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GEOHERMAL LOOP EXPERIMENTAL FACILITY

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SEPTEMBER 1976
BI-MONTHLY REPORT

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SDG&E - ERDA GEOTHERMAL LOOP EXPERIMENTAL FACILITY

May 1975 - August 1976

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1.0 INTRODUCTION

This is the first bi-monthly test report for SDG&E-ERDA Geothermal Loop Experimental Facility. As such it actually covers more than a two month period. Included in this report is a description of the Geothermal Loop Experimental Facility (GLEF) and its construction problems as well as a discussion of start-up testing. Thus, the period covered by this report begins with the start of plant construction in May of 1975, continues through start up testing starting on May 3, 1976 and concludes with the second series of start up tests ending on August 30, 1976.

This facility was first conceived early in 1972 when SDG&E in cooperation with the Magma Power Company, drilled and flowed a geothermal test well in the Niland Known Geothermal Resource Area (KGRA). This flow test demonstrated the ability of the Niland Reservoir to produce a significant amount of hydrothermal fluid capable of generating electric power. To determine the reservoir's capacity for power generation a demonstration plant was designed. Subsequent field test in 1973 and 1974 improve our understanding of this resource and cause some modification of the initial design.

This system was based on the binary concept in which geothermal fluid, or steam from the geothermal fluid, is contacted through heat exchangers with a secondary or working fluid which in turn drives a turbine generator.

This process is one of the most efficient technique available for utilizing geothermal resources. Because this is the first effort to develop the hydrothermal resources of the United States utilizing a binary process, SDG&E was able to enlist the support of the Energy Research & Development Administration (ERDA).

ERDA has not only supplied half of the cost of this facility but in addition has made available its technical expertises both from the Washington office and from the ERDA national laboratories. In particular, the Lawrence Livermore Laboratory has established a brine test facility on site and has provided invaluable technical support to the project.

In addition to the construction and operation of the GLEF, ERDA is supporting an extensive environmental study to assess the possible impact of geothermal development in the Imperial Valley. The U. S. Bureau of Mines Corrosion & Electrometallurgy Research Group has established a Materials Test Facility at the Niland test site to determine what materials are most suitable for geothermal power plants. The Imperial Magma Corporation, a resource company that pioneered geothermal development in the western United States, is monitoring the response of the Niland Reservoir to the operation of the GLEF. The information acquired by each of these groups is accumulated at different rates, therefore, summaries of their activities will be published by the individual contributors.

The SDG&E-ERDA 10 megawatt size Geothermal Test Loop Facility is located in the Imperial Valley near the town of Niland, California. The test loop utilizes hydrothermal fluid from the Niland KGRA which produces a high temperature brine with salinities ranging from 250,000 to 350,000 ppm. The geothermal test loop is expected to serve two purposes.

1. To determine the technical economic feasibility of the flash-binary cycle.
2. To establish the capacity and characteristics of the Niland KGRA. This information is vitally needed to ensure design of a reliable commercial hydrothermal power plant.

The problems that must be addressed by the test loop include the corrosion and scaling of surface and down-hole equipment due to the high mineral content of the hydrothermal fluid and the effective operation of a binary cycle.

The results of efforts so far expended on this project show that a geothermal facility utilizing the binary cycle can be successfully constructed in the Imperial Valley and that this facility can be operated effectively on the highly minerized hydrothermal brine available from the Niland Reservoir.

2.0 DESIGN AND CONSTRUCTION

2.1 INTRODUCTION

This section describes the design and construction of SDG&E-ERDA 10 Megawatt size Geothermal Loop Experimental Facility (GLEF) located in the Imperial Valley near the town of Niland, California.

Design of this facility started after one year of well tests and was followed by two years of on site cycle evaluation. Based on these field tests a flash-binary cycle was chosen. A direct steam turbine cycle did not appear feasible because of the high volume of non-condensable gases in the geothermal fluid.

2.2 FACILITY DESCRIPTION

The Geothermal Test Loop flashes the brine to steam in four stages (Figure 1). The steam is then separated from the brine and scrubbed to remove salts and minerals before it enters the heat exchangers where its heat vaporizes the working fluid. The cooled geothermal brine is then reinjected into the reservoir. An expansion valve simulates the pressure loss of a 10 megawatt turbine.

The total flow from two producing wells will be directed through five flash/steam separators. Two first stage separators operate in parallel. Each of these first stage separators is designed to handle the mass flow from one producing well. The total brine flow from the first stage is directed to the second, third and fourth stage

**GEO THERMAL LOOP
EXPERIMENTAL FACILITY
PROCESS FLOW DIAGRAM**

separators in series. Steam produced by the flashing brine then flows through a steam scrubber (one for each stage). The scrubbed steam is then directed through six heat exchangers. In this process all of the steam generated is condensed. Ultimately, the condensed steam is reinjected or pumped to a closed storage tank. The non-condensable gas, primarily carbon dioxide, is exhausted to atmosphere through a silencer and a 130 foot high stack to disperse the gas and meet the APCD requirements for ground level concentration of hydrogen sulfide.

The brine from the last stage steam separator is directly reinjected with the steam condensate through two injection wells located about 6,000 feet from the facility.

Energy from the condensing steam vaporizes the secondary or working fluid. The vapor is passed through a pressure control valve and then condensed in two water cooled exchangers. It is collected in a drum, and recirculated through the heat exchangers.

2.3 CONSTRUCTION

Site development consisting of grading, excavation and the construction of earth berms for the spray ponds began in May 1975. Twenty acres of farm land was purchased for siting the plant and cooling ponds.

The major features of the site are the settling pond and supply canal, the cooling water spray/storage pond, the process area, where the binary cycle plant equipment is located and the paved access road (Figure 2). About 30,000

cubic yards of native soil and 2,000 cubic yards of imported crusher-run-base was required to form the ponds, canal and process pad. Compaction in the berms was on the average 88% with 14% moisture and 96% in the process area.

Ponds and process pad construction occurred simultaneously. As the earth was excavated to form the ponds it was hauled and dumped in the process area. This activity continued until the 60,000 square foot pad was built up to the required elevation. It was expected that the excavation of the ponds would present some problems due to the high water table in this area of the Valley. This water table, at an average of 5 feet below grade, made moisture control and machinery movement difficult. Moisture in the soil averaged above 30% up to 18 inches below existing grade. Because of these conditions the finish grade of the process area pad elevation and the bottom elevations of the ponds was raised 1.5 feet from the design elevations. This decision resulted in a substantial cost savings.

Conventional earth moving equipment was utilized, however, the largest Michigan paddle-pull type earth mover that was used had a capacity of 20 cubic yards. This size was marginal since we pulled the machine out of the mud on numerous occasions. Earth bridges, wind rows and mats were required continuously during the work. Wind rows allowed the soil to dry to the proper moisture content before compaction. The earth bridges and mats supported the 2 cubic

SDG&E Co.
GEOTHERMAL PILOT PLANT
PLOT PLAN

FIGURE 2

yard backhoe which performed the excavation. It was necessary to handle the excavated soil three times, equivalent to moving 90,000 cubic yards, as a result of the wet soil conditions. In spite of the earth bridges our D-8 Caterpillar tractor lost traction and it was necessary to push the soil with a much lighter D-4.

As the ambient temperature climbed in the 90°F to 100°F range our construction crew experienced another problem with moisture content. Rather than too much moisture in the soil, the high ambient temperature caused the moisture level to drop below the required 14% and water trucks were needed to add water for the proper moisture content and compaction.

Finish grading operations were performed with a blade for the level areas such as the process areas, road and undeveloped land within the site boundaries. A Grade-All was used on the sides of the containment berms for the ponds. The site preparation described above required 42 days and cost \$87,000. Six men and five machines were the maximum size crew in operation at any one time. The road paving was performed after the erection of the facility for \$18,000 bringing the total site development cost to \$105,000.

On June 21, 1975, the Scott Company set up shop at the test site to begin the erection of the Geothermal Test Loop, and the geothermal fluid production and injection pipelines. This phase of the construction required 9 months and cost \$1,786,000. The cost of major equipment such as

the scrubbers, separators, pumps, control valves, instruments and controls was \$800,000, and is not included in the erection cost.

The first phase in the test facility construction was foundation installation. Approximately 800 cubic yards of concrete was poured for pump pits, vessel and exchanger supports, pipe supports, transformer, switch house and other miscellaneous pads.

Pits for the vertical centrifugal pumps were the most difficult part of the foundation pouring. The high water table forced the sub-contractor to use a construction method which controlled the soil and assured alignment of the pump can with pump head base.

First, a water well rig was used to drill an oversized hole which was immediately lined with reinforced, concrete pipe (RCSP) with a diameter substantially larger than the barrel of the pump. Then a prefabricated, steel liner was centered in this pipe and concreted in place to serve as the normal pump can. The sole purpose of the outer concrete pipe was to reinforce and to stabilize the surrounding earth such that the critical alignment of the pump can be performed. The deepest pump pit is 23 feet of which 16 feet is in mud and water. A large crane was used to hold the RCSP at the proper vertical elevation while the concrete was poured. The Geothermal Test Loop has four pump pits constructed with this method.

Following the completion of foundation work, the mechanical phase of construction was started with the installation of the separators, scrubbers and heat exchangers. Underground electric distribution from the switch house was installed in PVC conduit since the soil has a high salt content. Because the plant was designed to handle flammable fluid, such as isobutane, rigid conduit was required above grade in the main plant areas.

Once the vessels and heat exchangers were set, the process piping was installed. Mild carbon steel pipe, ASTM A-53 and A-106, Grade B, was used.

Much of the piping fabrication was performed in Scott Company's weld shop and the spools field-erected. Both field welds and shop welds were inspected by random radiography with interpretation of the film to Section VIII of the ASME code. The secondary (isobutane) system welds were 100% X-rayed. All vessels and heat exchangers conform to Section VIII of the ASME code for pressure vessels. The isobutane accumulator and piping system conform to the applicable sections of the California Safety orders. All structural steel and steel work conforms to the American Institute of Steel Construction for steel buildings and bridges. The electrical installation conforms with the National Electrical Code.

The construction methods for piping installed in the process area were standard for the construction industry.

One rather unique means of installing pipe was used for the one mile of 10 inch and 14 inch pipe required in the spray pond. A helicopter service was employed to set this pipe since the bottom of the pond would not support even two-ton capacity fork lift and the configuration of the berms would have required the use of a crane as well. The entire spray pond pipe system was positioned in four hours using one helicopter and four men at a total cost of \$3,600.

During the mechanical portion of construction, electrical conduit and cable installations were in progress. The millwright work, fireproofing and instrument setting, were phased in during the latter stages of the mechanical work. Insulation and painting were the final phases of construction to be initiated. Removable insulation pads were employed on flanges and valves to facilitate the removal of equipment for inspection and maintenance.

During the week of March 14, 1976 the construction of the facility was completed. Pressure tests of the system piping has been performed at 1.5 times the design pressure and other than the normal leaks at flanges, no serious discrepancies were encountered. With the successful completion of the pressure tests, each system was then turned over to SDG&E's start-up crew, under the direction of a start-up engineer, to begin system cleanout and equipment checks in placing each of the Test Loop systems in operation.

3.0 START UP TESTING

3.1 Objectives

The overall objectives of start up testing include:

1. Prepare and place into operation each sub system in proper sequence.
2. Review of all sub system configurations and their compatibility with the GLEF.
3. Evaluation of systems controls and their ability to provide stable plant operation for gathering valid test results.
4. Training of plant operating and maintenance personnel.
5. Prepare operating procedures for the GLEF.
6. Modify the GLEF as required to achieve stable operation and valid test results.

3.2 Introduction

This report covers that period of start up commencing near the end of the construction activities. The systems were near completion and ready for final check out prior to placing in service. The use of plant operating personnel to do check out work also served as a practical training period.

Prior to moving on site which occurred during the latter stages of the construction program the operating and maintenance personnel were hired. They were then conducted through a training program.

GTE START UP CRITICAL PATH

FIGURE 3

This training program included formal classroom training covering systems and operating philosophy. Later training on site was continued as an on-going program.

The ERDA on site representative, John Featherstone attended a portion of the formal classes conducted in San Diego, the problem of commuting prevented his full time attendance.

A start up critical path chart was formulated to aid the operators and various construction trades in start up planning. (Figure 3) The numbers displayed are only for task identification and are not necessarily sequential.

In order to describe the change made to the plant a full set of systems' drawings including before and after configurations are included in Appendix A.

The day to day operations including major problems and solutions are described in start up test reports covering the dates from May 3, 1976, which was the date of initial well operation, through the end of August, 1976.

TEST NO. 1

May 3, 1976

Prior to start up, steam from the geothermal fluid was used to clean the steam piping to prevent mill scale and construction debris from entering and possibly damaging the heat exchanger tubes. Steam was allowed to flow from the separators through the scrubbers and up to the heat exchangers. Metal plates were installed in the flange connection before the isolation valve to each heat exchanger. Short spool pieces were then installed to allow the steam to be vented to the atmosphere.

The vessel arrangement are described in Figure 1. Initially the secondary "isobutane" loop was filled with deionized water to eliminate any fire hazard during start up. Magmamax No. 1 was used as the hot geothermal fluid (brine) supply well and Magmamax No. 3 as the reinjection well during all the start up tests.

The chronology of start up Test No. 1 was as follows:

The supply well (Magmamax No. 1) had been primed with surface (irrigation) water following well flow test by the Magma crew.

8:35 a.m.   The first brine flow into the plant area was started! This flow was directed into the brine holding pond to allow time for the production well to stabilize and to heat the main supply line from Magmamax No. 1 to the GLEF.

9:20 a.m. Started brine flow through the 10" bypass system around all vessels into the brine holding pond to heat these lines.

10:15 a.m. Started brine flow to the 1st stage "B" separator (V-4) and on through the other three stages.

11:30 a.m. Secured brine flow because of high liquid level in the 3rd stage separator (V-14).

1:00 p.m. Drained the 3rd stage separator and restarted brine flow through the plant.

1.:30 p.m. Secured brine flow because the 3rd stage vessel was again flooded.

2:30 p.m. Restarted brine flow through the plant.

3:00 p.m. Off again. Still experiencing high liquid level in the 3rd stage separator. Blew out 3rd stage vessel with air to clear liquid.

3:40 p.m. Restarted brine flow.

4:00 p.m. Stable pressures and liquid levels in all vessels. Good steam flow from all four stages.

10:30 p.m. Observed high liquid levels in the 4th stage separator (V-11) which was attributed to a plugged suction strainer on the reinjection pump (P-2).

11:00 p.m. Begin shut down to check P-2. When changing valving in order to drain vessels, the 4th stage separator (V-11) bypass valve was opened in error, this caused an inrush of first cold and then hot fluid into 4th stage separator. A hydraulic shock (water hammer) resulted causing damage to the 4th stage vessel foundation.

FOLLOWING THE SHUTDOWN

1. The foundation damage was inspected by a Structural Engineer from the Ben Holt Company and was judged safe to be returned to service until repairs could be made to the concrete. The reinforcing rods were not effected.
2. It was judged that sufficient steam line blow out had been accomplished. The temporary blow off piping stubs were removed and permanent connections made to the heat exchangers.
3. The suction strainers for all pumps were opened for inspection and cleaning. Considerable construction debris was removed from all strainers before they were reinstalled.

TEST NO. 2

May 13, 1976

This was the initial full plant operation attempted. At 1:15 p.m. flow was initiated through the secondary loop and the auxiliary systems were prepared for service. The production well had been primed 24 hours earlier with 2800 gallons of fresh (irrigation) water.

1:43 p.m.   Brine was flowed to the brine pond to warm the supply line and stabilize well flow.

2:10 p.m.   Hot brine flow established at the test pad.

2:21 p.m.   Brine line pressure 194 psig and increasing.
Brine flow through the test loop was started.

PROBLEMS AND SOLUTIONS

The brine drain lines run overhead causing excessive pressure differences between stages and preventing proper drainage of the separators. This condition led to severe water hammer during system start up. This problem was solved later by using air pressure to blow the cold fluid out of lines prior to each cold start. A drain system was installed as a final solution so the vessels and connecting piping could be drained prior to each start up.

5:30 p.m.   Systems operation was secured because of excessive pressure and temperature in the 3rd and 4th stages. The over heating was caused by loss of the secondary system flow.

Loss of secondary system flow was caused by the inability to transfer the secondary fluid from the condenser to the accumulator.

FOLLOWING SHUT DOWN

1. The condenser drain problem was solved by limiting cooling water flow and maintaining a high water level in the condensers. This allowed the lower section to act as a sub-cooler so enough pressure differential could be maintained to cause the condensers to drain to the higher elevation existing in the accumulator.
2. Maintaining pressure control in the purge water system was a major problem during operation. Redesign of the purge water system piping plus increasing the pumping capacity was found to be necessary (see before and after drawings ME-5653, Appendix A). This was partially corrected at this time, final repiping was done later.

TEST NO. 3

May 18 and 19, 1976

The need to accumulate more "on stream" time to ferret out system problems so they may be dealt with, necessitated restarting plant prior to reaching a final fix on some previous problems. For example the purge water (P.W.) and condensate systems modification were not complete. The pressure control of the P.W. system created a problem as a result. The used condensate had to be dumped to the cooling water system which raised solids in the cooling water pond. Changes to the condensate piping to allow drainage of all condensate back into the reinjection piping were completed during the June 16 through August 9 outage. A cooling water blow down line to allow reduction of solids was installed at the same time.

A downhole pressure monitoring system was installed in Magmamax 1. This system consisted of a 10' long x 1" diameter stainless steel tube located near the bottom of the well (in the perforated zone) and connected to a 1/16" diameter tube which extended to the surface. Nitrogen gas under pressure was bled into the 1/16" tube and allowed to bubble slowly out of the 1" tube at the bottom of the well. Since the weight of the nitrogen column is negligible the pressure required to force nitrogen out of the bottom hole tube is the bottom hole pressure.

1:40 p.m. Magmamax 1 was opened up to the brine drain pond via the 3" cross manifold. The well pressure gauge at the plant indicated 45 psi, but as soon as the supply valve was opened the well pressure dropped rapidly to "0" and the flow stopped after approximately 5 minutes. This is probably due to depletion of a small volume of gas above the fluid in the well. The downhole pressure increased from 750 psi to 800 psi.

2:05 p.m. In an effort to start well flow, the 1 1/2" valve at 10" well head loop bypass was opened. This provided a drain at the lowest point in the supply line and allowed flow from the well. Downhole pressure started increasing again.

2:30 p.m. Downhole well pressure 900# and increasing rapidly. Valving to the brine pond was re-opened and the well flowed into the brine pond.

2:36 p.m. Steam was observed at the brine pond. Flow was started into the test loop.

2:45 p.m. Pressure/temperature rising in the first stage.

May 19, 1976

9:06 a.m. The plant operation was secure.

Shut down was made to check cause of the 4th stage scrubber condensate drain pump (P-9) loosing pressure. The suction strainer was found to be plugged with construction debris. The shaft seal had over heated and had to be replaced.

FOLLOWING SHUT DOWN

The 4th stage level control valve (LCV 718A) was opened for inspection to determine reason for it leaking through. The plastic seal ring was damaged and a new metal seal ring and backing ring was installed.

The high temperature problems that were experienced in the 4th stages appears to be caused by failure of the 4th stage heater to drain properly.

A vent line was installed between the hot well (V-13) and the outlet head in the 4th stage heat exchanger (E-1C) to improve drainage. The final solution appears to be increasing the drain line size. This was done during June 16 through August 9 outage.

START UP OPERATING CONDITIONS

Test No: 3

Date: May 18 & 19

<u>Parameter</u>		<u>Units</u>	<u>Average</u>	<u>Range</u>
Inlet Conditions				
	T	°F	410	390-420
	P	psig	300	250-320
1st Stage	T	°F	375	365-375
	P	psig	150	140-155
	LF	#/hr	--	--
	SF	#/hr	45M	40M-50M
2nd Stage	T	°F	312	310-315
	P	psig	70	66-75
	LF	#/h	550M	550M
	SF	#/hr	15M	12M-15M
3rd Stage	T	°F	275	270-280
	P	psig	32	29-35
	LF	#/hr	250M	200M-300M
	SF	#/hr	10M	8M-13M
4th Stage	T	°F	225	215-225
	P	psig	4.0	4-8
	LF	#/hr	200M	--
	SF	#/hr	--	--
Reinjection	T	°F	240	230-246
	P	psig	475	350-600
	LF	#/hr	250M	0-1000M

LF = Liquid Flow

SF = Steam Flow

M = 1000

TEST NO. 4

May 20, 1976

NOTES:

1. During shut down period between Test 3 and 4 the brine pond was pumped down using a rental pump. This brine was reinjected.

2. The reinjection pump (P-2) suction strainer was installed during the above operation and then removed prior to startup.

3. The 1st, 2nd and 3rd stage liquid level control points were each lowered 3" to reduce carry over.

11:30 a.m. Opened brine supply valve.

11:45 a.m. No brine flow due to a gas head on the well. Opening the supply valve allowed this gas to escape dropping the well head pressure to 0 without inducing brine flow. The well was not primed with surface water after the previous shut down on May 19, 1976.

12:00 p.m. Well head pressure 0 downhole pressure 800 psig.

4:45 p.m. Attempted to start brine flow by pulling suction on Magmamax No. 1 with P-2 pump through the brine bypass piping.

- 5:10 p.m. Downhole pressure 847 psig and rising, brine flow started. Secured P-2 and opened well supply line drain to allow brine flow to the brine pond.
- 5:15 p.m. Started brine flow to the 1st stage separator and through plant.
- 7:45 p.m. Secured plant, due to low flow in secondary loop which allowed over-heating in the 3rd and 4th stage. P-9 and P-10 strainers were found to be plugged due to construction debris and rust scale.

NOTE:

The well was not shut in after this operation but blew to the brine pond to keep temperature/pressure up over night. Well head and downhole pressures were as follows.

<u>Date</u>	<u>Time</u>	<u>Downhole Pressure at 2100' Psig</u>	<u>Line Pressure at Site Psig</u>
May 20	08:15 p.m.	824.0	
	08:45	866.0	
	09:15	850.4	
	09:45	852.0	290
	10:15	848.4	285
	10:45	855.0	288
	11:15	856.0	293
	11:45	856.0	295
May 21	12:15 a.m.	856.0	295
	12:45	856.0	299
	01:15	856.5	305
	01:45	856.5	305
	02:15	856.0	307
	02:45	856.0	307
	03:15	856.0	309
	03:45	856.5	310
	04:15	856.4	310
	04:45	856.6	310
	05:15	858.8	310
	05:45	856.4	310
	06:15	857.2	310
	06:45	858.2	311
	07:15	858.4	305
	07:45	846.0	268
	08:30	834.0	220
	09:00	840.0	175

START UP OPERATING CONDITIONS

Test No: 4

Date: May 20

<u>Parameter</u>		<u>Units</u>	<u>Average</u>	<u>Range</u>
Inlet Conditions				
	T	°F	410	390-420
	P	psig	300	250-320
1st Stage	T	°F	375	365-375
	P	psig	150	140-155
	LF	#/hr	--	--
	SF	#/hr	45M	40M-50M
2nd Stage	T	°F	312	310-315
	P	psig	70	66-75
	LF	#/h	550M	550M
	SF	#/hr	15M	12M-15M
3rd Stage	T	°F	275	270-280
	P	psig	32	29-35
	LF	#/hr	250M	200M-300M
	SF	#/hr	10M	8M-13M
4th Stage	T	°F	225	215-225
	P	psig	4.0	4-8
	LF	#/hr	200M	--
	SF	#/hr	--	--
Reinjection	T	°F	240	230-246
	P	psig	475	350-600
	LF	#/hr	250M	0-1000M

LF = Liquid Flow

SF = Steam Flow

M = 1000

TEST NO. 5

May 21, 1976

9:30 a.m. Auxiliary equipment was placed in service.
9:45 a.m. Brine flow to the test loop was started.
Well head pressure was 305 psi. Experienced water hammer caused were the geothermal steam contacted the cold brine remaining in the vessels and lines.

This problem was caused by pressurized drainage of brine from one separator to the succeeding one due to the overhead drain line routing. Pressure surges resulted. If the separator piping and elevations had been designed so gravity forced draining was incorporated this could have been avoided.

10:15 a.m. Suction strainers in P-9 and P-10 became plugged and the test facility was shut down to clean them.

FOLLOWING SHUT DOWN

The intervals of the secondary loop pressure control valve PCV 303 was removed. This modification will increase the flow in the secondary loop allowing more heat removal and thus lower temperatures and pressures in the 3rd and 4th stage.

TEST NO. 6

May 24 and 25, 1976

7:40 a.m. Cooling water system in service and starting up auxiliary equipment in preparation for start up.

8:20 a.m. Started brine flow to the pond.

10:20 a.m. Started brine flow to plant.

11:30 a.m. Plant shut down due to plugging of the P-9 strainer.

1:49 a.m. Started brine flow to plant.

2:30 p.m. Operating conditions relatively stable. Excessive steam pressure drop between the 4th stage scrubber and heat exchanger was observed.

3:30 p.m. Secured plant to check P-9 strainer and to check flow orifice in 4th stage steam line.

4:00 p.m. The orifice plate in the 4th stage steam line (FE 117) was found to be 2" smaller than specified and was removed.

4:05 p.m. Started brine flow to plant.

9:30 p.m. Increasing pressure drop indicated the P-9 strainer was plugged. The GLEF was shut down for inspection.

NOTE

The type of material found on P-9 strainer was a wet, clay-like sludge which the pump should be able to handle.

P-10 strainer was clean. In order to eliminate the problem of plugged strainers, the strainers on both P-9 and P-10 were removed and stored.

START UP OPERATING CONDITIONS

Test No: 6

Date: May 24

<u>Parameter</u>		<u>Units</u>	<u>Average</u>	<u>Range</u>
Inlet Conditions				
	T	°F	410	390-420
	P	psig	300	250-310
1st Stage	T	°F	350	350-360
	P	psig	115	105-155
	LF	#/hr	350M	175M-500M
	SF	#/hr	65M	30M-70M
2nd Stage	T	°F	310	280-320
	P	psig	60	46-65
	LF	#/h	290M	200M-380M
	SF	#/hr	21.5M	12.5M-38M
3rd Stage	T	°F	250	230-295
	P	psig	15	9-36
	LF	#/hr	--	--
	SF	#/hr	9.0M	8M-10M
4th Stage	T	°F	200	185-225
	P	psig	3 in Hg	5 in Hg-7.0
	LF	#/hr	--	--
	SF	#/hr	--	--
Reinjection	T	°F	212	200-221
	P	psig	600	600
	LF	#/hr	--	--

LF = Liquid Flow

SF = Steam Flow

M = 1000

TEST NO. 7

May 25, 1976

12:30 a.m.   Plant operation relatively stable.

PROBLEMS:

1. Control of 4th stage level, due to the failure of drain control valve (LCV 718A) to close tightly.
2. The liquid level in the 2nd stage scrubber remained high. Throttling the 1st stage scrubber drain reduced the liquid level in the 2nd stage scrubber.

CONCLUSION

The scrubber drain header size is not adequate. During the June 16 through August 9 modification period this was repiped to provide the 1st, 2nd and 3rd stage scrubbers with a 6" drain line direct to the 4th stage separator.

- 5:15 p.m.   Rolled the 30 kilowatt Lawrence Livermore Laboratory (LLL) turbine for test.
- 5:30 p.m.   Secured turbine. It has a loud rub in gear section due to misalignment.
- 5:35 p.m.   Shut down plant to perform the following maintenance items:

1. Modify the purge water system so CV 340 controls P-2 seal water diff. pressure, and CV 339 controls 240# purge water header pressure.
2. Clear drain line from 3rd stage heater to condensate drain header.
3. Pull and clean gas vent control valve.
4. All scrubber lower manholes were opened and lower interior inspected.
  - a. 4th stage build up of gray sludge below working water level. Cleaned and washed down. A broken piece of 2 x 4 was removed from bottom drain connection.
  - b. 1st, 2nd and 3rd stages were not fouled, a small amount of loose rust scale was removed.
  - c. Samples were taken for analysis.

5. The 33 KV insulators were washed by IID.
6. Steel valve ring seats were installed in LCV-719A.
7. Fiber ring with backing ring installed in LCV-712.
8. Removed P-7 suction strainer.
9. Installed most of the chain operators on valves required.
10. Pumped brine pond down to Magmamax 3 via rental pump and P-2.

11:45 p.m.   Primed Magmamax No. 1 with 2800 gallons of fresh (irrigation) water.

TEST NO. 8

May 27, 1976

12:30 p.m. Started flow of Magmamax 1 first to the sump then to the brine pond.

1:30 p.m. Ready to flow brine to plant, this was delayed as water was observed flowing from 1st stage scrubber drain. The source of the water was the cooling water system which back flowed through the vent gas separator drain system which is interconnected. This flooded the first stage heater, V-6 and the scrubber. A check valve was later added to prevent reoccurrence.

1:45 p.m. System drained and brine flow started to the plant.

5:15 p.m. The low flow switch (FV 110) which controls the low flow recirculation valve for the purge water pumps (P-7 and P-7A) failed. The bellows ruptured and allowed water to flow back through the connecting electrical conduit. GLEF operation was not impaired and the purge water level was monitored visually.

7:05 p.m. The brine reinjection pump (P-2) shaft seal failed and plant was shut down.

FOLLOWING SHUT DOWN

1. A severe water hammer occurred in the 3rd stage separator, shortly after start up. This damaged the east support foundation and the separator was moved approximately 1 1/2" on foundation. The separator was isolated from the system and drained. The Ben Holt Company Sturctural Engineer recommended the 3rd stage separator not be used until the foundation could be repaired. The GLEF was then operated as a three stage system until foundation was repaired. This water hammer was attributed to cold water remaining in the 3rd stage separator and connecting piping.
2. Seal water pressure to P-2 was still marginal and it was decided to install the new 40 hp P-7 pump using a temporary power source. A size 3 breaker motor starter was located and installed. The pump was tested and ready for service on May 29.
3. A gauge glass was installed during this outage on the secondary system condensers so liquid level may be controlled to maintain the desired degree of sub cooling.

TEST NO. 9

May 31 to June 1, 1976

8:00 a.m. Start up preparations in progress, this operation differs from previous ones as follows:

1. The 3rd stage was isolated and bypassed.
2. Prior to start up the 1st and 2nd stage vessels and piping were drained to the 4th stage using an air purge.
3. The well fluid was flowed through the bypass system around the 1st and 2nd stage and into the brine pond via LCV 719. The brine outlet valves on the 1st and 2nd stage vessels were cracked open to allow a controlled amount of hot brine to enter the vessels and warm the drain line and any cold fluid remaining in the vessel.
4. The brine bypass was then secured, P-2 was placed in service.

8:30 a.m. Brine flow was started. No water hammer occurred.

9:53 p.m. Plant secured because 1st stage drain valve failed to open. Cause was moisture in the control air system.

9:58 p.m. Brine flow to the test loop started again. Began routine blowing down of air filters on all equipment hourly.

June 1, 1976

4:40 a.m. Brine flow increased suddenly. This could have been caused by the control valve cycling due to water in the instrument air. A gas pocket in the supply well could also have been the cause.

5:45 a.m. Another surge.

8:45 a.m. Another surge.

NOTE: High liquid level was experienced in the 1st stage scrubber. This was apparently caused by excessive liquid carry over from the 1st stage separator. The problem was corrected by setting the liquid level control on the 1st stage separator to the lowest possible position.

1:30 p.m. The first stage inlet valve (PCV 301) closed for no apparent reason. To maintain operation it was controlled manually. Moisture in air was suspected.

June 2, 1976

LAWRENCE LIVERMORE LABORATORY STEAM TURBINE

The Lawrence Livermore Laboratory (LLL), as part of their Industrial Support Program, installed a 30 KW Westinghouse steam turbine at the GLEF. This turbine was connected to the 2nd stage scrubber outlet which furnishes steam at approximately 60 psia. The purpose of this test was to document the interval condition of a turbine exposed to scrubbed steam from the Niland geothermal field.

10:50 a.m.   Attempted to roll the LLL turbine for test.
10:55 a.m.   Turbine was secured. Pressure swing at low flow conditions will not allow automatic start.
11:30 a.m.   Rolled turbine using hand control.
11:55 a.m.   Turbine secured. The main governor was stuck in the closed position.
2:45 p.m.   LLL running turbine for test.
6:00 p.m.   A leak developed in the brine line elbow just after 1st stage brine inlet control valve (PCV 301).
The plant was shut down to repair the leak. The LLL turbine was secured just prior to shut down.

NOTES:

1. At 2:40 p.m. on June 1, 1976, the cooling water temperature reached 100°F. In an attempt to stabilize the cooling water temperature the cooling pond spray bypass valve was throttled to the 50% open position to increase spray head flow.

The plant was not operated long enough after this change to determine if this action was effective.

2. The leak in the brine line elbow after PCV 301 was caused by severe erosion at the heel of the ell. Some erosion was also observed on the inside face at the outlet of the ell end on the lower side of the valve body. The elbow was replaced to allow the test run to continue, but the final solution will require relocation of the valve to a straight run of pipe. The cause of this problem is simply poor design and is not due to the geothermal fluid.
3. To reduce carry over the level control sensors were lowered one port (3") in the 2nd and 4th stage separators. In the 1st stage separator, the lowest port is still being used to control the liquid level.

START UP OPERATING CONDITIONS

Test No: 9

Date: May 31 - June 2

<u>Parameter</u>		<u>Units</u>	<u>Average</u>	<u>Range</u>
Inlet Conditions				
	T	°F	410	390-420
	P	psig	300	250-310
1st Stage	T	°F	365	340-370
	P	psig	122	110-135
	LF	#/hr	500M	0-1000M
	SF	#/hr	58M	54M-60M
2nd Stage	T	°F	290	276-300
	P	psig	50	36-55
	LF	#/h	500M	0-1000M
	SF	#/hr	16M	15M-18M
3rd Stage	T	°F	No Data (Out of Service)	
	P	psig	"	"
	LF	#/hr	"	"
	SF	#/hr	"	"
4th Stage	T	°F	212	200-215
	P	psig	0	2"Hg-Opsig
	LF	#/hr	500M	400M-800M
	SF	#/hr	--	--
Reinjection	T	°F	236	218-240
	P	psig	475	350-600
	LF	#/hr	500M	400M-900M

LF = Liquid Flow

SF = Steam Flow

M = 1000

INSPECTION REPORT

P-9 DISCHARGE CONTROL VALVE (LCV-721)

June 2, 1976

During the previous startup test the 4th stage scrubber drain control valve (LCV-721) was observed to be sticking and not maintaining the proper liquid level in the scrubber. The system was put to bypass operation and the Fisher valve internals (whisper trim) were removed for inspection.

Some construction metal particles were found in the valve, but the primary cause of the sticking appeared to be a buildup of a hard black material in the valve clearances. This buildup is similar to that found on steam valves during SDG&E's 1974 field tests.

Based on current and previous tests, this type of valve and trim is not suitable for service in such an environment.

The drain control valve (LCV-722) installed in the 4th stage condensate (to P-10) drain was a Kaymar Ball valve. Since this is a much less severe environment, the two valve locations were exchanged on June 11 and to date (September 21, 1976) no further problems with these control valves have been experienced.

TEST NO. 10

June 3, 4, 5 and 6, 1976

June 3, 1976

1:20 p.m. Started brine flow to the test loop using the same procedure as on Test No. 9 (May 31).

1:30 p.m. Shut down the GLEF due to failure of the 4th stage scrubber condensate drain pump (P-9). The shaft would not turn. Made arrangements to pull pump for inspection. (See shut down note at end of test).

3:30 p.m. Starting brine flow again without P-9 by using P-10 with suction cross connected between 4th stage scrubber (V-12) and 4th stage heater drain tank (V-13). This operation necessitates running with a low level alarm on V-12 and the suction valve to V-12 throttled to prevent loss of suction to P-10.

6:35 p.m. Secured plant due to failure of shaft seal on P-10.

8:45 p.m. Replaced P-10 seals and restarted plant.

11:50 p.m. LLL turbine up and running and lights lit!

June 4, 1976 "Dedication Day"

2:10 a.m. Secured plant to inspect shaft seal on P-10 because of excessive leakage. Seal was adjusted and P-10 returned to service.

2:30 a.m. Restarted flow to test loop.

5:30 a.m. Completed repair of the 4th stage scrubber drain pump (P-9) and returned it to service.

9:10 a.m. Started LLL turbine-generator.

10:00 a.m. Plant was dedicated in all its glory. "AMEN"

11:20 a.m. Turbine was secured by LLL

4:00 p.m. to

12:00 midnight The GLEF was operated eight hours without alarm or adjustment.

June 5, 1976

24 hours of continuous stable operations achieved.

June 6, 1976

4:45 a.m. A brine leak developed in the outlet flange of the 1st stage inlet control valve (PCV 301). This could not be controlled and the plant was shut down. The leak was caused by erosion of valve body and flange. This erosion extended 3/4" into flange which was total holding surface of 1 1/4". The downstream elbow also showed signs of extensive erosion.

The plant was left secured until repairs could be made and the control valve relocated.

FOLLOWING SHUT DOWN

1. The 4th stage scrubber condensate drain pump (P-9) seal had shown signs of failing near the end of the previous run (Test No. 9) so it was disassembled for inspection. Prior to breaking the coupling it was noted that the shaft was not turning freely and would not drop as it had previously when checking wearing ring clearances. Several clearance settings were tried, but binding was observed at all settings. The pump was pulled and found to have a fair amount of the gray sludge deposited on pump housing and suction can. The bearings, bushings and shaft were scored, apparently from abrasive fluid and lack of lubrication. An SDG&E crew was sent from San Diego to ream bushings and polish shaft. The pump was cleaned, reassembled and returned to service at 5:30 a.m. Total pump outage time 14.5 hours.
2. P-10 seal failed and was replaced but needed to be re-adjusted. Two short plant shut downs were involved.
3. The 1st stage inlet valve (PCV 301), a Fisher V ball valve created an excessive pressure drop with subsequent erosion of the down stream elbow and valve body. It was replaced by PCV 300, a Kamar ball valve. The valve location was also changed to just before the 6" x 16" increaser. The original valve location ahead of the 6" elbow had caused severe erosion of this member.

START UP OPERATING CONDITIONS

Test No: 10

Date: June 2 - June 7

<u>Parameter</u>		<u>Units</u>	<u>Average</u>	<u>Range</u>
Inlet Conditions				
	T	°F	410	390-420
	P	psig	300	250-410
1st Stage	T	°F	360	355-363
	P	psig	122	118-125
	LF	#/hr	190M	150M-220M
	SF	#/hr	50M	
2nd Stage	T	°F	305	300-310
	P	psig	55	40-75
	LF	#/h	400M	400M-1000M
	SF	#/hr	10M	8M-24M
3rd Stage	T	°F	No Data (Out of Service)	
	P	psig	"	"
	LF	#/hr	"	"
	SF	#/hr	"	"
4th Stage	T	°F	215	200-230
	P	psig	4	0-15
	LF	#/hr	--	--
	SF	#/hr	--	--
Reinjection	T	°F	236	214-238
	P	psig	475	350-600
	LF	#/hr	400M	400M-1000M

LF = Liquid Flow

SF = Steam Flow

M = 1000

INSPECTION REPORT

June 6 through 9

1. All separator drain valves (LCV 711, LCV 714 and LCV 718-A) and adjoining piping sections were opened for inspection (see MC 5651, Appendix A).
2. Except for some minor deposits in LCV-718-A nothing of significance was found.
3. With arrival of purge water pump (P-7) permanent breakers, both P-7 and P-7A breakers were rewired.
4. The brine reinjection pump discharge elbow was pulled to replace a leaking gasket. The inter-surface of the pump discharge nozzle, elbow and check valve all were covered with approximately 3/8" of scale. The check valve was stuck open. Samples were taken for laboratory analysis and the results are discussed in Section 5.3 of this report. The check valve cleaned and replaced. The scale was not hard except on check flapper surface where flow velocities were high.
5. Thermo-wells and thermometers were installed in binary loop to monitor the temperatures in and out of each heater.

6. The level control valves for P-9 and P-10 were exchanged to place ball valve in 4th stage scrubber drain service. (See June 2 inspection report on LCV 721).
7. Opened 4th stage separator for inspection. Approximately 3/16" of scale observed. Scale flaked off in patches.

START UP TEST NO. 11

June 10 and 11

June 10, 1976

7:20 p.m. Started brine flow to test loop.

8:00 p.m. 1st stage separator level control system malfunctioning.

9:00 p.m. Secured brine flow found 1st stage water column filled with crud from drain boot on 1st stage.

NOTE: Secured operation to check and clean the water columns in all stages.

June 11, 1976

7:15 a.m. Begin flowing Magmamax No. 1 to the brine pond.

7:30 a.m. Closed valve to and diverted flow to the test loop. Brine flow from the well stopped.

NOTE: To restart flow from the well the brine system was connected through the bypass system to the 4th stage separator with the vacuum pump and reinjection pump (P-2) in operation. Pressure in the 4th stage separator was maintained at 20" of Hg vacuum for 20 minutes. The well supply line pressure dropped to 10" Hg then increased steadily until it reached 100 psi. At this point well flow was diverted to the brine pond and a normal pre-start warm up proceeded.

10:00 a.m. Started brine flow to test loop. Continued operation until high power demand by the 4th stage scrubber drain condensate pump (P-9) forced shut down.

1:50 p.m. The 4th stage scrubber condensate drain pump (P-9) was checked. The shaft could be rotated only with difficulty.

2:00 p.m. Secured operation and made preparations to remove and inspect P-9.

PROBLEMS WITH P-9

Found the two lower bearings to be severely worn allowing considerable run out, and a 3/16" deep groove on one side of the shaft. This problem was corrected during the June 16-August 9 inspection by:

- a. Fabricating a new lower monel shaft.
- b. Replacing the bushings above and below the impeller and realigning the shaft.
- c. Installing a temporary long center shaft until the original could be coated.
- d. Installing purge water connections on the pump bearings.

TEST NO. 12

June 12 through 16

June 12, 1976

3:55 p.m. Started auxiliary systems.

4:10 p.m. Started brine flow through bypass system to the pond.

4:22 p.m. Started brine flow to test loop.

4:50 p.m. GLEF in operation.

10:00 p.m. The high level alarm probe on 2nd stage scrubber was malfunctioning and was corrected by:

1. Moving the level control point to the lowest probe position.
2. Installing the high level alarm in the old control point position.

This action also eliminated the low level alarm on the 2nd stage scrubber.

June 13, 1976

6:35 p.m. Found that the flow transmitter, FT-120, which senses the condensate flow from V-6 to E-5 (ME 5652, Appendix A) had been installed backwards. Reversed sensing lines and returned the transmitter to service.

June 14, 1976

2:10 a.m. The air line nipple on the 1st stage pressure control valve (PCV 301) failed. The valve was controlled manually and temporary air system control repairs were made.

1:00 p.m. Encountered problems in draining V-6 to the 4th stage separator. The major portion of the drain line is 3" in diameter but at the control valve (LCV 702) the diameter is only 2" (ME 5652, Appendix A). This section was later upgraded to 3".

NOTE: LLL spent #3 shift taking radiograph of brine system.

June 16, 1976

9:30 a.m. Make temporary repairs on a cooling water thermocouple which had been damaged during installation.

10:00 a.m. Unable to hold vacuum in the accumulator (V-2). Inspected the vacuum pump and found that seal water contamination had caused the seals to fail. The seals were replaced and a temporary water source was installed. During next outage the seal water system was changed.

NOTE: LLL spent #3 shift doing radiographs of brine system. Radiographs were made during operation and after shut down.

9:15 p.m. Secured brine flow to the plant and proceeded to shut down the GLEF.

9:20 p.m. The shaft on P-9 seized. It was pulled on June 17, 1976 and sent to SDG&E shops for general overhaul and the addition of purge water ports for injecting lube water directly into the pump bearings.

FOLLOWING SHUT DOWN

Magmamax No. 1 and No. 3 were filled with cold brine to "kill" the wells. This was done to allow the well crew to "fish" out the downhole pressure tubing that failed during startup testing.

START UP OPERATING CONDITIONS

Test No: 12

Date: June 12 - June 16

<u>Parameter</u>	<u>Units</u>	<u>Average</u>	<u>Range</u>
Inlet Conditions			
T	°F	410	390-420
P	psig	300	250-310
1st Stage	T °F	365	355-370
	P psig	120	105-135
	LF #/hr	220M	100M-330M
	SF #/hr	58M	55M-60M
2nd Stage	T °F	280	260-290
	P psig	35	28-50
	LF #/h	--	--
	SF #/hr	22.5M	15M-30M
3rd Stage	T °F	No Data (Out of Service)	
	P psig	"	"
	LF #/hr	"	"
	SF #/hr	"	"
4th Stage	T °F	210	210-228
	P psig	0	0-8
	LF #/hr	--	--
	SF #/hr	--	--
Reinjection	T °F	220	213-237
	P psig	475	350-600
	LF #/hr	--	--

LF = Liquid Flow

SF = Steam Flow

M = 1000

GLEF INSPECTION

June 16 through August 9

During the period of June 16 through August 9 a complete inspection of the GLEF was made.

The 1st, 2nd and 3rd stage separators proper, contained no significant deposits. Thin scale was observed in the 2nd stage that appears to flake off as plant is cycled. The boot on first stage was 2/3 full of black sand-like materials.

The 4th stage separator contained some soft scale (less than 1/16" in thickness). This was removed and measured as approximately 6 cubic yards.

The 1st stage scrubber weir sections and wash loops were complete blocked off in the top tray and more than 50% in the lower trays.

The 2nd and 3rd stage scrubbers had some debris but no openings were blocked.

The 4th stage scrubber contained heavy scale deposits in lower section which are similar to those found earlier in the condensate drain pump (P-9) suction piping. This was probably formed during the early start up tests which significant solids carry over from the scrubbers was experienced. This scale is now flaking loose and depositing in the last (4th stage) scrubber.

All the trays and water wash lines were cleaned and inspected. The purge water piping into the scrubbers was flushed and checked.

Visual inspection of the steam side of the 1st, 2nd and 3rd stage heat exchangers was made through the inspection ports and by disconnecting inlet and/or outlet piping. No significant scaling was observed.

The tube sheet head cover was removed from the 4th stage heat exchanger to determine the reason for the low heat transfer rates experienced.

The drain piping from the heat exchanger to V-13 that originated as 8" O.D. and necked down to 3" O.D. at V-13 contained a scale deposits which reduced the pipe diameter to 1 5/8".

The 4th stage heat exchanger tube sheet was partially plugged and all tube openings were restricted by scale to some extent. The outlet section exhibited evidence of a high liquid level being maintained. This heavy scaling was attributed to poor drainage caused by the restricted drain line.

The heat exchanger was chemically cleaned (see Section 5 and Appendix B). To prevent any reflooding of the heat exchanger, the size of the piping to V-13 was increased to 6" O.D.

TEST NO. 13

August 9 through August 11, 1976

August 9, 1976

8:00 a.m. Secondary system and vacuum pump in operation in preparation for system start up.

3:30 p.m. Started flowing brine from Magmamax No. 1 into vessels.

NOTE: During the warm up and initial operation, the new (Karmar ball valve) PCV 301 that controls brine flow to the 1st stage "B" separator caused some problems by binding.

8:00 p.m. 1st stage up to full pressure and temperature.

August 10, 1976

5:25 a.m. Low liquid level in the 3rd stage separator. Inspection showed 3rd stage drain control (LCF-714) to be stuck in the 1/2 open position. The liquid level was controlled manually until LCF-714 could be cleaned.

3:20 p.m. Pressure upset in system caused by too high a flow rate during an adjustment of the 1st stage steam flow caused the brine control valve (PCV-301) to close. PCF 301 then stuck closed. It was freed and then slowly reopened to regain proper pressure and level in the 1st stage. No more problems were experienced with this valve for the balance of this operating period.

August 11, 1976

11:10 a.m. The 3rd stage level control valve (LCV-714) was returned to service after being cleaned by soaking in a 20% inhibited hydrochloric acid solution.

11:30 a.m. Erratic operation of the secondary loop flow control valve (FCV 104) because of water in the control air system was observed.

NOTE: Problem with moisture in the air control system continued during the balance of this operating period. The difficulty is caused by under design of the control air dryer.

12:45 p.m. The vacuum pump shaft broke and system pressure began to increase.

NOTE: An attempt was made to continue plant operation without the vacuum pump.

1:45 p.m. Reinjection pump (P-2) discharge pressure dropped to 50 psig and the 4th stage vessel level began to rise. Operation was continued at a very low rate, to allow P-2 to drain vessel.

4:30 p.m. Plant operation was secured to determine why the reinjection pump (P-2) was unable to drain the 4th stage separator.

NOTE: At the completion of this operation when the brine flow to the plant was secured, flow was continued to the Bureau of Mines test site Baker Tank. The foregoing was used as a means to continue well flow so well would not die and make priming necessary for the next operation. As the Baker tank filled up it was reinjected using the Bureau of Mines diesel driven pump.

START UP OPERATING CONDITIONS

Test No: 13

Date: August 9 - August 11

<u>Parameter</u>		<u>Units</u>	<u>Average</u>	<u>Range</u>
Inlet Conditions				
	T	°F	400	395-410
	P	psig	310	300-350
1st Stage	T	°F	372	370-375
	P	psig	145	135-150
	LF	#/hr	350M	0-500M
	SF	#/hr	40M	30M-50M
2nd Stage	T	°F	290	275-305
	P	psig	45	35-60
	LF	#/h	--	--
	SF	#/hr	18M	15M-25M
3rd Stage	T	°F	245	240-255
	P	psig	18	13-24
	LF	#/hr	350M	0-600M
	SF	#/hr	12M	8M-14M
4th Stage	T	°F	185	185-190
	P	psig	5"Hg	0-10"Hg
	LF	#/hr	--	--
	SF	#/hr	18M	12M-18.8M
Reinjection	T	°F	208	206-223
	P	psig	475	350-600
	LF	#/hr	--	--

LF = Liquid Flow

SF = Steam Flow

M = 1000

INVESTIGATION OF VACUUM AND REINJECTION FAILURE

1. The vacuum pump shaft was found to be broken. This was sent to the SDG&E Machine Shop for repair.
2. P-2 pump shaft was broken between the 4th and 5th stages. The exact cause has not yet been established. The shaft parts were sent to LLL for analysis. With the exception of the bearing location where the shaft failed, the bearings and ceramic coating on the shaft that was installed during the last outage appeared to be in excellent shape.

To allow the plant to continue operation, it was decided to return the pump to service with a replacement shaft without the ceramic coating and to change from water to grease lubrication for the pump shaft bearings. A detailed discussion of the reinjection pump failure is presented in Section 4 of this report.

3. Control valves (FCV 105) P-2 low flow recirculation control valve and (LCF 718B) fourth stage drain control valve were found to be sticking. These valves were cleaned with an inhibited hydrochloric acid solution.
4. The 1st stage brine control valve (PCV 301) was removed and inspected to determine why it was sticking. The

valve appeared clean, but scale build up on the stem indicated that the purge water pressure was not high enough to prevent brine from entering the valve packing.

The water supply was disconnected and a grease fitting was installed to lubricate the valve stem. This provision was later adapted with all ball type control valves.

START UP TEST NO. 14

August 16 through August 19, 1976

August 16, 1976

- 7:45 p.m. Started auxiliary systems in preparation for plant operation.
- 10:30 p.m. Testing of P-2 operation with the new shaft was completed satisfactorily.
- 11:00 p.m. Brine flow to the test loop started. Well at operating pressure since flow had continued to the Bureau of Mines' Baker Tank since August 11, 1976.
- 11:45 p.m. All systems in operation and temperature rising to normal level.

August 17, 1976

- 9:10 a.m. The 3rd stage drain control valve (LCV 714) was sticking and gave trouble for the remainder of this operating run.

August 18, 1976

- 4:25 p.m. Completed hook up of vacuum drag line from the brine pond to the 4th stage separator. This modification allows the brine pond to be drained during plant operation.

August 19, 1976

2:20 p.m.   While testing well pressure control hook up for the 1st stage pressure control valve (PCV 301), the control shut PCV 301 and it could not be reopened. This effectively shut down the plant.

FOLLOWING THE SHUT DOWN

PCV 301 was removed for maintenance but the valve seat could not be removed in the field. The Kaymar Ball valve installed in PCV 300 location, was used to replace PCV 301 until the factory representative could be contacted.

LCV 714 was removed and cleaned. After it was re-installed a program of cycling the valve periodically was instituted to prevent a scale build up and binding.

START UP OPERATING CONDITIONS

Test No: 14

Date: August 16 - August 19

<u>Parameter</u>		<u>Units</u>	<u>Average</u>	<u>Range</u>
Inlet Conditions				
	T	°F	390	380-410
	P	psig	290	250-320
1st Stage	T	°F	365	345-375
	P	psig	135	120-145
	LF	#/hr	175M	100M-175M
	SF	#/hr	55M	46M-58M
2nd Stage	T	°F	297	280-300
	P	psig	50	35-60
	LF	#/h	--	--
	SF	#/hr	--	--
3rd Stage	T	°F	240	230-250
	P	psig	18	8-20
	LF	#/hr	--	--
	SF	#/hr	14.0M	11.2M-15.2M
4th Stage	T	°F	185	175-200
	P	psig	4"Hg	10"Hg-0
	LF	#/hr	--	--
	SF	#/hr	19.2M	12M-19.2M
Reinjection	T	°F	210	192-228
	P	psig	475	350-600
	LF	#/hr	--	--

LF = Liquid Flow

SF = Steam Flow

M = 1000

START UP TEST NO. 15

August 20, 1976

9:00 a.m. Auxiliary systems in operation in preparation for system start-up.

The well was up to operating pressure as flow had been maintained through the Bureau of Mines Baker Tank during outage.

1:20 p.m. Started brine flow through the separator bypass system to the brine pond.

2:15 p.m. Secured bypass and started plant warm up by admitting brine into 1st stage vessel.

4:15 p.m. System up to temperature and pressure and steady state.

9:05 p.m. Cooling water low pressure alarm sounded. C.W. pump inlet screens was found plugged with crickets.

11:17 p.m. The plant brine flow was secured as cooling water flow could not be maintained.

August 21, 1976

12:30 a.m.   Crickets cleaned from screen and cooling
water flow re-established.

1:00 a.m.   Restarted brine flow through vessels.

2:45 a.m.   System back up to normal operating temperatures
and pressure.

5:25 a.m.   Reinjection pump (P-2) shaft failed and plant
operation was secured for P-2 repair.

NOTE: When disassembled it was discovered that several bearings had seized, apparently due to failure of the grease system to provide adequate lubrication to the bearing surfaces.

FOLLOWING SHUT DOWN

1. The brine reinjection pump P-2 was sent to the Machine Shop in San Diego for repair. It was necessary to replace the pump shaft and bearings. At a meeting with the pump manufacturer, LLL, General Atomics, Magma and Holt (Appendix D) it was decided to:
  - a. Provide lubricating water lines to each of the pump's 9 bearings.
  - b. Provide individual flow meters and a pressure guage for each supply line.
  - c. Install three different types of bearings, Teflon, bronze and tungsten carbide.

2. The 1st stage pressure control valve (PVC 301), a Kamar ball valve, that was removed due to sticking after shut down of August 19 was returned to service after seat angle and area had been modified under the supervision of the factory representative, Mr. Richard Campbell. PCV 300, also a Kamar ball valve, was removed and sent to the shop for modification. PCV 300 was still working well when removed. Inspection showed the Stellite seat was in excellent condition but the chrom plating on the ball was starting to peel as it had on PCV 301.
3. The electrical control for the purge water supply pumps was modified to allow both pumps to operate at the same time. The original design allowed only one pump to be operated and resulted in adequate purge water flow.

START UP OPERATING CONDITIONS

Test No: 15

Date: August 19 - August 21

<u>Parameter</u>		<u>Units</u>	<u>Average</u>	<u>Range</u>
Inlet Conditions				
	T	°F	395	390-410
	P	psig	300	300-340
1st Stage	T	°F	370	370-375
	P	psig	145	145-150
	LF	#/hr	180M	100M-225M
	SF	#/hr	43M	42M-45M
2nd Stage	T	°F	285	275-310
	P	psig	42	35-42
	LF	#/h	100M	100M
	SF	#/hr	--	--
3rd Stage	T	°F	240	230-245
	P	psig	15	8-15
	LF	#/hr	- Out of Service -	
	SF	#/hr	14.4M	8.8M-15.2M
4th Stage	T	°F	180	170-195
	P	psig	5"Hg	4m"Hg-10"Hg
	LF	#/hr	- Out of Service -	
	SF	#/hr	15.2M	14.M-16.8M
Reinjection	T	°F	200	186-218
	P	psig	475	350-600
	LF	#/hr	- Out of Service -	

LF = Liquid Flow

SF = Steam Flow

M = 1000

4.0   SPECIAL PROBLEMS
4.1   BRINE REINJECTION PUMP
4.1.1   INTRODUCTION & SUMMARY

Introduction

This report presents a history and description of the operation and maintenance with the brine injection pump for the Geothermal Loop Experimental Facility (GLEF). It contains a detailed description of the pump design and installation, operating conditions and results.

Conclusions are drawn regarding the incorporation of specific pump features that are based on the pump's performance to date. Recommendations for additional modifications are presented for implementation at a later date in the GLEF operations.

Summary

The brine injection pump has been operated for a total of 414 hours. Several shutdowns of the Geothermal Loop Experimental Facility occurred since full-plant operations were initiated. The operation of the injection pump and plant shutdowns associated with its operation are of prime concern in this report. Shutdowns unrelated to the injection pump will not be covered in this report.

Two shutdowns of the Facility were caused directly by injection pump operation. Actual pump performance of

discharge head and capacity has met the manufacturers guaranteed performance. The shutdowns were caused by the journal bearing problems.

The shaft journal bearings were replaced one time with Type 416 ss material hardened to Rockwell C-60. Lubrication was applied to each of the ten shaft bearings to prevent the intrusion of brine scale in the annulus between the shaft and bearing. The shaft itself was coated with a 10 mil layer of ceramic to improve bearing performance.

Lubrication of the bearings with purge water was not successful due to chemistry reaction of the brine with the purge water. High temperature grease was then used to replace the purge water. The condition of the bearings and shaft was excellent.

Purge water was used continually to lubricate and cool the shaft seal. This appears to be a viable means of preventing the brine from intruding into the seal. The paradox between the bearings and seal successes with purge water is apparently due to the fact that more seal water is available at the seal and a thorough "flushing" action occurs.

4.1.2 Pump Description

The brine reinjection pump is a nine stage, vertical, centrifugal type manufactured by the Peerless Pump Division

formerly a division of Food Machines Corporation (FMC). This pump is located near the fourth stage separator from which the pump takes its suction (refer to ME 5651 Appendix A). Spent brine from the fourth stage separator enters the barrel of the pump shown in Figure 4. The geothermal fluid normally would be at a temperature of 213° F, a pressure of 13.0 psia and contain about 300,000 ppm of total dissolved solids. The injection pump is centered in the barrel which is flooded to give the pump 18.0 feet of net positive suction head at the pump's suction bowl.

A manufacturers drawing of the initial pump configuration and the pump test curve is shown in Figure 5 and 5A. The pump bowls and impellers are manufactured from Carpenter 20, the shaft from Monel - K, the bearings from SAE 660 bronze. The shaft column, discharge head and barrel are ANSI 1041, mild carbon steel.

The pump driver is an 800 horsepower, 4000 volt, 3 phase induction motor with a thrust bearing to take the vertical loads of the pump when in service. Nominal pump/motor speed is 1800 rpm. The pump shaft is hardcoupled to the motor.

A mechanical shaft seal, manufactured by DuraSeal is located in the pump discharge head. This seal can be operated without seal water, however, we decided to provide the seal water to the seal.

PEERLESS PUMP

TYPE: 12x12x22 HH

HYDROLINE

BOWL UNIT: 9

STAGE 15 LC W/14 HH 1ST STG.

INDUSTRIAL TURBINE PUMP

HYDRO- LINE SIZE	NOZZLE HEAD																								BARREL						
	GENERAL			SECTION A & B & C								DISCHARGE A & B & C								DRIVER											
	A	B	C	RATING	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	
TYPE HH																															
12x12x23	15	54	20	150#	12	19	12	11	17	1 1/2	1 1/16	600#	12	22	29	1 1/2	19	1 1/4	25	1/4	13 1/2	25	1 1/8	1 1/4	3	27	42	1 1/2	39	1 1/2	

TYPE HH

I.D. OF BARREL = 20 1/2"

PARTS LIST					
ITEM NO.	MT'L	PART NO.	QTY.	QUAN.	DESCRIPTION
57.000					ASSY MOTOR V.S.S. U.S.
58.000	GRAPH. 80	2731989	A	1	BEARING SLEEVE 2 1/4 X 2 1/4 X 5" LG.
59.000	20 S.S.	T92402	B	1	BUSHING, TAPER LOCK 1 1/4 DIA 14 HH
60.000	GRAPH. 80	2731989	A	7	BEARING SLEEVE 2 1/4 X 2 1/4 X 5" LG. 15 LC
61.000	GRAPH. 80	2731989	A	1	BEARING SLEEVE 2 1/4 X 2 1/4 X 5" LG. 14 HH
62.000	20 S.S.	2726128	A	2	BEARING SLEEVE 2 1/4 X 2 1/4 X 5" LG.
63.000	20 S.S.	2726128	B	1	BOWL STD TOP STD 15 LC
64.000	20 S.S.	2726128	B	1	BOWL STD 14 HH
65.000	20 S.S.	2726128	B	1	BUSHING, TAPER LOCK 2 1/4 DIA 14 HH
66.000	20 S.S.	2726128	B	1	RING, IMP. WEAR 14 HH
67.000	20 S.S.	2726128	B	1	CONTAINER SEAL
68.000	STL	2682246	B	1	COUPLING MOTOR HALF 2 1/4 DIA
69.000	STL	2682246	B	1	COUPLING PUMP HALF 2 1/4 DIA
70.000	316 S.S.				FLANGE SEAL
71.000	VELL	2604678	A	2	GSRT. BOWL FLANGE 14 HH 3/4 DIA 14 HH
72.000	STL	2728025	D	1	HEAD DISCHARGE 12 X 12 1/2 DIA
73.000	20 S.S.	2613220	B	1	IMPELLER 15 LC
74.000	20 S.S.	2613220	B	1	IMPELLER 14 HH
75.000	1019 STL	V2380-10	A	1	KEY SQUARE 3/4 SQ. X 3/4 LG.
76.000	1019 STL	V2380-10	A	1	KEY SQUARE 1/2 SQ. X 5/8 LG.
77.000	20 S.S.	2715132	B	1	MANIFOLD, REEL SUCT 14 HH
78.000	BLANK	2621918	A	1	NUT, CPLG ADJUSTING 2 1/4 DIA
79.000	20	2610044	A	14	SCREW 3/8 DIA X 1 1/4 LG.
80.000	20 S.S.	2609841	A	8	NUT, HEX 5/8 DIA
81.000	20 S.S.	2610085	A	16	SCREW, HEX 5/8 DIA X 1 1/2 LG.
82.000	STL	2613220	A	1	RING, SPLIT 2 1/4 DIA
83.000	STL HT	2610085	A	1	SCREW, HEX HD CAP
84.000					SEAL MECHANICAL DURA PTO
85.000	HYCAR	2612292	A	9	SEAL O-RING 1/39 X 12 1/2 ID
86.000	HYCAR	2612292	A	1	SEAL O-RING 5/16 X 1 1/2 ID
87.000	HYCAR	2617540	A	1	SEAL O-RING 5/8 X 5/8 X 1 1/2
88.000	K-MORSE	2728133	B	1	SHAFT IMPELLER TOP 2 1/4 X 15-4 1/2 LG.
89.000	STL	2620852	B	1	SPACER DRIVE CPLG
90.000	20 S.S.	2622135	A	8	RING, BOWL STD 15 LC
91.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
92.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
93.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
94.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
95.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
96.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
97.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
98.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
99.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
100.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
101.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
102.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
103.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
104.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
105.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
106.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
107.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
108.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
109.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
110.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
111.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
112.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
113.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
114.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
115.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
116.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
117.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
118.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
119.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH
120.000	20 S.S.	2622135	A	8	RING, BOWL STD 14 HH

S.O. NO. **VI3772**

SOLD TO: **C.F. BRAUN & CO.**
ALHAMBRA, CALIF.

ORDER NO. **4691-100-131-1C**

USER: **—**

ITEM NO. **P-2**

PUMP NO. **227693**

PERFORMANCE

G.P.M. **1700**

FT. FIELD HD. **1000**

R.P.M. **1785**

800 H.P. 1800 R.P.M. 400 VOLTS

3 PHASE 60 CYCLE 58108 FRAME

U.S. MFG WP-1 TYPE

LETTER	DIMENSION	LETTER	DIMENSION
A	20.94	H	33.00
B	12.75	H	36.00
C	20.00	O	15.00
D	22.00	P	20.69
E	53.00	Q	2.62
F	16.00	R	2.5
G	30.94	S	13.62
H	1.50	T	4.54
I	159.94	U	6.00
J	133.94	V	11.00
K	15.00	W	11.00

ALL BOWL BRGS MTL WAS 220 BRZ. PART NOS 4-14 OF BRGS WERE 2623256, 2623255, 2623241, 2623240, 2623239, 2623238, 2623237, 2623236, 2623235, 2623234, 2623233, 2623232, 2623231, 2623230, 2623229, 2623228, 2623227, 2623226, 2623225, 2623224, 2623223, 2623222, 2623221, 2623220, 2623219, 2623218, 2623217, 2623216, 2623215, 2623214, 2623213, 2623212, 2623211, 2623210, 2623209, 2623208, 2623207, 2623206, 2623205, 2623204, 2623203, 2623202, 2623201, 2623200, 2623199, 2623198, 2623197, 2623196, 2623195, 2623194, 2623193, 2623192, 2623191, 2623190, 2623189, 2623188, 2623187, 2623186, 2623185, 2623184, 2623183, 2623182, 2623181, 2623180, 2623179, 2623178, 2623177, 2623176, 2623175, 2623174, 2623173, 2623172, 2623171, 2623170, 2623169, 2623168, 2623167, 2623166, 2623165, 2623164, 2623163, 2623162, 2623161, 2623160, 2623159, 2623158, 2623157, 2623156, 2623155, 2623154, 2623153, 2623152, 2623151, 2623150, 2623149, 2623148, 2623147, 2623146, 2623145, 2623144, 2623143, 2623142, 2623141, 2623140, 2623139, 2623138, 2623137, 2623136, 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HYDRAULIC PERFORMANCE WARRANTY

Guaranteed at designated point only and is contingent on

1. Proper and adequate flow to pump section.
2. Proper submergence and NPSH available.
3. Fluid free of gas, air and abrasive matter.
4. Impeller with proper lateral adjustment.

PEERLESS PUMP DIVISION FMC CORPORATION

Los Angeles, California 90031 • Indianapolis, Indiana 46208
FOR: C. F. BRAUN & CO ITEM P-2
BRINE REINJECTION PUMP

CURVE NO 227693
PUMP TYPE 14HH-15LC
COLUMN _____
BOWL 2728129 STAGES 8-15LC
RPM 1775 IMPELLER NO 8-2625230
PUMP NO 227693 S/O NO V13772

CERTIFIED CORRECT
AND APPROVED
BY [Signature]
DATE FEB 21, 1974
PEERLESS PUMP

PROJECT 4691 ITEM P-2
100-1311C-14 REV 1

PLOTTED BY 897 FROM TEST NO. 51419

DATE 2-21-74

FORM E-1

4.1.3 Operation

From May 3 through August 31, 1976 the brine re-injection pump was operated for 414 hours. The following text presents its performance during that time period.

History

On May 3, 1976 the pump was first placed in service to inject brine into Magmamax No. 3. The supply of geothermal fluid to the facility was from Magmamax No. 1. The pressure at the pump suction was between 0 and 5 psig and a corresponding temperature range of 213° F to 225° F. The brine total dissolved solids was about 280,000 ppm.

The pump was also utilized to pump irrigation water (Colorado River water) to prime the producing well and/or the injection well. The irrigation water conditions at the pump suction were 0 psig pressure and ambient temperature.

At all times during the operation of the brine injection pump the acceptable range of suction conditions was maintained.

Prior to initial operation of the pump, the SDG&E/ERDA task force for startup recommended modifying the pump to increase the acceptable suction temperature rating from 260° F to 305° F. The pump was sent to Peerless for this modification. Carbon bearings were used to replace the SAE 660 bronze ones and the shaft-to-bearing clearances were

increased from .010 inch (diametral) to .012 inch. The May 3 startup and subsequent operation through June 16 of the brine reinjection pump was with these carbon shaft bearings.

Throughout the operation time from May 3 through June 16 the brine reinjection pump did not cause or result in a shutdown of the Geothermal Loop Experimental Facility. This amounted to 290 hours of operation.

The operation of the pump during the period of August 9 through August 16 was intermittent. Two shutdowns of the GLEF were made to repair the pump shaft and shaft bearings. The first shutdown occurred on August 12 due to a sheared shaft just above the pump's fourth impeller, from the lower most impeller. The effect of this failure was indicated by a pump discharge pressure reduction from normal of 600 psi to 375 psi. On August 21, the GLEF was shut down a second time for the same reason but in this case the shaft had fractured at the ninth impeller in the shaft bearing. In this instance, all nine stages of the pump were parted from the motor and the discharge pressure was zero.

A two-week shut down of the GLEF resulted from the last pump failure. During this time a meeting was held to discuss the operating history of the pump and review these two shaft/bearing failures. A thorough discussion of the failures, findings and recommendation are covered in the next section of this report.

At the time of the two shaft failures, operating conditions were within the acceptable limits specified by the manufacturer.

Performance

During all GLEF operations, the pump discharge head and capacity followed the manufacturers curves. This, of course, is only true other than at the time of the shaft failures.

Pump vibration, discharge pressure stability were normal. Motor Amperage was observed as specified by the manufacturer.

Conclusion

- a. When the pump was operating, rated discharge head and capacity were achieved.
- b. Vibration when the pump was operating was normal.
- c. Discharge pressure was stable.

4.1.4 Maintenance

This section deals with the work done on the brine reinjection pump during the period of June 16 through August 31, 1976. This mechanical work was focused on the shaft and bearings.

June 17 through August 8

On June 17 the brine reinjection pump was delivered to the SDG&E machine shop and disassembled and inspected. Each of the nine stages were removed and the bowls, impellers and bushings inspected. The shaft, discharge head were cleaned and inspected.

The carbon bearings were in poor condition. Much of the bearing was missing, either because of corrosion or erosion. The Carpenter 20 bowls and impellers were lightly sandblasted and subsequently inspected for corrosion/erosion. None was found. The wear rings were in excellent condition also showing no signs of wear. The Monel K Shaft was scored in the areas where the shaft rotated in the carbon bearings. The discharge head and shaft column were in good condition. Refer to Figure 6 for a view of these components.

Corrective Action

Carbon bearing material was replaced with Type 416 stainless steel hardened to Rockwell C 60. The Monel K

MAT'L:

SHAFT	K-MONEL
BEARING	CARBON
BOWL	CARPENTER 20

SHAFT BEARING (TYPICAL) SECTION
BRINE INJECTION PUMP

FIGURE 6

shaft was provided with a ceramic coating at each of the bearings as shown in Figure 6A. A specification for the coating is presented in Appendix A.

Seal water was provided to each bearing as shown in Figure 7. The seal water was provided to minimize the scoring of the shaft surface at each bearing caused by handling the brine. The seal water is provided by the purge water system installed in the GLEF initially. A chemical analyses of the purge water, brine and scale is presented in Appendix C.

August 9 through August 12

On August 9 the brine injection pump was in service again with the above modifications and was removed from service on August 12 due to the sheared Monel K shaft. Once again the SDG&E machine shop disassembled the pump for inspection and repair.

The Monel K shaft had fractured just above the fourth bowl from the bottom of the pump. The ends of the shaft had been overheated at the point where the fracture had occurred due to friction. The shaft was sent to Lawrence Livermore Laboratory for further examination.

MAT'L:

SHAFT K-MONEL

BEARING 416 SS

BOWL CARPENTER 20

SHAFT - BEARING (TYPICAL) SECTION
BRINE INJECTION PUMP

4.2 CONTROLS

This section covers primarily the brine level and pressure control elements as well as the modifications associated with each of them. In addition two other critical control modifications to the well production and vent gas systems of the GLEF will be mentioned and described.

4.2.1 Brine Level Controls

The brine separator level control consisted of the ultrasonic level indicating probe connected electrically to the probe's power supply, to a current-to-pneumatic converter, a Fisher Multitrol and finally the actuator of the level control valve operator. This type of control as set up in this manner is an on-off type signal control. As the probe is covered, on rising level in the separator, the signal to the valve is to open. Likewise, as the probe is uncovered, on decreasing level in the separator, the pneumatic signal to the level control valve is to close.

All four stages of brine/steam separators in the GLEF were provided with this type of control initially. A level control valve for each separator is located in the brine drain line from each separator as shown in ME 5651, Appendix A.

With the exception of the first stage separators, the level control valves also to some extent control pressure. The first stage separators also have a pressure control valve, to control pressure. This valve is located upstream of the separators. Valves are located in the steam lines between the stage heat exchangers and scrubbers, however, these are manually operated and once their positions are set at a given well mass flow no further adjustments are required. Therefore, only oscillations of the level control valve affect stage pressure, all other system parameters being constant.

During initial operations through June 16, 1976 the time response of the valve was such that pressure fluctuations were observed to be 30 percent of the pressure level for the second, third and fourth stages. The first stage pressure fluctuations were about 7 percent. Pressure control in the first stage resulted in the lower percentage pressure fluctuation although level fluctuations were about the same, 0 to 12 inches, in all stages.

Level control of the plant's stages was improved with the installation of electrical capacitance in the ultrasonic level control circuit. This capacitance increased the time response of the electric signal actuating an electrical-to-pneumatic converter and thus the pneumatic signal which drives the level control valve. Resulting pressure fluctuations in

the separators was reduced from 30 psi to about 10 psi in the second stage and from 10 psi to 3 psi in the fourth stage. The third stage was out of service for foundation repairs, however, when it was operating, pressure fluctuations were about 20 psi.

The ultrasonic level control scheme has been modified to a proportional control from simply an off-on one. This was accomplished by increasing the number of control probes from one to six and installing a simple electric circuit which adds the electric signal of each ultrasonic probe in succession as the probes are covered by liquid.

A second type of proportional control tested was differential pressure. An adjustable range of 0-100 inches of water to 0-750 inches of water controller manufactured by Fisher Controls and appears to be a viable method for proportional control of the level control valves.

A third type of proportional control tested in the first stage level control was a Fisher Level-Trol, a float device. Purge water at a rate of 65 gph was supplied to this unit to prevent sluggish float action or complete loss of float action due to scale deposition between the float and float column. The radial clearance between the float and column is about 1/32 inch.

The three, candidate, proportional, level controls performed very well during this latest operation. Pressure fluctuations in each stage were reduced to an amplitude of about 2 percent or less of the stage pressure.

4.2.2. Production Well Back-Pressure Protection

Additional control was added to the first stage of the GLEF to protect the producing well or wells from over production. This control serves to override the first stage pressure control by sensing well pressure upstream of the GLEF. A cutback signal from the well back pressure controller, once the well pressure set point is reached, takes over control of the first stage pressure control valve and, as a result, limits production.

A schematic of this control system is presented in Figure 7.

4.2.3 Vent Gas System Control System

The initial control for the vent gas system consisted of temperature control of the vent gas separator used to reset pressure of the first stage separators. In this case, production well backpressure was controlled, with no direct control of first stage pressure.

ITEM	QUAN	MATERIAL LIST
①	1	HAGEN RATIO TOTALIZER WITH SPRING CHAMBER RC 301A
②	1	HAGEN RATIO TOTALIZER RC 301B
③	1	VOLUME CHAMBER
④	1	NEEDLE VALVE
⑤	1	FILTER REGULATOR G7FR
⑥	1	PRESS. TRANSMITTER FOXBORO 44BP
⑦	1	PANEL LOADER SERIES G70
⑧	1	AIR SWITCH #38360
⑨	3	1/2" BRASS GATE VALVE
⑩	9	1/4" BRASS TEE
⑪	6	1/4" TUBE x 1/8" NPT MALE CONNECTOR
⑫	35	1/4" TUBE x 1/4" NPT MALE CONNECTOR
⑬	3	1/4" TUBE x 1/2" NPT MALE CONNECTOR
⑭	-	1/2" GALV. PIPE
⑮		1/4" OD COPPER TUBING

THE BEN HOLT CO.				
TITLE BRINE CONTROL SYSTEM				
CUSTOMER SDG&E MILAND				
DRAWN BY	SCALE	DRAWING NO.	REV.	
APPROVED	DATE			

FIGURE 7

It was determined that this scheme would not work. The new vent gas control system is shown in Figure 7A. In this system the venting of the inert gases will be controlled by temperature in the vent gas separator. The temperature control valve is reset by the first stage pressure control.

Other modifications of the vent gas system and the first stage heat exchangers' condensate drain to allow the new vent control system to work properly are:

1. The condensate drain line (6"-SM6-AC) from the first stage heater E-2 will no longer connect to V-6 but instead connect directly to condensate piping (3"-SC6-AA) and drain direct via E-5 and LCV-702.
2. A hot well and level controller will be installed directly on E-2 heater to control liquid level in E-2 by LCV -702.
3. The present 1 1/2" vents from E-3 and E-2 with an additional vent line will all be routed directly to V-6.
4. Any condensation in V-6 will drain through a level control valve or trap via line 3"-SC8-AA to the 2nd stage separator (V-7).

The modifications are presently being installed and should be in operation by mid-October.

MATERIAL LIST

ITEM QTY

- 1 1 HAGEN RATIO TOTALIZER WITH SPRING CHAMBER RC-513
- 2 1 PANEL LOADER SERIES 670
- 3 1 AIR SWITCH #38360
- 4 1 FILTER REGULATOR 67FR
- 5 3 1/2" BRASS GATE VALVE
- 6 4 1/4" BRASS TEE
- 7 2 1/4" TUBE x 1/8" NPT MALE CONNECTOR
- 8 24 1/4" TUBE x 1/4" NPT MALE CONNECTOR
- 9 3 1/2" TUBE x 1/2" NPT MALE CONNECTOR
- 10 - 1/2" OD COPPER TUBING
- 11 - 1/2" GALV. PIPE

THE BEN HOLT CO.			
TITLE VENT CONTROL SYSTEM AT V-6 & V-6A			
CUSTOMER SDG&E		NILAND	
DESIGNED BY	SCALE	DRAWN BY	REV
APPROVED	DATE		

DATE	REVISION	DR	CH	DATE

5.0 SYSTEM CHEMISTRY

5.1 Introduction

This section discusses the chemistry of the GLEF. For convenience the GLEF was divided into five separate sections: steam and condensate system, brine system, purge water system, vent gas system, and cooling water system. An insight into the chemistry of each system is provided by analysis of samples taken. Scaling and corrosion effects of brine, steam, gas and water in these systems are described in detailed. The problems encountered and possible corrective measures, are presented.

5.2 Steam and Condensate System

The quality of the steam volitalized from the geothermal fluid is a crucial element for proper functioning of the GLEF. If the steam carried through the heat exchangers contains large quantities of solids or corrosive elements, the efficiency of the heat exchangers will decrease. Generally, during steady state operation of the plant, steam quality has been good. Dissolved solids, estimated from sodium content, are 20 ppm or less. Overall, the total solids carried through the steam system average 100 ppm or less.

The steam also contains large quantities of gases. The majority of these gases are carbon dioxide and ammonia. Carbon dioxide when dissolved in water forms a corrosive acid (carbonic acid) which can attack carbon steel. Ammonia

is also highly corrosive to copper and zinc bearing metals forming soluble ammonium compounds. Thus, these gases problems in the steam system such problems can be minimized by proper gas venting in the first stage.

During GLEF operation, samples of steam flowing from the flash vessel into and out of the scrubbers were taken. Sampling of the four stages was accomplished through one inch steel pipe lines attached to the major steam transfer lines. The steam sample coming through the one inch pipe was condensed in a cooling coil consisting of a three-eighth copper tube containing the sample and a concentric one inch steel pipe containing the cooling water. These coils condensed the steam samples and lowered the sample temperature to approximately 27°C.

Two sampling points, into and out of the scrubber, existed for the first through third stages. However, only a condensate sampling point was available on the fourth stage. This is because the 4th stage is operated under a vacuum. The sample taken, therefore, was the condensed steam from the fourth stage heat exchanger. This condensate is pumped to the cooling pond or brine reinjection line and the sample taken at the positive pressure side of the pump. The geothermal fluid entering the plant and the brine exiting from each stage was also so sampled using a cooling coil. Fourth stage brine was sampled at the exit of the reinjection pump.

As the geothermal fluid passes through the four stages of the test loop the steam showed definite chemical trends. The most common properties and major chemical elements of the condensed steams are listed in Table 1. From this data some conclusions may be drawn regarding the chemical mechanisms in the steam.

The pH values of the steam increase from the first to the third stage then decreases in the fourth stage condensate. The ammonia concentration in the steam during the first time period (August 9 to August 11) decreases through the test loop in the following order: first stage to third to fourth to second. During the second period (August 17 to August 19) the ammonia decrease followed a different order: first stage to second to fourth to third. Dissolved carbonate and bicarbonate concentrations indicate the amount of carbon dioxide mixed within the steam. The concentrations of these species decrease steadily from the first to the third stage, followed by an increase in the fourth stage.

Since both dissolved ammonia and carbonate dictate pH values in pure solutions, a similar action can prevail in the steam system. With a decrease in carbonate through the system its ability to lower the pH of the steam is lessened. The action of ammonia can be seen by observing the steam entering and exiting the scrubber. Where the ammonia concentration drops, the pH is lowered. The pH of approximately 6 in the first stage can be attributed to not only the dissolved

Table 1		GLEF Steam Parameters			August 10, 1976				
Sample	Conductivity	pH	ORP	Cl	Total Solids	Alkalinity CO ₃	HCO ₃	(As CaCO ₃) OH	Ammonia Nitrogen
	umho/cm ³		MV	mg/lit	mg/lit	mg/lit	mg/lit	mg/lit	mg/lit
1st Stage steam scrubber in	3,800	6.20	-232	13	105	ND	1,870	ND	510
1st stage steam scrubber out	2,000	6.10	-242	11	30	ND	1,190	ND	290
1st stage brine out	415,000	6.10	- 92	142,800	--	--	---	--	390
2nd stage steam scrubber in	890	9.10	-200	146	40	1,040	ND	ND	250
2nd stage steam scrubber out	790	8.95	-242	113	30	660	ND	80	210
2nd stage brine out	460,000	6.05	- 55	157,200	--	---	--	--	395
3rd stage steam scrubber in	730	10.20	-350	510	340	400	ND	1,610	490
3rd stage steam scrubber out	430	9.50	-140	254	20	780	ND	630	350
3rd stage brine out	500,000	5.95	- 25	164,400	--	--	--	--	340
4th stage steam scrubber out	1,850	8.70	- 20	113	40	760	550	ND	350
Reinjection brine	370,000	6.30	- 86	120,000	--	--	--	--	--

Table 1 (cont.)

Table 1 (cont.)			August 11, 1976								
Sample	Conductivity	pH	ORP	Cl	Total Solids	Alkalinity		(As CaCO ₃)	Ammonia Nitrogen	Na	Ca
	umho/cm ³					CO ₃	HCO ₃	OH			
			MV	mg/lit	mg/lit	mg/lit	mg/lit	mg/lit	mg/lit	mg/lit	mg/lit
1st stage steam in	2,500	6.05	-190	13	200	ND	1,440	ND	295	6.5	2.4
1st stage steam out	2,200	6.05	-220	7	128	ND	1,190	ND	265	1.5	0.5
1st stage brine out	440,000	5.75	- 88	--	---	--	---	--	385	--	--
2nd steam in	740	8.90	-200	100	111	820	130	ND	225	1.1	2.3
2nd steam out	700	8.85	-223	91	118	700	90	ND	190	1.2	0.4
2nd brine out	475,000	5.80	- 64	---	---	---	--	--	385	--	--
3rd steam in	230	9.75	-178	275	127	620	ND	660	310	1.7	1.5
3rd steam out	350	9.45	-136	155	99	580	ND	290	210	0.6	0.3
3rd brine out	487,500	5.80	- 19	--	---	---	--	---	390	--	--
4th steam out	2,500	7.40	- 5	6	122	ND	1,270	ND	320	1.8	1.5
Reinjection brine	360,000	6.25	- 82	--	---	---	---	---	340	--	--

Table 1 (cont.)

		August 17, 1976								
Sample	Conductivity	pH	ORP	Cl	Total Solids	Alkalinity		(As CaCO ₃)	Ammonia Nitrogen	Na
	umho/cm ³		MV	mg/lit	mg/lit	CO ₃	HCO ₃	OH		
Well brine	375,000	5.75	- 45	130,800	---	---	---	---	370	---
1st stage steam scrubber in	2,400	6.45	-217	---	170	ND	1,120	ND	260	17
1st stage steam scrubber out	2,100	6.50	-205	---	58	ND	1,100	ND	240	3.0
1st stage brine out	415,000	5.60	- 90	145,200	--	--	---	--	370	---
2nd steam in	1,520	9.80	- 22	---	302	600	ND	130	250	47
2nd steam out	6,300	9.00	- 26	---	3,440	280	ND	40	195	700
2nd brine out	460,000	6.06	- 63	157,200	---	---	---	--	340	---
3rd steam in	280	10.55	-244	---	68	280	ND	290	140	3.0
3rd steam out	470	10.45	-187	---	27	380	ND	220	140	2.5
3rd brine out	470,000	6.20	- 86	161,300	---	---	---	--	415	---
4th steam out	1,960	7.55	- 19	---	139	ND	970	ND	225	23
Reinjection brine	385,000	6.25	- 95	124,800	---	---	---	--	340	---

Table 1 (cont.)

August 18, 1976									
Sample	Conductivity	pH	ORP	Cl	Total Solids	Alkalinity CO ₃	HCO ₃	(As CaCO ₃) OH	Ammonia Nitrogen
	umho/cm ³		MV	mg/lit	mg/lit	mg/lit	mg/lit	mg/lit	mg/lit
Well brine	415,000	5.35	- 1	132,000	---	---	---	---	365
1st stage steam scrubber in	2,200	6.85	-33	---	10	ND	1,180	ND	275
1st stage steam scrubber out	2,050	6.65	-69	---	1.8	ND	1,140	ND	260
1st stage brine out	440,000	5.80	-81	156,000	---	---	---	---	375
2nd steam in	900	9.50	-138	---	3.6	600	ND	140	200
2nd steam out	710	9.70	-142	---	1.5	640	ND	120	200
2nd brine out	495,000	6.25	- 83	165,000	---	---	---	---	380
3rd steam in	158	10.35	-298	---	1.5	160	ND	340	130
3rd steam out	163	10.65	-209	---	1.3	120	ND	380	135
3rd brine out	500,000	6.20	- 57	120,000	---	---	---	---	390
4th steam out	1,420	9.15	-107	---	1.1	720	640	ND	310
Reinjection brine	410,000	6.50	-117	130,000	---	---	---	---	310

Table 1 (contd.)

August 19, 1976

Sample	Conductivity	pH	ORP	Cl	Na	Total Solids	Fe
	umho/cm ³		MV	mg/lit	mg/lit	mg/lit	mg/lit
Well brine	410,000	5.55	-16	139,200	---	---	---
1st stage steam scrubber in	2,300	6.45	-128	---	5.5	97	41
1st stage steam scrubber out	1,870	6.30	-119	---	1.4	75	21
1st stage brine out	455,000	5.65	- 85	146,400	---	---	---
2nd steam in	1,140	9.40	-134	---	46	196	0.5
2nd steam out	680	9.30	-139	---	1.4	25	1.1
2nd brine out	495,000	6.35	-83	151,200	---	---	---
3rd steam in	220	10.15	-272	---	11	80	0.6
3rd steam out	152	10.00	-180	---	1.8	25	3.4
3rd brine out	492,500	6.55	- 61	148,800	---	---	---
4th steam out	2,600	7.75	-54	---	1.2	16	0.2
Reinjection brine	370,000	6.53	-109	117,600	---	---	---

carbon dioxide, but also the presence of hydrogen sulfide and its associated atomic hydrogen. With the rise of dissolved carbonates in the fourth stage condensate, the pH is again lowered.

Oxidation-reduction potentials (ORP) also offer an insight into the chemical mechanisms in the steam. Throughout the system the steam is a reducing fluid because of the lack of oxygen in the brine. From August 9 to August 11, the most reducing steam was found in the first stage followed by the second, third, then fourth. From August 17 to August 19 the ORP almost reversed with the third stage exhibiting higher reducing than the second, first, and fourth. These values cannot be related to any particular element in the steam, except that it must be one of the more volatile elements within the geothermal fluid which can be carried over with the steam. Thus a general decrease in the ORP of the flashed brine as it flows through the test facility is observed.

The solids content of the steam is one of the most important elements in the GLEF operation. If large amounts of solids are carried over with the steam, the efficiency of the heat exchangers will be severely reduced because of scaling. During steady state operation, the amount of solids entrapped in the flashing steam was very low. Some representative values can be seen in Table 1. Estimating the dissolved solids content of the steam from conductivity

values is not possible due to the high content of dissolved gases in the steam. Conductivity values can only be used to indicate upsets in the system. Sodium is one element which shows promise for estimating steam purity. Other major cations and anions seen in the steam are ammonium, sodium, calcium, iron, carbonate, bicarbonate (carbon dioxide in the vapor phase), hydroxyl, chloride, and sulfide. Representative values of these species are listed in Table 1. Qualitative observation indicate the majority of the sulfides occur in the first stage steam. A large amount of iron is also found in the first stage mostly as particulate iron sulfide.

With little brine carry-over the steam supplied to the scrubbers and heat exchangers should not cause a great amount of scaling. This was confirmed by inspection of the first through third stage scrubbers following the first series of start up tests. The heat exchangers were not disassembled. However, no scaling was noted in the parts which were accessible for observation. The scale observed in the scrubbers contained large amounts of iron and appeared to be primarily a corrosion product formed after the scrubber was opened and the surface exposed to the atmosphere. Lesser amounts of other elements observed were probably deposited from brine carried over during plant upsets. An elemental analysis of the deposits found in the first and second stage scrubbers is given in Table 2. Little deposition was observed in the third stage scrubber.

TABLE 2

STEAM SYSTEM SCALE ANALYSIS

Element	1st Stage Scrubber	2nd Stage Scrubber	Condensate Pump (P-9)	4th Stage Heat Exchanger
Color	Black with red streaks	Black with red streaks	Black	Layers of white and gray
Thickness	0.5-1mm	0.5mm or less	2-5mm	2-3mm
Iron %	55.28	49.14	4.82	0.49
Copper %	0.07	0.00	0.01	ND(0.005)
Zinc %	0.55	0.90	0.51	1.00
Manganese %	1.48	2.40	2.13	0.73
Lead %	1.19	0.65	0.37	0.05
Calcium %	1.13	0.56	30.86	39.88
Aluminum %	ND(0.05)	ND(0.05)	ND(0.05)	ND(0.05)
Silicon %	3.82	7.50	0.20	ND(0.01)
(as SiO ₂) %	8.17	16.05	0.43	--
Barium %	ND(0.01)	ND(0.01)	0.04	0.05
Magnesium %	0.15	0.18	0.03	Trace(0.01)
Sulfur %	ND(0.1)	ND(0.1)	0.60	ND(0.1)
Carbonate %	ND	ND	45.0	57.3

The fourth stage scrubber and heat exchanger were the only two steam handling vessels in which significant scale deposits were observed. Elemental analysis of these scales are also given in Table 2. The majority of this scale is calcium carbonate. Calcium carbonate scale can be formed if brine (containing large amounts of dissolved calcium) contacts condensate (containing large amounts of dissolved carbonates).

Severe liquid carry over (brine) from the 4th stage separator occurred during start up. Since the second and third stage condensates with their associated dissolved carbonates are added to the 4th stage scrubber, calcium carbonate formation would be expected. The liquid carry over extended into the 4th stage heat exchanger, and, because of poor drainage, flooded the heat exchanger. This caused heavy scaling of the heat exchanger (Figure 8 and 9).

As noted above, carbonate scale was not observed in the first three scrubbers. This lack is attributed to the predominance of the vapor phase in these vessels. Any carbon dioxide is present as a gas and in this form does not react readily with the low pH (acid) brine. However, when CO_2 dissolves in the condensate and becomes a carbonate it can react with the brine to form metal carbonates.

The carbonate scale was removed from the heat exchanger by chemical cleaning. Inhibited hydrochloric acid at ambient temperature was circulated through the heat

FIGURE 8

exchanger for approximately 8 hours. Complete removal of the carbonate scale was achieved (Figure 10). A detailed description of this first descaling effort is presented in Appendix B. Scale in the scrubber was removed mechanically using a hose and high pressure water.

Chemical problems of the steams and condensates are primarily associated with the gases also liberated during the flashing process. The steam is highly corrosive to mild steel, especially in the first stage where the gas concentrations are high. The use of this steam in a turbine could induce early failure. However, for use in the binary system, the quality of the steam appears adequate. Long term analysis of plant operations are needed to conclusively document the conclusions drawn in this section. Such analysis show that some of these parameters are not detrimental to operation of the GLEF.

5.3 Brine System

The geothermal fluid from Magmamax No. 1 used in the GLEF is a composite of noncondensable gas, liquid, and vapor. The cooled liquid has a total solid content of between 200,000 and 225,000 ppm. The brine is basically an alkali chloride fluid contaminated with heavy metals. It is also reducing as seen in Table 1 and highly corrosive, due to its various salts, low pH, and gases. When allowed to cool or concentrate the brine will form scale on most sur-

FIGURE 10

faces. An elemental analysis of brine from Magmamax No. 1 is presented in Table 3. These elemental values do fluctuate, but ratios of the major elements in the fluid generally remain constant.

The brine handling system (those components which normally come in contact with the brine) is predominantly carbon steel, although some valves are stainless steel and the second stage separator is stainless steel clad. The brine system from the first to fourth stage seems resistant to corrosion from the brine, even when concentrated through water loss by steam flashing. An erosion-corrosion reaction did cause failure of a pipe elbow located just after the first stage inlet pressure control valve. This failure occurred during start up testing and was attributed primarily to erosion. Although some corrosion, substantiated by the high iron content (22% Fe) of the removed scale, did occur. Subsequently, the valve was as changed to reduce the possibility of generating a high velocity jet and moved into a straight section of line to prevent impingement of a contacting surface. No further erosion-corrosion has been observed.

Brine samples were taken at a number of points in the brine system. These were analyzed and the results presented in Table 4.

From these analyses some observations may be made concerning selected elemental precipitation. Between the first and second stage a substantial drop in lead concentra-

TABLE 3
PRODUCTION WELL

(Magmamax No. 1) Brine Analysis

July 26, 1976

<u>Element</u>	<u>Concentration mg/l</u>
Sodium	43,000
Potassium	7,550
Calcium	22,300
Magnesium	105
Lithium	170
Strontium	460
Iron	220
Manganese	420
Copper	2.5
Zinc	105
Lead	16
Barium	130
Silicon	205
Chlorides	115,200
Ammonia	335
Total Solids	215,000
Phosphorous	ND (2mg/lit)

TABLE 4

Brine System Fluid Analysis

August 17, 1976

Element	Plant Inlet mg/lit	1st stage out mg/lit	2nd stage out mg/lit	3rd stage out mg/lit	Reinjection mg/lit
Sodium	48,300	56,000	60,400	63,700	49,400
Potassium	10,800	12,500	13,100	13,400	10,800
Calcium	10,100	11,100	13,100	13,100	10,100
Chloride	130,800	145,200	157,200	161,300	124,800
Iron	325	350	345	380	325
Manganese	380	430	480	460	370
Lead	105	80	85	95	60
Zinc	250	305	330	340	255
Copper	0.6	1.2	1.3	2.0	0.9
Silicon	225	225	238	225	195
Barium	140	145	160	190	125
Total Dissolved Carbonate	245	32	ND(10)	ND(10)	230

tion occurs. This is particularly significant since solvent (water) losses cause the concentration of all other elements to increase. Other elemental ratios indicate precipitation of silicon throughout the system, loss of iron between the second and third stage, and a large loss of lead in the test loop. Continued operation of the GLEF is expected to provide more conclusive evidence on selective precipitation in the brine.

This precipitation can create serious problems. It can occur anywhere in the brine system and can coat and freeze moving parts in contact with the brine. Thus seizing was observed during the start up tests in several valves, including 301, 714, 718 and the reinjection check valve.

In an effort to gain a better understanding of brine scaling in the GLEF a number of scale samples were taken throughout the brine system (Figure 11) following the first series of start up tests (May 4 through June 30). These samples were analyzed and the results are summarized in Table 5 and 6. Table 5 presents elemental analyses of the scale samples taken from the brine lines connecting the separators while Table 6 presents elemental analysis of samples taken from within the flash vessels. Although every effort was made to obtain representative scale samples, it is not known how well they represent deposits in the entire line or vessel.

T=TABLE
SECOND NUMBER=TABLE NO.
LETTER=SAMPLE NO.

GEOHERMAL LOOP EXPERIMENTAL FACILITY SCALE SAMPLE LOCATIONS

FIGURE 11

TABLE 5

BRINE LINE SCALE ANALYSIS
June-July 1976

T5A: eroded elbow - 1st stage brine inlet line
 T5B: sediment from bottom of 1st stage separator
 T5C: valve in line from 1st stage separator
 T5D: 2nd stage inlet valve (FCV 711)
 T5E: pipe to 4th stage separator
 T5F: LCV 714
 T5G: reinjection line at Magmamax 3

Code and Location of Scale	T5A	T5B	T5C	T5D	T5E	T5F	T5G
Color	black/ blue white streaks	gray	multi- colored	black with rust	multi- colored	white	brown and red
Thickness	2-4mm	sardy	2-5mm	1mm	2-4mm	3-5mm	less than 1mm
Iron %	22.30	3.73	15.59	9.05	8.82	3.89	21.35
Copper %	0.69	0.03	0.08	2.24	0.54	0.17	0.13
Zinc %	0.02	3.53	0.06	0.10	0.32	0.10	0.02
Manganese %	0.58	0.29	1.54	1.34	2.11	0.38	1.52
Lead %	52.32	13.69	19.01	10.61	2.11	0.82	3.90
Calcium %	0.28	7.53	0.80	0.84	4.01	0.66	2.82
Aluminum %	0.32	1.74	0.40	1.42	0.40	ND(0.05)	ND(0.05)
Silicon %	4.02	14.70	11.05	16.07	27.37	42.86	26.51
(as SiO ₂) %	8.60	31.46	23.64	34.34	58.84	91.71	56.72
Barium %	ND(0.05)	0.09	ND(0.05)	ND(0.05)	0.92	0.09	0.92
Magnesium %	0.12	1.30	0.35	0.12	0.40	0.02	0.04
Sulfur %	8.5	4.4	5.9	ND	0.7	ND	ND

TABLE 6

FLASH VESSEL SCALE ANALYSIS

June-July 1976

T6A: 1st stage separator - above fluid level
 T6B: 1st stage separator - below fluid level
 T6C: 2nd stage separator inspection port
 T6D: 3rd stage separator - above fluid level
 T6E: 3rd stage separator - below fluid level
 T6F: 4th stage separator - above fluid level
 T6G: 4th stage separator - below fluid level

Code and Location of Scale	T6A	T6B	T6C	T6D	T6E	T6F	T6G
Color	green/ black/ rust	multi- colored	black and gray	multi- colored	multi- colored	black/ olive	multi- colored
Thickness	1-5mm	2-3mm	1mm or less	1-3mm	2-5mm	2-3mm	2-4mm
Iron %	27.47	20.19	24.39	12.10	5.59	7.34	1.37
Copper %	0.28	0.08	0.17	0.22	0.25	1.92	0.12
Zinc %	0.61	0.41	0.42	0.21	3.00	0.28	0.09
Manganese %	2.18	1.44	0.54	0.52	0.65	2.09	0.10
Lead %	2.50	3.68	0.93	1.05	6.05	0.77	0.20
Calcium %	1.17	1.79	0.14	0.49	1.63	1.31	0.33
Aluminum %	0.30	0.45	0.14	0.17	0.76	0.11	ND(0.05)
Silicon %	14.47	13.16	17.65	29.49	20.51	27.16	38.46
(as SiO ₂) %	30.97	28.16	37.77	63.11	43.89	58.12	82.30
Barium %	ND(0.01)	ND(0.01)	ND(0.01)	ND(0.01)	0.09	ND(0.01)	0.04
Magnesium %	0.58	0.61	0.24	--	--	0.02	ND(0.005)
Sulfur %	0.8	1.1	ND	ND	ND	ND	ND

General trends appear to exist for scaling within the brine loop. Sulfide scaling is apparent in the first stage before venting of the noncondensable gases. The most prevalent sulfide scale appears to be galena (lead sulfide). This scale is found exclusively in the line leading to the first stage separator. Lead also appears to be selectively deposited in areas of high flow velocity, such as the well line, the reinjection pump shaft, and around the reinjection check valve. As the brine flows through the plant it appears to deposit less silicon and more iron and lead. Thus an increase in silicon and decrease in the iron and lead content of the scale taken from the brine line connecting the first through the fourth stage was observed. Within the flash vessels (separators) the scale deposited above the normal liquid level contained more iron than the scale in contact with the brine. This implies that the noncondensable gas and water vapor above the brine is more corrosive than the brine itself. The stainless steel liner in the 2nd stage flash vessel (separator) showed no corrosion and limited scaling. More observations are needed to define precisely the corrosion and scaling mechanism.

Tables 7 and 8 demonstrate a phenomena that had not been previously predicted. During the first series of start up tests the steam condensate was not reinjected but pumped to the cooling water pond. This allowed the brine concentration to increase and resulted in the deposit of a

TABLE 7

REINJECTION SCALE

T7A: discharge nozzle reinjection pump (6/9)
 T7B: past check valve near reinjection pump in high flow area (6/9)
 T7C: LCV 718 (6/17)
 T7D: bottom of shaft housing entrance to impellers, highflow area (6/17)
 T7E: reinjection pump discharge nozzle (6/18)
 T7F: FCV 718A (6/21)
 T7G: impeller of reinjection pump (8/12)
 T7H: reinjection pump discharge nozzle (8/22)
 T7I: upper shaft of reinjection pump (8/22)

	Before Condensate Reinjection				After Condensate Reinjection				
Sample	T7A	T7B	T7C	T7D	T7E	T7F	T7G	T7H	T7I
Color	white	white	white	black	white/ gray	gray/ green	white/ yellow	gray	tan/ gray
Thickness	15mm	5-10mm	3mm	2-4mm	4-6mm	3-4mm	1-2mm	1-2mm	1-2mm
Iron %	1.67	1.42	0.95	5.65	9.30	10.46	21.90	7.47	2.14
Copper %	0.24	0.17	0.08	5.54	0.05	0.15	0.05	0.08	0.26
Zinc %	0.09	0.09	0.07	0.50	0.38	0.40	0.80	0.92	0.78
Manganese %	0.11	0.10	0.16	2.98	2.99	3.43	3.65	4.69	3.09
Lead %	1.15	8.14	0.56	22.92	1.32	1.05	0.76	1.11	35.16
Calcium %	0.65	0.50	1.36	3.58	4.81	3.21	13.17	21.78	12.89
Aluminum %	ND(0.05)	ND(0.05)	ND(0.05)	ND(0.05)	ND(0.05)	ND(0.05)	ND(0.05)	0.10	ND(0.05)
Silicon %	34.62	34.62	38.39	15.11	23.00	21.00	8.50	16.05	11.93
(as SiO ₂) %	74.08	74.08	82.16	32.33	49.22	44.94	18.19	34.36	25.52
Berium %	0.58	ND(0.01)	0.12	0.12	0.29	0.35	ND(0.01)	0.09	ND(0.01)
Sulfur %	ND	ND	ND	0.2	ND	ND	ND	ND	ND
Carbonate %	ND	0.3	0.2	ND	4.2	4.4	20.0	78.7	9.6

TABLE 8

Condensate Pump (P-9) Scale Before and
After Condensate Reinjection

T8A: impeller housing (6/3)
 T8B: inside shaft housing (6/3)
 T8C: impeller shaft (6/11)
 T8D: pump seal (6/30)

Sample	Before		After	
	T8A	T8B	T8C	T8D
Color	Green Brown	Yellow Green	Yellow Brown	Dark Gray
Thickness	5-7mm	1-2mm	2mm	less than 1mm
Iron %	18.54	19.78	19.29	1.39
Copper %	0.18	0.32	0.30	0.01
Zinc %	1.38	1.04	0.97	0.84
Manganese %	4.18	3.40	2.24	1.70
Lead %	0.90	9.61	2.50	0.90
Calcium %	1.37	0.89	18.38	40.31
Aluminum %	ND(0.05)	ND(0.05)	ND(0.05)	ND(0.05)
Silicon %	19.12	15.79	5.13	0.02
(as SiO ₂) %	40.92	33.79	10.98	0.04
Barium %	ND(0.01)	ND(0.01)	0.03	ND(0.01)
Sulfur %	0.1	ND	ND	ND
Carbonate %	ND	ND	26.1	57.5

high silica scale in the reinjection lines as shown in the first three scale analyses of Table 7. The operating procedure was then changed and the condensate was directed to the reinjection pump inlet. Table 7 shows that a large increase in carbonate scale formation, particularly iron, manganese and calcium carbonates, and a decrease in silica resulted. The increase in carbonate scale was attributed to the large amount of dissolved carbonates in the condensates. Dilution of the brine with a high pH liquid increases the silicon solubility and decreases silicon deposition. Operating in this manner appears to be beneficial because less scale is formed, 5 mm of "carbonate" scale vs. 15 mm of "silicon" scale, during the same operating time and it is readily removed by acid cleaning. However, this carbonate scale is much harder than the amorphous silica scale previously observed and, by coating the shaft and bearings, has apparently caused failure of the reinjection pump. The scrubber drain pump (P-9) also exhibited carbonate scaling (Table 8). This carbonate comes from the fourth stage scrubber drain into which cascade the second and third stage heat exchangers. See Appendix C for further discussion.

5.4 Purge Water System

Purge water is another use for steam in the GLEF. The purge water system uses condensate from the 4th stage condensate to supply wash water for cleaning the steam in

the scrubbers and lubrication water for the various valves and pumps. Because of the high amount of dissolved carbonates in the fourth stage condensate, problems have arisen in the purge water system. Carbon dioxide pitting and formation of magnesite in the lines feeding the scrubbers are two of the minor problems. Further discussion of the purge water system and its major problem can be found in Appendix C.

5.5 Vent Gas System

A mixture of water vapor and noncondensable gases composes the output of the vent gas system. A typical analysis is given in Table 9. Carbon dioxide comprises the bulk of the noncondensable gas with the remainder being nitrogen, oxygen, methane, hydrogen sulfide and molecular hydrogen. The nitrogen and oxygen may be atmospheric contamination and better sampling procedures are being developed to eliminate this source of contamination. If atmospheric contamination occurs in the plant, condensable samples may need to be taken from the well head, instead of the vent stack where they are currently being taken.

Corrosiveness of carbon dioxide and hydrogen sulfide may be a problem in the vent gas system. Hydrogen sulfide emission may also need to be controlled to prevent environmental contamination. Carbon dioxide is not corrosive as a pure gas, but when dissolved in water it forms a weak acid which can attack mild steel. Thus, with a large amount

TABLE 9

Vent Gas Analysis (Noncondensable Gases)

	8/18	9/8
Carbon Dioxide	95.60%	94.56%
Methane	0.74%	9.85%
Oxygen	0.01%	1.10%
Nitrogen	0.04%	3.18%
Hydrogen	ND	0.15%
Hydrogen Sulfide	1300ppm	1300ppm

of water vapor in the vent gas system, corrosion of the mild steel piping may be expected. Hydrogen sulfide also forms a weak acid in contact with water and is also corrosive by itself.

The hydrogen sulfide currently does not appear high enough to cause significant corrosion. The environmental effect of hydrogen sulfide at present does not appear to be a problem. On site ground level hydrogen sulfide concentrations have averaged about 0.005 ppm.

5.6 Cooling Water System

The cooling water system supplies cooling water to the isobutane (secondary loop) condensers. This water is drawn from the Vail Canal, a part of the Imperial Irrigation District system and originates at the Colorado River. An analysis of the water is given in Table 10. To prevent scaling and corrosion, this water was initially treated with Nalco 605, a suspended solids coagulant, and Nalcolyte 7350, a zinc based corrosion inhibitor and phosphate precipitant. The phosphate inhibits calcium sulfate scale by precipitating the calcium. Chlorine and sulfuric acid are added to inhibit algae growth and carbonate build-up, respectively.

Contamination of the cooling pond with brine occurred early in the start up testing. Condensate was at this time being pumped into the cooling pond rather than being reinjected. During a plant upset, brine flowed through

TABLE 10

COOLING WATER ANALYSIS

1: water from vail 4 lat
 2: cooling pond
 3/16/76

	1	2
Bicarbonates	178 mg/l	144 mg/l
Carbonates	2.7 mg/l	ND
Calcium	98 mg/l	--
Chloride	125 mg/l	--
Sodium	145 mg/l	320 mg/l
Magnesium	26 mg/l	--
Potassium	5 mg/l	--
Sulfate	340 mg/l	--
Fluoride	0.32 mg/l	--
Nitrate	0.2 mg/l	--
Phosphate	Trace	--
Total Iron	0.33 mg/l	--
Total Copper	0.005 mg/l	--
Total Zinc	0.007 mg/l	--
Total Manganese	0.02 mg/l	--
Boron	0.26 mg/l	--
Specific Conductance (u mohs/cm)	1300	2200
pH	8.00	--
Total Alkalinity (as CaCO ₃)	148 mg/l	--
Total Hardness (as CaCO ₃)	350 mg/l	--
Suspended Solids	15.6 mg/l	7.2 mg/l
Total Dissolved Solids	850 mg/l	1530 mg/l
B.O.D. 5	ND	--
C.O.D.	ND	--

the steam and condensate system and into the cooling pond. Sufficient brine was added to increase dissolved solids in the cooling pond to about 49,000 ppm and reduce the pH to 6. Under these conditions, the cooling water could corrode the condenser system. To mitigate this corrosion, the cooling pond was filled to capacity with canal water to reduce the solids content and raise the pH.

Currently water is being pumped from the pond into a drainage canal under a permit issued by the California Regional Water Quality Control Board. To meet requirements of this permit, canal water, which would ultimately flow into the Salton Sea, is used to dilute pond water to 4,500 ppm before entering the drainage canal.

The cooling pond water being pumped to the drainage canal is being replaced by irrigation water and the dissolved solids level in the cooling pond is gradually declining. Also when the GLEF achieves stable operation, the high pH low solids condensate from the 2nd, 3rd, and 4th stage will be added to further reduce the dissolved solids level and maintain an alkaline pH in the cooling pond.

5.7 Secondary Loop

The GLEF has been operated with the isobutane system (secondary loop) filled with distilled water. To prevent corrosion, hydrazine, oxygen scavenger, and cyclohexylamine, a pH controller, were added. A vacuum pump attached

to the accumulator has made maintenance of this treatment difficult. This pump is needed to control flow from the condenser to the accumulator and to remove any noncondensibles from the secondary loop. It also removes the volatile cyclohexylamine allowing the pH of the secondary loop to decline. To control the pH a chemical feed pump is being installed which will continuously add cyclohexylamine to the secondary system.

6.0 GEOHERMAL LOOP EXPERIMENTAL FACILITY TEST PROGRAM

A test program for the GLEF has recently been completed. This program was developed in cooperation with the Bechtel Corporation and the Lawrence Livermore Laboratory. The goals of the test program are:

1. Determine the technical and economic feasibility of commercial power generation using hydrothermal fluids from the Niland Reservoir.
2. Collect the engineering and chemical data needed to design and operate a commercial power plant.

The test program is divided into 18 tasks (Table 11). Implementation is expected following the installation of the data acquisition system.

TABLE 11

GEOTHERMAL TEST PROGRAM

Task 1 - Operational Stability of the Flash/binary Process; Plant Response to Transients and Upsets

Task 2 - Overall Heat and Mass Balance of the Plant Under Baseline Operating Conditions

Task 3 - Clean-tube Heat Transfer Coefficients with Water as the Binary Fluid

Task 4 - Purity of Vapor; Scrubber Performance

Task 5 - Scale Prevention

Task 6 - Materials and Component Evaluation

Task 7 - Effect of Noncondensable Gases on the Heat Transfer Coefficient

Task 8 - Continued Monitoring of Heat Transfer Coefficients and Fouling Resistance in Multistage Heat Exchangers

Task 9 - Restoration of Clean-tube Heat Transfer Coefficients

Task 10 - Operational Stability of the Flash/Binary Process during Isobutane Runs

Task 11 - Overall Heat and Mass Balance Baseline for Isobutane Runs

Task 12 - Condenser Performance with Isobutane as the Binary Fluid

Task 13 - Heat Transfer and Pressure Drop Performance of Isobutane in and Around the Critical Region

Task 14 - Performance of Liquid Isobutane Exchangers, E-1A, B, C, and E-5

Task 15 - Determination of Nonequilibrium and Boiling Point Elevation

Task 16 - Comparison of Flashing Devices and Mist Eliminators

Task 17 - Analysis of Turndown Capability of the Flash Process

Task 18 - Long-term Run under Baseline Conditions

7.0 DATA ACQUISITION

Since the major purpose of the GLEF is to gather information it is imperative that an organized procedure be set up to acquire and record the engineering data generated by the test facility. This need has been reviewed by the Lawrence Livermore Laboratory (LLL) and they have recommended the installation of a multi-channel automatic cycling data logger with magnetic tape output and a paper tape and digital display. It is expected that the magnetic tape record will be used by a larger computer for data analysis.

LLL has purchased the data logger and it is now being tested in SDG&E's instrument shop. The transducers, flow elements and thermocouples needed to record the required engineering data have been ordered. These will be installed as they arrive. The location and type of detectors are described in Table 12 and Figure 12. These will fulfill the needs of the geothermal test program described in Section 6.0.

TABLE 12

DATA LOGGER INSTRUMENTATIONFIRST STAGE

<u>Instrument Number</u>	<u>Location</u>	<u>Liquid/Gas/Steam</u>	<u>Instrument</u>	<u>Flow</u>	<u>Temp.</u>	<u>Press.</u>
F1-1	V-1 outlet	Brine	Venturi/ Δ P trans.	664 gpm		
F1-2	V-4 outlet	Brine	Venturi/ Δ P trans.	664 gpm		
F1-3	V-6 vent line	Non-condensibles	Orifice/ Δ P trans.	4,700 ft ³ /hr		
F1-4	V-6 outlet	Condensate	Venturi/ Δ P trans.	220 gpm		
F1-5	E-5 outlet	Isobutane	Venturi/ Δ P trans.	4,000 gpm		
P1-1	Magma Max 1	Brine	Pressure transducer			250 psia
P1-2	V-1 Press in vessel	2-phase	Pressure transducer			165 psia
P1-3	Woolsey #1	Brine	Pressure transducer			250 psia
P1-4	V-4 Press in vessel	2-phase	Pressure transducer			165 psia
P1-5	E-3 inlet	Steam	Pressure transducer			165 psia
P1-6	E-2 inlet	Steam	Pressure transducer			165 psia
P1-7	E-3 outlet	Isobutane	Pressure transducer			500 psia
P1-8	V-6 press in vessel	2-phase	Pressure transducer			160 psia
P1-9	E-5 inlet	Condensate	Pressure transducer			160 psia
P1-10	E-5 inlet	Isobutane	Pressure transducer			540 psia
Δ P1-1	V-8 across vessel	Steam	Δ P transducer			50" H ₂ O
Δ P1-2	E-3 across shell	Steam	Δ P transducer			5 psi
Δ P1-3	E-3 across tubes	Isobutane	Δ P transducer			5 psi
Δ P1-4	E-2 across shell	Steam	Δ P transducer			5 psi
Δ P1-5	E-2 across tubes	Isobutane	Δ P transducer			5 psi
Δ P1-6	E-5 across shell	Condensate	Δ P transducer			10 psi
Δ P1-7	E-5 across tubes	Isobutane	Δ P transducer			10 psi
T1-1	Magma Max 1	Brine	Thermocouple		400° F.	
T1-2	V-1 vessel	Brine	Thermocouple		370° F.	
T1-3	V-1 vessel	Steam	Thermocouple		370° F.	
T1-4	Woolsey #1	Brine	Thermocouple		400° F.	
T1-5	V-4	Brine	Thermocouple		370° F.	
T1-6	V-4	Steam	Thermocouple		370° F.	
T1-7	V-8 outlet	Steam	Thermocouple		370° F.	
T1-8	E-3 outlet	Steam	Thermocouple		300° F.	
T1-9	E-3 outlet	Isobutane	Thermocouple			
T1-10	E-2 outlet	Condensate	Thermocouple		300° F.	

Table 12 (Contd)

DATA LOGGER INSTRUMENTATIONFIRST STAGE

<u>Instrument Number</u>	<u>Location</u>	<u>Liquid/Gas/Steam</u>	<u>Instrument</u>	<u>Flow</u>	<u>Temp.</u>	<u>Press.</u>
T1-11	E-2 outlet	Isobutane	Thermocouple		300° F.	
T1-12	V-6 vent line	Non-condensibles	Thermocouple		300° F.	
T1-13	E-5 inlet	Condensate	Thermocouple		300° F.	
T1-14	E-5 outlet	Condensate	Thermocouple		160° F.	
T1-15	E-5 inlet	Isobutane	Thermocouple		120° F.	

Table 12 (Contd)

DATA LOGGER INSTRUMENTATIONSECOND STAGE

<u>Instrument Number</u>	<u>Location</u>	<u>Liquid/Gas/Steam</u>	<u>Instrument</u>	<u>Flow</u>	<u>Temp.</u>	<u>Press.</u>
F2-1	V-7 outlet	Brine	Venturi/ Δ P trans.	1205 gpm		
F2-2	E-1A outlet	Condensate	Venturi/ Δ P trans.	45 gpm		
P2-1	V-7 vessel	2-phase	Pressure transducer			60 psia
P2-2	E-1A inlet	Steam	Pressure transducer			60 psia
P2-3	E-1A outlet	Isobutane	Pressure transducer			510 psia
Δ P2-1	V-9 across vessel	Steam	Δ P transducer			50" H ₂ O
Δ P2-2	E-1A across tubes	Steam	Δ P transducer			15 psi
Δ P2-3	E-1A across shell	Isobutane	Δ P transducer			5 psi
T2-1	V-7 outlet	Steam	Thermocouple		293° F.	
T2-2	V-7 outlet	Brine	Thermocouple		308° F.	
T2-3	V-9 outlet	Steam	Thermocouple		293° F.	
T2-4	E-1A outlet	Condensate	Thermocouple		262° F.	
T2-5	E-1A outlet	Isobutane	Thermocouple		520° F.	

Table 12 (Contd)

DATA LOGGER INSTRUMENTATIONTHIRD STAGE

<u>Instrument Number</u>	<u>Location</u>	<u>Liquid/Gas/Steam</u>	<u>Instrument</u>	<u>Flow</u>	<u>Temp.</u>	<u>Press.</u>
F3-1	V-14 outlet	Brine	Venturi/ ΔP trans.	1197 gpm		
F3-2	E-1B outlet	Condensate	Venturi/ ΔP trans.	56 gpm		
P3-1	V-14 vessel	2-phase	Pressure transducer			28.3 psia
P3-2	E-1B inlet	Steam	Pressure transducer			28.3 psia
ΔP 3-1	V-10 across vessel	Steam	ΔP transducer			50" H ₂ O
ΔP 3-2	E-1B across tubes	Steam	ΔP transducer			15 psi
ΔP 3-3	E-1B across shell	Isobutane	ΔP transducer			10 psi
T3-1	V-14 outlet	Steam	Thermocouple		247° F.	
T3-2	V-14 outlet	Brine	Thermocouple		262° F.	
T3-3	V-10 outlet	Steam	Thermocouple		262° F.	
T3-4	E-1B outlet	Condensate	Thermocouple		221° F.	
T3-5	E-1B outlet	Isobutane	Thermocouple		520° F.	

Table 12 (Contd)

DATA LOGGER INSTRUMENTATIONFOURTH STAGE

<u>Instrument Number</u>	<u>Location</u>	<u>Liquid/Gas/Steam</u>	<u>Instrument</u>	<u>Flow</u>	<u>Temp.</u>	<u>Press.</u>
F4-1	Reinjection line	Brine	Venturi/ Δ P trans.	1194 gpm		
F4-2	Reinjection line	Brine	Orifice/ Δ P trans.	1194 gpm		
F4-3	P-10 outlet	Condensate	Venturi/ Δ P trans.	49.1 gpm		
P4-1	V-11 vessel	2-phase	Pressure transducer			13.3 psia
P4-2	Reinjection line	Brine	Pressure transducer			600 psia
P4-3	E-1C inlet	Steam	Pressure transducer			13.3 psia
P4-4	V-13 vessel	Condensate	Pressure transducer			11.5 psia
Δ P4-1	V-12 across vessel	Steam	Δ P transducer			50" H ₂ O
Δ P4-2	E-1C across tubes	Steam	Δ P transducer			50" H ₂ O
Δ P4-3	E-1C across shell	Isobutane	Δ P transducer			10 psi
T4-1	V-11 outlet	Steam	Thermocouple		221° F.	
T4-2	V-11 outlet	Brine	Thermocouple		221° F.	
T4-3	V-12 outlet	Steam	Thermocouple		207° F.	
T4-4	E-1C outlet	Condensate	Thermocouple		200° F.	
T4-5	E-1C inlet	Isobutane	Thermocouple		540° F.	
T4-6	E-1C outlet	Isobutane	Thermocouple		530° F.	
T4-7	V-13 outlet	Condensate	Thermocouple		200° F.	
T4-8	P-10 outlet	Condensate	Thermocouple		200° F.	
T4-9	Reinjection line	Brine	Thermocouple		180° F.	
T4-10	VP-1 outlet	Condensate	Thermocouple		160° F.	

Table 12 (Contd)

ISOBUTANE - COLD WATER SYSTEM

<u>Instrument Number</u>	<u>Location</u>	<u>Liquid/Gas/Steam</u>	<u>Instrument</u>	<u>Flow</u>	<u>Temp.</u>	<u>Press.</u>
F5-1	CW 24"-WR3-L	CW	Orifice/ Δ P trans.	---		
P5-1	E-4A &B inlet	Isobutane	Pressure transducer			500 psia
P5-2	E-4A &B outlet	Isobutane	Pressure transducer			95.7
P5-3	V-2 vessel	Isobutane	Pressure transducer			95.7
T5-1	E-4A &B inlet	CW	Thermocouple		---	
T5-2	E-4A &B outlet	CW	Thermocouple		---	
T5-3	E-4A &B outlet	Isobutane	Thermocouple		510° F.	
T5-4	V-2 vessel	Isobutane	Thermocouple		120° F.	

8.0 CONCLUSIONS

The conclusion that can be drawn at this time are as follows:

A. Construction

1. Location in an area of high water table such as Imperial Valley requires special construction techniques as follows:
  - a. The plant must be raised above the surrounding area to facilitate drainage.
  - b. The use of light construction equipment will be required.
2. The moisture content of the soil varies between summer and winter. Drying is required in the winter and moistening is required in the summer.
3. High salt content of the soil requires the use of PVC underground conduit and protection of any buried steel piping.

B. Operations

1. Many of the problems that occurred during startup were not caused by the use of geothermal fluids, but are either problem that could occur during any normal steam plant start up or due to improper design or material failure (See Appendix E).
2. All brine in vessels and plumbing must be drained prior to start up and the geothermal fluid admitted slowly to prevent severe water hammer.
3. Precipitation of solids in the test loop will cause plugging of the pump strainers. Since these solids can be processed by the pumps the strainers can be safely removed.
4. Failure of the reinjection pump can be attributed to poor lubrication of the bearings and poor choice of bearing materials. New bearings and improved lubrication appear to have corrected this problem.
5. Factory supplied ball valves in contact with geothermal brine soon become inoperative due to scale deposits. Application of lubrication to the sensitive areas can greatly reduce this problem.

6. The solids carryover from the scrubbers is sensitive to the liquid level in the flash vessels. Lowering the liquid level can significantly reduce solids carryover.
7. Control of the brine flow through the facility has been greatly improved by the addition of proportional liquid level controllers in the first and fourth stage vessels.
8. Because the accumulator is elevated above the condenser, circulating fluid through the condenser requires a vacuum to be maintained on the accumulator.
9. The above situation also requires the condenser to operate in a "flooded" mode making heat transfer data difficult to obtain.
10. Overhead brine line require the plant to be started slowly to prevent water hammer.

C. Chemistry

1. Corrosion so far has not been a major problem in the operation of the GLEF.
2. Opening the pressure vessels to the atmosphere for inspection caused rust buildup on exposed metal surfaces.
3. Some scaling on surfaces in contact with the geothermal brine has been observed.
4. Scaling problems have not been severe except as follows:
  - a. Light scaling is prevalent throughout the brine system and can be a problem where close tolerances exist such as valve stems and pump shafts.
  - b. When geothermal brine is blended with the steam condensate, significant precipitation of carbonates and carbonate scales are observed.
  - c. Cooling the brine in the absence of condensate creates a large amount of soft silica scale.

5. Carbonate scale deposited in the reinjection system is thinner and harder than silica scale.
6. These carbonate scales can be easily removed by acid cleaning.
7. The purity of the steam leaving the scrubber had generally been low enough to prevent any deposition on the heat exchangers.
8. Plant upsets can cause gross carryover of brine with the steam and result in severe deposition on heat exchanger surfaces.
9. Corrosion is accelerate in the vapor phase above the flashing brine.
10. Significant corrosion can occur when vessels are opened to the atmosphere for inspection.

8.1 RECOMMENDATIONS

Based on the experience gained during construction and initial operation of the GLEF, the following recommendations can be made:

A. Design

1. The vessels and lines should be capable of being easily drained.
2. Brine line should run under the vessels and not overhead.
3. Accumulators should be placed below the condensers.
4. Proportional liquid level control valves should be utilized on all vessels.
5. Positive lubrication should be provided to all valve stems and pump bearings.

B. Construction

1. All plant construction in Imperial Valley should be elevated in order to allow installation of hot well pumps and similiar equipment that may require underground installation.
2. All underground plumbing should be plastic or plastic protected pipe.

C. Operations

1. All plant vessels and lines should be drained prior to any startup.
2. The startup should be gradual allowing time for equipment to be heated.
3. Condensed steam should be directed to the cooling pond or the 4th stage scrubber.

D. Chemistry

1. The composition of both the brine and steam must be monitored carefully, in order to insure that blending will not cause problems.
2. Allowing brine to stand and cool in contact with close tolerance equipment such as valves and pumps should be avoided.
3. Vessels should be thoroughly drained before being opened to the air.

9.0 ACKNOWLEDGEMENT

SDG&E would like to acknowledge the invaluable contribution of the following groups to the successful installation and initial operation of the Geothermal Loop Experimental Facility.

1. Lawrence Livermore Laboratory.
2. Lawrence Berkeley Laboratory.
3. U.S. Bureau of Mines.
4. Imperial Magma, Inc.
5. Ben Holt Company.
6. Bechtel Corporation.

APPENDICES

APPENDIX A

GEOTHERMAL TEST FACILITY
DRAWINGS

ME 5649	Cooling Water System
ME 5650	Utility Water Sump System
ME 5651	Brine System
ME 5652	Steam and Condensate System
ME 5653	Instrument Purge Water System
ME 5772	Isobutane System

REV	SAN DIEGO GAS & ELECTRIC COMPANY GEOTHERMAL TEST FACILITY
	COOLING WATER SYSTEM
OWN: PLS	DATE: 9-08-75 ME 5649

C

7429-3100-SD-3	7429-B-103 (2-5HT5)
7429-3200-PD-20A	" " -107
" " " -22	" " -112 (2-5HT5)
" " " -27	" " -113
	" " -116
	" " -119

REV.	SAN DIEGO GAS & ELECTRIC COMPANY GEOTHERMAL TEST FACILITY		
9-16-76/8	COOLING WATER SYSTEM		
	DWN: PLS	DATE 9-08-75	ME 5643

REF. DWGS.

7429-B-117
7429-B-118

REV.	SAN DIEGO GAS & ELECTRIC COMPANY GEOTHERMAL TEST FACILITY	
	UTILITY WATER SUMP SYSTEM	
	DATE: 10-01-75	ME 5650
	DWN: PLS	SCALE: -

REF. DWGS.

7429-B-117
7429-B-118

REV.	SAN DIEGO GAS & ELECTRIC COMPANY GEOTHERMAL TEST FACILITY	
9-16-76 P3	UTILITY WATER SUMP SYSTEM	
	DATE: 10-01-75	ME 5650
	DWN: PLS SCALE: --	

V-1
1ST STAGE BRINE FLASH DRUM
78" DIA x 20'-0" T-T EA.

V-6
VENT GAS SEPARATOR
36" DIA x 10'-0" T-T

V-9
2ND STAGE STM. SCRUBBER
66" DIA x 14'-0" T-T

E-1B
3RD STAGE EXCHANGER
26.8 MMBTU/HR

V-13
CONDENSATE TANK
42" DIA x 12'-0" T-T

V-4
1ST STAGE BRINE FLASH DRUM
66" DIA x 20'-0" T-T

V-8
1ST STAGE STM. SCRUBBER
84" DIA x 14'-0" T-T

E-1A
2ND STAGE EXCHANGER
32.9 MMBTU/HR

V-11
4TH STAGE BRINE FLASH DRUM
90" DIA x 30'-0" T-T

E-5
1ST STAGE CONDENSATE
COOLER
14.2 MMBTU/HR

V-7
2ND STAGE BRINE FLASH DRUM
72" DIA x 20'-0" T-T

V-14
3RD STAGE BRINE FLASH DRUM
78" DIA x 20'-0" T-T

V-12
4TH STAGE STM. SCRUBBER
66" DIA x 19'-0" T-T

E-2&3
1ST STAGE EXCHANGERS
94.9 MMBTU/HR

V-10
3RD STAGE STM. SCRUBBER
66" DIA x 14'-0" T-T

E-1C
4TH STAGE EXCHANGER
23.0 MMBTU/HR

X TEMPERATURE — 39 PTS
+ PRESSURE — 22 PTS
Θ FLOWS — 13 PTS
Δ ΔP — 16 PTS

GEO THERMAL LOOP EXPERIMENTAL FACILITY DATA LOGGER MEASUREMENT POINTS

REFERENCE DRAWINGS		
7429-3200-PD-20	7429-B-149	7429-B-168
7429-3200-PD-21	7429-B-150	7429-B-184
7429-3200-PD-22	7429-B-152	7429-B-196
7429-B-130	7429-B-153	7429-B-197 (2 SHTS.)
7429-B-131	7429-B-156	7429-B-204
7429-B-135	7429-B-157	7429-B-205
7429-B-136	7429-B-160	7429-B-206
7429-B-139	7429-B-162	7429-B-207
7429-B-145	7429-B-165	7429-B-208
7429-B-146	7429-B-166	7429-B-210
7429-B-148	7429-B-167	7429-B-211

REV.	SAN DIEGO GAS & ELECTRIC COMPANY GEOTHERMAL TEST FACILITY	
	STEAM & CONDENSATE SYSTEM	
	DWN: PLS	SCALE: —
	DATE: 11-03-75	ME 5652

REFERENCE DRAWINGS

7429-3200-PD-20	7429-B-149	7429-B-188
7429-3200-PD-21	7429-B-150	7429-B-184
7429-3200-PD-22	7429-B-152	7429-B-196
7429-B-130	7429-B-153	7429-B-197 (2 SMTS.)
7429-B-131	7429-B-156	7429-B-204
7429-B-135	7429-B-157	7429-B-205
7429-B-136	7429-B-160	7429-B-206
7429-B-139	7429-B-162	7429-B-207
7429-B-145	7429-B-165	7429-B-208
7429-B-146	7429-B-166	7429-B-210
7429-B-148	7429-B-167	7429-B-211

SS - SAMPLE STATION

REV.	SAN DIEGO GAS & ELECTRIC COMPANY GEOTHERMAL TEST FACILITY
JF 9-21-76	STEAM & CONDENSATE SYSTEM
DWN: PLS	SCALE: —
DATE: 11-03-75	ME 5652

B

REFERENCE DRAWINGS
 7429-3200-PD-20
 7429-3200-PD-21
 7429-S-196
 7429-S-209
 7429-S-210

REV.	SAN DIEGO GAS & ELECTRIC COMPANY GEOTHERMAL TEST FACILITY		
	INSTRUMENT PURGE WATER SYSTEM		
	DWN: PLS	SCALE: --	ME 5653
	DATE: 11-03-75		

REFERENCE DRAWINGS

7429-3200-PD-20
7429-3200-PD-21
7429-B-106
7429-B-209
7429-B-210

REV.	SAN DIEGO GAS & ELECTRIC COMPANY GEOTHERMAL TEST FACILITY
7F 9-21-76	
	INSTRUMENT PURGE WATER SYSTEM
DWN: PLS	SCALE: —
DATE: 11-03-76	ME 5653

- REFERENCE DRAWINGS**
- 7429-3200-PD-20
  - 7429-3200-PD-20A
  - 7429-3200-PD-21
  - 7429-3200-PD-22
  - 7429-S-100
  - 7429-S-101 SHTS. 1 & 2
  - 7429-S-102
  - 7429-S-105
  - 7429-S-132
  - 7429-S-133
  - 7429-S-134
  - 7429-S-154
  - 7429-S-155
  - 7429-S-198
  - 7429-S-200
  - 7429-S-201
  - 7429-S-202
  - 7429-S-203
  - 7429-S-212

REV.	SAN DIEGO GAS & ELECTRIC COMPANY GEOTHERMAL TEST FACILITY
	ISOBUTANE SYSTEM
	OWN: PLS SCALE: --
	DATE: 11-03-76 ME 5772

7429-3200-PD-20
7429-3200-PD-20A
7429-3200-PD-21
7429-3200-PD-22
7429-B-100
7429-B-101 SHTS. 1 & 2
7429-B-102
7429-B-105
7429-B-132
7429-B-133
7429-B-134
7429-B-154
7429-B-155
7429-B-196
7429-B-199
7429-B-290
7429-B-201
7429-B-202
7429-B-203
7429-B-212

REV.	SAN DIEGO GAS & ELECTRIC COMPANY GEOTHERMAL TEST FACILITY		
	ISOBUTANE SYSTEM		
	DWN: PLS	SCALE: —	ME 5772
	DATE: 11-03-75		

APPENDIX B

SAN DIEGO GAS & ELECTRIC COMPANY

INTERNAL CORRESPONDENCE

FORM 115-6143C

FROM H. K. Bishop

DATE July 29, 1976

TO R. G. Lacy

FILE NUMBER

SUBJECT CHEMICAL CLEANING OF 4TH STAGE HEAT EXCHANGER

During shutdown and examination of the geothermal loop experimental facility (GLEF) following the initial operating period, the 4th stage heat exchanger (E-1C) was observed to be partially filled with a soft scale. This scale was possibly deposited during one of the upsets that occurred in the start up period.

The scale was analyzed and found to be predominantly calcium, as calcium carbonate, with some zinc, probably as zinc sulfide, see attached analyses. Samples were provided to Southwest Chemical Co. and it was determined that inhibited hydrochloric acid would dissolve and remove this scale.

Arrangements were made with Southwest Chemical to clean the 4th stage condenser. They provided a truck, a tank of acid and supervisory personnel. Site personnel provided the necessary fittings and a 1,000 gpm diesel powered centrifugal pump. This pump was used because it could be operated at variable speed and at high flow rates.

On July 13, the heat exchanger was filled with irrigation water and at one o'clock inhibited hydrochloric acid was slowly added to the circulating water. Extreme care was exercised in adding the acid as system venting, which consisted of a one-inch pipe and water hose connected below the pump exit, was not considered adequate. It is recommended that in all future cleaning operations, the pump exit be connected to the system below the system vent.

Acid was continually added with a careful watch maintained on the system pressure and pH until five o'clock. The system was then secured until morning when the cleaning was resumed and completed before noon. The heat exchanger was then drained and rinsed twice with irrigation water. Any residual acid was then neutralized by filling the heat exchanger with a pH 9 calcium hydroxide (lime) solution.

The heat exchanger head was removed and the tubes inspected and found to be completely clean. A small amount of debris in the lowest section of the exchanger was washed out with a water hose. At our request Southwest Chemical prepared a detailed log, attached.

R. G. Lacy

-2-

July 29, 1976

CONCLUSIONS

1. Scale of the type found in the 4th stage heat exchanger can be removed by inhibited hydrochloric acid in less than 24 hours.
2. Care should be taken to ensure the circulating pump is connected below system vent.

H. K. Bishop

HKB/vbw

SOUTHWEST CHEMICAL COMPANY, INC.

291 WEST ATEN ROAD
EL CENTRO, CALIFORNIA 92243

SCALE ANALYSIS ON 4TH STAGE HEAT EXCHANGER

JULY 13, 1976

Fe	.49%	
Cu	.005%	
Zn	1.00%	
Mn	.73%	
Pb	.05%	
Ca	39.88%	
Al	ND	
Si (as SiO ₂)	.01%	(less than)
Ba	.05%	
Mg	.01%	(less than)

ETCHANT NORMALITY VS ELAPSED TIME.

	2 hours	3 hours	16 hours	17 hours
Free H+	.07	1.55	1.50	1.50

ETCHANT METAL CONCENTRATION VS ELAPSED TIME (expressed in mg/liter)

	2 hours	3 hours	16 hours	17 hours
Ca	8180	11250	11720	11440
Fe	370	1000	2285	2370
Mn	40	466	616	616
Pb	17	49	44	28
Zn	268	466	507	507

Analytical data above furnished by SDG & E.

SOUTHWEST CHEMICAL COMPANY, INC.

EL CENTRO, CALIFORNIA 92243

ETCH CYCLE PAGE 1

GEOTHERMAL DESCALING TEST PROGRAM

Unit to Be Descaled 4th STAGE HEAT EXCHANGER

Date July 13, 1976

Location GTF NILAND Type Scale CALCIUM

Authorized By Dr. Bishop

Description: HEAT EXCHANGER, TUBE SIDE

P. O. No. _____

Size 1500 gal Diameter _____ Length _____ Scale Thickness _____

Comments N₁ - Etchant normality in Hydrogen equivalents
N₂ - Pressure.

OPERATING CONDITIONS

TIME ELAPSED	TEMPERATURE	FLOW RATE	SCALE REMOVAL	N ₁	N ₂	COMMENTS
	Initial	80° F	450 gpm	-	-	Began introduction of etchant at 10 g per 15 min.
	1 Hour	90°	450 gpm	-	18 psi	Rapid press incr with add of etch.
	2 Hours	98°	450 gpm	.07	35#	Add of etchant base on pressure. to cont rate of reaction.
	3 Hours	105°	450 gpm		12#	
	4 Hours	108°	450 gpm	1.55	10#	To this point: 160 g etch added.
	5 Hours					
	6 Hours	SHUT DOWN FOR EVENING-- ALL VALVES OPEN-VENT OPEN.				
	7 Hours					
	16 Hours	80°	600 gpm	1.50	3#	Due to lack of decre in N ₁ it appears
	17 Hours	100°	600 gpm	1.50	4#	reaction is complete
	~~18 Hours~~					

IMPERIAL PRINTERS

Operators DG AND JE Times _____ Authorized By _____

COMMENTS: Cut etchant injections at 20 #.
Heavy emissions of H S at vent tube.

RECOMMENDATIONS: Locate vent to atmospheric press at highest point in system.
Vent should be at least 1.5" ID
N₁ should be raised to 2.5 prior to beginning of rinse cycle.

Injection of etchant on vacuum side of pump works due to aspirator system. When pressure drops beyond 20 # injection stops.

SOUTHWEST CHEMICAL COMPANY, INC.

EL CENTRO, CALIFORNIA 92243

RINSE CYCLE PAGE 2

GEOTHERMAL DESCALING TEST PROGRAM

Unit to Be Descaled 4th STAGE HEAT EXCHANGER

Date July 14, 1976

Location GTF NILAND Type Scale CALCIUM

Authorized By Dr. Bishop

Description: HEAT EXCHANGER TUBE SIDE

P. O. No. _____

Size _____ Diameter _____ Length _____ Scale Thickness _____

Comments N₁ - Hydrogen equivalents

OPERATING CONDITIONS

E L A P S E D T I M E		TEMPERATURE	FLOW RATE	SCALE REMOVAL	N ₁	N ₂	COMMENTS
	Initial	80°	600 gpm		.22		Rinse #1 discard
	1 Hour	80°	600 gpm		.04		Rinse #2 discard
	2 Hours	80°					Addition of 15#
	3 Hours						Ca(OH) ₂ to pH of
	4 Hours						This soln left in
	5 Hours						exchanger until h
	6 Hours						removed.
	7 Hours						
	8 Hours						
	12 Hours						
	16 Hours						

IMPERIAL PRINTERS

Operators DG & JE Times _____ Authorized By _____

COMMENTS:

SELECTED ELEMENTAL LEVELS IN ACID WASH
OF HEAT ELEMENT EXCHANGER FLUID

	7/13 1430 <u>Mg/l</u>	7/13 1545 <u>Mg/l</u>	7/14 0730 <u>Mg/l</u>	7/14 0815 <u>Mg/l</u>	<u>1st Wash</u> 7/14 1000 <u>Mg/l</u>	<u>2nd Wash</u> 7/14 1100 <u>Mg/l</u>
Iron	370	1000	2285	2370	435	104
Manganese	40	575	616	616	101	25
Lead	17	49	44	28	20	4
Zinc	268	466	507	507	73	15
Calcium	8180	11,250	11,270	11,440	2,170	910
Free Acid	0.07N	1.55N	1.50N	1.50N	0.22N	0.04N

APPENDIX C

EVALUATION OF REINJECTION CARBONATE
GEOTHERMAL LOOP EXPERIMENTAL FACILITY

NILAND, CALIFORNIA

AUGUST 1976

SUBMITTED BY: John R. Bricarello

SAN DIEGO GAS AND ELECTRIC COMPANY

During the G.L.E.F. operation from August 9 to August 11, a problem arose that had not previously been encountered. Purge water supplied to the bearings of the reinjection pump contained an element which enhanced scale deposition within the bearings. This black scale evenly coated the pump shaft, bearings and impeller to about a millimeter thickness.

Purge water which is used to supply the bearings of the reinjection pump was found to contain about 1270 mg/liter (of carbonates in the form) of bicarbonate alkalinity. This amount of bicarbonate, in contact with the brine, caused the precipitation of various carbonates (see attached elemental scale analysis). The resulting scale has seriously affected the operation of the reinjection pump of the G.L.E.F.. The scale build-up prevented lubrication of the pump bearings by clogging the purge water feed lines and forming scale in the bearings. This lack of lubrication coupled with a sudden drop in reinjection well pressure may have caused the failure of the pump shaft on August 11. Further investigation showed dissolved carbonates also in other steam stages (see attached steam analysis).

Present G.L.E.F. piping arrangements combine fourth stage flashed steam with second and third stage condensates in the fourth stage scrubber. Possibly, carbonates from the second and third stage condensates are carried over with the fourth stage steam to the heat exchanger where the condensate is sampled. If so, carbonates may not be evolved in the fourth stage steam. There exists no suitable sampling point, due to the vacuum on the fourth stage, to determine the exact CO_3 level in the steam. Cascading second stage condensate into the third stage separator and third stage condensate into the fourth, would eliminate dumping condensate into the fourth stage scrubber. However, this may cause carbonate scale deposition in the intermediate lines and vessels. This scale was recently seen as the black sludge in the reinjection pump well. The scale formed is very hard and tenacious. It has been suggested that the condensates be treated chemically to alleviate the carbonate scale.

For treatment of the purge water system, several methods are available including lime softening, anion chloride

exchange and acid addition followed by degassing.

The first two methods are somewhat limited in this application, hence acid treatment would be advisable.

The last method would lower the pH of the condensate to 4, with the addition of approximately 195 gallons of concentrated hydrochloric acid per day, based on a fourth stage condensate flow rate of 50 gpm. At pH 4, in a properly agitated and vented system, the efficiency of the CO₂ would be 100 percent. This would necessitate a HCL feeder system and degassing unit.

An alternate approach would be to add suitably inhibited hydrochloric acid between the fourth stage heat exchanger and hotwell. This would facilitate mixing efficiency and venting. The venting of the CO₂ would be accomplished by the vacuum pump already in operation on the hotwell. Monitoring the pH of the resultant acidified condensate would be the feedback system for control of acid addition.

Further investigation is indicated to deal with carbonates in the first, second and third stages. One suggestion is not to reinject the condensates but flow them to the cooling pond. This could be done because of the low total dissolved solids in the condensate. However, this procedure deposits the carbonates in the cooling pond and non-reinjection results in silica deposits in the reinjection lines. With reinjection of the condensate, silica build-up seemed to be lessened. Treating the condensate with acid is another alternative which has not been investigated because of insufficient data.

Further monitoring of the first, second and third stage condensate for carbonate should be conducted. Knowledge of the carbonate values and accurate flow data would aid in forming a plan of action for the condensate and dictate the feasibility of treating the condensates chemically. Also, long term operation of the G.L.E.F. may prove treatment of the first, second and third stage condensate is unnecessary.

If fourth stage condensate is used for purge water, it should be treated to remove the dissolved carbonates. This would prevent carbonate scale deposition in areas where purge water comes in contact with brine. A sampling point should also be designed for sampling the steam evolved in the fourth stage separator. An evacuated sampling bomb connected to a suitable point in the system may provide the answer. Another solution to lessen the carbonate problem may be better venting of the CO₂ in the first stage.

J. R. Bricarello

J. R. Bricarello
CHEMIST

JRB:bt

8/26/76

ELEMENTAL SCALE ANALYSIS

SCALE FROM IMPELLER OF REINJECTION PUMP

Iron	21.90%
Copper	0.05%
Zinc	0.80%
Manganese	3.65%
Lead	0.76%
Calcium	13.17%
Aluminum	*ND less than 0.05%
Silicon	8.50%
(as Si O ₂)	18.20%
Barium	*ND less than 0.05%
Magnesium	0.03%
Sodium	1.10%
Carbonates (as CaCO ₃)	20.00%

* ND = None detected

ELEMENTAL SCALE ANALYSIS

Reinjection line exit from pump appeared to be scale formed elsewhere in system, then deposited at flange.

Iron		5.00%
Copper		0.04%
Zinc		1.32%
Manganese		5.65%
Lead		0.74%
Calcium		16.78%
Aluminum	*ND less than	0.05%
Silicon		8.50%
(as SiO ₂)		18.20%
Barium	*ND less than	0.05%
Magnesium		0.02%
Sodium		2.47%
Carbonates		30.50%

*ND = None detected

STEAM ANALYSIS

ALKALINITIES

Sample	Carbonate (as Ca CO ₃)	Bicarbonate (as Ca CO ₃)	Hydroxide (as CaCO ₃)
1st stage in	* ND	1440 mg/lit	*ND
Scrubber out	* ND	1190 mg/lit	*ND
2nd stage in	820 mg/lit	130 mg/lit	*ND
Scrubber out	700 mg/lit	90 mg/lit	*ND
3rd stage in	620 mg/lit	*ND	660 mg/lit
Scrubber out	580 mg/lit	*ND	290 mg/lit
4th stage out	* ND	1270 mg/lit	*ND
Scrubber			

* ND = None detected

TABLES

Table one lists certain steam properties and some brine parameters. Conductivity is measured in micromhos per centimeter cubed. ORP is the oxidation reduction potential in millivolts. Total solids were dried at 110° C. except for the first which was dried at 180° C. Total solids were run due to the formation of fine particular matter which was difficult to filter. Alkalinity was preferred by an acid filtration with organic base indicators. Carbonate, bicarbonate and hydroxide alkalinity are definitions applied to set pH potentials based on the acid titration.

In the following tables, ND means none detected by the analytical technique applied. Defection limits are given where applicable.

APPENDIX D

August 25, 1976
CNB 300

4. Bronze, Teflon and tungsten/carbide bearings will be tested in the pump. These three materials were judged to be the best candidate materials at this time. Of the three, bronze appears to be the poorest in this selection.

Peerless will provide the appropriate bearing dimensions, including tolerances and clearances. The necessary machine work and pump assembly will be performed by SDG&E. Holt will purchase the rotameters and valves.

Each representative at this meeting will receive all installation and operational data connected with this repair. In addition, the meeting participants will be invited to observe the pump parts at the next inspection. At this time, a second meeting should be held to review the operating and inspection results.

G. L. Lombard

GLL/cry

cc: R. G. Lacy
J. A. Campbell
H. K. Bishop
F. L. Enos
A. G. Follett - ERDA
J. L. Featherstone - ERDA

JAN DIEGO GAS & ELECTRIC COMPANY

INTERNAL CORRESPONDENCE

FORM 115-6143C

FROM G. L. Lombard

DATE August 25, 1976

TO C. R. Swanson

FILE NUMBER CNB 300

SUBJECT BRINE REINJECTION PUMP MEETING

The performance history of the brine reinjection pump was reviewed at this meeting on August 24, 1976. A list of representatives in attendance is presented in the attachment.

Observations connected with the pump performance and conditions associated with the shaft, bearing and scale deposition was presented to the group to pinpoint the probable cause or causes of the shaft failures. The scale compositions, steam analyses, material specifications and drawings of the pump assembly and bearings was given to the members. A copy of each is attached.

Several recommendations to repair the pump were presented. Following this brainstorming session, a compromise repair was unanimously agreed upon which combines the elements of four different recommendations. The adopted repair is:

1. Use 17-4 pH as the shaft material. K-Monel is a satisfactory alternate if 17-4 pH is not readily available.
2. Provide a separate supply of purge water to each pump shaft bearing. Provide a rotameter and needle valve to set each bearing flow to 1.0 GPM. Treat the purge water with hydrochloric acid to remove the carbonate.
3. Remove the uppermost impeller and reduce the pump discharge pressure to 545 psi. This will ensure that the purge water pressure of 630 psi will be substantially higher than the maximum pump discharge pressure and the purge water flow will be insensitive to available pressure differential.

APPENDIX E

SAN DIEGO GAS & ELECTRIC COMPANY

INTERNAL CORRESPONDENCE

FORM 115-6143B

FROM J. A. Campbell

DATE October 5, 1976

TO H. K. Bishop

FILE NUMBER CNB 300

SUBJECT TEST UNIT UNSCHEDULED SHUTDOWN'S CAUSES

The attached summation of the sixteen shutdowns during the period from May 3 thru August 21 is of interest. As you will note that only three of these could be attributed to "Geothermal" caused problems. The rest are normal steam plant problems, improper design or material failures. The pump bearing failures could in most cases have been prevented if purge water provisions had been provided in original design. This is normal practice for SDG&E Power Plants to provide purge water to bearings of pumps in salt water service.

J. A. Campbell

JAC:bt

cc: R. G. Lacy
C. R. Swanson
G. L. Lombard
K. K. Li

- May 3 Plugged injection pump (P-2) suction strainer.-
Construction debris.
- May 13 Problems with maintaining binary loop fluid flow-
due to condenser location.
- May 18/19 Plugged suction strainer 4th stage scrubber drain
pump (P-9) Construction debris.
- May 20 Plugged suction strainers 4th stage scrubber drain
pump (P-9) and 4th stage heater hotwell drain pump
(P-10) -Construction debris and mill scale.
- May 24 Plugged strainer suction strainer 4th stage scrubber
drain pump (p-9) wet clay like substance which pump
could handle in solution. Strainer removed at this
time.
- May 25 Shut down to perform maintenance items and modify
design.
1. Modified purge water system design.
  2. Cleaned drain line from 3rd stage heater of
construction debris.
  3. Pulled and cleaned vent gas control valve
(510). Whisper type trim plugged with mill
scale.
- May 27 Brine reinjection pump (P-2) seal failed due to
problems with supplying a reliable supply of seal
water.

NOTE: The 3rd stage separator was removed from service following this run due to foundation damage. The damage was caused by water hammer brought on by poor design of the separator's brine drain system.

May 31 Shut down due to failure of the 1st stage separator drain valve control, caused by moisture in the control air system.

June 2 Leak in elbow just after 1st stage separator inlet control valve (FCV 301). Poor piping design and valve sizing.

June 6 Same problem as above, the valve type was changed and the valve relocated at a point just before a 6" X 16" increasing bell.

June 11 The 4th stage scrubber drain pump (P-9) failed due to scaling of bearings and wearing rings.

June 16 P-9 failed again, sent to shop. Purge water provisions were added at this time.

Aug 11 P-2 shaft failed, materials failure.

Aug 19 PCV301 stuck due to scale, the piping configuration seat design needed to be changed.

Aug 20   Crickets plugged cooling water pump inlet screens.

Aug 21   P-2 failed shaft seized due to improper selection
of bearing materials and the bearing lubrication
system. After the last failure the water lube
system was changed to grease. After this water
was again used with additional feed provisions.