GL00588

Salton Sea SCIENTIFIC DRILLING PROGRAM

DRAFT

Phase 2

WELL REWORK

AND

FLOW TESTING

FINAL REPORT

12/19/88

WORK PERFORMED UNDER CONTRACT
DE-AC-03-84-SF12194

by

BECHTEL NATIONAL, INC.

ILLUSTRATIONS

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Phase 2--Well Rework and Flow Testing
Final Report

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Abstract

This report covers the activities of the Salton Sea Scientific Drilling Program from August 1986 to completion. The Phase 1 report covers the activities from project inception in the Fall of 1984 through the drilling and completion in April 1986 to the conclusion of the first rework operation in August 1986. This Phase 2 report includes well rework in August 1987, construction of a flow test facility, a flow test in June 1988 to characterize the well and reservoir, and cleanup of the site. The flow test in June 1988 showed that the well has high productivity and is capable of flow rates greater than 800,000 lbm/hr (363,000 kg/hr) at 250 psig (1,724 kPa) wellhead pressure; at this flow rate it could produce 12 MWe in a dual-flash power plant. Total dissolved solids of the preflash brine is about 250,000 mg/kg.

 12/19/88

SALTON SEA SCIENTIFIC DRILLING PROGRAM
Phase 2--Well Rework and Flow Testing
Final Report

EXECUTIVE SUMMARY

The Salton Sea Scientific Drilling Project (SSSDP) was the first major project performed under the Interagency Accord on Continental Scientific Drilling, involving the U.S. Department of Energy (DOE), the U.S. Geological Survey (USGS), and the National Science Foundation (NSF).

The primary objectives of the project were to:

- Explore the roots of the Salton Sea Geothermal Field by drilling into a deeper, hotter part of the system than had previously been probed
- Collect and place in the public domain samples and data, including core, cuttings, geothermal fluids and gases, and geophysical logs such as temperature and pressure surveys

As the prime contractor, Bechtel National, Inc. had responsibility for design and drilling of the well, provision of surface facilities and site support, environmental monitoring, preliminary resource evaluation, and reporting to the DOE. Kennecott Corporation provided leaseholds and a permitted well site for the scientific well.

At the outset of Phase 1, Bechtel's main objectives were to:

- Drill to an initial depth of 4,000 ft (1,220 m), where the 572 °F (300 °C) isotherm was expected, and then drill an additional 6,000 ft (1,830 m)
- Take cores at depths selected by science management
- Provide time in the drilling schedule for downhole investigations, including logging and fluid sampling
- Conduct three limited flow tests in the course of drilling
    - From the first lost circulation zone below 3,000 ft (914 m)
    - From the first lost circulation zone below 6,000 ft (1,830 m)
    - At total depth of the well

- Provide collection stations for liquid and gas sampling
- Acquire selected commercial geophysical well logs to support research logging to be performed by the USGS
- Place the site on a 6-month, post-drilling standby with the well shut in, providing access for scientific study such as temperature and pressure buildup monitoring

Phase 2 additions to the Bechtel scope of work included:

- Rework the well in August 1987 to reestablish a passageway to the bottom of the hole and to isolate production zones above 8,000 ft (2,440 m) with a new 7-in. liner cemented in place from approximately 5,700 to 8,600 ft (1,739 to 2,623 m)
- Construct facilities for a well flow test of 30-day duration
- Conduct a 30-day well flow test of the deep flow zones
- Clean up the site

This report addresses the results of the Phase 2 activities to fulfill these additional objectives.

Well Rework in August 1987

Inability to run logging tools to the bottom of the well led to additional rework performed in August 1987. The objectives of this rework were to reestablish a passageway for logging tools to the bottom of the hole and to cement off production zones above 8,000 ft (2,438 m) with a new 7-in. liner cemented in place, isolating the production zones below 8,000 ft for a long-term (30-day) flow test. The scope of work called for removal of the temporary 7-in. repair liner installed in August 1986 and as much of the original 7-in. liner as possible.

The 7-in. repair liner that was installed during the first rework operation in August 1986 was retrieved without incident.

A second spear run engaged the top of the original 7-in. liner at a depth of 6,529 ft (1,990 m). Retrieval of the lower liner indicated that pulling the liner through the dogleg at about 6,200 ft (1,890 m) was going to be exceptionally difficult.

Curtailment of fishing operations was considered prudent because of:

- Indications that the lower section of liner was probably full of debris
- Difficulty experienced in pulling the liner through the dogleg
- High probability of the well flowing while the liner was in the blowout preventer with no way to shut in the well

The decision was made to attempt to sidetrack the hole instead of continuing with the fishing operations. Sidetracking was not successful even though mud motors, a locked bottom hole assembly, and a conventional whipstock were used consecutively. After these unsuccessful attempts, no further efforts were made to reestablish a passageway to bottomhole for logging tools.

A short flow test was conducted on August 31, 1987 after completion of the rework activities. The State 2-14 well was flowed for 12 hours averaging 569,000 lbm/hr of total flow (steam and liquid combined). The maximum production rate was 1,222,000 lbm/hr of total flow during the last half hour of the test when the throttling valve was fully open.

Construction of Flow Test Facility

The flow test facility was originally designed, constructed, and used in 1982 to test a geothermal well of the CU–1 Venture at the South Brawley resource, under the DOE Geothermal Loan Guaranty Program. The flow test equipment was subsequently disassembled, moved, reassembled, and used to test two wells of the Parsons–Republic joint venture in the Niland resource area, also under the Geothermal Loan Guaranty Program. After the tests at Niland, the equipment was again disassembled, moved, and stored at the DOE Geothermal Test Facility at East Mesa.

Construction of the flow test facility for testing the State 2-14 well was accomplished in two stages. The first stage was in the Fall of 1987; the second in May 1988.

During the first stage of construction, the equipment was moved from storage at East Mesa, vessels were set in place, and piping was connected after reconditioning. Instruments were stored rather than installed. Construction of the flow test facility was suspended in November 1987 because funding levels were uncertain.

Construction of the flow test facility resumed on May 1, 1988 with a scheduled start date of June 1, 1988 for the well flow test. During May, some changes to the piping were made, piping installation was completed, hydrostatic leak tests were performed, instrumentation and controls were installed, and rental pumps were installed for the flow test.

Flow Test

A 19-day step-rate flow test of the State 2-14 well was conducted from June 1-20, 1988. In the first 13 days of testing, there were three rate steps of 2 to 7 days' duration with flow rates from 125,000 to 400,000 lbm/hr (57,000 to 181,000 kg/hr). A flow rate of 768,000 lbm/hr (348,000 kg/hr) was achieved on June 15, but this was maintained for less than an hour. Through the remaining 5 days, persistent cavitation problems in the pumps limited capacity for brine disposal, which became the limiting factor on well flow rate. On June 20, it was possible to increase the flow rate to 386,000 lbm/hr (175,000 kg/hr).

The planned duration of each rate step was 7 days, based on a conservative estimate of the time required to reach stable operation. However, the well stabilized very quickly, and the test plan was revised to employ 3-day rate steps with a 6-day flow period at the end of the test.

Downhole temperature and pressure profile surveys were conducted on June 5, 12, 14, and 20. Pressure drawdown was recorded as the rate was increased on June 12 and 14, and pressure buildup was recorded for 44 hours after shutin on June 20. Production logs, which would normally be run to delineate and quantify zones of inflow, were not conducted because the questionable mechanical condition of the deeper portion of the well made it inadvisable to run logging tools deeper than 5,500 ft (1,676 m).

A period of production at high flow rate (>1,000,000 lbm/hr or 454,000 kg/hr) directly into the brine pond was planned to follow shutin and pressure buildup. The purpose was to define a higher point on the deliverability curve within the expected commercial operating range. However, the well would not flow spontaneously when the valves were opened, and two attempts to induce flow were unsuccessful. This was probably because the wellbore had cooled during shutin. To induce flow, common techniques of pressuring the well with air at the wellhead and displacing brine from the wellbore with fresh water were employed. More effective, yet lengthy and expensive methods, such as nitrogen lift or allowing the well to heat up for a few days with fresh water in the wellbore, were precluded by budgetary constraints.

The results of the flow test and reservoir analysis are summarized as follows:

- The well has high productivity and is capable of flow rates greater than 800,000 lbm/hr (363,000 kg/hr) at a typical commercial operating wellhead pressure of 250 psig. At this flow rate, it could produce approximately 12 MWe in a two-stage flash power plant.

- Reservoir engineering analysis of the pressure buildup test indicates that the near-well reservoir has a transmissivity of about 233,600 md-ft and a skin factor of +23.1. This indicates a highly productive reservoir with some near-well impairment, probably caused by drilling and workover operations.

- Well productivity improved during the course of the flow test. On at least two occasions (June 2 and 5), there were rapid increases in the wellhead pressure that were not associated with any flow rate change; this strongly suggests that the productivity suddenly improved. This is unusual and probably resulted from brine flow clearing blockages inside the wellbore or in nearby formation fractures.

Brine Chemistry

The primary objective of the brine chemistry sampling program was to characterize the brine produced by the State 2-14 well during the flow test in June 1988.

Chemical sampling was supervised by Kennecott, and the primary chemical analyses were conducted for the Electric Power Research Institute (EPRI) by Combustion Engineering, Inc. using the EPRI Mobile Geothermal Chemistry Laboratory that was on site during the flow test.

Three types of sampling events were conducted during the flow test. Signature tests, measuring 64 chemical species, were conducted at each of the three rate steps to characterize the chemical and physical characteristics of the total well flow. Tracking tests were performed daily to observe changes in selected properties as a function of time. Special tests were conducted as needed to investigate flow streams or equipment of special interest.

The primary focus was on the results of the signature and tracking tests yielding information needed to characterize the brine.

The TDS concentration and the geothermometers, Na/K, Na/Ca, and Ca/K, were examined for indications that various zones were producing in different proportions as the well flow was varied during the flow test. The TDS concentration varied little during the flow test even though the flow rate varied over a range of 7:1. A slight increase in the TDS concentration occurred as the well flow rate was increased for the second rate step. Initially, the TDS concentration was about 232,000 mg/kg, which increased to about 250,000 mg/kg. No other significant changes were observed after this shift between the first and second rate steps.

During the flow test in June 1988, the Na/Ca and Ca/K ratios changed considerably (-20 and +19 percent, respectively), while the Na/K ratio changes were less dramatic (+8 percent from the first to second rate steps and -4 percent from the first to the third). These changes in the geothermometers, Na/K, Na/Ca, and Ca/K, lead to the following conclusions:

- More than one zone is producing a significant portion of the total well flow.
- The various zones may be producing different proportions of the total flow as the well flow is increased.

Comparison of the Na/K, Na/Ca, and Ca/K ratios for the second rate step during the June 1988 flow test with the corresponding ratios for the March 1986 test shows very little difference. Therefore, the producing zones and their relative contributions were essentially the same for the two test conditions.

The information for the December 1985 test and the data for the flow test in June 1988 permit comparison of fluids produced from 6,000 to 6,200 ft (1,829 to 1,890 m) depth with fluids that are from several different zones. The fluid produced by the zone from 6,000 to 6,200 ft (1,829 to 1,890 m) in December 1985 appears higher in potassium and roughly equal in sodium, calcium, and TDS concentrations to the fluids produced in June 1988. Curiously, these generalizations apply more closely for the second and third rate steps than for the first; one hypothesis is that higher well flow rates may favor production from the relatively shallow zone from 6,000 to 6,200 ft (1,829 to 1,890 m).

The chemistry and static (nonflowing) temperatures for the State 2-14 well were compared with those for 11 other wells in the vicinity for which data are available as nonproprietary information. In general, the wells to the southwest of State 2-14 have lower TDS concentrations. Although depth has often been reported as an important factor with respect to TDS, the River Ranch No. 1 and Sportsman No. 1 wells, which are near State 2-14, produce fluid with relatively high TDS concentration from relatively shallow production zones starting at about 4,000 ft (1,219 m) depth.

Because of virtually identical sodium, potassium, and calcium concentrations and similar depth of production zones, the geothermal fluid produced from the zone between 6,000 to 6,200 ft (1,890 m) depth in the State 2-14 well and the fluid produced from the nearby Hudson No. 1 well probably come from the same source.

Scientific Research Projects. The following research organizations conducted the indicated scientific research projects during the June 1988 flow test of the State 2-14 well:

- Battelle Pacific Northwest Laboratories. Particle meter testing to
  - Establish the suspended solids content of the separated brine
  - Characterize the chemical and size characteristics of the suspended solids
  - Evaluate an online computerized ultrasonic particle counter
  - Evaluate the effects of scale deposits on the optical window of a laser particle counter
- Brookhaven National Laboratory. Geothermal waste treatment biotechnology
- Electric Power Research Institute. Chemical sampling and analysis to characterize the brine

- Lawrence Livermore National Laboratory. Seismic monitoring to characterize the microseismic activity related to the flow–injection test in the Salton Sea Geothermal Field

- New Mexico State University. Collection and analysis of brine samples to measure metal ion concentrations

- University of California at Riverside. Collection and analysis of fluid and solid samples to study the transport of platinum group elements, gold, and sulfur in the Salton Sea geothermal brines

- University of Southern California. Fluid sampling and uranium series isotope measurements to

  - Constrain models of radioisotope exchange mechanisms

  - Develop new methods of estimating hydrogeologic parameters

- University of Utah Research Institute. Liquid and gas sampling and analysis to determine

  - Differences in the chemistry of the fluid as a result of changing flow rates

  - Silica precipitation when a cooling coil is used during sample collection

Site Cleanup (later)

A Perspective of Scientific Accomplishments from the Salton Sea Scientific Drilling Project

Research objectives in the SSSDP focused on probing the roots of a hot (355 ± 10°C) , near-surface, magmatically driven, hypersaline geothermal system to increase basic scientific understanding of the development of geothermal resources and to advance the technology of drilling and testing to achieve those objectives. Forty-one science and technology-development projects were funded by the USGS, DOE–Office of Basic Energy Sciences, DOE–Geothermal Technology Division, and National Science Foundation. Results of completed and ongoing studies on recovered data and samples indicate that the SSSDP met or exceeded most of its initial objectives. Despite hostile subsurface conditions, a wealth of new data were collected in a geotectonic environment of active continental rifting, metamorphism and ore genesis.

A key finding with implications for commercial resource evaluation and development throughout the Salton Sea geothermal system (SSGS) is that although porosity decreases and rock induration increases with depth, permeability-controlling fractures increase with depth. High flow-rate test results suggest strong commercial merit in evaluating both shallow and deep resource potential in the SSGS.

Fundamental geologic work remaining includes the following:

- Detailed correlations between the State 2-14 well and other geothermal wells in the SSGS
- Comparisons between the SSGS and other geothermal systems, such as lithologically similar Cerro Prieto, which has a strikingly lower occurrence of hydrothermal vein mineralization
- A future, deep geothermal research well that is located on the axis of the thermal anomaly could provide a valuable opportunity to significantly extend the understanding of continental rifting and geothermal-system genesis that is currently being formulated from the data of the off-axis State 2-14 well

Section 1

INTRODUCTION

The Salton Sea Scientific Drilling Project (SSSDP) was the first major project performed under the Interagency Accord on Continental Scientific Drilling, involving the U.S. Department of Energy (DOE), the U.S. Geological Survey (USGS), and the National Science Foundation (NSF).

The final report for the SSSDP is divided into two parts:

- Phase 1. The well design and drilling are reported in "Salton Sea Scientific Drilling Project, Phase 1—Drilling and Engineering Program, Final Report," Volumes 1 and 2, which cover the activities from project inception in the Fall of 1984 through the drilling and completion at 10,564 ft (3,220 m) in March 1986 to the conclusion of the first rework operation in August 1986.
- Phase 2. This second report covers the activities from August 1986 to site cleanup in August 1988. These activities include rework of the well in August 1987, construction of flow test facilities, completion of a flow test in June 1988 to characterize the well and reservoir, and cleanup of the site and abandonment of equipment in place.

1.1 PURPOSE AND OBJECTIVES

The primary objectives of the project were to:

- Explore the roots of the Salton Sea Geothermal Field by drilling into a deeper, hotter part of the system than had previously been probed
- Collect and place in the public domain samples and data, including core, cuttings, geothermal fluids and gases, and geophysical logs such as temperature and pressure surveys

As the prime contractor, Bechtel National, Inc., in association with Kennecott Corporation, was responsible for overall project management. Bechtel's responsibilities included planning, design and drilling of the well, provision of surface facilities and site support, environmental monitoring, preliminary resource evaluation, and reporting to the DOE. The purpose of the project was to provide opportunities to scientists from many organizations for collection of the best samples and data available within the limitations of technical feasibility, safety and well integrity, and project budget. Kennecott Corporation was responsible for providing leaseholds and a permitted well site for the scientific well.

At the outset of Phase 1, Bechtel's main objectives were to:

- Drill to an initial depth of 4,000 ft (1,220 m), where the 572 °F (300 °C) isotherm was expected, and then drill an additional 6,000 ft (1,830 m)
- Take cores at depths selected by science management
- Provide time in the drilling schedule for downhole investigations, including logging and fluid sampling
- Conduct three limited flow tests in the course of drilling
  - From the first lost circulation zone below 3,000 ft (914 m)
  - From the first lost circulation zone below 6,000 ft (1,830 m)
  - At total depth of the well
- Provide collection stations for liquid and gas sampling
- Acquire selected commercial geophysical well logs to support research logging to be performed by the USGS
- Place the site on a 6-month, post-drilling standby with the well shut in, providing access for scientific study such as temperature and pressure buildup monitoring

Phase 2 additions to the Bechtel scope of work included:

- Rework the well in August 1987 to reestablish a passageway to the bottom of the hole and to isolate production zones above 8,000 ft (2,440 m) with a new 7-in. liner cemented in place from approximately 5,700 to 8,600 ft (1,739 to 2,623 m)
- Construct facilities for a well flow test of 30-day duration
- Conduct a 30-day well flow test of the deep flow zones
- Clean up the site

This report addresses the results of the Phase 2 activities to fulfill these additional objectives.

1.2 SUMMARY OF PHASE 1

The results of the Phase 1 activities have been reported in "Salton Sea Scientific Drilling Project, Phase 1—Drilling and Engineering Program, Final Report, Volumes 1 and 2." This section summarizes the results of the Phase 1 activities.

The project site is in the southeast corner of Section 14, Township 11 S, Range 13 E, near the intersection of McDonald and Davis Roads, approximately 225 ft (68.6 m) below sea level. This site is in the northeastern part of the Salton Sea Geothermal Field, within a mile of five previous wells, several of which have been inundated by the rising level of the Salton Sea. Kennecott offered to provide two well sites for which it had secured drilling permits, one for deep drilling and the other for injection of spent brine. Between the time of the proposal and the final project design, the injection well and the brine handling and disposal system were deleted from the project because of budgetary limitations. The injection well originally proposed, State 2-14, became the primary well, and a simplified brine-handling system was incorporated. Kennecott provided use of property on the east side of Davis Road for a brine storage pond. Details of the final design and site layout are presented in Section 3 of "Salton Sea Scientific Drilling Project, Phase 1—Drilling and Engineering Program, Final Report, Volumes 1 and 2."

The State 2-14 well was spudded on October 23, 1985, and in the following 160 days it was drilled to a depth of 10,564 ft (3,220 m). Thirty-six spot cores were taken, recovering approximately 725 ft (220 m) of sample. Two flow tests of limited duration (54 and 37 hours) were performed, one from an upper zone at 6,120 ft (1,865 m), and the second, a mixed-zone flow test from 6,000 ft (1,829 m) to bottomhole. Logging and fluid sampling were also performed.

At completion, the State 2-14 well had 9-5/8 in. production casing cemented to 6,000 ft (1,829 m) with uncemented 7-in. liner from 5,773 to 10,136 ft (1,760 to 3,089 m) in the 10,564 ft (3,220 m) hole. The purpose of the uncemented 7-in. liner was to keep the hole open for scientific logging for a 6-month period after well completion.

In late May 1986, USGS attempted temperature logs to a depth of 10,000 ft (3,048 m), but were able to atttain only a depth of 6,380 ft (1,945 m). During this run, the logging tool repeatedly stopped at 6,380 ft (1,945 m) going down the wellbore, and it also hung up consistently at 6,195 ft (1,888 m) coming up the well. The cause of the blockage at 6,380 ft (1,945 m) was determined to be separation and possible collapse of the fin hang-down liner. The cause of the hangup pulling out of the hole was believed to be a dogleg in the wellbore at about 6,200 ft (1,890 m).

In August 1986, rework was undertaken to reestablish access to the bottom of the well permitting temperature profile measurements. Rework involved removing the liner hanger with attached liner and replacing it with a new hanger plus sufficient liner to tie into the lower string of the original liner. In late October 1986, the first temperature logging after the August 1986 rework was attempted, but the liner below 5,800 ft (1,768 m) was full of congealed drilling mud. This led to additional well rework in Phase 2.

1.3 ORGANIZATION OF PHASE 2 REPORT

The remaining sections of the Phase 2 report are organized as follows:

- Section 2—Well Rework recounts the unsuccessful efforts in August 1987 to reopen a passageway to bottomhole for logging tools.
- Section 3—Construction of Flow Test Facility describes the construction of a flow test facility capable of injecting the produced fluids. This facility was used to perform a 19-day test to characterize the State 2-14 well and associated reservoir.
- Section 4—Flow Test reports the June 1988 flow test and discusses the results.
- Section 5—Brine Chemistry explains the fluid sampling program for chemical analyses during the June 1988 flow test, discusses the chemistry results and compares them with chemistry data from earlier short-term flow tests of the State 2-14 well, compares the State 2-14 well with others in the vicinity, and describes scientific research tests conducted by others during the June 1988 flow test.
- Section 6—Site Cleanup primarily discusses disposal of sludge waste from the brine pond.

- Section7—Conclusions and Recommendations concisely restates the conslusions and recommendations drawn from the Phase 2 work and concludes with a brief statement of a perspective of the scientific accomplishments resulting from the SSSDP.

Section 2

WELL REWORK

2.1 BACKGROUND

At completion in March 1986, the State 2-14 well had 9-5/8 in. production casing cemented to 6,000 ft (1,829 m) with an uncemented hang-down 7-in. liner from 5,773 to 10,136 ft (1,760 to 3,089 m) in the 10,564 ft (3,220 m) hole. The purpose of the uncemented 7-in. liner was to keep the hole open for short-term flow testing of deep reservoir zones and for scientific logging for a 6-month period after well completion.

In late May 1986, USGS temperature logs that were scheduled to reach 10,000 ft (3,048 m) were obtained only to a depth of 6,380 ft (1,945 m). During this run, the logging tool repeatedly stopped at 6,380 ft (1,945 m) going down the wellbore, and it repeatedly hung up at 6,195 ft (1,888 m) coming up. The hang-up at 6,195 ft (1,888 m) probably was caused by a dogleg in the hole created when the well was directionally drilled.

Diagnostic testing in June 1986 indicated the following:

- The liner had separated at a collar at 6,181 ft (1,884 m)
- Open hole existed from 6,181 to 6,422 ft (1,884 to 1,957 m)
- The liner had not suffered any great amount of general corrosion or wear

In August 1986, rework was undertaken to remove the liner hanger and attached liner and to replace it with a new hanger and sufficient liner to tie into the lower string of original liner. This was intended to reestablish access to the bottom of the well, permitting temperature profile measurements. The field work began on August 7, 1986 and was completed on August 21. The liner hanger and nine joints of 7-in. liner were removed. A tapered mill was then run inside the lower liner from 6,521 to 8,005 ft (1,988 to 2,440 m). Then, 793 ft (242 m) of a 7-in. patch liner (no liner hanger) was installed from 5,728 to 6,521 ft (1,746 to 1,988 m) as illustrated in Figure 2–1. The August 1986 rework is discussed in

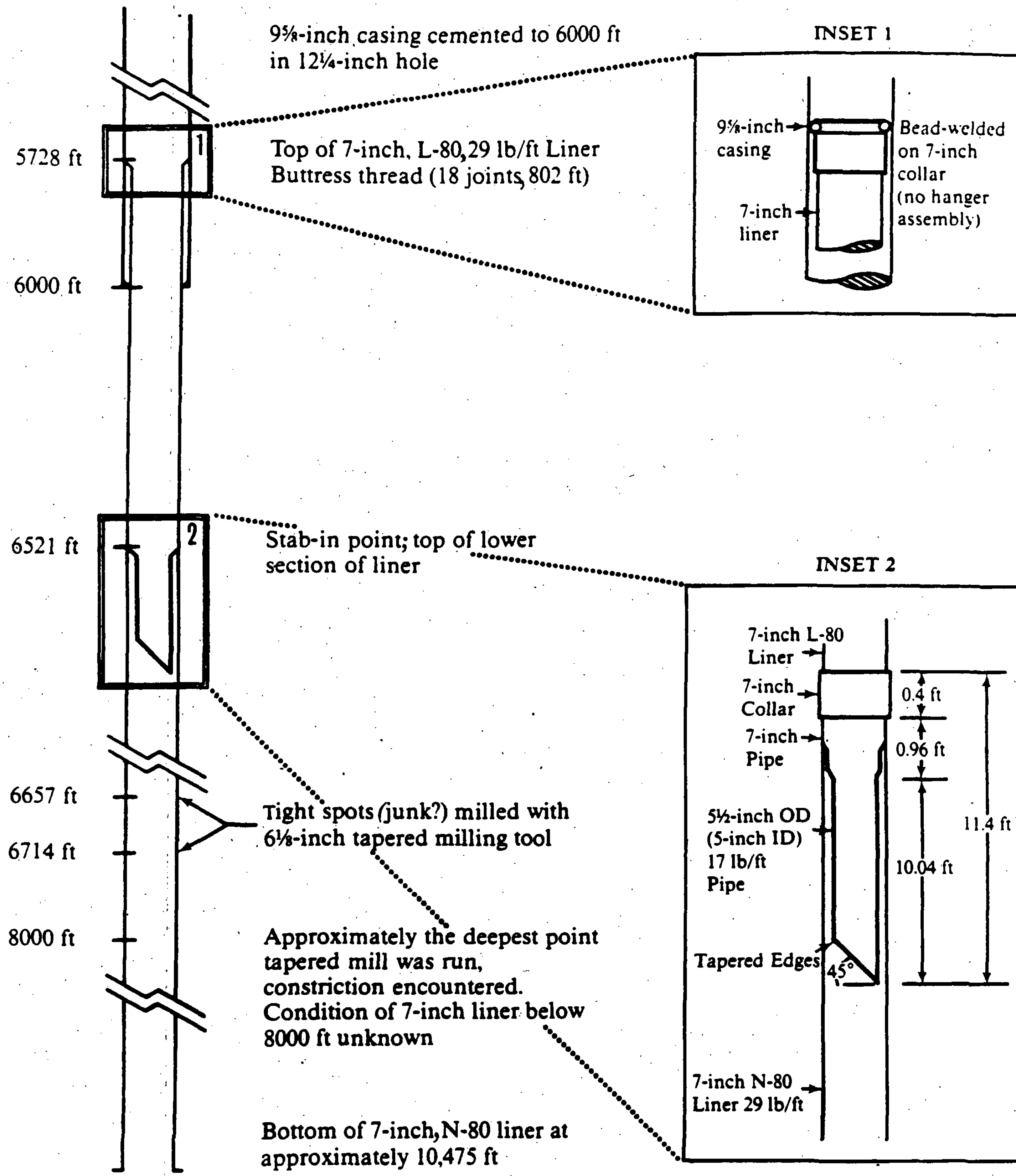


Figure 2-1 Schematic of Wellbore Construction After August 1986 Repairs

Section 4.9 of "Salton Sea Scientific Drilling Project (SSSDP), Phase 1—Drilling and Engineering Program, Final Report, Volumes 1 and 2."

On the first temperature logging attempt, in late October 1986, following this rework, the liner was found to be full of congealed drilling mud from 5,800 to 6,717 ft (1,768 to 2,047 m), the greatest depth to which a sinker bar could be driven. The most likely explanation for drilling mud in the liner is that during final water displacement of drilling mud used in the August rework, the water flush evidently flowed around the outside of the repair liner instead of flowing through it, leaving drilling mud in the liner.

The need to reestablish well integrity for conducting downhole measurements and for long-term flow testing of the deeper reservoir zones led to more extensive well repair in August 1987.

2.2 WELL REWORK IN AUGUST 1987

The objectives of the rework in August 1987 were to reestablish a passageway to bottomhole for logging tools and to isolate production zones shallower than 8,000 ft (2,438 m) with a new 7-in. liner cemented in place.

The scope of work called for removal of the 7-in. repair liner installed in August 1986 and as much of the original 7-in. liner as possible. If the removal of the 7-in. liner proved slower than redrilling, the hole would be sidetracked to the greatest depth possible below 8,000 ft (2,438 m). A new liner would be installed and cemented to isolate zones shallower than 8,000 ft (2,438 m) from deeper production zones.

Field work began on August 1, 1987 with mobilization of the drilling rig for well repair and was terminated with demobilization of the drilling rig on September 2, 1987. Appendix A contains the daily drilling reports. The logging and surveying, liner retrieval, directional drilling, bit record, drilling fluids program, and short flow test are summarized below.

2.2.1 Logging and Surveying

Before the well was disturbed by repair operations, the USGS ran two temperature surveys. The first survey was limited to 3,000 ft (914 m) where the temperature reached 610 °F (321 °C), the maximum temperature for using the wireline system. A second temperature log by the USGS was made to 6,000 ft (1,829 m) with a digital temperature tool. This tool failed due to leakage of fluid into the tool causing failure of the electronic circuits.

Directional surveys were made for orienting the mud motors and the whipstock tool while attempting to sidetrack the hole. Only two surveys were run after drilling past the 7-in. liner stub at 6,741 ft (2,055 m). Results of the directional surveys are as follows:

Depth (ft)	Angle (degrees)	Azimuth	Remarks
6,038	8	N75E	
6,537	5	N38W	
6,790	6–3/4	S13W	Possible magnetic interference
7,030	8–1/2		Film fogged by heat

1 ft = 0.305 m

2.2.2 Liner Retrieval

The 7-in. temporary repair liner that was installed during the first rework operation in August 1986 was retrieved without incident. Eighteen joints of liner (802 ft, 244 m) plus the 10 ft (3 m) x 5-1/2 in. stab-in joint were removed from the well. Inspection of the repair liner showed it to be in good condition with little or no corrosion.

A second spear run engaged the top of the original 7-in. liner at a depth of 6,529 ft (1,990 m). Retrieval of the lower liner indicated that pulling the liner through the dogleg at about 6,200 ft (1,890 m) was going to be difficult. The liner stuck several times coming through the dogleg causing the jars to trip.

Five joints (210 ft, 64 m) of 7-in., 29 lbm/ft, N-80, LTC liner were recovered. The pin end of the fifth joint was split, indicating that it had dropped onto the collar of the liner section below it. Additionally, the last joint of liner was packed full of rocks, baked mud, and some centralizer springs. Inspection of the recovered liner showed it to be in relatively good condition, with some corrosion and no stress cracking in the collars.

Curtailment of fishing operations was considered prudent because of:

- Indications that the lower section of liner was probably full of debris
- Offset of the lower section of liner from the section removed, making success of further fishing operations improbable
- Difficulty experienced in pulling the liner through the dogleg
- High probability of the well flowing while the liner was in the blowout preventer with no way to shut in the well

The decision was made to attempt to sidetrack the hole instead of continuing with the fishing operations.

2.2.3 Directional Drilling

Methods for Directional Drilling. There are two fundamental methods for directional drilling to sidetrack a hole. The more common method is the mud motor using a bent sub. The other method is the conventional whipstock. Both methods rely on setting a good cement plug at the point from which the hole is to be sidetracked.

Mud motors consist of two types:

- Positive displacement motor (PDM). PDMs use an elastomer stator to radially seal around a helical spiraled steel rotor.
- Turbine motor. Turbine motors are comprised of a series of steel-bladed rotors and stators similar to a jet engine.

The turbine motor is more commonly used in geothermal drilling, because of its ability to operate at slightly higher temperatures [approximately 300 °F (149 °C) versus 260 °F (127 °C) for a PDM]. However, the radial and thrust bearings of a turbine motor can also be destroyed by exposure to excessive temperature.

A conventional whipstock consists of a long tapered wedge of steel that is concave on one side to hold and guide a bit against the side of the hole. This tool is used in extremely hot holes or holes that are difficult to sidetrack. The disadvantage of the whipstock is that it must be accurately positioned and cemented; therefore, using it is more time consuming and more expensive.

A locked bottom hole assembly is formed by placing stabilizers every few feet behind the drill bit. This produces a stiff assembly that tends to progress in a straight line. Where the existing bore deviates abruptly from a straight line, such as at the dogleg near 6,200 ft (1,890 m), a locked bottom hole assembly may kick out from the existing bore in a straightline extension of the bore above the deviation. This would initiate a sidetrack from the existing hole.

Sidetracking the State 2-14 Well. The initial approach to sidetracking the State 2-14 well was to start the sidetrack above the dogleg at 6,200 ft (1,890 m). This would eliminate the dogleg problem for the next liner installation.

A cement plug was set from 6,036 to 6,480 ft (1,840 to 1,975 m) with 360 ft^3 (10 m^3) of cement. Three samples of the cement were taken during the cementing operation, and each indicated that a good hard cement plug had been set.

Four mud motors, one locked bottom hole assembly, and two whipstock runs were made in attempting to sidetrack the hole. A brief summary of the results follows.

Run No. 1 Using a Mud Motor. Since mud return temperatures were low (about 115 °F or 46 °C) and injection of 5,000 bbl (795 m^3) of cold water was assumed to have cooled the wellbore, a PDM was chosen for the first run because it has higher torque for a lower flow of mud. It is also usually easier to start than a turbine motor.

To ensure that the PDM would stay cool, it was staged into the hole. That is, circulation was established at 2,000-ft (610 m) intervals while tripping into the hole.

After tagging the cement plug, the plug was dressed off from 6,036 to 6,058 ft (1,840 to 1,846 m) before running a survey to orient the tool. The orientation shots took about an hour, during which the mud motor was not circulated.

After the orientation shots, the mud motor would not start.

The PDM was then pulled out of the hole and checked. The bit shaft could be turned by hand (which is normally impossible); therefore, the failure of this PDM was initially judged to be the result of shearing the coupling between the power shaft and the bit shaft. However, later inspection showed that failure of the elastomer stator from excessive temperature had disintegrated the stator and allowed drilling fluid to wash the stator away.

Run No. 2 Using a Mud Motor. A second PDM was staged into the hole. While a directional survey was being completed, one of the rig engines went down causing complete power failure. The PDM was on bottom, without circulation, for 1-1/2 hours before it could be pulled from the hole. Upon retrieval, the PDM was tested and appeared to be in good condition. However, after repair of the rig engines, the PDM was tested again before running into the hole, and it would not run.

Run No. 3 Using a Mud Motor. The first turbine motor was picked up and tested before staging in the hole. The motor was run to 6,063 ft (1,848 m) where an hour was required to survey for orienting the tool. After surveying, the motor would not start, and it was pulled from the hole. Inspection at the surface revealed that the elastomer thrust bearing was shattered, probably because of exposure to high temperature.

Run No. 4 Using a Mud Motor. A second turbine motor was tested at the surface and then run to the bottom of the hole as fast as possible without staging. Since temperature appeared to be the problem, the faster transit was expected to alleviate the problem. Nevertheless, the motor failed to start, and it was pulled from the hole.

Run Using a Locked Bottom Hole Assembly. After the mud motor failures, an attempt was made to effect a sidetrack in the 5-degree dogleg at about 6,200 ft (1,890 m) using a locked bottom hole assembly. Such a stiff assembly will often sidetrack when it encounters a dogleg; however, this attempt was not only unsuccessful but also ended up drilling out the cement plug. This necessitated setting another cement plug before using a whipstock.

Run No. 1 Using a Whipstock. A whipstock tool was run in the hole. While a directional survey was being conducted to orient the tool, the directional drilling supervisor collapsed and was taken to a hospital. The tool was pulled from the hole and a bit run was made to clean out 17 ft (5 m) of fill while waiting for a new directional supervisor to arrive.

Run No. 2 Using a Whipstock. The whipstock was set at 6,536 ft (1,992 m), and a 6-in. (15 cm) pilot hole was drilled to 6,547 ft (1,996 m). This was followed by an 8-1/2 in. (22 cm) hole opener to 6,547 ft (1,996 m). An 8-1/2 in. bit was then used to drill from 6,547 ft (1,996 m) to 6,630 ft (2,021 m).

While dressing-off the cement plug, the cement appeared to be relatively soft. However, cutting samples during the whipstock operation indicated hard cement mixed with formation cuttings; this indicates that some kickoff from the original hole was accomplished. During the drilling operation, the cuttings began to grade more toward cement, indicating that the bit had wandered back into the original hole. Eventually, the bit penetrated the bottom of the cement plug.

Review of the Data. Temperature measurements taken shortly after the PDM runs using a maximum recording thermometer show a temperature of 302 ^{o}F at 6,000 ft (150 ^{o}C at 1,829 m). Failure of the PDMs is traceable to high temperature.

The cause of failure of the turbine motors was not immediately evident. One hypothesis in the field was that the motors may have become blocked by debris, since mud screens had not been used; however, a subsequent report by the subcontractor (Eastman), after the motors were disassembled and inspected, indicated that this was not the case. Rather, failure occurred from destruction of the radial and thrust bearings by high temperature. This result was surprising, since turbine motors had been used during the initial drilling of the State 2-14 well where greater temperatures were encountered.

The drilling contractor's reports showed that both mud pumps were run at 110 strokes per minute, which implies approximately 550 gpm (35 l/s) flow. This should have been ample to run and cool the turbine motors. However, subsequent examination of computer printout sheets from the mud logging firm showed that the average pump speed during the first turbine motor run was about 100 strokes per minute for 250 gpm (16 l/s) mud flow, and that average pump speed was about 120 strokes per minute, producing 300 gpm (19 l/s), during the second turbine motor run. This flow rate was insufficient to start the turbine motors and was barely enough (at 300 gpm or 19 l/s) to sustain motor operation once started.

Conclusions. The PDMs did not operate because excessive temperature caused the elastomer stators to disintegrate.

Failure of the turbine motors was caused by insufficient fluid flow to operate and cool the motors. Inadequate cooling caused failure of the radial and thrust bearings.

Drilling with a whipstock achieved some kickoff as indicated by formation cuttings in the returns, but the bit may have never completely exited the original hole, as shown by the presence of some cement in the cuttings the whole time.

2.2.4 Bit Record

A total of 10 bits were used in reworking the well: five mill-tooth and five button bits. Three of the mill-tooth bits were 8-1/2 in. diameter, and they were used on the mud motors for sidetracking the hole and for drilling cement and cleaning out fill. Two 6-in. diameter mill tooth bits drilled the pilot hole during attempts to sidetrack using a whipstock.

The five button bits were used in attempts to drill a new hole. The original hole was drilled primarily with API 537 (medium soft) bits which showed wear on the cone, indicating that a longer tooth (soft) bit might be used with a resulting increase in penetration rates. The button bits used for the rework were API 437 (soft formation) bits. Because little new hole was drilled (and most of that was on junk), no conclusions can be made concerning the suitability of the soft formation bits.

A copy of the detailed bit record is provided in Appendix B.

2.2.5 Drilling Fluids Program

Fresh water was used primarily for cooling the well, and brine from the brine pond with density of 9.2 lbm/gal (1.10 kg/l) was used for killing the well.

A fresh water gel mud with Kenseal was used for drilling. Mud weight and funnel viscosity were maintained at 8.7 lbm/gal (1.04 kg/l) and 38 sec/qt, respectively.

Loss of circulation was not a problem because the mud weight was so low; however, the under-balanced system allowed the well to flow on numerous occasions. The well flow was controlled by bullheading brine down the hole to kill it.

A solids control system similar to that used for the original hole was used to maintain a low weight and solids content of mud.

Mud chillers were used to maintain the return mud well below its flash point.

A recapitulation of daily mud properties and material usage and the mud engineer's report are furnished in Appendix C.

2.2.6 Short Flow Test

A short flow test was conducted on August 31, 1987, after terminating the rework activities, to ensure that State 2-14 could be used as the production well for an injection experiment planned for the Imperial 1-13 well by the Idaho National Engineering Laboratory.

The State 2-14 well was flowed for 12 hours, averaging about 569,000 lbm/hr of total flow (steam and liquid combined). The maximum production rate was estimated to be 1,222,000 lbm/hr during the last 32 minutes of the test when the throttling valve was fully open.

A more detailed report of the short flow test of the State 2-14 well is included as Appendix D.

Section 3

CONSTRUCTION OF FLOW TEST FACILITY

3.1 DESCRIPTION OF FLOW TEST FACILITY

The flow test facility was originally designed, constructed, and used in 1982 to test a geothermal well of the CU–1 Venture at the South Brawley resource, under the DOE Geothermal Loan Guaranty Program. The flow test equipment was subsequently disassembled, moved, reassembled, and used to test two wells of the Parsons–Republic joint venture in the Niland resource area, also under the Geothermal Loan Guaranty Program. After the tests at Niland, the equipment was again disassembled, moved, and stored at the DOE Geothermal Test Facility at East Mesa.

Figure 3-1 shows a simplified flow diagram of the flow test facility, and Figure 3–2 shows a plot plan.

Two-phase geothermal fluid produced by the State 2-14 well flows to the high pressure separator, V-1. Startup piping is provided for bypassing the separator and sending flow to the brine pond through either a vent-silencer, V-4, the atmospheric flash tank, V-3, or directly to the brine pond through the blooie line.

The normal flow path admits two-phase flow to the separator where liquid and steam are disengaged by centrifugal force. The liquid entering the separator spirals downward along the walls and exits the separator from the bottom, with the steam leaving through the top.

A hand-operated valve to throttle flow was installed in the two-phase flow line between the State 2-14 well and the high pressure separator. This valve allows operating with wellhead pressure greater than the pressure in the separator. Thus, wellhead pressure could safely exceed the allowable operating pressure of the separator (500 psig or 3.45 MPa); this condition is most likely when adjusting the system for a low well flow rate. The throttling valve also allows use of low separator pressure at high well flow rate. This helps minimize carryover of liquid droplets in the steam leaving the atmospheric flash tank; relatively low enthalpy and low flow rate of brine from

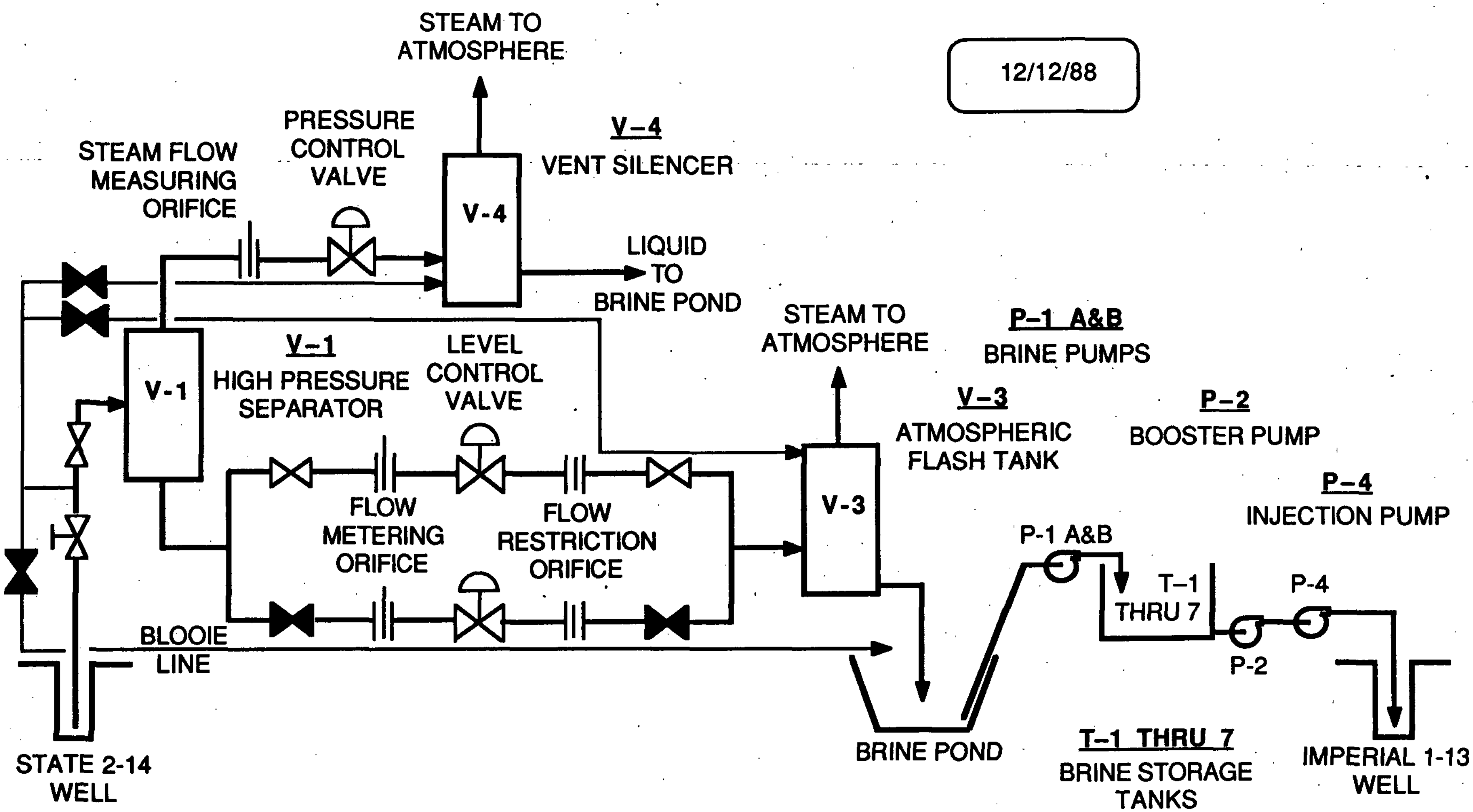


Figure 3–1 Simplified Flow Diagram of Test Facility

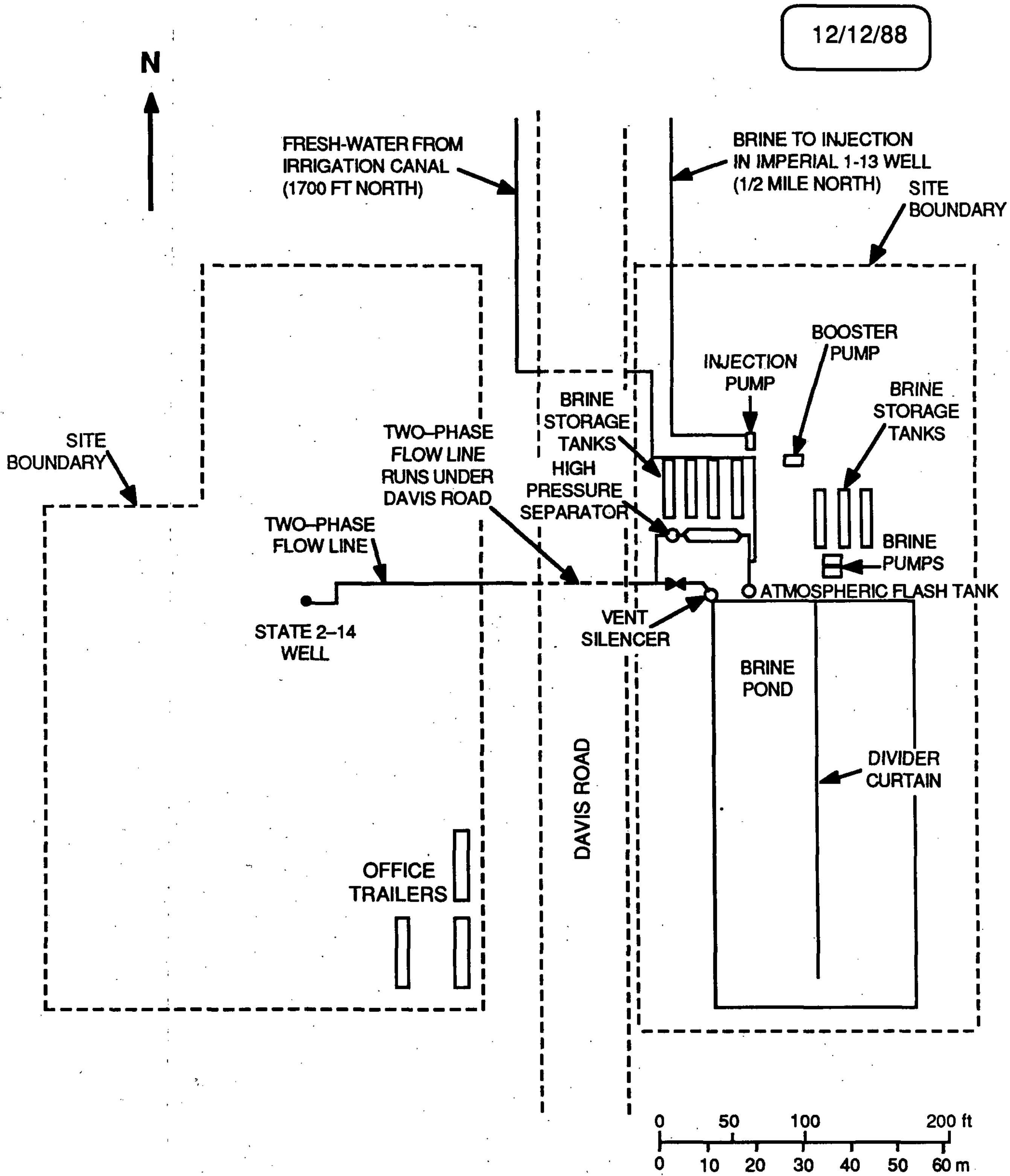


Figure 3–2 Plot Plan of Flow Test Facility

the separator (due to low operating pressure in the separator) limit the steam flow rate from the atmospheric flash tank.

Steam flow rate is measured using an orifice meter. Then the pressure is reduced by a pressure control valve that regulates the separator pressure. Steam is vented to the atmosphere through the vent silencer, V-4.

Separated brine exiting from the bottom of the separator flows through one of two parallel measuring loops. Each of the two loops contains an orifice meter, a level control valve, and a flow restriction orifice. Two loops are provided for reliability because of the high potential for scaling in the brine flow line from the separator. Use of a redundant control loop allows continuing a flow test while inspecting and performing maintenance work on one of the loops. The two sets of metering and restriction orifices downstream of the separator were sized to handle the complete range of expected flow rates without disassembling either loop to insert different orifice plates. Low pressure brine leaving the flow restriction orifice is a mixture of steam and liquid which flows to the atmospheric flash tank, V-3.

The atmospheric flash tank separates the two phases that enter from the flow restriction orifice. Steam escapes to the atmosphere through the top of the flash tank. Liquid exits from the bottom and flows into the brine pond.

The brine pond serves two functions in the process. First, it provides surge capacity (i.e., storage) so that the production rate of the State 2-14 well and the injection rate into the Imperial 1-13 well are not required to be exactly equal at all times. Second, it provides residence time for solid particles to precipitate and settle from the brine. A vertical divider curtain made of reinforced polyethylene is designed to force the brine to flow to the south end of the pond and then back to the north end as it travels from the pond inlet to the brine pump suction. The brine pond was constructed during the Phase 1 work; it measures 112 by 287 ft (34 by 87 m) by 8 ft deep (2.4 m) and holds 1.1 million gallons (4.2 million liters) of brine. It is made of impermeable native soil.

Liquid from the brine pond is pumped to brine storage tanks, T-1 through 7, by one of the two brine pumps, P-1 A or B. Two full-capacity brine pumps are installed to provide high reliability.

Liquid from the brine pond is pumped to brine storage tanks, T-1 through 7, by one of the two brine pumps, P-1 A or B. Two full-capacity brine pumps are installed to provide high reliability.

Seven 500-bbl (80 m^3) capacity tanks are connected in parallel. This provides a region with low brine velocity for sludge to settle. Thus, it serves as a safeguard against plugging the injection well with sludge inadvertently entrained in brine pumped from the brine pond.

One booster pump, P–2, and one injection pump, P–4, take brine from the brine storage tanks and inject it into the Imperial 1-13 well.

A Kennecott evaluation indicated that the Imperial 1-13 well could be used for injecting unfiltered brine during a 30-day test without undue hazard from plugging. Another resource developer has successfully injected unfiltered brine into the same strata.

3.2 CONSTRUCTION

Construction of the flow test facility at the State 2-14 well site was accomplished in two stages. The first stage was in the Fall of 1987; the second in May 1988.

3.2.1 Construction in Fall 1987

When construction of the flow test facility began, in September 1987, the objective of the flow test was to perform an injection experiment using the nearby Imperial 1-13 well. For this experiment, the State 2-14 well would operate at virtually a constant and uninterrupted flow rate to furnish brine for injection into the Imperial well. This required connecting four of the 500-bbl tanks for use as media filters and installation of installed spares for the booster and injection pumps to provide a highly reliable supply of filtered brine for injection.

The existing brine pond, two-phase flow line, and vent silencer were used. The remainder of the flow test equipment was installed at the north end of the brine pond.

Site Preparation. Soil in the area where the flow test facility was installed consists of sand and clay loam. The water table is 3 to 4 ft (about 1 m) below grade during dry periods, and it may be virtually at grade when the Salton Sea level is high.

The foundation for the high pressure separator was excavated to a depth of 12 in. (30 cm) and filled with rock, covered with 3 in. (8 cm) of soil, and compacted.

For the other equipment, no foundations were needed. The vessels were set on the ground after clearing the sparse vegetation from the particular locations for the equipment.

A new entrance to the area was established to provide better access during inclement weather.

Initial Condition of Vessels, Piping, and Instruments. The high pressure separator was coated with rust and other corrosion products on the inside. On the outside, the insulation sheathing was crumpled and dented, but the insulation was in place. The supporting skirt was coated with rust over about one-third of its surface area. The platform near the top of the high pressure separator was bent so badly that it was virtually destroyed. The high pressure separator is the only pressure vessel in the test facility, and it was hydrostatically tested to 1,200 psig (8.3 MPa) before it was moved from the storage area. This test demonstrated the structural integrity of the separator for pressures in excess of the design test pressure. The brine outlet pipe elbow from the separator was noticeably thinned from erosion during previous use, but ultrasonic inspection confirmed that enough steel remained for safe use at the design operating pressure of 500 psig (3.4 MPa).

The atmospheric flash tank and the vent-silencer were coated inside and out with rust from previous use and storage. The tanks for media filters and brine storage were covered with rust on the inside, but the paint on the outside showed only isolated areas of rust. The amount of material removed from these open-top vessels by corrosion did not jeopardize use for atmospheric pressure operation.

The major piping was badly rusted and corroded; some was also coated with scale on the inside. None of the valves were operational. Many of the valve handles and stems were broken. Numerous flange connecting bolts were galled and had to be replaced. Some sample ports and pressure taps had been seal-welded, and because of corrosion, many of the remainder were virtually without thread to withstand operating pressures.

The instrumentation was in poor condition. The flow and level recorders were in such bad shape that renting replacements for the flow test was less expensive than reconditioning. The flow orifices were either missing or had to be replaced due to erosion, corrosion, or bending. Most of the temperature and pressure indicators were in storage, but good instrumentation practice requires calibration before use in the flow test.

Reconditioning. All valves were reconditioned before installation. The four 12-in. valves that isolate the measurement loops downstream of the separator were sent to a local valve shop for replacement of stems, handles, and packing; the internals were sandblasted as part of this reconditioning. All valves were disassembled and cleaned; defective parts were either replaced or hand refurbished. Valves that were beyond cost-effective reconditioning were replaced.

Installation. The high pressure separator was set in place on a cross-shaped support made of 10-in. pipe to spread the load over a large bearing surface; the support was filled with concrete for ballast. Other vessels were set in place on the ground with no foundations. Because the pumps were rental items, they were not set in place at this time.

Usable piping spool assemblies were reconnected in the previous configuration. All flanges were broken open, cleaned, regasketed, and reassembled. New piping sections, as required, were fabricated and installed. All piping was installed on temporary wooden-block supports. These temporary supports were replaced with concrete and steel supports during the second phase of construction in May 1988.

The instruments were refurbished and stored. In early November 1987, projection of the start-date indicated that mid-January 1988 would be the earliest date for starting a flow test. With a period of at least two months before start of testing, instrument storage was better than having the instruments installed and exposed to the weather.

Construction of the flow test facility was suspended in November 1987 because funding levels were uncertain. Therefore, construction activity was shut down and all personnel left the site, awaiting restart of flow test preparation.

3.2.2 Construction in May 1988

Construction of the flow test facility resumed on May 1, 1988 for a flow test to characterize the State 2-14 well and reservoir instead of an injection experiment. The scheduled start date for the well flow test was June 1, 1988. Performance of the hydrostatic leak tests is such a significant milestone that construction activities may be classified for discussion as occurring before or after hydrostatic test as follows:

- Before hydrostatic leak tests

  Review of the facility during the period from November 1987 to May 1988 indicated that the elbows in the existing two-phase flow line could erode so rapidly that a 30-day flow test would be jeopardized. Such rapid erosion has been observed with some of the other geothermal wells in the Imperial Valley. Therefore, eight elbows in the 10-in. two-phase flow line were removed and Tee's, with one of the straight connections capped, were installed. By orienting the Tee's with the remaining straight connection in the direction of incoming flow, the capped connection serves as a liquid-filled cushion to turn the flow 90 degrees without eroding the walls of the piping.

  The four 12-in. gate valves that isolate the measuring loops downstream of the separator were initially installed with the valve stems vertical. Review and discussion of this orientation indicated that these large valves should be oriented with the stems about 45 degrees from horizontal to allow manual operation. This orientation allows use of a person's weight as part of the turning force. With such large valves, this weight component is often required, unless a mechanical operator is installed on the valve. Therefore, the metering loops were disassembled, and the four large valves reoriented. During reassembly, the piping was found to be badly misaligned, and considerable cutting and rewelding was needed to straighten the measuring loops.

  A 10-in. valve for throttling the two-phase flow was installed in the existing 10-in. two-phase flow line from the State 2-14 well to the high pressure separator.

The wooden temporary pipe supports were replaced with more substantial supports, typically a Tee-shaped member fabricated of steel pipe held in place by a poured-in-place concrete base.

The railing for the platform near the top of the high-pressure separator was repaired to make installation or operation activities safer.

Approximately one hundred feet of 6-in. piping was connected from the injection pump location to the existing injection line that leads to the Imperial 1-13 well. The Imperial well is approximately one-half mile straight north of the well flow test facility.

A fresh-water supply was installed to draw water from an irrigation canal and transport it to the flow test facility. The fresh-water supply system consists of a pump driven by a stationary engine and a 4-in. diameter temporary pipeline. The fresh-water pipeline was laid on the ground for the 1,700 ft (518 m) distance from water source to test facility. Large quantities of fresh water were used before the test for hydrostatic testing, during the test for brine dilution, and after the test for cleaning the equipment.

- Hydrostatic leak tests

Two hydrostatic leak tests were performed on May 25, 1988 to demonstrate the structural integrity of the high pressure vessels and piping.

First, the high pressure separator and the piping from the State 2-14 well to the 12-in. valves at the downstream end of the measuring loops were qualified for operating pressures up to 500 psig (3.4 MPa) at operating temperatures to 470 ^{o}F (243 ^{o}C). The actual hydrostatic test pressure at ambient temperature was 900 psig (6.2 MPa).

After the first hydrostatic test was concluded, the throttling valve in the two-phase flow line was closed, the high pressure separator and piping downstream of the throttling valve were vented, and the two-phase flow line upstream of the throttling valve was pressurized further to qualify it for operation to its design pressure of 700 psig (4.8 MPa) at temperatures to 500 ^{o}F (260 ^{o}C). The actual hydrostatic test pressure was 1260 psig (8.7 MPa).

- After hydrostatic leak tests

After the hydrostatic leak tests, a rupture disk rated for 590 psig (4.1 MPa) was installed to limit pressure in the high pressure separator.

Calibration and installation of the flow test instrumentation and controls was completed, and the compressed air system to operate the controls was installed. Most of the recorders were found to be unusable, and rental units were obtained for the flow test. One of the flow control valves installed from the brine storage tanks to the brine pond so that the tanks could not be overfilled.

The divider curtain was installed in the north-south direction across the brine pond. The divider curtain was made of 6-mil reinforced polyethylene. Heavy scrap steel cable was attached as weight to hold the bottom edge along the bottom of the pond. The top was supported with a cable anchored at one end and attached to a hand-operated winch at the other to adjust the tension.

The pumps were rented with a diesel engine to drive each pump. Each pump/engine combination was attached to a trailer to facilitate transportation. Each pump was connected with reinforced hose on both the intake and the outlet. The pumps were the last major equipment items installed before the test began.

Flow from the State 2-14 well began on June 1, 1988. At the start, flow bypassed the separator and entered the brine pond, first through the blooie line and later through the atmospheric flash tank. Installation of pumps and piping to transfer brine from the pond to the brine storage tanks was completed on June 3. The next day, installation of the booster pump on the injection line was completed, and injection began. On June 6, two-phase flow was admitted to the high pressure separator. This concluded the construction phase of the flow test facility.

Section 4

FLOW TEST

This section summarizes the results from the earlier short-term flow tests and discusses the flow test that was conducted in June 1988 to characterize the State 2-14 well and reservoir. Brine chemistry results from the June 1988 test are discussed in Section 5.

4.1 RESULTS FROM SHORT–TERM FLOW TESTS

Short-term flow tests were conducted in December 1985 with well depth 6,227 ft (1,898 m), in March 1986 shortly after completion to total depth of 10,564 ft (3,220 m), and in August 1987 after the second well rework.

Table 4–1 summarizes the results of the short-term flow tests. The maximum well flow rates for the three tests were from 600,000 to 1,220,000 lbm/hr (272,000 to 553,000 kg/hr), indicating that the well is likely to be highly productive. Wellhead tempertures were generally 460 °F (238 °C) and higher after warmup; therefore, downhole temperatures, before any fluid is flashed, are quite high. The high total dissolves solids concentration is consistent with values for other hypersaline wells in the Salton Sea area. The geothermometers Na/K, Na/Ca, and Ca/K have different values for the March 1986 test from those for the test in December 1985; this indicates that other zones in addition to the one at 6,120 ft (1,865 m) are apparently contributing to the production.

4.2 TEST PLAN

The objectives of the flow test in June 1988 were to:

- Investigate the long-term production characteristics of the well and reservoir system
- Obtain well-flow data and downhole measurements needed to perform reservoir engineering analyses of the well performance and determine near-well reservoir properties

Table 4–1

Summary of Results from Short–Term Flow Tests

Date of Test	December 1985 during drilling	March 1986 after well completion	August 1987 after second rework
Well Depth, ft	6,227	10,564	10,564
Estimated Flow Zones, ft	6,120	6,100 6,600 8,800 10,475	6,100 6,600 8,800 10,475
Duration of Flow Test, hours	29	32	12
Total Brine Produced, lbm	5,570,000	10,045,000	6,830,000
Average Well Flow Rate, lbm/hr	192,000	314,000	569,000
Maximum Well Flow Rate, lbm/hr	600,000	700,000	1,220,000
Range of Wellhead Temperatures, °F	400 to 460	445 to 490	355 to 465
Range of Wellhead Pressures, psig	200 to 450	310 to 485	118 to 388
Total Dissolved Solids, mg/kg	255,000	251,000	236,000
Geothermometers			
Na/K	3.19	4.09	No data
Na/Ca	1.99	1.86	No data
Ca/K	1.61	2.20	No data

- Obtain samples of brine, steam, and noncondensible gases for chemical analyses to characterize the reservoir fluid, calculate physical and thermodynamic properties, and analyze for changes in composition associated with flow rate changes

- Measure the preflash temperature of the brine and obtain other data to calculate the enthalpy of the fluid produced and the rate of energy production for the well

- Provide opportunities for other experimenters to perform tests in conjunction with the flow test. The following scientific research projects were conducted during the flow test in June 1988:

  - Particle meter testing by Battelle Pacific Northwest Labortaories

  - Chemical sampling and analysis to characterize the brine by Electric Power Research Institute

  - Seismic monitoring by Lawrence Livermore National Laboratory

  - Metal ion concentrations by New Mexico State University

  - Transport of platinum group elements, gold, and sulfur in the Salton Sea Geothermal brines by University of California at Riverside

  - Uranium series isotope measurements by University of Southern California

  - Liquid and gas sampling by University of Utah Research Institute

The flow test of the State 2-14 well in June 1988 was originally planned as a 30-day step-rate test with three rate steps scheduled as follows and as shown in Figure 4-1:

	Planned Duration (days)	Planned Flow Rate (lbm/hr total mass)
First rate step	7	200,000 to 250,000
Second rate step	7	400,000 to 500,000
Third rate step	16	600,000 to 750,000

1,000 lbm/hr = 454 kg/hr

Three previous short-duration flow tests, during and after drilling, were conducted with a simple test facility that held the residual brine in a brine

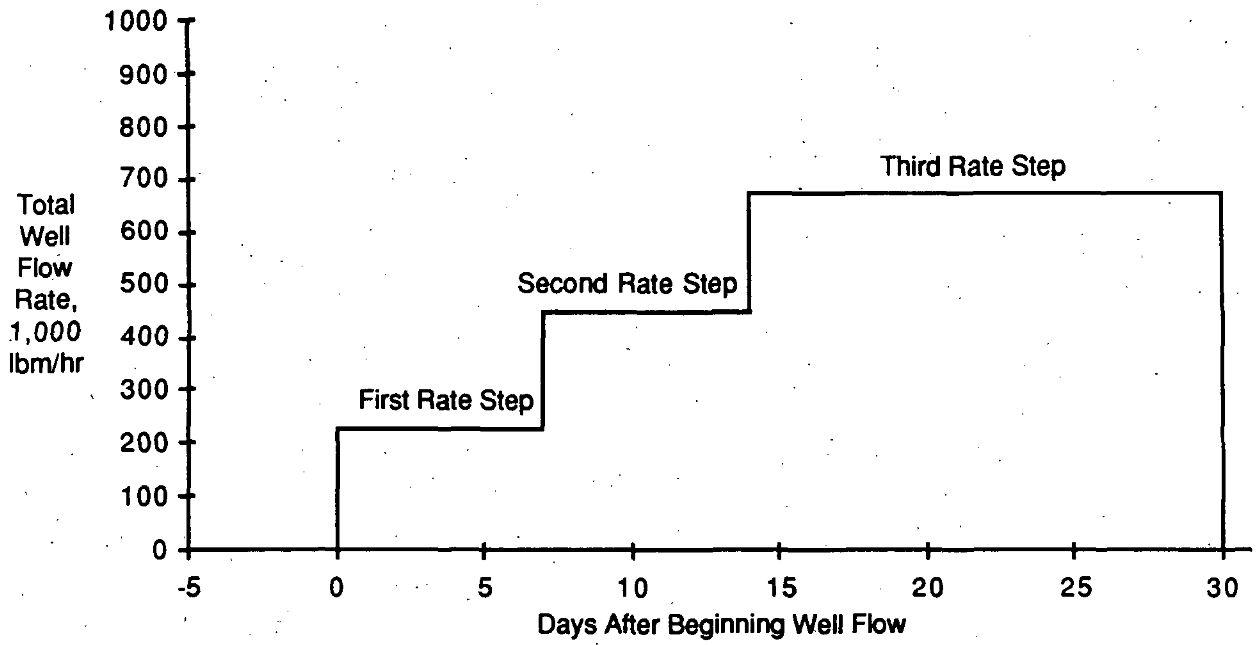


Figure 4-1 Planned Schedule for 30-Day Flow Test

pond without injection. These tests were limited to 29, 32, and 12 hours' duration by the capacity of the brine pond. To perform a longer-term (i.e., 30-day) flow test, the more elaborate test facility described in Section 3 is required. This facility provides the necessary capability of brine injection and the advantages of steam/brine separation for separate metering and sampling of the two phases.

The step-rate test is a standard reservoir engineering method for obtaining the downhole pressure response data for determining reservoir properties while obtaining wellhead data to define a deliverability curve (i.e., graph of production rate versus wellhead pressure). The planned duration of each rate step was estimated to be adequate for the well to reach stable operation with respect to flow rate, pressure, and chemistry. The schedule of increasing flow rates also facilitated operation of the flow test facility by allowing a step-wise approach to the higher flow rates.

A total of five downhole pressure and temperature surveys were planned to acquire data for reservoir engineering analysis and for characterization of the brine before flash. Production logs, which would normally be run to delineate and quantify zones of inflow, were not planned because the questionable mechanical condition of the deeper portion of the well made it inadvisable to run logging tools deeper than 5,500 ft (1,676 m).

The schedule for flow rates and durations of the steps was revised during the first week of the test for the following reasons:

- The budget could not support 30 days of testing.
- The State 2-14 well was confirmed as a high productivity well, and flow conditions stabilized within hours after a rate change. For purposes of reservoir engineering analysis and for defining the deliverability characteristic of the well, shorter duration flow steps would suffice.
- The well is clearly capable of high flow rates, and the initial rate step was about one-half the planned rate because brine could not be injected early in the test. To define the useful range of flow rates for the well, three additional rate steps (for a total of four) were considered necessary.
- The maximum flow rate of the well would be limited by the capacity of the test facility. Therefore, the full flow rate potential of the well would be determined by a maximum rate flow test directly to the brine pond. To

accomplish this without compromising the reservoir and well performance analyses, a separate full flow rate test was scheduled following the four rate steps and a shutin period. Because brine production would exceed the injection rate, the test at full flow rate was to last only a few hours as determined by the maximum injection rate and the brine pond capacity.

The revised schedule for the flow test is summarized below and is shown in Figure 4-2:

	Planned Duration (days)	Planned Flow Rate (lbm/hr total mass)
First rate step	7	125,000
Second rate step	3	250,000
Third rate step	3	450,000 to 500,000
Fourth rate step	6	650,000 to 750,000
Shutin to monitor pressure buildup	2	Zero
Test at full flow	<1	Maximum flow rate probably >1,000,000

1,000 lbm/hr = 454 kg/hr

4.3 WELL AND RESERVOIR TEST RESULTS

4.3.1 Test Operating Conditions

Figure 4-3 shows the flow rate during the test. In this plot, the flow rate during each step is smoothed; that is, the flow rate is averaged during each step to focus on the flow rate trends. Figure 4-4 shows the wellhead temperature and pressure (smoothed) during the test. Detailed plots of the flow rate, wellhead temperature, and wellhead pressure at 2 hour intervals are given in the well test engineering report (Appendix F).

The test was planned and conducted as a step-rate test, but there were some deviations from the ideal of long periods with constant flow rate. Although the well itself showed no appreciable pressure decline, there was a tendency for the flow rate to drift downward, probably because of scale deposition in the throttle valve. Occasional adjustments of the throttle valve were required to achieve the desired flow rate. This commonly occurs in well testing in the Salton Sea field and did not significantly affect the results.

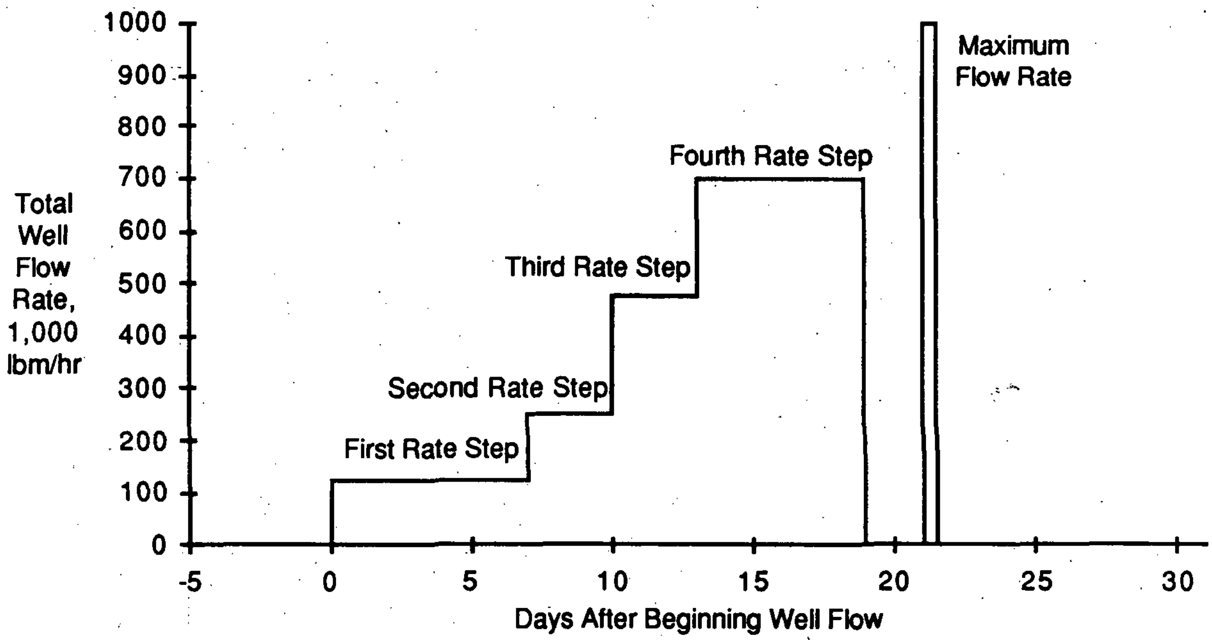


Figure 4-2 Revised Schedule for Flow Test

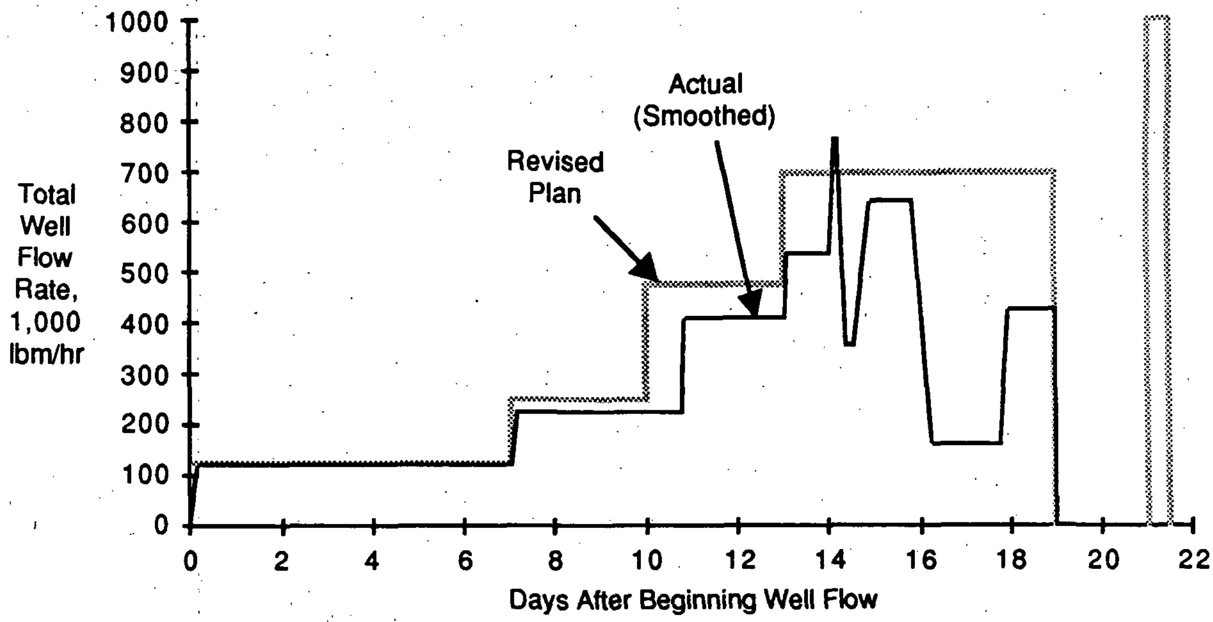


Figure 4-3 Total Well Flow Rate

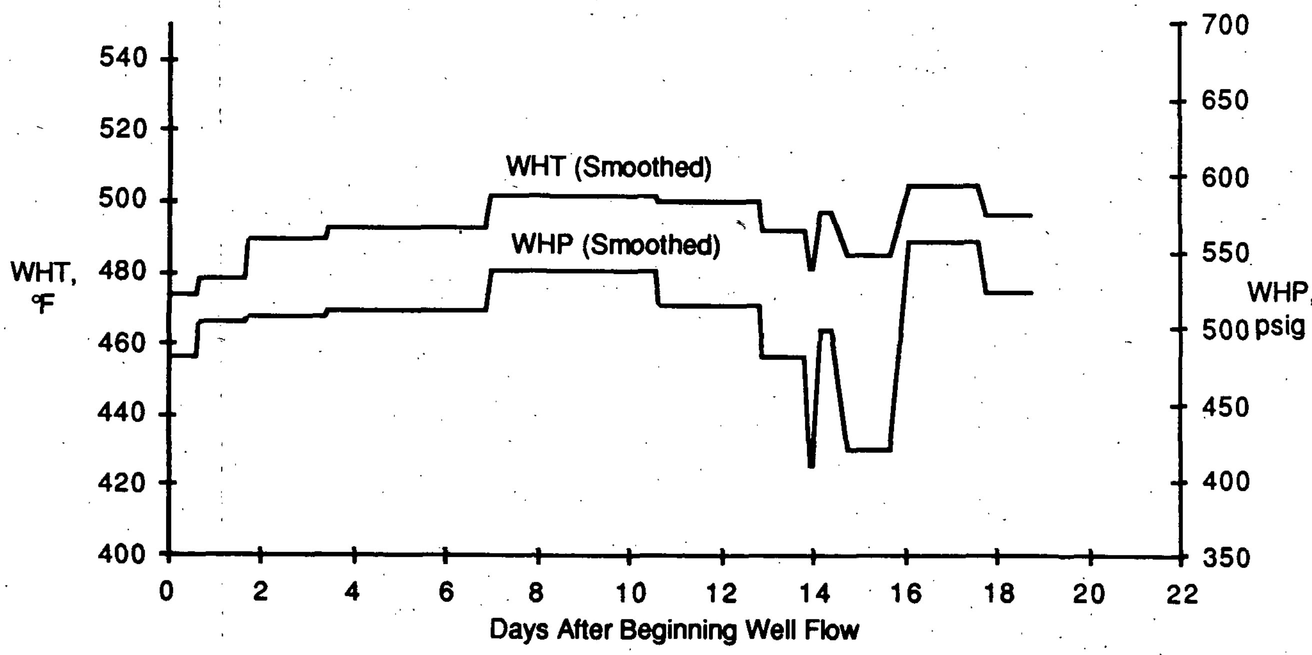


Figure 4-4 Wellhead Temperature and Pressure

The highest rate of 768,000 lbm/hr (348,000 kg/hr) was maintained for less than 1 hour because separator control was not functioning properly. Therefore, the deliverability data at that rate do not represent a fully stabilized condition. Nevertheless, the results are adequate to achieve the reservoir engineering test objectives.

The well was initially produced at about 125,000 lbm/hr (57,000 kg/hr), significantly lower than the planned initial rate of 200,000 to 250,000 lbm/hr (91,000 to 113,000 kg/hr). This lower flow rate was used because the residual brine had to be retained in the brine pond until the injection system was completed on June 4. Ideally, test startup would have waited for completion of the injection system, but budgetary and schedule considerations necessitated the June 1 start.

Once the injection system was operational, the production rate was held at about 125,000 lbm/hr (57,000 kg/hr) until June 8 to complete the planned 7-day period for the lowest flow rate step.

Late on June 8, the flow rate was increased to 250,000 lbm/hr (113,000 kg/hr), and the durations of succeeding rate steps were shortened as indicated in the revised test schedule (Figure 4-2).

Downhole temperature and pressure profile surveys were conducted on June 5, 12, 14, and 20. These surveys measured stabilized flowing pressure at the 5,000 ft (1,524 m) datum at various flow rates to define the well inflow performance. They also measured flowing temperature and pressure profiles between the surface and 5,000 ft (1,524 m) to provide data for thermodynamic flash calculations and to establish whether a relationship exists between brine temperature and flow rate. The temperature surveys were conducted with Amerada-type Kuster instruments, and pressure data were obtained with a helium-filled capillary tube downhole and a Paroscientific digital quartz pressure transducer at the surface.

Pressure drawdown was recorded as flow rate was increased on June 12 and 14, and pressure buildup was recorded for 44 hours after the shutin on June 20. Data from these pressure response measurements were used to calculate near-well reservoir properties.

Typically, a flow test would involve a static downhole temperature and pressure survey to establish equilibrium shutin conditions before the test. This was not done immediately prior to the June 1988 flow test because 1) a suitable static survey was run in November 1987 and 2) brine in the wellbore had been displaced with fresh water in April 1988, distorting any static downhole pressure measurements.

4.3.2 Well Performance

Flow rates and wellhead pressure measurements were used to plot a deliverability curve. Stable wellbore pressures measured at 5,000 ft (1,524 m) before and after step rate changes were used to plot a productivity curve and calculate the productivity index.

Deliverability. Figure 4-5 shows the deliverability curve for the State 2-14 well. The following points should be noted about this plot:

- The dashed line represents the shape of the projected curve to lower wellhead pressures. For example, at typical commercial operating wellhead pressure of 250 psig (1,724 kPa), about 840,000 lbm/hr (381,000 kg/hr) could be produced.
- Increased well deliverability observed later in the test suggests that the well improved during the course of the test. It is likely that flowing the well at higher rates may have cleaned drilling solids from the reservoir rock and also may have opened additional flow paths unavailable at the start of the test.
- At low flow rates, deliverability curves often show a curve toward the origin just before the lowest sustainable flow rate. Points on this curve for low flow rates at the beginning of the test are more likely representative of the improved wellbore condition noted above.

Productivity. Well productivity was assessed using pressure measurements made in the liquid column at 5,000 ft (1,524 m). This is shallower than the suspected primary entry zone at 6,200 ft (1,890 m). During flow conditions, this should not influence the reliability of either productivity or pressure drawdown measurements because the temperature in the flowing single-phase liquid column is subject to only slight cooling due to heat losses.

Figure 4-6 shows flow rate plotted against downhole pressure for three stabilized flow rates. The productivity index of a well is usually defined as the

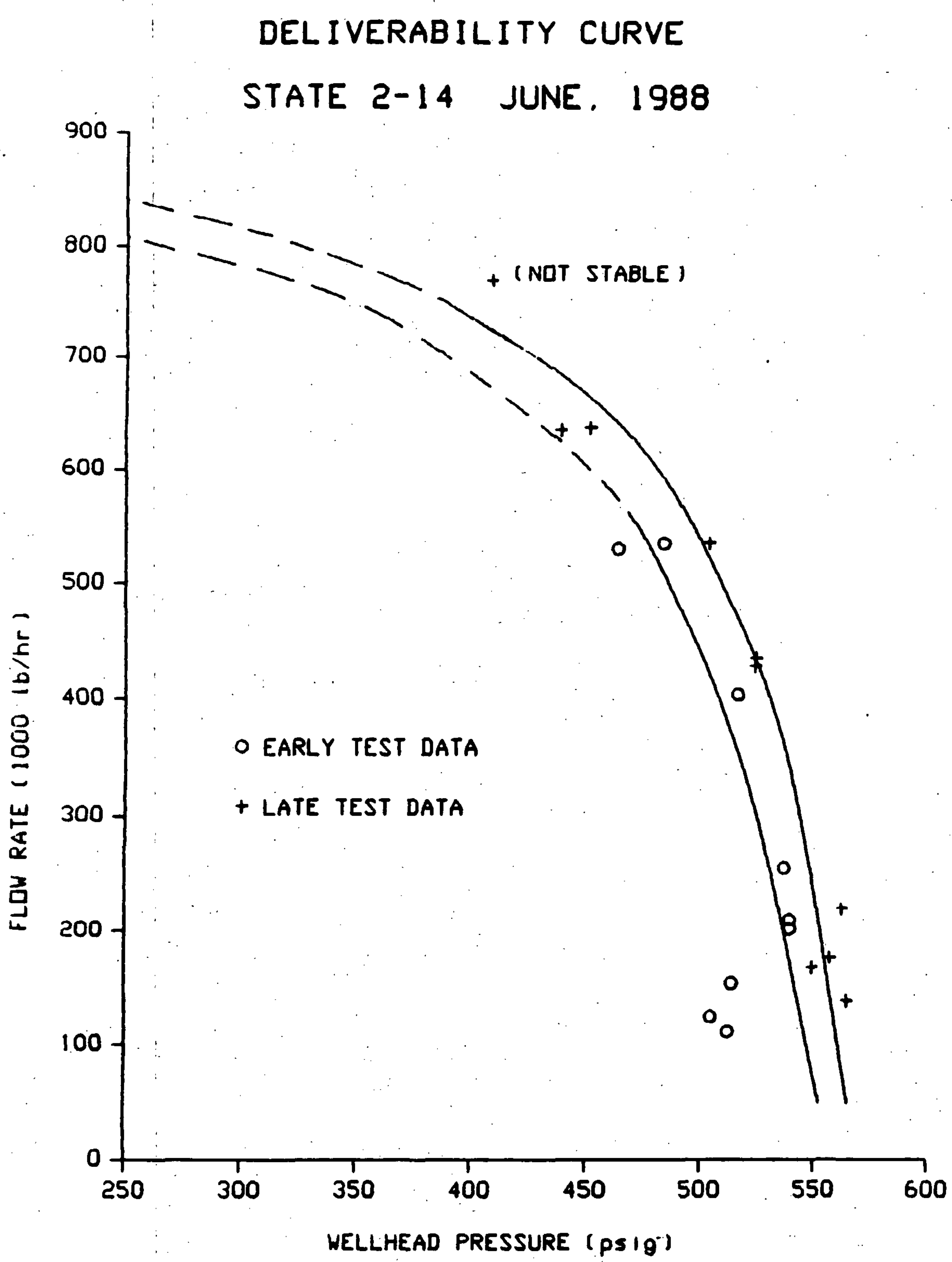


Figure 4-5 Deliverability Curve

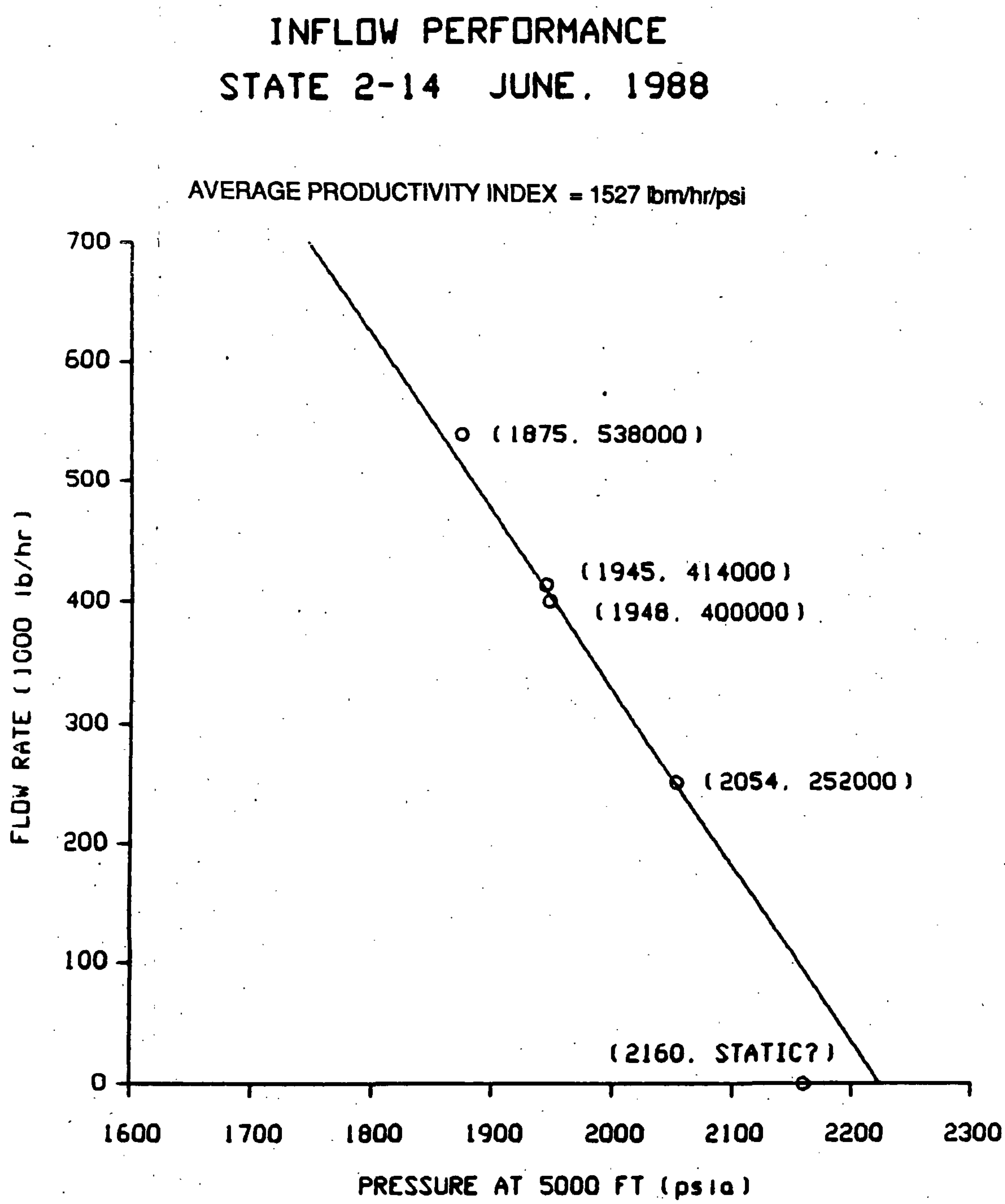


Figure 4-6 Total Well Flow Rate as a Function of Downhole Pressure

flow rate change per unit change in downhole pressure. An average productivity index of 1,527 lbm/hr per psi (100 kg/hr per kPa) was calculated using these data.

The productivity curve is a straight line through the three points, which would be expected from matrix permeability alone. However, reservoirs in the Salton Sea area typically are extensively fractured but also have significant matrix storage capacity. Because well improvement was noted from other data during the flow test and an available static pressure measurement does not fall on the productivity line, the straight line productivity curve does not necessarily imply matrix-only permeability. The permeability is no doubt affected by fracturing in addition to matrix permeability.

Skin. Downhole pressure drop includes not only pressure changes in the reservoir under flowing conditions, but also pressure losses as fluid enters the wellbore (i.e., skin effects) and pressure changes due to differences in the amount of fluid stored in the wellbore (i.e., wellbore storage). For geothermal wells, separating pressure losses due to skin effects and wellbore storage is almost impossible; therefore, they are generally lumped together and calculated as a "skin factor."

Horner plot analysis of the buildup data yields a calculated skin factor of +23.1. Positive values indicate large pressure losses as fluid enters the wellbore. These can be caused by wellbore damage, pressure drop across liners or through perforations, partial penetration completions, wellbore storage effects, closing of fractures as pressure decreases, and turbulent flow as fluid enters the wellbore at high rates. For the State 2-14 well, the well no doubt sustained wellbore damage during drilling and rework activities; however, high flow rates into the wellbore probably contributed to the apparent skin effect also.

4.3.3 Reservoir Performance

Two measurements of drawdown were made during flow rate changes with the following results:

- June 12.
  - Flow rate change: 210,000 to 414,000 lbm/hr (95,000 to 188,000 kg/hr)
  - Initial drawdown: 104.1 psi (718 kPa). Recovered rapidly; then began to draw down again
  - Maximum drawdown: 113.6 psi (783 kPa) at 95 minutes after rate change
  - Recovery: 9.5 psi (66 kPa) in 18.5 hr
- June 14.
  - Flow rate change: 404,000 to 538,000 lbm/hr (183,000 to 244,000 kg/hr)
  - Initial and maximum drawdown: 115.5 psi (796 kPa) at 20 minutes after rate change
  - Recovery: 42 psi (290 kPa) in 14 hr

Pressure recovery following drawdown (when additional drawdown should be expected) is further evidence of well improvement during the flow test. Unfortunately, it makes both drawdown curves impossible to analyze accurately for quantitative reservoir parameters.

At shutin on June 20, the beginning of pressure buildup was not detected at 5,000 ft (1,524 m) until 6 minutes after shutin because of the effects of wellbore storage and the slow rate at which the valves could be closed. Initial buildup was 163 psi (1,124 kPa) within an hour. This was followed by a slow pressure decrease of about 0.05 psi/hr (0.34 kPa/hr) for the next 44 hours. This decrease was probably due to cooling of the fluid between the bottom of the pressure tool and the inflow zone, largely the result of density changes in the wellbore.

The following semiquantitative estimates of reservoir performance factors and skin effect were made using a Miller–Dyes–Hutchinson semilog plot:

- Transmissivity. 233,600 md-ft
- Skin factor. +23.1

The reservoir and well performance estimates indicate that the reservoir has high permeability and adequate storage capacity capable of producing at high flow rates for extended periods. However, because the data were not amenable to boundary analysis, it is not possible to estimate the life of the reservoir or the total production capacity.

4.3.4 Injection Well Performance

The Imperial 1–13 well was used as the injection well throughout the test, with total injected brine of 72.6 million lbm (32.9 million kg).

From the start of injection, the injectivity (flow rate per unit of wellhead pressure) began to decline. Injectivity at the end of the test was only about 20 percent of the initial value.

Brine injection directly from the brine pond without settling in the brine storage tanks occurred following interruption of the fresh water supply on June 15, and concentration of suspended solids in the brine was probably higher for two or three days following this upset. However, high suspended solids during this period alone do not account for the observed plugging.

The observed progressive injectivity decrease is typical of a well undergoing formation plugging by suspended solids. Injection of unfiltered fluid, with some suspended solids, throughout the test no doubt explains much of the reduced injectivity.

4.3.5 Adverse Test Conditions and Incidents

A number of adverse test conditions and incidents occurred during the flow test. These situations are discussed here in an effort to be helpful to others in the geothermal industry in planning and conducting flow tests in the Imperial Valley and wherever brines have high TDS content. The items are discussed in chronological order with their effects on the flow test and possible remedies indicated.

Start of test before all systems were completed. The well was initially produced at a rate significantly lower than the planned initial rate. This lower flow rate was used because the injection system was not completed until June 4.

The results of this adverse situation were that the initial low flow rate was about 60 percent of the planned rate, and its duration was longer than necessary. This longer operation at low flow rate reduced the time available for testing at higher flow rates, where more well and reservoir information can be obtained.

The remedy is to hold test startup for completion of the injection system. However, budgetary and schedule considerations necessitated the June 1 start.

Fresh water dilution was not used at the start of the test. The short flow test in August 1987 produced little salt precipitation in the piping, vent silencer, or brine pond. Therefore, freshwater was not used at the start of the flow test in June 1988, awaiting appearance of salt precipitation to indicate a need for dilution water.

The main result was that salt began to accumulate on the divider curtain, possibly contributing to its failure as discussed below.

A remedy is to begin freshwater dilution at the start of a flow test rather than waiting for the appearance of salt precipitate.

Plugging of pressure taps. The pressure taps for the wellhead pressure gage and for one of the brine orifice meters plugged during the flow test. When this happened, a rodding tool was used for cleaning the ports without shutting down the line; this allowed the test to proceed with essentially no interruption.

The pressure taps were promptly cleaned; therefore, the consequences of these events were insignificant.

The use of a rodding tool is an appropriate remedy for plugged pressure taps. The piping and valve for the tap must be straight and short enough to permit use of the rodding tool.

Failure to log downhole data during one rate change. When the test schedule was revised and the flow rate was changed, with short forewarning, on June 8, the logging contractor was unable, because of other commitments, to furnish the equipment needed for measuring the downhole pressure and temperature during this drawdown process.

The consequences of this particular adverse event were virtually negligible, primarily because it occurred at one of the changes at low flow rate. Some well and reservoir performance data were lost but not so much as to affect the overall results.

An apparent low-cost remedy is to set a test schedule and rigidly stick to it. However, flow tests never proceed exactly as expected, and some flexibility to change the timing of events should be maintained to gain the most useful information. An expensive remedy is to have exclusive use of logging tools during a flow test.

Interruption of freshwater supply. On June 15, the pump supplying fresh water for dilution of the spent brine ran out of fuel and was out of service for 4 hours. During this outage, salt precipitate formed in the atmospheric flash tank, weirbox, and brine pond. During June 16 and 17, the injectivity of the injection well dropped dramatically, although it increased somewhat on June 18.

The consequences of this event were 1) formation of salt precipitate caused operational problems for a day or two and contributed to decisions to reduce flow rate temporarily, 2) plugging of the injection well may have been accelerated, and 3) salt depositing on the divider curtain may have been accelerated, contributing to divider curtain failure as discussed below. Although this adverse event brought about frenzied activity for a few days and may have contributed to later problems, it did not materially alter the overall test outcome and results.

An appropriate remedy is to designate monitoring of pump fuel reserve as a high priority item for operations personnel.

Failure of the diverter curtain. The diverter curtain accumulated so much salt and sludge that, on June 15, brine flowed over the top of the curtain near the brine pond inlet, short-circuiting the longer path to the opposite end of the brine pond and back. This allowed brine from the pond inlet to flow directly to the brine pump inlet.

The consequences of this situation were that 1) hot brine no doubt contributed to cavitation problems with the brine pumps, limiting the rate of brine that could be pumped from the brine pond, 2) a large amount of sludge built up near the brine pump intake, and 3) sludge entrained with the brine probably increased and was eventually injected into the injection well, accelerating the plugging process.

Remedies for this adverse condition include 1) a different design for the diverter curtain, possibly using floats instead of a tensioned cable to support the curtain or 2) a permanent baffle, such as an earthen dike, to serve the same function as the diverter curtain.

Pump cavitation. Cavitation occurred at the intake of the brine and the booster pumps at one time or another during the flow test. It was most severe for the brine pumps, especially when hot brine began to flow over the diverter curtain directly from the brine pond inlet.

The results of this situation were that 1) high well flow rate could be maintained for only short periods because cavitation limited the rate of brine removal from the brine pond and 2) flow rate was reduced occasionally for a few hours to permit changing or maintaining pumps.

A number of remedies are called for; each is likely to help, but none is a complete cure: 1) Pump inlets should be large, short, and free of unnecessary valves, elbows, Tees, and other pipe fittings, 2) The brine pump inlet line should be imbedded in the brine pond berm rather than going over the top of it, 3) Pumps should be kept as low as feasible, in this regard, skid mounting is better than trailer mounting, and 4) Brine should be allowed to cool before arriving at the pump inlet.

Capacity of the atmospheric flash tank. The limitation for maximum flow rate of the flow test facility was the capacity of the atmospheric flash tank. For well flow greater than about 640,000 lbm/hr (290,000 kg/hr), carryover of brine droplets in the steam from the atmospheric flash tank was experienced. Greater flow rates increased the liquid carryover.

The consequence of this limitation is that testing at high flow rates is not feasible.

The main remedy is to install an atmospheric flash tank with adequate capacity for the maximum flow rate expected from the well. Another tactic that extends the capacity somewhat is to operate the high pressure separator at as low pressure as feasible; this flashes more steam in the high pressure separator and reduces both the flow rate of separated brine and its enthalpy, thus reducing the steam flashed in the atmospheric separator. This approach is limited, however, because reducing the operating pressure of the high pressure separator reduces its flow rate capacity such that it can become the limiting factor on the facility flow capacity.

Debris in the steam flow meter. After the flow test was completed, the steam flow meter (orifice plate) was found to be obstructed by some debris, pieces of metal or scale apparently dislodged upstream. This caused all the steam flow rate readings to be erroneously high.

The consequences of this situation were minimal because the obstruction apparently occurred early in the flow test, allowing a correction factor to be calculated by matching the indicated flash fraction with the flash fraction calculated using a computer model for hypersaline brines.

Remedies for such flowmeter obstruction include 1) The upstream piping should be completely disassembled (if used equipment is installed) and cleaned; corroded or scaled components should be replaced if they cannot be thoroughly cleaned, 2) The indicated flash fraction should be compared with theoretical values early in the test period, and discrepancies should be traced and remedied to within the expected accuracy of the flow meters, and 3) Provisions should be made to isolate and disassemble flow meters without affecting well flow.

4.3.6 Casing Constriction

On August 8, 1988, 44 days after the end of testing, Kennecott attempted to run a casing inspection caliper log in the State 2-14 well. Caliper tools having outside diameters of 7 1/4 and 3 1/2 in. (18.4 and 8.9 cm) stuck at approximately the same place in the 9 5/8 in. casing. The upper end of the constriction occurs about 26 in. (66 cm) below the upper end of the casing string, where the casing comes through the casing head. A television camera having a diameter of 2 1/8 in. (5.4 cm) was run through the constriction to a point 2 ft (60 cm) below the point where the logging tools stuck, and the video tape shows what may be interpreted as a heavy buildup of white scale. Unsuccessful attempts were made to obtain a sample of the scale for analysis.

Because the constriction apparently did not exist at the time of the casing inspection log in April 1988, it probably formed during the flow test in June 1988. The possibility of its developing after the flow test is remote.

Two explanations for the formation of the constriction are apparent, but both explanations are flawed:

- Scale buildup. Normally, heavy scale buildup would be reflected in declining well deliverability, but deliverability actually increased as the test progressed. This implies that either 1) the constriction formed early in the flow test or 2) factors increasing the deliverability more than offset the increasing flow resistance from scale accumulation.

  Abrupt scale buildup would be expected only in a region where high pressure gradient exists; no such high pressure gradient would be expected at the location of the constriction.

- Casing collapse. Casing collapse could occur at the beginning of a flow period because of thermal expansion of water trapped in the annulus outside the 9 5/8 in. casing. Although this is a common failure mode for production casing or tieback strings in geothermal wells, it did not occur in three previous flow tests of the well, and valves to vents of the annulus were left open during the flow test. Furthermore, casing collapse from thermal expansion of trapped water is much less likely at the upper end of the casing than it is further down the wellbore because venting the water without casing damage is more likely near the upper end.

In short, the cause of the constriction cannot be determined with confidence with the data presently available. Physical inspection of the casing section where the constriction occurred would be necessary to explain why the constriction developed.

Estimates of fluid velocity through the constriction indicate that the constriction did not constitute a critical choke during the flow test. Further evidence that the flow restriction was not severe is obtained from the pressure surveys; extrapolations of pressure profiles to the surface do not reveal any gross mismatches with measured wellhead pressures as would be expected for a large, localized pressure drop through the constriction.

If the constriction existed during the flow test, its effect on well deliverability was not severe. The downhole pressure profiles, as discussed above, suggest that the actual pressure drop through the constriction was small.

The constriction did not prevent the well from flowing spontaneously for the attempted high-rate flow test on June 23 and 24. A constriction causes pressure drop only when flow passes through it. Therefore, a constriction could cause apparent low deliverability because of a large pressure drop, or it could limit the maximum flow rate as a critical choke, but it would not prevent the well from flowing as observed on June 23 and 24.

Section 5

BRINE CHEMISTRY

This section discusses the brine chemistry results that were obtained during the flow test in June 1988, compares them with chemistry data from the earlier short-term flow tests, compares the brine chemistry and temperature of the State 2-14 well with those for other wells in the area, and summarizes the results of the scientific research projects that were conducted during the June 1988 flow test.

5.1 BRINE CHEMISTRY PROGRAM DURING FLOW TEST IN JUNE 1988

The primary objective of the brine chemistry program during the flow test in June 1988 was to characterize the brine produced by the State 2-14 well.

Chemical sampling was supervised by Kennecott, and the primary chemical analyses were conducted for the Electric Power Research Institute (EPRI) by Combustion Engineering, Inc. using the EPRI Mobile Geothermal Chemistry Laboratory that was on site during the flow test.

Three types of sampling events were conducted during the flow test. Signature tests were conducted three times to characterize the chemical and physical characteristics of the total well flow. Tracking tests were performed daily to observe changes in selected properties as a function of time. Special tests were conducted as needed to investigate flow streams or equipment of special interest.

- Signature Tests. The flow test program was planned to stabilize flow in three rate steps. Fluid sampling for signature analyses was conducted at each of the three rate steps as shown in Figure 5-1. In each case, sampling was done well after the flow had stabilized, usually near the end of each rate step.

  For the signature tests, samples of separated brine and separated steam were collected from the brine and steam outlet lines leaving the high pressure separator. Characterizing the total well flow involved combining measurements of both brine and steam.

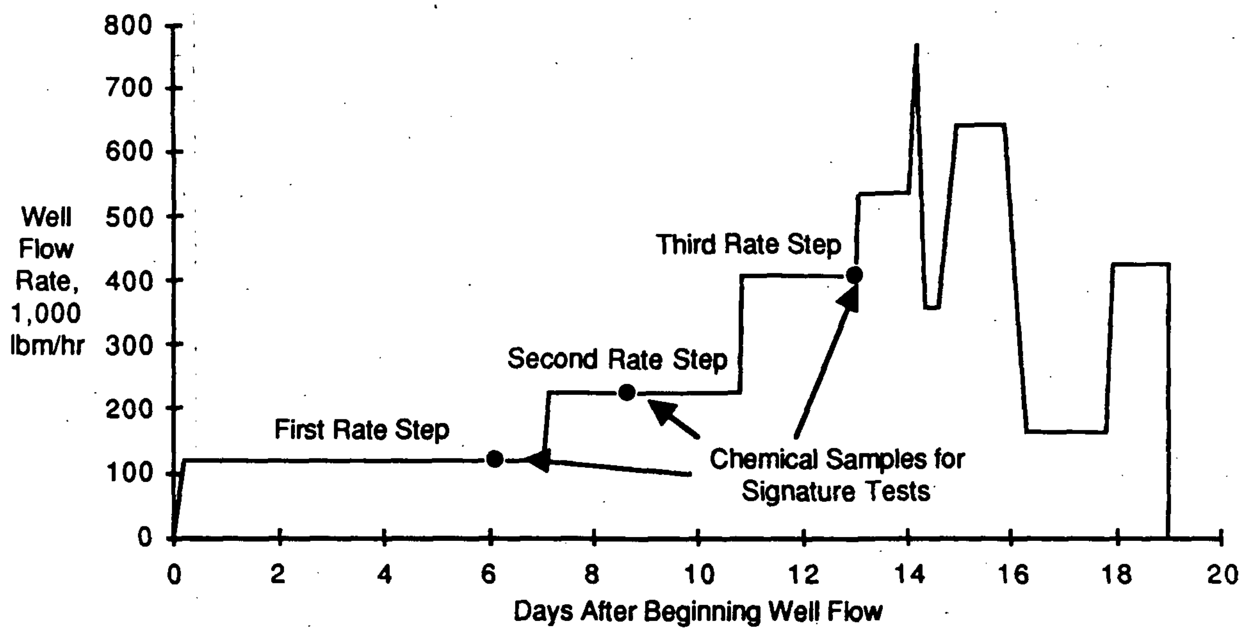


Figure 5-1 Smoothed Flow Curve Showing Times for Collection of Samples for Signature Tests

The signature tests included measurement of 64 separate chemical species. Raw condensate samples were collected to measure pH, conductivity, Eh, dissolved oxygen, anions, and carbonate. Acidified samples (1 percent nitric acid) were collected for analysis of 30 metals by inductively coupled argon plasma spectrophotometry. Trapping solutions were used to trap and measure hydrogen sulfide and carbon dioxide. Noncondensible gases were collected at approximately atmospheric pressure and ambient temperature for analysis by gas chromatography.

- Tracking Tests. Samples for chemical tracking were collected daily. Raw samples of separated brine were taken for immediate measurement of pH, conductivity, Eh, dissolved oxygen, and chloride. Acidified samples were collected for analysis of 30 metals by inductively coupled argon plasma spectrophotometry.

- Special Tests. Tests for total suspended solids were conducted to provide data to help estimate the rate of sludge accumulation in the brine pond.

This section focuses on the results of the signature and tracking tests for information needed to characterize the brine produced by the State 2-14 well. It presents the results of the signature tests for each flow rate step, explores the reservoir conditions inferred from the brine chemistry, and compares the State 2-14 well with others in the area.

Chemistry Analyses for Each Flow Rate Step. The signature test results were converted to a mass ratio basis (i.e., mg of component per kg of total well flow) by one of the following procedures:

- Noncondensible Gases. The concentration of each noncondensible gas (NCG) component is stated in the laboratory reports as mg of component per kg of steam downstream of the separator. Multiplying these results by the mass fraction of steam (ratio of steam flow rate to total well flow rate) converts them to mg of NCG per kg of total well flow. This assumes that the amount of NCG dissolved in the separated brine is negligible.

- Dissolved Components. The concentration of each dissolved component is stated in the laboratory reports as mg of component per liter of separated brine (cooled to ambient temperature) and mg of component per liter of steam condensate. These results were first converted to mg of component per kg of separated brine by dividing the mg per liter by the density of the separated brine or steam condensate at ambient temperature. A value of 1.22 kg/l was used throughout as an average value for the density of separated brine, and 1.00 kg/l was used as the density of steam condensate.

The concentrations in mg of component per kg of separated brine or steam condensate were then multiplied by the mass fraction of separated brine (ratio of separated brine flow rate to total well flow rate) and mass fraction of steam, respectively, and added to convert to mg of component per kg of total well flow.

Carbonate and sulfide were converted using this procedure even though the flash/separator conditions (i.e., carbon dioxide and hydrogen sulfide in the steam) could affect the result; therefore, the values stated for these ions should be considered as only rough indications.

Brine chemistry results from analyses of samples taken during the three rate steps appear in Table 5-1. The following observations are readily drawn from these results:

- Total dissolved solids (TDS) increased for the second and third rate steps. This variation of TDS is examined and discussed in more detail below.
- Sodium and potassium increased 7 and 12 percent, respectively, from the first to the third rate step, but calcium increased 31 percent.

Noncondensible gas content and composition results appear in Tables 5-2 and 5-3. Noncondensible gas content is rather high. Concentrations of the half-percent magnitude (3,928 to 5,731 mg/kg) reported here would force extensive and probably expensive measures, such as a high capacity noncondensible gas removal system or reboilers for high pressure steam, in the construction and operation of a power plant using this brine. Additional testing should confirm these results before designing a power plant to use brine from this well.

Carbon dioxide comprises more than 98 percent of the noncondensible gases; this is commonly the case for geothermal fluids.

Hydrogen sulfide is reported as 22, 2.2, and 6 mg/kg for the three rate steps. Additional testing to quantify the hydrogen sulfide is appropriate before application of this brine for power production. This should be done to assess whether and to what degree hydrogen sulfide abatement may be needed.

Reservoir Chemistry. Nine possible production zones were encountered during the drilling process at 2,619 to 3,160; 5,450 to 5,460; 6,110 to 6,130; 6,635 to 6,650; 8,090 to 8,100; 8,580; 8,950; 9,095 to 9,125; and 10,475 ft (798 to 963; 1,661 to 1,664; 1,862 to 1,868; 2,022 to 2,027; 2,466 to 2,469; 2,615; 2,728;

Table 5–1

Brine Chemistry
State 2–14 Geothermal Well
Flow Test in June 1988

	First Rate Step Concentration in Total Well Flow (mg/kg)	**Second Rate Step** Concentration in Total Well Flow (mg/kg)	**Third Rate Step** Concentration in Total Well Flow (mg/kg)
Aluminum	0.159	0.202	0.199
Antimony	0.43	0.65	0.68
Arsenic	5.76	6.49	11.4
Barium	112	71	93
Boron	396	No data	No data
Cadmium	0.45	0.521	0.44
Calcium	23,093	29,650	30,220
Cobalt	0.032	0.027	0.034
Chromium	0.079	0.021	0.20
Copper	1.58	2.60	3.62
Gold	No data	No data	0.00005
Iron	1,275	1,294	1,425
Lead	77	71	69
Lithium	154	162	171
Magnesium	14.40	13.5	13
Manganese	1,158	1,105	1,113
Mercury	< 0.002	< 0.002	< 0.002
Molybdenum	0.023	0.015	0.020
Nickel	0.018	0.031	0.031
Potassium	13,304	13,077	14,868
Selenium	< 0.001	< 0.001	0.0008
Silicon	195	175	176
Silver	0.142	0.164	0.19
Sodium	49,013	51,677	52,280
Strontium	333	321	364
Tin	< 0.01	< 0.06	< 0.06
Titanium	< 0.01	< 0.01	< 0.01
Tungsten	2.96	3.15	3.19
Vanadium	0.26	0.333	0.346
Zinc	414	396	452
Carbonate	356	194	346
Chloride	142,000	147,000	147,000
Sulfate	76	No data	No data
Sulfide	5	4	No data
TDS	232,000	245,000	249,000
NCG, mass %	0.57	0.39	0.40*
Ammonia, mg/kg	370	No data	No data
Well flow rate, lbm/hr	127,000	227,000	402,000

* From 6/20/88 with 435,000 lbm/hr well flow rate
NCG analysis data not available for third rate step

Table 5–2

Noncondensible Gas Content
State 2–14 Geothermal Well
Flow Test in June 1988

	First Rate Step Concentration in Total Well Flow (mg/kg)	Second Rate Step Concentration in Total Well Flow (mg/kg)	Sample on 6/20/88* Concentration in Total Well Flow (mg/kg)
Carbon dioxide	5,642	3,897	4,005
Hydrogen	3.1	0.55	0.77
Hydrogen sulfide	22	2.2	6
Nitrogen	8.6	5.5	15
Methane	12.7	7.3	6.0
Other hydrocarbons	43	16	8.86
Total NCG	5,731	3,928	4,041
Well flow rate,lbm/hr	127,000	227,000	435,000

*NCG analysis data not available for third rate step

Table 5–3

Noncondensible Gas Composition
State 2–14 Geothermal Well
Flow Test in June 1988

	First Rate Step Concentration mass % of NCG	Second Rate Step Concentration mass % of NCG	Sample on 6/20/88* Concentration mass % of NCG
Carbon dioxide	98.44	99.21	99.10
Hydrogen	0.05	0.01	0.02
Hydrogen sulfide	0.38	0.06	0.14
Nitrogen	0.15	0.14	0.38
Methane	0.22	0.18	0.15
Other hydrocarbons	0.75	0.40	0.22
Total NCG	100.00	100.00	100.00
Well flow rate, lbm/hr	127,000	227,000	435,000

*NCG analysis data not available for third rate step

2,772 to 2,781; and 3,193 m). A 9 5/8 in. casing was cemented to a depth of 6,000 ft (1,829 m), preventing the two zones at lesser depths from producing. However, with open hole sections and uncemented liner below 6,000 ft (1,829 m), the seven deeper zones are all possible sources of geothermal fluid with different composition and temperature for the various zones.

The TDS concentration and the geothermometers, Na/K, Na/Ca, and Ca/K, were examined for indications that various zones were producing in different proportions as flow rate was varied during the flow test. Results for the June 1988 flow test were compared with similar indicators from the flow test of the zone from 6,000 to 6,200 ft (1,829 to 1,890 m) in December 1985 and the flow test of zones from 6,000 to 10,564 ft (1,829 to 3,220 m) conducted shortly after well completion in March 1986.

Total Dissolved Solids. The TDS concentration is plotted in Figure 5-2 as a function of time for the June 1988 flow test. The TDS data from the three rate steps are supplemented in this plot with estimates of TDS concentration from the tracking tests. The chloride concentration was measured in the tracking tests, and TDS concentration was calculated from the measured chloride content. The ratio of TDS to chloride is virtually constant for highly saline geothermal wells in the Imperial Valley. For the signature test results, this ratio varies from 1.63 to 1.69 for the three rate steps. Therefore, a value of 1.66 was used to estimate TDS for plotting Figure 5-2.

A slight increase in TDS concentration apparently occurred as the well flow rate was increased. Initially, the TDS concentration was about 232,000 mg/kg, which increased to about 249,000 mg/kg.

Figure 5-3 shows the TDS concentration as a function of instantaneous flow rate at the time a brine sample was taken for chemical analysis. This perspective of the TDS–flow rate information leads to the same conclusion as indicated above. TDS varied little during the flow test even though the smoothed flow rate varied over a range of 7:1. For well flow rate somewhat greater than 100,000 lbm/hr (45,359 kg/hr), the TDS concentration was about 232,000 mg/kg, increasing to about 249,000 mg/kg as the flow rate increased to 400,000 lbm/hr (181,400 kg/hr).

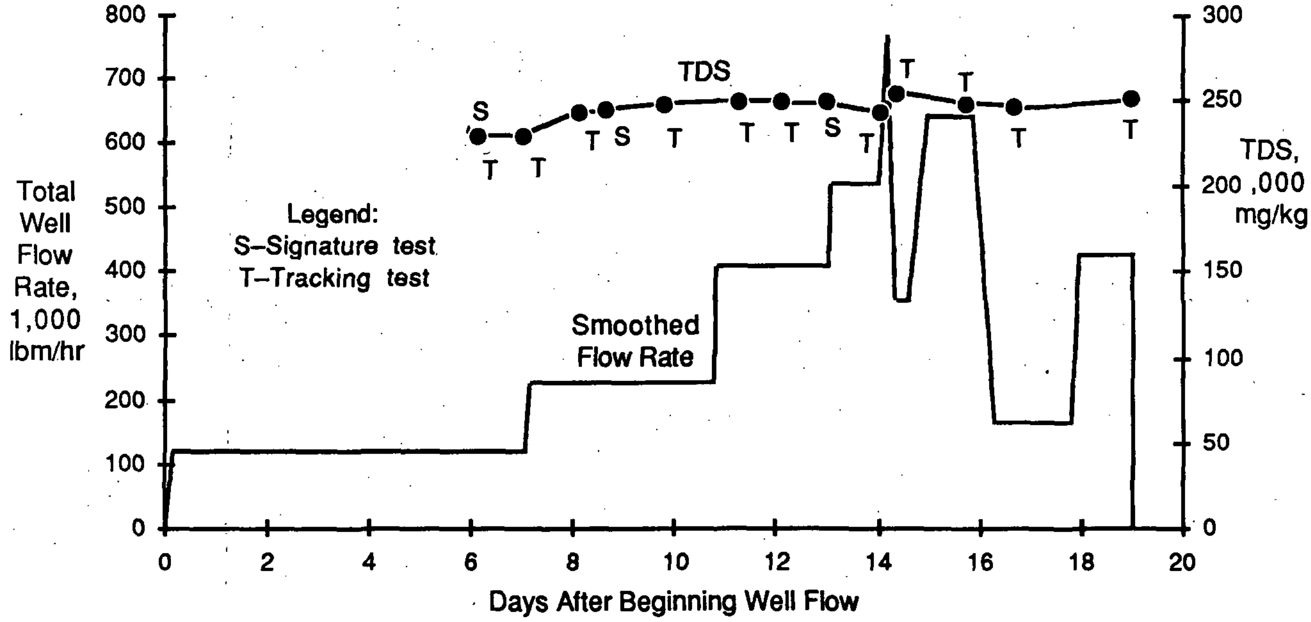


Figure 5-2 Total Dissolved Solids During Flow Test

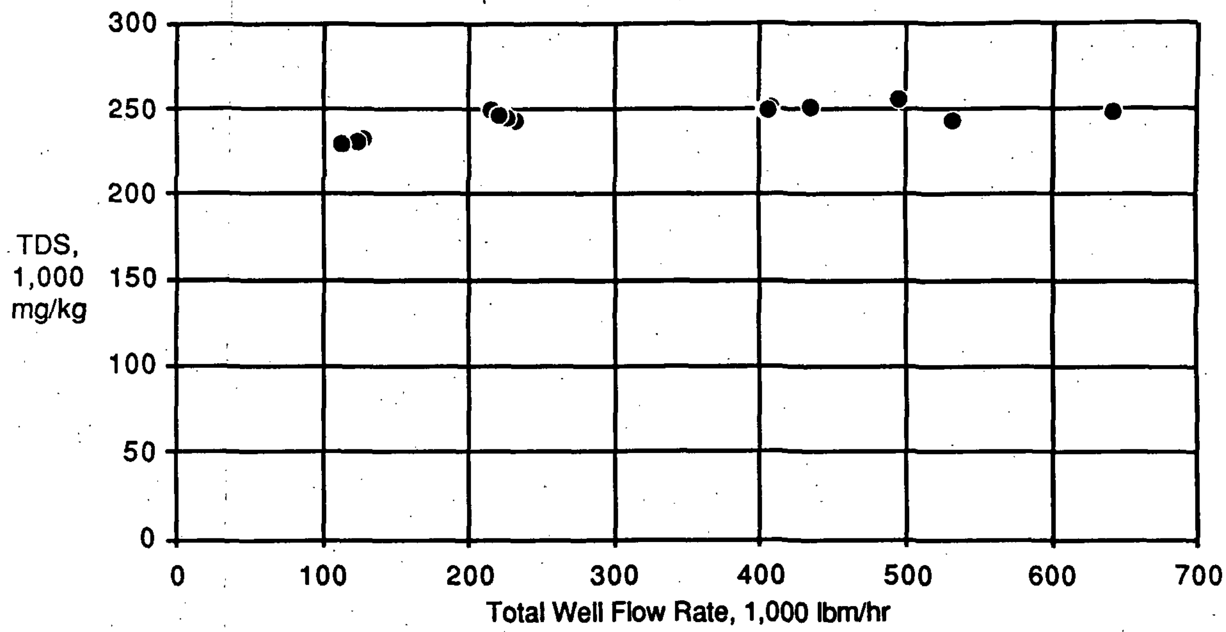


Figure 5-3 · Variation of Total Dissolved Solids with Flow Rate

Geothermometers. Table 5-4 shows values for the geothermometers, Na/K, Na/Ca, and Ca/K, for the three rates steps and for earlier tests in March 1986 and December 1985.

The short flow test in December 1985 was conducted with the well drilled to a depth of about 6,200 ft (1,890 m), with casing installed and cemented to 6,000 ft (1,829 m). Thus, it was a test of the zone from 6,000 to 6,200 ft (1,829 to 1,890 m), primarily from 6,110 to 6,130 ft (1,862 to 1,868 m).

The short flow test in March 1986 was conducted shortly after completion of the well to a depth of 10,564 ft (3,220 m). At that time, the well had a cemented casing from the surface to a depth of 6,000 ft (1,829 m) and an uncemented liner from 5,748 to 10,148 ft (1,752 to 3,093 m). Thus, any zone from 6,000 ft (1,829 m) to bottomhole could have contributed to the flow.

During the flow test in June 1988, sodium and potassium increased slightly from the first to the third rate step (sodium: 7 percent; potassium: 12 percent). However, calcium increased by 31 percent. Thus, the Na/Ca and Ca/K ratios changed considerably (–18 and +17 percent, respectively) while the Na/K ratio changes were less dramatic (+7 percent from the first to second rate steps,–4 percent from the first to the third).

These changes in the geothermometers, Na/K, Na/Ca, and Ca/K, lead to the following conclusions:

- More than one zone is producing a significant portion of the total well flow.
- The various zones are producing different proportions of the total flow as the well flow is increased.

Comparison of the Na/K, Na/Ca, and Ca/K ratios for the second rate step during the June 1988 flow test with the corresponding ratios for the March 1986 test shows very little difference. Therefore, production zones and relative contributions were essentially the same for the two test conditions.

Information from the December 1985 test and data from the flow test in June 1988 permit comparison of fluids produced from 6,000 to 6,200 ft (1,829 to 1,890 m) depth with fluids from several different zones. In December 1985, the

Table 5–4

Geothermometers
State 2–14 Geothermal Well
Flow Test in June 1988

	First Rate Step	Second Rate Step	Third Rate Step	Flow Test in Mar 1986	Flow Test in Dec 1985
Sodium (Na), mg/kg	49,013	51,677	52,280	Not available	52,661
Potassium (K), mg/kg	13,304	13,077	14,868	Not available	16,502
Calcium (Ca), mg/kg	23,093	29,650	30,220	Not available	26,515
Na/K	3.68	3.95	3.52	4.09	3.19
Na/Ca	2.12	1.74	1.73	1.86	1.99
Ca/K	1.74	2.27	2.03	2.20	1.61
TDS, mg/kg	232,000	245,000	249,000	251,000	255,000
Total well flow, lbm/hr	127,000	227,000	402,000	569,000	100,000 (approximate)

fluid produced by the zone from 6,000 to 6,200 ft (1,829 to 1,890 m) appears higher in potassium and roughly equal in sodium, calcium, and TDS concentrations to fluids produced in June 1988.

Is the Brine Hazardous? Table 5-5 compares the concentrations in

- total well flow
- brine remaining after flash to atmospheric pressure, and
- residue that would be left after totally drying the brine remaining after flash to atmospheric pressure

for 14 of the 17 hazardous metal species with the respective California Department of Health Services regulatory limits. No data were reported for beryllium, chromium (VI), and thallium.

None of the concentrations exceeds the total threshold limit concentrations (TTLC). Therefore, neither the brine nor its residue would be classified as hazardous with respect to total concentrations.

The concentrations of four metals (arsenic, barium, lead, and zinc) exceed the soluble threshold limit concentrations. However, this does not necessarily mean that the brine should be considered hazardous. The data reported lump soluble and insoluble together without resolving them into the quantities that are soluble and insoluble in cold water. The comparisons with STLC in Table 5-5 are interpreted as indicators of possible hazardous concentrations. Additional chemical analysis would be required to quantify the soluble concentration.

The following additional data are needed to classify the brine as hazardous or nonhazardous with respect to the California limits:

- Soluble concentrations of the metals for which the total concentration exceeds the STLC (arsenic, barium, lead, and zinc)
- Total and soluble concentrations of the metallic species that were not reported (beryllium, chromium (VI), and thallium)

Comparison with Other Wells in the Area. The fluid chemistry and static (nonflowing) temperatures for the State 2-14 well were compared with those for

Table 5–5

Concentrations Compared to Hazardous Limits

Substance	Concentration in Total Well Flow (mg/l)	Solubles + Insolubles in Brine Flashed to Atm Pressure (mg/l)	STLC* (mg/l)	Concentration in Total Well Flow (mg/kg)	Concentration in Brine Flashed to Atm Pressure (mg/kg)	Concentration in Dried Residue (mg/kg)	TTLC** (mg/kg)
Antimony	0.84	1.14	15	0.68	0.93	3	500
Arsenic	13.9	18.8	5.0	11.4	15.4	46	500
Barium	137	187	100	112	153	460	10,000
Beryllium	No data	No data	0.75	No data	No data	No data	75
Cadmium	0.636	0.856	1.0	0.521	0.701	2	100
Chromium (VI)	No data	No data	5	No data	No data	No data	500
Chromium	0.097	0.132	560	0.079	0.108	< 1	2,500
Cobalt	0.041	0.056	80	0.034	0.046	< 1	8,000
Copper	4.42	6.02	25	3.62	4.93	< 1	2,500
Lead	93	128	5.0	77	105	< 1	1,000
Mercury	< 0.002	< 0.002	0.2	< 0.002	< 0.002	< 1	20
Molybdenum	0.029	0.039	350	0.023	0.032	< 1	3,500
Nickel	0.038	0.052	20	0.031	0.042	< 1	2,000
Selenium	< 0.001	< 0.001	1.0	< 0.001	< 0.001	< 1	100
Silver	0.23	0.31	5	0.19	0.25	1	500
Thallium	No data	No data	7.0	No data	No data	No data	700
Vanadium	0.422	0.574	24	0.346	0.471	1	2,400
Zinc	551	750	250	452	615	1,844	5,000

* STLC—Soluble Threshold Concentration Limit (California)
** TTLC—Total Threshold Concentration Limit (California)

11 other wells in the vicinity for which data are available as nonproprietary information.

Chemistry. Table 5-6 lists chemical composition data for the State 2-14 well (for the third rate step) and 11 other wells shown in Figure 5-4. Comparing the order of listing in Table 5-6 with the locations in Figure 5-4 shows that the wells are listed left to right in Table 5-6 in roughly a southwest–to–northeast order. Additional information about the relative depths of the wells is shown in Figure 5-5, using the same left-to-right order as in Table 5-6. The comparisons may be summarized as follows:

- TDS. In general, wells in the northeast part of this area have higher TDS concentrations. Although depth has often been reported as an important factor with respect to TDS, the River Ranch No. 1 and Sportsman No. 1 wells produced fluids with relatively high TDS concentration from relatively shallow production zones starting at about 4,000 ft (1,219 m) depth.

- Sodium, Potassium, and Calcium. Wells in the northeast part of this area tend to have lower Na/K ratio, except for the State 2-14 well; this may be due, at least in part, to the greater depth of its production zones. Likewise, wells in the northeast part of this area tend to have lower values of Na/Ca ratio. Generalizations concerning Ca/K are not apparent.

The sodium, potassium, and calcium concentrations for fluids produced during the December 1985 test of the State 2-14 well and those from the Hudson No. 1 well, about one-half mile away, are strikingly similar, as shown below:

	Hudson No. 1	State 2-14
Sodium, mg/kg	52,250	52,661
Potassium, mg/kg	16,500	16,502
Calcium, mg/kg	26,917	26,515
Na/K	3.17	3.19
Na/Ca	1.94	1.99
Ca/K	1.63	1.61

In December 1985, an interval between 6,000 and 6,200 ft (1,829 to 1,890 m) of the State 2-14 well was tested, and the production zone in the Hudson No. 1 well was at about 6,000 ft (1,829 m). Thus, the same reservoir zone may be involved in production from both wells.

Table 5–6

Brine Chemistry of Geothermal Wells in the Vicinity of State 2-14
(mg/kg of total well flow)

	Sinclair No. 4	Sinclair No.3	Magmamax No. 1	Woolsey No. 1	Elmore No. 1	State No. 1	IID No. 2	IID No. 1	Sportsman No. 1	River Ranch No. 1	**State 2–14**	Hudson No. 1
Ammonia	—	283	304	254	342	—	—	341	—	—	370	—
Arsenic	8	8	—	—	—	—	—	10	—	—	11	—
Barium	—	—	—	—	—	—	208	196	—	167	93	—
Boron	633	450	117	121	—	158	325	325	124	—	396	—
Calcium	22,492	12,125	17,583	13,250	26,083	17,667	24,000	23,333	28,725	31,667	30,220	26,917
Chloride	128,825	78,042	109,417	95,667	153,333	105,833	129,167	129,167	167,500	173,333	147,000	173,333
Copper	—	—	0.8	1	—	2	3	7	—	—	4	—
Iron	—	—	233	121	3,833	1,000	1,667	1,742	3,500	1,750	1,425	1,667
Lead	34	67	39	24	74	67	67	70	—	81	70	—
Lithium	239	41	42	54	233	150	175	179	125	250	171	267
Magnesium	613	650	92	142	150	23	8	45	15	183	13	—
Manganese	850	342	529	363	825	792	1,142	1,250	—	1,583	1,113	1,833
Potassium	12,425	6,517	8,667	7,500	18,917	11,667	13,750	14,583	20,000	18,583	14,868	16,500
Silicon	75	—	200	125	—	—	333	333	4	—	176	—
Silver	—	—	0.3	—	—	1	—	1	—	—	0.19	—
Sodium	48,700	30,283	42,750	36,083	53,500	39,833	44,167	42,000	58,333	57,167	52,280	52,250
Strontium	358	300	—	296	608	—	367	500	—	700	364	650
Zinc	—	—	183	92	—	417	417	658	—	—	452	—
TDS	215,000	129,000	180,000	154,000	258,000	178,000	216,000	215,000	278,000	285,000	249,000	273,000
pH	5.3	5.3	5.6	6.0	—	—	—	5.2	—	—	5.3	[illegible]

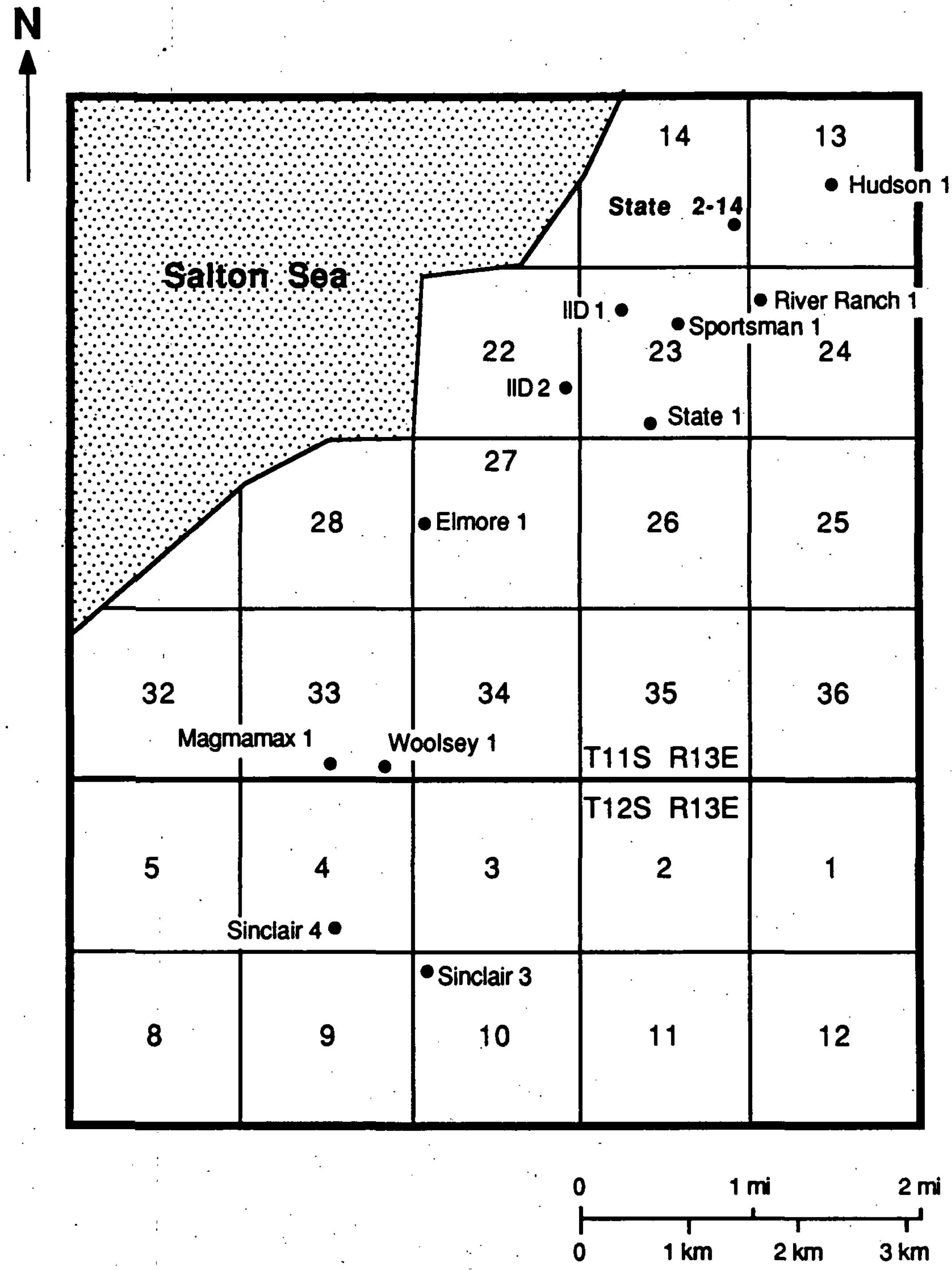
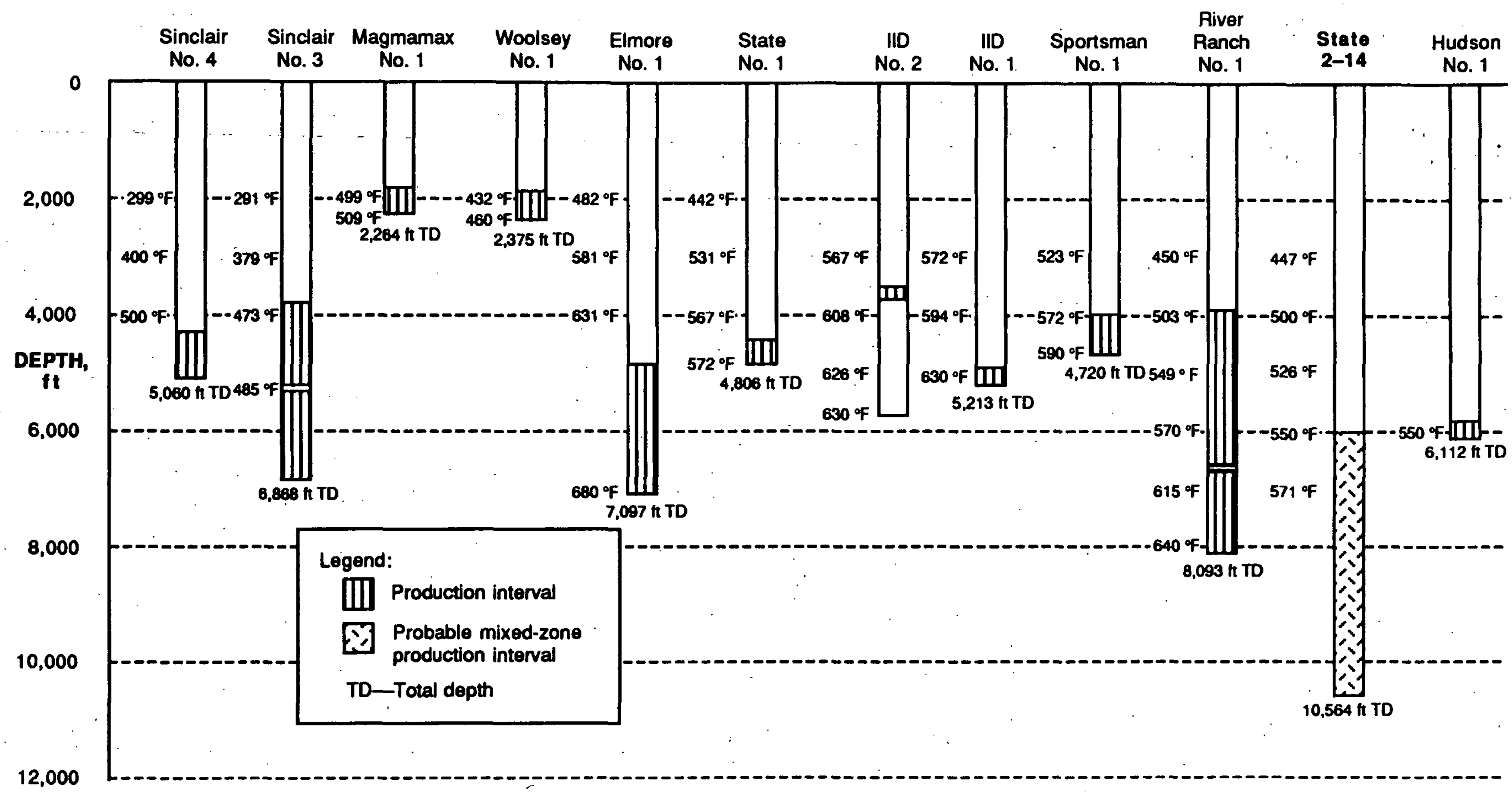


Figure 5-4 Locations of Other Wells in the Salton Sea Field Compared with State 2-14



	Sinclair No. 4	Sinclair No. 3	Magmamax No. 1	Woolsey No. 1	Elmore No. 1	State No. 1	IID No. 2	IID No. 1	Sportsman No. 1	River Ranch No. 1	State 2–14	Hudson No. 1
Na/K	3.92	4.65	4.93	4.81	2.83	3.41	3.21	2.88	2.92	3.08	3.52	3.17
Na/Ca	2.17	2.50	2.43	2.72	2.05	2.25	1.84	1.80	2.03	1.81	1.73	1.94
Ca/K	1.81	1.86	2.03	1.77	1.38	1.51	1.75	1.60	1.44	1.70	2.03	1.63
TDS, mg/kg	215,000	129,000	180,000	154,000	258,000	178,000	216,000	215,000	278,000	285,000	253,000	273,000

Figure 5-5 Characteristics of Geothermal Wells in the Vicinity of State 2-14

Although TDS concentrations reported in the two cases are different (273,000 mg/kg for Hudson No. 1 and 255,000 mg/kg for State 2-14), there may be no real difference. An anion–cation check of the two data sets revealed that the report for Hudson No. 1 shows apparent excess chloride of about 30,000 mg/kg, and the data set for State 2-14 implies an apparent 10,000 mg/kg excess chloride. Subtracting the calculated excess chloride quantities from the reported TDS concentrations yields virtually equal values for TDS concentrations: 243,000 mg/kg for Hudson No. 1 and 245,000 mg/kg for State 2-14.

Therefore, the geothermal fluid produced from the zone between 6,000 to 6,200 ft (1,890 m) depth in the State 2-14 well and the fluid produced by the Hudson No. 1 well probably come from the same source.

Temperatures. Figure 5-5 shows static temperatures at depths from 3,000 to 7,000 ft (914 to 2,134 m).

Temperatures in the State 2-14 well track those in the nearby River Ranch No. 1 well from 3,000 to 5,000 ft (914 to 1,524 m). At 6,000 and 7,000 ft (1,829 and 2,134 m), the temperatures are 23 and 20 °F (13 and 11 °C) higher, respectively, in the River Ranch No. 1 well.

Temperatures in the State 2-14 well are 120 to 130 °F (67 to 72 °C) lower than those in the Elmore No. 1 well for all depths from 3,000 to 7,000 ft (914 to 2,134 m). Likewise, temperatures in the State 2-14 well are 80 to 120 °F (44 to 67 °C) lower than those in the IID Nos. 1 and 2 wells from 3,000 ft (914 m), to the total depths for the IID wells, 5,213 ft (1,589 m) for IID No. 1, and almost 6,000 ft (1,829 m) for IID No. 2.

5.2 SCIENTIFIC RESEARCH PROJECTS

One of the objectives of the June 1988 flow test of the State 2-14 well was to provide opportunity for scientific research projects to be conducted at the same time. Section 5.2 summarizes those projects based on materials submitted by the experimenters, and the submitted materials are included *in toto* in Appendices H through N. Although the seismic monitoring project of Section 5.2.3 does not address brine chemistry, it is summarized in this section to keep all the scientific research results together in this report.

5.2.1 Particle Meter Testing (Battelle Pacific Northwest Laboratories)

The objectives of the field test were as follows:

- Establish the suspended solids content of the brine from the bottom of the separator immediately after flashing and after a two-hour hold time
- Characterize the chemical and size characteristics of the suspended solids
- Evaluate an on-line computerized ultrasonic particle counter in a high-solids brine
- Evaluate the effects of scale deposits on the optical window of a laser particle counter

Figure 5-6 shows a schematic diagram of the experimental equipment. Brine from the bottom of the separator was run through 1/2-in. line about 125 ft (38 m) to the test stand. Brine flow of 5 to 10 gpm (0.32 to 0.63 l/sec) was maintained in this line to limit the residence time, before measurement in the test stand, to about 30 seconds.

Brine entered the test stand and was split into two streams.

- One stream was available for immediate flow through the laser optical window, an ultrasonic detector, and a weighed filter for measurement of the suspended solids content. Samples of both brine and solids were collected for later analyses.
- The second stream was directed into a heated 6-gallon vessel to hold the brine at temperature for 90 to 160 minutes to allow precipitation. Then the brine was either filtered for weighed samples, or it was directed through a second ultrasonic cell.

The test was started on June 8 and continued until June 15.

Preliminary results may be summarized as follows:

- Solids content of the brine at the test stand inlet varied over a wide range (166 to 670 mg/l). The high inlet solids content indicates that just 30 seconds after flashing in the separator, a substantial solids content had already formed in the brine. The data have a fairly wide scatter, probably due both to varying solids content and to difficulties in washing residual soluble salts out of the salt cake on the filter media.

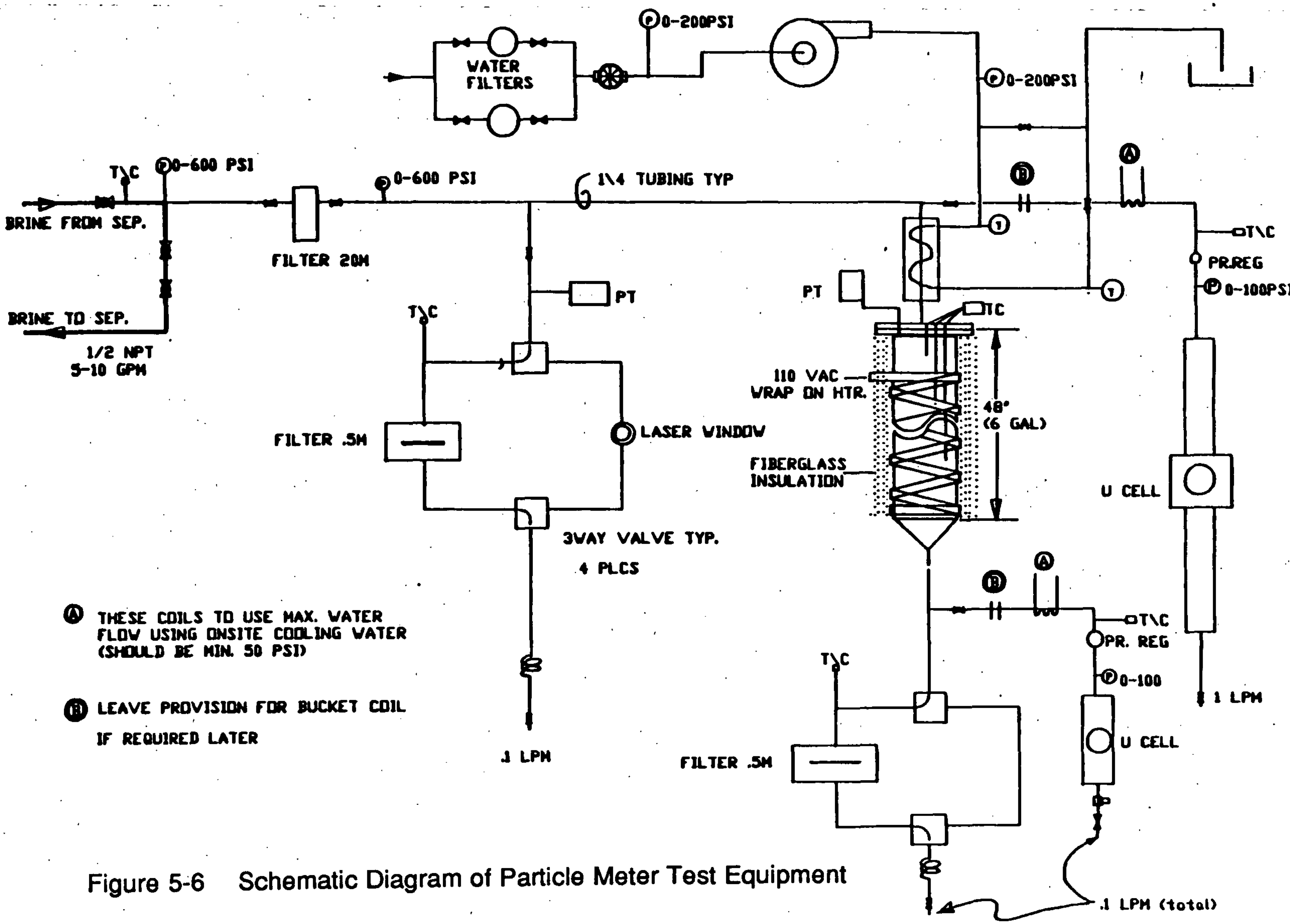


Figure 5-6 Schematic Diagram of Particle Meter Test Equipment

- Silica is a major constituent of the solids. Barium sulfate was identified, and compounds of lead, arsenic, strontium, zinc, calcium, antimony, and silver were detected.
- The ultrasonic particle counter operated successfully under severe scaling conditions and is usable in its current form. There is a temperature limit of 180 °F (82 °C) on the current ultrasonic transducer.
- The window of the laser particle counter quickly coated with solids and was totally obscured in two days of operation. The laser counter approach would require almost continuous maintenance and would not be suitable for geothermal plant use until a method for keeping the window transparent is developed.

The report by Battelle Pacific Northwest Laboratory appears as Appendix H.

5.2.2 Geothermal Waste Treatment Biotechnology (Brookhaven National Laboratory)

The objective was to conduct research studies on waste samples using biochemical techniques to remove toxic elements that exceed environmental regulations.

The results were reported in a paper presented at the GRC annual meeting in October 1988; the results are summarized in the abstract of that paper quoted below:

> "Recent studies have indicated that biotechnological processes for detoxification of geothermal residual brine sludges are feasible. Preliminary studies have also shown that such processes are controlled by several factors which include the concentration of the residual sludge in the bioreactor, the type of bioreactor and the strain of acidophilic microorganisms used."

The GRC paper by Brookhaven appears as Appendix I.

5.2.3 Chemical Sampling and Analysis to Characterize the Brine (Electric Power Research Institute)

The EPRI CHEMLAB mobile geothermal laboratory was on-site throughout the flow test to collect and analyze samples from the State 2-14 well. Results of the analyses from the EPRI mobile geothermal laboratory were used extensively in preparation of Section 5.1, Brine Chemistry Results. As discussed in Section 5.1, the types of sampling events are defined as follows:

- Signature. To characterize chemical and physical properties of total fluid flow from the well. This involves combining measurements of steam and brine to determine properties of the total stream.
- Tracking. To observe changes in selected parameters as a function of time
- Special. To investigate flow streams or equipment of special interest

Complete signature tests were conducted at the three rate steps with flows ranging from 125,000 to 402,000 lbm/hr (57,000 to 240,000 kg/hr).

Daily tracking tests were conducted at the brine sampling port from June 7 to June 20 (except for June 19). This port sampled the separated brine emerging from the separator as in the signature tests.

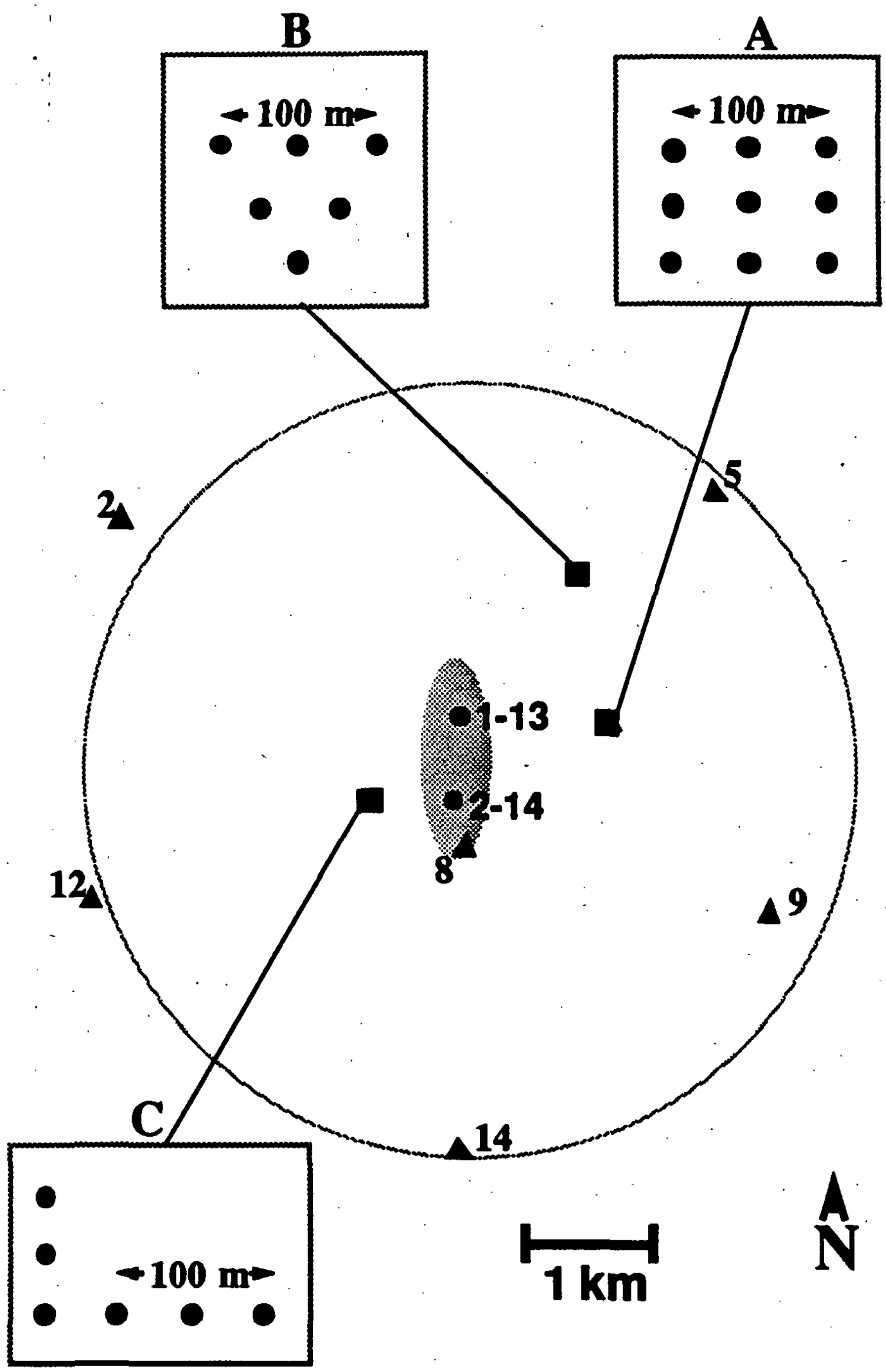
Special tests included collection of raw samples for determination of the total suspended solids. These results were made available to help estimate the sludge accumulation rate in the brine pond.

The report from Combustion Engineering, Inc. to EPRI appears as Appendix J.

5.2.4 Seismic Monitoring (Lawrence Livermore National Laboratory)

The purpose of the seismic monitoring project was to characterize microseismic activity related to the flow/injection test of the State 2-14 and Imperial 1-13 wells in the Salton Sea Geothermal Field. The goal was to determine if any sources of seismic energy related to the test were observable at the surface.

Figure 5-7 shows the configuration of the seismic stations during the flow test. The network consisted of seven three-component stations within a 3 km (1.86 mi) radius of the two wells and three arrays (100 m or 328 ft square area) of six to nine sensors at distances of 1 to 2 km (0.62 to 1.24 mi). The three-component stations, which provide primarily phase arrival times, were used to detect and locate microearthquakes. The network of three arrays of sensors, which can provide direction, velocity, and depth information for incoming seismic energy, was used to monitor all possible low-frequency (3 to 25 Hz) sources of seismic energy originating from the flow/injection zones.



The triangles are three-component station locations and the squares are the array locations. The insets show the geometries of the arrays A, B, and C. The shaded elliptical zone delineates the area within which we expected to see seismic activity related to the test.

Figure 5-7 Configuration of Seismic Stations

Results do not indicate any microearthquake activity larger than magnitude 0.0 within the zone of interest. This result indicates that neither stress nor thermal effects were large enough to induce microearthquakes larger than this threshold during the test.

A single small (magnitude –0.5) seismic event followed a few seconds later by an air wave was detected. The horizontal distance was 1,500 m (4,900 ft) at 251 degrees (clockwise from North) with depth of 900 m (3,000 ft). The origin of this event is not known. Analysis of this event shows that the arrays are more useful than traditional network methods when events are smaller than magnitude 0.0 and are not recorded well by all of the network stations; this is primarily a result of their ability to enhance the signal amplitude relative to the noise.

A LLNL report on this seismic monitoring project appears as Appendix K.

5.2.5 Metal Ion Concentrations (New Mexico State University)

Brine samples were collected from the two-phase flowline near the wellhead of the State 2-14 well, and an additional sample of brine was taken from the weirbox at the outlet of the atmospheric flash tank.

Samples of the liquid phase from the flowline were taken with a teflon-lined probe and cooling coil assembly. Temperatures at the sampling point were essentially the same as at the wellhead, or near 492 °F (256 °C).

The weirbox sample was obtained by dipping a container into the active flow stream. That fluid was then suction filtered directly into a sample vial.

All samples were sent to a commercial laboratory for neutron activation analyses of precious metals. Results of those analyses are given in Table 5-7.

The results shown in Table 5-7 are particularly confusing for silver. None of the flowline samples indicated silver above the detection limits; however, the weirbox sample showed the presence of nearly 1 ppm (890 ppb) silver.

The report on this experiment by New Mexico State University appears as Appendix L.

Table 5-7

Neutron Activation Analysis of Precious Metals in Salton Sea Geothermal Water: Well State 2-14

Metal Concentration (PPB)*

Sample	Ag	Au	Pt	Ir	Pd	Comments
DMA 05	ND < 540.	0.0717±0.0122	ND < 16	-	-	Sample from flowline collected 6/3/88 after 500 ml passed through sampler.
DMA 08	ND < 290.	-	-	-	-	Sample from flowline collected in dilute nitric acid immediately after collection of DMA 05.
DMA 02	-	0.0586±0.0047	5.25±1.47	-	-	Sample from flowline (unacidified) collected immediately after DMA 08.
DMA 03	-	0.0683±0.0057	4.80±1.10	-	-	Sample from flowline (unacidified) collected 6/4/88 after 1000 ml passed through sampler.
DMA 06	ND < 500.	-	-	-	-	Sample from flowline (acidified) collected immediately after DMA 03
DMA 01	890.±134	0.0258±0.0054	ND < 12.	-	-	Sample collected 6/5/88 at Weirbox after geothermal waterexposed to atmosphere. Sample was filtered through 0.45μ filter prior to collection.
DMA 07	ND < 140.	-	-	ND < 0.8	-	Sample from flowline collected 6/5/88 and acidified.
DMA 04	-	0.0325±0.0036	ND < 4.	-	ND > 6.5	Sample from flowline (unacidified) collected immediately after DMA 07.
179	ND < 140	0.120±0.008	ND < 8.4	-	-	Sample from flowline (acidified) collected immediately after DMA 04

* ND - Not Detected below limit of detection

5.2.6 Transport of Platinum Group Elements, Gold, and Sulfur in the Salton Sea Geothermal Brines (University of California at Riverside)

Fluid and solid samples were collected between June 10 and 15, 1988, during the flow test of the State 2-14 well. After the flow test, scale samples were collected from the throttle valve and from an orifice plate valve in the brine line downstream of the separator.

The findings were reported in a paper presented at the Geothermal Resources Council (GRC) annual meeting in October 1988; the results are summarized in the abstract of that paper quoted below:

> "Sulfur isotope data demonstrate that H_2S in the SSGS brines is generated by partial hydrothermal reduction of SO_4^{2-} derived from dissolution of lacustrine sulfate minerals in the host sediments. No magmatic input of sulfur is indicated. SO_4^{2-} reduction is promoted by interaction of the sediments with an upwelling diapir of Fe^{2+}–rich hypersaline brine. Base metals are carried in the brines as the chloride complexes $PbCl_3^-$, $AnCl_2^0$, $CdCl_2^0$, $CuCl_3^{2-}$, and $MnCl_2^0$. Fe is probably carried as both $FeCl_3^-$ and $FeCl_4^-$ complexes. Vein sulfide precipitation within the reservoir occurs during brine dilution and oxidation at an interface between the hypersaline brines and overlying, more oxidized lower-salinity fluids."

Preliminary reports and the GRC paper by UC Riverside appear as Appendix M.

5.2.7 Uranium Series Isotope Measurements (University of Southern California)

Brine and gas samples were collected from the State 2-14 well on June 10 and 15, 1988, during the flow test. This fluid sampling and subsequent uranium series isotope measurements are expected to provide information that will further constrain models of radioisotope exchange mechanisms and develop new methods of estimating hydrogeologic parameters.

In December 1988, only an interim report of August 16, 1988 was available. This interim report appears as Appendix N.

5.2.8 Liquid and Gas Sampling (University of Utah Research Institute)

The purposes of this liquid and gas sampling and analysis are to determine if differences in the chemistry of the fluid occur as a result of changing flow rates and to determine whether silica precipitates when a cooling coil is used during sample collection.

Three samples were taken during a 1-hour period on June 8, when the flow rate was about 125,000 lbm/hr (57,000 kg/hr), which was near the lowest flow rate of the test. Four samples were collected during a 2-hour period on June 17, when the flow rate was approximately 640,000 lbm/hr (290,000 kg/hr), which was the highest flow rate that was sustained for a few hours during the test. The samples were taken from the brine and steam lines downstream of the separator.

Two different methods were used for sampling the brine:

- The first method involved cooling the hot brine in a 1/4-in. stainless steel tube coil prior to capturing the fluid in a preservative solution. Although this method is commonly employed, it may promote precipitation of silica in the cooling coil prior to capturing the fluid.
- The second method used a 6-in. length of 1/8-in. tube that was inserted directly into the preservative solution with no prior cooling. This method is expected to prevent silica precipitation prior to capturing the fluid.

Both methods use a preservative solution of 5 percent by weight nitric acid for ICP analysis, 5 percent by weight hydrochloric acid for sulfate and ammonia analysis, and an undiluted sample for chloride, fluoride, and total dissolved solids analysis. The acid-to-sample dilutions in the samples were 10:1.

Steam samples were taken through a 1/4-in. stainless steel cooling coil. The samples were taken in evacuated Pyrex flasks that contained solutions of sodium hydroxide and cadmium chloride.

Precipitation of silica during sampling is reported for some cases with the the larger diameter sample line. "However, the variability of the silica concentrations from sample to sample in a closely spaced time interval indicates that silica may be precipitating in the wellbore, or, more likely, the separator."

The UURI report appears as Appendix O.

Section 6

SITE CLEANUP

(later)

Section 7

CONCLUSIONS AND RECOMMENDATIONS

7.1 WELL REWORK

7.1.1 Conclusions

The 7-in. temporary repair liner that was installed during the first rework operation in August 1986 was retrieved without incident.

Retrieval of the lower liner indicated that pulling the liner through the dogleg at about 6,200 ft (1,890 m) was going to be exceptionally difficult. Curtailment of fishing operations was considered prudent because of:

- Indications that the lower section of liner was probably full of debris
- Offset of the lower section of liner from the section removed, making success of further fishing operations improbable
- Difficulty experienced in pulling the liner through the dogleg
- High probability of the well flowing while the liner was in the blowout preventer with no way to shut in the well

Attempts to sidetrack the hole were unsuccessful. The positive displacement motor type of mud motors did not operate because excessive temperature caused the elastomer stators to disintegrate. Failure of turbine motor type mud motors was caused by insufficient fluid flow to operate and cool the motors. Drilling with a whipstock achieved some kickoff as indicated by formation cuttings in the returns, but the bit may have never completely exited the original hole, as shown by the presence of some cement in the cuttings the whole time.

A total of 10 bits were used in reworking the well: five mill-tooth and five button bits.

The five button bits were used in attempts to drill new hole. The original hole was drilled primarily with API 537 (medium soft) bits which showed wear on the cone, indicating that a longer tooth (soft) bit might be used with a resulting increase in penetration rates. The button bits used for the rework were API 437 (soft formation) bits. Because little new hole was drilled (and most of that was on junk), no conclusions can be made concerning the suitability of the soft formation bits.

Loss of circulation during the rework was not a problem because the mud weight was so low; however, the under-balanced system allowed the well to flow on numerous occasions. Well flow was controlled by bullheading brine down the hole to kill it.

The State 2-14 well was flowed for 12 hours, averaging about 569,000 lbm/hr of total flow (steam and liquid combined). The maximum production rate was estimated to be 1,222,000 lbm/hr during the last 32 minutes of the test when the throttling valve was fully open.

Because sidetracking using mud motors was unsuccessful, improved designs for mud motors to resist high temperatures are needed to increase the chances for success in hot geothermal wells.

7.1.2 Recommendations

If similar sidetracking is to be undertaken on this or similar wells, it is recommended that use of mud motors be considered only if improved designs to resist high temperatures are available.

7.2 CONSTRUCTION OF FLOW TEST FACILITY

7.2.1 Conclusions

The foundation for the high pressure separator was excavated to a depth of 12 in. (30 cm) and filled with rock, covered with 3 in. (8 cm) of soil, and compacted. For the other equipment, no foundations were needed.

The high pressure separator is the only pressure vessel in the test facility, and it was hydrostatically tested to 1,200 psig (8.3 MPa) before it was moved from the storage area. This test demonstrated the structural integrity of the separator for pressures in excess of the design test pressure.

The high pressure separator was coated with rust and other corrosion products on the inside.The atmospheric flash tank and the vent-silencer were coated inside and out with rust from previous use and storage. The tanks for media filters and brine storage were covered with rust on the inside, but the paint on the outside showed only isolated areas of rust. The amount of material removed from these open-top vessels by corrosion did not jeopardize use for atmospheric pressure operation.

The major piping was badly rusted and corroded. None of the valves were operational; many of the valve handles and stems were broken. Numerous flange connecting bolts were galled and had to be replaced. Some sample ports and pressure taps had been seal-welded, and because of corrosion, many of the remainder were virtually without thread to withstand operating pressures.

The instrumentation was in poor condition. The flow and level recorders were in such bad shape that renting replacements for the flow test was less expensive than reconditioning. The flow orifices were either missing or had to be replaced due to erosion, corrosion, or bending.

It can be concluded that the approach taken to construct the flow test facility through the use of previously used equipment was successful and probably less costly than new construction.

7.2.2 Recommendations

A number of recommendations concerning facility construction arose because of adverse test conditions and incidents experienced during the test period in June:

- The pressure taps for the wellhead pressure gage and for one of the brine orifice meters plugged during the flow test. When this happened, a rodding tool was used for cleaning the ports without shutting down the line; this allowed the test to proceed with essentially no interruption.

  Use of a rodding tool is recommended as an appropriate remedy for plugged pressure taps. The piping and valve for the tap must be straight and short enough to permit use of the rodding tool.

- A nylon reinforced polyethylene diverter curtain accumulated so much salt and sludge that brine flowed over the top of the curtain near the brine pond inlet, short-circuiting the longer path to the opposite end of the brine pond and back. This allowed brine from the pond inlet to flow directly to the brine pump inlet.

Recommendations to avoid this adverse condition include 1) a different design for the diverter curtain, possibly using floats instead of a tensioned cable to support the curtain or 2) a permanent baffle, such as an earthen dike, to serve the same function as the diverter curtain.

- Cavitation occurred at the intake of the brine and the booster pumps at one time or another during the flow test. It was most severe for the brine pumps, especially when hot brine began to flow over the diverter curtain directly from the brine pond inlet.

  Recommendations to mitigate this condition, although none is a complete cure, are 1) Pump inlets should be large, short, and free of unnecessary valves, elbows, Tees, and other pipe fittings, 2) The brine pump inlet line should be imbedded in the brine pond berm rather than going over the top of it, 3) Pumps should be kept as low as feasible, in this regard, skid mounting is better than trailer mounting, and 4) Brine should be allowed to cool before arriving at the pump inlet.

- After the flow test was completed, the steam flow meter (orifice plate) was found to be obstructed by some debris, pieces of metal or scale apparently dislodged upstream. This caused all the steam flow rate readings to be erroneously high.

  Recommendations to avoid such flowmeter obstruction include 1) The upstream piping should be completely disassembled (if used equipment is installed) and cleaned; corroded or scaled components should be replaced if they cannot be thoroughly cleaned, 2) The indicated flash fraction should be compared with theoretical values early in the test period, and discrepancies should be traced and remedied to within the expected accuracy of the flow meters, and 3) Provisions should be made to isolate and disassemble flow meters without affecting well flow.

7.3 FLOW TEST IN JUNE 1988

7.3.1 Conclusions

At typical commercial operating wellhead pressure of 250 psig (1,724 kPa), about 840,000 lbm/hr (381,000 kg/hr) could be produced from the State 2-14 well. This could generate about 12 MWe in a two-stage flash plant.

Increased well deliverability during the flow test suggests that the well improved during the course of the test. It is likely that flowing the well at higher rates may have cleaned drilling solids from the reservoir rock and may have opened additional flow paths unavailable at the start of the test.

Pressure recovery following drawdown (when additional pressure decrease should be expected) was recorded after flow rate changes. This is further evidence of well improvement during the flow test. Unfortunately, it makes the drawdown curves impossible to analyze accurately for quantitative reservoir parameters.

The average productivity index of the State 2-14 well during the flow test was 1,527 lbm/hr per psi (100 kg/hr per kPa).

The productivity curve is a straight line, which would be expected from matrix permeability alone. However, reservoirs in the Salton Sea area typically are extensively fractured but also have significant matrix storage capacity. Because well improvement was noted from other data during the flow test, the straight line productivity curve does not necessarily imply matrix-only permeability. The permeability is no doubt affected by fracturing in addition to matrix permeability.

Horner plot analysis of the pressure buildup data yields a calculated skin factor of +23.1. Positive values indicate large pressure losses as fluid enters the wellbore. These can be caused by wellbore damage, pressure drop across liners or through perforations, partial penetration completions, wellbore storage effects, closing of fractures as pressure decreases, and turbulent flow as fluid enters the wellbore at high rates. For the State 2-14 well, it is concluded that the well no doubt sustained wellbore damage during drilling and rework activities; however, high flow rates into the wellbore probably contributed to the apparent skin effect also.

The Imperial 1–13 well was used as an injection well during the flow test, with total injected brine of 72.6 million lbm (32.9 million kg). From the start of injection, injectivity (flow rate per unit of wellhead pressure) began to decline. At the end of the test, injectivity was only about 20 percent of the initial value. This progressive decrease is typical of a well undergoing formation plugging by suspended solids. Because injection throughout the test consisted of unfiltered fluid containing some suspended solids, it is concluded that this condition caused most of the reduced injectivity.

A constriction in the well casing, that was discovered after the June 1988 flow test, probably developed sometime during the flow test although the precise time that it developed and the reasons for it cannot be determined with the information that is presently available. It is concluded that the effects of the constriction were minimal, because the flow was not choked and downhole pressure profiles suggest that the actual pressure drop through the constriction was small.

7.3.2 Recommendations

It is recommended that, for highly saline brines, injected brine should be filtered to protect the injection well from plugging by suspended solids.

7.4 BRINE CHEMISTRY

7.4.1 Conclusions

Total dissolved solids varied little during the flow test in June 1988 even though the well flow rate varied over a range of 7:1. For flow rate slightly greater than 100,000 lbm/hr (45,359 kg/hr), the TDS concentration was about 232,000 mg/kg, increasing to about 249,000 mg/kg as the flow rate increased to 400,000 lbm/hr (181,400 kg/hr).

Noncondensible gas content is rather high. Concentrations measured during the June 1988 flow test were approximately one half of one percent (3,928 to 5,731 mg/kg).

Hydrogen sulfide is reported as 22, 2.2, and 6 mg/kg for the three rate steps in the June 1988 flow test.

As well flow rate was changed in the June 1988 flow test, changes in the geothermometers, Na/K, Na/Ca, and Ca/K, lead to the following conclusions:

- More than one zone is producing a significant portion of the total well flow.
- The various zones are producing different proportions of the total flow as the well flow is increased.

The sodium, potassium, and calcium concentrations for fluids produced during the December 1985 test of the State 2-14 well and those from the Hudson No. 1

well, about one-half mile away, are strikingly similar. In December 1985, an interval between 6,000 and 6,200 ft (1,829 to 1,890 m) of the State 2-14 well was tested, and the production zone in the Hudson No. 1 well was at about 6,000 ft (1,829 m). Therefore, the geothermal fluid produced from the zone between 6,000 to 6,200 ft (1,890 m) depth in the State 2-14 well and the fluid produced by the Hudson No. 1 well probably came from the same source.

Temperatures in the State 2-14 well track those in the nearby River Ranch No. 1 well from 3,000 to 5,000 ft (914 to 1,524 m). At 6,000 and 7,000 ft (1,829 and 2,134 m), the temperatures are 23 and 20 °F (13 and 11 °C) higher, respectively, in the River Ranch No. 1 well. Temperatures in the State 2-14 well are 120 to 130 °F (67 to 72 °C) lower than those in the Elmore No. 1 well for all depths from 3,000 to 7,000 ft (914 to 2,134 m). Likewise, temperatures in the State 2-14 well are 80 to 120 °F (44 to 67 °C) lower than those in the IID Nos. 1 and 2 wells from 3,000 ft (914 m), to the total depths for the IID wells, 5,213 ft (1,589 m) for IID No. 1, and almost 6,000 ft (1,829 m) for IID No. 2.

7.4.2 Recommendations

Additional testing should be done to confirm the high noncondensible gas content before designing a power plant to use brine from this well.

Additional testing to quantify the hydrogen sulfide should be done before application of this brine for power production to assess whether and to what degree hydrogen sulfide abatement may be needed.

7.5 SITE CLEANUP

7.5.1 Conclusions

(later)

7.5.2 Recommendations

(later)

7.6 A PERSPECTIVE OF SCIENTIFIC ACCOMPLISHMENTS FROM THE SALTON SEA SCIENTIFIC DRILLING PROJECT

Research objectives in the SSSDP focused on probing the roots of a hot (355° ± 10°C) , near-surface, magmatically driven, hypersaline geothermal system to increase basic scientific understanding of the development of geothermal resources and to advance the technology of drilling and testing to achieve those objectives (Sass and Elders, 1986; Elders and Sass, 1988). Forty-one science and technology-development projects were funded by the USGS, DOE–Office of Basic Energy Sciences, DOE–Geothermal Technology Division, and National Science Foundation (Adduci, et al., 1986). Results of completed and ongoing studies on recovered data and samples indicate that the SSSDP met or exceeded most of its initial objectives (Adduci, et al., 1986; Elders and Sass, 1988). Despite hostile subsurface conditions, a wealth of new data were collected in a geotectonic environment of active continental rifting, metamorphism and ore genesis (Lachenbruch, et al., 1985; Charles, et al., 1988; McKibben and Elders, 1985).

A key finding with implications for commercial resource evaluation and development throughout the Salton Sea geothermal system (SSGS) is that although porosity decreases and rock induration increases with depth, permeability-controlling fractures increase with depth (Paillet and Morin, 1988; Daley, et al., 1988). High flow-rate tests were completed successfully through multiple flow zones from depths of 6,120 to 10,564 ft (1,865 to 3,220 m). These results suggest strong commercial merit in evaluating both shallow and deep resource potential in the SSGS (Section 4 of this report; Harper and Rabb, 1986; Michels, 1986).

Unprecedented recovery of 725 ft (220 m) of rock core from a geothermal well made possible pioneering studies of petrophysical properties (Lin and Daily, 1988; Tarif, et al., 1988), sedimentary and evaporitic facies analysis (Herzig, et al., 1988; McKibben, et al., 1988a; McKibben, et al., 1988b; McKibben, et al., 1987) , resolution of the source of salts in the SSGS brines (McKibben, et al., 1988a), evaluation of structural relationships (Herzig, et al., 1988; Daley, et al., 1988), identification of igneous intrusive units (Herzig and Elders, 1988), the resolution of mineral-paragenesis and vein-deposition sequences related to ore-body emplacement (Charles, et al., 1988; Caruso, et al., 1988; McKibben and Elders, 1985), and detailed petrography, whole-rock chemistry, and isotope analysis that permitted identification of sulfur sources in ore mineralization (McKibben and Eldridge, 1988; Herzig, et al., 1988). Earlier work that was based on studies of drilling chips recovered from geothermal wells in the SSGS identified progressive metamorphism of up to greenschist facies (Muffler and White, 1969; McKibben and Elders, 1985), implying metamorphism under low-temperature conditions; drill core from the State 2-14 well demonstrates the presence of higher grade metamorphism (low amphibolite) at temperatures and pressures that presently are lower than expected for that metamorphic grade (Sass, et al., 1988; Cho, et al., 1988; Shearer, et al., 1988).

Geophysically, laboratory petrophysical measurements of porosity, density, and P-wave velocity correlated well with downhole well-logging values (Lin and Daily, 1988; Tarif, et al., 1988), and vertical seismic profiling showed strong reflectance and scattering effects that agreed well with fracture zones encountered by the borehole (Daley, et al., 1988). Despite disappointing performance of wireline tools at depths greater than 5,900 ft (1,800 m) -- which speaks directly to the need for upgrading high-temperature performance and reliability -- significant advances in logging technology were demonstrated. In particular, a rapid-response-time, heat-shielded, digital temperature tool and downhole samplers that proved capable of withstanding 660°F (350°C) offer innovations for future downhole-tool development (Carson, 1986; Solbau, et al., 1986; Wolfenbarger, 1986; Sass, et al., 1988; Grigsby, et al., 1987).

As a part of the SSSDP program, gravity and magnetic anomalies were combined with conductive heat-flow data to 1) refine the boundaries of the local, intense thermal anomalies that are responsible for the rate of heat flux for the entire Salton Trough (Newmark, et al., 1988; Elders and Sass, 1988), and 2) confirm earlier work that inferred that the SSGS is about 1,000 years old (Sass, et al., 1988).

Fundamental geologic work remaining includes the following:

- Detailed correlations between the State 2-14 well and other geothermal wells in the SSGS (Section 5 of this report).
- Comparisons between the SSGS and other geothermal systems, such as lithologically similar Cerro Prieto, which has a strikingly lower occurrence of hydrothermal vein mineralization.

- A future, deep geothermal research well that is located on the axis of the thermal anomaly could provide a valuable opportunity to significantly extend the understanding of continental rifting and geothermal-system genesis that is currently being formulated from the data of the off-axis State 2-14 well (Sass, et al., 1988; Newmark, et al., 1988).