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MASTER

GTF TEST PROGRAM

**DRAFT
12-31-75**

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GTF TEST PROGRAM

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INTRODUCTION

The goal of the GTF (Geothermal Test Facility) Test Program is to evaluate the geothermal resources in the Niland area and determine if they can be effectively converted into electric power. This program will examine the four critical areas of geothermal power development.

- I. Reservoir.
- II. Energy Extraction and conversion.
- III. Environmental effects.
- IV. Operation & Maintenance.

These areas are discussed in the following sections and a detailed test program is presented in Appendix A, B C, D and E.

Reservoir Analyses.

Analysis of the geothermal reservoir will be a joint project of SDG&E and NARCO-Magma. A reservoir engineering firm will be engaged by NARCO-Magma to develop a detailed program to evaluate the reservoir capabilities. It is expected that reservoir parameters associated with operation

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of the GTF such as brine temperature, pressure, flow and composition will be measured by GTF operating personnel. Other specialized measurements such as resistivity or gravity tests will be conducted by the reservoir engineering firm. The reservoir engineers will also analyze the data developed and construct a reservoir model.

SDG&E also expects to engage Dr. William E. Brigham, Professor of Petroleum Engineering Stanford University, to evaluate the proposed reservoir analysis program and the results.

An outline of the reservoir analysis program follows. The details of this program are included in Appendix D. (To be supplied by the reservoir engineering firm).

A. Communication

The communication between wells and within the reservoir is very critical to the determination of reservoir capacity and withdrawal rates. In order to determine if communication exists trace amounts of a radioactive material, for example tritium,

may be injected into the reinjection well. Subsequently the producing well will be monitored for this radioactive material.

B. Reservoir Parameters

The temperature and pressure of the production, reinjection and observation wells will be measured over a range of flow rates and time to estimate the effect of flow rate on the production capability of the reservoir. In addition to the above measurements, the flow at various levels in the reinjection well will be measured to determine the effect of the flow and other parameters on the ability of the reservoir to assimilate the reinjection fluid.

A complete analysis will be made of the production fluid including a chemical analysis of the liquid, steam and non-condensable gases. This will be used to determine the effect of production and reinjection on the properties of the geothermal fluid within the reservoir.

Other characteristic parameters of the reservoir fluid, such as the Na/K ratio, CO_2/CH_4 ratio and $\text{C}_{13}/\text{C}_{12}$ ratio may be either calculated or measured. These ratios will be used to estimate the source of waters within the reservoir.

An electrical resistance log will be made on the production and reinjection wells before and after the first year test phase. A gravity survey will also be made to detect water movement within the reservoir.

C. Reservoir Model

The results of the above measurements will be used to develop a reservoir model. This model should allow an estimate to be made of the reservoir size, capacity, permeability, replenishment rate and source, and the effect of withdrawal and reinjection.

Energy Extraction and Conversion

This portion of the test program considers the production and reinjection well, the reinjection line, gathering lines, separator, scrubber, heat exchanger, process piping and the isobutane and cooling system. The parameters of the extraction and conversion process, temperature, pressure, flow, liquid level, etc., will be measured.

These parameters will be varied and their effect on GTF operation determined. An optimum operating procedure will be developed and the equipment capability under these conditions determined.

Based upon previous field testing it is anticipated that the major problems that will be encountered are scaling and corrosion. The material of construction and the equipment design will be carefully evaluated to determine how well it can withstand the corrosive geothermal fluids and how susceptible it is to scaling. Operation procedures to minimize corrosion and scaling will also be evaluated.

To achieve a better understanding of the reservoir it may be desirable to operate the two production wells (Magmamax No. 1 and Woolsey No. 1) in succession. Also if possible, only one reinjection well (Magmamax No. 3) will be used. By injecting all fluid through one well the effect of reinjection on the casing and surrounding strata can be determined more rapidly.

The effect of reinjecting noncondensable gases and cooling pond blow down into the underground formation will be determined, particularly its effect on the reinjection well casing and formation permeability.

An outline of the energy extraction and conversion portion of the GTF Test Program follows. The detailed

program for this phase is presented in Appendix A, B and C .
Additional technical support including a detailed study of
the chemical and corrosion properties of the geothermal
fluid will be provided by the U. S. Bureau of Mines, see
Appendix E and Lawrence Livermore Laboratory, see Appendix F.

ENERGY EXTRACTION & CONVERSION TESTING

A. Production Well

1. Inspect well casing and gathering lines for scaling and corrosion.
2. Monitor and optimize operating parameters.

B. Reinjection Well

1. Inspect well casing and reinjection lines for scaling and corrosion.
2. Monitor operating parameters.

C. Separator, Scrubber and Heater Exchangers

1. Inspect for scaling and corrosion.
2. Monitor and optimize operating parameters.
3. Calculate performance.

D. Isobutane Cycle

1. Monitor operating conditions.
2. Calculate performance.
3. Evaluate safety.

E. Cooling Water

1. Record

- a. Properties. (Temperature, TDS constituents)
- b. Flow.
- c. Measure usage and or make up.
- d. Chemical treatment.

F. Descaling.

- 1. Describe equipment.
- 2. Record.

- a. Scale properties.
- b. Cleaning procedures.
- c. Results.

G. Pumps, Valves, Instrumentation.

- 1. Describe equipment.
- 2. Prepare and maintain maintenance logs.

Environmental Effects.

The possible adverse environmental effects that can arise from recovery process are: 1) Subsidence of the land surrounding the plant or (2) Seismic due to disturbances associated with fluid extraction and reinjection from and to the reservoir. 3) Emissions, either gas or liquid can be generated by the geothermal fluid which may contain small quantities of noncondensable gases and highly saline liquids. A discussion of these effects and their application to the GTF program follow.

Subsidence and Seismic Disturbances

The occurrence of subsidence and seismic disturbances has long been associated with the movement of fluids under the earth's surface. Substantial withdrawal of liquids from beneath the earth's surface such as in Long Beach has been associated with subsidence. Conversely the injection of fluids into a deep reservoir has been associated with seismic disturbances in the Denver area. Operation of the GTF is not expected to cause any significant earth movement since the amount of fluid removed and the amount of fluid injected will be approximately the same.

Emissions

A. Gas Emission

The gaseous emissions which may be expected from a geothermal plant in the Niland area have been shown by field testing to be primarily (~95%) carbon dioxide with the remainder mostly nitrogen. A small amount, ~30ppm, of hydrogen sulfide (H_2S) has also been observed as well as trace amounts of methane.

These noncondensable gases are associated with the geothermal fluid as it flow out of the reservoir and must be removed in order to effectively extract energy from the fluid. They could be blended or reintroduced in to the injection fluid and thus return to the reservoir. However the effect of reinjecting noncondensable into the reservoir on the reinjection well and surrounding strata is not known, so that during the initial portion of the GTF tests these noncondensable gases will be vented.

Isobutane will be used as a secondary working fluid and, although the system is sealed, there is a possibility that small amounts of this material could escape into the atmosphere.

Of all the gaseous emissions the only two which could be present in sufficient concentration to be hazardous are hydrogen sulfide and isobutane. The hydrogen sulfide and other noncondensibles will be vented through a tall stack to allow adequate dispersions. On and near site monitoring of both H_2S and isobutane will be made to insure that there is no hazard to personnel in the vicinity of the site.

B. Liquid Emission

The only liquid that might be expected to produce an adverse environmental impact is the geothermal brine. The process is designed to immediately reinject this fluid directly into the geothermal formation. However if any surface leaks developed the high salinity of the geothermal fluid would temporarily reduce the soil fertility in the immediate vicinity of the leak.

The water discharged from the cooling ponds (blow-down) will contain more minerals than are normally present in agricultural run off, but much less than that of the Salton sea. The quantity of this discharge is insignificant when compared to the total agriculture run off in the Imperial Valley.

Normally the cooling pond blow down would be simply injected into the formation along with the geothermal brine. However, because of possible adverse reaction with the well casing and the geothermal formation evaluation will also be made of the discarding the cooling pond blowdown into the Salton sea. This will allow base line measurements (no blow-down) to be made on the formation and well pipe.

An outline of a program to detect any adverse environmental effects follows.

A. Subsidence

1. Survey markers.
2. Determine change.
3. Develop simple model.

B. Seismic

1. Set up supplemental seismic detectors and obtain base line date.
2. Record any seismic activity during test period.
3. Construct simple seismic model.
4. Coordinate activity with US Geological Survey.

C. Emission

1. Set up and measure.

- a. Liquid
- b. Air
- c. Noise

Special Tests

A. Mineral Recovery

Other processes such as mineral recovery has been considered as a possible beneficial use of the large amount of geothermal fluids that are brought to the surface for energy extraction. These fluids are normally simply reinjected. However, since in mineral recovery a substantial expenditure of dollars and energy is required to extract the mineral laden fluids from the earth, a significant saving could accrue if mineral could be extracted from the fluids already brought to the earth's surface.

An evaluation of the minerals available in the geothermal brines show that the major constituent, salt (Na Cl), probably has little economic value. Other minerals such as calcium and lithium chloride as well as some of rare platinum metals have also been found in geothermal brines. These minerals do have significant industrial uses and should

be considered for possible recovery. Since the amount of these minerals brought to the surface during energy extraction process are much larger than the current needs of this country it is expected that only a small portion of the geothermal flow will be treated. A suggested program to evaluate mineral recovery is outlined below.

1. Analyze geothermal fluid for:

- a. Li Cl
- b. Ca Cl₂
- c. Rare Earths
- d. Platinum Metals

2. Evaluate Extraction Processes for Promising Species.

- a. Laboratory
- b. Pilot

B. Helical Expander

It has been proposed to recover energy from geothermal fluid by passing the entire fluid (liquid and vapor) directly through a helical expander. The potential technical problems for such a process appear formidable. To determine if such a process is feasible it is proposed to challenge a small (1000 k w) expander at Niland using a side stream of fluid from one of the producing wells.

C. Anti Scalent Techniques

1. Coatings.

A process for scale prevention which utilizes a hydrophobic coating on the process equipment and a small percentage of organic fluid has been proposed. It is postulated that the organic fluid preferentially wets the hydrophobic surfaces and resists scale deposition. Such a process is costly and is expected to be initially evaluated on a sensitive system such as the tubular heat exchangers.

2. Additives

Certain dispersant type chemical have been used by water treatment firms to control deposit of scale in boilers, cooling towers and other industries. An evaluation of some of the more promising additives as proposed using geothermal

brine and a two tube heat exchanger developed for the first field tests.

APPENDICIES

- A. Test Schedule
- B. Operating Conditions to be Recorded
- C. Test Description
- D. Reservoir Analysis
- E. U.S. Bureau of Mines Corrosion & Fluid Analysis
Program
- F. Lawrence Livermore Laboratory Material & Scaling
Program

Appendix A

TEST SCHEDULE

Introduction

The goal of this program is to demonstrate the binary cycle and associated equipment for power production and to assess the potential of the Niland Geothermal Reservoir for production of electric energy. The geothermal wells have been drilled and collection lines and processing equipment have been assembled on the Niland site. It is expected that the initial phase of the test program will be devoted to setting up the test that will be required for reservoir and process evaluation and determining if the process equipment is operating satisfactorily. After all the equipment has been checked out and determined to be operating correctly, testing of this geothermal energy extraction concept will begin.

The geothermal test facility (GTF) will be initially operated over a range of flows both to demonstrate the capability of the reservoir and to challenge the process. The process itself involves a number of systems which must

be balanced so that at each flow condition it will be necessary to adjust the GTF in order to operate in an optimum manner. All operating conditions will be carefully recorded (Appendix B).

In addition to recording operating conditions and demonstrating the capabilities of the GTF process, the reservoir parameters and emissions and other effects on the environment will be carefully monitored. As noted previously the special reservoir parameters will be monitored by a reservoir engineering firm in addition to GTF personnel. GTF operation and environmental effects such as, liquid gas and noise emissions will be monitored by GTF personnel.

It is expected that the production wells will be started step wise, that is one production well will be started and used to conduct the initial checkout of the process equipment. Operation of one production well and one reinjection well is also expected to assist the reservoir engineers in evaluation of the reservoir.

An outline of the test program is presented below. The details of operating conditions to be recorded and the test procedures themselves are presented in Appendix B and C

respectively to this report. Additional testing is also expected to be conducted by other agencies such as the U.S. Bureau of Mines & Lawrence Livermore Laboratory. An outline of the test that they expect to accomplish are presented in Appendix E & F.

I. Pretest (1 month)

A. Production and reinjection wells.

1. Casing condition.

a. Visual examination.

b. Calibers.

2. Current well depth.

3. Temperature profile.

4. Electric logging.

5. Install test specimens.

B. Process equipment and piping.

1. Photograph surface and measure metal thickness at designated test points on process equipment and piping.

2. Calculate volume of system.

3. Weigh and install corrosion coupons.

4. Weight (removable) sections of processed piping.

5. Number all valves, pressure gauges and other instrumentation and set up maintenance logs.

6. Conduct training program for operating personnel.

C. Observation Wells.

1. Temperature profile.
2. Electric log.
3. Down hole fluid composition.
4. Liquid level.

D. Subsidence.

1. Survey USGS markers adjacent to site.
2. Establish additional markers as required.

E. Emissions.

1. Set up air and noise monitoring stations on site and at site boundry.
2. Set up water monitoring sites on Vail drainage canal upstream and downstream of site.
3. Conduct a base line measurement on all air, noise and water monitoring sites.

II. Initial Equipment Checkout (3 weeks)

A. Fill cooling pond and check cooling system (See Appendix C for procedure).

1. Pumps
2. Instrumentation
3. Record operating parameters

B. Fill Isobutane system (see Appendix C for procedure) and check.

1. Pumps
2. Instrumentation
3. Record operating parameter

C. Fill condensate system with condensate from power plant and check.

1. Pumps
2. Instrumentation
3. Record operating parameter

III. Production stimulation. (1 week)

A. Cold water injection.

1. Flow rate.
2. Total volume.
3. Composition.
 - a. Mineral
 - b. Oxygen
 - c. PH
 - d. Suspended Solids

B. Observation Wells.

1. Down hole temperature.
2. Down hole pressure.
3. Water level.

IV. Complete Equipment Checkout. (4 week)

- A. Operate production well (Magmamax No. 1) at nominal flow and reinject into Magmamax No. 3.
- B. Check for leaks.
- C. Correct any malfunction.
 1. Controllers.
 2. Valves.

3. Flow meters and recorders.
4. Temperature meters and recorders.
5. Pressure meters and recorders.
6. Liquid level meters and recorders.

D. Record all operating parameters of production and reinjection well (Appendix B).

V. Initial flow test of Magmamax No. 1 (1-2 weeks)

A. Operate the production well (Magmamax No. 1) over the maximum flow range possible and reinject into Magmamax No. 3.

B. Record operating conditions (Appendix B).

VI. Initial flow tests of Woolsey No. 1 (2 weeks)

A. Reduce Magmamax No. 1 flow to minimum.

B. Bring Woolsey No. 1 into production (following Section II & III above).

C. Operate Woolsey No. 1 over the maximum flow rate possible and continue to reinject into Magmamax No. 3.

- D. Record operating conditions (Appendix B & C).

VII. Production Optimization test (4 weeks).

- A. Determine optimum back pressure for production wells.
- B. Adjust controls of GTF to yield optimum performance.
- C. Record all operating condition. (Appendix B)

VIII. Production scale and corrosion test.

- A. Operate production wells and GTF at rated or optimum pressures and temperatures for 1500 hours (approximately 4 months).
- B. Record operating conditions. (Appendix B)

IX. Maximum flow tests.

- A. Operate Magmamax No. 1 and Woolsey No. 2 alternately at maximum flow and record operating parameters, particularly reservoir conditions.

B. Operate both Magmamax 1 and Woolsey No. 2 at maximum flow and record results.

X. Post Test Evaluation (2 weeks)

A. Reservoir Model.

1. Brine composition including.

- a. C_{12}/C_{13} ratio.
- b. CO_2/CH_4 ratio.
- c. Na/K ratio.

2. Production/Reinjection Well

- a. Pressure vs Flow rate and time.
- b. Temperature vs Flow rate and time.

3. Observation Well.

- a. Liquid level vs time and production well flow.
- b. Down hole pressure and temperature vs time and production well flow.

B. System Evaluation.

1. Production and Reinjection Casing.
 - a. Visual inspection.
 - b. Sample deposits.
2. Separators and Scrubbers.
 - a. Visual inspection.
 - b. Sample and analyze deposits.
 - c. Measure wall thickness and calculate metal loss.
3. Heat exchangers.
 - a. Visual inspection.
 - b. Sample and analyze deposits.
 - c. Measure wall thickness and calculate metal loss.
 - d. Calculate and plot U (Heat transfer coefficient).
 - e. Pressure loss, ATLM, duty.
4. Pumps Valves and Instruments (Controls).
 - a. Specification.
 - b. Estimate Reliability.

- c. Calculate Maintenance required (hours).
- d. Estimate life time.

5. Cooling pond.

- a. Calculate water consumption vs plant operation.
- b. Estimate effect on environment.

XI. Chemical Cleaning.

Chemical cleaning of GTF equipment will be conducted as needed following the procedure described in Appendix C.

XII. Special Projects.

It is expected that a number of special projects will be undertaken by SDG&E and other organizations during the GTF test period. These projects will normally use a small side stream of geothermal fluid, either brine or steam, and may in addition require other facilities such as cooling water. Careful control will be maintained by SDG&E to insure that a total energy and mass balance for the geothermal project can always be made. It is

expected that SDG&E will furnish advice and emergency service to these special projects, but will not be concerned with the day to day operation and the collection and analysis of the data or publication of the results. Some of the special projects that will be conducted during the test period will include:

- A. U.S. Bureau of Mines-corrosion test loop and geothermal fluid analysis. The details of this program are presented in Appendix E.
- B. Lawrence Livermore Laboratory-materials testing and scaling tendency of geothermal fluids. The details of this program are presented in Appendix F.
- C. The helical expander project.

In this project unseparated well head geothermal fluid (both brine and steam) will be passed through a helical expander.

D. Coated Tube Concept.

In this project heat exchange tubes will be coated with a hydrophobic material, such as teflon and a small amount of organic fluid, such as oil will be added to the geothermal brine to prevent deposition and scaling on the metal surfaces.

Other special projects may develop as the program progresses. These will be incorporated into this test program whenever possible.

APPENDIX B

OPERATING CONDITIONS
TO BE RECORDED*

I. Production Well

A. Operating Parameters

1. Flow

- a. Liquid
- b. Vapor
- c. Gas

- 2. Well head pressure
- 3. Well Head Temperature
- 4. Composition

- a. Liquid
- b. Gas

B. Gathering Line

- 1. Scaling rate and location

*See Appendix C for procedures

2. Scale composition
3. Corrosion (rate and location)
 - a. Pitting
 - b. General
 - c. Sulfide Fracture
 - d. Fatigue

II. Reinjection Well

A. Operating Parameter

1. Flow
2. Well head pressure
3. Well head temperature
4. Composition

B. Reinjection Line

1. Scaling rate and location
2. Scale composition
3. Corrosion (rate and location)
 - a. Pitting
 - b. General
 - c. Fatigue Fracture

III. Separator

A. Operating Parameters

1. Flow
 - a. Liquid
 - b. Vapor
 - c. Gas
2. Pressure
3. Temperature
4. Composition (exit)
 - a. Liquid
 - b. Vapor
 - c. Gas
5. Liquid level
6. Dwell Time
7. Fluid Velocity

B. Scaling

1. Rate & location
2. Composition

C. Corrosion (rate & location)

1. Pitting
2. General
3. Sulfide Fracture
4. Fatigue Fracture

IV. Scrubber

A. Operating Parameter

1. Flow
 - a. Liquid
 - b. Vapor
 - c. Gas
2. Pressure (in/out)
3. Composition (exit)
 - a. Liquid
 - b. Vapor
 - c. Gas
4. Reflux
 - a. Flow
 - b. Temperature
 - c. Composition
5. Liquid Level
6. Temperature (in/out)
7. Fluid Velocity

B. Scaling

1. Rate and Location
2. Composition

C. Corrosion (rate & location)

1. Pitting
2. General
3. Sulfide Fracture
4. Fatigue Fracture

V. Heat Exchanger

A. Operating Parameters - Steam

1. Flow (mass)
 - a. Vapor
 - b. Gas
 - c. Liquid
2. Pressure (in/out)
3. Temperature (in/out)
4. Vapor Velocity

B. Operating Parameters - Isobutane

1. Flow (mass)
2. Pressure (in/out)
3. Temperature (in/out)
4. Composition (impurities)
5. Velocity

C. Corrosion (rate & location)

1. Pitting
2. General
3. Sulfide Fracture
4. Fatigue Fracture

D. Scaling

1. Rate and Location
2. Composition

E. Heat Transfer Coefficient

1. Initial
2. Final
3. Change with time
4. Hours to reach minimum U

F. Calculate Isobutane Cycle Efficiency

VI. Process Piping

A. Scaling

1. Rate and Location
2. Composition

B. Corrosion (rate & location)

1. Pitting
2. General
3. Sulfide Fracture
4. Fatigue Fracture

VII. Isobutane & Condensate Storage

A. Level

B. Temperature

C. Pressure

VIII. Maintenance Log

A. Equipment type & location

B. Outage

1. Reason
2. Length (hours)

C. Maintenance required

1. Hours
2. Parts

D. Lifetime

IX. Cooling Water

A. Properties

1. PH
2. Conductivity
3. TDS
4. Cl residual
5. Chromate concentration

B. Additives (amount & frequency)

1. Corrosion inhibitor
2. Acid
3. Chlorine
4. Cougulant

C. Make Up water

1. pH
2. Conductivity
3. TDS
4. Amount
5. Frequency

D. Blow Down

1. Amount
2. Frequency
3. Disposal

X. Environment

A. Subsidence

1. Survey height of appropriate markers semi-monthly
2. Record location & change

B. Seismic

1. Record seismic activity

C. Emission

1. Liquid

- a. Vail drain conductivity up & down stream of site (weekly)
- b. Cooling water properties if released into Salton Sea.

2. Air

- a. Hydrogen Sulfide on site and at site boundary (daily)
- b. Rador on site & at boundary monthly
- c. Isobutane (continuously)

3. Noise

Level on site & at site boundary
(monthly)

D. Meteorological

1. Wet & dry bulb temperature (daily)
 - a. Down wind of spray pond
 - b. Up wind of spray pond
2. Wind direction & speed (recorder)

XI. Corrosion Testing

A. Corrosion Specimen

1. Location
 - a. Well fluid
 - b. Steam
 - c. Brine
 - d. Reinjection fluid
2. Coupon material
3. Weight change vs. time
4. Fluid properties
5. Fluid Velocity
6. Visual inspection
 - a. Type of corrosion
 - b. Pitting (depth & frequency)

B. Process Equipment

1. Equipment description
2. Equipment location
3. Fluid properties
4. Fluid velocity
5. Weight change
6. Visual inspection
 - a. Corrosion type
 - b. Pitting (deth, location, frequency)

XII. Chemical Descaling

A. Equipment Descaled

1. Equipment Description
2. History
 - a. Length of contact with geothermal fluid
 - b. Previous treatment

B. Scale Properties

1. Thickness (before & after)
2. Weight (before & after)
3. Composition

C. Cleaning solution

1. Initial Composition/Acid No
2. Temperature
3. Flow
4. Velocity
5. Final Composition/Acid No
6. Total quantity
7. No. of cycles
8. Length of cycle

C. Settleable Solids

1. Weight
2. Composition

APPENDIX C
Test Description
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APPENDIX C

TEST DESCRIPTION

I. Temperature measurements

A. Equipment

1. Thermometer wells
2. Thermometers, mercury
3. Thermometers, dial
4. Thermocouple and recorder/controller
5. Down hole temperature probe and recorder

B. Installation

Because this is an experimental installation, two thermometer wells will be installed on the production and reinjection wells and on the inlet and exit of all process equipment. One of these temperature wells will be fitted with a dial thermometer or temperature recorder, the other will be fitted with a mercury thermometer which will provide a

more accurate reading and serve as a check on the accuracy of the dial thermometer or temperature recorder. Temperature recorders will be installed on:

1. Production well
2. Steam output from the first stage brine flash drums
3. First stage steam scrubber
4. Gas vent separator vent
5. Brine output from the fourth stage brine flash drum

6. Isobutane inlet to second and third stage heat exchangers
7. Isobutane to throttling valve
8. Isobutane from condenser
9. Cooling water to and from pond
10. Reinjection well

All temperature recorder probes will be inserted into thermometer wells so that they may be removed without interruption of testing. Thermometer wells will also be installed adjacent to the temperature recorder probes to allow field calibration of the thermocouple and recording system. The wells for mercury thermometers will be installed near the top of the pipe to prevent the thermometer from falling out of the well and to facilitate reading the thermometer. All temperature indicators will be readily accessible for reading. Valving and bushing to allow insertion of a down hole temperature probe fluid sampler will be installed

on all wells.

C. Procedure

During the operation of the geothermal test facility the dial thermometers will be read hourly and the data recorded on appropriate data sheets. Mercury thermometers will be used to check the accuracy of the dial readings and also the temperature recorders. The mercury thermometers will be read daily and the readings recorded on the appropriate log sheets or on the temperature recorder chart. Mercury thermometers should be read by adjusting head height so that the top of the mercury is at eye level. Readings should be to the nearest half degree.

The temperatures at which the respective equipment may be expected to operate are:

1. 1st stage flash drum, scrubber and heat exchanger -
370°F (188°C)

2. 2nd stage flash drum, scrubber and heat exchanger - 308°F (153°C)
3. 3rd stage flash drum, scrubber and heat exchanger - 262°F (128°C)
4. 4th stage flash drum, scrubber and heat exchanger - 221°F (105°C)
5. Steam condenser - 200°F (93°C)
6. Condensate cooler - 160°F (71°C)
7. Isobutane flash valve - 300°F (149°C)
8. Isobutane condenser - 120°F (49°C)
9. Cooling water inlet - 70°F (21°C)
10. Cooling water exit - 110°F (43°C)

These temperatures may vary as the operation of the GTF is changed to evaluate different parameters. Cooling water inlet temperature will fluctuate with ambient conditions. After the operation of

the GTF has been optimized, it will be operated in such a manner so as to maintain the optimum temperatures.

Particular care should be taken in reading and recording the temperatures throughout the isobutane cycle as these values will be used to calculate heat transfer coefficients and cycle efficiencies.

Mercury thermometer readings should be used whenever possible.

A temperature log of each observation well will be made weekly by lowering a temperature probe attached to a surface recorder into the well. The temperature and drum revolutions (depth) will be recorded.

II. Pressure measurements

A. Equipment

1. Pressure taps

2. Isolation diaphragm
3. Dial pressure gauge
4. Compound pressure gauges
5. Pressure indicator controllers
6. Pressure recorders
7. Valves
8. Dead weight gauges and calibration equipment

B. Installation

Pressure gauges with appropriate diaphragm arrangement to isolate the bourdon tube from the geothermal fluid will be installed on the production and reinjection wells, and all pressure vessels and pumps. Differential pressure gauges with appropriate isolation will be installed on all scrubbers and heat exchangers. Pressure indicator controllers with appropriate isolation will be installed on:

1. First stage flash drums
2. Instrument water system
3. Isobutane throttle valve

Pressure recorders will be installed on the production and reinjection wells and the isobutane throttle valve.

All pressure sensing devices will be connected to the equipment through a 1/2" or greater hand operated shut off valve. This arrangement will allow the pressure sensing instrument to be removed for repair or calibration without shutting down the GTF. The shut off valve may also be used to isolate the pressure sensor from a pulsating fluid.

Compound dial gauges will be installed on reinjection lines and condensers. Dial gauges will be readily accessible for easy reading and repair.

C. Procedure

During the operation of the GTF the dial pressure gauges will be read hourly and the data recorded on the appropriate log sheets. Once a week the pressure recorders will be calibrated by attaching a dead weight gauge to the pressure sensing lines. The dead weight gauge reading will be entered on the recorder chart. Each pressure gauge will be calibrated monthly with a dead weight gauge.

The pressures at which the respective equipment may be expected to operate are:

1. 1st stage flash drum, scrubber and heat exchanger - 165 psia
2. 2nd stage flash drum, scrubber and heat exchanger - 60 psia

3. 3rd stage flash drum, scrubber and heat exchanger - 28 psia
4. 4th stage flash drum, scrubber and heat exchanger - 13 psia
5. Steam condenser - 11 psia
6. Condensate water - 150 psia
7. Isobutane flash valve - 500 psia
8. Isobutane condenser - 96 psia

Theses pressures may vary during the initial operating period of the GTF. However, after the operation of the GTF has been optimized it will be desirable to operate the GTF so as to maintain the optimum pressures.

Pressures at the isobutane flash valve should be read carefully to allow accurate determination of the cycle efficiency.

III. Flow

A. Equipment

1. Sharp edge orifice meter for steam
2. Annubar meter for liquid
3. Flow recorder

B. Installation

The flow of fluid will be determined using an orifice type meter, either a straight sharp edged orifice for the steam flow or annubar type meter for liquid flow. The orifice meter should include provisions for easy removal and inspection of the orifice plates. Particular attention should be paid to the pressure taps which should include provisions for cleaning by backflushing or other means and should include isolation diaphragms to

Pressures at the isobutane flash valve should be read carefully to allow accurate determination of the cycle efficiency.

III. Flow

A. Equipment

1. Sharp edge orifice meter for steam
2. Annubar meter for liquid
3. Flow recorder

B. Installation

The flow of fluid will be determined using an orifice type meter, either a straight sharp edged orifice for the steam flow or annubar type meter for liquid flow. The orifice meter should include provisions for easy removal and inspection of the orifice plates. Particular attention should be paid to the pressure taps which should include provisions for cleaning by backflushing or other means and should include isolation diaphragms to

insure physical separation of the recording instruments from the brine.

Flow recorders will be installed on the following equipment:

1. Steam and brine exits from all flash drums
2. Vent gas separator
3. All steam scrubbers
4. All heat exchangers
5. All condensers
6. Cooling ponds
7. Reinjection well

C. Procedure

Flow recorders cannot effectively measure two phased flow. Therefore, to estimate production well flow rates the flow of both the steam and brine from all four flash drums must be recorded. Flow from the vent gas separator must also be measured to determine the production of noncondensibles during the GTF tests.

Flow indicators will be used to determine the flow of condensate to the steam scrubbers.

The flow rates will be used to calculate:

1. Steam flow from each flash drum
2. Brine flow from each flash drum
3. From the above total production well flow
4. Steam flow to isobutane heat exchangers
5. Isobutane flow through the flash valve, heat exchangers and the condensers

6. Cooling water flow
7. Cooling water blow down
8. Cooling water make up
9. Noncondensibles generated
10. Reinjection rate and total volume.

Flow of fluid into the reinjection well will be measured at a number of different depths throughout the perforated section of the well. A turbine flow meter will be lowered into the well until it reaches the perforated casing section. The number of revolutions of the cable drum will be recorded and used to calculate the depth reached by the flow meter. The flow velocity at that depth will also be recorded and a flow profile (flow vs

depth) for the reinjection well developed. From this flow profile the amount of fluid flowing into any specific strata can be estimated.

IV. Liquid level

A. Equipment

1. Brine - liquid level indicators, controllers and gauges for measuring brine levels will use ultrasonic detection of the liquid level. Sight glasses will be of the type that allow easy cleaning.
2. Non-brine - simple liquid level detectors such as floats may be used for measuring the level of condensate, cooling water, etc.

B. Installation

Each vessel will be equipped with a liquid level detector leg consisting of a vertical section of 2" pipe. This pipe will be attached to the side of the vessel at the normal liquid level. Connection

to the vessel will be through valving to allow isolation of the detector leg from the geothermal fluid. The pipe will contain several ports to allow adjustment of the detector position. A glass sight gauge may also be installed on the detector leg to allow visual determination of the liquid level. The sight glass will require frequent cleaning and should be connected to the detector leg with isolation valves and be easily accessible.

The location of the ultrasonic level detector and high and low level alarm detector on the detector leg will be determined by trial and error measurements during the preliminary test period.

A simple liquid level detector and recorder will also be installed on the observation wells to record any change in liquid level.

C. Procedure

As noted above the location of the liquid level detectors and the high and low alarm detectors will be determined during the preliminary test phase. The liquid level in the flash drum is one of the two parameters (mass flow rate being the other) that controls the velocity or dwell time, and hence the quality of steam from the flash drums. Thus, proper location of the liquid level detector is essential to effective operation of the GTF. Since the liquid level detector senses only the presence or lack of a liquid it is essential that the liquid level controller detector be placed exactly at the level desired.

The liquid level of all the steam scrubber flash drums as well as the condensate and isobutane tanks will be checked hourly to insure the equipment is operating correctly.

Sight guages in contact with the geothermal brine will rapidly become coated with scale. Either contact must be minimized or sight guages must be cleaned frequently. Cleaning should be with the

following solution:

Hydrochloric Acid	10%
Nitric Acid	2%
Water	88%

V. Sampling

A. Equipment

1. One half inch or greater sample ports and valves
2. Sample bombs
3. Sample coolers
4. Vacuum pump, guage and manifold.

B. Installation

1. Sample valves

Sample valves will be installed on the inlet and exit of all GTF process equipment to allow appropriate sampling of specified streams. Sample valves on well collection lines will include provisions for traverse sampling of the fluid within the line.

2. Sample bombs will be used for both liquid and steam flow and will be installed as required on each sample valve to provide a representative total sample at the particular system conditions.

3. Sample coolers will be required on both brine and steam lines where it is desired to collect a liquid sample and flashing could occur.

4. Sample bomb with remote valve operation and auxiliary equipment for obtaining down hole samples of geothermal fluid.

C. Procedure

Sampling of the individual streams from each of the process systems will be done every two hours until stream properties have stablized. Hourly sampling will be reinstituted whenever there is a change in the process or in the flows from the production well.

The following samples will be taken:

<u>Sample Point</u>	<u>Sample Type</u>	<u>Sample Frequency</u>
Inlet to 1st stage flash drum top & bottom of pipe. Steam from all vessels (V-1, 4, 6, 7, 8, 9, 10, 11, 12, 13 & 14).	Bomb (purge) & cooling coil	Every 2 hours until equilibrium - (usually 12 hours) then daily.
Brine from all vessels (V-1, 4, 6, 7, 8, 10, 11, 12, 13 & 14)	Cooling coil	Ditto
Reinjection line (at a positive pressure point)	Direct	Ditto
Cooling water make up, blow down & CW	Direct	Daily
Isobutane Accumulator	Evacuated Bomb	Weekly
Observation well	Evacuated Bomb	Weekly

All samples will be carefully labeled as to location and time and date the sample was collected.

The sampling of corrosion and scale products will be discussed in detail in subsequent sections.

D. Sampling technique

1. Evacuated bomb - if an evacuated bomb is used it is only necessary to attach it tightly to the sample point and open the sample valve. Allow 1 minute for the sample to reach equilibrium with the process stream. The connection between the bomb valve and sample valve should be as short as possible and its volume known so as to allow for air introduced during sampling. Sample bomb should be mounted so that any air introduced

during the sampling process will remain in the sample bomb and not contaminate the isobutane system.

Bombs will be prepared by attaching them to a vacuum manifold and evacuating to 1000 microns.

2. Purged bomb - the purge bomb has a valve on either end, one of which is attached to the sample valve. The process fluid is usually allowed to vent to the atmosphere through the bomb until both temperature and chemical equilibrium are established, usually about 5 minutes. The vent valve is closed and then the sample valve, trapping a representative sample of the process fluid in the bomb.
3. Sample coolers - sample coolers will be used to condition the sample so that collection can be made in unpressurized containers. These samples will normally be brine or steam streams which will condense on cooling. Samples will be collected in glass or plastic bottles for subsequent analysis. (Plastic bottles should be used if the silica content of the sample must be accurately determined.)

The sample line and cooler must be thoroughly purged before the actual sample is taken.

VI. Analysis of samples

A. Equipment

1. Atomic absorption spectrophotomer
2. pH meters
3. Conductivity bridges
4. Defraction spectrophotometer
5. Gas chromatograph
6. Specific ion electrodes

B. Installation

The analytical equipment will be housed on site in a separate portable laboratory with a controlled atmosphere necessary for the effective operation of the equipment.

The three types of samples that will be analyzed are solid, liquid and vapor (gaseous). Solid samples will normally be scale or corrosion productions and these will be discussed in detail in subsequent sections.

The procedure for analysis of liquid and vapor samples are outlined below.

1. Liquid samples - liquid samples will normally be brine or condensed steam. These samples will usually be stored in glass bottles and will be analyzed for conductivity, pH, and mineral composition. The pH and conductivity will normally be measured near ambient temperatures using a laboratory pH meter and conductivity cell, respectively. The cation

constituents of the mineral species will normally be analyzed with an atomic absorption spectrophotometer, while the anion species will need to be analyzed using wet chemistry techniques.

One of the very important parameters in the operation of the GTF is steam purity. In order to measure this parameter the steam samples can be condensed and analyzed for pH, conductivity, and, if required, total dissolved solids (TDS). Once a week, or whenever there is a change in operating procedure, the condensed steam samples may also be analyzed for specific constituents to determine if any of the mineral species are preferentially being carried over with the steam.

The brine properties are an excellent measure of:

- a. The reservoir conditions
- b. The operation of the GTF .
- c. The possibilities of scaling and corrosion of equipment

For this reason brine samples are taken of the well head fluids and throughout the geothermal test process for analysis. The easiest analysis to make are pH, Eh, and conductivity and these will be, of course, made on all samples. Composition analysis will be used to determine if there are any changes in the reservoir, the effect of flashing in the geothermal test facility and as a measure of scaling tendency.

If the liquid sample is to be used for mineral analysis, usually performed with an AA, it should be preserved by adding three drops of nitric acid to the sample bottle.

2. Vapor (gas) samples - These samples are collected in a sample bomb as described in the preceding section. If possible, the samples should be analyzed soon after being taken. If this is not possible and it is necessary to allow the sample bombs to cool to ambient temperatures, it is desirable to reheat the bomb to approximately the same temperature as the original fluid sample. Analysis of such samples will be by gas chromatograph since the noncondensable gases present are normally the species of interest. This is particularly true of the well head fluid and the first stage flash and vent vessel. The amount of noncondensable gases down stream of first stage flash is expected to be very low.

Most GC's will allow the sample bomb to be attached to the unit and a sample drawn through a sampling train. If the sample was taken at a stream elevated temperatures it is

important that the bomb be raised to approximately that temperature and maintained for approximately 30 minutes in order to allow equilibrium to occur. The GC sample train should, of course, be carefully purged with the sample before analysis is started.

If only low boiling point non-condensibles with limited solubility in water are to be measured, ambient temperatures may be used. The non-condensibles are drawn through the GC as described above and the water in the bomb measured volumetrically.

C. Procedure

The analysis required for this program are summarized below.

1. The pH, Eh, and conductivity of all steam and brine samples will be measured and recorded using a laboratory pH meter and conductivity bridge.
2. For each test condition three liquid samples from each brine sample point will be analyzed as follows:

<u>Compound</u>	<u>Analytical Technique</u>
Total Dissolved Solids	Gravimetric (Evaporation)
Boron	AA
Calcium	AA
Iron	AA
Lead	AA
Lithium	AA
Magnesium	AA
Silica	AA
Sodium	AA
Zinc	AA
Bicarbonate	Wet Chemistry

3. For each test condition three condensed liquid samples from each steam sample point will be analyzed as follows:

<u>Component</u>	<u>Analytical Technique</u>
TDS	Evaporation
Calcium	AA
Iron	AA
Lead	AA
Potassium	AA
Silica	AA
Sodium	AA
Ammonia	GC

4. For each well head test condition three samples of well fluid will be taken and analyzed as follows:

<u>Constituent</u>	<u>Analytical Technique</u>
Cooled liquid sample:	
TDS	Evaporation
All Cations	Spectrographic
Anions	
Bicarbonate	Wet Chemistry
Bromine	" "
Carbonate	" "
Chloride	" "
Iodide	" "
Sulfate	" "
Sulfide	" "
Gas (bomb) sample:	
Ammonia	GC
Carbon dioxide	GC
Hydrocarbons (CH ₄ , etc)	GC
Hydrogen Sulfide	GC
Nitrogen	GC
Oxygen	GC or volumetric
Water	

5. Down hole samples from the observation wells will be analyzed as in 4 above.
6. Condensed steam samples will be analyzed for pH, Eh, and conductivity. If conductivity cannot be used as an indication of steam purity the TDS in the sample must be measured gravimetrically.

VII. Casing condition

The condition of the well casing is very critical to the reliable operation of the geothermal test facility. In order to determine if scaling buildup or extensive corrosion of the well casing is occurring examination of the down hole casing before and after each test will be made.

A. Equipment

1. A television camera which can be lowered into the well and transmit to the surface a picture of the well casing. Equipment normally limited to temperatures below 160°F (71°C).
2. Calipers may be used to measure the casing diameter and from any changes ascertain whether or not deposition or corrosion is occurring. The limitations of calipers are:
 - a. Scratches can cause increased corrosion
 - b. Pits and other imperfections in the casing may not be detected by the caliper fingers

Accordingly, a visual examination, if possible is suggested.

B. Installation

It is expected that neither TV cameras or calipers would be permanently installed in the well.

A frame will need to be attached to the well head to facilitate removal of the well head pipe and insertion of a TV camera or calipers into the well.

C. Procedure

With either visual or calipers measurements the instrument will be gradually lowered into the well. Before the television camera can be lowered into the well it will be necessary to purge the well with approximately 10 volumes of cool water to insure the down hole temperatures will not effect the television camera electronics. To protect the television camera a temperature sensor should be attached and the temperature of the well water monitored. Other possible methods of monitoring of the casing such as by electric or gamma ray logging will be investigated.

VIII. Corrosion

Because of the high mineral content of geothermal brine, the possibility of catastrophic corrosion is always present, particularly if oxygen is allowed to enter any of the equipment. Mild steel is used throughout except for the heat exchangers and is susceptible to corrosion by the geothermal brine particularly in the presence of oxygen, as noted above. In order to determine the corrosion problems that may exist in the operation of a geothermal facility, corrosion coupons or specimens will be installed at numerous points in a major GTF equipment.

In addition, it is expected that the U.S. Bureau of Mines will operate their corrosion test facility at the Niland site and also measure the corrositivity of fluid from the Niland reservoir.

A. Equipment

1. Test coupons or specimens
2. Sections of processed piping or equipment

3. Corroisometer
4. Corrorator
5. Microscope
6. Analytical balance

B. Installation

Test coupons will be installed in:

1. All process equipment
2. Production and reinjection wells
3. Cooling ponds

Test spools or sections of processed piping will be installed in:

1. Production and reinjection lines
2. Steam and brine lines from first stage flash drums
3. Vent pipe from vent gas separator

In addition, the condition and thickness of specified areas of the process equipment will be recorded and used for subsequent measurements.

U.S. Bureau of Mines--fluid from the production well will be provided to the U.S. Bureau of Mines facility:

Lawrence Livermore Laboratory (LLL) - material test specimens from LLL will be inserted in:

1. Production line at well head
2. 1st stage brine separator
3. 1st stage brine exit
4. 1st stage steam exit

C. All test specimens will be weighed prior to installation. At the end of each test, or at least once a

month, the test specimens will be removed, examined, and reweighed and returned to their original locations. Sections of processed piping will also be removed and examined as well as the services of the various test areas inside the process vessels. The U.S. Bureau of Mines proposed test program is presented in Appendix E to this report and the Lawrence Livermore Laboratory test program in Appendix F.

IX. Scaling

Scaling, which can occur anywhere in the geothermal process, is due to the high mineral content of the geothermal fluid. Deposition is greatest in areas of high pressure or temperature drop. As noted in section VII. scaling in the wells will be determined visually and/or with calipers. Process piping and equipment will also be examined visually and the amount, thickness and composition measured.

A. Equipment

1. Microscope for visual examination.

2. Calipers will be used to determine scale thickness on various sections of process piping.

B. Installation

Will be essentially the process equipment itself.

C. Test procedure

As noted above the scale will be measured as to thickness and examined visually as to color and point of deposit. Samples will be taken for analysis to determine the composition.

At the end of each test, or at least once a month, all equipment and processed pipe sections will be examined for scaling. The thickness of the scale will be measured and the scale will be examined visually as to color and location of deposits. Samples will be taken for analysis of composition. As described in the analytical section (section VI.).

X. Maintenance

A. Equipment

Log sheets

B. Installation

All equipment

C. Procedures

A maintenance record will be maintained on all equipment both major and minor and the following data recorded:

1. Date

2. Equipment description

3. Maintenance required in hours

4. Parts required

From this log sheet the equipment life time and reliability will be estimated and the effect of changes in operation of the geothermal facility on maintenance and reliability determined.

XI. Cooling ponds

A. Equipment

The equipment used on the cooling ponds has been partially described elsewhere. It will consist of:

1. Dial and mercury thermometers
2. Pressure gauges
3. Flow meters
4. pH meters
5. Conductivity meters
6. Wet chemistry facilities

B. Installation

1. Temperature sensors will be installed on the:
 - a. Condenser inlet and exit
 - b. Cooling water make up
 - c. Cooling water blow down
2. Pressure gauges will be installed on the cooling water pumps.
3. Flow meters or flow measuring devices will be installed on the pond make up, pond blow down flow, and the cooling water flow through the condensers.

4. A recording pH controller will be installed on the cooling pond make up flow.

C. Procedure

Most of the parameters of the cooling system, e.g., temperatures, pressures, flows, will be recorded as described in previous sections. In addition, the chemical treatment required to control corrosion and biological growth must also be recorded as well as the make up and blow down flows and conditions. A log will be prepared incorporating the following:

1. Properties of the cooling pond water and make up and blow down. These will include pH, conductivity, total dissolved solids, chlorine residuals and chromate concentration.
2. The type of additive and the amount and frequency of their use will also be recorded. Additives include corrosion inhibitors, acids, chlorine and coagulants used to control water turbidity.

3. The amount and frequency of make up will also be recorded as well as the frequency and disposal of the blow down from the cooling pond.

XII. Heat exchanger

A. Equipment

1. Temperature, pressure and flow detectors

B. Installation

1. Temperature detectors on inlet and exit streams.
2. Pressure gauges on steam stream.
3. Flow meters on each steam stream and isobutane stream.

C. Procedure

The operating parameters of the heat exchanger, namely the temperature, pressure and mass flow of the steam and isobutane will be recorded hourly. From this information the heat transfer coefficient of the heat exchangers will be calculated.

XIII. Isobutane system

A. Equipment

1. Vacuum pump
2. Vacuum pressure gauges
3. Combustible gas detectors
4. Oxygen detectors
5. Moisture detectors
6. Manifold arrangement or detector mounting

B. Installation

A vacuum pump suitable for processing combustible

liquids will be installed on the isobutane system. Appropriate pressure and vacuum gauges will be attached to the connecting lines. A manifold system will also be installed to allow sampling of the gas being processed by the vacuum pump. Sampling equipment to be installed on this manifold includes:

1. Oxygen detector
2. Nitrogen detector
3. Combustible gas detector
4. Moisture detector

C. Procedure

Initially the isobutane system will be inspected and all accessible sections wiped or blown out with air. The four carbon based solutions will be removed and the entire isobutane system will then be evacuated. During the evacuation process the gases removed will be analyzed for oxygen, nitrogen, combustible gases and moisture. The system will then be filled with dry nitrogen and re-evacuated utilizing the same procedure. The evacuated system will then be filled with isobutane and operation began. During initial operation samples will be drawn from the isobutane condenser and analyzed for nitrogen, oxygen, combustible gases, and moisture.

The pressure drop across the isobutane filter will also be monitored carefully during initial operation and the screens themselves examined daily for the first three days and weekly thereafter.

Particularly during loading and initial operation of the isobutane system the combustible gas detector should be carefully monitored. These detectors

should be calibrated weekly using the procedure recommended by the manufacturer and the results logged.

XIV. Isobutane cycle

A. Equipment

Temperature, pressure and flow detectors.

B. Installation

Temperature, pressure and flow detectors will be installed around a isobutane flash valve and on the isobutane condenser.

C. Procedure

The operating parameters of the isobutane flash valve and condenser, namely the temperature,

pressure and mass flow of the isobutane and the cooling water will be recorded hourly. From this information the isobutane cycle efficiency will be calculated.

XV. Chemical cleaning (descaling)

A. Equipment

The equipment required for chemical cleaning consists of:

1. A chemical holding tank
2. A spent chemical receiving tank and sludge separator
3. Circulating pumps
4. Temperature and flow measuring equipment
5. Analytical equipment described previously in section VII.

B. Installation

The storage and receiving tanks will be located on a pad in a berm. The chemical pumps will also be located in the berm and will be connected to the equipment requiring cleaning by means of rubber hoses and LPVC pipe with vitalic connections.

C. Procedure

It is expected that all process equipment will be chemically cleaned during the GTF program. In order to eliminate requirements for a large storage and receiving tankage it is expected that only one piece of equipment will be cleaned at one time. The chemical cleaning procedure will be as follows:

1. The necessary chemicals will be brought on site and diluted to the required concentration in the chemical supply tank.

2. The equipment to be cleaned will be connected to the chemical pump. The cleaning solution will be circulated through the process equipment to be cleaned and returned to the receiving tank. The receiving tank will also act as a settling tank with solid pieces of scale remaining in the receiving tank.
3. The cleaning solution will be returned to the supply tank and reused.

The chemical cleaning is expected to serve two purposes:

1. It will allow the GTF to continue to operate at full capacity.
2. It will demonstrate the effectiveness and limitations of chemical cleaning.

To document the effectiveness and problems associated with chemical cleaning the following information will be recorded:

1. Equipment description
2. Equipment history including length of contact with the geothermal fluid and any previous scaling treatment.
3. Analysis of scale.
4. Scale thickness before and after chemical treatment will be measured and the scale weight and composition before and after treatment determined.
5. The composition of the chemical cleaning solution.
6. The parameters of the cleaning process including temperature, flow rate and velocity.
7. The total quantity of chemical cleaning solution used.

8. The number of cycles and length of cycles.
9. The effect of chemical solution on the base metal including metal removal and pitting.
10. The amount of scale remaining in the settling tank.
11. The composition of scale in the settling tank.

XVI. Emissions

A. Equipment

1. Conductivity bridge
2. pH meter
3. Hydrogen sulfides detector
4. Combustible gas detector

B. Installation

This test equipment will be located in the laboratory and samples brought in for analysis.

C. Procedure

1. Liquid emissions
2. Cooling pond blow down

This water will be monitored for pH and conductivity to determine that it meets the emission requirements. Brine is also a possible emission, although normally the brine generated will be returned to the reservoir by means of reinjection well. However, to insure that no contamination of the drains from site occur weekly samples of the Vail drains that pass through the test facility will be taken up and downstream of the site and analyzed for conductivity changes.

3. Gaseous emissions

Possible gas emissions from the geothermal site include hydrogen sulfide, carbon dioxide, hydrocarbon gases and isobutane. The carbon dioxide which is present in the geothermal fluid is not considered toxic and no particular effort will be made to measure it once it is released into the atmosphere. Hydrogen sulfide is expected to be a minor constituent of the geothermal fluid but because of its toxicity monitoring for hydrogen sulfide will be periodically conducted throughout the test facility and at the facility boundaries. Trace amount of hydrocarbon gases have been observed in the geothermal fluid. These small amounts of hydrocarbons are not expected to be of any consequence. However, because of the storage of isobutane on site and its use as a secondary fluid in the GTF system, continuous monitoring for combustible gases will be made. Calibration of both the H_2S detector and combustible gas detector should be made weekly following the manufacturer's procedure.

XVII. Subsidence and seismic changes

A. Equipment

1. Survey markers
2. Seismic detectors

B. Installation

The survey markers and seismic detectors will be located in cooperation with the U. S. Geological Survey so as to detect any subsidence and increase in seismic activity during the test period.

C. Procedure

It is expected that the survey markers will be re-surveyed monthly to detect any possible change in

APPENDIX D

RESERVOIR ANALYSIS

(To be supplied by the reservoir engineering consulting firm)

APPENDIX E

CORROSION & FLUID ANALYSIS PROGRAM

(To be supplied by the U.S. Bureau of Mines)

APPENDIX F

MATERIAL & SCALING PROGRAM

(To be supplied by the Lawrence Livermore Laboratory)