supply was opening the valve. This lock out was not used during LTFT No. 2.

Under normal operations pulling the emergency shut-in knob would remove the nitrogen supply from the piston and allow the depressed spring to close the gate even if the open knob is locked open. However, this was not the case during LTFT No. 1, as during the check out portion of LTFT No. 2 in June it was discovered that the emergency shut down system would not operate when the "open" knob was locked open. The system was reconnected so that it worked in the proper function. There were two other ways of shutting in the well by use of the 10 inch safety valve, both of which are automatic if the "open" knob is not locked in the open position. One was on high pressure, the other on low pressure. These two functins operated off a sensing system which was located just downstream of SV-1. If the pressure increased above 500 psig, the valve would close. By the same token if the pressure fell below 200 psig, the well would close. This actually happened during the last days of testing on November 13, 1979. While varying the controls on the separator the pressure was decreased in the two-phase flow system below 200 psig and the low pressure sensing system did function and close the valve. It was corrected by raising the pressure back above the 200 psig and the valve continued its normal operation.

When the test was completed, the valve was closed and left in the closed position. Sometime before actaul selection of the equipment for the development phase of the Roosevelt Hot Springs Unit the 10 inch safety valve should be checked to determine if scale deposits occurred across the spring causing the sticking problems as exhibited during the December startup portion of the LTFT No. 2. If this is the case, efforts should be made to find another type of valve that will operate without being affected by scale or it should be made certain that the injection of scale inhibitor is upstream of the safety valve so that scale deposits can be eliminated or kept to a minimum.

Fluid Piping System

The piping system used to transport the produced fluids from the wellhead of RHS well No. 54-3 to the separator, disposal well and pit is discussed in this section. The piping discussion will be broken into the following areas: two-phase flow, steam flow, and water flow. Reference Figure No. 4 for a drawing of the system used from June 8 to June 13 and Figure 20 for the system used from August 22 to December 5.

The two-phase flow section of the piping consists mainly of flanged twelve inch pipe, which runs from the wellhead to the inlet of the separator. This section of piping was unflanged after LTFT No. 2 and was sand blasted on the inside for removal of scale in May 1979. This piping remained basically the same from LTFT No. 1 with the exception of a ten inch scale loop that was fabricated and connected by flanges to ten inch valves and is discussed and shown in the drawings associated with the Scaling Section of this report.

The main control valve, CV-1, used in the LTFT No. 2 was a 6 inch Fisher Type 8500 Eccentric disk control and equipped with a hand wheel. During the LTFT No. 1 an 8 inch cage valve was used as CV-1 and at the termination of the first test this valve was removed from the system. The stem was cut off and the cage was removed and sent to Bartlesville. Before LTFT No. 2 was conducted, this 8 inch valve was salvaged and the 6 inch Fisher valve was installed. Based on the flow characteristics of an eccentric disk valve vs. a gate valve a 6 inch valve was adequate to allow flow of 1.5 MM lbm/hr of fluid so there was no need to go to a larger 8 or 10 inch eccentric disk valve. By increasing the valve size the allowable pressure drop across the valve would have been reduced and it would have been impossible to use the valve to shut the well in.

The 12 inch valve at the bottom of the inlet to the separator CV-3 was opened and inspected prior to the commencement of the LTFT No. 2 and it was discovered that the dog guides on the gate of the valve needed repairing and also the stem was broken just above the dog. The gate and the stem were taken to Del Mar Construction, Milford, Utah and were repaired there at a machine shop by drilling a hole into the stainless steel stem and fastening the dog with a screw and then welding with a stainless steel rod the dog to the stem. The dog guides on the gate were repaired. The valve was left in the open position during LTFT No. 2 with instructions given that under no circumstances was the valve to be used in the closed position, it was strictly used as a spacer.

The second area of the piping system consisted of the run from the separator to the disposal well, approximately 1.4 miles of welded 10 inch pipe. This pipe was flanged off the separator and at the dispoal well 82-33. The thermal expansion loops made use of flanged barco joints. This section of piping remained the same from LTFT No. 1. The only work that was required to be performed before starting LTFT No. 2 was to install the barco joints at the top of the wash. These joints had been removed for inspection at the end of LTFT No. 1. Also, the meter run was moved from 82-33 to the wash and the vortex meter and 6" eccentric disc were installed.

The third and final area of the piping system is the steam portion that runs from the separator to the pit including the piping in the pit that connects to the muffler. This section is completely flanged with the exception of piping in the pit from the dike to the muffler. During LTFT No. 1, and the June flow portion of LTFT No. 2, the 10" line connecting the muffler to the 10" line through the dike was welded. After the valve failure in June this connection was changed to 10" flanges. The steam valve (CV-4) is an 8 inch Fisher gate valve and is discussed in the separator control section. Originally this valve was located at RHS well No. 82-33 during LTFT No. 1 to allow back pressure to be held against the separator system to eliminate water hammering. With the new separator level control system water hammering was not a problem so the valve was reinstalled as the steam control valve. The valve that was used originally as the steam control valve in LTFT No. 1 was a 10" gate valve and was used in the 10 inch scale loop section during LTFT No. 2.

After the June failure of the master valve (MV-1) Phillips Petroleum's E & S Group performed a field inspection of the system and ran a computer model for stress analysis on the system. Two weak stress points were found and corrected prior to the August 22 startup. The weak points were the piping angles associated with the 2 Ø flow bypass to the pit and the steam line. The bypass line was rerouted and a 10 inch loop was built between the steam valves and the pit wall to allow for expansion of the steam piping. The bypass valves that were constructed during the LTFT No. 1 around CV-4 were not utilized at all during LTFT No. 2.

Safety Inspections

During the work that was performed in 1979 on the Roosevelt Hot Springs Unit various safety inspections were performed by Phillips personnel and outside inspection groups. These safety inspections consisted of the vessel inspection, an ultrasonic acoustic pipe inspection, x-rays taken of the pipe and welds and a vibration and noise inspection.

The first inspection performed was by Mr. Bennie Barker of Phillips Petroleum, Denver, Colorado office with the NRG Safety section. The vessel was laid down by use of the crane, Mr. Barker inspected both the inside and the outside of the vessel and found no problems which would affect the flow test being planned. This inspection was conducted during April 10 and 11, 1979 and a copy of his report is included in Attachment No. 8.

After the failure of the master valve during June it was expressed by Mr. John Whitmire of Energy Minerals in Bartlesville that our piping should be inspected. The piping was inspected by Mr. Larry Ross also of the NRG Safety Section located in Denver, Colorado. He performed an ultrasonic inspection measuring wall thicknesses and weld thickness between the wellhead and the separator. These welds were found to be within the specifications of the Engineering Services of Phillips Petroleum and the piping was also within allowable wall thicknesses. This inspection was completed on June 26, 1979 and the results are contained in Attachment No. 9.

In July at the request of Mr. William Berge of this office, an x-ray inspection was performed by MSI, Inc. of Salt Lake City. The various welds between the separator and the wellhead, the separator and the muffler, and between the separator and the disposal well were tested. A total of twenty welds were selected and of these twenty, eighteen passed with no problem. Two welds were found to have slag in them and these were buffed out and re-welded prior to the commencement of the LTFT No. 2 August to December portion. The results of this inspection are filed in the Salt Lake City Roosevelt Field files.

On the final day of the November test, November 14, 1979, Mr. Dale Viers and Mr. Eark Hicks of Engineering & Services, Bartlesville, Phillips Petroleum visited the site to make a vibration and noise inspection. There was very little vibration throughout the test or witnessed during the visit. Mr. Viers commented in a letter (Reference Attachment No. 10) that dampeners with springs could be utilized to negate any type of vibration. The noise inspection conducted by Mr. Hicks found that while some of the high DB levels (Reference Attachment No. 11) associated with the steam valve CV-4 and the steam expansion loop were above the limits for long term exposure for the human ear, these noise levels could be decreased by use of trim valves and dampeners located in the piping. It was Mr. Hicks' opinion that there would be no problem meeting the federal requirements for noise levels associated with development of the field.

Muffler

As discussed in the detailed day to day events of the June portion of LTFT No. 2, the muffler used during LTFT No. 1 had become defective and was not connected to the piping that ran from the pit wall to the muffler. Consequently prior to opening the well on August 22, a 36 inch diameter, 20 feet in length piece of culvert pipe was cemented into the ground with a hole cut in the side and a 10 inch pipe from the steam system run tangentially into the culvert pipe (Reference Figure 21). This muffler did nothing to alleviate the noise level and was quite loud. It was evident within a few hours after the well was opened that the muffler would not last long as it began to shake and lean to one side. Finally on Sunday, November 27, the muffler was completely laying on its side.

A new muffler had been fabricated in the field and was ready to be installed (Reference Figure No. 22). The well was shut-in, the muffler was moved in and located in place and set on 2 H-braces. Due to the desire to shut the well in for only a short time interval, the muffler was installed with a slight slope to the southwest, however this presented no problem. The muffler did effectively reduce the sound of the steam venting to the atmosphere and worked very well.

In Mr. Hicks' letter (Reference Attachment No. 11) concerning the noise inspection he indicated that commercial mufflers are available and these commercial mufflers will be checked out for possible use in the event that steam and water has to be vented to the atmosphere during the commercialization of Roosevelt or if there are any other future tests in which a separator system is to be used.

SCALE INHIBITOR TESTING EVALUATION

The scale inhibitor testing was conducted during the August 22 and November 14, 1979 period of the LTFT No. 2 under the direction of Dr. Robert G. Asperger. The testing consisted of evaluating five chemical scale inhibitors and solving the various problems associated with field testing. Four of the inhibitors handled 20 ppm of calcium satisfactorily. Dr. Asperger's report on "Surface Equipment Antiscale Experiments at Roosevelt 54-3"; RGA-6-79 is included in this report as Attachment No. 12.

While the actual testing of the scale inhibitors by R & D personnel R. G. Asperger and C. D. Javine occurred between August 27, 1979 and October 29, 1979, the testing was divided into two inhibitor injection periods being 1) injection into 2" test loop and 2) injection into the 2Ø flow (Reference Figure No. 24 for a drawing of the scale injection system).

Period one, from August 27 to October 1, 1979, was comprised mostly of C. D. Javine modifying designs for 1) methods for injecting scale inhibitor, 2) the 2" test loop, and 3) screens for collecting scale samples in the 10" 2Ø flow test loop. Dr. Asperger and C. D. Javine began testing the inhibitors by injecting the inhibitor into the 2" line and making visual inspections of a 1/2" orifice plate and monitoring two Heise gauges to obtain a pressure drop across the orifice plate due to scaling.

During the testing, small flow rates of 20,000 lbm/hr were tapped off the main 2Ø flow line by use of the 2" line. Calcium chloride was injected into the 2" line by means of a pulsating pump to cause scaling. Once scaling was observed by visual inspection or a change in the pressure drop across the 1/2" orifice, the scale inhibitor was injected by means of a pulsing pump. Both injectors for the calcium chloride and the scale inhibitor were located 3' from the orifice plate. Dr. Asperger has plotted the concentrations of scaling inhibitor required to control specific concentrations of calcium and these are contained in his referenced report.

Period two was a continuation of period one with the major difference being the point of scale inhibitor injection. The scale injector was moved from the 2" line to the 2Ø line between SV-1 and CV-1. On October 1, 1979 scale inhibitor was injected into the well's total mass flow. A 20,000 lbm/hr flow was still tapped off with the 2" line and injected with calcium chloride and testing of the inhibitor continued as described before.

During the period from October 1 to October 7 the wellhead pressure that had previously been increasing with scale buildup in the surface equipment remained constant. The decline in flow rates and wellhead pressures after October 7 are an indication of downhole scaling.

The long term observation of the effectiveness of the scale inhibitors tested was also evident on a short term observation. Some of the tests performed by Dr. Asperger and Mr. Javine required discontinuation of inhibitor injection into the total flow for 4 to 6 hours. During this time interval the wellhead pressure would increase 1 to 2 psig. Consequently, the method used to verify that the inhibitor pump was functioning properly was to watch for increases in wellhead pressure.

The scale inhibitor was mixed with fresh water during the majority of the test. During one three-day period in late October, brine water was mixed with one inhibitor and the scaling test was duplicated with no noticeable difference. The inhibitors are highly acidic but tests did indicate that the inhibitor could be neutralized without compromising effectiveness.

BRINE CHEMISTRY AND NONCONDENSABLE GAS

Produced water from RHS well No. 54-3 was sampled on 16 separate days during LTFT No. 2 and a brine chemistry analysis was performed. The samples were collected by Messrs. S. Johnson and G. Chadburn and Mrs. K. Farrow of the Salt Lake City office. Stu Johnson has reviewed the analysis, and indicated there was no change in brine chemistry from previous analysis. A report covering the brine chemistry of Roosevelt Hot Springs will be issued at a later date by Mr. Johnson.

The noncondensable gas (NC) content of steam was measured between 0.581 ± 0.101 and $0.609 \pm 0.069\%$ (weight basis) to total flow. Dr. John P. Walters (R & D) and Stu Johnson made these calculations using two methods developed by them for measuring the noncondensable gas content of steam during the August 22 to November 14, 1979 portion of LTFT No. 2

A trip report dated November 5, 1979 by John P. Walters (Reference Attachment No. 13) discussed the NC work along with H_2S content of NC, sampling program design, and analytical results (brine, steam and NC).

TRACER STUDY OF BRINE DISPOSAL

The tracer study performed by Teledyne Isotopes of Westwood, New Jersey was inconclusive. Six hundred pounds of sodium iodide were injected into RHS well No. 82-33 in May and four observation points were monitored for determining water movement in and around the RHS unit. Each point was sampled daily during LTFT No. 2 and one sample from each week was sent to Teledyne for analysis. Attachment No. 14 is the final report furnished by Teledyne.

Teledyne's report makes reference that there were only 73 samples taken, and this is in error as samples were taken daily at RHS well No. 54-3, Negro Mag Seep, Observation Hole No. 4, and Observation Hole No. 5. Mr. Andrew Carmichael of Teledyne agreed prior to the study that one sample per week from each sampling point would be sufficient and when any abnormalities showed up, the samples taken before and after would be analyzed.

Mr. Stu Johnson (SLC office) suggested that the potassium or sodium level of the samples taken be checked and the ratio of iodine to these other elements be plotted. This suggestion was relayed to Mr. Carmichael and no reply to this suggestion has been received to date. The samples collected before and after the high iodine concentration will be sent to Teledyne for this ratio comparison.

the separator. Terra Tek was well prepared and posed absolutely no problems during their four days on location from September 11 to September 14 1979. Their report has been written and the information provided has no effect on our noncondensables as the system they were trying to test was based on knowing the exact composition of the noncondensables.

FIELD OPERATIONS

Field operations at Roosevelt Hot Springs pose many problems due to the location of the field being in rural southwestern Utah. There is no choice of roustabout crews, trucking lines or major equipment suppliers and this dictates a "make do" situation.

Field supervision for the majority of the work performed in the RHS Unit during 1979 was by Mr. Terry S. Allen of the Salt Lake City office. Mr. C. D. Javine (Bartlesville), and Mr. John Baza (Salt Lake City) helped supervise field operations during the August 22 to November 14 portion of LTFT No. 2 with Mr. Ott Rolls (Salt Lake City) supervising the kill operation of RHS well No. 54-3 in June. Mr. Lee Peiffer, a former Phillips employee, acted as field supervisor for four days in November.

The roustabout and welding work was performed by AAA Welding of Milford, Utah. While the majority of the work was acceptable, the cost and time required to accomplish the job was beyond normal limits. Flint Engineering of Vernal, Utah was contacted and visited RHS during LTFT No. 2 and indicated that in the future arrangements could be made for them to furnish crews from Vernal on short term bases. Flint Engineering would be willing to locate an office in Milford when RHS is developed and field work would be on a continual basis.

Mr. Robert Puffer of Milford contracted with Phillips to read meters, gauges, collect water samples for the tracer survey and any other work Phillips required during LTFT No. 2. While there were small problems with some of the readings taken by Mr. Puffer's men, the majority of the services provided were excellent. The painting of the site for the December visit of dignitaries was performed by Mr. Puffer contracting with a local sand blaster (Cedar City) and painter (Milford) and charging Phillips' cost only. This was a definite departure from past experience with local contract help who would charge cost plus 15 to 25%.

Gaskets, flange bolts, and other normal oil field equipment was purchased in Salt Lake City and shipped by truck or bus line to Beaver or Milford. In some instances, special trips were made by Phillips Salt Lake City personnel to Milford to deliver equipment.

INJECTIVITY STEP-RATE TESTING

Between the June 13 shut-in and the August 22 commencement of the LTFT No. 2 injectivity step-rate (ISR) tests were run at Roosevelt Hot Springs. This testing program was designed to measure the rates and pressures associated with various wells in an attempt to establish a precedent for predicting injection into the reservoir during future design considerations prior to commercialization of RHS. The test consisted of pumping fresh water into the wellhead at various pre-determined rates for a pre-determined pumping time and monitoring the pressure. After the pre-determined pumping time had been reached, the rate would be changed and pumping continued for the predetermined pumping time. These changes or steps in rate would continue until the pressure became too high or the rate reached 60 BMP. An alternative to the rate steps is to use pre-determined pressures and let the rate fluctuate as a function of pressure.

The initial testing procedure, (Reference Attachment No. 15), called for starting rates at one half barrel and preceding to one, two, three, four and five barrels with each rate pumped for 10 minutes. During each step the pressure would be monitored and recorded. Once five barrels had been pumped for ten minutes, the rate was to be increased to twenty BPM and and increased in ten barrel increments from 20 BPM to 60 BPM with pumping time of five minutes for each pump rate. It was anticipated that a maximum of 60 BPM would be reached and once this rate had been pumped for five minutes the test would be terminated.

The lines were pressure tested to make sure that they would withstand anything up to 2,000 psig, as this was the limit based on burst rating of casing downhole. The 1/2 to 5 BPM in 10 minute increment was chosen to make sure that cold water was past the casing shoe prior to the large pump rates being started on the surface. The Western Company was used and supplied five Western pace setter 1000 HHP frac trucks, and a blender, which was used to supercharge the water to the frac trucks. Two five hundred barrel tanks were set on location and filled with fresh water and two water trucks holding one hundred barrels of fresh water were also connected to the system.

In all, seven wells were tested, the Phillips' wells being RHS well No's. 82-33, 12-35, 13-10, 25-15, and 54-3. In addition, Getty's well 52-21 and Thermal Power's well 14-2 were also tested. The results of the pump tests are contained in Attachment No's 16 to 22.

The first well tested was RHS well No. 82-33. There was no wellhead equipped at the surface, and the only surface pressure measuring device was the one located in Western's monitoring panel which recorded rates and pressures. The well started out taking 16 2/3 BPM at 0 psi and dropped off to 5 BPM, still at 0 psi. After 18 minutes of pumping, the rate was 17 BPM at 0 psi. After 28 minutes, the rate was 39 BPM with 100 psi. The final pumping point was 62 BPM at 400 psi. The well was on vacuum at the surface during the early portion of the test.

The second well tested was RHS well No. 12-35 on August 2, 1979. This well performed more as anticipated as the first pumping point was 1.5 BPM with the last being 56.33 BPM. Pressure varied form 4 to 850 psig respectively.

The third well tested was RHS well No. 13-10. This well also performed as expected with the first pumping rate being .4 BPM and the last one being 62 BPM at 575 psi.

On August 3, RHS well No. 25-15 was tested and the rates obtained on this well started out at .8 BPM and proceeded to 20 BPM when the well's surface gauge was shut-in at 560 psig reading and the pressure gauges in Western's panel monitor were used during the remainder of this test. The final pumping point was 62 BPM at 750. There is a change in slope on this well which indicates that there are two producing fracture zones and this accounts for the little pressure change between the rate increases of 20 to 62 BPM.

On August 4, RHS well No. 54-3 was injected into with varying rates from 1 to 62 BPM. Pressure change was from 24 psig to 340 psig at 62 BPM. At 10 BPM the well was in essence on vacuum due to the thermal conductivity of the well. At 20 BPM, the pressure was 35 psig and increased to the maximum of 340 psig.

Also on August 4 Getty's well RHS No. 52-21 was tested. This well demonstrated itself as very tight as the maximum rate obtained was 45 BPM at a pressure of 840 psig. At 20 BPM, the pressure was 27 psi and as the rate was increased toward 30 BPM, the pressure increased to 688 psi and the rate dropped off to 16 BPM. The rate was then stepped up after five minutes to 25 BPM and the pressure was 735 psig. The rate was then stepped up in 10 barrels of water increments to a maximum of 45 BPM.

The last well tested was Thermal's RHS well No. 14-2. This well also demonstrated the double fracture zone that was seen in 25-15. As the rates were increased from .5 to 58 BPM, the pressure increased from 109 to 345 psig with an actual pressure decrease in the range of .5 BPM to the five BPM. Plotting the last slopes of the 10, 20, 30, 40, 50 and 58 BPM, it is seen that there are two different slopes.

RATE PREDICTIONS

Analyzing the data that was gathered during the LTFT No. 2 and making use of the Denver Research Institute's (DRI) Handbook[3] for calculating two-phase flow, various rate predictions have been generated for use in predicting well performance of the Roosevelt Hot Springs field. The rate predictions have been adapted from various flow measurements taken during the LTFT No. 2 and used to calculate rate predictions for wells during commercialization of RHS.

During the beginning of the August portion of the LTFT No. 2 wellhead pressures (WHP) were obtained for various flow rates as the well was brought on line. As the flow rate increased the WHP decreased. These measurments were compared to the WHP calculated using the DRI data and are shown in Figure No. 27 as the WHP versus flow rate for a clean wellbore for RHS well No. 54-3. Also plotted on this graph are the calculated WHP versus flow rates for RHS wells No. 13-10 and 25-15.

A curve for predicting cumulative production versus WHP for RHS well No. 54-3 can be generated by drawing a straight line from any point A represented by a WHP for a given rate at 0 cumulative production through a point B located at 4.61 MM reservoir barrels (RB) at 425°F cumulative production and 290 psig (Reference Figure No. 28). The 4.61 MM RB at 290 psig was the cumulative production and pressure on December 5 when the rate was 640,000 lbm/hr while the pressure should have been 445 psig. This approach has limitations as during early time production the WHP versus cumulative production will be above the straight line. Similarly during the late stages of production, wellbore scaling will cause the WHP versus cumulative production to fall below the straight line. Additional information is needed to write an equation that will characterize the flow pattern of the well.

Using RHS well No. 54-3 as an example, a WHP of 400 is calculated for a 800,000 lbm/hr flow rate in a clean well. The DRI data indicates that once 200 psig WHP is reached, the flow rate will start decreasing. Following the 200 psig line to the intersection of the line previously drawn between points A and B cumulative production of 8.7 MM BBL is found. Dividing this by 55,000 bbl/day (equals 800,000 lbm/hr) yields 157 days of production at 800,000 lbm/hr.

Based on the results witnessed during the last month of production during LTFT No. 2, it was estimated that every day the rate was dropping by 5,000 lbm/hr while the WHP change was approximately 2 1/2 psi. If the system can support 150 psig to the plant, then there will be a 50 psi difference from the WHP that will maintain 800,000 lbm/hr while the well drops off in production before shut-in is required due to no deliverability to the plant. This figures out to approximately 20 days of production from the time the well cannot sustain a constant flow rate of 800,000 lbm/hr and drops off to 700,000 lbm/hr when it reaches 150 psi. Adding the 157 days of production at 800,000 lbm/hr to the 20 days of decreasing flow, a total production time of 177 days is forecasted for RHS well No. 54-3 at

800,000 lbm/hr. Using this method the following production rates were calculated for the existing wells to be used during the 20 megawatt plant development of RHS.

54-3	800,000 lbm/hr	25-15	400,000 lbm/hr
72-16	800,000 lbm/hr	14-2	500,000 lbm/hr
13-10	600,000 lbm/hr	New well	700,000 lbm/hr

Terry S. Allen

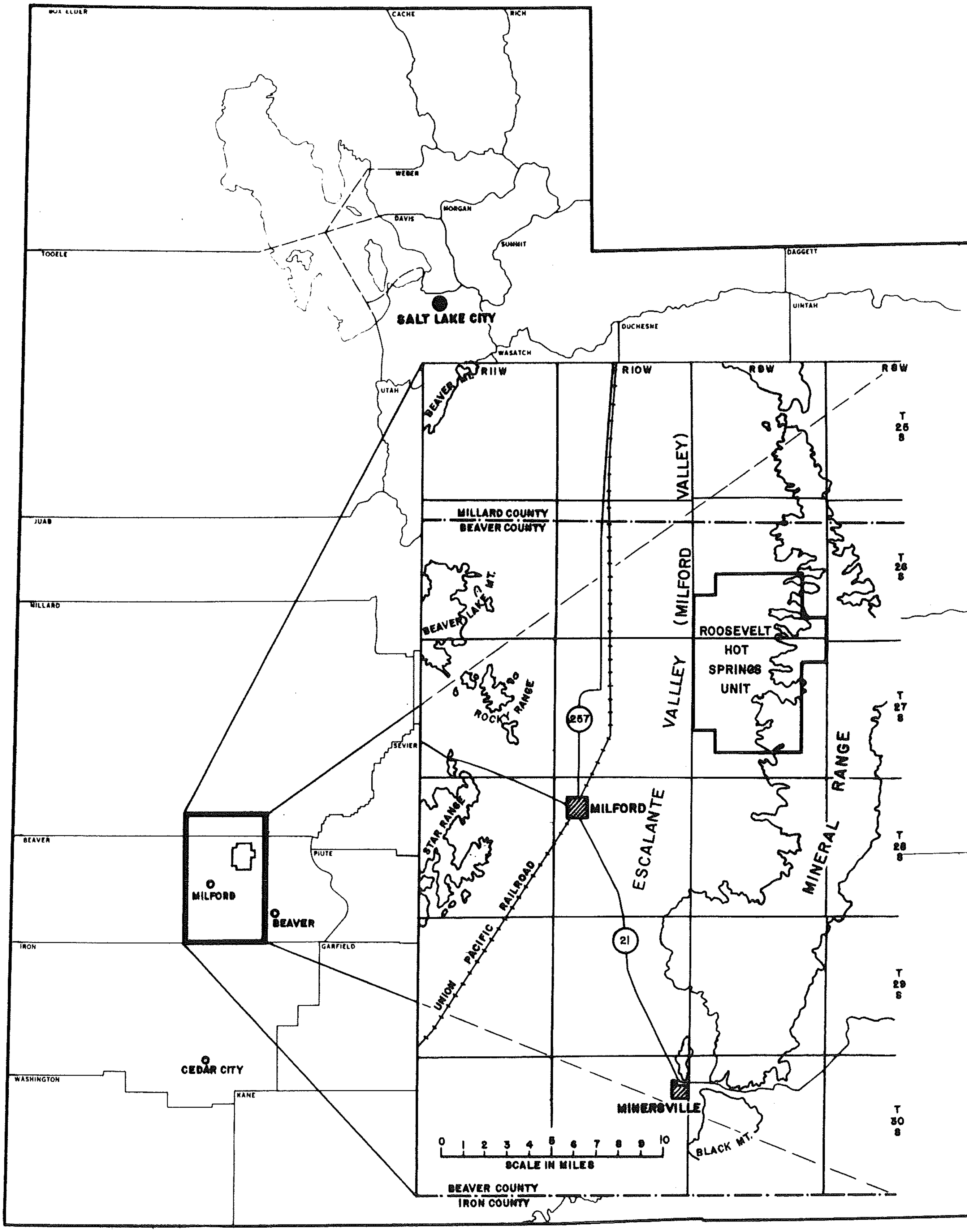
Terry S. Allen
Associate Geothermal Engineer

REFERENCES

1. Lenzer, R. C., Forrest, R. J., Johnson, S. D., and McChesney, D. E. 1979, An Evaluation of Roosevelt Hot Springs Geothermal Reservoir Beaver County, Utah: Volume II, Reservoir Description.

2. Beck, V. C. 1969, Orifice Meter Constants Handbook E-2: Gas, Air, Steam, Oil & Water.

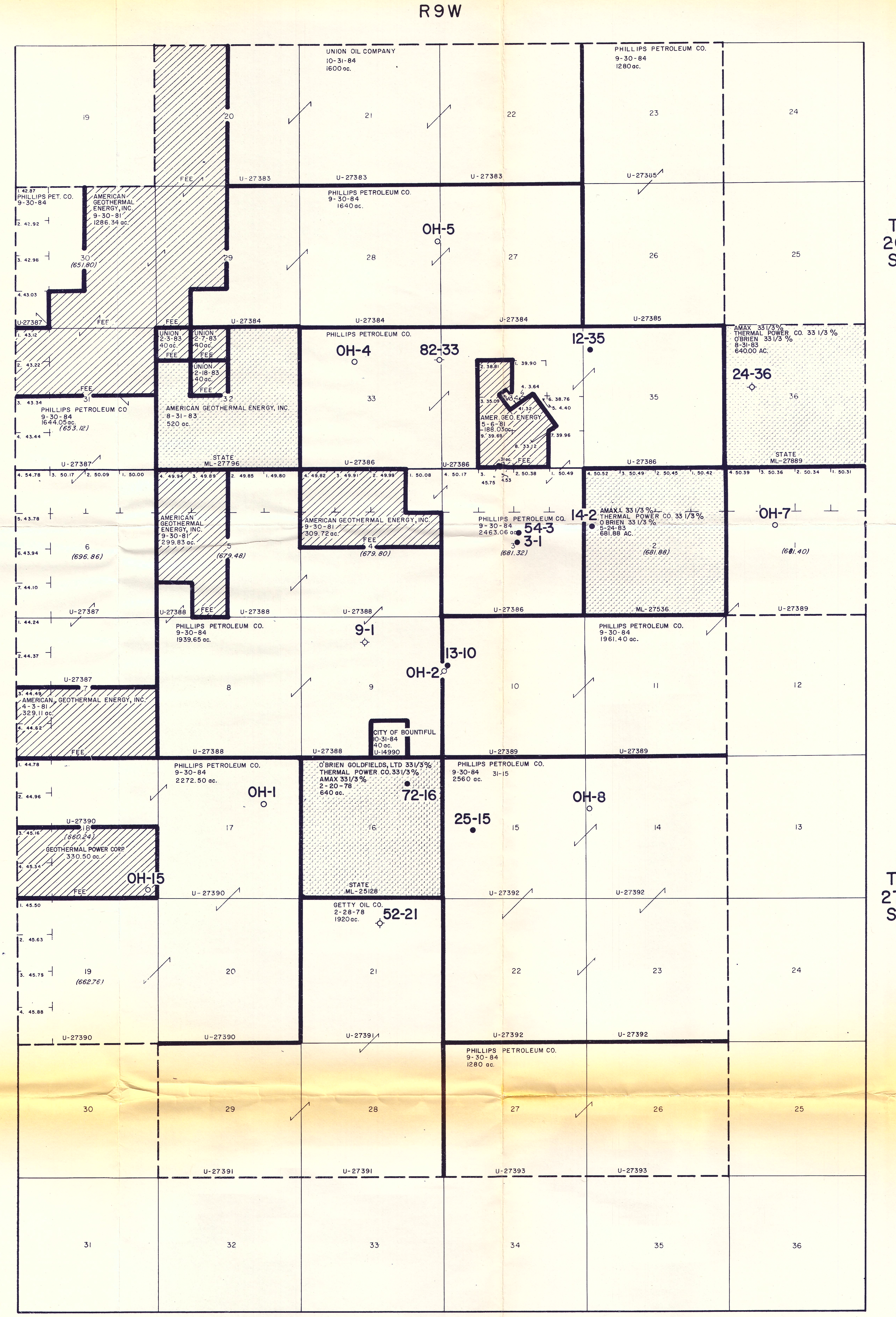
3. Denver Research Institute and Coury and Assoc., 1979, Geothermal Well Design Handbook: Comment Issue.



ROOSEVELT HOT SPRINGS UNIT
LOCATION MAP
BEAVER COUNTY, UTAH

FIGURE 1

A00033-2of4



- - - - UNIT OUTLINE

FEE LANDS — 2,863.53 Ac. - 11.04%

STATE LANDS — 2,481.88 Ac. - 9.56 %

FEDERAL LANDS — 20,600.97 Ac. - 79.40%

25,946.38 total acres

○ OBSERVATION WELL

● PRODUCTION WELL

SERVICE WELL Inj., disp., etc.)

PLUGGED & ABANDONED

DRY HOLE

COMPANY	LEASED ACRES		% OF UNIT
AMAX	653.96	STATE	2.52 % (% figures are approx.)
AMERICAN	520.	STATE	2.00
	2393.2	FEE	9.22
	2913.2	total	11.22
CITY OF BOUNTIFUL			
	40.	FED.	.15
GETTY	1920.	FED.	7.40
O'BRIEN	653.96	STATE	2.52
PHILLIPS	17040.97	FED.	65.68
THERMAL	653.96	STATE	2.52
UNION	1600.	FED.	6.17
	120.	FEE	.46
	1720.	total	6.63
GEOTHERMAL POWER CORP.	330.5	FEE	1.27

REVISIONS	
T.L. GRIFFIN	12-6-77
D. L. OLSON	12-15-78
D. L. OLSON	3-8-79

PHILLIPS PETROLEUM COMPANY
GEOTHERMAL OPERATIONS
431 SOUTH 300 EAST SALT LAKE CITY, UTAH 84111

ROOSEVELT HOT SPRINGS UNIT
UNIT MAP
BEAVER COUNTY, UTAH

0 2000 4000 6000 FT.
SCALE

GEOLOGIST		DATE	
DRAFTSMAN		DATE	
REVISED	D. L. OLSON	DATE	MARCH, 1979

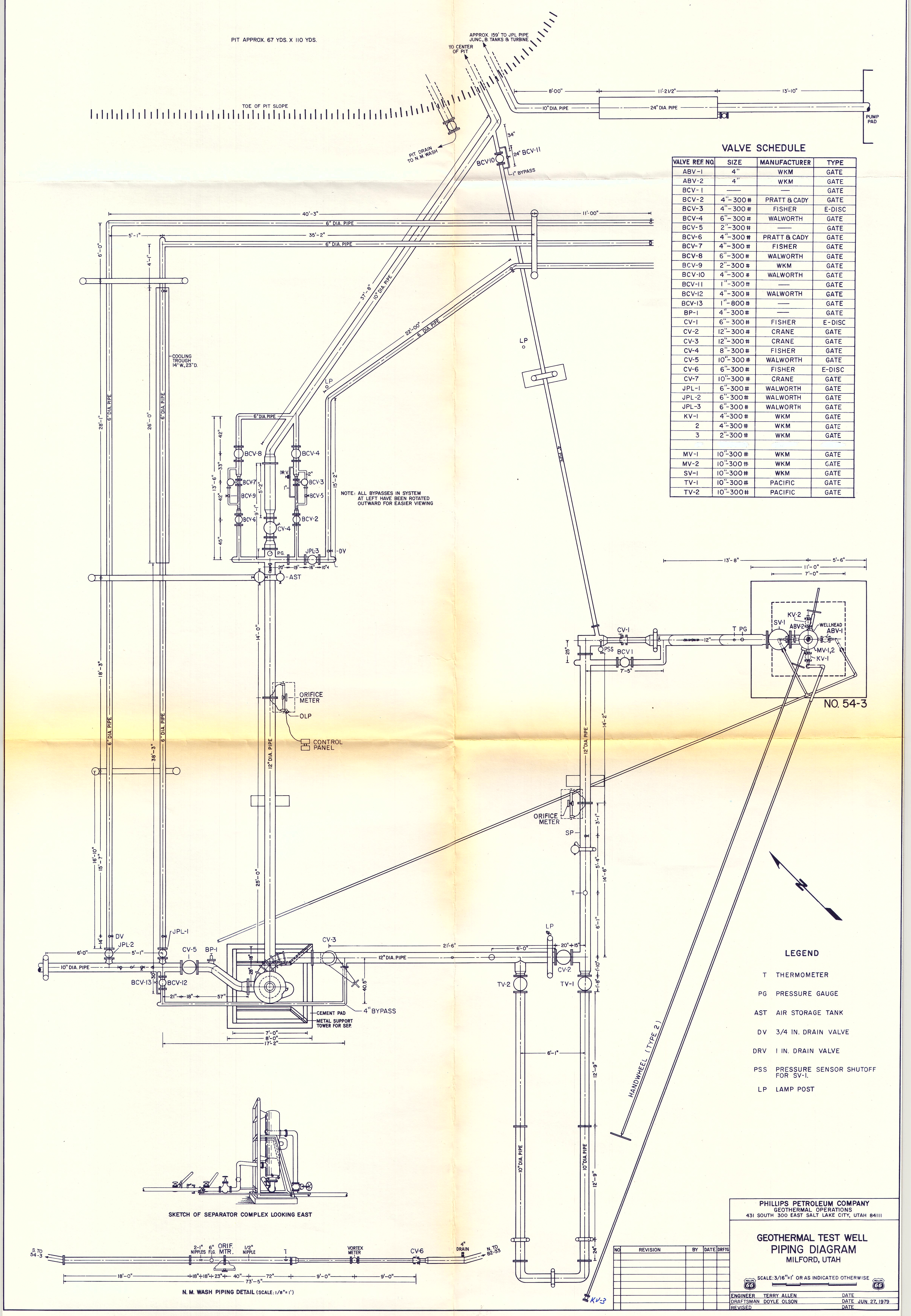
FIGURE 2

FIGURE NO. 3

RHS Flow Test History
Geothermal Performance Test
Roosevelt Hot Springs Unit, Beaver Co., UT

WELL NAME	OPERATION	DATE TEST COMM.	FLOW TIME (Days)	RATE (lbm/hr)	CUM. PROD. STBF	CUM. INJ. into 82-33 STBW
3-1	P.P.Co.	5/23/75	.13	600,000	5,175	0
54-3	"	8/26/75	1.02	795,000	55,952	0
54-3	"	10/9/75	2.0	722,600	99,718	0
54-3	"	12/12/76	3.65	688,000	173,273	0
12-35	"	4/12/76	NR	NR	NR	0
54-3	"	4/23/76	NR	NR	NR	0
13-10	"	4/23/76	.097	784,528	5,250	0
13-10	"	9/23/76	2	816,000	112,608	0
14-2	T.P.	11/24/76	2	491,000	67,758	0
54-3	P.P.Co.	10/7/77	237	275,178	4,500,000	3,800,000
72-16	T.P.	4/77	.917	1,300,000	82,225	0
54-3	P.P.Co.	6/8/79	5	800,000	276,000	238,600
54-3	"	8/22/79	81.8	630,303	3,557,556	3,240,023
54-3	"	12/3/79	2	567,421	78,304	72,397
TOTAL					8,970,170	7,351,020

A00033-3of4



VALVE SCHEDULE

VALVE REF. NO.	SIZE	MANUFACTURER	TYPE
ABV-1	4"	WKM	GATE
ABV-2	4"	WKM	GATE
BCV-1	——	——	GATE
BCV-2	4"-300#	PRATT & CADY	GATE
BCV-3	4"-300#	FISHER	E-DISC
BCV-4	6"-300#	WALWORTH	GATE
BCV-5	2"-300#	——	GATE
BCV-6	4"-300#	PRATT & CADY	GATE
BCV-7	4"-300#	FISHER	GATE
BCV-8	6"-300#	WALWORTH	GATE
BCV-9	2"-300#	WKM	GATE
BCV-10	4"-300#	WALWORTH	GATE
BCV-11	1"-300#	——	GATE
BCV-12	4"-300#	WALWORTH	GATE
BCV-13	1"-800#	——	GATE
BP-1	4"-300#	——	GATE
CV-1	6"-300#	FISHER	E-DISC
CV-2	12"-300#	CRANE	GATE
CV-3	12"-300#	CRANE	GATE
CV-4	8"-300#	FISHER	GATE
CV-5	10"-300#	WALWORTH	GATE
CV-6	6"-300#	FISHER	E-DISC
CV-7	10"-300#	CRANE	GATE
JPL-1	6"-300#	WALWORTH	GATE
JPL-2	6"-300#	WALWORTH	GATE
JPL-3	6"-300#	WALWORTH	GATE
KV-1	4"-300#	WKM	GATE
2	4"-300#	WKM	GATE
3	2"-300#	WKM	GATE
MV-1	10"-300#	WKM	GATE
MV-2	10"-300#	WKM	GATE
SV-1	10"-300#	WKM	GATE
TV-1	10"-300#	PACIFIC	GATE
TV-2	10"-300#	PACIFIC	GATE

LEGEND

T	THERMOMETER
PG	PRESSURE GAUGE
AST	AIR STORAGE TANK
DV	3/4 IN. DRAIN VALVE
DRV	1 IN. DRAIN VALVE
PSS	PRESSURE SENSOR SHUTOFF FOR SV-1.
LP	LAMP POST

NO	REVISION	BY	DATE	DRFTG

PHILLIPS PETROLEUM COMPANY
GEOTHERMAL OPERATIONS
431 SOUTH 300 EAST SALT LAKE CITY, UTAH 84111

GEOTHERMAL TEST WELL
PIPING DIAGRAM
MILFORD, UTAH

SCALE: 3/16"=1' OR AS INDICATED OTHERWISE

ENGINEER TERRY ALLEN DATE
DRAFTSMAN DOYLE OLSON DATE JUN. 27, 1979
REVISED DATE

FIGURE 4

FIGURE NO. 5

RHS Well No. 54-3 WHP & WHT June 8 - 13, 1979
Geothermal Performance Report
Roosevelt Hot Springs Unit, Beaver Co., Utah

DATE	TIME	WHP PSIG	WHT °F
6/8	1035	150	-
6/8	1215	285	200
	1340	460	440
	1930	410	430
6/9	2035	400	430
	2130	400	430
	0100	400	430
	0310	400	430
	0610	400	430
	1030	400	430
	1330	400	430
	2000	400	430
6/10	1030	400	430
	1500	400	430
	200	400	430
6/11	1200	400	430
6/12	1000	400	430

FIGURE NO. 6

RHS Well No. 54-3 LTFT No. 2 Pre-Test Check List
Geothermal Performance Report
Roosevelt Hot Springs Unit, Beaver County, Utah

Prior to Day of Startup

1) Hammer Up All Flange Bolts

2) Hammer Up All Bolts on Valve Bonnets

3) Pressure Test Line

4) Check Generators

5) Check Air Compressor

6) Check Electrical Lines & Connections

7) Check Steam Line for Obstructions

8) Check Vortex Connections

9) Check Separator Control Instruments

10) Check Kill Line

11) Connect Handwheels

12) Plug Unused Valves

FIGURE NO. 7

RHS Well No. 54-3 LTFT No. 2 Pre-Startup Check List
Geothermal Performance Report
Roosevelt Hot Springs Unit, Beaver County, Utah

Day of Startup

1) Open Valves between 13 3/8" & 9 5/8" Csg in Cellar

2) Close 12" (CV-2) & 10" (TCV-1 & 2) Valves in Total Flow Line

3) Open Valves in Steam (CV-4) & Water Lines (CV-7)

4) Close All Bypass Lines Except Bypass to Pit

5) Start Generator & Compressor

6) Open 82-33 (Master Valve)

7) Make Sure 6" Valve (CV-6) in Wash Is Closed

8) Close 6" Valve (CV-1) in 2 Phase Flow to Separator

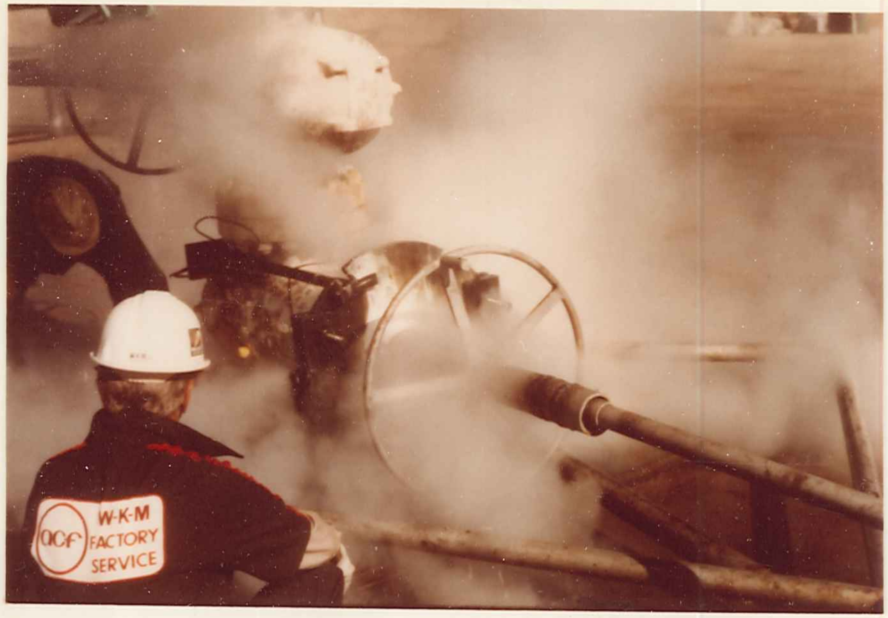
A. MASTER VALVE (MV-1)
LEAKS AROUND BONNET AND STEM.

B. STEAM DISCHARGE INSIDE PIT.

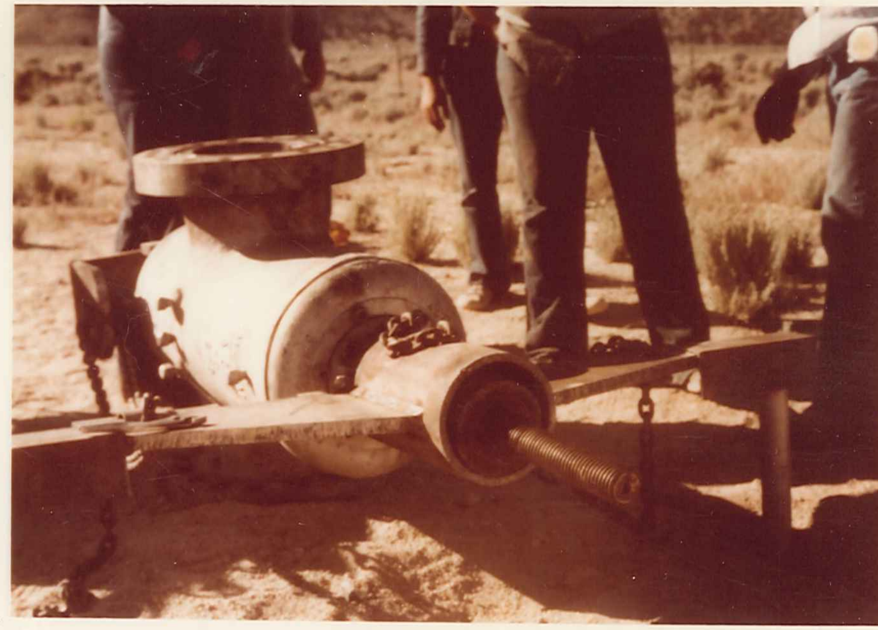
C. BYPASS VALVE (BPV-13)
LEAK AROUND UNION DOWNSTREAM BPV-13.

D. SEPARATOR CONTROL VALVE (CV-3)
LEAK AROUND BONNET.

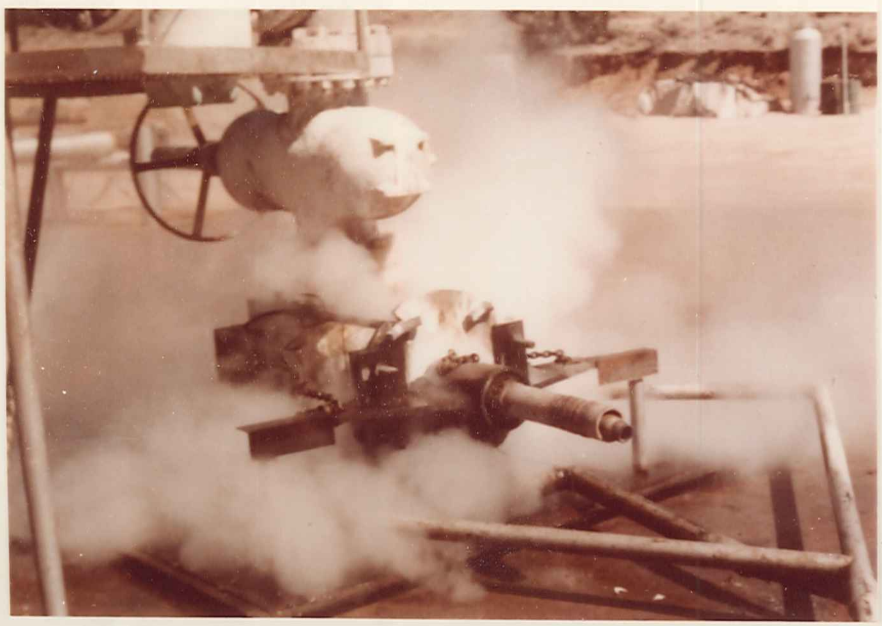
FIGURE NO. 8



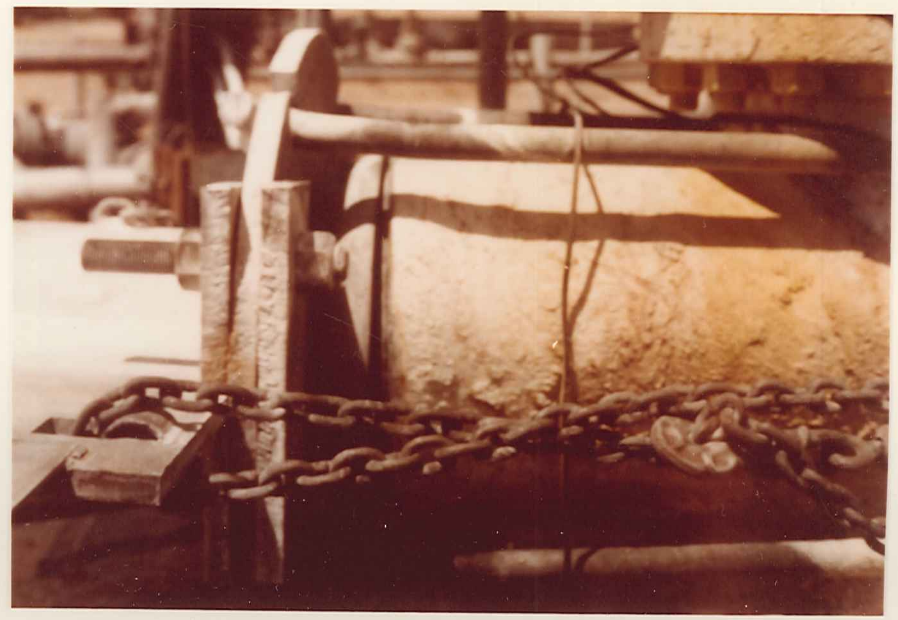
A. SAFETY BRACE NO. 1 INSTALLED ON MV-1.



B. SAFETY BRACE NO. 2.



C. SAFETY BRACE NO'S 1 AND 2 INSTALLED ON MV-1.



D. MV-1 GAP BETWEEN BONNET AND BODY.

FIGURE NO. 9

FIGURE NO. 10

RHS Well No. 54-3 WHP During Kill Operations
Geothermal Performance Report
Roosevelt Hot Springs, Beaver County, Utah

DATE	TIME	PERCENT CV-1 CLOSED	WHP
6/11	2255	0	400
	2300	1 1/2	410
	2310	3	410
	2320	4 1/2	408
	2330	6	410
	2340	7 1/2	410
	2350	0	400
6/12	1155	0	400
	1200	3	415
	1210	6	412
	1220	9	412
	1230	12	412
	1240	15	412
	1250	18	413
	1300	21	416
	1310	24	420
	1320	27	423
	1330	30	428
	1340	33	432
	1400	36	436
	1410	39	439
	1420	42	443
	1430	45	446
	1530	48	449
	1540	51	452
	1550	54	454
	1600	57	457
	1610	60	460
	1710	63	462
	1725	66	463
6/13	1300	69	470
	1305	75	470
	1310	78	470
	1315	100	470

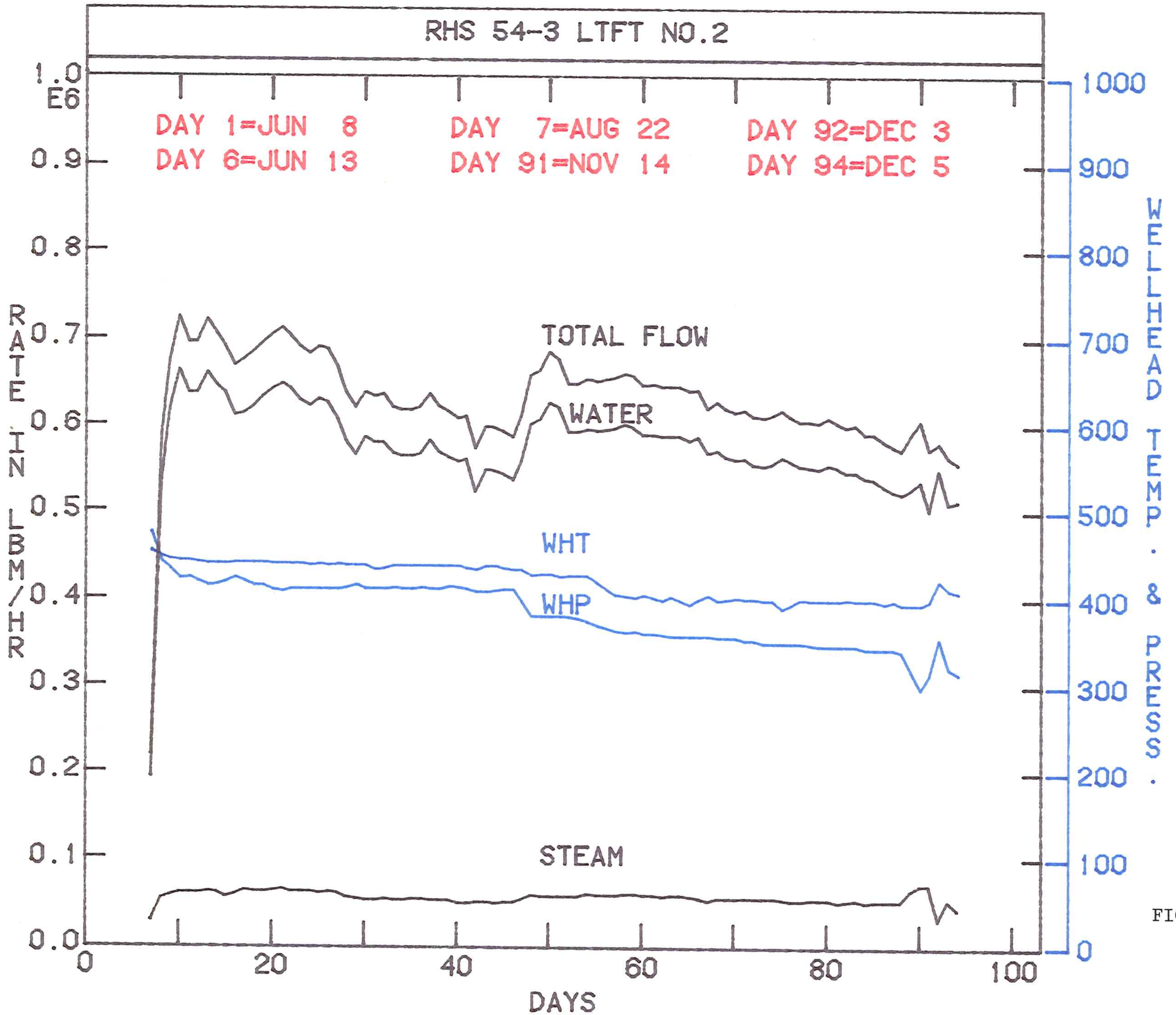
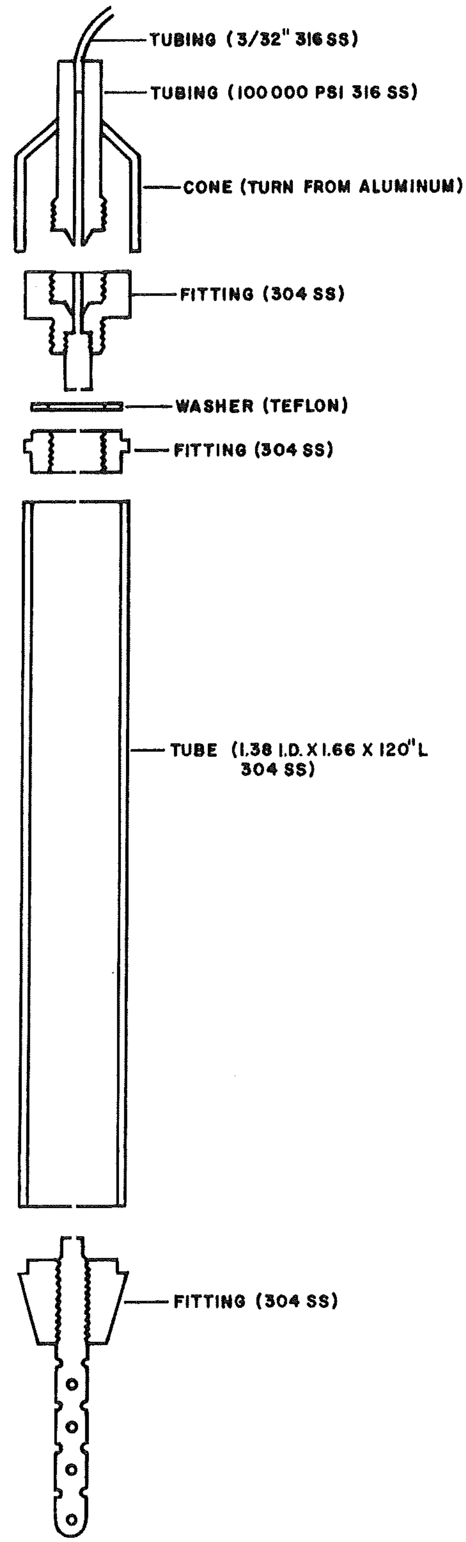

RHS 54-3 LTFT NO.2
DAY 1=JUN 8
DAY 6=JUN 13
DAY 7=AUG 22
DAY 91=NOV 14
DAY 92=DEC 3
DAY 94=DEC 5
TOTAL FLOW
WATER
WHT
WHP
STEAM
RATE IN LBM/HR
1.0 E6
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
WELLHEAD TEMP. & PRESS.
1000
900
800
700
600
500
400
300
200
100
0
DAYS
0
20
40
60
80
100

FIGURE NO. 11

FIGURE 12

SUBSURFACE PRESSURE CHAMBER

GEOTHERMAL PERFORMANCE REPORT
ROOSEVELT HOT SPRINGS
BEAVER COUNTY, UTAH



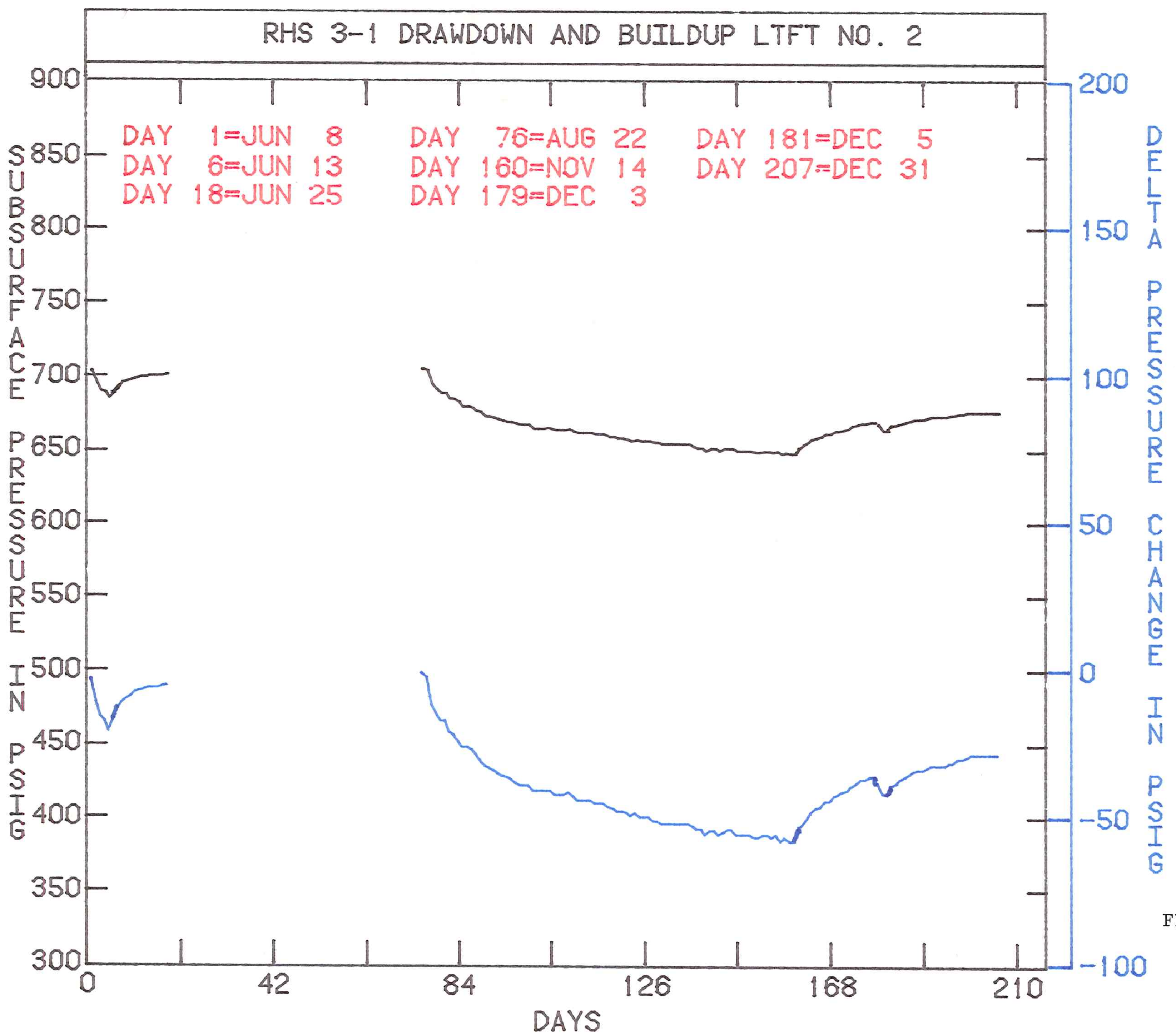
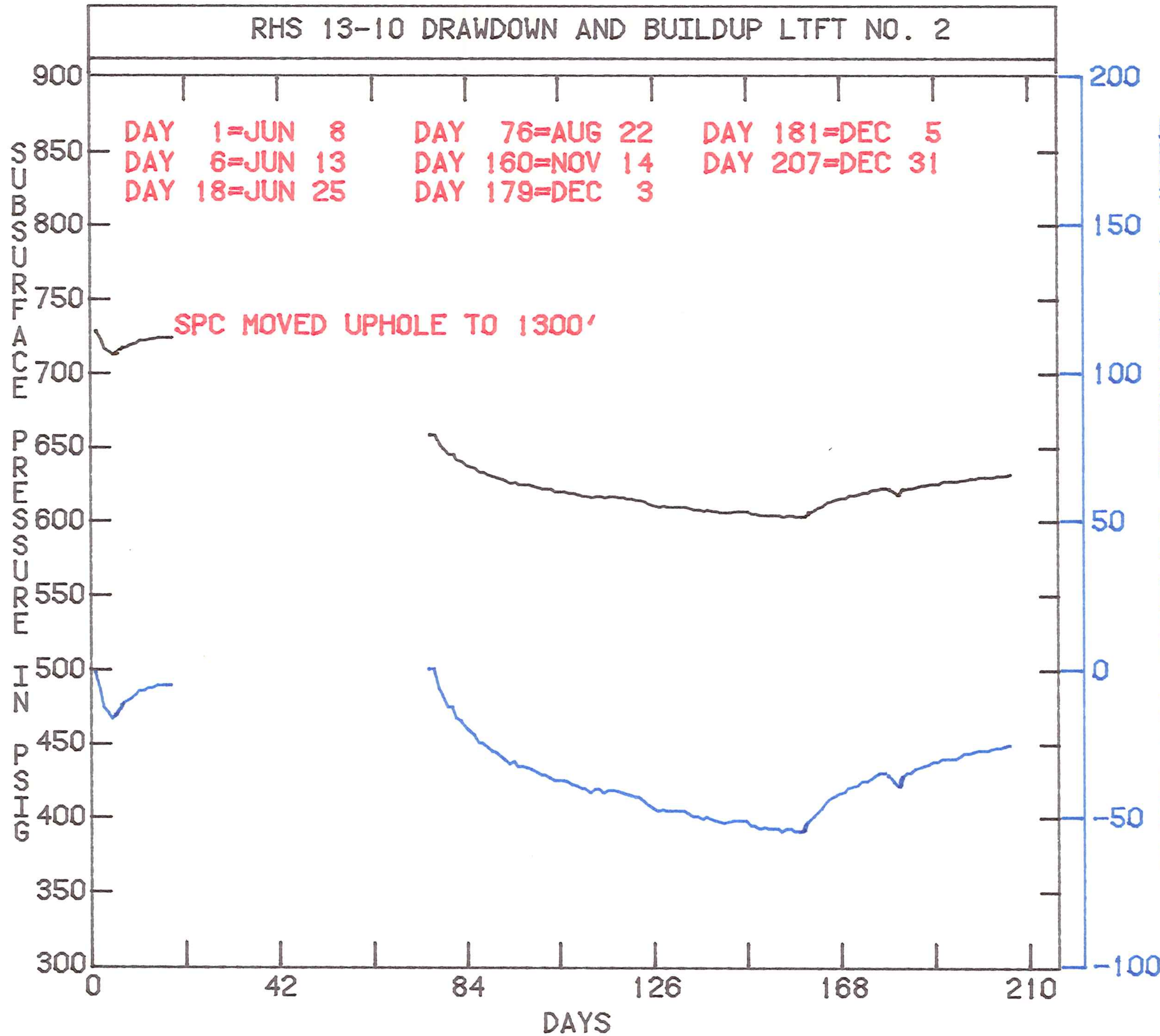

RHS 3-1 DRAWDOWN AND BUILDUP LTFT NO. 2
DAY 1=JUN 8
DAY 6=JUN 13
DAY 18=JUN 25
DAY 76=AUG 22
DAY 160=NOV 14
DAY 179=DEC 3
DAY 181=DEC 5
DAY 207=DEC 31
SUBSURFACE PRESSURE IN PSIG
900
850
800
750
700
650
600
550
500
450
400
350
300
DELTA PRESSURE CHANGE IN PSIG
200
150
100
50
0
-50
-100
0
42
84
126
168
210
DAYS

FIGURE NO. 13



RHS 13-10 DRAWDOWN AND BUILDUP LTFT NO. 2
DAY 1=JUN 8
DAY 6=JUN 13
DAY 18=JUN 25
DAY 76=AUG 22
DAY 160=NOV 14
DAY 179=DEC 3
DAY 181=DEC 5
DAY 207=DEC 31
SPC MOVED UPHOLE TO 1300'
SUBSURFACE PRESSURE IN PSIG
DELTA PRESSURE CHANGE IN PSIG
DAYS
0
42
84
126
168
210
900
850
800
750
700
650
600
550
500
450
400
350
300
200
150
100
50
0
-50
-100

FIGURE NO. 14

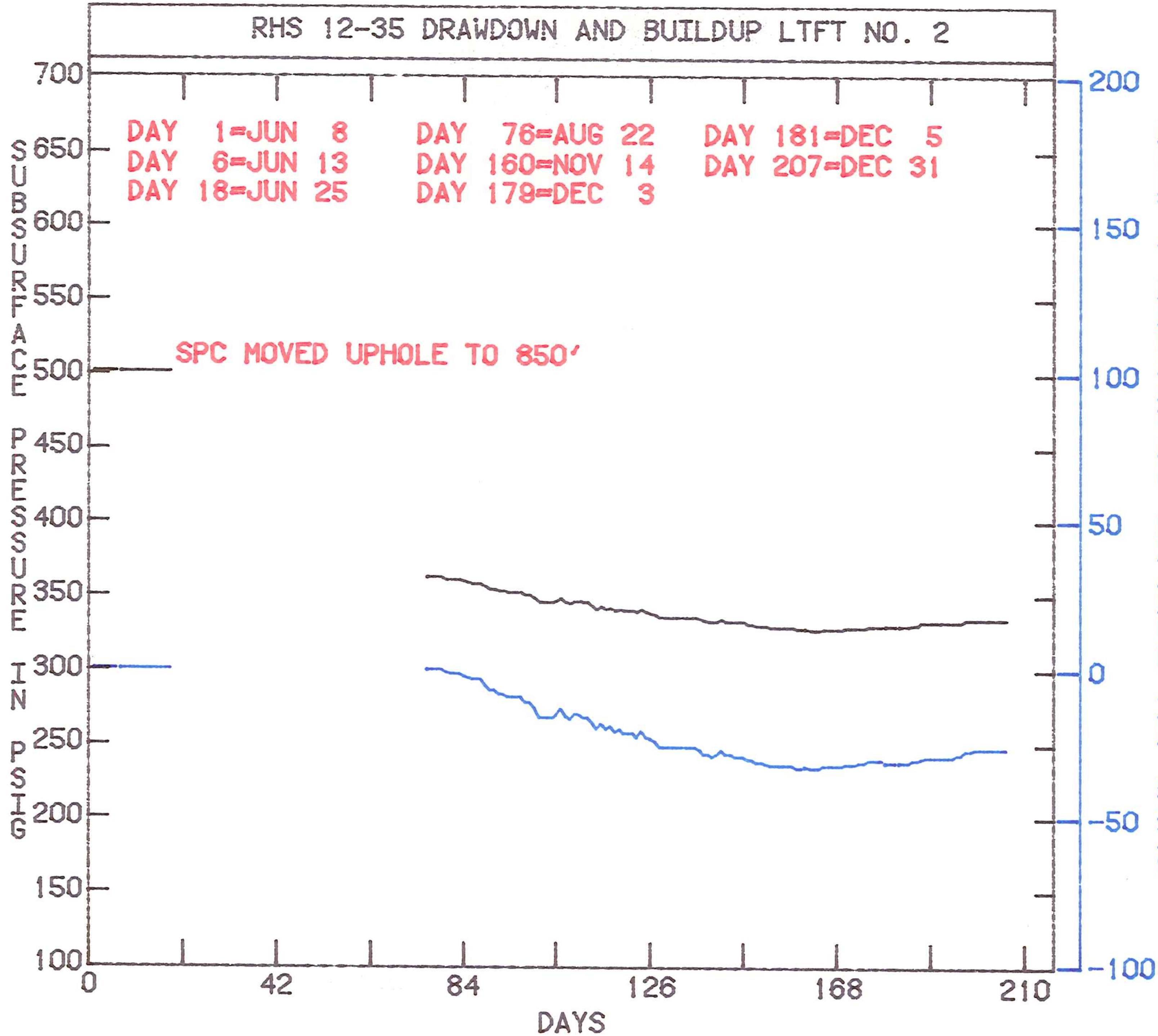
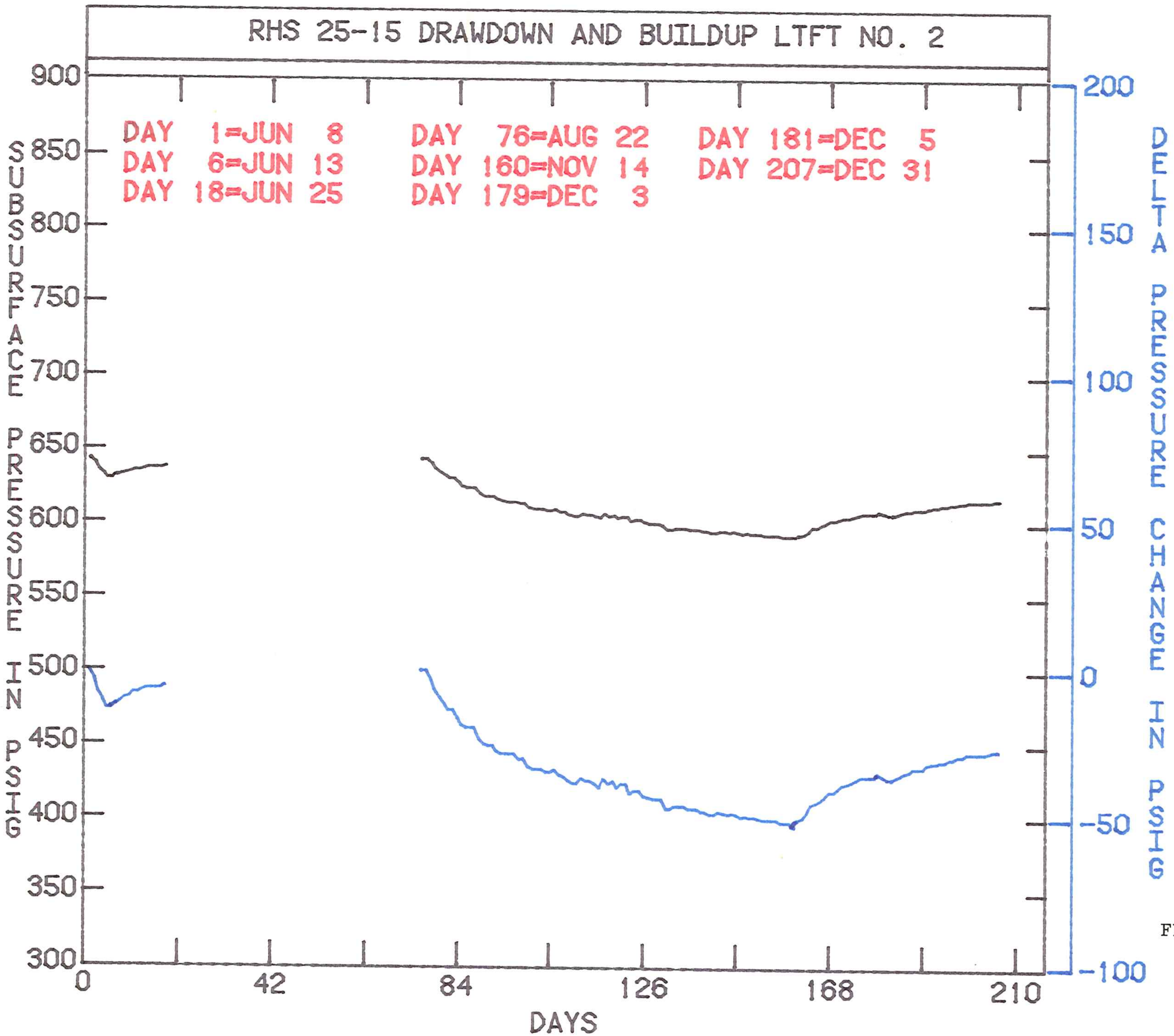
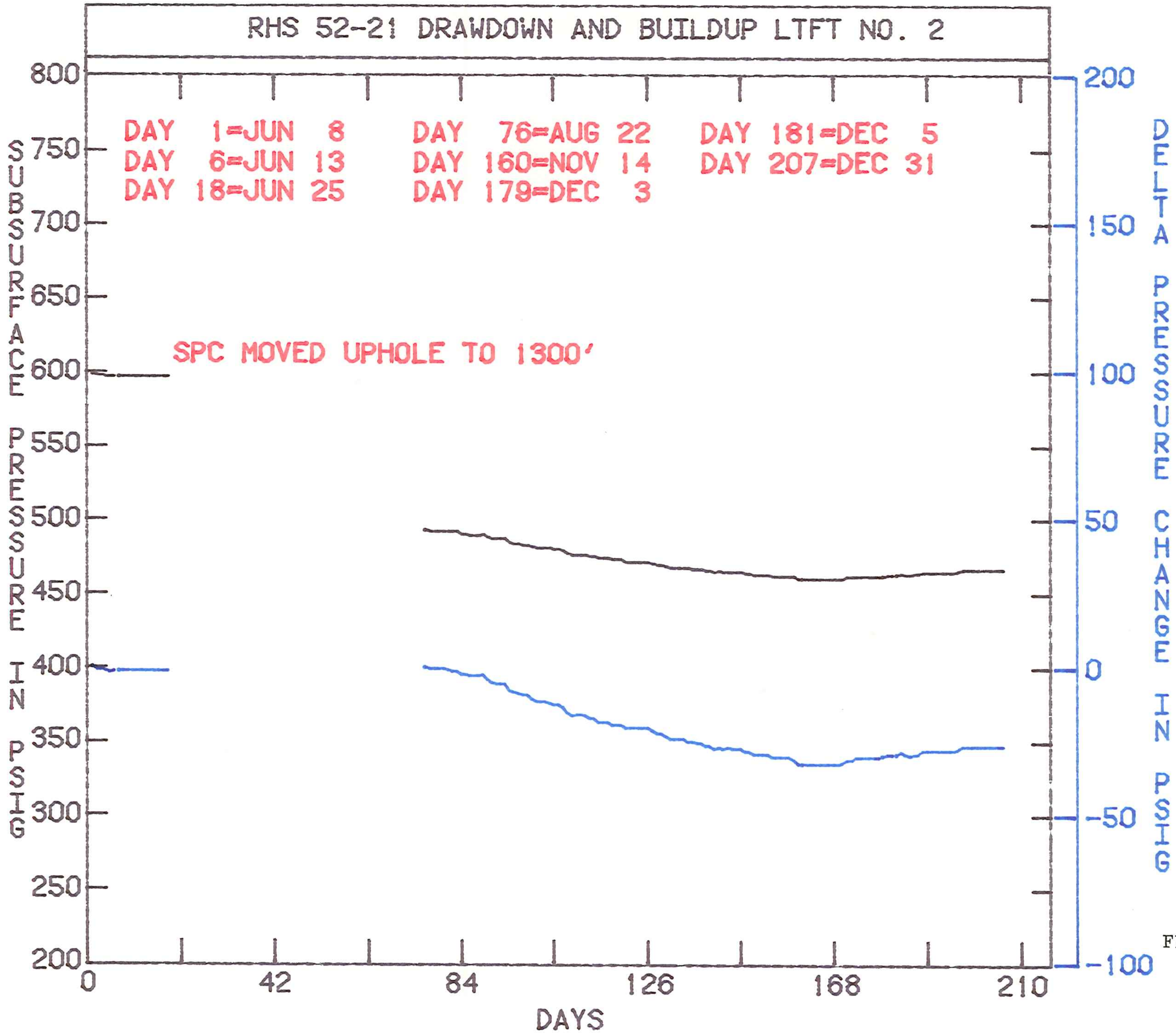

RHS 12-35 DRAWDOWN AND BUILDUP LTFT NO. 2
DAY 1=JUN 8
DAY 6=JUN 13
DAY 18=JUN 25
DAY 76=AUG 22
DAY 160=NOV 14
DAY 179=DEC 3
DAY 181=DEC 5
DAY 207=DEC 31
SPC MOVED UPHOLE TO 850'
SUBSURFACE PRESSURE IN PSIG
700
650
600
550
500
450
400
350
300
250
200
150
100
DELTA PRESSURE CHANGE IN PSIG
200
150
100
50
0
-50
-100
0
42
84
126
168
210
DAYS

FIGURE NO. 15



RHS 25-15 DRAWDOWN AND BUILDUP LTFT NO. 2
DAY 1=JUN 8
DAY 6=JUN 13
DAY 18=JUN 25
DAY 76=AUG 22
DAY 160=NOV 14
DAY 179=DEC 3
DAY 181=DEC 5
DAY 207=DEC 31
SUBSURFACE PRESSURE IN PSIG
900
850
800
750
700
650
600
550
500
450
400
350
300
DELTA PRESSURE CHANGE IN PSIG
200
150
100
50
0
-50
-100
0
42
84
126
168
210
DAYS

FIGURE NO. 16



RHS 52-21 DRAWDOWN AND BUILDUP LTFT NO. 2
DAY 1=JUN 8
DAY 6=JUN 13
DAY 18=JUN 25
DAY 76=AUG 22
DAY 160=NOV 14
DAY 179=DEC 3
DAY 181=DEC 5
DAY 207=DEC 31
SPC MOVED UPHOLE TO 1300'
SUBSURFACE PRESSURE IN PSIG
800
750
700
650
600
550
500
450
400
350
300
250
200
DELTA PRESSURE CHANGE IN PSIG
200
150
100
50
0
-50
-100
0
42
84
126
168
210
DAYS

FIGURE NO. 17

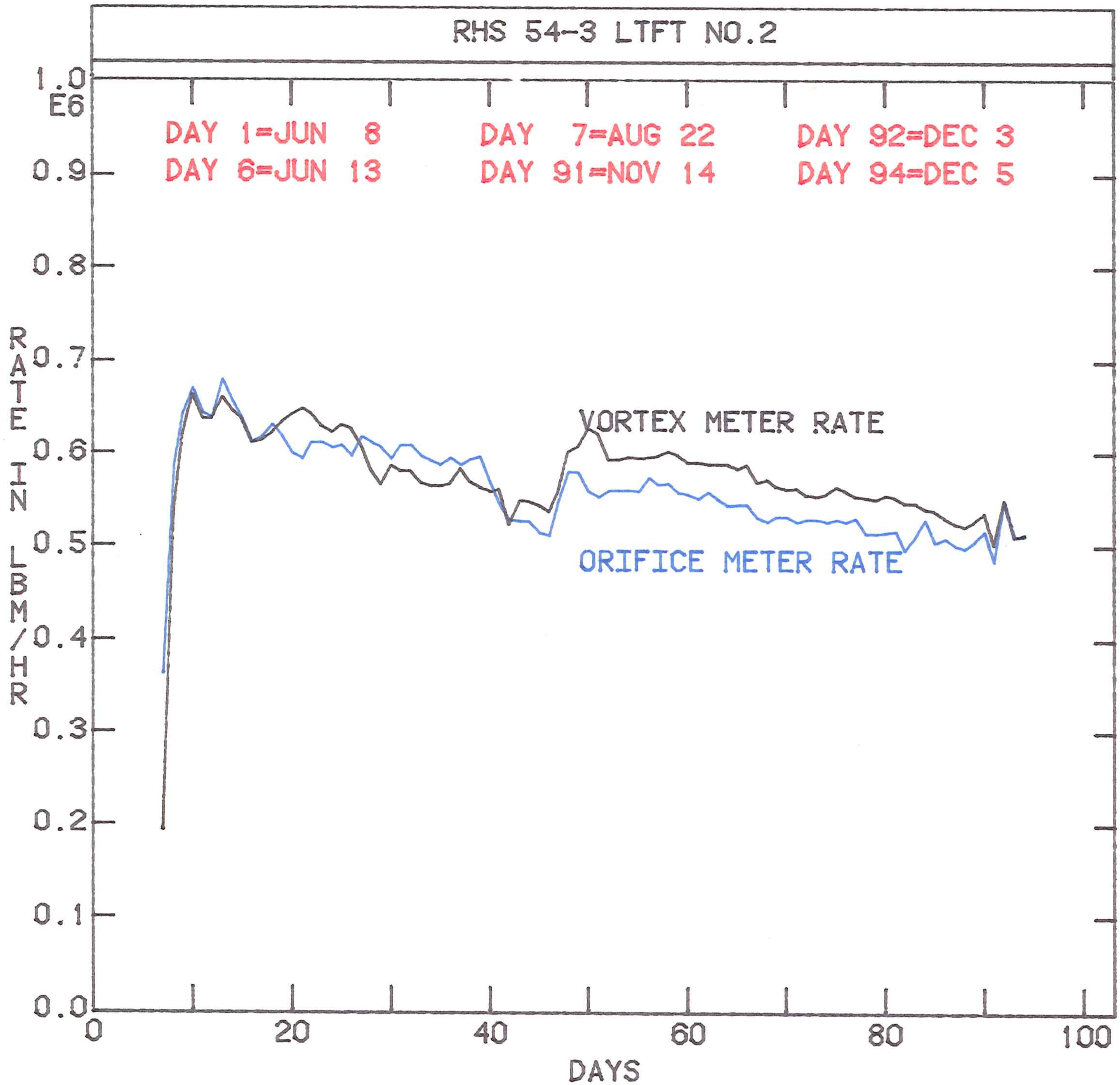

RHS 54-3 LTFT NO.2
DAY 1=JUN 8
DAY 6=JUN 13
DAY 7=AUG 22
DAY 91=NOV 14
DAY 92=DEC 3
DAY 94=DEC 5
VORTEX METER RATE
ORIFICE METER RATE
RATE IN LBM/HR
E6
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
0
20
40
60
80
100
DAYS

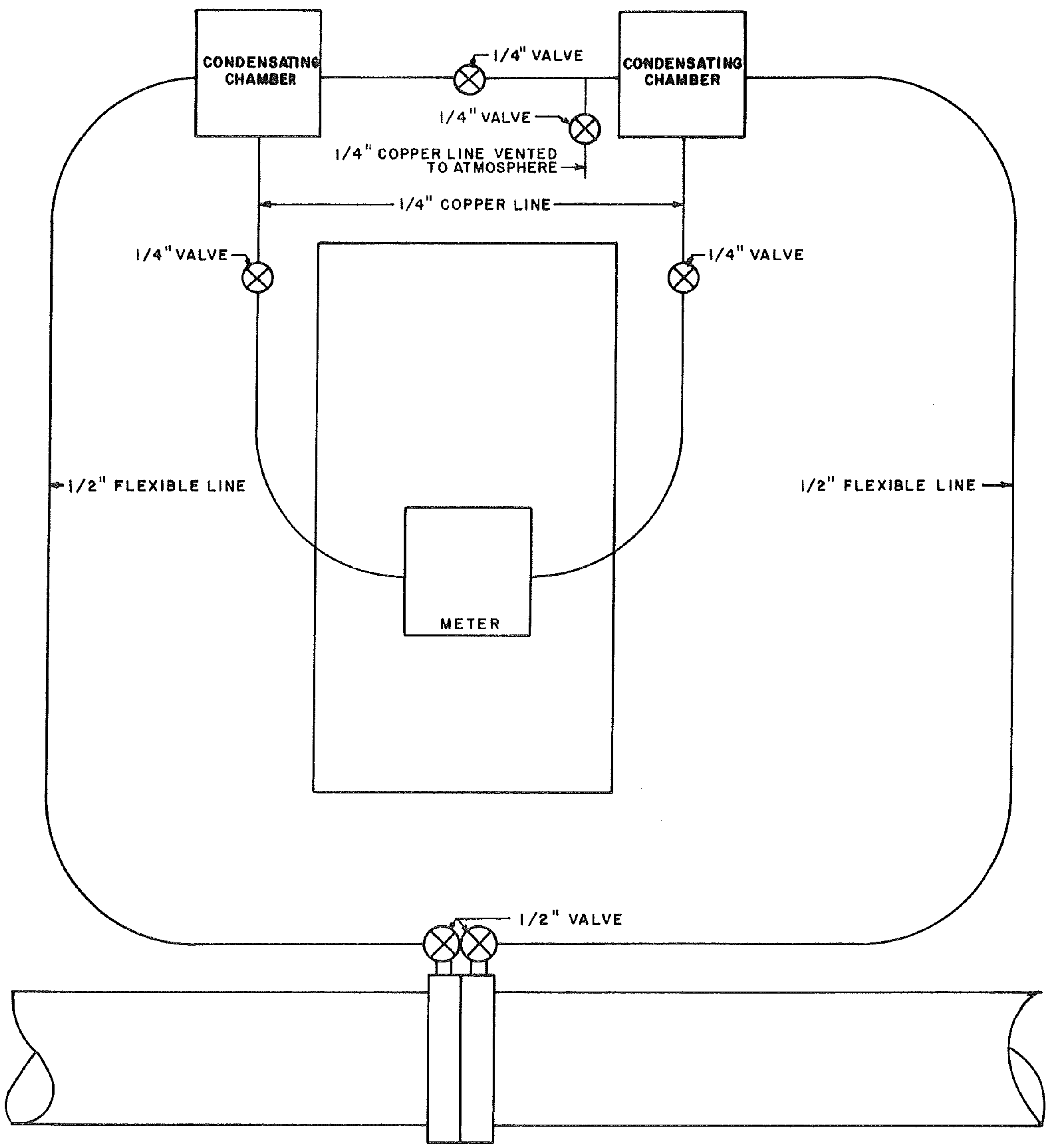
FIGURE NO. 18

FIGURE NO. 19

ORIFICE METER PIPING DRAWING FOR STEAM AND WATER MEASUREMENT

GEOTHERMAL PERFORMANCE REPORT

ROOSEVELT HOT SPRINGS, BEAVER COUNTY, UTAH



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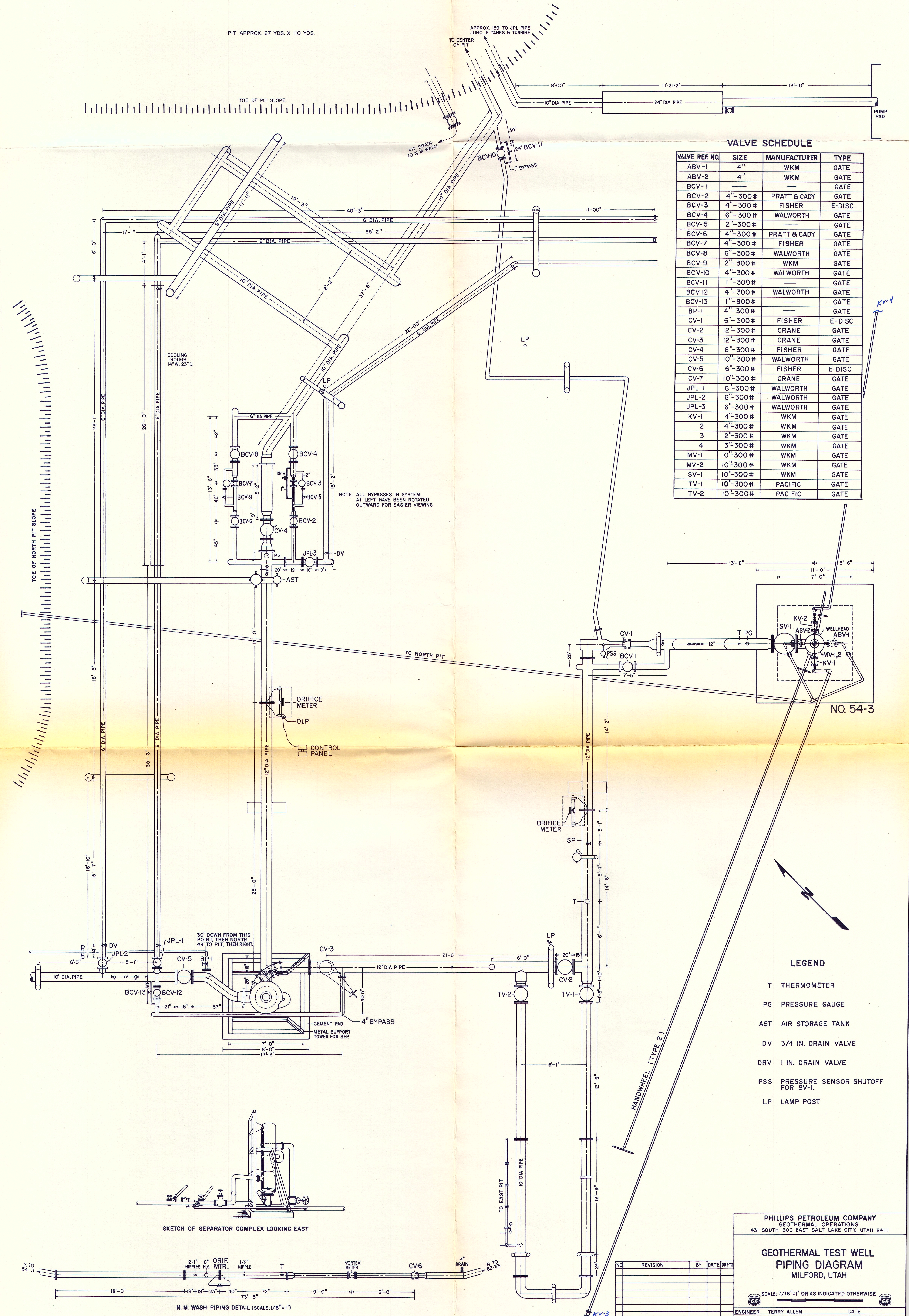


VALVE SCHEDULE

VALVE REF. NO.	SIZE	MANUFACTURER	TYPE
ABV-1	4"	WKM	GATE
ABV-2	4"	WKM	GATE
BCV-1	—	—	GATE
BCV-2	4"-300#	PRATT & CADY	GATE
BCV-3	4"-300#	FISHER	E-DISC
BCV-4	6"-300#	WALWORTH	GATE
BCV-5	2"-300#	—	GATE
BCV-6	4"-300#	PRATT & CADY	GATE
BCV-7	4"-300#	FISHER	GATE
BCV-8	6"-300#	WALWORTH	GATE
BCV-9	2"-300#	WKM	GATE
BCV-10	4"-300#	WALWORTH	GATE
BCV-11	1"-300#	—	GATE
BCV-12	4"-300#	WALWORTH	GATE
BCV-13	1"-800#	—	GATE
BP-1	4"-300#	—	GATE
CV-1	6"-300#	FISHER	E-DISC
CV-2	12"-300#	CRANE	GATE
CV-3	12"-300#	CRANE	GATE
CV-4	8"-300#	FISHER	GATE
CV-5	10"-300#	WALWORTH	GATE
CV-6	6"-300#	FISHER	E-DISC
CV-7	10"-300#	CRANE	GATE
JPL-1	6"-300#	WALWORTH	GATE
JPL-2	6"-300#	WALWORTH	GATE
JPL-3	6"-300#	WALWORTH	GATE
KV-1	4"-300#	WKM	GATE
2	4"-300#	WKM	GATE
3	2"-300#	WKM	GATE
4	3"-300#	WKM	GATE
MV-1	10"-300#	WKM	GATE
MV-2	10"-300#	WKM	GATE
SV-1	10"-300#	WKM	GATE
TV-1	10"-300#	PACIFIC	GATE
TV-2	10"-300#	PACIFIC	GATE

LEGEND

T	THERMOMETER
PG	PRESSURE GAUGE
AST	AIR STORAGE TANK
DV	3/4 IN. DRAIN VALVE
DRV	1 IN. DRAIN VALVE
PSS	PRESSURE SENSOR SHUTOFF FOR SV-1.
LP	LAMP POST

NO	REVISION	BY	DATE	DRFTG

PHILLIPS PETROLEUM COMPANY
GEOTHERMAL OPERATIONS
431 SOUTH 300 EAST SALT LAKE CITY, UTAH 84111

GEOTHERMAL TEST WELL PIPING DIAGRAM
MILFORD, UTAH

SCALE: 3/16"=1' OR AS INDICATED OTHERWISE

ENGINEER TERRY ALLEN DATE
DRAFTSMAN DOYLE OLSON DATE JUN. 27, 1979
REVISED DATE

FIGURE 20

FIGURE 21

PHILLIPS PETROLEUM ENGINEERING AND SERVICES MUFFLER SYSTEM

GEOTHERMAL PERFORMANCE REPORT
ROOSEVELT HOT SPRINGS
BEAVER COUNTY, UTAH

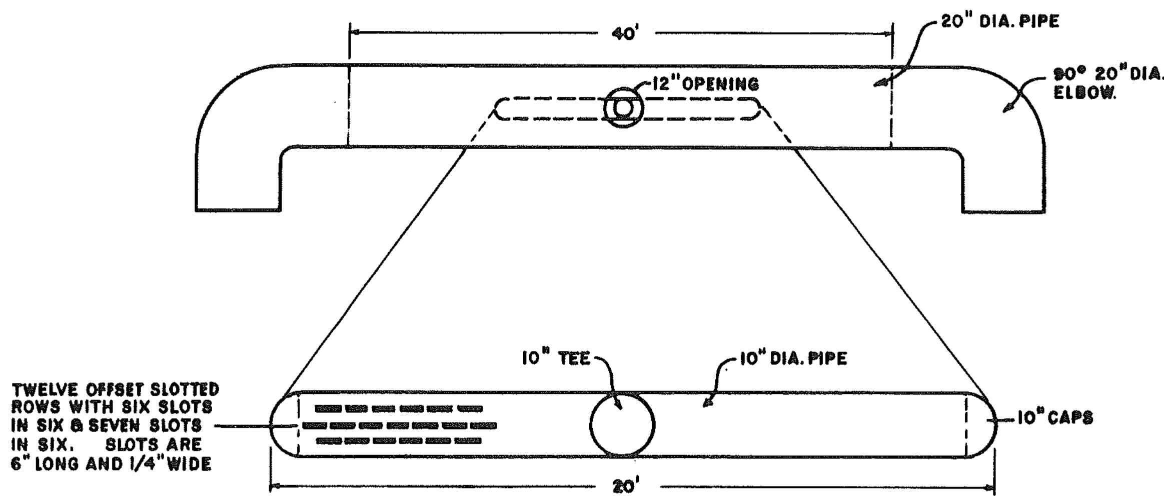


FIGURE 22

MUFFLER USED DURING LT FT NO. 2

GEOTHERMAL PERFORMANCE REPORT
ROOSEVELT HOT SPRINGS
BEAVER COUNTY, UTAH

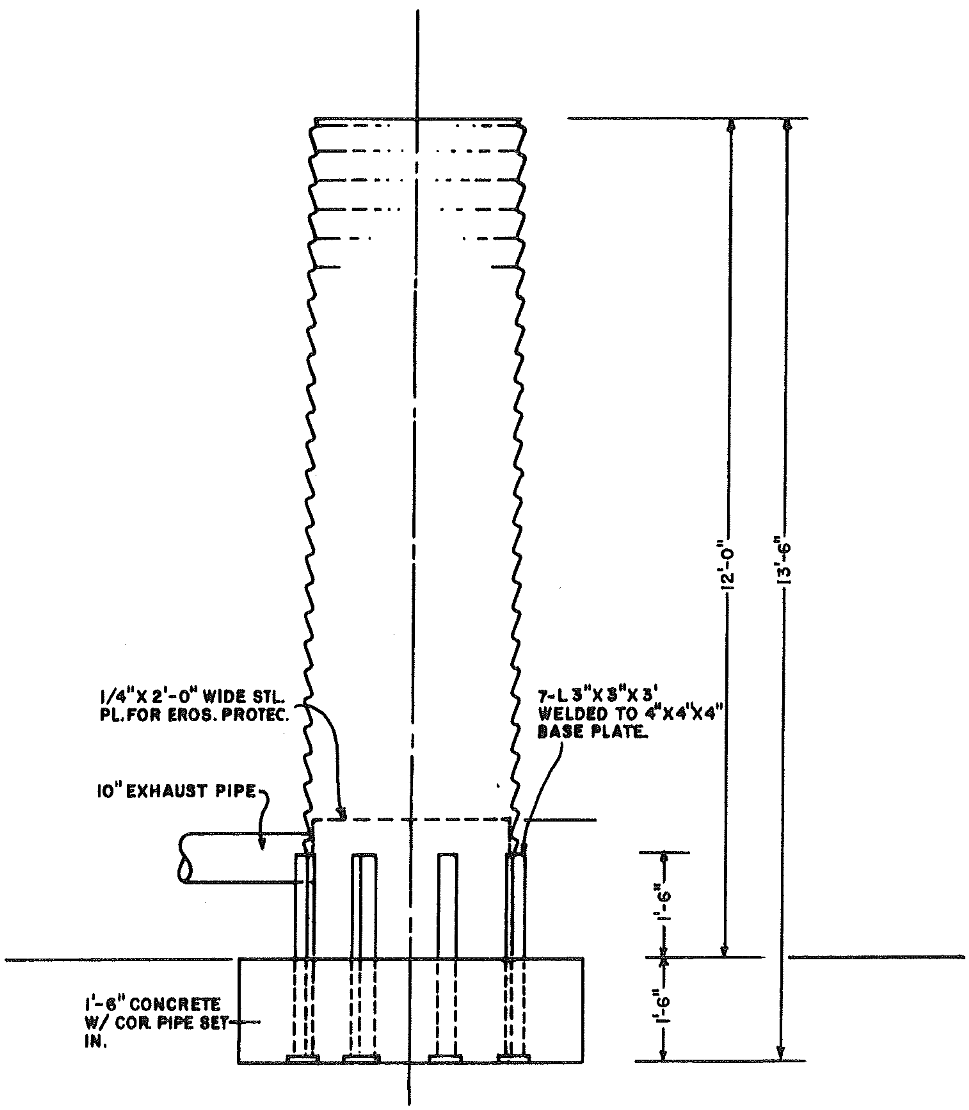


FIGURE 23

SINGLE LINE DRAWING OF LT FT NO. 2 ELECTRICAL SYSTEM

GEOTHERMAL PERFORMANCE REPORT
ROOSEVELT HOT SPRINGS
BEAVER COUNTY, UTAH

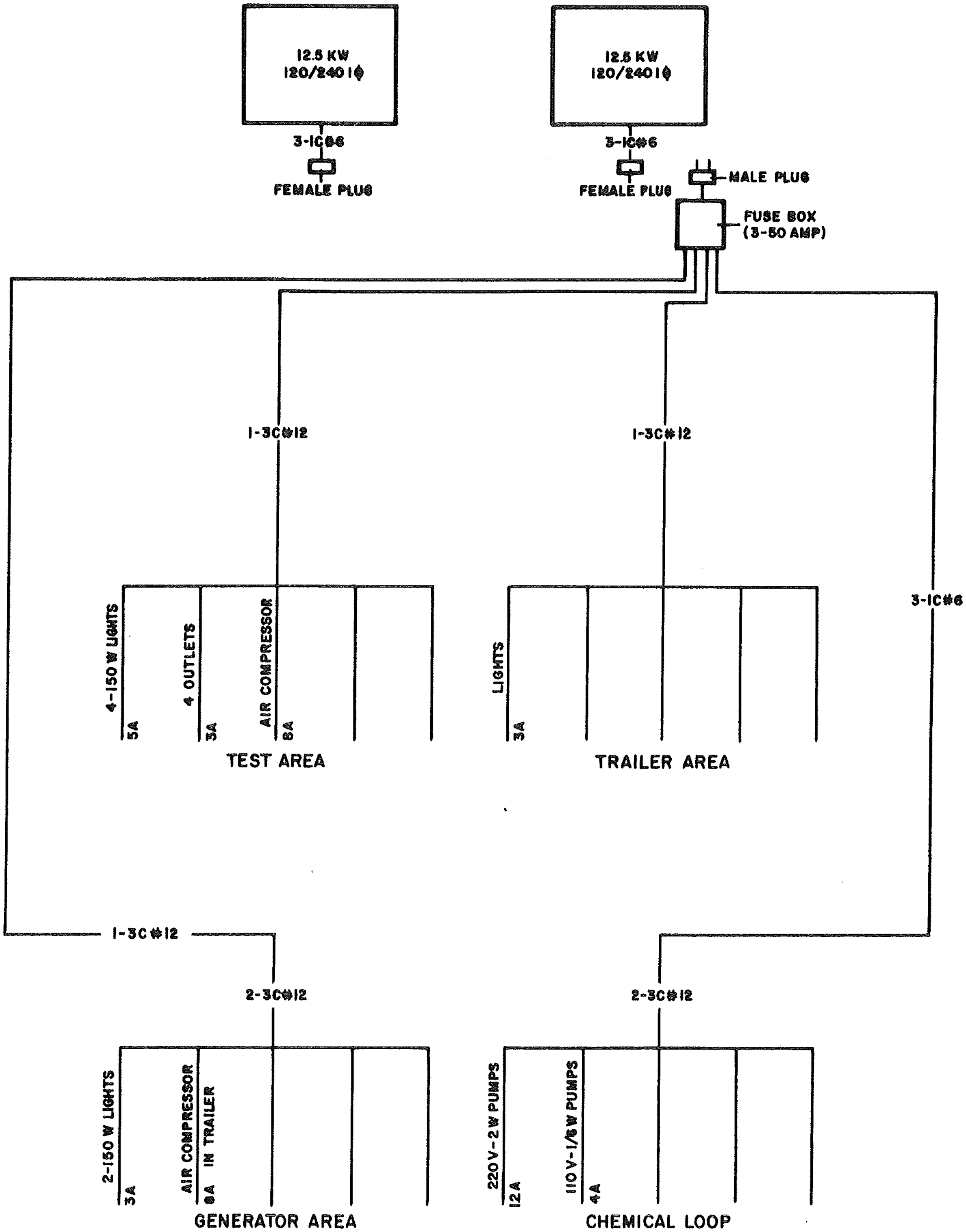


FIGURE 24

SCALE INJECTION AND TESTING SYSTEM

GEOTHERMAL PERFORMANCE REPORT
ROOSEVELT HOT SPRINGS
BEAVER COUNTY, UTAH

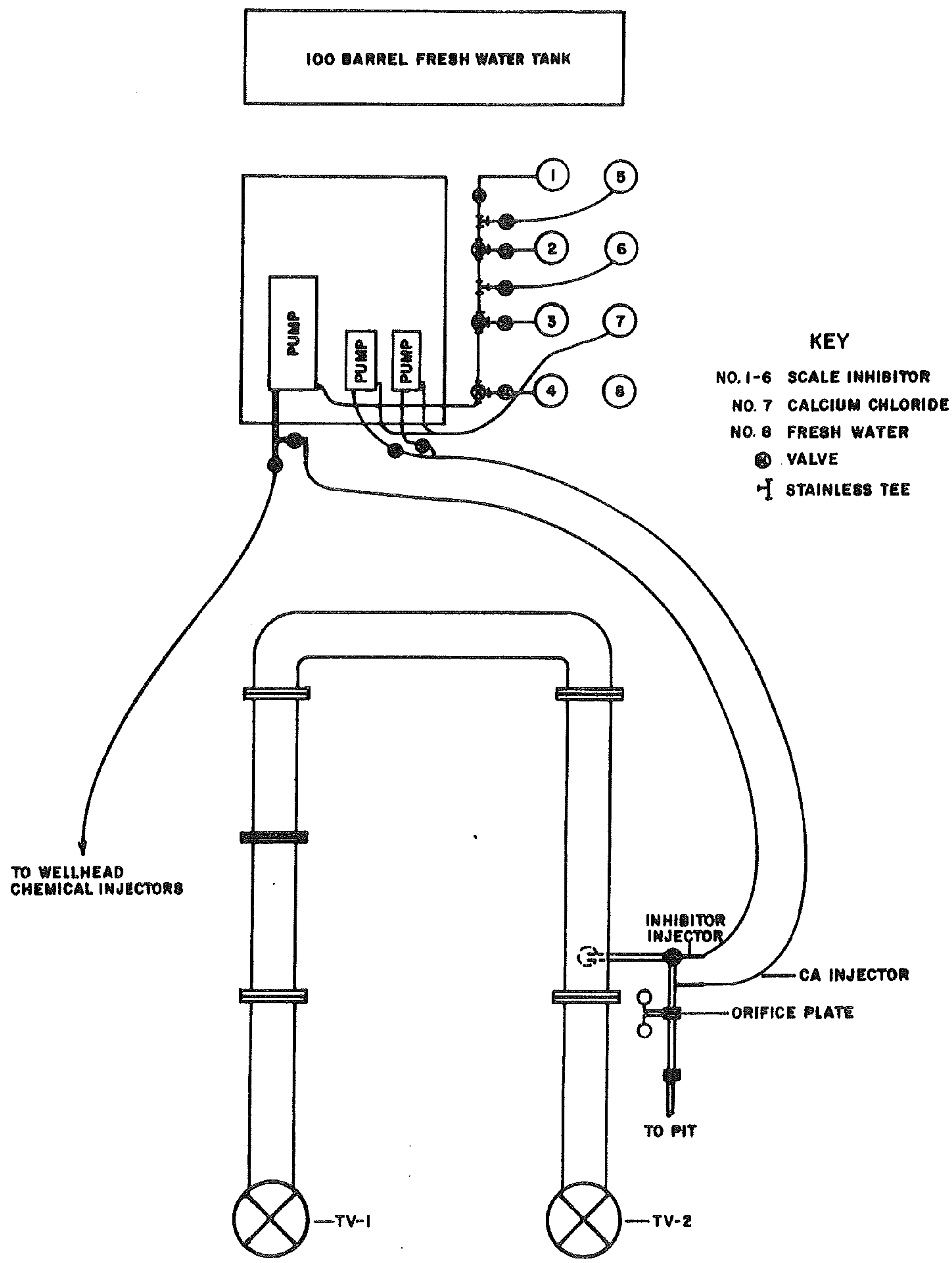


FIGURE NO. 25

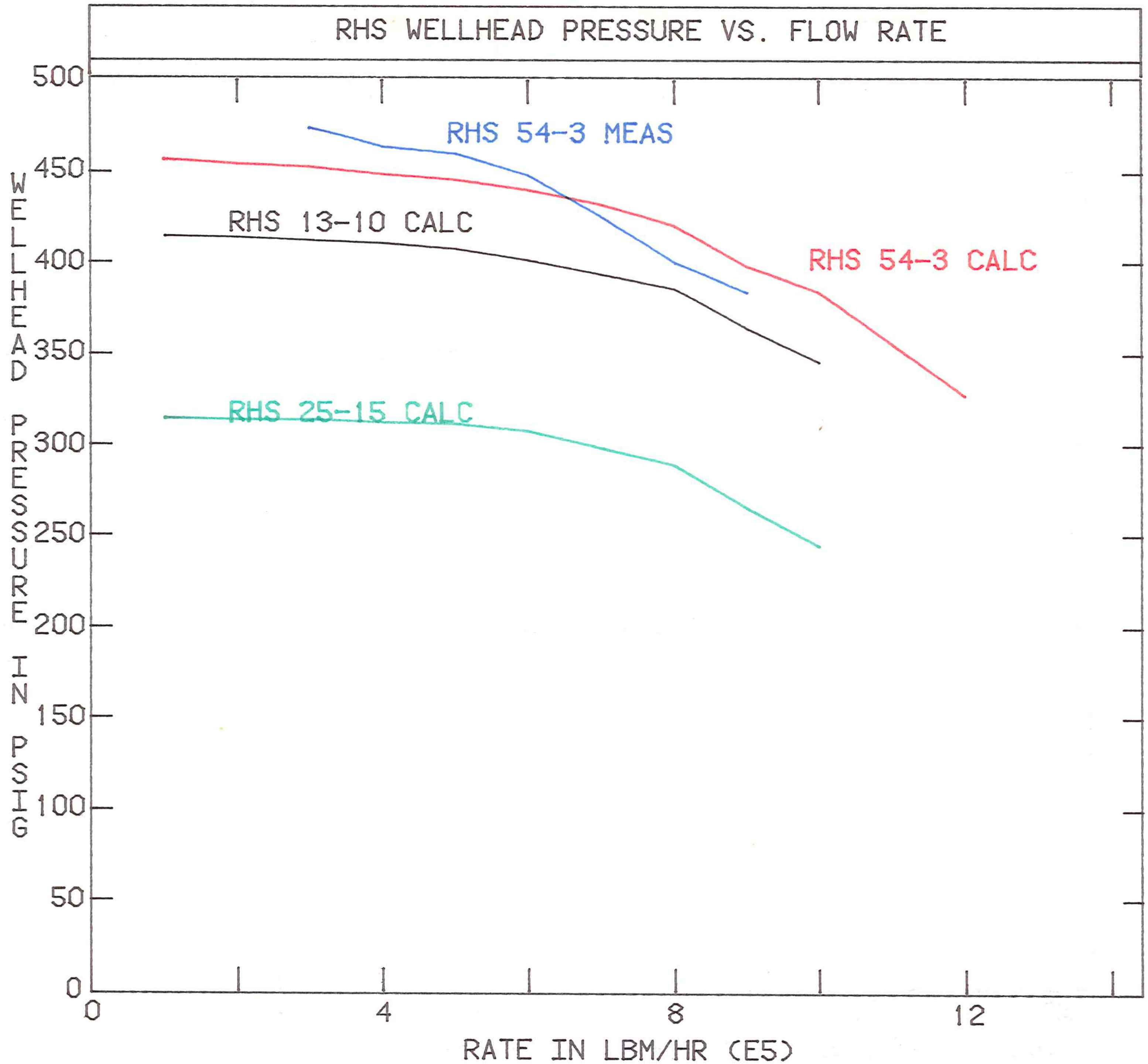
JPL Flow Data During LTFT No. 2
Geothermal Performance Report
Roosevelt Hot Springs Unit, Beaver County, Utah

DATE	TIME (HRS.)	TOTAL BRINE TO JPL 10^3 LBM	TOTAL BRINE FROM JPL 10^3 LBM	REMARKS
9/03	-	.3	0	Couldn't Keep Running
04	-	1.38	0	Same as Above
05	.05	9.88	0	
06	.45	14.3	0	
07	2.6	43.6	0	
08	3.0	86.7	129	Emptied Baker Tanks
21	4.5	318	298.5	
25	7.3	569.4	533.7	
28	5.9	666.7	614.4	
10/12	6.0	484	457	
16	5.7	596	509	
17	3.4	161	123	
18	2.08	475	342	
20	5.72	368	282	
23	4.68	810	689	
11/03	4.0	334	302	
04	-	.1	0	Couldn't Keep Running
11	1	78	12	
13	6	735	570	
14	6	180	180	
TOTAL	68.38	5931.36	5041.6	

FIGURE NO. 26

Biphase Flow Data During LTFT No. 2
Geothermal Performance Report
Roosevelt Hot Springs Unit, Beaver County, Utah

DATE	TIME HR	TOTAL BRINE lbm
8/30	2.1	8,400
8/31	5.4	55,837
9/11	5.8	41,760
9/12	4.9	45,800
9/13	3.9	38,450
9/20	1.5	16,200
9/27	4	33,100
9/28	2	20,500
10/04	3	7,200
10/05	5	31,500
10/08	2	21,600
10/09	6.66	63,800
10/10	4	32,000
TOTAL	50.26	416,147



RHS WELLHEAD PRESSURE VS. FLOW RATE
RHS 54-3 MEAS
RHS 13-10 CALC
RHS 54-3 CALC
RHS 25-15 CALC
WELLHEAD PRESSURE IN PSIG
500
450
400
350
300
250
200
150
100
50
0
0
4
8
12
RATE IN LBM/HR (E5)

FIGURE NO. 27

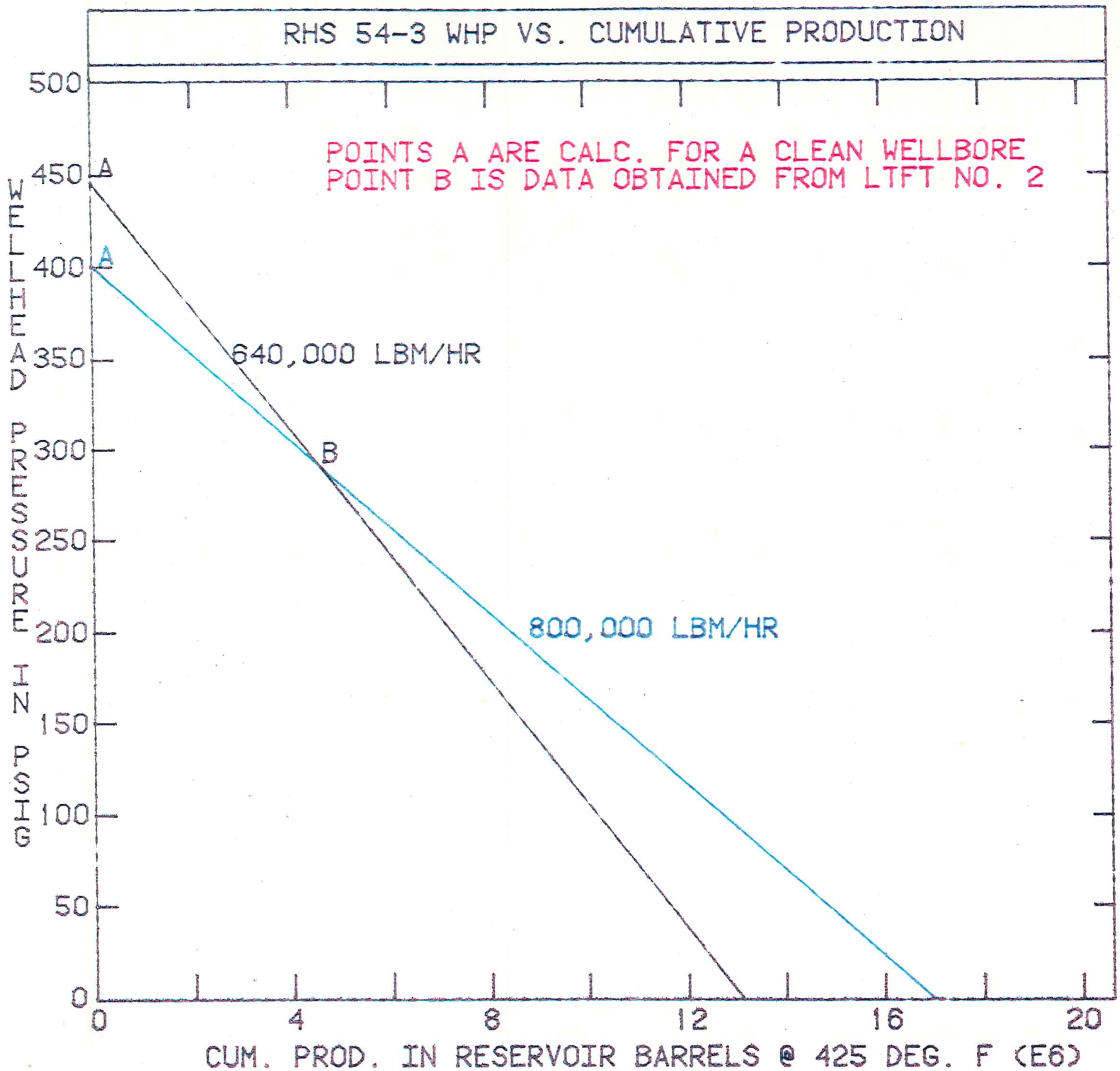

RHS 54-3 WHP VS. CUMULATIVE PRODUCTION
POINTS A ARE CALC. FOR A CLEAN WELLBORE
POINT B IS DATA OBTAINED FROM LTFT NO. 2
640,000 LBM/HR
800,000 LBM/HR
A
A
B
WELLHEAD PRESSURE IN PSIG
0
50
100
150
200
250
300
350
400
450
500
0
4
8
12
16
20
CUM. PROD. IN RESERVOIR BARRELS @ 425 DEG. F (E6)

FIGURE NO. 28

ATTACHMENT NO. 1

RHS Well No. 54-3 Flow Test Objectives
Geothermal Performance Report
Roosevelt Hot Springs Unit, Beaver County, Utah

Thirty Day Flow Test to Commence Approximately June 1, 1979

TEST PHASE	OBJECTIVE	COMMENTS	DATA TO BE OBTAINED
1	Verify that the well can sustain a flow rate of at least 600,000#/hr. for 20 consecutive days.	The ability of a well in the field to sustain high rates of flow has not been demonstrated. The rate of 600,000#/hr. per well has been used in economic projections and needs to be verified by a field test.	Flow rates and temperature of steam and water. Anticipated Accuracy of Data - Temperature ± 1% Flow rates (orifice meter) ± 3% Flow rate (vortex meter) ± 0.5%
2	Determine noncondensable gas volume and evaporation.	Earlier noncondensable gas measurements are in question. Obtain new data for use in commercial plant design.	Total volume of noncondensable gases per volume of steam. Gas composition: CO_2, H_2S, CH_4, NH_3, O_2, N, Rn.
3	Attempt to determine flow pattern of produced water injected into disposal well #82-33.	Millions of barrels of produced water were placed in this disposal well during previous flow test of well #54-3. Flow pattern is unknown.	Location and concentration of tracer as recovered from observation sites.
4	Improve liquid level control in the steam/water separator.	Problems such as water carryover were encountered in previous flow tests by a highly fluctuating fluid level.	Visual observation of liquid level in separator and timed recovery of water level in separator after an upset to the system.
5	Evaluate the reliability of a vortex meter in geothermal application.	Vortex meter may prove to be more reliable and trouble free than standard orifice meters for the measurement of geothermal fluids in commercial operations.	Flow rates of geothermal water on vortex and orifice meters for comparison. Observe operational problems. Anticipated Accuracy of Data - Orifice meter ± 3% Vortex meter ± 0.5%

TEST PHASE	OBJECTIVE	COMMENTS	DATA TO BE OBTAINED
6	Furnish geothermal steam and water to Jet Propulsion Laboratory helical screw expander for further testing.	JPL has requested access to geothermal fluids to permit additional short-term testing.	Data as required by JPL.
7	Evaluate effectiveness of inhibitors for the prevention of scale buildup in wellbore and surface facilities.	After the previous long-term flow test, it became apparent that $CaCO_3$ scaling will be a problem at least in the early stages of commercial production.	Data as determined by R & D.

NOTE: Test Phase 7 may not be carried out as a part of this flow test depending on whether R & D has scale inhibitor candidates identified by the time other phases of this test are concluded. Both downhole injection and injection of inhibitors in surface lines are being considered. This Phase may be deferred to a later flow test.

ATTACHMENT NO. 2

Startup Procedure for Roosevelt 54-3 During LTFT No. 2
Geothermal Performance Report
Roosevelt Hot Springs Unit, Beaver County, Utah

Following is a step by step procedure to be used when bringing RHS well No. 54-3 on line for flow testing. The procedure is divided into 3 phases, pre-startup, startup to pit, and separated flow. Each phase consists of objectives and a check list.

<u>Pre-startup</u>

Objective: Verify all equipment is ready prior to day of actual startup.

Pre-startup consists of a series of checks that are to be performed prior to the day of actual startup and are as follows:

1. Hammer up all flange bolts
2. Hammer up all valve bonnet bolts
3. Check electrical supply
   a. Check generators
   b. Check outlets for power
   c. Check compressor in wash for power
   d. Check separator controls for power
4. Check air compressor in wash for proper shut-off (high pressure) and startup (low pressure)
5. Check vortex for proper connections
6. Connect hand wheels to master valve
7. Plug all unused 1/2 valves
8. Check Barton meters
   a. Wind clocks
   b. Ink pens
   c. Install charts
9. Check all water injection line drain ports for closed positions
10. Fill separator and water injection line.

<u>Startup to Pit</u>

Objective: To bring RHS well No. 54-3 on line slowly so wellhead, piping, etc. can undergo slow increases in temperature and thus avoid thermal shock.

By performing the steps listed below, and in the order listed, water and steam from RHS well No. 54-3 will flow to the pit through the separator.

1. Insure pop-off valves are in place on both master valves MV-1 and MV-2.

2. Insure all valves listed in Attachment No. 2-A are in the position indicated under column labeled "Position Before Startup".

3. Open 3" valves in cellar to 13 3/8" - 9 5/8" annulus.

4. With 2" valve at end of kill line closed, open 3" valve in collar to kill line.

5. Open master valve at RHS well No. 82-33.

6. Open MV-1 fully and backoff 1/2 turn.

7. Open MV-2 fully and backoff 1/2 turn.

Note: Check wellhead pressure and record.
Well now open to CV-1 - Check for leaks. If any leaks are found, close MV-2 first - then MV-1.

8. Open CV-1 one turn (6% of open).

Note: Now have flow to CV-4. Separator will fill. Check for pressure and temperature in CV-4. Check for leaks. If any leaks are found, close MV-2 then MV-1, and then CV-1.

9. Open CV-4 1/2 way.

Note: Now have flow to pit.
Wellhead pressure and temperature will increase. Steam will flow for 5-10 minutes out the 13 3/8" - 9 5/8" annulus line. The plate over the collar will begin to rise above the ground (3-4 inch).

10. After the wellhead pressure has stabilized for 10 minutes, open CV-1 another 1 turn (valve now 12% open).

11. Allow wellhead pressure and temperature to stabilize for 15 minutes.

12. Repeat steps 9 and 10 until CV-1 is 24% open and wellhead pressure and temperature has stabilized for 30 minutes. (Should take 1 1/2 to two hours from time CV-1 is first opened).

Separated Flow

Objective: Separate flow so water is injected into RHS well No. 82-33 and steam is vented to the atmosphere in the pit.

With flow to the pit and the wellhead in a stable condition, perform the steps to allow for separation of 2 Ø flow.

1. With the remote controller for CV-6 set in manual position, barely open CV-6. This will allow a small amount of flow down the injection system and heat the injection line.

2. Slowly open CV-6 until the separator water level is adjusted to the proper level (50%). May have to adjust CV-4 also.

When separated 2 Ø flow has been accomplished the remote control for CV-6 can be put in the automatic position and tuned for automatic control of separator water level. When this separator is controlled by the water level in a satisfactory manner, CV-1 can be opened or closed to obtain the desired flow rates.

ATTACHMENT NO. 2-A

STARTUP PROCEDURE TO PIT

VALVE NO.	LOCATION	POSITION BEFORE STARTUP	POSITION DURING STARTUP	REMARKS
MV-1	Wellhead (Btm)	Closed	Open	Always Open MV-1 and shut MV-2 before MV-1
MV-2	Wellhead (Top)	Closed	Open	See Remark for MV-1
SV-1	Wellhead	Open	Open	
CV-1	2Ø Flow Line	Closed	Open	This valve controls flow of well
BCV-1	2Ø Flow Line	Closed	Closed	Bypass around CV-1
CV-2	2Ø Flow Line	Open	Open	Used with TV-1 & TV-2 when flowing through chemical loop. See remarks for CV-2
TV-1	Chemical Loop	Closed	Closed	See remarks for CV-2
TV-2	Chemical Loop	Closed	Closed	See remarks for CV-2
CV-3	2Ø Flow Inlet to Separator	Open	Open	Always open - never close - used as spacer - gate has been welded to stem
CV-4	Steam Line	Open	Open	This valve controls flow of steam from separator
BCV-2	Steam Line	Closed	Closed	Bypass around steam control valve CV-4
BCV-3	Steam Line	Closed	Closed	See Remarks for BCV-2
BCV-4	Steam Line	Closed	Closed	See Remarks for BCV-2
BCV-5	Steam Line	Closed	Closed	See Remarks for BCV-2
BCV-6	Steam Line	Closed	Closed	See Remarks for BCV-2

VALVE NO.	LOCATION	POSITION BEFORE STARTUP	POSITION DURING STARTUP	REMARKS
BCV-7	Steam Line	Closed	Closed	See Remarks for BCV-2
BCV-8	Steam Line	Closed	Closed	See Remarks for BCV-2
BCV-9	Steam Line	Closed	Closed	See Remarks for BCV-2
JPL-3	Steam Line	Closed	Closed	Control Valve for steam to JPL
BCV-1 0	2Ø Flow Bypass	Closed	Closed	Controls 2 Ø Flow to Pit Pressure
BCV-11	2Ø Flow Bypass	Closed	Closed	Bypass around BCV-10
CV-5	Water Outlet from Separator	Open	Open	
BCV-12	Bypass Around Separator	Closed	Closed	
JPL-3	Steam Line	Closed	Closed	Control valve for steam to JPL
BCV-10	2Ø Flow Bypass	Closed	Closed	Controls 2Ø Flow to Pit Pressure
BCV-11	2Ø Flow Bypass	Closed	Closed	Bypass around BCV-10
CV-5	Water outlet from Separator	Open	Open	
BCV-12	Bypass Around Separator	Closed	Closed	Controls 2Ø flow to bypass separator to injection well
BCV-13	Bypass Around Separator	Closed	Closed	Pressure Bypass around BCV-12
JPL-1	Water Line	Closed	Closed	JPL Water Inlet Line
JPL-2	Water Line	Closed	Closed	JPL Water Return Line

VALVE NO.	LOCATION	POSITION BEFORE STARTUP	POSITION DURING STARTUP	REMARKS
BP-1	Water Line	Closed	Closed	Biphase Inlet
CV-6	Water Line	Closed	Closed	Control for CV-6 in manual position. Water level in separator controls position of valve when in automatic.
CV-7	Water Line	Open	Open	Used as spacer.

ATTACHMENT NO. 3

RHS 54-3 LTFT NO. 2 DAILY FLOW RATES

DATE	WHP	WHT	STEAM RATE	WATER RATE	TOTAL RATE	STEAM RATIO
*****	****	****	******	*******	*******	******
08/22	475	452	26734	193650	220384	12.13
08/23	440	447	53390	535765	589155	9.06
08/24	432	443	56678	618389	675067	8.40
08/25	421	441	60253	664349	724602	8.32
08/26	423	441	59490	635430	694921	8.56
08/27	419	440	59349	635817	695167	8.54
08/28	413	439	61404	659959	721364	8.51
08/29	415	439	59399	645242	704641	8.43
08/30	418	439	55866	633494	689360	8.10
08/31	423	440	58300	610256	668556	8.72
09/01	419	440	62402	614000	676402	9.23
09/02	414	440	62073	622391	684464	9.07
09/03	414	440	61977	632977	694955	8.92
09/04	409	438	62593	642014	704607	8.68
09/05	407	438	63780	648598	712378	8.95
***						
09/06	410	438	60634	641756	722390	8.63
09/07	411	438	60920	628588	689508	8.81
09/08	411	437	60920	621875	682795	8.92
09/09	410	438	60348	629879	690227	8.74
09/10	410	435	61397	625102	686499	8.94
09/11	410	438	59776	606770	666546	8.97
09/12	412	435	55773	581983	637756	8.75
09/13	416	437	53721	565845	619566	8.67
09/14	411	435	51483	586372	637856	8.07
09/15	411	433	51769	580434	632203	8.19
09/16	411	434	53676	580046	633722	8.47
09/17	412	435	52385	567394	619780	8.45
09/18	411	435	52151	564296	616447	8.46
09/19	411	435	52900	563909	616809	8.58
09/20	412	435	53435	568040	621475	8.60
09/21	410	435	52679	583661	636340	8.28
09/22	410	435	52334	569073	621407	8.42
09/23	413	435	51848	563263	615111	8.43
09/24	412	435	49660	558357	608018	8.17
09/25	410	434	49428	561069	610496	8.10
09/26	408	433	50763	522597	573360	8.85
09/27	408	435	50000	548675	598675	8.35
09/28	409	435	49672	547642	597315	8.32
***						

ATTACHMENT NO. 3
RHS 54-3 LIFT NO. 2 DAILY FLOW RATES

09/29	410	434	50573	542349	592922	8.53
09/30	410	433	50244	536152	586397	8.57
10/01	397	432	53129	557454	610583	8.70
10/02	379	426	58675	600960	659635	8.90
10/03	380	427	57287	607803	665090	8.61
10/04	380	427	56639	627168	683807	8.28
10/05	379	425	56223	620196	676420	8.31
10/06	378	426	56501	591536	648037	8.72
10/07	376	426	56501	591536	648037	8.72
10/08	373	426	59878	594893	654771	9.14
10/09	368	418	58537	593344	651881	8.98
10/10	365	410	58582	596055	654637	8.95
10/11	362	405	58767	597604	656371	8.95
10/12	361	403	59230	600831	660062	8.97
10/13	362	402	59100	597604	656704	9.00
10/14	360	404	58678	588438	647116	9.07
10/15	359	402	58863	589600	648463	9.08
10/16	358	399	57426	586889	644315	8.91
10/17	357	403	57797	586889	644685	8.97
10/18	356	399	57844	587921	645765	8.96
10/19	356	394	56639	583661	640300	8.85
10/20	356	400	54926	587405	642331	8.55
10/21	356	405	52333	568556	620889	8.43
***						
10/22	355	399	55712	572300	628012	8.87
10/23	354	400	55619	564812	620432	8.96
10/24	355	402	55341	560552	615894	8.99
10/25	352	400	55945	562230	618175	9.05
10/26	351	400	55944	555130	611074	9.16
10/27	349	399	55667	554097	609764	9.13
10/28	348	398	55712	556421	612133	9.10
10/29	348	389	53389	564554	617943	8.64
10/30	348	393	52190	559390	611580	8.53
10/31	348	400	51920	552935	604855	8.58
11/01	347	398	52938	551386	604324	8.76
11/02	346	399	53907	549708	603615	8.93
11/03	345	399	54278	555388	609666	8.90
11/04	345	398	50707	551902	602610	8.41
11/05	345	400	52703	546093	598796	8.80
11/06	345	399	53815	547384	601199	8.95
11/07	342	399	51129	539638	590767	8.65
11/08	343	398	52425	538347	590772	8.87
11/09	342	395	52654	530343	582996	9.03
11/10	343	398	52839	524533	577372	9.15
11/11	340	394	51356	520660	572016	8.98
11/12	318	394	64423	526599	591022	10.90
11/13	297	394	69947	536281	606229	11.54
***						
11/14	315	399	71115	502457	573572	12.40
12/03	355	422	30920	550870	581790	5.31
12/04	320	410	54204	510461	564665	9.60
12/05	315	408	43281	512527	555808	7.79

ATTACHMENT NO. 4

RHS 54-3 LTFT NO. 2 RAW DATA

DATE	WHP	WHT	STEAM DIFF.	STEAM STAT.	VORTEX PERCENT	WATER DIFF.	CALOR-IMETER	STEAM TEMP.
*****	****	****	******	*****	*******	*****	******	*****
08/22	475	452	3.4	4.6	15	2.93	200	364
08/23	440	447	5.6	5.75	41.5	4.75	200	415
08/24	432	443	5.95	5.78	47.9	5.2	195	416
08/25	421	441	6.32	5.72	51.46	5.42	197	415
08/26	423	441	6.24	5.7	49.22	5.2	200	415
08/27	419	440	6.22	5.71	49.25	5.15	200	414
08/28	413	439	6.43	5.66	51.12	5.5	200	413
08/29	415	439	6.22	5.6	49.98	5.3	200	413
08/30	418	439	5.85	5.68	49.07	5.15	200	413
08/31	423	440	6.11	5.68	47.27	4.95	200	414
09/01	419	440	6.54	5.66	47.56	5	200	414
09/02	414	440	6.5	5.66	48.21	5.1	200	413
09/03	414	440	6.49	5.64	49.03	5	200	413
09/04	409	438	6.56	5.68	49.73	4.85	200	414
09/05	407	438	6.69	5.68	50.24	4.8	200	415
***								
09/06	410	438	6.36	5.67	49.71	4.95	200	415
09/07	411	438	6.39	5.66	48.69	4.95	199	415
09/08	411	437	6.39	5.63	48.17	4.9	200	415
09/09	410	438	6.33	5.67	48.79	4.92	200	415
09/10	410	435	6.44	5.6	48.42	4.82	199	415
09/11	410	438	6.27	5.66	47	5	199	415
09/12	412	435	5.85	5.65	45.08	4.95	201	415
09/13	416	437	5.63	5.67	43.83	4.9	202	414
09/14	411	435	5.4	5.68	45.42	4.8	201	415
09/15	411	433	5.43	5.66	44.96	4.92	200	415
09/16	411	434	5.63	5.67	44.93	4.92	200	415
09/17	412	435	5.49	5.67	43.95	4.82	200	414
09/18	411	435	5.47	5.67	43.71	4.78	200	415
09/19	411	435	5.53	5.64	43.68	4.75	200	412
09/20	412	435	5.6	5.66	44	4.81	201	414
09/21	410	435	5.53	5.65	45.21	4.75	201	416
09/22	410	435	5.48	5.58	44.08	4.8	201	413
09/23	413	435	5.42	5.63	43.63	4.82	200	412
09/24	412	435	5.2	5.64	43.25	4.6	200	413
09/25	410	434	5.18	5.66	43.46	4.4	200	414
09/26	408	433	5.32	5.66	40.48	4.27	201	414
09/27	408	435	5.24	5.65	42.5	4.25	200	414
09/28	409	435	5.21	5.62	42.42	4.25	200	415
***								

ATTACHMENT NO. 4

RHS 54-3 LIFT NO. 2 RAW DATA

09/29	410	434	5.3	5.61	42.01	4.16	200	414
09/30	410	433	5.27	5.65	41.53	4.13	200	415
10/01	397	432	5.75	5.53	43.18	4.42	200	409
10/02	379	426	6.34	5.47	46.55	4.69	200	407
10/03	380	427	6.19	5.48	47.08	4.68	200	407
10/04	380	427	6.12	5.5	48.58	4.52	200	407
10/05	379	425	6.08	5.47	48.04	4.47	200	408
10/06	378	426	6.11	5.57	45.82	4.53	200	408
10/07	376	426	6.11	5.57	45.82	4.53	200	408
10/08	373	426	6.47	5.47	46.08	4.53	200	407
10/09	368	418	6.32	5.44	45.96	4.52	200	406
10/10	365	410	6.33	5.47	46.17	4.64	200	407
10/11	362	405	6.35	5.48	46.29	4.58	200	407
10/12	361	403	6.4	5.46	46.54	4.59	200	407
10/13	362	402	6.36	5.46	46.29	4.51	200	403
10/14	360	404	6.33	5.47	45.58	4.49	200	405
10/15	359	402	6.35	5.47	45.67	4.45	200	405
10/16	358	399	6.2	5.48	45.46	4.52	200	406
10/17	357	403	6.24	5.47	45.46	4.45	200	406
10/18	356	399	6.24	5.48	45.54	4.39	200	405
10/19	356	394	6.11	5.49	45.21	4.4	200	405
10/20	356	400	5.93	5.52	45.5	4.4	200	406
10/21	356	405	5.65	5.5	44.04	4.29	200	406
***								
10/22	355	399	6.01	5.48	44.33	4.26	200	405
10/23	354	400	6	5.47	43.75	4.31	200	405
10/24	355	402	5.97	5.43	43.42	4.3	200	405
10/25	352	400	6.04	5.44	43.55	4.25	200	406
10/26	351	400	6.04	5.47	43	4.28	200	406
10/27	349	399	6.01	5.47	42.92	4.28	200	406
10/28	348	398	6.01	5.43	43.1	4.26	200	405
10/29	348	389	5.75	5.5	43.73	4.28	200	404
10/30	348	393	5.63	5.5	43.33	4.26	200	405
10/31	348	400	5.61	5.5	42.83	4.29	200	407
11/01	347	398	5.72	5.47	42.71	4.16	200	407
11/02	346	399	5.82	5.46	42.58	4.15	200	406
11/03	345	399	5.86	5.43	43.02	4.17	200	406
11/04	345	398	5.47	5.43	42.75	4.18	200	405
11/05	345	400	5.69	5.44	42.3	4.01	200	406
11/06	345	399	5.81	5.46	42.4	4.13	200	406
11/07	342	399	5.52	5.45	41.8	4.28	200	406
11/08	343	398	5.66	5.43	41.7	4.08	200	406
11/09	342	395	5.68	5.43	41.08	4.12	200	405
11/10	343	398	5.7	5.41	40.63	4.05	200	405
11/11	340	394	5.54	5.43	40.33	4.03	200	405
11/12	318	394	7.38	4.98	40.79	4.09	200	393
11/13	297	394	8.99	4.67	41.54	4.18	200	375
***								
11/14	315	399	9.14	4.46	38.92	3.91	200	375
12/03	355	422	5	3.9	42.67	4.45	200	390
12/04	320	410	10	4.6	39.54	4.13	200	368
12/05	315	408	10	4.2	39.7	4.14	200	372

ATTACHMENT NO. 5

RHS LIFT NO. 2 DRAWDOWN RAW DATA

DATE	RHS 3-1	RHS 13-10	RHS 25-15	RHS 52-21	RHS 12-35
06/08	702.9	728.1	642.5	597.8	501.0
06/09	695.4	722.0	639.3	597.1	501.0
06/10	690.1	716.0	635.0	597.0	501.0
06/11	688.5	714.0	632.0	596.5	501.0
06/12	685.1	712.1	629.1	596.0	501.0
06/13	689.2	713.5	629.1	596.5	501.0

END OF DATA

DATE	RHS 3-1	RHS 13-10	RHS 25-15	RHS 52-21	RHS 12-35
08/22	705.0	658.0	643.5	492.5	361.3
08/23	703.5	658.0	643.5	492.0	361.3
08/24	694.5	651.5	640.0	492.0	361.1
08/25	691.5	649.0	637.0	492.0	361.0
08/26	689.0	645.0	634.0	492.0	360.5
08/27	689.0	645.0	632.0	491.5	360.0
08/28	685.0	641.1	630.0	491.0	360.0
08/29	684.0	640.0	630.0	491.0	360.0
08/30	682.0	638.0	627.0	490.0	359.0
08/31	680.0	637.0	625.0	490.0	358.3
09/01	680.0	635.5	624.0	489.5	358.0
09/02	679.0	633.0	623.8	489.5	358.0
09/03	677.0	633.0	623.8	489.5	358.0
09/04	675.5	631.2	620.0	490.0	355.5
09/05	673.2	630.0	618.5	488.0	354.0
09/06	673.0	629.0	618.0	487.5	354.0
09/07	672.0	628.0	617.8	487.0	353.0
09/08	671.0	627.0	616.0	487.0	353.0
09/09	670.0	626.0	615.0	487.0	352.1
09/10	669.6	626.5	614.5	484.3	352.1
09/11	669.0	625.0	614.5	483.8	352.0
09/12	668.0	625.0	614.5	483.5	352.0

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ATTACHMENT NO. 5

RHS LIFT NO. 2 DRAWDOWN RAW DATA

DATE	RHS 3-1	RHS 13-10	RHS 25-15	RHS 52-21	RHS 12-35
09/13	667.0	624.5	613.0	483.0	350.0
09/14	667.0	624.0	613.5	483.0	350.0
09/15	667.0	623.0	611.0	481.5	348.0
09/16	665.0	622.0	610.0	481.0	345.0
09/17	665.0	622.0	610.0	481.0	345.0
09/18	665.0	621.0	610.0	481.0	345.0
09/19	665.2	620.0	609.0	480.5	345.0
09/20	665.0	620.0	609.0	480.0	346.0
09/21	663.8	620.0	610.0	479.7	348.0
09/22	663.5	619.5	608.2	478.6	345.5
09/23	663.8	619.0	607.5	477.2	344.5
09/24	664.5	618.2	606.0	476.0	346.2
09/25	663.2	617.5	605.0	476.6	346.0
09/26	662.0	617.3	605.0	476.4	345.0
09/27	662.0	616.0	607.0	476.2	345.0
09/28	662.0	617.5	606.0	475.0	343.0
09/29	662.0	617.3	606.0	475.0	341.0
09/30	661.0	616.0	605.0	474.0	343.0
10/01	661.0	617.0	604.0	474.0	341.0
10/02	661.0	617.0	607.0	474.0	342.0
10/03	659.5	616.5	605.0	473.0	340.2
10/04	659.0	616.0	606.0	473.0	341.0
10/05	658.0	615.5	604.0	473.0	340.0
***					
10/06	658.0	615.0	605.0	472.0	340.0
10/07	657.5	614.5	605.0	472.0	340.0
10/08	656.5	614.0	602.0	472.0	338.5
10/09	657.5	613.0	603.0	472.0	340.5
10/10	656.0	612.0	603.0	472.0	338.5
10/11	656.0	611.0	601.0	472.0	338.0
10/12	656.0	610.0	600.8	471.0	337.0
10/13	655.0	610.2	600.0	470.0	335.2
10/14	655.0	610.0	600.0	470.0	335.2
10/15	654.0	610.0	599.5	469.0	335.0
10/16	654.0	610.0	597.0	468.0	335.0
10/17	654.0	610.0	597.0	468.0	335.0
10/18	654.0	610.0	598.0	468.0	335.0
10/19	654.0	609.0	598.0	468.0	335.0
10/20	654.0	608.0	598.0	467.5	335.0
10/21	654.0	608.0	597.0	467.3	335.0
10/22	653.0	607.0	597.0	467.0	334.0
10/23	652.0	608.0	597.0	467.0	333.0
10/24	652.0	607.0	596.0	466.0	332.5
10/25	650.2	606.8	596.0	466.0	332.0
10/26	651.5	606.0	595.0	465.0	332.5
10/27	651.5	605.7	595.2	465.6	334.0
10/28	650.2	606.0	596.0	465.0	332.5
***					

ATTACHMENT NO. 5

RHS LIFT NO. 2 DRAWDOWN RAW DATA

DATE	RHS 3-1	RHS 13-10	RHS 25-15	RHS 52-21	RHS 12-35
10/29	651.0	606.5	595.5	465.2	332.8
10/30	652.0	606.5	595.0	465.0	332.0
10/31	652.0	606.5	595.5	465.0	332.0
11/01	650.0	606.5	595.0	465.1	332.0
11/02	650.0	605.0	594.0	464.0	331.0
11/03	650.0	605.0	594.5	464.0	331.0
11/04	650.0	604.0	594.0	463.0	330.0
11/05	649.0	604.5	594.0	463.0	330.0
11/06	649.0	604.0	593.5	463.0	329.5
11/07	650.0	604.0	593.0	463.0	329.0
11/08	650.0	604.0	593.0	462.0	329.0
11/09	649.0	603.0	593.0	462.0	329.0
11/10	650.0	604.0	593.0	462.0	329.0
11/11	648.0	604.0	592.0	462.0	329.0
11/12	649.0	603.0	592.0	462.0	329.0
11/13	648.0	603.0	592.0	461.0	328.0
11/14	648.0	603.5	591.0	460.0	328.0

END OF DATA

DATE	RHS 3-1	RHS 13-10	RHS 25-15	RHS 52-21	RHS 12-35
12/03	668.0	622.0	609.0	462.5	330.0
12/04	664.0	620.0	608.0	463.0	330.0
12/05	664.0	618.5	607.0	463.0	330.0

END OF DATA

ATTACHMENT NO. 6

RHS LIFT NO. 2 BUILDUP RAW DATA

DATE	RHS 3-1	RHS 13-10	RHS 25-15	RHS 52-21	RHS 12-35
06/14	693.0	716.7	630.8	596.5	501.0
06/15	695.0	718.1	631.9	596.5	501.0
06/16	696.1	719.3	633.0	596.5	501.0
06/17	697.3	720.4	633.5	596.5	501.0
06/18	698.5	722.0	635.0	596.5	501.0
06/19	699.0	722.0	635.0	596.5	501.0
06/20	699.5	723.0	636.0	596.5	501.0
06/21	699.9	723.0	636.5	596.5	501.0
06/22	700.0	724.0	636.5	596.5	501.0
06/23	700.0	724.0	636.5	596.5	501.0
06/24	700.2	724.0	636.5	596.5	501.0
06/25	701.0	724.0	637.5	596.5	501.0

END OF DATA

DATE	RHS 3-1	RHS 13-10	RHS 25-15	RHS 52-21	RHS 12-35
11/15	652.0	606.0	593.0	460.0	327.5
11/16	654.0	608.0	594.0	460.0	327.0
11/17	656.0	609.5	596.0	460.0	327.0
11/18	658.0	611.0	598.5	460.0	327.0
11/19	659.5	613.0	599.0	460.0	328.0
11/20	660.0	614.0	600.0	460.0	328.0
11/21	662.0	615.0	601.0	460.0	328.0
11/22	662.0	616.0	603.0	460.0	328.0
11/23	663.5	616.5	603.0	460.0	328.0
11/24	664.0	618.0	604.0	460.5	328.5
11/25	665.0	618.5	605.0	461.0	328.5
11/26	665.5	619.0	605.5	461.0	328.5
11/27	667.0	620.0	606.0	462.0	329.0
11/28	668.0	620.1	607.0	462.0	329.0
11/29	669.0	621.0	608.0	462.0	330.0
11/30	669.0	622.0	608.0	462.0	330.0
12/01	670.0	623.0	608.0	462.0	330.0
12/02	670.0	623.0	608.0	462.0	330.0

END OF DATA

ATTACHMENT NO. 6

RHS LIFT NO. 2 BUILDUP RAW DATA

DATE	RHS 3-1	RHS 13-10	RHS 25-15	RHS 52-21	RHS 12-35
12/06	667.0	621.0	607.0	463.5	330.0
12/07	668.0	622.5	608.0	464.0	330.0
12/08	669.0	622.5	608.5	463.5	330.0
12/09	670.0	624.0	609.5	463.0	331.0
12/10	671.0	624.5	610.0	463.7	331.0
12/11	672.0	625.0	611.0	463.7	331.5
12/12	672.5	625.5	611.0	465.0	332.0
12/13	672.5	626.0	611.0	465.0	332.0
12/14	673.0	626.0	612.0	465.0	332.0
12/15	674.0	627.0	612.5	465.0	332.0
12/16	674.0	627.0	612.5	465.0	332.0
12/17	674.0	627.0	613.0	465.0	332.0
12/18	674.0	627.0	613.0	465.0	332.0
12/19	675.0	628.0	614.0	465.0	332.5
12/20	675.0	628.5	614.0	465.5	332.5
12/21	676.0	629.0	615.0	466.5	334.0
12/22	676.0	629.5	615.0	466.5	334.0
12/23	676.5	630.0	616.0	466.5	334.5
12/24	677.0	630.0	616.0	466.5	334.5
12/25	677.0	630.0	616.0	466.5	334.5
12/26	677.2	630.5	616.0	466.5	334.5
12/27	677.2	631.0	616.0	466.5	334.5
***					
12/28	677.2	631.0	616.5	466.5	334.5
12/29	677.2	631.5	617.0	466.5	334.5
12/30	677.2	632.0	617.0	466.5	334.5

END OF DATA

ATTACHMENT NO. 7
RHS 54-3 LTFT NO. 2 WATER FLOW RATES

DATE	VORTEX WATER RATE	ORIFICE WATER RATE	VORTEX/ ORIFICE RATIO	DATE	VORTEX WATER RATE	ORIFICE WATER RATE	VORTEX/ ORIFICE RATIO
*****	*******	*******	********	*****	*******	*******	********
08/22	193650	361917	53.507	10/05	620196	552139	112.33
08/23	535765	586725	91.315	10/06	591536	559550	105.72
08/24	618389	642309	96.276	10/07	591536	559550	105.72
08/25	664349	669484	99.233	10/08	594893	559550	106.32
08/26	635430	642309	98.929	10/09	593344	558315	106.27
08/27	635817	636133	99.95	10/10	595055	573137	104
08/28	659959	679365	97.143	10/11	597604	565726	105.63
08/29	645242	654661	98.561	10/12	600831	566961	105.97
08/30	633494	636133	99.585	10/13	597604	557080	107.27
08/31	610256	611429	99.808	10/14	588438	554609	106.1
09/01	614000	617605	99.416	10/15	589600	549668	107.26
09/02	622391	629957	98.799	10/16	586889	558315	105.12
09/03	632977	617605	102.49	10/17	586889	549668	106.77
09/04	642014	599077	107.17	10/18	587921	542257	108.42
***							
09/05	648598	592901	109.39	10/19	583661	543492	107.39
09/06	641756	611429	104.96	10/20	587405	543492	108.08
09/07	628588	611429	102.81	10/21	568556	529905	107.29
09/08	621875	605253	102.75	10/22	572300	526199	108.76
09/09	629879	607723	103.65	10/23	564812	532376	106.09
09/10	625102	595371	104.99	10/24	560552	531140	105.54
09/11	606770	617605	98.246	10/25	562230	524964	107.1
09/12	581983	611429	95.184	10/26	555130	528670	105.01
09/13	565845	605253	93.489	10/27	554097	528670	104.81
09/14	586372	592901	98.899	10/28	556421	526199	105.74
09/15	580434	607723	95.51	10/29	564554	528670	106.79
09/16	580046	607723	95.446	10/30	559390	526199	106.31
09/17	567394	595371	95.301	10/31	552935	529905	104.35
09/18	564296	590430	95.574	11/01	551386	513847	107.31
09/19	563909	586725	96.111	11/02	549708	512612	107.24
09/20	568040	594136	95.608	11/03	555388	515083	107.83
09/21	583661	586725	99.478	11/04	551902	516318	106.89
09/22	569073	592901	95.981	11/05	546093	495319	110.25
09/23	563263	595371	94.607	11/06	547384	510142	107.3
09/24	558357	568197	98.268	11/07	539638	528670	102.07
09/25	561069	543492	103.23	11/08	538347	503966	106.82
09/26	522597	527435	99.083	11/09	530343	508907	104.21
09/27	548675	524964	104.52	11/10	524533	500260	104.85
***							
09/28	547642	524964	104.32	11/11	520660	497790	104.59
09/29	542349	513847	105.55	11/12	526599	505201	104.24
09/30	536152	510142	105.1	11/13	536281	516318	103.87
10/01	557454	545963	102.1	11/14	502457	482967	104.04
10/02	600960	579313	103.74	12/03	550870	549668	100.22
10/03	607803	578078	105.14	12/04	510461	510142	100.06
10/04	627168	558315	112.33	12/05	512527	511377	100.22

ATTACHMENT NO. 8

RHS Vessel Inspection
Geothermal Performance Report
Roosevelt Hot Springs, Beaver County, Utah

cc: Denver Safety Files

PHILLIPS PETROLEUM COMPANY
PRESSURE VESSEL INSPECTION AND RECERTIFICATION REPORT

TO: E. G. Hoff-NRG-EM-Salt Lake City FILE:
FROM: B. R. Barker-NRG-E&P-Denver, Colorado DATE: 4/17/79

VESSEL IDENTIFICATION: PLANT AND UNIT Roosevelt KGRA 54-3
SIZE 36"OD x 16'8"S-S (HORIZ) (VERT). SERVICE Water-Steam Separater
NATL BD NO. NB 684 PO NO. 5-286207A
AFE OR EQUIPMENT NO. RFE 65655 MFG BY The Brewster Co.-Shreveport, LA
MFG DWG NO. 429024-5 MFG SIGNATURE Ser. No. 8319 YR '75
PVI NO. 7688 CO DWG

INSPECTION: (EXTERNAL)&(INTERNAL). DATE OF PREVIOUS INSPECTION April 22, 1977
REASON FOR INSPECTION Returning to service
METHOD(S): (VISUAL) ~~(XXXXXXX)~~ (HAMMER TEST) ~~(XXXXXXXXX)~~ (MAGNETIC PARTICLE)
~~(XXXXXXXXXXXX)~~ (ULTRASONIC) OTHER

PRESSURE: ORIG. DESIGN 550 PSIG. @600° f MAX. ALLOWABLE WORKING (RV SET) 550 PSIG @ 600 ° F.
ORIG. TEST 825 PSIG. CURRENT OPERATING - PSIG. CURRENT RV SET * PSIG.

SHELL: MATERIAL SA 516-70 ORIGINAL THK .625 & 1.000 IN.
CORROSION ALLOWANCE 0 METAL LOSS 0 EFFECTIVE THK .625 & 1.000

HEADS: IDENTIFY
CORROSION ALLOWANCE 0 MATERIAL SA 516-70
ORIGINAL THK .625 METAL LOSS 0 EFFECTIVE THK .625
TYPE Ellip. ELLIP RATIO 2:1 KNUCKLE RADIUS (r)
DISH INCH, RISE IN INCHES, DISH RADIUS (L)

OPPOSITE HEAD:
MATERIAL ORIGINAL THK METAL LOSS
EFFECTIVE THK TYPE ELLIP RATIO
KNUCKLE RADIUS (r) Same DISH INCH, RISE IN INCHES.
DISH RADIUS (L)

JOINTS: LONG. SEAM DWBJ CIRCULAR SEAM DWBJ&DWBJ/BS X-RAYED 100%
STRESS RELIEF No DIA. RIVET HOLES PITCH
STRAP THK: INTERNAL EXTERNAL

NOZZLES: TYPE WF - RF SERIES 300 REINF yes & no SIZE (S) 2-2" 1-12" 2-4" 1-16"
Water Steam Inlet: 13 3/4 sq. x 1" thick
COUPLINGS: TYPE SERIES REINF SIZE (S)
MANWAY(S): TYPE RF SERIES 300 REINF SIZE (S) 12
PATCHES: SIZE, LOCATION AND TYPE OF JOINT None

CORROSION DESCRIPTION: Insignificant

REPAIRS: (ATTACH SKETCHES OF MODIFICATIONS AND WELD JOINT DETAILS.)
REPAIRS MADE: None

WELDING PERFORMED: None

WELDING PROCESS:
WELDING PERFORMED IN ACCORDANCE WITH WELDING PROCEDURE NUMBER:

WELDER QUALIFICATIONS

WELDER QUALIFICATIONS

WELDER QUALIFICATIONS

WELDER QUALIFICATIONS

* 600 PSI Rupture Disc.

NATL BD NO. ____________

RE-RATING

THIS VESSEL RATED IN ACCORDANCE WITH 1974 ASME Pressure Vessel Code

MAX. ALLOWABLE PRESSURE (MAX RV SET) 550 PSIG @ 600 °F

WITH 0 CORROSION ALLOWANCE HYDROSTATIC TEST PRESSURE ____ DATE ____

RATING GOVERNED BY Original Design

CERTIFICATION: I CERTIFY THE ABOVE INSPECTION AND RATING WAS PERFORMED IN ACCORDANCE WITH: (NATIONAL BOARD INSPECTION CODE) (API RP 510) (PHILLIPS ENGINEERING STANDARD NO.(S) ____________), OR

Phillips Pressure Vessel Rating Manual & ASME Code.

SIGNATURE OF INSPECTOR B R Barker

GROUP/STAFF NRG E&P - Safety DATE 4-17-79

APPROVED ____________ DATE ____

TITLE ____________ GROUP/STAFF ____

RECOMMENDED DATE OF NEXT INSPECTION After one year of continuous service.

CALCULATIONS

(BASED ON 1974 ASME CODE FORMULAS)

SHELL: JOINT EFFICIENCY = E = ____ %   ALLOWABLE STRESS = S = ____ PSI

INSIDE DIAMETER = D = ____ IN.

$$P = \frac{2SEt}{D + 1.2t} = \_\_\_\_ \text{ PSI}$$

HEADS: JOINT EFFICIENCY = E = ____ %   ALLOWABLE STRESS = S = ____ PSI

FLANGED AND DISHED $\frac{L}{r}$ = ____ FACTOR M = ____ $P = \frac{2SEt}{LM + .2t} = \_\_\_\_$ PSI

(TORISPHERICAL)

$P = \frac{2SEt}{KD + .2t} = \_\_\_\_$ PSI

ELLIPSOIDAL: AXIS RATIO ____

FACTOR K ____ $P = \frac{4SEt}{D + .2t} = \_\_\_\_$ PSI

HEMISPHERICAL:

CONICAL: a = ____ O. CONSINE a = ____ $P = \frac{2SEt \cos a}{D + 1.2t \cos a} = \_\_\_\_$ PSI

WHERE: P = MAXIMUM ALLOWABLE PRESSURE; DESIGN PRESSURE, PSI

S = ALLOWABLE UNIT STRESS FOR MATERIAL, PSI (PAGE 117)

E = JOINT EFFICIENCY (PAGE 74)

t = METAL THICKNESS, INCHES

D = INSIDE DIAMETER, INCHES

L = INSIDE CROWN RADIUS, INCHES

r = INSIDE KNUCKLE RADIUS, INCHES

M = HEAD FACTOR DEPENDING ON L/r RATIO (PAGE 228)

K = HEAD FACTOR DEPENDING ON AXIS RATIO (PAGE 228)

a = ONE-HALF OF THE INCLUDED (APEX) ANGLE OF CONICAL HEADS

(PAGE REFERENCES ARE TO 1974 ASME CODE - SECTION VIII, DIV. 1)

ADDITIONAL REMARKS:

Found no conditions that would warrant derating this vessel.

ATTACHMENT NO. 9

RHS Ultrasonic Piping Inspection
Geothermal Performance Report
Roosevelt Hot Springs, Beaver County, Utah

July 8, 1979

INTER-OFFICE CORRESPONDENCE / SUBJECT: Roosevelt Hot Springs Unit
Well No. 54-3, Utah

Terry Allen
Box 239
Salt Lake City, Utah 84110

Attached are the results of pipe thickness readings on subject well taken June 26, 1979. The piping checked was from the safety valve to the separator, including the corrosion loop. Due to the lack of records on original piping installed, we would recommend that a similar check be made in approximately one year.

All welds were ultrasonically inspected the same day and no flaws were found other than misalignment on three joints and they do not affect the integrity of the welds. The welds were evaluated using a Model 301 B Branson Flaw Detector, 70^{o} angle, ¼", 2.5 MH_{Z} probe calibrated according to AWS structural steel code, using a standard DSC calibration block.

The flat plate welded into the end of the two tees, upstream of the 2Ø meter run and at the bottom of the riser to the separator, will not rate for pressure piping. For this plate to rate, the inside would have to be welded. We would recommend that a flange be welded on the end of the tees, and then a blind flange be bolted on.

Answering your question as to which flange we would recommend, we recommend a raised face, series 600 flange with a flextalic gasket. The ring joint will stand a higher pressure but due to the temperatures encountered, ambient to 430^{o}, the ring joint is compressed initially and heated, then cooled down and heated up again. This heating up allows the steam to flow around the ring and cut it somewhat and leak. The flextalic is spring metal and when compressed initially, still retains some spring, so when it is cooled it still contacts the raised face flanges. When heated up again, the flextalic gaskets are right and allow less of a chance for leaking and cutting of gasket material.

B. R. Barker

B. R. Barker

BRB:LER:mar

attachment

cc: J. Ingvalson - Bartlesville

Sonoray readings on pipe taken at SEE ITEM NO. intervals with 6-8 readings taken around circumference of pipe.

Facility ROOSEVELT HOT SPRINGS UNIT WELL # 54-3. Service GEOTHERMAL PRODUCTION Date JUNE 26, 1979

Normal Operating Pressure 470 psi. Maximum Operating Pressure 505 psi. Operating Temperature 430°F.

Item No.	Location & Footage	Pipe Size O.D.	Grade & Type	Nom. Wall Thk.	Eff. Wall Thk.	Maximum Allow Press. Based on Eff. W.T.	Remarks	Recommendations
1.	10"x12" Reducer off 10" Safety valve	12"	UNKNOWN	UNK	.425"	760	Grade and type of piping unknown - Rating as plant piping, Gr. A, ERW, stress 11,100 psi	
2.	STRAIGHT piece off reducer before 1st 45° ELL	12"	"	"	.425	760	"	
3.	First 45° ELL	12"	"	"	.375	669	"	
4.	Line from 1st 45° ELL to 2nd 45° ELL on riser. 3 locations w/6-8 readings on circumference.	12"	"	"	.395	704	"	
5.	2nd 45° ELL, Bottom of Riser	12"	"	"	.375	669	"	
6.	STRAIGHT piece from 45° ELL to 12"x8" Reducer	12"	"	"	.410	733	"	
7.	middle of 12"x8" Reducer before 6" control valve	12"	"	"	.435	777	"	
8	middle of 8"x6" Reducer before control valve	8"	"	"	.360	957	"	

Sonoray readings on pipe taken at SEE ITEM 20 intervals with 6-8 readings taken around circumference of pipe.

Facility Roosevelt Hot Springs Unit WELL #54-3. Service Geothermal Production Date June 26, 1979

Normal Operating Pressure 470 psi. Maximum Operating Pressure 505 psi. Operating Temperature 430 °F.

Item No.	Location & Footage	Pipe Size O.D.	Grade & Type	Nom. Wall Thk.	Eff. Wall Thk.	Maximum Allow Press. Based on Eff. W.T.	Remarks	Recommendations
9.	STRAIGHT pipe before 6" Control Valve	6"	UNKNOWN	UNK.	.280	971	~~Grade and Type of piping unknown~~ RATING AS PLANT PIPING, GR A, ERW, STRESS 11,100 psi.	
10.	middle of 6"x8" reducer downstream of 6" CONTROL VALVE	8"	"	"	.330	875	"	
11.	middle of 8"x12" reducer downstream of Control Valve	12"	"	"	.420	750	"	
12.	STRAIGHT Piece before TEE	12"	"	"	.325	669	"	
13.	FLAT plate welded in end of TEE	12"	"	"	1.285		RATED IN ACCORDANCE WITH RULES OF UG-34 OF ASME Code.	
14.	Beginning of Pipe upstream of 2 Ø meter run	12"	"	"	.375	669	Rated as plant piping, Gr. A, ERW, STRESS 11,100 psi.	
15.	middle of pipe upstream of 2 Ø meter Run	12"	"	"	.375	669	"	
16.	End of pipe upstream of 2 Ø meter Run	12"	"	"	.375	669	"	

Sonoray readings on pipe taken at SEE Item NO. intervals with 6-8 readings taken around circumference of pipe.

Facility Roosevelt Hot Springs Unit Well #54-3. Service Geothermal Production Date June 26, 197[illegible]

Normal Operating Pressure 470psi. Maximum Operating Pressure 505psi. Operating Temperature 430 °F.

Item No.	Location & Footage	Pipe Size O.D.	Grade & Type	Nom. Wall Thk.	Eff. Wall Tnk.	Maximum Allow Press. Based on Eff. W.T.	Remarks	Recommendations
17.	Beginning of pipe downstream of 2 ϕ meter run	12"	UNKNOWN	UNK.	.325	669	Rated as plant Piping, Gr. A, ERW, stress 11,100 psi.	
18.	middle of pipe downstream of 2 ϕ meter run	12"	"	"	.325	669	"	
19.	End of pipe downstream of 2 ϕ meter run	12"	"	"	.325	669	"	
20.	TEE TO ENTRANCE of Chemical Loop	12"	"	"	.525	945	"	
21.	STRAIGHT pipe 12" crane valve and chem. Loop Tee	12"	"	"	.325	669	"	
22.	12"x10" reducer of chem. Loop Tee.	12"	"	"	.405	722.	"	
23.	START of pipe between Chem. Loop & Separator	12"	"	"	.325	669	"	
24.	middle of pipe between chem. Loop & Separator	12"		"	.325	669	"	
25.	End of pipe between chem. Loop & Separator	12"		"	.325	669	"	
26.	Tee at end of pipe between chem. Loop and Separator	12"		"	.525	945	"	

Sonoray readings on pipe taken at SEE ITEM NO. intervals with 6 - 8 readings taken around circumference of pipe.

Facility Roosevelt Hot Springs Unit Well #54-3. Service Geothermal Production. Date June 26, 1979

Normal Operating Pressure 470 psi. Maximum Operating Pressure 505 psi. Operating Temperature 430°F.

Item No.	Location & Footage	Pipe Size O.D.	Grade & Type	Nom. Wall Thk.	Eff. Wall Thk.	Maximum Allow Press. Based on Eff. W.T.	Remarks	Recommendations
27.	FLAT plate welded in end of Tee	12"	UNKNOWN	UNK.	1.255	0	RATED IN accordance with Rules of UG-34 of ASME Code,	
28.	Riser from Tee to Separator	12"	"	"	.375	669	Rated as plant piping, Gr. A, ERW, STRESS 11,100 psi.	
29.	Section 1 of Chem. Loop.	10"	"	"	.300	633	"	
30.	Section 2 of Chem. Loop	10"	"	"	.325	687	"	
31.	90° ELL between Section 2 & 3 of Chem. Loop.	10"	"	"	.360	763	"	
32.	Section 3 of Chem. Loop.	10"	"	"	.295	622	"	
33.	90° ELL between Section 3 & 4 of Chem. Loop	10"	"	"	.360	763	"	
34.	Section 4 of Chem. Loop.	10"	"	"	.295	622	"	
35.	Section 5 of Chem. Loop.	10"	"	"	.300	633	"	

[illegible]

Sonoray readings on pipe taken at SEE ITEM NO. intervals with 6-8 readings taken around circumference of pipe.

ROOSEVELT HOT SPRINGS UNIT

Facility WELL #54-3. Service Geothermal Production Date June 26, 1979

Normal Operating Pressure 420 psi. Maximum Operating Pressure 505 psi. Operating Temperature 430° F.

Item No.	Location & Footage	Pipe Size O.D.	Grade & Type	Nom. Wall Thk.	Eff. Wall Tnk.	Maximum Allow Press. Based on Eff. W.T.	Remarks	Recommendations
36.	STRAIGHT Section of pipe from bottom of well head RISER TO 1ST 45° ELL ON Bypass of 6" control valve,	6"	UNKNOWN	UNK,	.300	1042	Rated as plant piping, Gr. A, ERW, STRESS 11,100 psi.	
37,	1ST 45° ELL ON bypass of CONTROL valve	6"	"	"	.325	1132	"	
38.	2ND 45° ELL ON bypass OF Control valve	6"	"	"	.325	1132	"	
39,	STRAIGHT piece of pipe before 6" bypass valve	6"	"	"	.265	917	"	
40.	STRAIGHT piece of Pipe downstream of Control valve	6"	"	"	.280	970	"	
41.	6" bypass TO pit	6"	"		.250	864	"	

ATTACHMENT NO. 10

RHS Well No. 54-3 Vibration Inspection
Geothermal Performance Report
Roosevelt Hot Springs, Beaver County, Utah

PHILLIPS PETROLEUM COMPANY
BARTLESVILLE, OKLAHOMA 74004
PHONE: 918 661-6600 CABLE CODE: PHILPETROL TELEX: 49-2455

ENGINEERING AND SERVICES

January 11, 1980

Geothermal Test Facility
Inspection Comments

Mr. Terry Allen
Phillips Petroleum Co.
P. O. Box 239
Salt Lake City, Utah 84110

On November 14, 1979 Earl Hicks and I visited the Geothermal Test Facility at Milford, Utah. Our purpose was to observe the facility in operation to determine if there were any design problems that would require solving in future geothermal facility designs.

The problems that I noted were minimal. As we have discussed previously, spring supports should be used at certain locations to provide support for the pipe at all operating conditions. This is especially true for the piping near the wellhead where the piping has considerable vertical movement due to the thermal expansion of the well casing. Spring supports for the piping near the separator would also be useful to keep the loads on the vessel nozzles low. Vibration snubbers could be utilized to minimize piping vibration. These snubbers, which are commercially available, allow thermal expansion of the piping but resist vibration. Spring supports are also commercially available.

Several problems associated with the line to the reinjection well were noted. At a few locations, the pipe shoe has severely deformed the horizontal member of the pipe support. The pipe supports were fabricated from salvaged pipe which was in very poor condition. This problem could be eliminated by using a better class of material for the structural members of the supports and protecting them from corrosion.

Some of the pipe shoes come very close to falling off of the pipe supports when the pipe is hot. The design drawings provide that various shoe lengths be used dependent upon the thermal movement of the pipe at the support. The shoes were to be positioned, relative to the supports, to take full advantage of their length. If properly done, there should be no chance of the shoe sliding off the support. It is possible that a shoe of the wrong length was used or the shoe could have been improperly positioned. At any rate, these details should be closely checked in future designs and inspected after construction.

The Barco joints, used to absorb the expansion in the reinjection line, appeared to have operated satisfactorily and seem to be a good solution to the problem.

On the whole, I can forsee no insurmountable problems that would be encountered in the design of a geothermal facility.

Attached is a letter from Earl Hicks with his comments on the noise and vibration problems at the test facility.

D D Viers

D. D. Viers
8 D4 PB

DDV/bbr - RC

Attachments

cc: J. Whitmire (w/a)
E. J. Hicks (wo/a)
M. O. Clark (w/a)
G. W. Poole (w/a)
J. F. Eilers (w/a)
(r) D. D. Viers

ATTACHMENT NO. 11

RHS Well No. 54-3 Noise Inspection
Geothermal Performance Report
Roosevelt Hot Springs, Beaver County, Utah

cc: ES 05.11/6-342 - RC
(r) C. E. Rawlins
F. Prange
D. L. Castle

PHILLIPS 66

December 20, 1979

INTER-OFFICE CORRESPONDENCE / SUBJECT: Inspection of Geotherm Facility, Milford, Utah
BARTLESVILLE, OKLAHOMA

Hicks-36-79

D. D. Viers (3) ← COPY FOR
Office

You asked that I give you my thoughts on the inspection we made of the geotherm test facility at Milford, Utah, on November 14, 1979. I listened to the noise, made noise measurements and witnessed the vibration of the piping system. Noise measurements I made are given in Data Sheets 1 and 2 attached. The major and dominating noise from equipment in the test loop is coming from the pressure reduction valve. The measurements show this and indicate levels that would cause restricted exposure as defined by OSHA. The frequency analysis of the noise is typical of that found for pressure-reducing valves. It is useless to attack other noise sources unless this one is dealt with first. The three main causes of control valve noise are aerodynamic, cavitation, and mechanical. Aerodynamic noise is the most common and generates the highest levels. It is caused by fluid turbulence and shock waves due to high velocity and mass flow. Actually, pressure-reducing valve noise increases with flow and pressure reduction until the critical ratio is reached. After this, the noise level increases only with an increase in flow. The critical pressure ratio for most gases is slightly less than 2:1. Acoustical velocity at Mach 1.0 always produces high noise levels because of the turbulence and shock waves, but when the mass flow is large, relatively high noise levels are generated at a Mach number as low as 0.4.

Noise reduction can, of course, be accomplished by reducing the pressure drop ratio, taking the pressure drop in stages, and/or reducing the mass flow. Other means of dealing with the noise problem are to use valves which incorporate diffuser elements, called "Whisper Trim" by one manufacturer, silencers downstream of the valve, and/or acoustically wrapping the silencer and line. Noisy valves are generally accompanied by severe piping vibration downstream of the valve. This can cause pipe failures, particularly small appendages, and instrument problems (pressure gages and thermowells). The technology is available to deal with these problems. These types of problems are very common to the process industry and I see no reason why they cannot be dealt with effectively at a geotherm facility.

A secondary noise source observed was that due to regeneration of noise where steam was being exhausted to the atmosphere in the pit. Good commercial silencers are available to deal with this problem, and I recommend one of these over trying to design one.

In addition to the thermal expansion noticed at the well head, there was some vibration observed. The source of vibration was not obvious, but I would guess that it was due to flashing of steam in the well. The vibration did not appear to me to be of a magnitude that would be structurally damaging. However, should it prove necessary to reduce this vibration, some specially designed vibration dampener would be necessary.

In summary, I saw no problems or potential problems of a noise and vibration nature which would be insurmountable.

EJH:mjl

Earl J. Hicks

Attachments

DATA SHEET

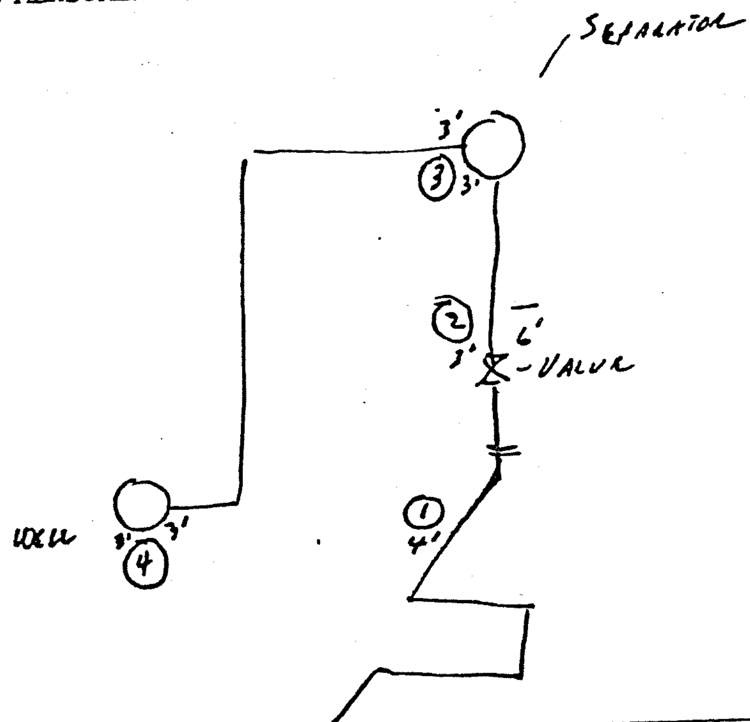
SOUND SURVEY DATA SHEET

PLANT Geotherm - Milford Utah DEPARTMENT NRG DATE 11-14-79

PLANT AREA ~~Downstream of~~ Pressure Reducing Valve SURVEY BY Earl J. Hicks

SOUND MEASURING EQUIPMENT B&K

NOISE MEASUREMENT LOCATIONS:



Location	1	2	3	4
DB$_A$ F S	108	95	89-90	87
DB$_B$ F S	108	95	90	87
DB$_C$ F S	108	95	90	89
31.5 Hz	69-72	74-76	76-78	79-82
63	72-74	76-78	78-81	80-81
125	75	76-78	78-80	80
250	77-78	81-83	80-82	79
500	88	82	81	79
1000	102	92	87	79
2000	104	90	81	84
4000	102	87	79	79
8000	90	79	70	64
16000	79	66	56	46

EJH 10/9/69,
7/29/71

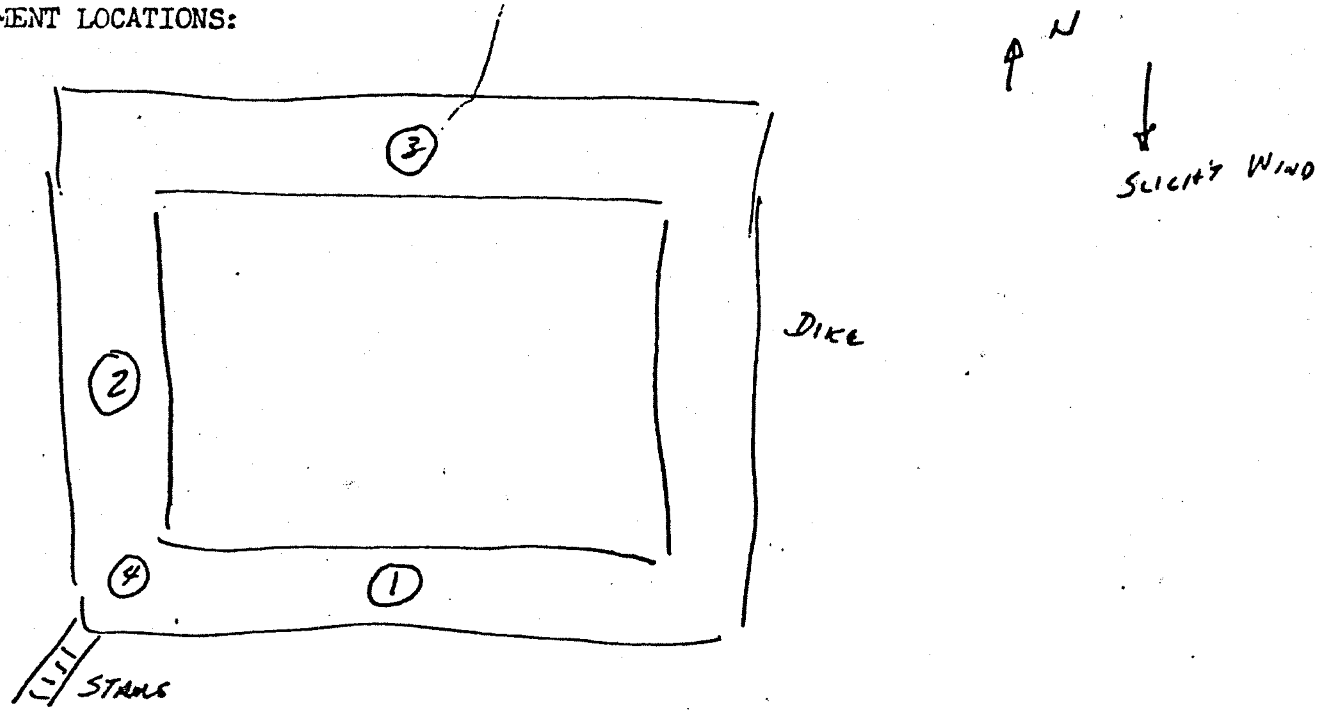
SOUND SURVEY DATA SHEET

PLANT Geotherm - Milford, Utah DEPARTMENT NRC DATE 11-14-79

PLANT AREA Dike Area SURVEY BY Earl J. Hick

SOUND MEASURING EQUIPMENT B&K

NOISE MEASUREMENT LOCATIONS:



Location	1	2	3	4
DB_A F S	92-94	90-94		94-96
DB_B F S	94-96			94-96
DB_C F S	97-98			94-96
31.5 Hz	80-84			80-83
63	88-91			85-87
125	92-93			89-90
250	84-86			88-89
500	82-84			88-90
1000	81-84			84-88
2000	79-83			85-88
4000	74-78			82-85
8000	61-66			69-76
16000	51-56			68-74

EJH 10/9/69,
7/29/71

ATTACHMENT NO. 12

Surface Equipment Antiscale Experiment at Roosevelt 54-3
Geothermal Performance Report
Roosevelt Hot Springs, Beaver County, Utah

cc: R&D Records - RC
C. W. Berge
T. S. Allen
W. J. Wride
B. M. Thompson
R. B. Needham
D. R. Wier (r) Y. Wu
R. G. Asperger

INTER-OFFICE CORRESPONDENCE / SUBJECT: Surface Equipment Antiscale Experiments at Roosevelt 54-3
BARTLESVILLE, OKLAHOMA

December 6, 1979

RGA-6-79

Mr. Earl Hoff
Salt Lake City Office

Introduction

This letter reports the results of experiments conducted from August 27 through October 29 with five antiscalants in surface equipment at Well 54-3 in the Roosevelt geothermal field. In these experiments the produced brine flowing through a 2-inch test line, off the 10-inch scaling loop, at a temperature of approximately 410°F and a rate of about 20,000 lbs/hr was spiked with calcium to accelerate scaling and permit completion of the experimentation in a reasonable time period. The antiscalants were injected at the desired concentrations and scale deposition was qualitatively monitored using a sensitive pressure gauge to detect changes in the pressure drop across a 1/2-inch orifice plate in the line. Normally, pressure trends indicating scale deposition could be detected in a 1/2 to 1 hour time period. However, in some cases, test conditions were held constant over several days. The reliability of this approach to detect scale deposition was verified several times during the experimentation by removing and visually inspecting both the orifice plate and the 2-inch spools.

Summary

At the highest added calcium concentration tested, 45 ppm, three antiscalants, Magna MEP 720, Dequest® 2000, and Dequest® 2060, prevented scale deposition at concentrations $\leq$ 1.5 ppm. At 20 ppm added calcium, the above three antiscalants plus Dearborn® 8010 were effective at concentrations no greater than 1 ppm. Dearborn® X1867 was the only antiscalant tested which was unsatisfactory. Calcium concentrations in the 20 to 45 ppm range are of interest because the downhole concentration in the CO_2 flash zone at Roosevelt is suspected to fall within this range. For a well with a brine flow rate of 15 mm lbs/day and at an anticipated antiscalant price of $1.00/lb, the antiscalant cost for continuous treatment at 1 ppm would be $15/day/well.

Three other significant findings were made during the experimentation. It was found that the concentrated antiscalant liquids could be diluted with geothermal brine as well as fresh water in the preparation of solutions for injection. The antiscalants were effective in either the acidic form as received or after neutralization with sodium hydroxide. All attempts to form and detect pseudoscale, a co-precipitate of a brine component and an antiscalant component, were unsuccessful.

Conclusions

The results indicate that chemical antiscalants can be economically used to prevent calcium carbonate scale in surface equipment at Roosevelt and in lower temperature fields such as Humboldt House. Also, they suggest, although this remains to be proven, that downhole scaling could be controlled economically with chemicals at Roosevelt.

Current Status

A limited effort is continuing in our laboratories with respect to chemical stability of the antiscalants in hot Roosevelt brine, the corrosivity of these chemicals, and the development of the analytical tools and techniques needed to routinely use the chemicals in the field. We are prepared and willing to assist in the design and execution of experiments involving downhole antiscalant injection at Roosevelt upon request.

Surface Test Results

The antiscalants investigated at Roosevelt are listed in Attachment I. Attachment II is a graph showing the added calcium concentration and the antiscalant concentration used in each of the experiments conducted with Magna MEP-720. The calcium-antiscalant combinations leading to scale formation, no scale formation, or uncertainty with respect to scale are delineated on the graph. Attachments III, IV, and V are similar graphs for the other three antiscalants which gave positive results.

In the field experimentation, the approach was to start with a calcium-antiscalant combination not giving scale and then move in the direction of scale formation by either increasing the calcium concentration or decreasing the antiscalant concentration. In several cases, once scale was observed then the variables were changed so as to move in the direction of no scale and it was determined whether the deposition of scale could be readily stopped. It was found that in some cases the scale was stopped while in others it was not. The arrows shown in Attachments II and IV identify the experiments in which the scaling was stopped by increasing the antiscalant concentration.

The 2-inch line data were confirmed by inhibitor injection into the brine at the wellhead. Wellhead injection prevented calcite precipitation in the control valves where scaling had previously been a serious problem.

Acknowledgments

Thanks for the assistance and cooperation extended Dale Javine and myself during this testing. I'll be happy to answer any further questions you may have regarding the testing.

Bob Asperger
R. G. Asperger

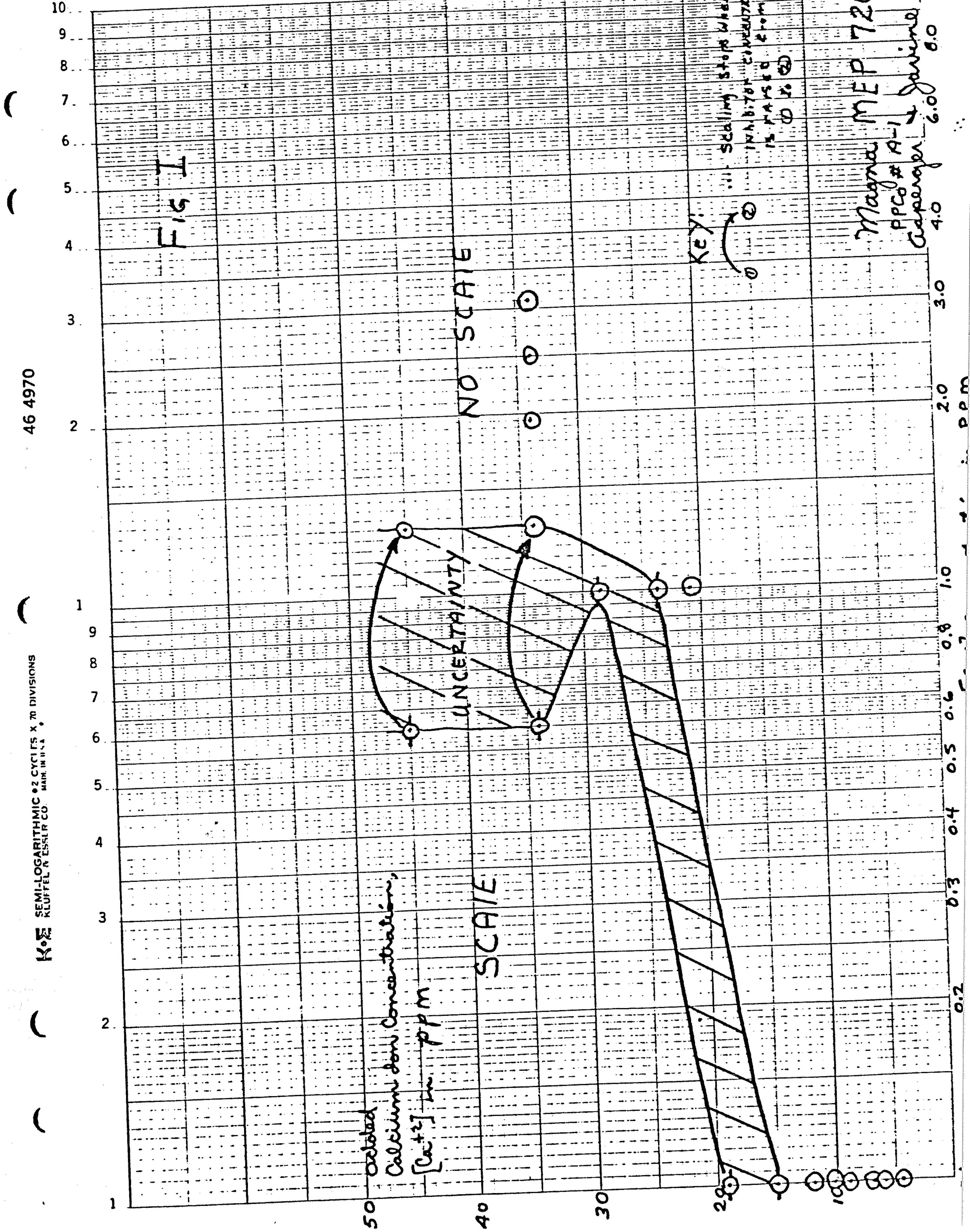
RGA:Lyn
Attachments

ATTACHMENT I

Antiscalants Tested in Surface Equipment at Roosevelt 54-3

Antiscalant Tradename	Phillips Code	Manufacturer
Magna MEP-720	A-1	Magna Corporation Petroleum Treating Division 7505 Fannin, Suite 600 Box 33387 Houston, TX 77033 ATTN: Ed Clarkson (713) 795-4270
Dequest® 2060	A-2	Monsanto Industrial Chemicals Co. 800 N. Lindbergh Blvd. St. Louis, Missouri 63166 ATTN: Richard T. Haynes (314) 694-3741
Dequest® 2000	A-5	"
Dearborn® 8010	A-3	Dearborn Chemical 300 Genesee St. Lake Zurich, Ill. 60047 ATTN: D. Anthony Carter (312) 438-8241
Dearborn® X1867	A-4	"

Attachment II to RGA-6-79



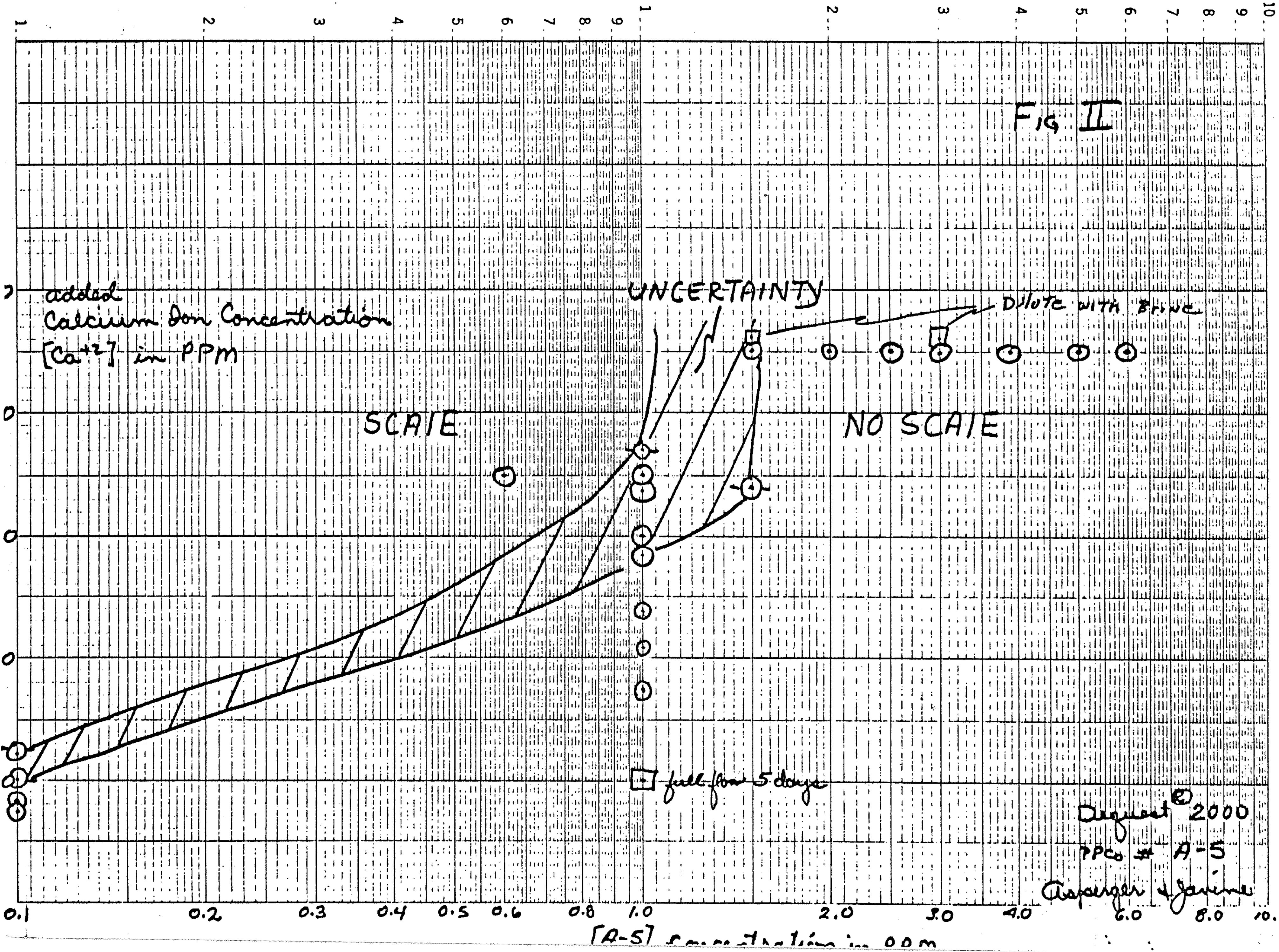


Fig II
added
Calcium Ion Concentration
[Ca+2] in PPM
UNCERTAINTY
Dilute with Brine
SCALE
NO SCALE
full flow 5 days
August 2000
PPCo # A-5
Asperger & Javine
0.1
0.2
0.3
0.4
0.5
0.6
0.8
1.0
2.0
3.0
4.0
6.0
8.0
10.0
[A-5] concentration in ppm

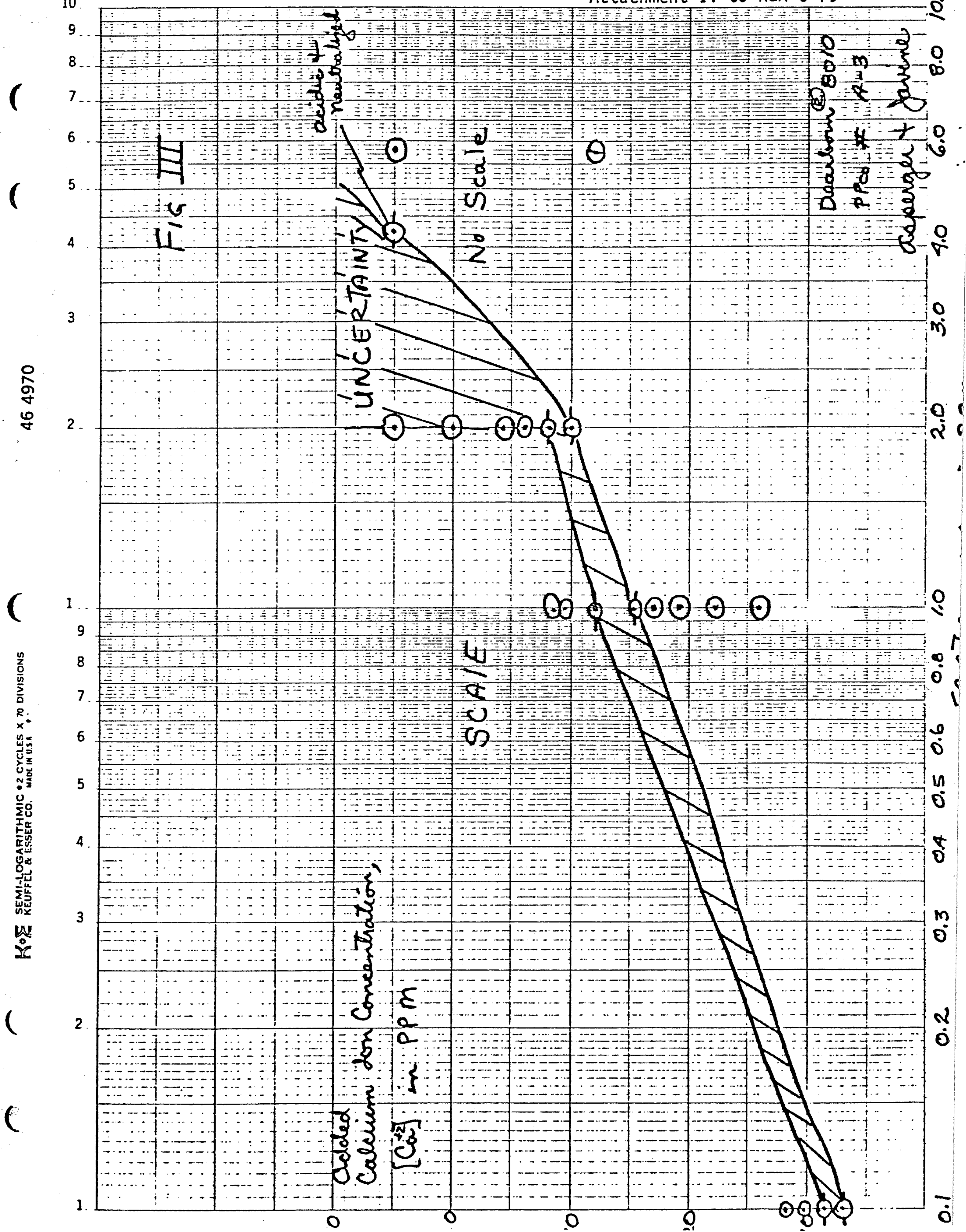


FIG III
UNCERTAINTY
No Scale
SCALE
acidic + Neutralized
Dearborn ® 8010
PPCo # A-3
Added Calcium Ion Concentration, [Ca+2] in PPM
0.1
0.2
0.3
0.4
0.5
0.6
0.8
1.0
2.0
3.0
4.0
6.0
8.0
10.0
46 4970
K+E SEMI-LOGARITHMIC 2 CYCLES X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

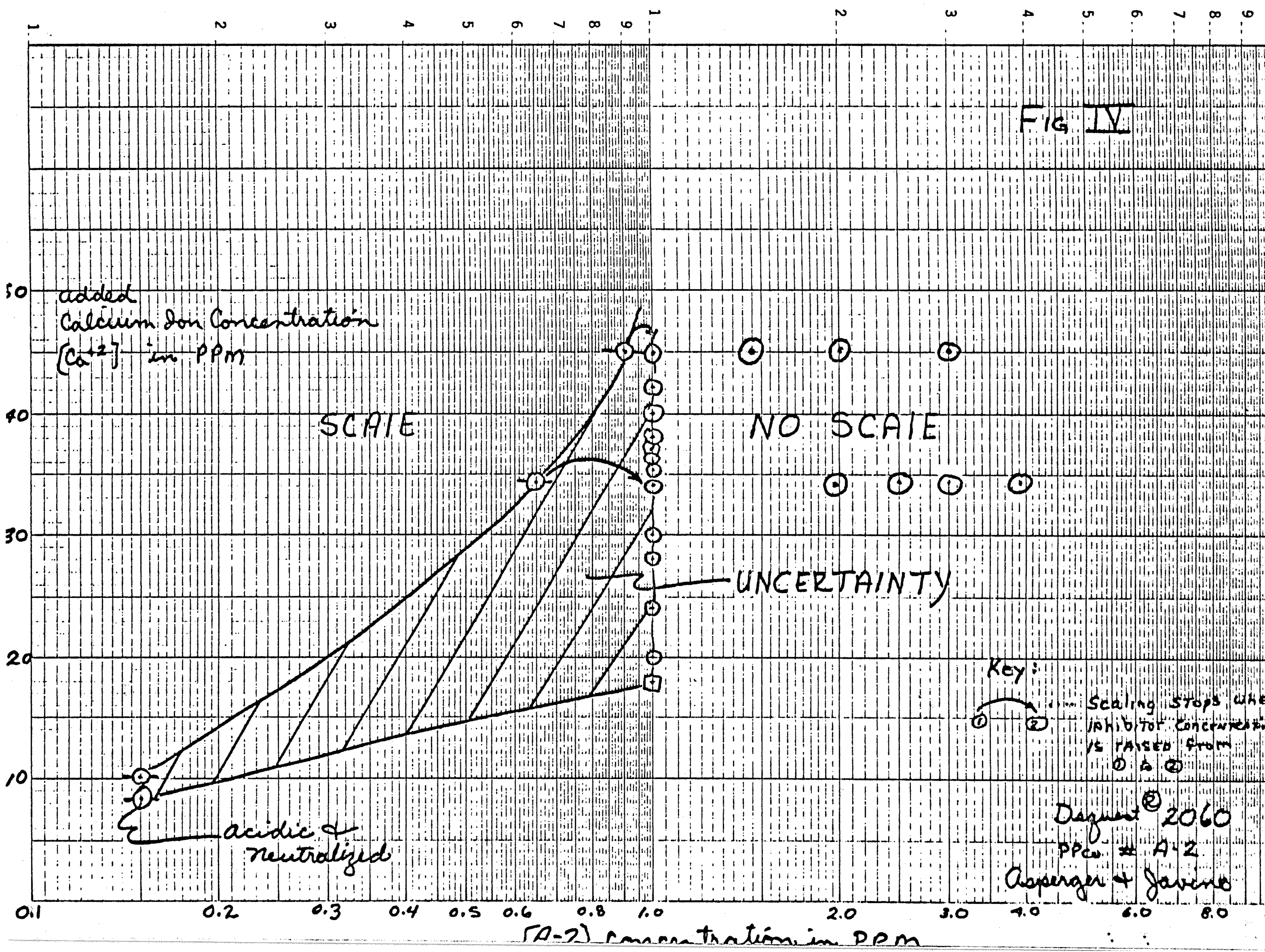


FIG IV
added
Calcium Ion Concentration
[Ca^{+2}] in PPM
SCAIE
NO SCAIE
UNCERTAINTY
acidic &
neutralized
Key:
.... Scaling stops when inhibitor concentration is raised from ① to ②
Dequest® 2060
PPCo # A-2
Asperger & Javino
[A-2] concentration in PPM
0.1
0.2
0.3
0.4
0.5
0.6
0.8
1.0
2.0
3.0
4.0
6.0
8.0
10.0
10
20
30
40
50

ATTACHMENT NO. 13

Trip Report - RHS, Utah Well 54-3 Noncondensable Gas
Geothermal Performance Report
Roosevelt Hot Springs, Beaver County, Utah

Attachment to JPW-7-79

TABLE I

NON-CONDENSABLE GAS CONTENT OF GEOTHERMAL FLUIDS FROM ROOSEVELT HOT SPRINGS WELL 54-3 - AUGUST, 1979

Date/Time	Method	Sample Valve	T (°C)	BP-VP (in.Hg) *	Condensed Steam Volume (ml.-gm.)	NC Volume (ml.)	NC Weight (gm.)	NC/Steam (Wt. %)	NC/Total Flow (Wt. %) **
8/26-12:40PM	Volume Displac.	Vertical (Top)	35	22.34	37.5	2340	3.04	8.11	0.673
5:50PM			40	21.77	33	2170	2.70	8.18	0.679
6:00PM			40	21.77	36	2180	2.72	7.56	0.627
8/31- 1:20PM			32.5	22.49	42	2541.5	3.35	7.98	0.662
1:40PM			33	22.48	38	2416	3.18	8.37	0.695
1:50PM			33.5	22.43	45.5	2299	3.02	6.64	0.551
8/28-11:55AM		Horizont. (Side)	30	22.64	33.5	2053	2.75	8.21	0.681
12:20PM			30	22.63	54	2500.5	3.35	6.20	0.515
12:45PM			31	22.55	41.5	1941	2.58	6.22	0.516
12:50PM			31.5	22.51	32.5	2047.5	2.71	8.34	0.692
8/31-10:50AM			28	22.88	52	2525	3.44	6.61	0.549
10:55AM			27.5	22.92	52	2532	3.46	6.65	0.552
11:05AM			28	22.87	57	2679	3.65	6.40	0.531
11:15AM			28	22.86	42	2326	3.17	7.55	0.627
11:22AM			28	22.85	56.5	2913	3.96	7.01	0.582
8/26- 4:41PM	Rate of Flow	Vertical (Top)	36	22.19	5.97/ min	400/ min	0.515/ min	8.62	0.715
5:00PM			30	22.69	5.94/ min	353/ min	0.474/ min	7.97	0.662
8/28- 4:10PM		Horizont. (side)	29	22.75	10.26/ min	480/ min	0.648/ min	6.32	0.524
4:32PM			29	22.74	10.71/ min	462/ min	0.623/ min	5.82	0.483
4:43PM			29.5	22.69	9.84/ min	462/ min	0.621/ min	6.30	0.523

*Barometric Pressure - Vapor Pressure of Water
**Steam/Total Flow = 8.3 wt. %

TABLE II

H_2S CONTENT OF NON-CONDENSABLE GASES FROM ROOSEVELT HOT SPRINGS WELL 54-3

AUGUST-SEPTEMBER 1979

AS DETERMINED BY CH29101 DRAGER TUBE

Date	Time	T (^oC)	BP-VP (in. Hg)	Sample Volume (ml)	Tube Reading	H_2S (Wt. ppm)
8/31	12:20PM	27	22.95	10	2.0	2063
				60	11.0	1891
				100	18.0	1856
	12:32PM			50	9.5	1960
	12:35PM			50	9.75	2011
9/1	10:35AM	28	22.92	50	10.0	2072
	10:37AM			50	9.0	1865
	10:38AM			100	18.0	1865

TABLE III

ANALYTICAL RESULTS FROM GI24081 SAMPLES COLLECTED

FROM ROOSEVELT HOT SPRINGS, UTAH - WELL 54-3 ON 8/29 & 8/30/79

		42-1 Brine	42-2 Acidified Brine	42-3 Steam	42-4 Acidified Steam
Li	ppm	22	22	12	4
Na	ppm	2160	2130	9	.4
K	ppm	458	512		
Rb	ppm		6.0		
Cs	ppm		7.6		
Be	ppm		ND ≤ 0		
Mg	ppm		ND ≤ 0.1		
Ca	ppm	10	12		
Sr	ppm		1.3		
Ba	ppm		ND ≤ 0.2		
V	ppm		ND ≤ 0		
Cr	ppm		ND ≤ 0.1		
Mo	ppm		0.1		
Mn	ppm		ND ≤ 0		
Fe	ppm		ND ≤ 0.2		
Co	ppm		ND ≤ 0.1		
Ni	ppm		ND ≤ 0.1		
Cu	ppm		ND ≤ 0.1		
Ag	ppm		ND ≤ 0.2		
Zn	ppm		ND ≤ 0.1		
Cd	ppm		ND ≤ 0		1.5
Hg	ppb		0.8		
B	ppm	29	29	2	
Al	ppm		ND ≤ 0.2		
$CO_3^=$	ppm	0		0	
HCO_3^-	ppm	188		0	
CN^-	ppb	9		3	
SiO_2	ppm				
Pb	ppb		ND ≤ 600		
NH_4^+	ppm	3		3	
$NO_3^- + NO_2^-$	ppm				
PO_4^-	ppm	3			
As	ppb	3930		3.3	
Sb	ppm		ND ≤ 0.4		
$SO_4^=$	ppm	54		2.5	
$SO_3^=$	ppm	4.5		ND ≤ 1	
$S^=$	ppm	0.12		2.0	
Se	ppb	ND≤0.3			
Te	ppm	0.063			
F	ppm	ND≤1			
Cl	ppm	3600			
I	ppm	ND ≤ 3			
pH		6.1		4.4	
TDS	g/l		7.5		

TABLE IV

COMPOSITION OF NON-CONDENSABLE GASES

COLLECTED AT ROOSEVELT HOT SPRINGS WELL 54-3

8/30/79

	GI24081 -42-5	GI24081 -42-6
CO_2	99.47* Wt. %	99.47* Wt. %
H_2S	0.20	0.20
N_2	0.30	0.30
O_2	0.043	0.043
CH_4	ND $\leq$ 0.005	ND $\leq$ 0.005
H_2	0.0005	0.0006
H_4	0.0006	0.0006

*By difference.

**From Table II, determined in the field.

Geothermal Fluid Collection Apparatus

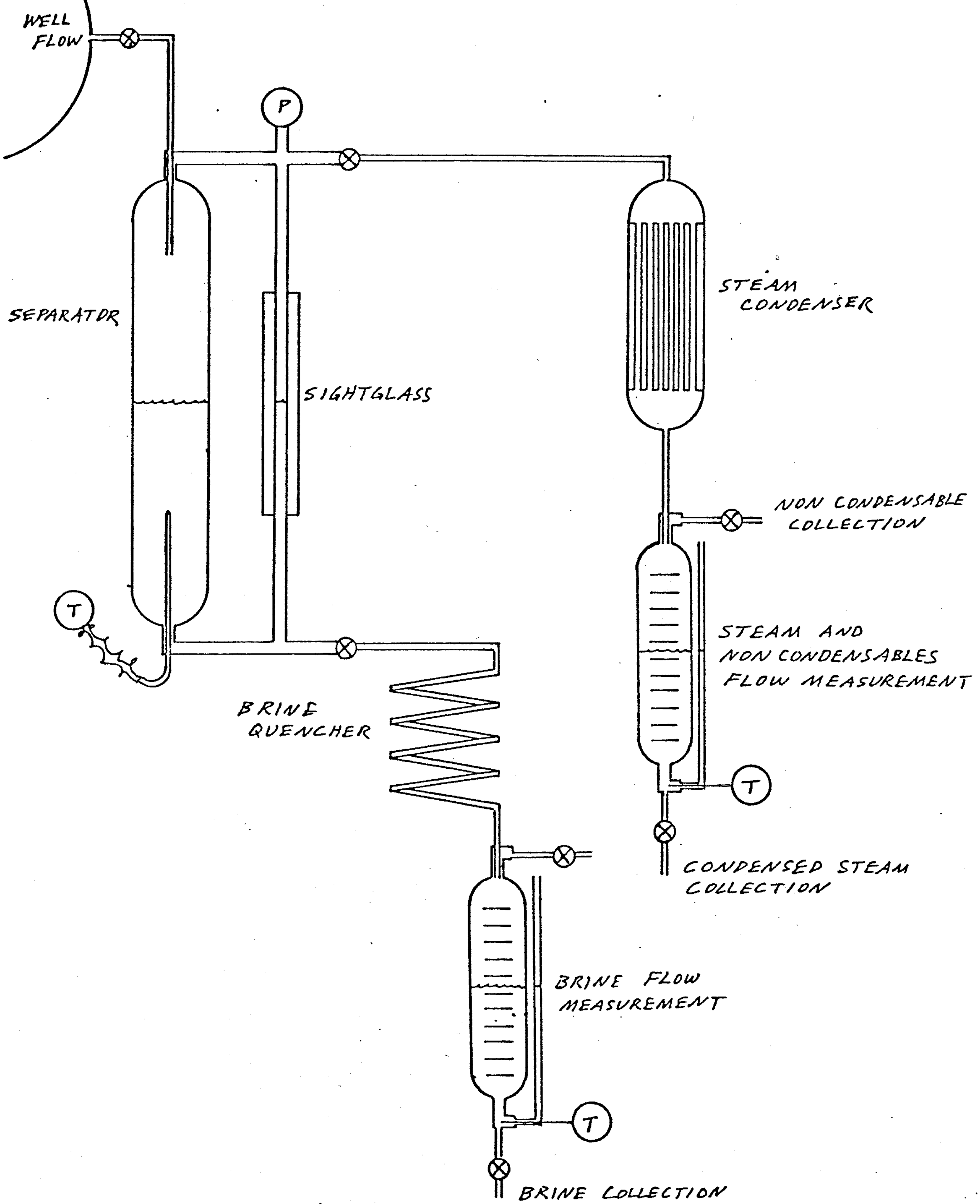


Figure 2. Apparatus for Determining Non-Condensable Gas Content in Geothermal Steam by Relative Rate of Flow

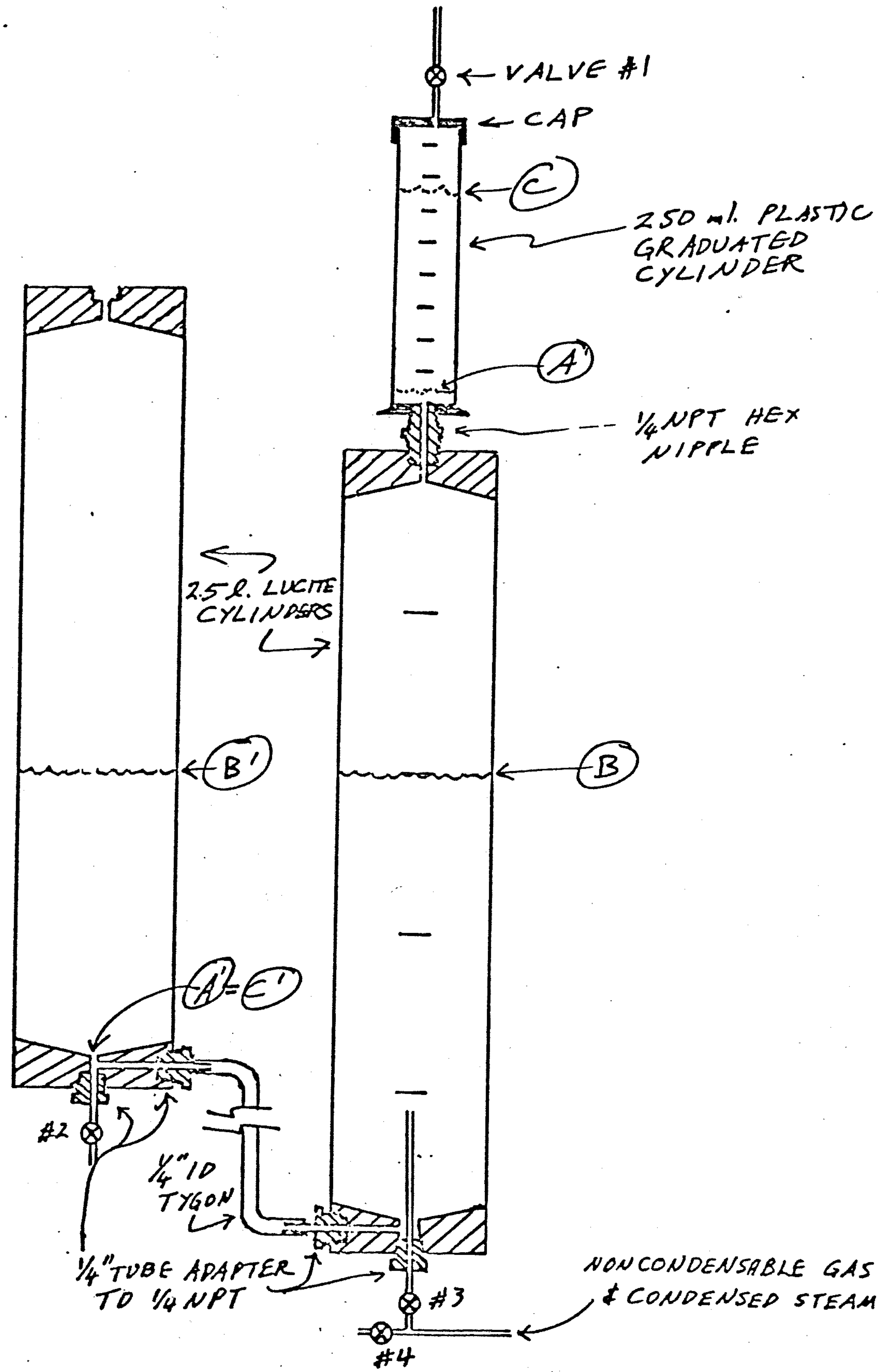


Figure 1. Apparatus for Determining Non-Condensable Gas Content in Geothermal Steam by Volume Displacement

ATTACHMENT NO. 14

Summary of Tele Trace Injection at RHS
Geothermal Performance Report
Roosevelt Hot Springs, Beaver County, Utah

TELEDYNE
ISOTOPES
50 VAN BUREN AVENUE
WESTWOOD, NEW JERSEY 07675
(201) 664-7070
TELEX 134474 TDYISOT WTWD

26 February 1980

Mr. Terry Allen
Phillips Petroleum Company
Geothermal Operations
P. O. Box 239
Salt Lake City, Utah 84110

Re: Summary of TeleTrace Injection
at Roosevelt Hot Springs

Dear Terry:

On May 30, 1979 Teledyne Isotopes injected 600 pounds of non-radioactive sodium iodide into Phillips Petroleum Company's disposal well No. 82-33 located at Roosevelt Hot Springs, in the KGRA Unit, Beaver County, Utah.

The amount of tracer calculated for injection was based on a total brine injection volume of $2.0 \times 10^8 \ell$ (40,000 BWPDx30Dayx167ℓ/B), and an in situ volume of $6.0 \times 10^8 \ell$. The total water volume of $8.0 \times 10^8 \ell$ was to be tagged with sufficient NaI to produce an average I^- concentration of 0.34 mg/ℓ. This is about three times above the 0.12 ± 10% mg/ℓ I^- level present in a background sample taken from Observation Hole #5 in May, 1979. It was further calculated that had the in situ volume been greater by as much as a factor of three, the average produced I^- concentration would be 0.14 mg/ℓ; still sufficiently above the base line level to be distinguished as a positive signal.

The injection procedure was carried out by adding about 300 pounds of NaI into each of two 55 gallon drums filled about three quarters with water. The solution was mixed and finally pumped into the top of 82-33 by means of a hand drum pump. The injection line had been shut-in throughout the injection procedure.

The solubility of NaI in cold water is about 184 g/100cc. Therefore, the amount of water needed for complete dissolution in one drum is:

$$\left(\frac{1.84\text{Kg}}{\ell}\right)\left(\frac{2.20\text{LB}}{\text{Kg}}\right)\left(\frac{4\ell}{\text{gal.}}\right) = 16.2\ \frac{\text{LB}}{\text{gal.}}, \quad \text{and}$$

$$\frac{300\text{LB NaI}}{16.2\ \frac{\text{LB}}{\text{gal.}}} = 18.5\ \text{gal.}$$

TELEDYNE ISOTOPES

26 February 1980
Mr. Terry Allen
Phillips Petroleum Co.
Salt Lake City, UT
page two

Each drum contained over twice that amount of water, insuring complete dissolution of the tracer and, therefore, insuring its complete injection.

A total of 73 water samples were analyzed from five (5) sampling points with the following identifications:

Producing Well 54-3	-	A
NEGRO MAG SEEP	-	B
Observation Hole #4	-	C
Observation Hole #5	-	D
Don Johnson Well		

Samples were collected intermittently in June, August, September and October of 1979. Elemental iodide concentrations ranged from "less than" 0.05 mg/ℓ to "greater than" 4.7 mg/ℓ.

The results of the tracer data are fairly inconclusive. This is due mainly to the lack of sufficient data points. An incomplete sampling program left out many collection dates and, in many instances, not all the sampling stations were sampled on the same day. Secondly, a good background or base line I^- concentration had not been established since only one sample was represented. Finally, a more detailed history of ongoing injection rates, etc. are needed to better correlate the tracer results.

I have, however, listed below the observations made, based on the tracer data. (Please note two corrections in previously reported data. The Seep sample, collected 18 June '79 should read 0.12 mg/ℓ I^-, not 1.2 mg/ℓ. Also the sample from well 54-3, collected 25 October '79 should read 0.15 mg/ℓ and not 0.21 mg/ℓ as previously stated).

1) Non-radioactive sodium iodide appears to have been successful in use as a chemical tracer for observation of gross water movement. This seems to be verified by several spikes of I^- in concentrations much higher than the background sample.

2) The data appears to rule out any major anomolies of water movement in a direction or speed not before anticipated.

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3) The concentration of elemental iodide is essentially the same in the Don Johnson well sample (no collection date) as that of the one background sample from O.H. #5.

4) Based on only one sample from each sampling site it is not possible to determine the presence, or absence of communication between the Don Johnson well and O.H. #5.

5) The beginning of the flow test in June correlates to several high spikes of I^- in O.H. #4 and O.H. #5.

6) In three separate spikes of increased iodide concentration the tracer arrived at O.H. #4 2 to 3 days before reaching O.H. #5. (see enclosed tracer summary).

It is noted, that O.H. #5 sampling depth was approximately 100 feet deeper than that of O.H.#4. However, there does not seem to be an increased dilution at O.H. #5 as the tracer concentration average is about the same as in O.H. #4.

7) It does not appear that there is much, if any, communication between the NEGRO MAG SEEP and the reservoir. My earlier interpretation, defining a quick return of injection water across the Seep to 54-3, was based on only a couple of data points. These early points appear to be invalid, probably contaminated sampling containers. Also there was only one point from producer 54-3.

8) Within the ± 20% uncertainty level for the laboratory results, all but three data points from the NEGRO MAG SEEP are analytically the same. This may help validate poor, or absent communication between the Seep and the rest of the reservoir.

9) The estimated in situ volume of $6.0 \times 10^8 \ell$ appears reasonable as an average quantity of water in the area under study. This is based on the fact that the average I^- concentration from 71 of the 73 samples analyzed was 0.25 mg/ℓ and the design concentration for a maximum I^- level was 0.34 mg/ℓ. (Excluded were the Seep sample from 6-13-79 and Producer 54-3 from 6-13-79 due to suspicions of contamination)

10) The I^- values from spikes in June and again in October, which averaged around 1.0 mg/ℓ, may suggest the in situ volume is somewhat less, or that all the water present had not come in contact with the tracer over the sampling period.

11) The following table lists the average I^- concentration from each of the 4 main sampling points:

Well 54-3	(A)	0.25 mg/ℓ
Seep	(B)	0.17 mg/ℓ
O.H. #4	(C)	0.33 mg/ℓ
O.H. #5	(D)	0.25 mg/ℓ

This data suggests only that the average NEGRO MAG SEEP sample contained about half the I^- as did the O.H. #4, O.H. #5, and producer 54-3 samples.

I think all the valid interpretations and observations have been made. Useful information has been derived from this tracer project in relation to connate water volume, flow speed and, to a lesser extent, direction. The next step in continuing with a tracer program should be the injection of radioisotopes. They eliminate any problem of background interference and their analytical results allow for less ambiguity in interpretation. The water quality will allow for the use of several different radioisotopes which will allow for more flexibility in project design and enhance data interpretation. Many have short half-lifes (1-3 months), eliminating the concern for radioactivity persisting over a long period of time.

All projects are designed for produced tracer concentrations to be well below NRC regulations for release to an uncontrolled environment. This means no special handling or labeling precautions are required. Finally, project costs for use of radioisotopes are comparable to those of similar designs using chemical tracers.

TELEDYNE ISOTOPES

Teledyne Isotopes enjoyed working with you on this project. Should you have any questions on the above, or on any future projects, please do not hesitate to contact me.

Yours truly,

Andrew Carmichael

Andrew Carmichael
TeleTrace Project Coordinator

AC:hp
enclosure: Revised I^- Data Report

TELEDYNE ISOTOPES

I^- Concentration in mg/ℓ (ppm)*

Collection Date	Seep (B)	Well 54-3(A)	O.H.#4(C)	O.H.#5(D)
6-06-79	-	-	0.19	0.11
6-07-79	-	-	.22	.22
6-13-79	> 4.7	1.6 ± .2	.21	.08
6-14-79	.15	-	.12	< .05
6-15-79	.33	-	.19	.11
6-16-79	-	-	.12	< .05
6-17-79	.15	-	.29	+.05
6-18-79	0.12**	-	.83	.56
6-19-79	.16	-	.38	.06
6-20-79	.16	-	.11	.83
6-21-79	.16	-	.93	.28
6-22-79	.33	-	.24	.19
6-24-79	-	-	.33	.14
8-21-79	.21	-	.26	.31
8-28-79	.15	-	-	-
9-03-79	-	.22	.12	-
9-10-79	.14	.28	-	-
9-17-79	.13	< .05	< .05	.08
9-24-79	.11	.15	.09	.10
10-08-79	.16	.12	.56	.15
10-15-79	.15	.23	.21	.28
10-19-79	.17	.93	.93	.17
10-21-79	.21	-	-	-
10-22-79	-	.10	.36	1.2
10-25-79	.12	0.15**	.52	.26

Don Johnson Well 0.11 mg/ℓ (BKGD)

* All positive values ±20% uncertainty

** Corrected as of 24 December '79

ATTACHMENT NO. 15

Injectivity Step-Rate Test Procedure
Geothermal Performance Report
Roosevelt Hot Springs Unit, Beaver County, Utah

Objective: Test wells in RHS Unit for injectivity rates and pressures by monitoring rate and pressure increases in a controlled situation.

Following is a step by step procedure to be followed while testing the first well. Attachment 15-A is a typical drawing for the wellhead and equipment hookup during testing. Rates of 1/2 BPM to 5 BPM were selected to allow slow cooling of the wellhead and the casing down to the casing seat. The higher rates of 20 BPM to 60 BPM were selected so the wells could be tested at rates comparable to active injection rates during production. These higher rates are dependent on pressure and actual rate step increases will be dictated on a well by well basis during the test.

1. No pre-test stabilization work required as all wells are shut-in.
2. Connect Western's lines to 3" valve located in cellar opposite kill line.
3. Connect a sensitive surface pressure gauge to the wellhead.
4. Hold safety meeting.
5. Pressure test Western's lines to 2000 psi.
6. Open 3" valve in cellar.
7. Pump at the following rates and times to cool the wellhead & casing & record rate, pressure, time and plot data.

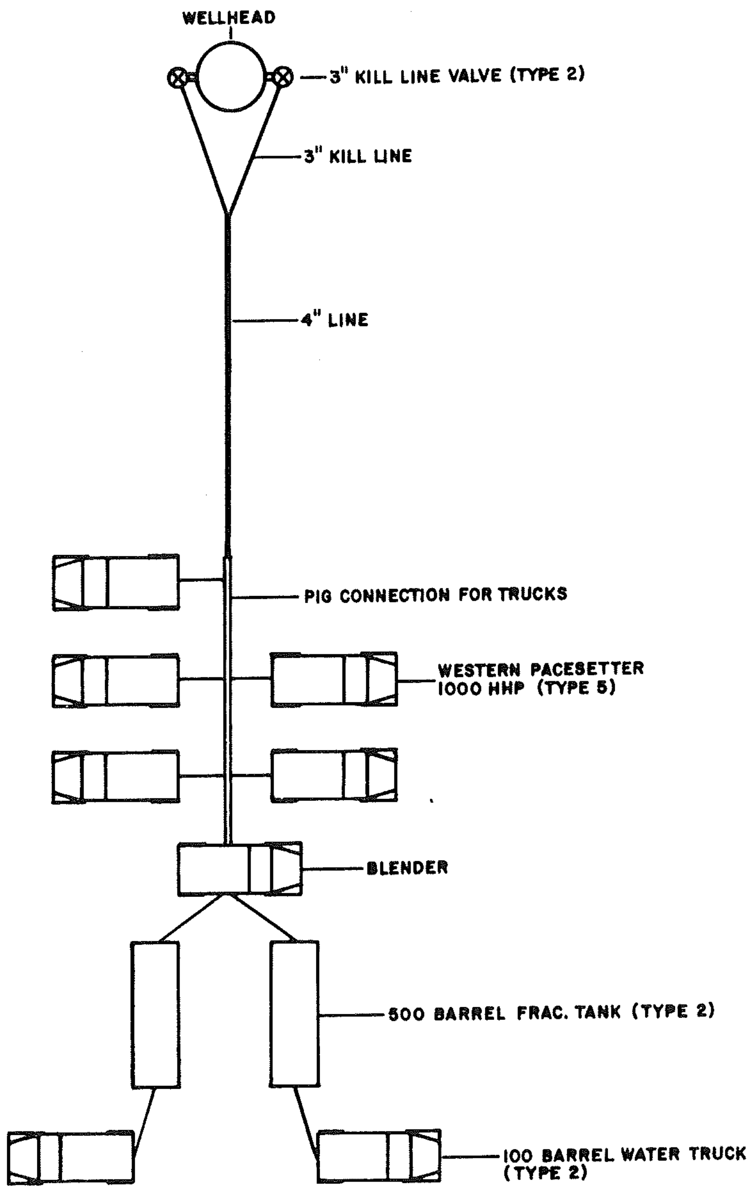
Rate	Pumping Time	Total Volume Pumped
1/2 BPM	10 min.	5
1	10 min.	15
2	10 min.	35
3	10 min.	65
4	10 min.	105
5	10 min.	155

8. After pumping at 5 BPM for 10 minutes increase rate to 20 BPM and pump for 5 min. Record rate, pressure, time and plot data.
9. Repeat step 7 in 10 BPM steps until 60 BPM is reached or increase pressure in equal steps until 60 BPM has been reached. Actual field conditions (pressure at 20 BPM) will dictate which method of incremental increases will be used.
10. Do not exceed 2000 psi.
11. When last increase has been made and pumped for 5 minutes, shut down.

ATTACHMENT 15-A

WELLHEAD AND EQUIPMENT HOOKUP FOR INJECTIVITY AND STEP-RATE TESTS

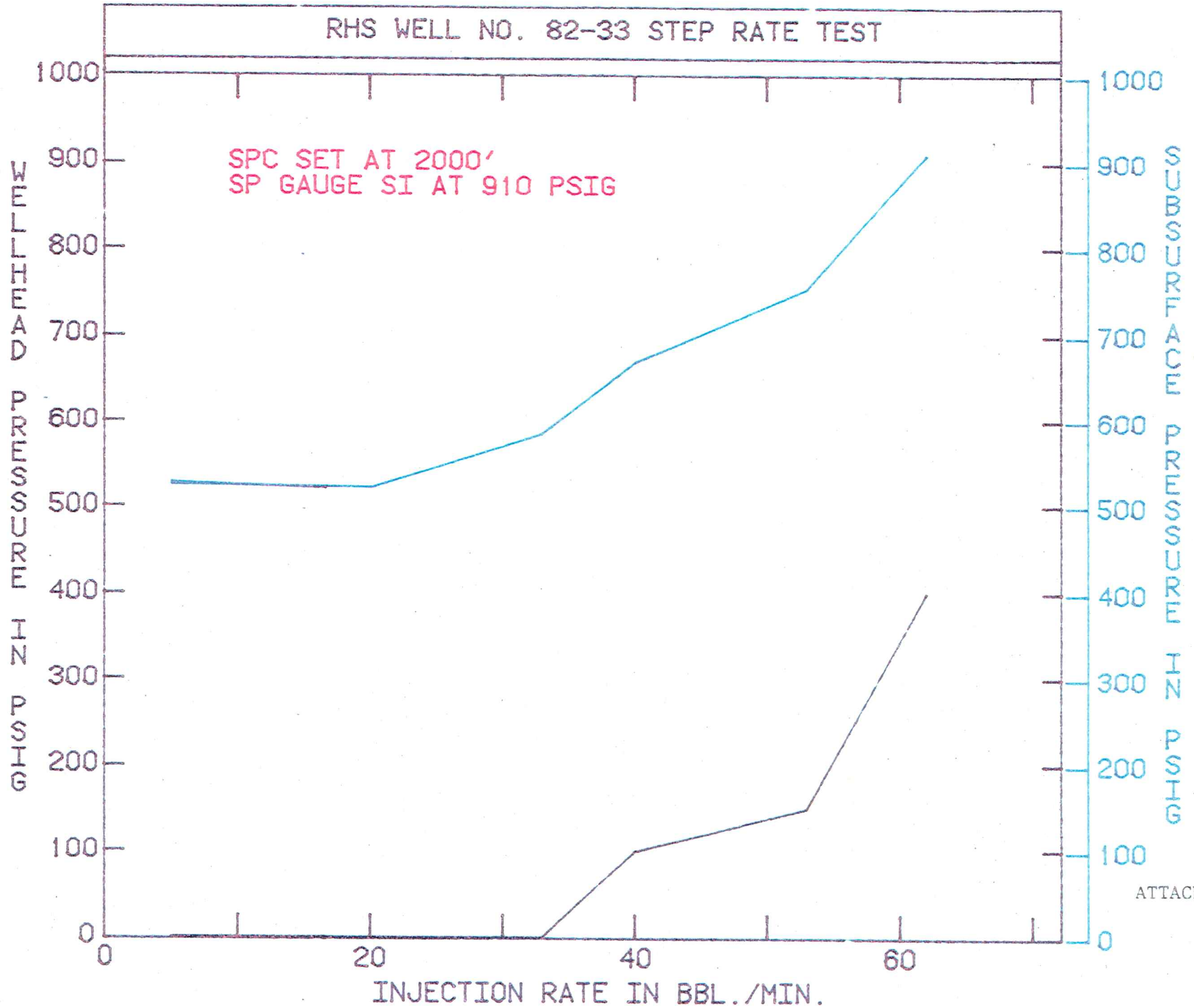
GEOTHERMAL PERFORMANCE REPORT
ROOSEVELT HOT SPRINGS
BEAVER COUNTY, UTAH



ATTACHMENT NO. 16

RHS Well No. 82-33 Injectivity Step-Rate Test
Geothermal Performance Report
Roosevelt Hot Springs Unit, Beaver County, Utah

PT. NO.	DATE	TIME	END PT. PRESSURE SURFACE PSI	END PT. PRESSURE BHP @ 2000 FT	METER RDNG. BBLS.	INJ. RATE BWPM AVG.	INJ. RATE BWPM END PT.	REMARKS
	8/1	1755		523	0			Pressure tested lines to 2000 psi.
1		1801	0	530	100	16 2/3	5	Well on vacuum - can't control rate.
2		1806	0	525	125	5	5	8" turbine on blender idling - well on vacuum.
3		1814	0	522	165	5	5	Same as above.
4		1819	0	585	250	17	20	
5		1824	0	670	415	33	33	Rate still hard to control.
6		1829	100	755	610	39	40	Surface pressure readings are Western's transducer-no surface gauge was connected to the wellhead.
7		1834	150	910	875	53	53	Turned off BHP guage (max. 1000 psi).
8		1835	400		910	62	62	Ran out of water to maintain high rate - pumped out tanks.

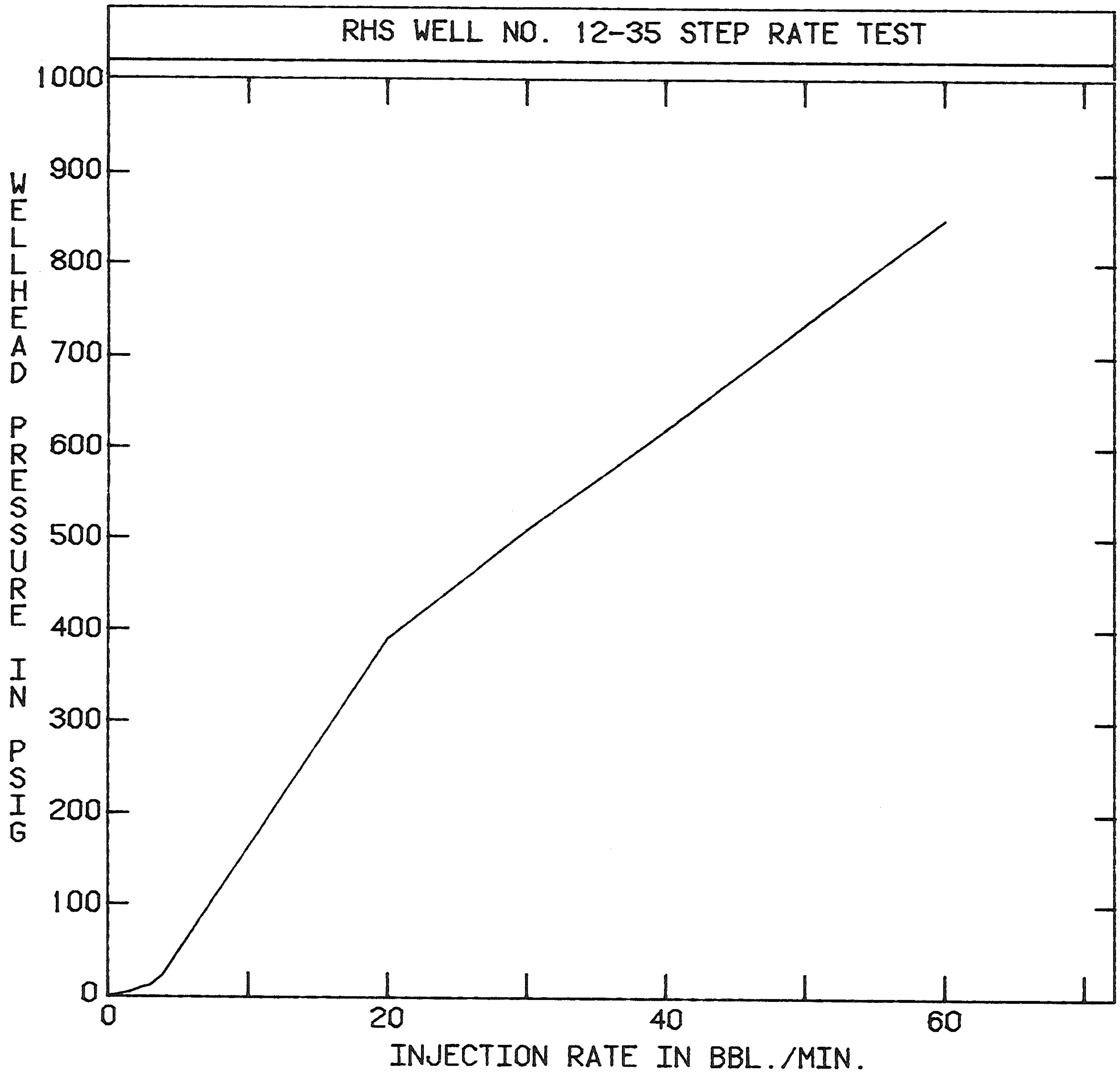


ATTACHMENT NO. 16

ATTACHMENT NO. 17

RHS Well No. 12-35 Injectivity Step-Rate Test
Geothermal Performance Report
Roosevelt Hot Springs Unit, Beaver County, Utah

PT. NO.	DATE	TIME	END PT. PRESSURE SURFACE PSI	END PT. PRESSURE BHP @ FT	METER RDNG. BBLS.	INJ. RATE BWPM AVG.	INJ. RATE BWPM END PT.	REMARKS
	8/2	1040	0		0			Pressure tested lines to 2000 psi.
1		1050	4		15	1.5	1.5	Using 2" turbine to get low flow rate.
2		1100	8		38	2.25	2.25	
3		1110	12		67	2.9	3	
4		1120	23		106	3.9	3.9	
5		1130	48		155	4.9	5	
6		1135	390		251	19.2	20	
7		1140	510		397	29.2	30	
8		1145	620		597	40	40	
9		1150	735		837	48	50	
10		1153	850		1006	56.33	60	
								Pumped out tanks 40 BWPM @ 620 psi. SI pressure 250 psi.

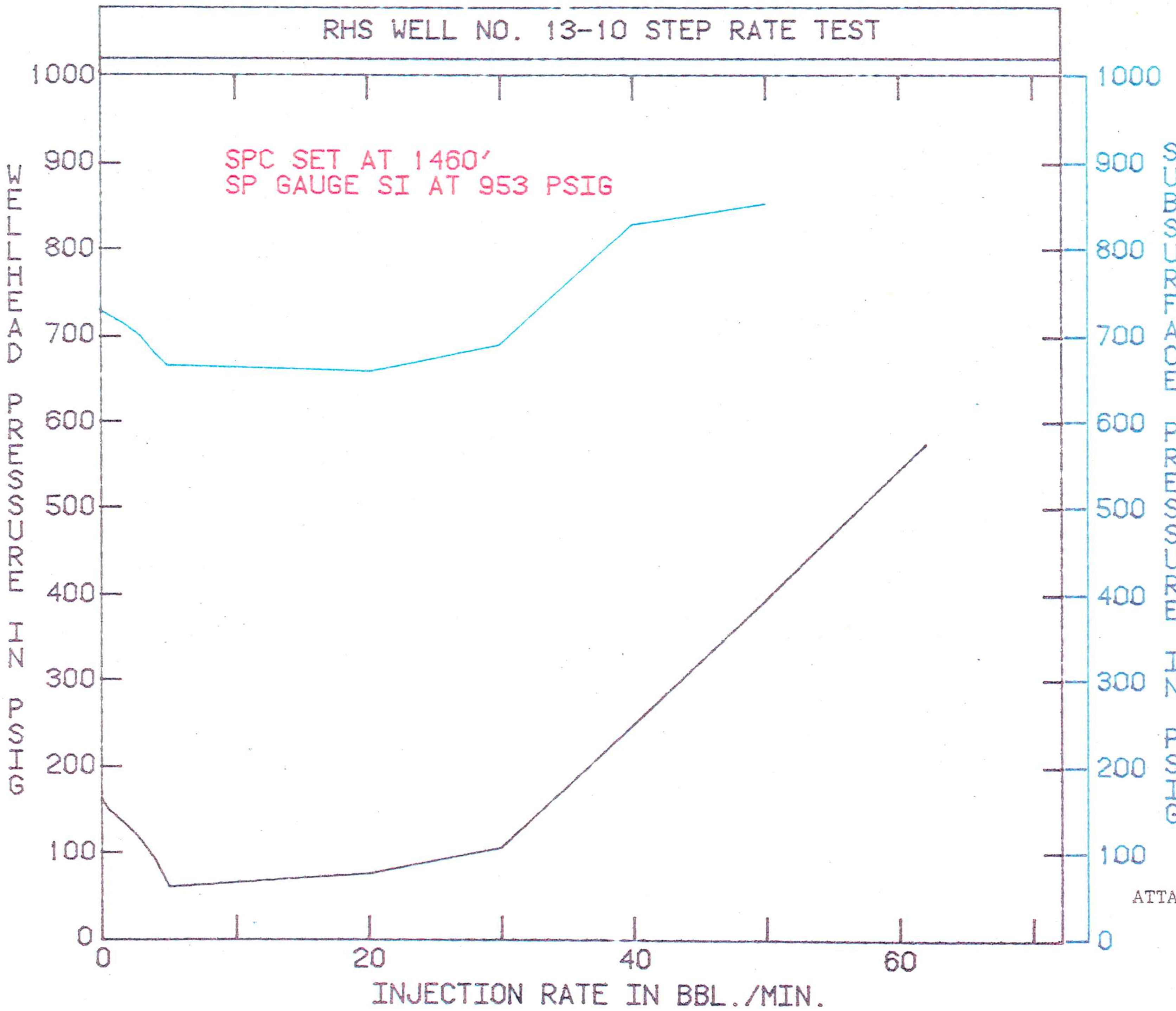


ATTACHMENT NO. 17

ATTACHMENT NO. 18

RHS Well No. 13-10 Injectivity Step-Rate Test
Geothermal Performance Report
Roosevelt Hot Springs Unit, Beaver County, Utah

PT. NO.	DATE	TIME	END PT. PRESSURE		METER RDNG. BBLS.	INJ. RATE BWPM		REMARKS
			SURFACE PSI	BHP @ 1460 FT		AVG.	END PT.	
	8/2	1632	160	727	0			Pressure tested lines to 2000 psi.
1		1642	150	722	4	.4	.4	
2		1652	142	718	14	1	1	
3		1702	128	709	34	2	2	
4		1712	111	697	64	3	3	
5		1722	88	678	104	4	4	
6		1732	60	664	154	5	5	
7		1742	75	658	254	20	20	
8		1747	106	689	404	30	30	
9		1752	250	828	604	40	40	
10		1757	395	953	854	50	50	
11		1758	575	SI	916	62	62	Shut-in Heise gauge-BHP > 1000 psi. Pumped out tanks at 40 BPM @ 250 psi.

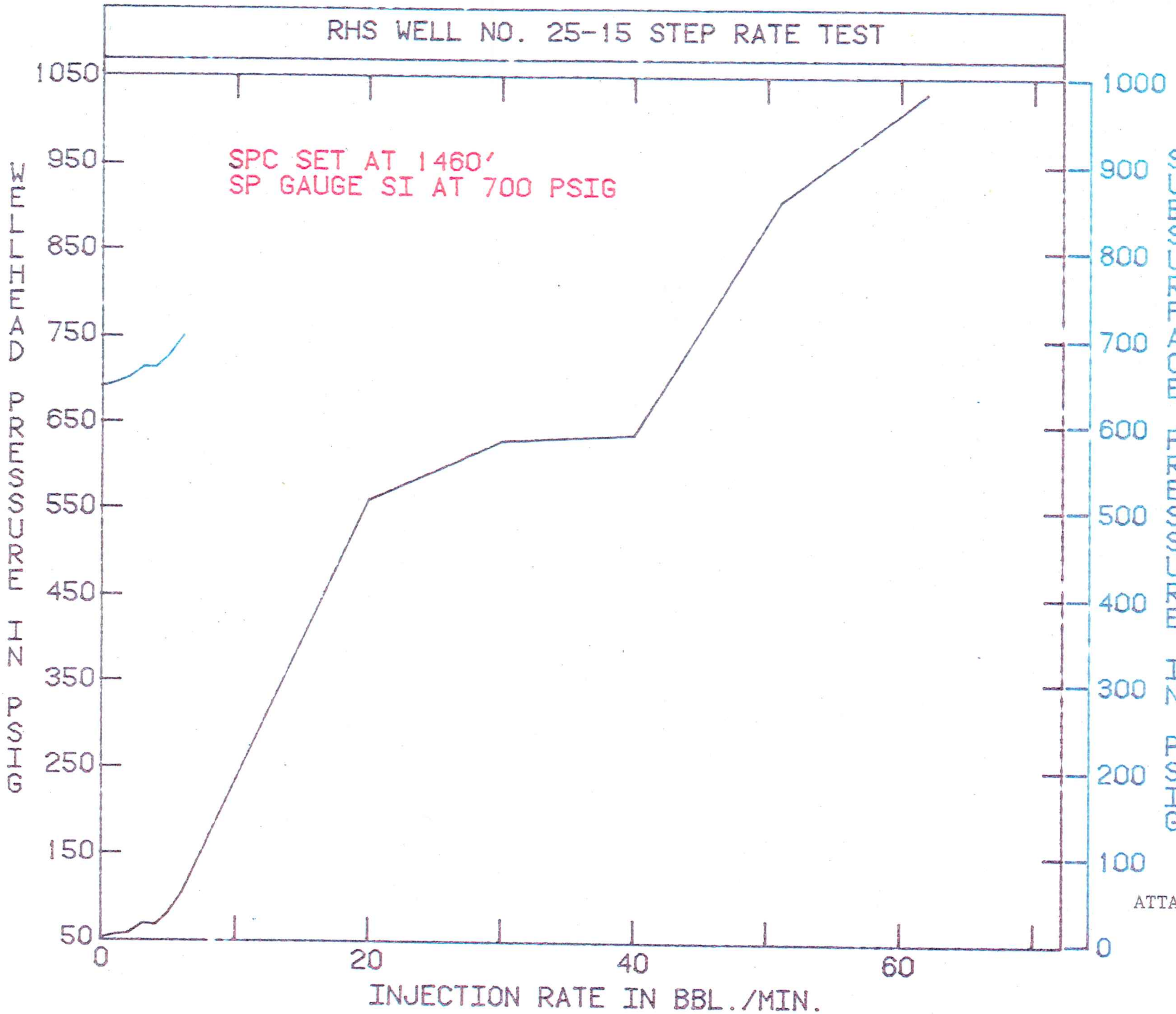


ATTACHMENT NO. 18

ATTACHMENT NO. 19

RHS Well No. 25-15 Injectivity Step-Rate Test
Geothermal Performance Report
Roosevelt Hot Springs Unit, Beaver County, Utah

PT. NO.	DATE	TIME	END PT. PRESSURE SURFACE PSI	END PT. PRESSURE BHP @ 1460 FT	METER RDNG. BBLS.	INJ. RATE BWPM AVG.	INJ. RATE BWPM END PT.	REMARKS
	8/3	1121	51	641	0			Pressure tested lines to 2000 psi.
1		1131	55	645	8	.8	1	
2		1141	57	651	28	2	2	
3		1151	68	663	58	3		
4		1201	66	663	98	4		
5		1211	80	677	148	5		
6		1221	104	700	208	6		
7		1231	560	SI	308	20		Shut-in Heise gauge-BHP > 1000 psi.
8		1236	630		458	30		Max. pres. 650 psi.
9		1241	638		658	40		Max. pres. 660 psi.
10		1246	695		908	51		
11		1248	750		1032	62		
								Pumped out tanks at 25 BPM @ 525 psi. Shut-in wellhead pressure - 400 psi.

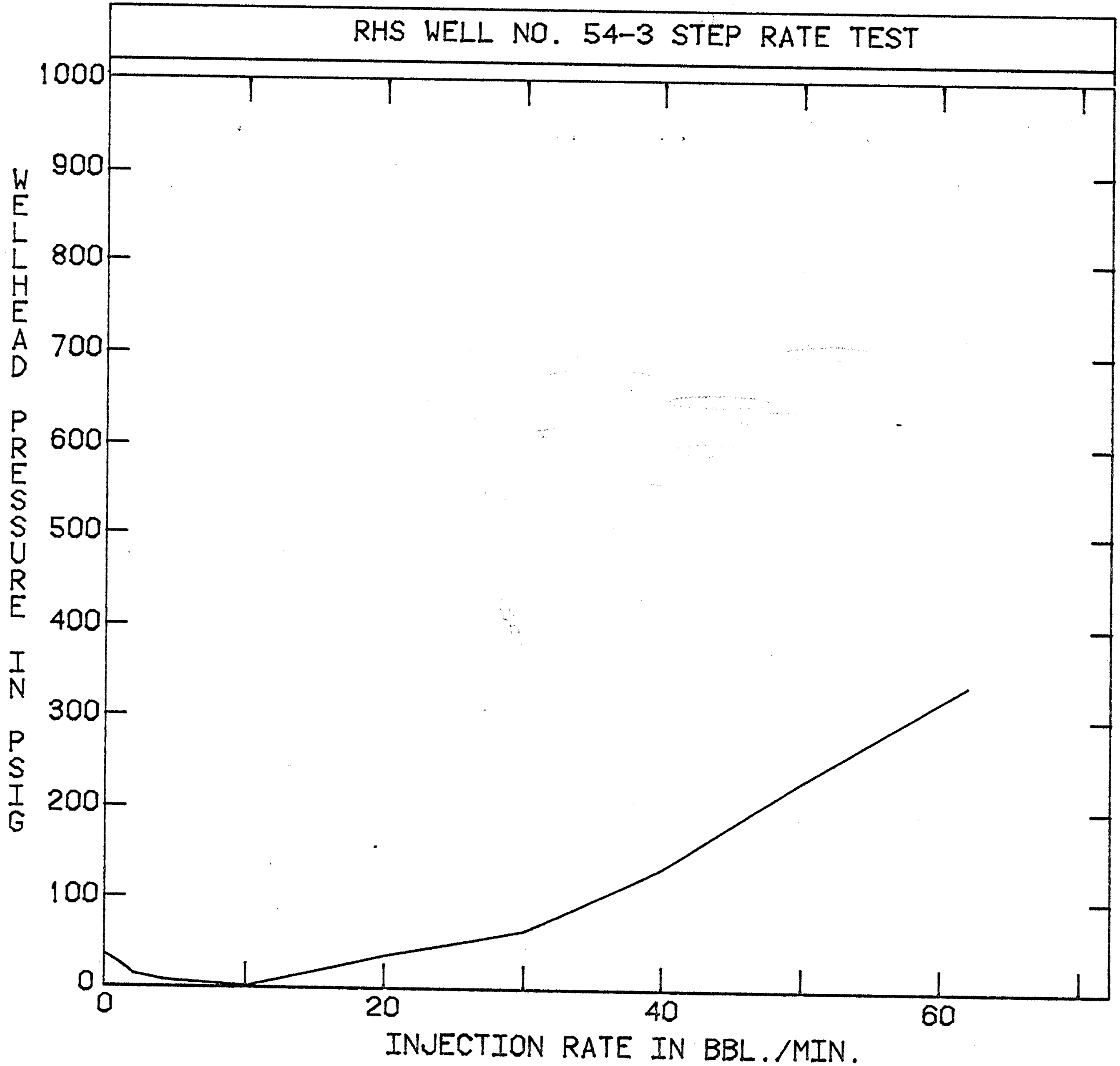


ATTACHMENT NO. 19

ATTACHMENT NO. 20

RHS Well No. 54-3 Injectivity Step-Rate Test
Geothermal Performance Report
Roosevelt Hot Springs Unit, Beaver County, Utah

PT. NO.	DATE	TIME	END PT. PRESSURE		METER RDNG. BBLS.	INJ. RATE BWPM		REMARKS
			SURFACE PSI	BHP @		AVG.	END PT.	
	8/4	1200	34		0			Surface pressure @ 3-1 128.85 psi. Pressure tested lines to 2000 psi.
1		1210	24		10	1	1	
2		1220	11		30	2	2	
3		1230	5		66	3.6	4	Tried 3 BPM - no pressure - went to 4 BPM.
4		1235	4		92	5.2	5	
5		1240	0		142	10	10	
6		1245	35		242	20	20	
7		1250	65		392	30	30	
8		1255	134		592	40	40	
9		1300	230		827	47	50	
10		1303	340		1026	62	62	
								Pumped out tanks at 7 BPM - SI @ 0 psi.

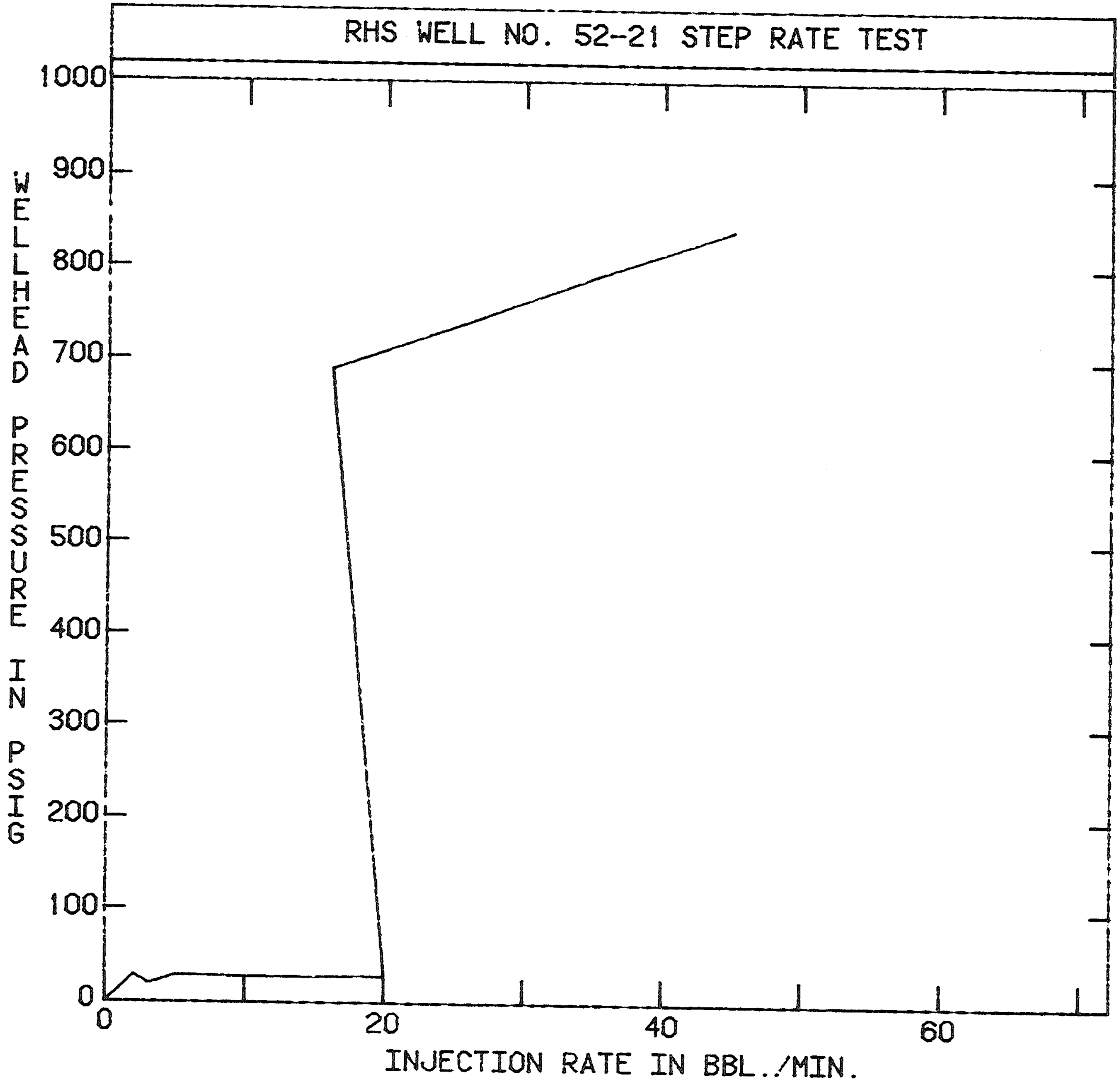


ATTACHMENT NO. 20

ATTACHMENT NO. 21

RHS Well No. 52-21 Injectivity Step-Rate Test
Geothermal Performance Report
Roosevelt Hot Springs Unit, Beaver County, Utah

PT. NO.	DATE	TIME	END PT. PRESSURE		METER RDNG. BBLS.	INJ.RATE BWPM		REMARKS
			SURFACE PSI	BHP @		AVG.	END PT.	
	8/4	1844	0		0			No casing data - tested lines to 2000 psi - using 8" turbine pump.
1		1900	27		32	2	2	Well sucking on pump trucks - cannot pump any slower.
2		1915	18		77	3	3	Same as above - increased time to obtain volume - changed to 6" turbine pump.
3		1922	27		112	5	5	
4		1925	26		142	10	10	
5		1930	27		242	20	20	
6		1935	688		322	16	16	Planned to increase to 30 BPM-pressure increased at end of point 5-so dropped to 16 BPM.
7		1940	735		447	25	25	
8		1945	790		622	35	35	
9		1950	840		712	45	45	Test terminated when valve on 6" Turbine pump slammed shut.

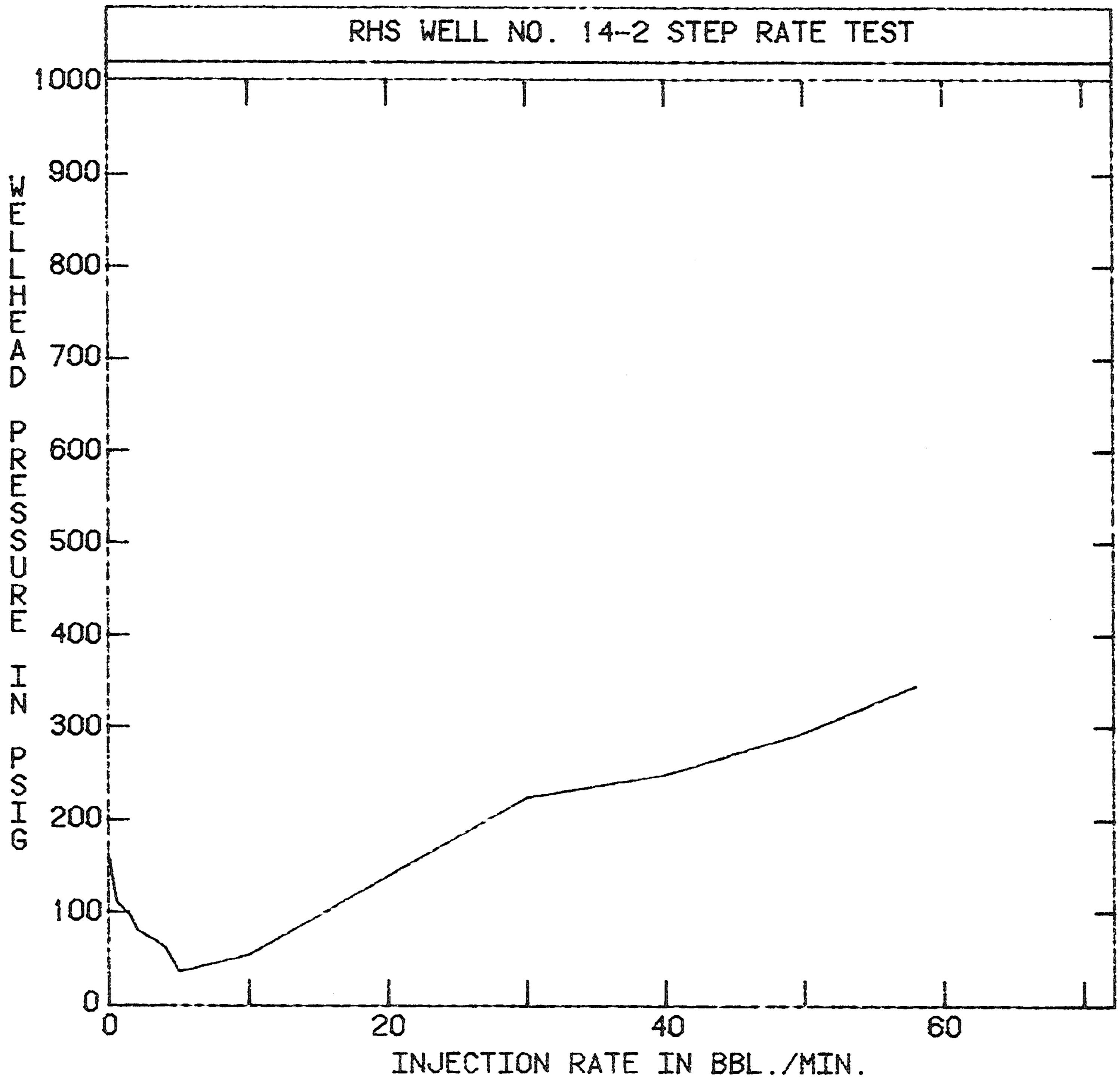


ATTACHMENT NO. 21

ATTACHMENT NO. 22

RHS Well No. 14-2 Injectivity Step-Rate Test
Geothermal Performance Report
Roosevelt Hot Springs Unit, Beaver County, Utah

PT. NO.	DATE	TIME	END PT. PRESSURE SURFACE PSI	END PT. PRESSURE BHP @	METER RDNG. BBLS.	INJ. RATE BWPM AVG.	INJ. RATE BWPM END PT.	REMARKS
	8/5	0750	154		0			Pre-test surface pressure low due to wellhead blender valve - valve bypassed during test. Tested lines to 2000 psi.
1		0800	109		5	.5	.5	
2		0810	94		20	1.5	1.5	
3		0820	80		40	2	2	
4		0830	62		80	4	4	
5		0840	35		130	5	5	
6		0845	54		180	10	10	
7		0850	139		280	20	20	
8		0855	225		430	30	30	
9		0900	250		630	40	40	
10		0905	295		930	50	50	
11		0907	345		1046	58	60	Pumped out tanks 41 BPM @ 240 psi. SI @ 120 psi.



ATTACHMENT NO. 22