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MONITORING THE CHEMISTRY AND
MATERIALS OF THE MAGMA BINARY-
CYCLE GENERATING PLANT

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MONITORING THE CHEMISTRY AND MATERIALS OF THE MAGMA BINARY CYCLE GENERATING PLANT

1.0 INTRODUCTION

The Magma Binary Cycle Plant began operation in the fall of 1979. The plant is located on the East Mesa KGRA just east of Holtville, California, in the Imperial Valley, east of San Diego. The plant was built with private capital and is operated by the Magma Electric Company.

The Magma Plant has been described in Hinrichs (1978,1980). The binary cycle concept is an efficient way to extract energy from medium temperature geothermal resources. The hot (175 to 180°C) geothermal water is pumped from the ground by deep centrifugal pumps and delivered to the plant at a pressure of about 250 to 275 psig. After boosting the pressure to a nominal 350 psig, the brine is passed through heat exchangers. Here the heat is transferred to isobutane which is preheated and boiled on the tube side of the heat exchangers. The hot isobutane gas drives a turbine-generator set. After exiting the turbine, the isobutane is cooled through a recuperator (to transfer some of the remaining energy to a propane bottoming cycle system), and then is condensed back to liquid isobutane on the tube side of the condensor system. The condensers are cooled with treated water from a large spray pond system. The cooled isobutane is repressurized by a boiler feed pump and returned to the heat exchangers for reheating.

Since Magma's plant is the first binary cycle plant in the United States, there will be considerable interest by future geothermal plant designers in how various features of the plant performed. In their effort to further the general knowledge and use of geothermal energy, Magma adopted a policy of open release of information about the plant. Thus it was possible to set up a co-operative program between Magma and Pacific Northwest Laboratory (PNL) in a DOE-sponsored program to monitor and analyze the fluid chemistry, and materials performance of the plant during the first two years of operation. Magma made

their plant available for study, and installed, at their own expense, many of the fixtures, samples, instruments, and experimental systems described in this report.

While a number of features of the plant will be of interest, it was necessary to limit the scope of this monitoring program to studies of the following areas:

- Chemistry of the Geothermal Brine
- Chemistry of the Cooling Water
- Corrosion of Materials in Both Water Systems
- Scale Formation
- Suspended Solids in the Brine
- Methods and Instruments to Monitor Corrosion and Chemistry.

A decision was made to conduct no studies in the isobutane system, primarily for safety reasons. Any penetration into the isobutane system to insert instruments or samples creates the possibility of leaks or of loose parts that could damage the turbine.

In the past many geothermal energy projects have experienced operational problems with corrosion and mineral scale formation. The geothermal brine used in the Magma plant has a salinity of 0.8% to 1.0%, a pH of about 5.6, and a total carbonate content of about 1700 mg/l (as CO_2). Since the calcium content of the water is in the range of 30 to 80 mg/l, the brine would rapidly form carbonate scale if the brine were flashed to make steam for a conventional turbine. When this brine is flashed, CO_2 is released to the steam, initiating rapid calcium carbonate scale deposition. The binary cycle largely eliminates this problem by keeping the brine pressurized at all times. However if sufficient overpressure is not maintained, carbonate scale will form. Thus detection of flash conditions is important to plant operation.

Because the plant efficiency depends on good heat transfer in the heat exchangers, fouling of these surfaces with excessive scale could seriously degrade performance. Observations on heat exchanger fouling rates would be of interest to future plants.

Since the geothermal water is slightly acidic at pH 5.6, there was concern about the corrosion rates on carbon steel, especially the thin wall (0.035 in.) heat exchanger tubes. There is a tradoff between initial cost of heat exchangers built of special alloys and their life. Obviously if carbon steel will suffice, considerable cost savings can be made.

The long-term economics of any geothermal power plant depends on satisfactory disposal of the cooled brine, usually by reinjection into a cooler part of the reservoir. While reservoir engineering is outside the scope of this work, we did collect information on the suspended solids content of the spent brine, and monitored injection well flows and pressures for a period of months.

Concurrently with this monitoring program, PNL conducted a program to develop new instruments to measure geothermal brine chemistry directly in-line at full system pressure and temperature (see Table 1.1). The instrument sensors tested in the Magma plant are brine conductivity, oxidation-reduction potential (ORP), and two types of modified commercial corrosion probes.

TABLE 1.1. In-Line Monitoring Measurements Needed for Geothermal Power Plants

What	Why	Where	How
Corrosion Rate	Prevent Failures	Major Components	Corrosion Probes, In-Line Coupons
Suspended Solids	Plug Injection Wells	Plant Outlet	Sample/Filter, Solids Meter
Gas Breakout	Flash Causes Scale Isobutane Leak	Pump Suction; HX Outlet	Conductivity Meter
Salinity	Verify Normal Brine	Plant Inlet	Conductivity Meter, Sample/TDS
pH	Low pH-Corrosion High pH-Scale	Well Head; Plant Inlet	pH Probe Sample/ Field pH
Oxidation-Reduction Potential	Detects Air Inleakage	Plant Outlet	ORP Probe
Scale Rate	Fouling Component Failures	Pumps, HX	In-Line Coupons

Examples of the usefulness of these devices will be illustrated in several examples where plant operational problems were detected and corrected before plant damage occurred.

Geothermal power plants are capital intensive. When the plant is shut down because of a failure, the costs can be large. Considering the interest costs on the plant, staff costs, and lost power sales, a plant shutdown of a geothermal power plant can cost thousands of dollars per day. Clearly early detection and correction of problems relating to normal handling of geothermal fluids can be very cost effective.

We hope this record of the early chemistry and materials performance will prove useful to others designing similar plants. The measurements made at the beginning of the production of energy from this reservoir should assist others in future years to track changes in the reservoir and the plant components.

1.2 REFERENCES

Hinrichs, T. C. and W. H. Falk, Jr. 1978. "The East Mesa Magmamax Process Power Generation Plant," Geothermal Energy Magazine, 6(1):44-46.

Hinrichs, T. C. and B. W. Dambly. 1980. "East Mesa Magmamax Power Process Generating Plant-A Preliminary Analysis," EPRI, TX-80-907.

2.0 SUMMARY AND CONCLUSIONS

During the period of November 1979 to September 1981, Pacific Northwest Laboratory (PNL) conducted a program to monitor chemistry, corrosion, scaling, and suspended solids in the Magma Binary Cycle Generating Plant. During this period a number of methods were tested to establish those that were effective and reliable for use in future geothermal plants.

2.1 CHEMISTRY

Water is supplied to the Magma plant by five supply wells. The chemistry of each well is unique, although they are all in the 0.8% to 1% salinity range. During the monitoring period we detected no significant change in the chemistry of the wells as result of production of fluids from the reservoir.

As the brine passed through the plant, the only chemistry change that occurred in the brine was an increase in iron content of ~1.5 to 2.5 mg/l. The source of this increase in iron was corrosion of the carbon steel piping system. Estimates of this corrosion indicated 20 to 40 pounds of steel were being removed per day.

2.2 SCALE FORMATION

In a binary cycle plant, pump pressures are kept high enough to suppress flash boiling of the hot water. This was found to be very effective in suppressing scale formation. The only scale observed in the plant piping and heat exchanger tubes were very thin films of iron sulfide with traces of iron carbonate and other metal sulfides. In fact the scale was so thin that consideration should be given to trying to build up a little scale to suppress the steel corrosion rate.

The thickest iron sulfide scales were observed in the plant inlet region and the inlet to the first heat exchanger. The cause for this scaling is suspected to be related to blowdown which is required to flush the sand separator at the plant inlet. During blowdown we detected a 0.2 ppm drop in the iron

content of the brine. It is reasonable to expect the flashing which occurs during blowdown to alter the CO_2 content of the brine enough to slightly affect solubilities.

On several occasions calcium carbonate scale formed in down hole supply pumps, primarily in the first three stages. The cause of this scale formation is probably flashing in the pump suction due to insufficient hydrostatic overpressure on the suction side of the pump.

2.3 CORROSION

Corrosion of carbon steel was measured in the brine system, and corrosion of carbon steel and copper were measured in the cooling water system. Because of a decision not to make any test penetrations into the isobutane system, no measurements were made of materials in isobutane.

Corrosion was measured using weight loss coupons and two types of electrical corrosion probes which give continuous readings. The corrosion of carbon steel in the brine system was in the range of 5 to 25 mils/year (1 mil/yr = 0.001 in. loss in metal thickness loss per year). In low velocity regions, especially under protective scale, corrosion was near the 5-MPY level. In regions of high turbulence we measured rates of 25 MPY, averaged over months. On a few occasions we observed rates in the 200 + MPY range due to oxygen inleakage, or high turbulence or both.

The basic cause of the corrosion in carbon steel is the mildly acidic (pH 5.2 to 5.8) conditions caused by the carbon dioxide dissolved in the brine, coupled with high turbulence which prevents the formation of protective films.

The observations on corrosion led to the ultrasonic examination of the heat exchangers in the plant, since the carbon steel tube wall was only 0.035 in. thick. We measured wall thinning of about 2 to 4 mils on most tubes in February 1981. In some areas where the hot brine impinged directly on the tubes up to 15 mils was gone in the worst cases. We recommend that in future plants in pH 5.5 brine, that either a corrosion rate of up to 10 MPY be considered in the heat exchanger design, or that more corrosion resistant alloys be selected.

Corrosion of carbon steel in the cooling water system was 3 to 5 MPY, and the copper corrosion only about 0.1 MPY. However, several cooling water chemistry excursions were detected which produced high corrosion rates for short periods before corrective action was taken. Had these events not been corrected corrosion damage in the cooling water system could have been high. Several water chemistry excursions that were detected by the in-line corrosion probes are described in the body of this report.

2.4 IN-LINE INSTRUMENTS

In-line corrosion probes were found to be of considerable value in detecting incidents which caused high corrosion. Commercially available instruments worked well in the cooling water system. However, in the brine system rapid sensor failures were observed. A development program to improve performance is still underway and the current R&D versions fabricated by PNL produce long enough life to be useful.

The in-line brine conductivity cell on the plant outlet proved useful on a number of occasions. It has detected CO₂ gas flashing and contaminated brine. On one occasion the conductivity cell detected a major isobutane leak from the heat exchangers.

2.5 SUSPENDED SOLIDS

Suspended solids are of interest because of the potential for plugging the injection wells where the spent brine is pumped back underground. The pump power for this reinjection is a parasitic load on plant output, so preventing injection well plugging has economic implications, even if total plugging does not occur.

We found that solids are carried from the supply wells through the plant at about the 2 mg/l concentration. The size of most of these particles are <5 microns and did not seem to affect injection well performance.

On occasion, much larger concentrations of sand were produced and injected. During plant startups, the thermal shock would cause iron sulfide

scale to be removed from the plant. We observed concentrations of up to 180 mg/l iron sulfide particles during one startup.

2.6 FUTURE MONITORING OF PLANTS

As part of this program we have prepared a separate study (to be published later) for the Heber Geothermal Binary Demonstration Plant. This study indicates the methods and locations we feel are useful and cost effective.

We estimate that a day of downtime for a plant the size of the Heber Demonstration Plant has a financial value of over \$100,000. Corrosion and scaling failures of long lead-time components could cause shutdowns for repairs that could last from a day to several months. Thus, a monitoring program such as has been detailed here has a very beneficial effect. Even when adverse conditions cannot be easily corrected, knowing about a problem so that repairs can be scheduled, can have a beneficial effect in preventing surprise shutdowns.

3.0 MONITORING SYSTEMS IN MAGMA PLANT

The monitoring systems were set up to collect data at selected locations in the plant. These data were to be used to establish historical records on corrosion, scaling, brine chemistry changes, suspended solids, cooling water chemistry, and how these relate to plant and injection well performance.

The monitoring locations were chosen after construction of the plant had begun, so there were some constraints on locations that were available. The goal in selecting monitoring locations was to provide the maximum insight into what was happening to the plant systems, using the smallest number of plant penetrations. The monitoring locations are listed in Tables 3.1 and 3.2. The brine system monitoring locations are shown in Figure 3.1.

3.1 IN-LINE MONITORING STATIONS AND CONDUCTIVITY CELL

The brine monitoring station illustrated in Figure 3.2 evolved through several revisions into its present form. Geothermal brine is collected by a 1/2-in.-dia tube mounted on a flange through a 2-in. penetration on the top of the main 12-in. brine pipe. The tip of the sample tube has a 90° elbow facing upstream. The tube is located about 3-in. into the flow stream. This principle of a sample tube facing upstream was used in all plant sampling. The flow from the sample tube is routed to the 2-in. vertical pipe tees shown in Figure 3.2 where in-line sensors were installed. The vertical U-tube trap arrangement was selected so the electrodes would stay wet with brine, even if the main 12-in. line were drained. Clean-out plugs are provided to remove sand. A sample valve permits connection of cooling coils for collection of brine and gas samples. After passing by the in-line sensors the brine passes through a small orifice plate which regulates the flow to 6 to 10 gpm. Just downstream of the orifice is the electrodeless conductivity cell. The brine passes a thermocouple for temperature measurement (and conductivity temperature corrections), and then re-enters the plant system just upstream of the injection pumps. This arrangement provides >100 psi pressure drop to assure flow past the instruments. The system was designed so the conductivity cell operates as close to pump suction pressure as possible. Since this is the lowest

TABLE 3.1. Locations of Brine System Monitoring Stations

Location	Type	Function	Instruments
Well Head	Valve	Brine Samples	None
Plant Inlet (PC-1)	12-in. Spool	Corrosion/Scale Samples	Temperature Pressure
Plant Inlet (PC-1)	Type III Station	In-Line Monitors Brine Samples Brine to Test Loop	Conductivity Temperature Corrosion Probes ORP
HX Inlet	Flow Orifice	HX Flow Rate	Flow Transducer
HX 7	Sample Probe	Scale/Corrosion Rates	Temperature
HX 6	Valve	Brine Samples/to Test Loop	None
HX 3	Corrosion Probe	Corrosion Rate	Portable Meter Readout
HX 2	Sample Probe	Scale/Corrosion Rates	Temperature
HX 1	Valve	Brine Samples/to Test Loop	None
Plant Outlet (PC-2)	12-in. Spool	Corrosion/Scale Samples	Temperature Pressure
Plant Outlet (PC-2)	Type III Station	Corrosion/Scale Samples Brine Samples In-Line Monitoring Detect Insobutane Leaks	Temperature Corrosion Probes Conductivity ORP
Injection line	Turbidity	Suspended Solids	Turbidity, Temperature
Injection Wells	Injection Pressure Flow Orifice	Monitor Well Performance	Injection Flow and Wellhead Pressure

TABLE 3.2. Locations of Cooling System Monitoring Stations

Location	Type	Function	Instruments
Inlet to Condensers	Type II Station	Water Sample Corrosion/Scale Samples	Temperature Magna Plant pH and Conductivity
Inlet to Propane Condenser	Corrosion Probes	Fe Corrosion	Recorder/Data Logger Readout
Outlet Propane Condenser	Corrosion Probe	Cu Corrosion	Recorder/Data Logger Readout
Outlet Isobutane Condensers	2 Corrosion Probes	Fe Corrosion Cu Corrosion	Recorder/Data Logger Readout Recorder/Data Logger Readout
Outlet of Condensers	Type II Station	Water Samples Corrosion/Scale Sample	Temperature

NOTE-NOT TO SCALE

FIGURE 3.1. Monitoring Locations at Magma Power Plant

FIGURE 3.2. Typical Monitoring Station

pressure in that part of the system, if gas breakout occurs, the conductivity cell will detect the fluctuations as gas bubbles come through. A diagram of that electrodeless conductivity cell is shown in Figure 3.2 (see Figure 3.3 for details of construction).

3.2 IN-LINE PROBE

The latest version of an in-line probe is shown in Figure 3.4. This probe mounts on a 2-in. gate valve as shown in Figure 3.2. The probe can be inserted and withdrawn at full system pressure through the gate valve. Probes of this type were installed at many locations throughout the plant. The probe incorporates a commercially available resistance type corrosion probe and space for Teflon® insulated corrosion/scale coupons. As the thin-wall element of the corrosion probe corrodes, its electrical resistance changes and can be converted by calculation to a corrosion rate in units of MPY (0.001 in./yr). The probe includes temperature compensation on the inside for a bridge circuit. Some of the probes used in the plant had only samples and a thermocouple.

3.3 LINEAR POLARIZATION CORROSION PROBE

Commercial three-electrode type linear polarization probes were used in both the brine- and cooling-water systems. These probes gave satisfactory life in the cooling water system and the corrosion results correlate fairly well with the weight loss coupons (see Section 6). However, the commercial probes failed rapidly in the hot brine. It was found that a high electrical resistance was forming between the electrodes and the screw mounting studs inside the brine system. This high resistance caused the probe to read lower and lower corrosion rates, until it was in error by up to a factor of 100. A probe fabricated by PNL, shown in Figure 3.5, has given good service for over five months and is continuing. The electrodes on the PNL probe pass through a spring-loaded Teflon seal to preserve electrical continuity in the high-temperature system. The electrode area is the same as the commercial probe so the standard electronics can still be used.

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① 1/2" SCH 80 PIPE STEEL	⑦ 1/2" HIGH STR STEEL STUDS
② TOROID IMC # 51038-IF 75 TURNS IN ALUMINUM CASE POTTED STYCAST 2762 (2) REQUIRED	⑧ NUT 1/2" - 1/2" THICK STEEL
③ 3/8" SS TUBE 4 TEFLON INSULATED WIRES 2 CALIB 2 SIGNAL (EACH SIDE)	⑨ RULON INSULATOR FLANGE 1" OD
④ 1" 300 # RAISED FACE FLANGES CARBON STEEL	⑩ 1/4" THERMOWELL TUBE
⑤ TEFLON SPOOL	⑪ 1/2" SCH 80 TEE
⑥ ALUMINA TUBE 0.5" BORE	⑫ EXPL PROOF APPLETON # GRT-50
	⑬ BELLEVILLE WASHERS 1/2" NOM ID 56 mil THICK

FIGURE 3.3 Electrodeless Conductivity Cell

FIGURE 3.4. Electrical Resistance Corrosion Probe Assembly with Coupons

FIGURE 3.5. PNL Linear Polarization Corrosion Probe for Geothermal Applications

Even with the improved PNL probe, the linear polarization method suffers some disadvantages for use in geothermal plants. First the electrodes must stay wet, since an electrolyte is needed for the method to work. This means if the system is drained, and air admitted, the very high corrosion that occurs may not be recorded. We attempted to avoid this problem by placing the probe in the U-tube water trap shown in Figure 3.2. However, in this configuration, the probe is subject to being buried in sand, and is not in the main flow stream. This proved to be a problem, since we found brine velocity to be very significant in determining how much corrosion occurred.

3.4 OXIDATION-REDUCTION POTENTIAL (ORP)

The oxidation reduction potential (ORP) probe used is a high-temperature, ruggedized reference electrode, protected from H_2S , coupled to a platinum

electrode. The voltage output of this probe is an extremely sensitive detector of oxygen in the system. The ORP system is shown in Figure 3.6.

3.5 IN-LINE SPOOLS

During plant construction, two 12-in. spools were fabricated and installed at the plant inlet and outlet (at PC-1 and PC-2 in Figure 3.1). Sections of 12-in. brine pipe were collected during construction, fabricated into coupons, and mounted inside these spools. Enough specimens were included to monitor scaling and corrosion for many years. Half of the specimens were on Teflon insulators, and half were grounded. These spools proved to be very difficult to remove, since the plant had to be shut down, and a crane brought in.

3.6 IN-LINE SAMPLE FIXTURE IN COOLING WATER

The fixture used to hold samples of cooling-water pipe and copper coupons (condensor tubes are copper) is shown in Figure 3.7. This fixture also required shutdown and draining of the main cooling-water lines, however this could be done on an annual basis. Use of the in-line probes described in Section 3.2 above proved to be the most convenient.

3.7 BYPASS INSTRUMENT TEST LOOP

As indicated in Figure 3.2 and Table 3.1 brine from the plant inlet, heat exchanger No. 6 (mid-point), and heat exchanger No. 1 (outlet) were piped to a test loop at PNL's test pad and field trailer near the plant. This loop was used to test instruments and procedures before they were used inside the explosion-proof zone at the plant.

3.8 DATA ACQUISITION AND COMPUTER RECORDING SYSTEM

All of the instrument wires from the plant were installed in explosion proof conduit and boxes, meeting the same code requirements as the plant instrumentation. All of the instrument wires were run in an underground conduit to PNL's mobile field trailer located about 200 ft from the Magma plant.

FIGURE 3.6. Oxidation Reduction Potential Probe

FIGURE 3.7. Fixed Specimen Holder for Cooling-Water Corrosion Measurements

Signals from the corrosion probes in the cooling-water system, were recorded on local strip chart recorders, since they were too far away to wire to the trailer. Later in the project a radio telemetry system was installed to transmit these data to the trailer. A list of all the plant data channels, and the bypass test loop data channels is given in Table 3.3.

These data were connected to a 60-channel data logger as shown in Figure 3.8. The data logger scanned channels every 15 minutes, 24 hours/day. Unless computer-based data reduction is applied, such a system can bury the operator in so much data nothing can be found. The raw data on each scan was recorded on a 9-track computer tape recorder, which would hold about a month of data. This tape was returned to PNL and the data transferred to a hard disk on a mini-computer, which had complete plotting capabilities. This made it possible to scan broad time periods of data and then examine those areas of special interest on an hour-by-hour basis.

In order to provide daily visibility and to provide summary averages each data logger scan was recorded in a desk-top computer in the PNL field trailer. The computer also applied engineering units to the raw voltage data. These data along with summary reports were available by telephone modem to the home laboratory almost 2000 miles away. This system proved very useful in detecting problems both in the plant and especially with some of the new, unproved in-line instrumentation.

TABLE 3.3. Data Channels Monitored

CH#	Sensor/Location	Readout and Conversions
00	Temperature Plant Inlet	DEG. C
01	Temperature Plant Outlet	DEG. C
02	Conductivity Temp. In	DEG. C
03	Conductivity Temp. Out	DEG. C
04	Heat Exchanger #7 Temp.	DEG. C
05	Heat Exchanger #2 Temp.	DEG. C
06	Turbidity Cell Temp. Injection Line	Volts
08	Inside Trailer Temp.	DEG. C
09	Outside Temp.	DEG. C
10	Pressure Plant Inlet	PSIG = Volts*100
11	Pressure Plant Outlet	PSIG = Volts*100
12	Test Loop Hi Inlet Press.	PSIG = Volts*100
13	Test Loop Med. Inlet Press.	PSIG = Volts*100
14	Test Loop Lo Inlet Press.	PSIG = Volts*100
15	Test Loop Hi Outlet Press.	PSIG = Volts*100
16	Test Loop Med. Outlet Press.	PSIG = Volts*100
17	Test Loop Lo Outlet Press.	PSIG = Volts*100
18	Test Loop Pump Outlet Press.	PSIG = Volts*100
19	Test Loop Return Line Press.	PSIG = Volts*100
20	Conductivity Plant Inlet	M-MHOS = Volts*51.28
21	Conductivity Plant Outlet	M-MHOS = Volts*52.90
Conductivity Temperature Correction:		
$C(25\text{ C}) = C(\text{Temp.}) / (1 + (0.0288 * (\text{Delta Temp})))$		
22	Redox Plant Inlet	Volts = $0.875 * (\text{Volts} - 1.2)$
23	Redox Plant Outlet	Volts = $0.875 * (\text{Volts} - 1.2)$
24	Corrosion Plant Inlet	Mils/yr (1 volt = 5 mils/yr)
25	Corrosion Plant Outlet	Mils/yr (1 volt = 5 mils/yr)
26	110 V Power Monitor	Volts
27	Turbidity Plant Outlet-Injection Line	Volts (0-30 ppm scale, 0.45 V = OPPM 2.4 V = 30 ppm, 1.43 = 13 ppm (Calibration Point))
28	Test Loop Flow	0.68 Volts = 0 flow
29	Plant Heat Exch. Flow (10 ⁻⁶ #/hr.)	# hr*10 ⁻⁶ = $1.03 * \text{SORT}(\text{ABS}(V - 1.65))$ IF (V-1.65)>0
30	Test Loop Hi Inlet Temp.	DEG. C
31	Test Loop Med. Inlet Temp.	DEG. C
32	Test Loop Lo Inlet Temp.	DEG. C
33	Return Line to Plant—Temp.	DEG. C
34	Cool. Water Corr.—Propane FE	Mils/yr = Volts (10 V F.S.) (0-10 mil/yr scale)
35	Cool. Water Corr.—Isobut CU	Mils/yr = Volts (10 V F.S.) (0-10 mil/yr scale)
36	Cool. Water Corr.—Isobut FE	Mils/yr = 2*Volts (10 V F.S.) (0-20 mil/yr scale)
37	Cool. Water Corr.—Propane CU	Mils/yr = Volts (10 V F.S.) (0-10 mil/yr scale)
38	Cool. Water In—Temp.	DEG. C = Volts*10
39	Cool. Water Out—Temp.	DEG. C = Volts*10

FIGURE 3.8. Data Acquisition and Computer Recording System

4.0 GEOHERMAL BRINE

4.1 LOCATION OF SUPPLY WELLS

Five wells were drilled to supply brine to the Magma Plant (see Figure 3.1). Three wells (44-7A, 44-7, and 44-7B) are located one-eighth mile north of the plant. Two other wells (48-7A and 48-7) are located one-eighth mile south of the plant. The wellhead of 44-7 is located 50 ft east of wellhead 44-7A and the wellhead of 44-7B is located 100 ft east of 44-7A. The wellhead of 48-7 is located 50 ft east of wellhead 48-7A. The wells are directionally drilled.

Listed in Table 4.1 are the well depths, original perforations, and dates and locations of additional perforations.

A centrifugal pump is installed in each well to lift the water with sufficient overpressure to prevent flashing (see Figure 4.1).

4.2 SAMPLING OF SUPPLY WELLS

The five supply wells were sampled and analyzed between August 1978 and October 1980 as shown in Table 4.2. Some of the known well modifications are indicated in Table 4.2.

4.2.1 Sampling Procedure

Samples were taken as recommended in PNL-3412 (Shannon 1980) and PNL-3801 (Kindle 1981). A summary of those sampling methods used follows.

Well sampling was performed using a 1/4-in. SS insertion probe (see Figure 4.2) inserted through a 1-in. valve located within five feet of the wellhead. The probe was inserted mid-way into the flow of the brine coming from the well. Tapping into the main flow minimizes wall effects or contaminants of scale present in the 1-in. valve. Attached to the outlet of the 1/4-in. probe were two 1/4-in. SS cooling coils (see Figure 4.2). The first coil was placed in a bucket filled with water and the second coil in a bucket filled with ice and water. Flow was regulated downstream of the coils to prevent steam flashing before cooling to deliver a cool ($25^{\circ}\text{C} \pm 5$) sample. By using the heat of

TABLE 4.1. Summary of Geothermal Wells Supplying Brine to Magma Plant

Supply Well	Horizontal Depth (MD) from Wellhead	Vertical Depth (MD) from Wellhead	Bottom of Well in Ref. 1 Wellhead	Original Perforation Depth (MD)	Date of Additional Perforations	Additional Perforation Depth (MD)
44-7A	7080 ft	6992 ft	159.34 ft N 646.44 ft W	7075 to 5767 ft	February 1980 June 1980	5767 to 5200 ft 5200 to 4500 ft
44-7	7328 ft	7328 ft	Straight Hole	7301 to 5699 ft	---	---
44-7B	6821 ft	6725 ft	463.46 ft S 390.09 ft W	6818 to 5788 ft	February 1980 November 1980	5788 to 5200 ft 5200 to 4500 ft
44-7A	6919 ft	6821 ft	201.34 ft N 599.19 ft W	6916 to 5913 ft	May 1980	5780 to 5230 ft
48-7	7323 ft	7523 ft	Straight Hole	7517 to 5735 ft	---	---

FIGURE 4.1. Magma East Mesa Site Typical Production Well

TABLE 4.2. Dates PNL Sampled Wells

WELL 44-7A (SW1)

05/24/79 Sampled by PNL
 02/80 Perforated at 5767 to 5200 ft
 06/80 Pump pulled—lube string scaled
 07/29/80 Sampled by PNL
 08/30/80 Pump pulled—lube string scaled, oil lube installed

WELL 44-7 (SW2)

05/24/79 Sampled by PNL
 11/14/79 Sampled by PNL (sampling done when well was still flowing kill solution)
 01/29/80 Sampled by PNL (resampled at this time because we did not get a "true" brine sample 11/14/79)
 05/09/80 Lube string scaled and replaced
 09/11/80 Sampled by PNL
 12/04/80 Pump pulled, oil lube installed

WELL 44-7B (SW3)

12/06/79 Sampled by PNL
 02/80 Perforated 5788 to 5200 ft
 05/03/80 Pump pulled—lube string scaled
 06/19/80 Blew out well with N₂ and water to remove plug at 3000-ft level
 07/22/80 Flow check—5 hr
 09/25/80 Pulled pump—low flow coming from well
 11/19/80 Well acidified to remove plug
 11/80 Well redrilled and perforated 5200 to 4500 ft
 07/22/80 Flow check—5 hr
 09/25/80 Pulled pump—low flow coming from well
 11/19/80 Well acidified to remove plug
 11/80 Well redrilled and perforated 5200 to 4500 ft
 12/80 Ran just this well for propane run at plant, had very good flow

WELL 48-7A (SW4)

11/08/79 Sampled by PNL
 05/80 Pump pulled—lube string scale—perforated 5780 to 5230 ft
 09/14/80 Pump pulled—oil lube installed (I believe they also had a broken shaft on this one)
 10/07/80 Sampled by PNL

WELL 48-7 (SW5)

08/09/78 Sampled by PNL during well flowcheck done by Magma
 11/08/79 Sampled by PNL
 05/09/80 Lube string scaled and replaced
 09/12/80 Sampled by PNL
 12/04/80 Pump pulled—oil lube installed

NOTE: All wells are now being run with oil lubes instead of using the canal or pond water run through water softners.

FIGURE 4.2. Arrangement of Sampling System Used for Hot Brine Samples from Supply Wells and Plant Locations

vaporization of the cooling water in the first bucket and the heat of fusion of ice in the second bucket, a large cooling system was not necessary.

A complete wellhead sample "set" consisted of six different bottles, a suspended solids sample, a gas bulb, and field determinations for pH, O_2 , H_2S , NH_3 , and redox potential.

4.2.2 Raw Unacidified Sample

One liter of cooled brine was taken for measurement of pH, conductivity, turbidity, bicarbonate, and chloride.

A separate silica sample was taken at the beginning of the project by diluting 10 ml of raw unacidified brine to 100 ml. This practice, however, was discontinued because the silica at the Magma location is low enough in concentration that the silica does not precipitate out of solution.

4.2.3 Filtered Unacidified Sample

One liter of cooled brine was passed through a $0.45\text{-}\mu$ filter contained in an in-line filter housing. This sample was used for the determinations of total dissolved solids and anion analyses done on the ion chromatograph.

4.2.4 Filtered Acidified Sample

Filtered (in-line) cooled brine was measured into a one-liter sample bottle containing 10 ml of ultrapure hydrochloric acid. This sample was used to make cation determinations.

4.2.5 Total Carbon Dioxide Sample

The brine and gas mixture from the coil outlet was directed through a sintered glass frit dispersion tube into a one-liter bottle containing 500 ml of absorbing solution (2N NaOH).

4.2.6 Hydrogen Sulfide Sample

Like the carbon dioxide sample, the brine and gas mixture was directed through a sintered glass frit dispersion tube into a one-liter bottle containing 500 ml of absorbing solution (0.5 m Zinc Acetate).

4.2.7 Gas/Liquid Ratio and Dissolved Carbon Dioxide Samples

Brine from the cooling coils outlet was passed to a glass separator. The gas from the separator was passed through a Wet Test Meter. The brine was discharged into a graduated cylinder. The amount of gas collected was integrated over a five-minute period, and liquid was measured at the same time to give a gas-to-liquid ratio.

The dissolved carbon dioxide sample was taken by sparging the brine from the outlet of the separator into a one-liter bottle containing 500 ml of absorbing solution.

4.2.8 Gas Sample

A 750-ml glass gas bulb was filled with brine then inverted, enabling the bulb to collect gas by displacing the brine. Gravitational flow allows the gas to collect at the top of the bulb and the brine to exit out the bottom.

4.2.9 Suspended Solids Sample

Five liters of cooled brine was passed through a pre-weighed 0.45- μ filter contained in the in-line filter housing. After five liters of brine was passed through the filter, it was rinsed with deionized water to wash off soluble salts that could otherwise affect the weight after drying.

Suspended solids were also determined by using a laser particle counter and graded filters for size distribution as in Section 8.

4.3 WELL BRINE CHEMISTRY DATA

The results of the well sampling and analyses are given in Tables 4.3, 4.4, 4.5, 4.6, and 4.7. The data show that while all the wells are similar in chemistry, they are not exactly alike. There has been no significant changes in brine chemistry during the first year of operation. The overall ranges of the major constituents are given in Table 4.8

4.4 BRINE CHEMISTRY AT PLANT INLET AND OUTLET

The geothermal brine was sampled at the plant inlet (location PC-1), and outlet (location PC-2) on a number of occasions. We observed no significant

**TABLE 4.3. Brine Chemistry of Magma Well 44-7A (SW-1)
Concentration (mg/l) or Other**

Sample ID/Parameter	Magma Well 44-7A 05/24/79	Magma Well 44-7A 07/29/80
pH (Lab)	5.8	5.8
Conductivity (umho)	10,900	10,800
TDS	7,320	7,510
Suspended Solids	2	ND
Turbidity (FTU)	10	ND
Hardness (as CaCO ₃)		74
HCO ₃ ⁻ (Titration)	509	506
CO ₃ ²⁻ (Titration)	ND	ND
H ₂ S (Titration)	1.6	1.3 - 0.9
SO ₄ ²⁻ (Ion Chrom.)	79	86
F ⁻ (Ion Chrom.)	3.2	3.6
NO ₃ ⁻ (Ion Chrom.)	<0.2	
Cl ⁻ (Ion Chrom.)		3,680
Cl ⁻ (Titration)	3,860	
SiO ₂ (Colorimetric)	270	
SiO ₂ (Calc. from ICP)	231	259
NH ₃ (Electrode)	14	23
Total CO ₂	1,690	2,090
CO ₂ (Brine Only)		1,850
eH		-50
Gas/Liquid	187 ml/l	280 ml/l
Al	<0.5	<0.5
As	0.4	<0.3
B	9.3	9.0
Ba	0.8	0.9
Ca	20	26.7
Fe	0.3	0.6
K	218	233
Li	9.2	8
Mg	0.3	1.0
Na	2,860	2,670
P	<0.5	<0.5
Si	108	121
Sr	4.4	5.8
<u>Gas Sample</u>		
<u>Mass Spec. (m%)</u>		
CO ₂	69.5	29.3(a)
Ar	0.1	0.6
O ₂	0.4	12.6
N ₂	11.2	49.7
CO	<0.1	<0.1
He	<0.1	<0.1
H ₂	0.3	0.1
CH ₄	15.3	7.7
C ₂ H _x	—	—
<u>Wellhead Conditions</u>		
<u>at Sampling</u>		
Pressure (psig)	270	300
Temperature (°F)	361	355
Flow (gpm)	600	855
pH (Field)	5.8	5.6
O ₂ (Chemetrics)	<5 ppb	<5 ppb
Fe (Chemetrics)	—	—
H ₂ S (Chemetrics)(mg/l)	0.3	0.9
NH ₃ (Chemetrics)	10	20

(a) Gas bulb leaked during shipping

**TABLE 4.4. Brine Chemistry of Magma Well 44-7 (SW-2)
Concentration (mg/l) or Other**

Sample ID/Parameter	Magma Well 44-7 05/24/79	Magma Well 44-7 11/14/79	Magma Well 44-7 01/29/80	Magma Well 44-7 09/11/80
pH (Lab)	5.6	5.6	5.8	5.5
Conductivity (umho)	13,500	15,100	13,400	12,400
TDS	8,620	10,250	8,240	7,570
Suspended Solids	5	1.4 - 15	1	ND
Turbidity (FTU)	10	15	ND	ND
HCO ₃ ⁻ (Titration)	385	390	403	380
CO ₃ ²⁻ (Titration)	ND	ND	ND	ND
H ₂ S (Titration)	1.6	0.7	0.7	1.7
SO ₄ ²⁻ (Ion Chrom.)	68	84	78	78
F ⁻ (Ion Chrom.)	2.7	2.5	2.4	2.5
NO ₃ ⁻ (Ion Chrom.)	<0.2			
Cl ⁻ (Titration)	4,590	6,270	4,600	4,300
SiO ₂ (Colorimetric)	225	260	255	220
SiO ₂ (Calc. from ICP)	235	227	229	257
NH ₃ (Electrode)	17	20.4	12	
Gas/Liquid	235 mL/L	74 mL/L	--	
Total CO ₂	1,810	1,850		1,680
Al	<0.5	<0.5	<0.5	<0.5
As	0.4	1.0	0.5	0.5
B	9.8	9.0	9.3	8.9
Ba	1.5	1.4	1.2	1.1
Ca	47	49	36	39
Fe	0.4	0.6	0.3	0.3
K	286	300	238	236
Li	12	12	11	10
Mg	1.2	1.3	1.1	1.3
Na	3,390	4,040	2,960	2,790
P	<0.1	0.6	0.3	<0.5
Si	110	106	107	120
Sr	10	10	9	8.5
Gas Sample Mass Spec. (m%)				
CO ₂	72.9	69.2	74.8	78.9
Ar	0.1	0.1	0.1	0.1
O ₂	<0.1	<0.1	0.5	0.5
N ₂	10.6	6.5	6.6	5.9
CO	<0.1	<0.1	<0.1	<0.1
He	<0.1	<0.1	<0.1	<0.1
H ₂	0.3	0.2	0.2	0.1
CH ₄	15.9	23.7	17.6	14.2
C ₂ H _x	0.2	0.1	0.2	0.2
Wellhead Conditions at Sampling				
Pressure (psig)	290	310	330	290
Temperature (°F)	353	350	365	360
Flow (gpm)	600		698	675
pH (Field)	5.5	5.3	5.9	5.5
O ₂ (Chemetrics)	<5 ppb	<5 ppb	<5 ppb	<5 ppb
Fe (Chemetrics)	--	--	0.6	0.2
H ₂ S (Chemetrics)(mg/l)	1	0.9	1.0	0.4
NH ₃ (Chemetrics)	>10	10	20	4

**TABLE 4.5. Brine Chemistry of Magma Well 44-7B (SW-3)
Concentration (mg/l) or Other**

Magma Well 44-7B 12/06/79	
<u>Sample ID/Parameter</u>	
pH (Lab)	5.6
Conductivity (μmho)	15,600
TDS	10,100
Suspended Solids	ND
Turbidity (FTU)	10
HCO ₃ ⁻ (Titration)	339
CO ₃ ²⁻ (Titration)	ND
H ₂ S (Titration)	1.3
SO ₄ ²⁻ (Ion Chrom.)	73
F ⁻ (Ion Chrom.)	3.3
Cl ⁻ (Titration)	5,660
SiO ₂ (Colorimetric)	280
SiO ₂ (Calc. from ICP)	223
NH ₃ (Electrode)	23
Total CO ₂	1,790
Al	<0.5
As	0.3
B	9.3
Ba	2.3
Ca	72
Fe	0.9
K	261
Li	12
Mg	2.4
Na	3,660
P	<0.5
Si	104
Sr	21
<u>Gas Sample Mass Spec. (m%)</u>	
CO ₂	74.0
Ar	0.1
O ₂	<0.1
N ₂	5.4
CO	<0.1
He	<0.1
H ₂	0.2
CH ₄	20.4
C ₂ H _x	0.1
<u>Wellhead Conditions at Sampling</u>	
Pressure (psig)	240
Temperature (°F)	364
Flow (gpm)	686
pH (Field)	5.4
O ₂ (Chemetrics)	<5 ppb
H ₂ S (Chemetrics)	0.8
NH ₃ (Chemetrics)	20

**TABLE 4.6. Brine Chemistry of Magma Well 48-7A (SW-4)
Concentration (mg/l) or Other**

Sample ID/Parameter	Magma Well 48-7A 11/08/79	Magma Well 48-7A 10/07/80
pH (Lab)	5.8	5.7
Conductivity (umho)	11,100	11,100
TDS	7,630	7,400
Suspended Solids	19	2
Turbidity (FTU)	5	ND
Hardness (as CaCO ₃)		82
HCO ₃ (Titration)	454	419
CO ₃ (Titration)	ND	ND
H ₂ S (Titration)	1.5	0.9
SO ₄ (Ion Chrom.)	84	83
F ⁻ (Ion Chrom.)	2.5	2.8
Cl ⁻ (Titration)	4,080	3,990
SiO ₂ (Colorimetric)	235	175
SiO ₂ (Calc. from ICP)	197	235
NH ₃ (Electrode)	17	19
Total CO ₂	1,640	1,730
Gas/Liquid	156 mL/L	194 mL/L
CO ₂ (Brine Only)		1,530
Al	0.5	<0.5
As	0.3	0.5
B	7.3	7.8
Ba	0.9	1.0
Ca	31	28
Fe	0.4	0.4
K	220	214
Li	9	9
Mg	1.0	1.0
Na	2,720	2,840
P	<0.5	<0.5
Si	92	111
Sr	7	8
Gas Sample Mass Spec. (m%)		
CO ₂	63.3	70.8(a)
Ar	0.2	0.1
O ₂	<0.1	0.1
N ₂	10.4	7.2
CO	<0.1	1.2
He	<0.1	<0.1
H ₂	0.1	0.1
CH ₄	25.8	20.2
C ₂ H _x	0.2	0.2
Wellhead Conditions at Sampling		
Pressure (psig)	290	280
Temperature (°F)	345	350
Flow (gpm)	653	551
pH (Field)	5.2	5.5
O ₂ (Chemetrics)	<5 ppb	<5 ppb
Fe (Chemetrics)	—	0.3
H ₂ S (Chemetrics)(mg/L)	0.9	0.6
NH ₃ (Chemetrics)	7	>10

(a) Gas bulb leaked during shipping

**TABLE 4.7. Brine Chemistry of Magma Well 48-7 (SW-5)
Concentration (mg/l) or Other**

Sample ID/Parameter	Magma Well 48-7 08/09/78	Magma Well 48-7 11/08/79	Magma Well 48-7 09/12/80
pH (Lab)	5.9	5.6	5.5
Conductivity (μmho)	13,100	12,600	13,900
TDS	9,290	8,840	8,410
Suspended Solids	ND	0.8	ND
Turbidity (FTU)	ND	7	ND
HCO ₃ (Titration)	305	316	299
CO ₃ (Titration)	ND	ND	ND
H ₂ S (Titration)	0.7	0.7	1.5
	3.4 Sparge		
SO ₄ (Turbidimetric)	78		
SO ₄ (Ion Chrom.)	82	84	74
F ⁻ (Ion Chrom.)	2.2	2.4	2.5
Cl ⁻ (Titration)	4,850	4,850	5,200
SiO ₂ (Colorimetric)	218	225	
SiO ₂ (Calc. from ICP)	278	201	244
NH ₃ (Electrode)	16	19	20
Total CO ₂	1,990	1,580	1,830
NO ₃ (Colorimetric)	9		
Gas/Liquid	170 mL/L	150 mL/L	—
Mass Balance	0.96		
Charge Balance	0.98		
Al	<0.1	0.5	<0.5
As	0.6	0.4	0.4
B	8.9	6.9	7.5
Ba	0.2	1.3	1.3
Ca	77.7	81	69.3
Fe	0.4	1.1	0.3
K	405	272	264
Li	16.9	11	11
Mg	2.9	2.2	2.2
Na	2,920	3,030	2,950
P	0.2	0.5	<0.5
Si	130	94	114
Sr	32.8	20	18.6
Gas Sample			
Mass Spec. (m%)			
CO ₂	67.5	68.5	72.9
Ar	0.2	0.2	0.2
O ₂	0.03	<0.1	0.1
N ₂	9.7	8.6	10.7
CO	0.8	<0.1	<0.1
He	<0.01	<0.01	<0.01
H ₂	0.1	0.1	0.1
CH ₄	21.7	22.6	15.8
C ₂ H _x	—	0.1	0.1
Wellhead Conditions			
at Sampling			
Pressure (psig)	280	265	285
Temperature (°F)	352	332	353
Flow (gpm)	647	911	855
pH (Field)	5.3 - 5.4	5.4	5.4
O ₂ (Chemetrics)	<5 ppb	<5 ppb	<5 ppb
Fe (Chemetrics)	—	—	0.3
H ₂ S (Chemetrics)(mg/l)	1	0.9	0.5
NH ₃ (Chemetrics)	—	10	10

**TABLE 4.8. Summary Brine Chemistry of Magma Wells
Concentration (mg/l) or Other**

Sample ID/Parameter	44-7A		44-7		44-7B		48-7A		48-7	
	Min.	Max.	Min.	Max.	Min.	Max.	Min.	Max.	Min.	Max.
pH (Lab)	5.8		5.5	5.8	5.6		5.7	5.8	5.5	5.9
Conductivity (µmho)	10800	10900	12400	15100	15600		11100	11100	12600	13900
TDS	7320	7510	7570	10250	10100		7400	7630	8410	9290
Suspended Solids	0	2	1.4	15	ND		2	19	0.8	
Turbidity (FTU)	0	10	10	15	10		5		7	
Hardness (as CaCO3)	0	74					82			
HCO3 (Titration)	506	509	380	403	339		419	454	299	316
CO3 (Titration)	ND	ND	ND		ND		ND		ND	
H2S (Titration)	0.9	1.6	0.7	1.7	1.3		0.9	1.5	0.7	1.5
SO4 (Turbidimetric)									78	
SO4 (Ion Chrom.)	79	86	68	84	73		83	84	74	84
F- (Ion Chrom.)	3.2	3.6	2.4	2.7	3.3		2.5	2.8	2.2	2.5
NO3 (Ion Chrom.)	<0.2		<0.2							
Cl- (Titration)	3680	3860	4300	6270	5660		3990	4080	4850	5200
SiO2 (Colorimetric)	270		220	260	280		175	235	218	225
SiO2 (Calc. from ICP)	231	259	227	257	223		197	235	201	278
NH3 (Electrode)	14	23	12	20.4	23		17	19	16	20
CO2 (Brine Only)							1530			
Gas/Liquid (ml/l)	187	280	74	235	—		156	194	150	170
Total CO2	1690	2090	1680	1850	1790		1640	1730	1580	1990
Al mg/l	<0.5		<0.5		<0.5		<0.5	0.5	<0.1	0.5
As	<0.3	0.4	0.4	1.0	0.3		0.3	0.5	0.4	0.6
B	9.0	9.3	8.9	9.8	9.3		7.3	7.8	6.9	8.9
Ba	0.8	0.9	1.1	1.5	2.3		0.9	1.0	0.2	1.3
Ca	20	27	36	49	72		28	31	69.3	81
Fe	0.3	0.6	0.3	0.6	0.9		0.4		0.3	1.1
K	218	233	236	300	261		214	220	264	405
Li	8	9.2	10	12	12		9		11	16.9
Mg	0.3	1.0	1.1	1.3	2.4		1.0		2.2	2.9
Na	2670	2860	2790	4040	3660		2720	2840	2920	3030
P	<0.5		<0.1	0.6	<0.5		<0.5		0.2	0.5
Si	108	121	106	120	104		92	111	94	130
Sr	4.4	5.8	8.5	10	21		7	8	18.6	32.8
Gas Sample										
Mass Spec. (m%)										
CO2	29.3*	69.5	69.2	78.9	74.0		63.3	70.8	67.5	72.9
Ar	0.1	0.6	0.1		0.1		0.1	0.2	0.2	
O2	0.4	12.6	<0.1	0.5	<0.1		0.1		0.03	0.1
N2	11.2	49.7	5.9	10.6	5.4		7.2	10.4	8.6	10.7
CO	<0.1		<0.1		<0.1		0.1	1.2	<0.1	0.8
He	<0.1		<0.1		<0.1		<0.1		<0.01	
H2	0.1	0.3	0.1	0.3	0.2		0.1		0.1	
CH4	7.7	15.3	14.2	23.7	20.4		20.2	25.8	15.8	22.6
C2Hx	—	—	0.1	0.2	0.1		0.2		0.1	
Wellhead Conditions										
at Sampling										
Pressure (psig)	270	300	290	330	240		280	290	265	285
Temperature (°F)	355	361	350	365	364		345	350	332	353
Flow (gpm)	600	855	600	698	686		551	653	647	911
pH (In Field)	5.6	5.8	5.3	5.9	5.4		5.2	5.5	5.3	5.4
O2 (ppb)	<5		<5		<5		<5		<5	
Fe	—	—	0.2	0.6			0.3		0.3	
H2S (mg/l)	0.3	0.9	0.4	1.0	0.8		0.6	0.9	0.5	0.9
NH3	10	20	4	20	20		7	>10	10	

* Gas bulb leaked during shipping.

differences in the inlet and outlet chemistry, except for an increase in iron content as the brine passed through the plant. The significance of this increase in iron content will be discussed in Section 6.0 on corrosion.

On September 15, 1980, we conducted a simultaneous sampling at the plant inlet and outlet. Two sampling rigs were set up and the two operators coordinated their sampling with two-way radios so that each sample was taken at exactly the same time. This arrangement prevented variations in well flow (and the resulting change in mixture) from disturbing the chemistry. The analyses of these samples are given in Table 4.9.

4.5 TRACE CATION CONTENT OF MAGMA BRINE

On July 28, 1981 the plant inlet was sampled for analysis of trace cations that might be present at levels below 1 ppm. At this time the flow was a mixture from Wells 44-7, 44-7B, and 48-7. The samples were preserved in both 1% HCl and 1% HNO₃ and analyzed by Argon Plasma Emission and Graphite Furnace AA. The results are given in Table 4.10.

4.6 DETECTION OF ISOBUTANE IN OUTLET BRINE

On May 2, 1980, a routine sampling of the plant outlet produced a gas sample that was high in isobutane as shown in Table 4.11. This was subsequently traced to a leaking sliding seal in the heat exchangers between the isobutane system and the brine. During operation the isobutane pressure is higher than the brine pressure, so analysis of gas samples collected by our methods proved sensitive to detection of such leaks. Magma has now instituted collection and onsite analysis of such gas samples using a gas chromatograph.

On May 14, 1981, during a plant startup, a major leak developed in the heat exchangers which was detected on our conductivity cell at the plant outlet. This conductivity voltage trace is given in Figure 4.3. Analysis of the process conditions indicates that both liquid and gaseous isobutane were passing through the cell during this time period. Going back over our data it appears a warning of gas in the exit line appeared on the conductivity cell about 30 min. before it was detected in the plant control room when so much

TABLE 4.9. Comparison of Brine Chemistry at Plant Inlet and Outlet
(mg/l unless stated)

Sampling conditions: Date—September 15, 1980
Wells on—Well No. 1—810,000 pounds/hr
—Well No. 2—675,000 pounds/hr

	<u>Inlet (PC-1)</u>	<u>Outlet (PC-2)</u>
Pressure (psi)	335	370
Temperature °F	350	160
pH	5.67	5.66
O ₂	<5 ppb	<5 ppb
Conductivity (μmho)	12,350	12,200
TDS	7,500	7,470
Turbidity (FTU)	<5	<5
HCO ₃ ⁻	435	434
H ₂ S	1.6	2.1
SO ₄ ⁼	83	91
F ⁻	3	3
Cl ⁻	4,000	4,050
SiO ₂ (calc. from Si)	252	252
NH ₃ (electrode)	18	18
Total CO ₂	1,800	1,900
Al	<0.5	<0.5
As	0.4	0.9
B	9.0	8.8
Ba	1.0	1.0
Ca	32	32
Fe	0.3	1.9
K	232	234
Li	8.9	9.0
Mg	1.3	1.6
Na	2,650	2,610
P	<0.5	<0.5
Si	118	118
Sr	7.2	7.0

TABLE 4.10. Trace Cations in Magma Brine (ppm)

	<u>1% HCl Sample</u>	<u>1% HNO₃ Sample</u>
Fe	0.3	0.24
Mn	0.02	0.02
Se	0.1	0.1
Sn	<0.1	0.2
Cu	0.046	0.030
Pb	0.008	~0.001
Zn	~0.004	~0.003
Sb	<0.020	<0.020

TABLE 4.11. Gas Analysis--Magma Plant Outlet

- Plant Operating May 2, 1980
- Brine Temperature 69°C (155°F)
- Brine Pressure 350 psig

	<u>Mole %</u>
CO ₂	79.8
Ar	0.08
O ₂	0.2 (sample contam.)
N ₂	4.9
H ₂	0.2
CH ₄	13.2
Isobutane	1.6

isobutane had been lost as to require a shutdown. The recorder chart in Figure 4.3 suggests that a conductivity cell and strip chart recorder can be a useful device on the outlet of a binary cycle plant.

FIGURE 4.3. Conductivity Cell at Plant Outlet Detects Major Isobutane Leak

4.7 REFERENCES

Shannon, D. W. et al. 1980. "Field Evaluation of Sampling Methods for Pressurized Geothermal Liquids, Gases, and Suspended Solids." Pacific Northwest Laboratory, PNL-3412.

Kindle, C. H. and E. M. Woodruff. 1981. "Techniques for Geothermal Liquid Sampling and Analysis." Pacific Northwest Laboratory, PNL-3801.

5.0 COOLING-WATER CHEMISTRY

The cooling water for the Magma plant is taken from the east branch of the All-American Canal system used for irrigation in the Imperial Valley. We were concerned about possible contaminants, such as ammonia due to agricultural run-off, which could affect plant corrosion. Ammonia could damage the copper tubes of the plant condenser system. In order to establish a base-line for the cooling water chemistry, we sampled the water in the canal at the plant intake for about a year. These data (given in Table 5.1), cause little concern for corrosion, however the pH and calcium hardness pose potential scaling problems.

TABLE 5.1. Composition of All-American Canal Water at Magma Plant Inlet Concentration (mg/l) or Other

Sample ID/Parameter	Canal Water at Magma Intake 08/09/78	Canal Water at Magma Intake 09/21/78	Canal Water at Magma Intake 10/20/78	Canal Water at Magma Intake 05/03/79	Canal Water at Magma Intake 11/06/79	Canal Water at Magma Intake 02/05/79	Canal Water at Magma Intake 07/31/80
pH (Lab)	8.2	8.1	8.2	8.2	8.2	8.2	8.0
Conductivity (μ mho)	1,050	1,300	1,200	1,010	1,320	1,240	1,030
TDS	848	871	873	868	967	848	798
Suspended Solids	60	115	ND	34	3	2	4
Turbidity (FTU)	25	30	ND	18	10	9	5
Hardness (as CaCO_3)				166	230	228	220
Alkalinity (as CaCO_3)				150	150	143	
HCO_3^- (Titration)	162	164	177	179	182	174	165
CO_3^{2-} (Titration)	ND	ND	ND	ND	ND	ND	ND
SO_4^{2-} (Turbidimetric)	280	320	300	330			320
SO_4^{2-} (Ion Chrom.)	315	350	322	323	331	307	318
F^- (Ion Chrom.)	0.4	0.5	0.02	1.0	0.2	0.4	0.4
NO_3^- (Ion Chrom.)	32	2.2	7.9	21.6		<0.5	0.4
PO_4^{3-} (Ion Chrom.)						<1	<0.3
Cl^- (Ion Chrom.)						130	108
Cl^- (Titration)	102	123	113	121	139	120	113
SiO_2 (Colorimetric)	10	11.5	11	10			
SiO_2 (Calc. from ICP)	13	13	13				
NH_3 (Electrode)	1.7	<1.0	<0.2	0.2	<0.02	<0.2	
NH_4^+ (Ion Chrom.)	<1						
K (Ion Chrom)				5.0			
Total Hardness					435		
K (AA)					4	7	
Field pH							8.1
Al	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
As	0.1	0.1	<0.05	<0.05	<0.05	<0.05	0.2
B	0.2	0.2	0.2	0.2	0.2	0.2	0.1
Ba	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Ca	94.5	103	85.9	96.4	96.9	91.9	88.8
Fe	0.2	0.1	0.1	0.3	0.1	0.1	<0.1
K	27.4	22.3	37.3	—	—	—	4
Li	0.06	0.06	0.06	0.07	0.06	0.06	0.05
Mg	38.5	38.1	32.8	34.9	35.9	33.9	32.8
Na	97	*	134	151	156	138	109
P	<0.1	<0.1	<0.1	<0.1	0.2	0.2	0.1
Si	6	6	6	4.8	4.6	4.2	4.3
Sr	1.4	1.5	1.3	1.5	1.4	1.3	1.3

* Unable to determine Na due to Na leaching from sample container. This deduction was made from the following:

- Canal water data of 08/09/78 had a sodium concentration of 97 mg/l.
- Sodium concentration of 09/21/78 canal water sample analyzed 09/25/78 was 145 mg/l and reanalyzed 10/04/78 was 175 mg/l. All other parameters for these two measurements (of 09/21 sample) are comparable to the data from the 08/09/78 sample.

The water from the canal is stored in very large spray cooling ponds for the plant. This pond water is pumped to a treatment station at the inlet of the condenser heat exchangers. After treatment with sulfuric acid for pH control, addition of proprietary compounds for scale, corrosion and algae control, the water is pumped through the condenser system. The outflow is pumped into two holding ponds with spray cooling. After cooling, the water returns to the main storage pond.

In the beginning of plant operation we sampled the storage pond (Table 5.2), and the plant inlet and outlet (Table 5.3). This was to establish a basis for the interpretation of the corrosion of plant materials in Section 6.0.

TABLE 5.2. Cooling-Water Chemistry in Main Storage Pond Concentration (mg/l) or Other

Sample ID/Parameter	Main Storage Pond 05/03/79	Main Storage Pond 11/15/79	Main Storage Pond 07/31/80
pH (Lab)	8.3	8.6	7.83
Conductivity (μ mho)	1,270	1,520	2,070
TDS	1,030	1,350	1,800
Suspended Solids	5	13	4
Turbidity (FTU)	<10	7	12
Hardness (as CaCO_3)	227	300	440
Alkalinity (as CaCO_3)	131	168	
CaCO_3 (Calc. from ICP)	390		
HCO_3^- (Titration)	156	195	185
CO_3^{2-} (Titration)	2	5	—
SO_4^{2-} (Turbidimetric)	400		
SO_4^{2-} (Ion Chrom.)	405	514	752
F^- (Ion Chrom.)	0.4	0.4	1.0
NO_3^- (Ion Chrom.)	<0.25		2.0
PO_4^{3-} (Ion Chrom.)			3.3
Cl^- (Ion Chrom.)	145	196	260
Cl^- (Titration)	153		
SiO_2 (Colorimetric)	3		
NH_3 (Electrode)	<0.2	0.14	
NH_4^+ (Ion Chrom)	<1		
K (Ion Chrom)	12		
Total Alkalinity	364		
Al	<0.1	<0.1	
As	<0.05	<0.05	
B	0.2	0.2	
Ba	0.1	0.1	
Ca	91	119	
Fe	<0.1	0.07	
K	—	6	
Li	0.08	0.09	
Mg	39	48	
Na	117	205	
P	0.1	0.9	
Si	1.6	4.5	
Sr	1.7	1.8	

**TABLE 5.3. Cooling-Water Chemistry at Condenser Inlet and Outlet
Concentration (mg/l) or Other**

Sample ID/Parameter	Cooling Water Inlet 11/06/79	Cooling Water West Outlet 11/06/79	Cooling Water Inlet 11/10/79	Cooling Water West Outlet 11/10/79
pH (Lab)	8.4	8.4	8.6	8.6
Conductivity (umho)	1,760	1,700	1,780	1,740
TDS	1,330	1,330	1,350	1,350
Suspended Solids	8	6	9	10
Turbidity (FTU)	<5	8	15	<5
Hardness (as CaCO ₃)	295	298	298	298
Alkalinity (as CaCO ₃)	164	164	166	166
HCO ₃ ⁻ (Titration)	277	196	193	194
CO ₃ ²⁻ (Titration)	ND	2.5	4.6	4.2
SO ₄ ²⁻ (Ion Chrom.)	495	497	498	507
F ⁻ (Ion Chrom.)	0.7	0.9	0.5	0.5
Cl ⁻ (Titration)	190	190	195	193
NH ₃ (Electrode)	0.1	0.15	0.1	0.03
Cu (ICP)	0.01	0.01	0.01	0.01
Al	<0.1	<0.1	<0.1	<0.1
As	<0.05	<0.05	0.07	<0.05
B	0.2	0.2	0.2	0.2
Ba	0.1	0.1	0.1	0.1
Ca	118	119	119	119
Fe	0.2	0.2	0.2	0.6
K	6	6	6	6
Li	0.08	0.08	0.09	0.08
Mg	48.2	48.4	49.2	48.6
Na	203	203	207	203
P	0.7	0.7	0.7	0.7
Si	4.6	4.6	4.7	4.7
Sr	1.9	1.9	1.9	1.8

Sample ID/Parameter	Cooling Water Inlet 01/30/80	Cooling Water West Outlet 01/30/80	Cooling Water Inlet 02/01/80	Cooling Water West Outlet 02/01/80	Cooling Water Inlet 02/02/80	Cooling Water West Outlet 02/02/80
pH (Lab)	8.4	8.4	8.2	8.1	8.3	8.4
Conductivity (umho)	1,830	1,760	1,830	1,930	1,820	1,760
TDS	1,280	1,300	1,290	1,300	1,250	1,260
Suspended Solids	5	10	6	8	6	9
Turbidity (FTU)	11	10	10	10	12	10
Hardness (as CaCO ₃)	310	310	301	301	310	301
Alkalinity (as CaCO ₃)	168	169	161	160	160	162
HCO ₃ ⁻ (Titration)	203	206	196	195	196	193
CO ₃ ²⁻ (Titration)	1.3	ND	ND	ND	ND	0.9
SO ₄ ²⁻ (Ion Chrom.)	547	539	539	537	535	526
F ⁻ (Ion Chrom.)	0.34	0.8	0.34	0.5	-0.37	0.5
NO ₃ ⁻ (Ion Chrom.)	0.2	0.3	0.4	0.2	0.4	0.9
PO ₄ ³⁻ (Ion Chrom.)	<2.5	<1	<2.5	<1	<2.5	<1
Cl ⁻ (Ion Chrom.)	205	204	203	197	203	193
SiO ₂ (calc. from ICP)	9.2	9.8	9.0	9.2	9.2	9.2
NH ₃ (Electrode)	<0.17	<0.17	<0.17	<0.17	<0.17	<0.17
Cu (ICP)	0.01	0.01	0.01	0.01	0.02	0.01
Al	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
As	<0.1	<0.1	<0.1	0.1	<0.1	<0.1
B	0.25	0.26	0.24	0.27	0.25	0.25
Ba	0.12	0.12	0.12	0.11	0.12	0.11
Ca	125	123	122	121	122	125
Fe	0.2	0.2	0.2	0.2	0.2	<0.1
K	7.2	7.2	6.6	6.6	7.0	6.5
Li	0.09	0.1	0.09	0.09	0.1	0.09
Mg	54.6	54.2	52.5	52.0	52.6	53.3
Na	223	240	218	219	225	227
P	1.4	1.2	1.7	1.2	1.5	1.2
Si	4.3	4.6	4.2	4.3	4.3	4.3
Sr	2.0	2.0	2.0	2.0	1.9	2.0

TABLE 5.3. (contd)

Sample ID/Parameter	Cooling Water Inlet 02/26/80	Cooling Water West Outlet 02/26/80	Cooling Water East Outlet 02/26/80
pH (Lab)	7.9	7.9	7.7
Conductivity (μ mho)	1,820	1,820	1,820
TDS	1,320	1,320	1,330
Suspended Solids	16	20	19
Turbidity (FTU)	10	13	11
Hardness (as CaCO_3)	350	360	350
Alkalinity (as CaCO_3)	165	167	168
HCO_3^- (Titration)	161	163	164
CO_3^{2-} (Titration)	ND	ND	ND
SO_4^{2-} (Ion Chrom.)	566	563	568
F^- (Ion Chrom.)	0.7	1.0	0.3
NO_3^- (Ion Chrom.)	1.0	0.2	0.2
PO_4^{3-} (Ion Chrom.)	<1	<1	<1
Cl^- (Ion Chrom.)	209	203	203
SiO_2 (Calc. from ICP)	9	9	9
NH_3 (Electrode)	<0.2	<0.2	<0.2
Cu (ICP)	0.06	0.14	0.09
Al	<0.1	<0.1	<0.1
As	<0.1	<0.1	<0.1
B	0.3	0.3	0.3
Ba	0.12	0.12	0.12
Ca	128.2	128.5	128.6
Fe	0.25	0.5	0.3
K	7.7	8.0	7.8
Li	0.09	0.09	0.09
Mg	53.5	53.6	53.6
Na	214	216	219
P	2.0	1.9	2.1
Si	4.2	4.3	4.2
Sr	2.0	2.0	2.0

Magma maintained routine analysis of the cooling water and control of the additives in their plant analytical laboratory. Since the routine control of the plant was not part of our program, we discontinued routine cooling water analysis in February 1980, except for investigation of specific occurrences.

The initial chemistry data on the cooling water showed a positive Langlier saturation index, especially at the temperature of the inlet to the isobutane condenser. We advised Magma of this scaling potential. They worked with their water treatment consultant on scale control. This treatment appears to be satisfactory, since there has been no significant scaling observed to date. However, the use of sulfuric acid for pH control can raise sulfate levels toward calcium sulfate solubility limits. The calcium carbonate scaling potential of this water is large, so careful water chemistry control is required.

6.0 CORROSION IN BRINE AND COOLING-WATER SYSTEMS

6.1 CORROSION IN GEOTHERMAL BRINE

Corrosion was measured in the geothermal brine system using weight loss coupons and two types of continuous reading corrosion probes.

As discussed in more detail in Section 3.0, samples were located at the plant inlet, two locations in the heat exchangers, and at the plant outlet. One set of coupons was fabricated from actual plant piping. This piping was ASTM Grade A 53B. The chemical analysis on the plant piping (Table 6.1) confirmed that it was standard carbon steel. We also fabricated some 1-in.-dia disk samples from 1/16-in. ASTM-A36 sheet carbon steel that we purchased.

6.1.1 Brine Chemistry

The detailed chemistry of the geothermal wells is given in Section 4.0. As various wells were brought on line, the chemistry would assume an average composition, depending on the relative flows from the various wells. We sampled the plant inlet and outlet on a number of occasions. These analyses were examined to see if anything was added or lost as the heat was extracted from the brine. There was no change in the brine composition as it went through the plant, other than an increase in iron content. As shown in Table 6.2 there was a consistent increase in the iron content from inlet to

TABLE 6.1. Composition of A 53B Pipe--wt%

	<u>Brine Piping</u>	<u>Cooling Water Piping</u>
C	0.12	0.09
Mn	0.31	0.31
Si	0.01	0.01
P	0.01	0.01
S	0.005	0.004
Cr	0.01	0.01
Ni	0.05	0.05
Cu	0.05	0.04

TABLE 6.2. Iron Content Increases as Brine Passes Through Heat Exchangers

<u>Date</u>	<u>Fe-Plant Inlet (PC-1) mg/l</u>	<u>Fe-Plant Outlet (PC-2) mg/l</u>	<u>Brine Flow Rate 10³ pounds/hr</u>	<u>Iron Removal Rate pounds/day</u>
11/06/79	0.5	3.1	475	30
11/10/79	0.7	1.7	780	19
01/30/80	0.2	2.2	610	29
01/31/80	0.2	2.1	610	28
09/15/80	0.3	1.9	660	25
10/22/80	0.5	2.1	600	25
07/28/81	0.3	1.9	1,050	40

outlet of about 2 mg/l. Considering the large total brine flow through the plant, the data implied loss of 20 to 40 pounds of steel per day from the plant piping. Initially we considered that this might have been residual rust, and weld slag left from construction. However, since the iron increase persisted over 20 months of operation we must conclude that corrosion of the steel is the source.

6.1.2 Corrosion Measured by Weight Loss Coupons

One set of corrosion coupons fabricated from plant piping was exposed during a one-year period during plant construction. These coupons were installed in the PC-2 spool piece on December 12, 1978, and recovered on December 13, 1979. Most of the time the samples were in air as the plant was built. However, about 20 days of brine testing began late in 1979 before the samples could be recovered.

These samples were stripped of all their film using inhibited hydrochloric acid, and the weight losses converted to corrosion penetration expressed in mils/year (MPY). One MPY is the loss of 0.001 in. of surface per year. All the carbon steel samples in this program were treated in a similar manner.

The corrosion of the carbon steel during this construction period was a very low 2 MPY, as shown in Table 6.3.

TABLE 6.3. Average Carbon Steel Corrosion in Brine System (mils/yr)

<u>Location</u>	<u>Number of Coupons</u>	<u>Based on Calendar Time</u>	<u>Based on Operating Time</u>
Plant outlet—(during construction)	6	2.0	—
Plant Inlet Pipe Samples on Spool	6	4.3	11.3
Plant Inlet Coupons on Probe	9	10.6	20.5
Plant Outlet Pipe Samples on Spool	9	6.1	19.7
Plant Outlet Coupons on Probe	7	11.7	26.1
HX No. 2 Coupons on Probe	6	2.6	5.2
HX No.7 Coupons on Probe	6	2.7	6.8

In the fall of 1979, four probes (Figure 3.4) were installed in the plant inlet, Heat Exchangers 2 and 7, and the plant outlet. These probes carried 15 one-in. disks for corrosion and scale deposition measurements. A thermocouple was also included at each location and the temperatures recorded at 15-min intervals. Since the plant was up and down a number of times, these coupons were exposed to a variety of conditions. In Figure 6.1 the temperature history at the plant inlet (PC-1) and outlet (PC-2) is recorded. In Table 6.4 are listed the hours of brine exposure above 50°C as computed from our computer-based data system.

We pulled samples at various intervals from the four locations, stripped and weighed the samples and computed corrosion rates given in Table 6.4 (see Section 7.0 for scale analyses on these samples). When we computed the time of exposure, it was obvious that using just calendar time would understate the corrosion rates, since we obviously saw higher steel corrosion losses during operation, implied by the iron analyses of the brine. In order to bracket the rates, we also computed the corrosion rates using just the operating hours above 50°C as shown in Table 6.4. This "based on operating hours" rate will be too high, since it assumes corrosion is zero when the plant is down. However, we feel the "based on operating hours" data should be used to project future corrosion rates. We observed some extremely high corrosion at location PC-2 (plant outlet) where high-velocity brine impinged directly on some fixtures.

FIGURE 6.1a. Brine Temperature at PNL Test Spools at Plant Inlet (PC-1) and Outlet (PC-2)

FIGURE 6.1b. Brine Temperature at PNL Test Spools at Plant Inlet (PC-1) and Outlet (PC-2)

FIGURE 6.1c. Brine Temperature at PNL Test Spools at Plant Inlet (PC-1) and Outlet (PC-2)

FIGURE 6.1d. Brine Temperature at PNL Test Spools at Plant Inlet (PC-1) and Outlet (PC-2)

TABLE 6.4. Operating Time Above 50°C at Plant Inlet Test Station

<u>Month</u>	<u>Days</u>
November 1979	16.191
December	9.946
January 1980	10.382
February	15.078
March	0
April	0
May	14.563
June	0
July	4.596
August	7.933
September	30.000
October	26.66
November	7.241
December	0
January 1981	6.500
February	0
March	11.023
April	20.039
May	24.842
June	19.016
July	23.841
August	3.084

A probe-end fixture and a 1/2-in. nut, which show loss of considerable metal in just 862 operating hours, are shown in Figure 6.2. These samples were about three feet downstream from the plant flow control valve in a very highly turbulent region. We should emphasize this is an extreme case, but future plant designers should consider such high turbulence impingement areas as regions of higher corrosion.

**LOCATION — MAGMA PLANT OUTLET
4 FT. DOWN STREAM FROM VALVE
TEMP - 75 TO 178 C
TIME - 6 MONTHS (826 OPERATING HOURS)**

FIGURE 6.2. High Corrosion Due to Impingement Flow

In general, corrosion rates were in the range of 5 to 10 MPY in the brine system. This general corrosion is shown in Figure 7.7 where pitting is occurring under the scale.

6.1.3 Corrosion of Heat Exchanger Tubes

The observation of the high iron content and the brine, coupled with the observation of higher corrosion in the impingement areas, caused us to look more closely at the heat exchangers. This heat exchanger design has the brine on the shell side of the tubes, and the brine enters and exits from 12-in. risers, as shown in Figure 6.3. We were especially concerned about the 0.035-in. wall heat exchanger tubes under the inlet. In the week of February 9, 1981, Magma made arrangements for PNL to conduct an NDT examination of the heat exchanger tubes using ultrasonic methods. We obtained a piece of the original 0.035-in. wall carbon steel tubing to use as a standard. This was machined down to various thicknesses to serve as a calibration source. An insert probe was fabricated that slid down the tube while deionized water was pumped in to maintain coupling to the wall. The arrangement is shown in Figure 6.3.

We examined some tubes in all the heat exchangers and in general found that about 0.003 to 0.005 in. of wall thickness had been lost. The worst condition was found at the inlet to Heat Exchanger No. 10. The tubes measured are shown in Figure 6.4. These data are given in Table 6.5. It can be seen in the data in Table 6.4 that tubes No. 2 and 3 just under the impingement area have lost up to 0.015 in. of their original 0.035-in. wall.

Magma installed some impingement collars to help protect the tubes where the brine flow enters and leaves the heat exchangers. The early warning provided by the monitoring program has made it possible to extend the life of the existing heat exchangers, and to make orderly plans for eventual replacements.

6.1.4 Corrosion Measured by Linear Polarization Corrosion Probes

We initially installed commercial linear polarization probes at the plant inlet and outlet (see Figure 3.2) in order to assess their effectiveness. We encountered problems with early failure of the probes in the hot brine. The failures were caused by formation of an electrically insulating corrosion

FIGURE 6.3. Heat Exchanger Design

FIGURE 6.4. Tubes Examined

TABLE 6.5. Ultrasonic Wall Thickness of North End of Heat Exchanger No. 10

<u>Tube</u>	<u>Probe Position</u>	<u>Wall Thickness (mils)</u>	<u>Comments</u>
2	3 in. at 12:00	30	Against tube sheet
2	6 in. at 12:00	26	
2	17 in. at 12:00	25	Overall thickness
2	17 in. at 12:00	20	Pit depths to 20 mils
2	17 in. at 12:00	28	Under scale deposit
2	27 in. at 12:00	28 to 30	Pitted
3	3 in. at 12:00	30	Against tube sheet
3	12 to 14 in. at 12:00	25	Tube average
3	12 to 14 in. at 12:00	18	Pits—screen rubbing on tubes
11	9 in. at 12:00	26	Below screen—no scale
11	9 in. at 02:00	28	Maximum impingement area
39	19-3/4 to 22-1/4 in. at 09:00	25	Under strap
39	19-3/4 to 22-1/4 in. at 09:00	20	Off to side of strap
45	18 in. at 03:00	28 to 30	Under strap
45	18 in. at 03:00	22	Off to side of strap
71	16 in. at 03:00	30	No scale on outside, not under screen
77	9 in. at 04:00	28 to 30	Under scale deposit
102	15 in. at 03:00	23 to 25	Not much scale
102	27 in. at 03:00	27 to 28	No scale—metal nearly bare
108	3 in. at 06:00	29	} Bottom small amount of scale
108	15 in. at 06:00	26 to 27	
108	27 in. at 06:00	29	

Note: Original wall thickness = 35 mils.

product/geothermal scale (primarily iron sulfide). This scale altered the electrical contacts with the electrodes, and caused the output of the probe to read lower and lower, until it was well below 1 MPY.

At the plant outlet, temperatures were much lower, so a useful life of a month or so was obtained. During one period in July 1980, when the probe was working, we detected high corrosion rates at the plant outlet at PC-2. These data are shown in Figure 6.5.

We originally noted the increase in corrosion rate at our Richland, Washington, laboratory over 1800 miles away via our computer data link. Upon calling the plant on July 10 we were told a valve in the plant exit line was removed for repair. As corrosion rates continued to climb in this system, which included the expensive injection pumps, we recommended measures be taken to get the air out of the system. As soon as the system was filled with cold brine, the corrosion rate stopped rising, and when the system was flushed the corrosion dropped to normal.

It is estimated that ~0.1 mil of corrosion took place during this incident, which is negligible for most components. However, this incident illustrates how air inleakage during outages can create conditions, which if left uncorrected, could have severely damaged the system.

In addition to the electrical resistance problems discussed above, we had difficulty keeping the linear polarization electrodes in water during plant outages, when the system was drained. The linear polarization probe is an electrochemical device that must be submerged in water in order to work. We tried making "U"-shaped "water traps" for the probes, only to encounter problems with the electrodes being covered with sand which collected in the well. In our latest configuration, (shown in Figure 3.2) the probe is in a "U"-shaped well, with ~10-gpm flow to sweep out sand. With this piping arrangement and the new electrode assembly shown in Figure 3.5 we believe it is possible to get useful linear polarization readings.

FIGURE 6.5. Linear Polarization Corrosion Probe Detects High Corrosion in Injection Line

6.1.5 Corrosion Measurements with Resistance Type Corrosion Probe

We began use of a commercially available resistance-type corrosion probe in February 1981. In this probe the electrical resistance of a thin wall tube is measured, and this electrical reading can be correlated with corrosion of the carbon steel tube. We included one of these corrosion elements in our probe as shown in Figure 6.6.

On March 20, 1981, the resistance probe at the plant outlet (PC-2) detected much higher corrosion rates downstream of the flow control valve as shown in Figure 6.7.

Shortly after this, on March 27, Magma had to replace the seal on their injection pump just upstream. Our data in Figure 6.7 show corrosion rates begin to decline on March 28. This suggests the possibility that air could have been pulled into the worn pump seal, raising the oxygen content in the brine. We had just installed an experimental oxidation reduction probe (ORP) on March 21. The readings of this probe are given in Figure 6.8 where positive readings above zero indicate oxygen in the system. In this case the probe does show oxygen was there, however the drop in ORP values on March 23 does not correlate well with the corrosion probe. This was a new R&D version of the ORP probe, and its readings are not yet reliable. During the testing of the ORP probe one chemical analysis for oxygen was run at PC-2 on March 25 which showed 5 ppb oxygen present. Normally oxygen is nondetectable. Another source of oxygen in the system is the bearing seal water which contains ~8 ppm oxygen injected into the brine. Magma has now converted this system to deoxygenated water.

At the present time we cannot draw any conclusions about the cause of the high corrosion probe readings in the March 20-27 period except to say they were real. Examination of the probe showed it was actually corroded just as the readings indicated.

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FIGURE 6.6. Corrosion Meter/Sample Insertion Probe

FIGURE 6.7. Corrosion at Plant Outlet (PC-2) Measured by Resistance-Type Corrosion Probe

FIGURE 6.8. Record of REDOX Probe at Plant Outlet, March 23-June 1, 1981

The resistance probe data at the plant inlet (PC-1) and Heat Exchanger No. 3 are given in Figures 6.9 and 6.10. The corrosion probe data agree with the weight loss data in Table 6.3 in the relative order of increasing corrosion; namely HX—lowest, PC-1—middle, and PC-2—highest. The probe quantitative readings are slightly higher than the weight loss data.

6.1.6 Discussion of Causes of Corrosion in Brine System

While oxygen in the brine has contributed to corrosion occasionally, clearly there is no oxygen in the brine most of the time. Oxygen was never detected during the brine sampling for the data in Table 6.2. We must look elsewhere for the cause of the corrosion.

It seems fairly clear that this is a case of corrosion of carbon steel by carbonic acid, which is a weak acid. The pH of the solution is 5.4 to 5.8 due to the dissolved carbon dioxide. It has been shown (Shannon 1978) (Figure 6.11) that CO_2 containing saltwater is very corrosive to carbon steels. The reactions are:

Scale forms by:

The laboratory data also showed that the formation of protective films or scale on the surface were very important to form protective barriers to corrosion. In the highly turbulent conditions at the plant outlet there is almost no scale present on the metal. Under these conditions, aggravated by the sand and suspended solids in the brine, a high corrosion rate is not surprising.

FIGURE 6.9. Corrosion at Plant Inlet (PC-1) Measured by Resistance-Type Corrosion Probe

FIGURE 6.10. Corrosion at HX-3 Measured by Resistance-Type Corrosion Probe

FIGURE 6.11. Average Corrosion of Ten Carbon Steels in CO₂-Bicarbonate Brine

This monitoring of the Magma plant clearly indicates that a corrosion rate of ~5 to 10 mils/yr is to be expected in mildly acid geothermal waters. Under these conditions, carbon steel heat exchanger tubing for binary-cycle plants should be made very thick and replaceable, or an alternate alloy should be considered. Our data indicate that 0.035-in. wall tubes will have only a few years of life in this application.

6.2 CORROSION IN COOLING-WATER SYSTEM

6.2.1 Corrosion Measured by Weight Loss Coupons

Weight loss coupons were exposed at two locations in the plant cooling-water system. The first test location was in the main 28-in. water inlet water line between the water treatment system and the condenser. The second test location was on the west exit water line which returned water from the condenser to the cooling ponds. These fixtures are described in Section 3.0.

One set of coupons was fabricated from a piece of the plant piping used in the water system. In addition we used some of the same ASTM A36 carbon steel disks used in the brine system. Since copper tubes from the heat exchangers were not available, we obtained some sheet of the same DHP grade and fabricated weight loss coupons. Some of the coupons were exposed on an in-line rack, (Figure 3.7) and others were on an in-line probe.

Samples were pulled at intervals from both the inlet and the outlet water lines. After stripping off the corrosion product films, the specimen weight losses were determined, and the corrosion penetration calculated. The average corrosion rates are given in Table 6.6. In general, corrosion of the carbon steel from the actual pipe was 1.5 to 3 MPY. The copper corrosion was about

TABLE 6.6. Corrosion in Magma Cooling Water System (1 MPY = 0.01 in./yr)

<u>Location</u>	<u>Average Corrosion Rate (MPY) Calendar Time</u>
Plant Inlet Cooling Line:	
- Carbon Steel—Actual Pipe	2.9
- Carbon Steel—Coupons on Probe	3.9
- Copper—Coupons on Probe	0.3
- Copper—In-Line Rack	0.05
Plant Outlet Cooling Line:	
- Carbon Steel—Actual Pipe	1.5
- Carbon Steel—Coupons on Probe	4.0
- Copper—Coupons on Probe	0.2
- Copper—In-Line Rack	0.03

0.1 MPY. Corrosion on the plant outlet was slightly higher, probably due to a higher water temperature. The in-line probe samples gave somewhat higher rates, probably because they were more directly in the flow stream, however the corrosion was still only 5 MPY.

6.2.2 Corrosion Measured by Linear Polarization Corrosion Probes

Commercially available corrosion probes were installed to give a continuous record of the corrosion rates. Two probes used carbon steel electrodes and two used copper electrodes. The probes were inserted directly into the condensor unit shell through 2-in. gate valves. The output of the probes was recorded on chart paper initially, and then connected to the computer data system via a radio-telemetry link in April 1981.

It is impractical to report on the mass of data collected by this system. The normal output of the carbon steel probes was in the 5- to 8-MPY range and the copper in the 0.1- to 0.2-MPY range. These rates were slightly higher than was observed on the weight loss coupons. The major usefulness of the probes was to alarm on excessive corrosion.

6.2.3 Corrosion Probes Detect Copper Corrosion Due to Chlorine

In the fall of 1979, when the plant began operation, we noted an increase in corrosion on the copper corrosion probes every time the water treatment system was used.

We ran a series of tests which showed that the copper corrosion was increasing when the chlorine addition for slime control was activated as in Figure 6.12. We sampled the exit water during a 2-ppm chlorine injection and found a 0.2- to 0.3-ppm copper level in the outlet water versus 0.05-ppm copper on the inlet. When the chlorine level was dropped to 0.5 ppm Cl^- the copper in the water dropped to 0.09 ppm. These data, along with the data in Figure 6.13, led to a change in water treatment specifications to lower the chlorine level to 0.5 ppm. This is an example of how the in-line probes can assist in plant operation.

FIGURE 6.12. Corrosion Probes Respond to Chlorine Water Treatment

FIGURE 6.13. Corrosion Probes Detect Sulfuric Acid in Plant Cooling Water System

6.2.4 Corrosion Probes Detect Sulfuric Acid Injection

The corrosion probes indicated a problem on the morning of February 4, 1980, as shown in Figure 6.13. The iron corrosion rate had doubled and the copper rate was climbing when the problem was observed. A quick check of the system showed that the sulfuric acid injection pump had failed to turn off after the plant shut down on February 2, and had been injecting concentrated acid into the main water line for two days. When the main water pumps were off, water slowly siphoned from the pond through the condensor. This acid was slowly being injected into the condenser system.

The acid pump problem was corrected and the system immediately flushed with clean water. Since the corrosion rates never reached high levels, no damage was done. However, it does not take much imagination to see what would have happened to the plant condensers if the problem had not been detected early.

6.2.5 Corrosion Probes Detect High Copper Corrosion

In late June 1981 both copper corrosion probes show a severe rise in copper corrosion rate as shown in Figure 6.14.

We ran an analysis of the cooling water for hydrogen sulfide and ammonia and detected both as shown in Table 6.7. The presence of H_2S in the water was unexpected. We had not analyzed the cooling water for H_2S in the past. On July 1 an H_2S analysis during chlorine treatment was negative, since chlorine will oxidize H_2S to sulfate. Magma resumed their program to clean up the pond water with chemical additions and pond water replacement. Gradually as the cleanup was achieved the copper corrosion rates came down.

We pulled some of the copper weight loss coupons which showed a 1-MPY rate based on 18 months of exposure. If you assume all the weight loss occurred in a couple of weeks, then short-term rates of 20 to 40 MPY can be estimated. Note in Table 6.6 that the average copper corrosion rate was only 0.2 to 0.3 MPY prior to this incident. We confirmed that copper sulfide was present on the specimens as shown in Figure 6.15.

FIGURE 6.14. Linear Polarization Corrosion Probe Data on Copper Corrosion in Plant Isobutane Condenser

TABLE 6.7. Cooling Water H₂S and Ammonia at Condenser Inlet

Date	pH	NH ₃ (mg/L)	H ₂ S (mg/L)
06/25	8.12	0.6	0.3
06/29	—	—	0.1
07/01	—	—	<0.05 during Cl ₂ add
07/02	—	—	<0.05 after Cl ₂ add
07/07	8.75	0.4	<0.05
07/10	7.75	0.34	0.1
07/13	8.35	0.5	<0.05
07/16	8.25	0.3	<0.05
07/24	8.40	0.3	<0.05
07/27	8.28	0.2	<0.05
07/29	8.25	0.3	<0.05
07/31	8.10	0.1	<0.05
08/27	8.15	0.1	<0.05

FIGURE 6.15. XEM Spectra of Surface Film Area on Copper Sample (E16) in Magma Inlet Cooling Water

We believe this incident was caused by decay of algae and other organic matter in the pond system that accumulated during several extended plant shutdowns when water treatment was suspended. With the onset of higher summer temperatures, the decay of this material released both H_2S and ammonia to the ponds.

6.3 REFERENCE

Shannon, D. W. "The Role of Chemical Components in Geothermal Brines on Corrosion." National Association of Corrosion Engineers Paper No. 57. CORROSION '78 National Meeting, March 6-10, 1978. Houston, Texas.

6.32

7.0 COMPOSITION, SOURCE, AND HISTORY OF SCALING

Scale samples are collected on weighed coupons exposed along with corrosion samples discussed in Section 6.0. Coupons are placed inside the brine inlet line to the power plant, two locations are the heat exchangers and the waste brine line before the reinjection wells. Inline temperature and pressure are continuously recorded. Coupons made from carbon steel and DHP copper are also placed in the inlet and outlet lines of the cooling water system. A complete listing of scale samples collected at Magma is presented on Table 7.1.

TABLE 7.1. Scale Samples Collected from Magma Power Plant

Sample Number	Date Collected	Description of Location	Analysis Performed
M-1	12/06/79	SW end of HX-3 isobutane side	
M-2	12/06/79	On ID of HX-2 (NE end)	
M-3	12/07/79	PC-2—Valve ID	XRF
M-4	12/07/79	PC-2—Test Probe	XRF
M-5	12/07/79	Turbine oil drained from boiler feed turbine	XRF
M-6	12/07/79	Seal grease scraped from floating end HX-3 (SW)	XRF
M-7	12/07/79	Seal grease—unused supply, Darmia, EP No. 1	XRF
M-8	12/12/79	PC-1—pilot tube	XRF
M-9	12/12/79	PC-2—pilot tube	XRF
M-10	12/13/79	PC-2—top of spool	XRF
M-11	12/13/79	PC-2—bottom of spool	XRF, SEM
M-12	12/13/79	PC-2—top, upstream of spool	XRF
M-13	12/13/79	PC-2—loose scale, upstream of spool	XRF
M-14		Well No. 3, third bowl pump	IC, ICP
M-15		Well No. 3, outside pump housing	IC, ICP
M-16		Well No. 3, pump section ID	IC, ICP
M-17	03/30/80	Well No. 4, brown scale from top of wellhead	IC, ICP

NOTE: XRF = X-ray fluorescence; SEM = scanning electron microscope; IC, ICP = ion chromatograph and argon plasma spectrograph analysis of acid solution of scale; XRD = X-ray diffraction.

TABLE 7.1. (contd)

Sample Number	Date Collected	Description of Location	Analysis Performed
M-18	03/30/80	Well No. 4, white scale from top of wellhead	IC, ICP
M-19	04/07/80	Well No. 1, lube string	IC, ICP, XRF
M-20	05/08/80	Cooling water bubblers--MPND	XRF
M-21	05/08/80	Well No. 5, nitrogen pressure line	XRF
M-22	05/08/80	Well No. 5, top of wellhead	XRF
M-23	05/09/80	Well No. 5, 4-in. bearing at top of well	IC, ICP
M-24	05/09/80	Well No. 5, first 4-in. bearing cap	IC, ICP
M-25	05/09/80	Well No. 5, first 20-ft lube string	IC, ICP
M-26	05/09/80	Well No. 5, 20- to 40-ft section lube string	IC, ICP
M-27	05/13/80	Well No. 4, No. 4 bearing	IC, ICP
M-28	05/13/80	Well No. 4, No. 9 bearing top joint	IC, ICP
M-29	05/29/80	Well No. 1, No. 3 section lube string	IC, ICP
M-30	10/30/80	Well No. 3, sand plug obtained from bottom of baker tank	
M-31	12/12/80	Boost feed pump at PC-1	XRF, XRD
M-32	12/12/80	Well No. 2, lube string--20 ft	XRF, XRD
M-33	12/12/80	Well No. 2, lube string--40 ft	XRF, XRD
M-34	12/03/80	Pump No. 2, bottom bowl brine side	XRF, XRD
M-35	03/21/81	Suction section of condensate pump No. 1, isobutane system	XRF, XRD
C-4	03/24/80	Cooling water, carbon steel coupon, insulated--outlet	SEM, XRF
C-23	03/24/80	Cooling water, carbon steel coupon, uninsulated--outlet	SEM
C-16	03/24/80	Cooling water, carbon steel coupon, uninsulated--inlet	
C-9	03/24/80	Cooling water, carbon steel coupon, insulated--inlet	
D-4	03/24/80	Cooling water copper coupon, insulated--inlet	
D-10	03/24/80	Cooling water, copper coupon, insulated--outlet	
D-17	03/24/80	Cooling water, copper coupon, uninsulated--outlet	SEM

TABLE 7.1. (contd)

Sample Number	Date Collected	Description of Location	Analysis Performed
D-24	03/24/80	Cooling water, copper coupon, uninsulated--inlet	SEM
PC1-E+3	02/01/80	PC-2--insulated pipe metal coupon	SEM
PC2-E+2	02/02/80	PC-1--insulated pipe metal coupon	SEM
A-10	02/14/80	PC-2--insulated pipe metal coupon	SEM, XRD
A-4	02/14/80	PC-1--insulated pipe metal coupon	SEM
A-38	02/14/80	PC-1--insulated pipe metal coupon	SEM
A-21	02/14/80	PC-2--insulated pipe metal coupon	SEM
PC-1(3)	09/04/80	PC-1--1-in. disk	SEM
F-34	09/04/80	PC-2--1-in. disk	SEM
HX-2(3)	09/04/80	HX-2--1-in. disk	SEM
HX-7(3)	09/04/80	HX-7--1-in. disk	SEM
C-19	09/04/80	Cooling water--inlet	SEM
C-25	09/04/80	Cooling water--outlet	SEM
D-7	09/04/80	Cooling water--inlet	SEM
D-13	09/04/80	Cooling water--outlet	SEM
CWI-1	09/04/80	Cooling water--inlet	SEM
CWI-6	09/04/80	Cooling water--outlet	SEM
F-23	09/04/80	Cooling water--inlet	SEM
E-13	09/04/80	Cooling water--outlet	SEM
F-98	10/29/80	PC-1	SEM, XRF
F-3	10/29/80	PC-1	SEM
F-51	10/29/80	HX-7	SEM
F-94	10/29/80	HX-7	SEM
F-80	10/29/80	HX-2	SEM
F-66	10/29/80	HX-2	SEM, XRF
F-83	10/29/80	PC-2	SEM, XRF
F-12	10/29/80	PC-2	SEM
MA-28	12/02/81	PC-2	SEM
MA-55	12/02/81	PC-2	SEM
MA-36	12/02/81	PC-2	SEM

7.1 SCALING IN BRINE LINES

After almost two years of sample and data collecting throughout the power plant during various stages of operation, the character and potential for scaling has been established. Scaling rates were found to be very low, especially when compared to flash-type power plants. The Magma Power Plant maintains the total pressure in the brine lines above the flash point, thus preventing flashing of CO_2 , and subsequent carbonate scaling. During heat extraction from the brine the temperature is not lowered below amorphous silica solubility. Since the SiO_2 concentrations of Magma brine is $\sim 214 \text{ mg/l}$, amorphous silica solubility is not reached until the brine is cooled to 60°C . Due to pressure and temperature control in the plant process, neither carbonate nor silica scale were deposited. What was deposited were thin films of insoluble sulfides, primarily of iron with some iron carbonate. Table 7.2 lists the major elemental components of typical scales analyzed and their mineralogical character.

The source of the iron in the scale is probably corrosion of the carbon steel pipes. The iron contained in the brine at the wellheads is generally $\sim 0.5 \text{ ppm}$, but increases up to 3 ppm by the time the brine reaches the plant outlet. This increased ferrous iron content is above the iron's solubility at the plant outlet. The metals Hg, Br, Sb, As, and Ba, were also present in the scale and originate from the brine. As the brine temperature is lowered, these elements form insoluble sulfides.

Some carbonate scales are also present as shown in Table 7.3. Carbonate scales occurred in the shaft lubrication annulus of some production pumps, due to calcium in the surface water used for pump bearing cooling. (The pumps now are lubricated with oil.) Carbonate scale also forms if the brine is allowed to flash. This has occurred on several occasions in the pump bowls (Sample M-34) due to insufficient waterhead over the pump suction to suppress flashing. A diagram of the pumps is given in Figure 4.1. With only the 50-ft waterhead over the pump, there would be insufficient overpressure to prevent flashing at the pump suction. If the gas pressure in the sealed annulus above the pump is not high enough (as occasionally happened) flashing and scale formation could occur. Current pump operating procedures limit minimum pressures above the pump to maintain adequate overpressure to suppress scaling.

TABLE 7.2. XRF Analysis of Scale from Magma Power Plant

Sample Number	Location	Concentration							
		Weight%				PPM			
		Si	S	Ca	Fe	Hg	Br	Sb	Ba
M-3	PC-2—valve	34.0	1.66	3.14	6.83	225	32	151	3002
M-4	PC-2—test probe	<5.0	36.5	0.58	59.0	180	17	280	84
M-8	PC-1—pitot tube	<0.58	16.72	0.57	52.26	24	<5	132	
M-9	PC-2—pitot tube	<0.58	13.82	2.81	59.58	332	348	305	
M-10	PC-2—top of spool	0.77	23.31	0.20	45.45	391	40	686	
M-11	PC-2—bottom of spool	2.03	31.63	0.27	42.82	1131	112	329	
M-12	PC-2—top, upstream	<0.51	22.22	0.12	57.19	566	64	276	
M-13	PC-2—loose scale, upstream	0.76	29.48	0.11	43.00	1250	136	375	
M-32	Well No. 2—lube string 20 ft	<3.0	19.0	33.0	0.77				
M-34	Pump No. 2—bottom bowl brine side	<3.9	0.56	49.6	2.2				
F-98	Plant inlet scale, PC-1	<11.0	20.9	0.24	5.0				
F-83	Plant outlet scale, PC-2	<3.0	5.1	1.6	37.7				
F-66	Heat exchanger scale, HX-2	<7.0	3.6	<0.5	12.2				
C-23	Cooling water outlet scale	<9.0	1.8	9.5	61.0				

TABLE 7.3. Mineralogical Evaluation of Scale at Various Locations in Magma's Geothermal Power Plant

Sample Number	Location	Minerals, in Order of Predominancy
M-31	Boost feed pump at plant brine inlet (PC-1)	Marcasite, pyrite
M-32	Well No. 2, lube string, 20-ft depth	Anhydrite, trace calcite
M-33	Well No. 2, lube string, 40-ft depth	Anhydrite, trace calcite
M-34	Pump No. 2, bottom bowl, brine side	Calcite, trace quartz
M-35	Suction section, pump No. 1, isobutane system	Magnetite
A-4	Plant brine inlet (PC-1)	Siderite, pyrite, marcasite
A-38	Plant brine inlet (PC-1)	Pyrite, marcasite, siderite
A-10	Plant brine outlet (PC-2)	Siderite, pyrite, marcasite
A-21	Plant brine outlet (PC-2)	Marcasite, siderite, pyrite

A detailed examination of typical plant scale in the brine system reveals a complex layering structure. A scale coupon exposed at the plant outlet (PC-2) was removed, sectioned, then studied by electron microscopy. The scale averaged a thickness of 300 μm and was deposited during 334 days air exposure during plant construction, and 20 days of brine exposure. As shown in Figure 7.1, the scale is multilayered. In several crevices Fe-Cl was predominant. Next outward from the metal were two bands of Fe-CO₃ (siderite) with the outer band lower in its weight percentage of Fe. Within this lower Fe band were lenses of particulates (Fe-Si-Al-K). The outermost layer was Fe-S.

As can be seen by this example, the scale on the plant pipes is a product of both corrosion and deposition. The Fe-Cl, Fe-CO₃ bands resulted from the corrosion of the pipe during construction and initial washings with brine during early testing. The Fe-S band is depositional. Although the coupon was continuously exposed to hot brine only for the last 20 days, or 6% of the time, the Fe-S band represents 35% of the scale thickness. Thus the scaling rate of the Fe-S band is higher than the other bands (4 $\mu\text{m}/\text{day}$ versus 0.7 $\mu\text{m}/\text{day}$). It is also interesting to note that the Fe-S band is less dense than the Fe-CO₃ band. Similar scale structure is observed in the heat exchangers (Figure 7.2) and in the plant inlet line (Figure 7.3). Scaling was lower on the heat

- A METAL
- B Fe-Cl IN CREVICE
- C Fe-CO₃
- D Fe-CO₃ (LOWER % OF Fe)
- E Fe-Si-Al-K
- F Fe-S
- G MOUNT

(THICKNESS OF SCALE 300 μ)

334 DAYS AIR EXPOSURE DURING CONSTRUCTION
20 DAYS BRINE EXPOSURE

FIGURE 7.1. Section of Initial Geothermal Scale at Magma Power Plant at Startup

COUPON F51
 LOCATION: BRINE SIDE HEAT EXCHANGER NO.7
 EXPOSURE TIME: 2664 HRS

FIGURE 7.2. Section of Typical Geothermal Scale Deposited in Heat Exchangers

exchanger tubes and in the plant outlet (PC-2) line than in the plant inlet piping (PC-1). Figure 7.4 demonstrates this difference. Two observations have been made that could explain this variation in scale depositional rates. The sand separator which is located just upstream of sample point PC-1 is blown down several times a day. This blowdown produces chemical transients. These could increase scaling rates directly downstream of the sand separator. We measured the iron content of the brine at PC-1 during a blowdown and detected a 0.2-ppm drop in the iron content.

As discussed in Section 8 we observed greater quantities of Fe-S particles in the brine at the plant outlet compared to the plant inlet. This implies that Fe-S scale in the heat exchangers are being eroded by the turbulent flow. As the brine proceeds downstream more particulates are added producing a more erosive flow. Erosion of the scale apparently partially counterbalances the depositional rate. These suspended scale particles have a potential for well plugging. The measurement and interactions of the suspended particle with the

COUPON F98
LOCATION: MAGMA'S PLANT BRINE INLET
EXPOSURE TIME: 1546 HRS

COUPON F3
LOCATION: MAGMA'S PLANT BRINE INLET
EXPOSURE TIME: 3408 HRS

FIGURE 7.3. Scale Deposition at Plant Inlet Valve (PC-1) Versus Exposure Time

reinjection wells will be discussed in the section on suspended particles and well productivity. Average scale thickness versus exposure time at several plant locations are plotted in Figure 7.5. In Figure 7.6 the buildup of scales over time is illustrated. Also note the decrease in carbon steel thickness and some broad pitting.

COUPON MA-36
LOCATION: MAGMA'S PLANT BRINE INLET
EXPOSURE TIME: 4056 HRS

COUPON MA-28
LOCATION: MAGMA'S PLANT BRINE OUTLET
EXPOSURE TIME: 4056 HRS

FIGURE 7.4. Comparison of Scale Deposition at Plant Inlet and Outlet for Same Exposure Time

7.11

FIGURE 7.5. Scaling Rates in Magma Brine

CARBON STEEL COUPONS LOCATED AT MAGMA'S PLANT BRINE INLET FOR VARIOUS EXPOSURE LENGTHS

FIGURE 7.6. Comparison of Scale Deposition at Plant Inlet (PC-1) for Various Hours of Exposure

7.2 SCALING IN COOLING WATER LINES

Coupons composed of carbon steel and DHP copper have been bolted inside the cooling water inlet and outlet lines to the isobutane condensor system. The coupons were installed November 6, 1978. One-half of the coupons were electrically insulated and the other half were not. Eight coupons, one of each kind from the inlet and outlet lines, were removed October 15, 1979, for scale examination. During this almost first year of exposure (8232 hours) the power plant was still in its shakedown period and had not yet produced power, although water had been intermittently pumped through the cooling system. Thus scaling potentials determined during this phase of operation will provide a comparison for scaling potentials determined later during normal power production.

The source for the cooling water was the All-American Canal, East Highland Branch. This water was treated and recirculated through the isobutane condensers, then pumped to storage ponds for cooling then reused. The calcium concentration in the East Highland Canal averaged 90 mg/l (225 mg/l CaCO_3), and in the cooling ponds as high as 124 mg/l (310 mg/l CaCO_3), both well above CaCO_2 saturation at 75°C (18 mg/l CaCO_2). The Langelier Index (L) and the Ryzner Stability Index (R) were calculated (Table 7.4) for the East Highland Canal, the main storage pond, and the canal water at 110°F which is the temperature at the surface of the condenser tubes. For all three chemistries the

TABLE 7.4. Calculated Potential of Cooling Water to Corrode or Scale

	<u>Main Storage Pond 05/03/79</u>	<u>East Highland Canal 05/03/79</u>	<u>Canal Water at Temperature</u>
pH	8.3	8.2	8.2
TDS	1270	1010	1010
Hardness (Ca only)	228	242	242
Alkalinity	131	149	149
Temperature °(F)	<u>75</u>	<u>75</u>	<u>110</u>
Langelier Index	+0.7	+0.6	+0.9
Ryzner Stability Index	7.0	7.0	5.8

L-Index indicated mildly scaling tendencies, but using the R-Index, only the heated water at the cooling tube surface would have scaling tendencies.

The coupons were examined optically and with SEM to determine both the quantity and the composition of scale present. For both electrically insulated and uninsulated coupons of copper or carbon steel a film was present. All coupons had a net weight loss, implying the rate of corrosion greater than the rate of scale deposition. For the copper coupons the scale was a low-porosity unevenly deposited calcium carbonate with an average thickness of 20 μm (Figure 7.7). The only feature distinguishable between the inlet and outlet copper coupons was the more crystalline nature of the scale at the outlet locations. The similar nature and rate of scale deposition between the inlet and outlet is not surprising because for most of the 8232 hours of exposure the condensers were not operating. Both the calcium carbonate deposition and the occurrence of corrosion which was observed was predicted from the water chemistry.

The carbon steel coupons had a chemically different scale than what was deposited on the copper coupons. There was also a distinction between the scale at the plant inlet and outlet (see Figure 7.8). For both the inlet and outlet locations, corrosion was predominant with iron being the major component of the scale. In addition to the iron oxide, Zn "spheres" were sandwiched between the oxide layers. These Zn spheres were only found in the inlet scale. The source for the Zn was the chemicals added to the cooling water for scale and corrosion control. In the outlet scale minor amounts of CaCO_3 were also found.

Coupons were again removed both from the inlet and outlet cooling water lines after the plant began producing power. One set was removed after 1884 hours of plant operation and another after 2966 hours. Scale thickness on the carbon steel coupons was always greater than that on the copper coupons as shown in Figure 7.9. Again iron oxide plus other layers high in Fe were the scale on the carbon steel coupons, while CuCO_3 and Cu-S layers were the deposit on the copper coupons. (See discussion in Section 6.2.5 on this Cu-S.) For both the carbon steel and the copper coupons, scale deposition rates were higher in the cooling water outlet line than in the inlet line. No major chemical differences were observed between the inlet and outlet lines except

FIGURE 7.7. Calcium Carbonate Scale Deposited on Copper Coupon in Cooling-Water Outlet Line

- 1 COUPON
- 2 Fe
- 3 Zn, MINOR Fe
- 4 Fe, MINOR Zn
- 5 Fe
- 6 Fe, MINOR S

(A) INLET TO CONDENSER, 1 mm = 1.0 μ m

- 1 COUPON
- 2 Fe
- 3 Ca, MINOR Fe
- 4 Fe, MINOR Ca

(B) OUTLET LINE FROM CONDENSER, 1 mm 3.33 μ m

FIGURE 7.8. Elemental Analysis of Cooling-Water System Scale

the occasional presence of Zn-spheres in the inlet scale. SEM photographs of cross sections of representative coupons of carbon steel and copper from both the inlet and outlet locations are on Figure 7.9.

FIGURE 7.9. Comparison of Scale Deposited in Cooling-Water Lines Versus Coupon Material and Location

8.0 SUSPENDED SOLIDS IN GEOTHERMAL BRINE

Over 135 brine samples have been collected of solids suspended in the fluid lines. Over 50 brine samples have also been analyzed for their suspended solid population using a laser particle counter. Locations where suspended solids are collected for sizing and chemical analysis are shown in Figure 3.1. Suspended solids were determined at each production well, after the sand separator, at the inlet to the heat exchanger, after each leg of the heat exchanger, the inlet and outlet of each of the three legs of the PNL Bypass Test Facility, and finally down stream of the booster pumps before reinjection.

The hardware for obtaining a representative sample of brine from a large flowing volume has been standardized (at PNL) and is shown in Figure 8.1. The sampling system consists of an insertion probe, cooling coils, filter housing and necessary valves and gauges. A more detailed description of the sampling hardware can be found in an earlier report (Shannon et al. 1980, Section 4). The suspended solid sampler, or multiple filter housing displayed on Figure 8.2 was designed by PNL to size particles during sampling and to collect sized particles for later chemical analysis. The filters and filter supports are nonmetallic. Millipore's cellulose filters were used for cooled-depressurized sampling and polytetrafluoroethylene or Teflon filters were used during sampling at the geothermal system operating temperature and pressure.

Samples of the geothermal fluids were also collected in 8-ounce clear glass bottles that were previously rinsed with filtered (0.45 μ m) distilled water. The brine was cooled and depressurized through the sampling apparatus used for the filtered samples. Particulate populations were sized using a laser particle counter model ILI 1000, Spectrex Corp.

It has been found that both the quantity and size distribution of suspended solids in the brine at each sampling port is constant during steady-state plant operation. Table 8.1 lists mg/l of suspended solids measured at various locations throughout the plant from November 1979 through April 1981. All five production wells have been sampled for particulates and they typically produce up to 2 mg of particulates per liter of brine. As shown in Figure 3.1, after the brine from the production wells is combined, it flows through a sand

FIGURE 8.1. Sampling System for Collecting and Measuring Suspended Solids; a) System for Cold Sampling, b) System for Hot Sampling

separator and can be again sampled at PC-1. After the sand separator, the particulate content of the brine has been reduced only very slightly. The sand separator does perform separation of large suspended grains from the brine, and provides a service when large slugs of sand are produced during well startups. Typically total suspended solids in the brine are increased slightly after passage through the heat exchanger, as noticed during sampling at Valve PC-2.

Plant operations which produce unusually large particulate contents are: recirculation of brine through the heat exchangers which occurs during warmup; and the first few hours of brine production just after a well is started.

FIGURE 8.2. Cross-Sectional Drawing of Suspended Solid Sampler Showing Location of Filter Supports and Gauges

TABLE 8.1. Suspended Solid Content of Geothermal Brine at Magma's Geothermal Power Plant Determined by Standard Filter-Weight-Gain Technique

Location	Date	Filter Number	Time	Collection Data	Weight (mg/l) of Brine
Well SW2	11/14/79	MA-33	11:00 am	0.45 μ , 0.54 ℓ (well just turned on)	11.0
		MA-34	11:10 am	0.45, 0.208 ℓ	14.9
		MA-19	02:15 pm	0.45, 2.275 ℓ	2.15
		MA-24	02:20 pm	0.45, 5.0 ℓ	1.42
Well SW4	11/08/79	M-7		8.0	1.89
		M-17		5.0	3.44
		M-27	05:00 pm	1.2	3.67
		M-37		0.45	3.67
		M-57		0.22	5.56
Well SW5	11/08/79	MA-1	10:00 am	0.45, 10 ℓ	0.82
So. Brine Line	11/09/79	MA-8	05:00 pm	0.45, 6 ℓ (bottom of pipe)	0.78
Inlet Spool	11/06/79	No. 6	03:30 pm	0.45, 10 ℓ	0.35
	11/15/79	MA-21	10:00 am	0.45, 5 ℓ	1.08
		MA-3		8.0	0.21
		M-13		5.0	0.72
		M-23	12:15 am	1.2	0.21
		M-43		0.45	0.23
		M-53		0.22	0.40
Bypass Inlet	11/12/79	MA-32	03:30 pm	0.45, 5.03 ℓ	0.40
		MA-31	04:00 pm	0.45, 3.35 ℓ	0.45
		MA-30	04:15 pm	0.45, 5 ℓ	0.50
		MA-29	04:30 pm	0.45, 4.2 ℓ	0.55
		M-6		8.0	0.64
		M-16		5.0	0.32
		M-26	05:15 pm	1.2	0.16
		M-36		0.45	0.16
		M-56		0.22	0.20
Outlet Spool	11/06/79	No. 2	04:25 pm	0.45, 10 ℓ	0.34
	11/10/79	MA-13	02:15 pm	0.45, 1.6 ℓ	2.27
	11/12/79	MA-15	—	0.45, 5 ℓ	1.06
		MA-16	—	0.45, 5 ℓ	0.34
	11/14/79	MA-53	11:20 am	0.45, 5 ℓ	2.04
Well SW2	01/29/80	No. 13	11:40 am	0.45 μ , 5 ℓ	0.60
PC-1 (inlet spool)	01/30/80	No. 3	02:00 pm	0.45, 2.92 ℓ	1.06
		No. 8	04:00 pm	0.45, 4.58 ℓ	0.87
	01/31/80	MA-27	02:40 pm	0.45, 5 ℓ	0.02
		M-1		8.0	
		M-11		5.0	
		M-21	03:25 pm	1.2	5 ℓ
		M-31		0.45	
		M-51		0.22	
PC-2 (outlet spool)	01/30/80	No. 11	02:00 pm	0.45, 5 ℓ	1.50
		MA-23	04:00 pm	0.45, 5 ℓ	0.58
	01/31/80	No. 2	02:40 pm	0.45, 4.65 ℓ	0.19
		M-2		8.0	0.44
		M-12		5.0	tr
		M-22	04:00 pm	1.2	tr
		M-32		0.45	tr
		M-52		0.22	tr

TABLE 8.1. (contd)

Location	Date	Filter Number	Time	Collection Data	Weight (mg/l) of Brine
PC-2 (outlet spool)	02/01/80	M-4	02:30 pm	8.0	tr
		M-14		5.0	1.24
		M-24		1.2	tr
		M-34		0.45	tr
		M-54		0.22	tr
		M-37	10:00 am	0.45 0.07	180.0
	02/02/80	MA-75	11:00 am	8.0	18.50
		MA-79		5.0	12.93
		MA-82		1.2	12.21
		MA-36		0.45	4.57
		MA-86		0.22	6.07
BY 17 Low Temperature	02/01/80	MA-25	02:25 pm	0.45 2.15 l	0.74
		M-5	03:15 pm	8.0	1.06
		M-15		5.0	0.12
		M-25		1.2	tr
		M-35		0.45	tr
		M-55		0.22	tr
	02/02/80	MA-55	10:42 am	0.45, 0.1 l	111.0
		MA-56	10:50 am	0.45, 0.24 l	61.25
		MA-57	10:56 am	0.45, 0.48 l	37.5
		MA-51	11:02 am	0.45, 0.40 l	32.75
		MA-52	11:11 am	0.45, 0.60 l	16.67
		MA-74	11:30 am	8.0	2.67
		MA-78		5.0	0.53
		MA-81		1.2	9.47
		MA-38		0.45	---
		MA-85		0.22	0.67
		MA-54	03:10 pm	0.45 5 l	0.48
		MA-73	04:00 pm	8.0	0.42
		MA-77		5.0	0.06
		MA-80		1.2	0.06
		MA-22		0.45	---
		MA-83		0.22	0.18
PC-2	05/18/80	MA-2	10:00 am	No. 2 Well, recirculating HX startup-- 245°F, 245 psi 53 WGS	4.2
PC-2	05/18/80	MA-48	01:00 pm	Nos. 2 and 3 wells HX 145°F, 325 psi, 5 l	1.4
PC-2	05/18/80	104	02:00 to	Nos. 1, 2, and 3 wells 157°F, 340 psi, 3 l (collected w/SSS)	1.1
		105	02:15 pm		1.5
		106			2.0
		107			1.3
		108			0.9
PC-2	05/19/80	MA-7	10:00 am	Nos. 1, 2, 5 wells, 145°F, 350 psi 0.93 l	0.6
BY-27	05/19/80	MA-47	02:00 pm	4.7 l	0.3
BY-18LT	05/19/80	M-45	02:00 pm	4.0 l	1.4
BY-15LT	05/20/80	MA-50	09:00 am	5 l	0.5
BY-17MT	05/20/80	MA-39	10:20 am	3.16	1.0
PC-2	12/07/79	No. 9		5.0 l	3.02

TABLE 8.1. (contd)

Location	Date	Filter Number	Time	Collection Data	Weight (mg/l) of Brine
SW3	12/06/79	No. 10		5.0 l	2.16
PC-2	05/02/80	MA-4	02:45 pm	5.0 l, 25° to 29°C	1.40
	05/07/80	101	09:32 am	1.425 l, 30 to 0 psig	0.35
		102	10:00 am	0.920 l, 30 to 0 psig	1.30
		100	10:20 am	1.3 l, 50 to 0 psig	5.08
SW3	06/19/80	110		back flashing well	2.33
46-7A	06/20/80	109		back flashing well	1.32
PC-2	10/30/80	111	11:00 am	4.2, reinjector lot, ΔP 45 psig	2.3
		112	11:00 am	4.0, reinjector lot, ΔP 45 psig	5.9
	03/24/80	M300	11:00 am	1.17, Filter chain test, 25 to 30 μ	3.2
		M303		15 to 20 μ	7.6
		113		10.0	11.1
		114		1.2	8.5
		115		11 μ	4.4
		M301			2.7
		M304			1.9
	03/24/81	M61	11:15 am	1.0, Filter chain test	4.1
		116			4.4
		117			2.4
		M302			1.8
	03/24/81	M305	11:34 am	1.0, Filter chain test	3.5
		M601			2.1
					3.6

These observations are documented on Table 8.2 which lists total suspended solids at various locations under varying plant conditions. In Figure 8.3 the output of the inline turbidity meter is shown. It can be seen that plant startups and temperature transients produced "bursts" of solids much higher than the "normal" level. Unfortunately this instrument could not be kept operational due to deposits on the optical window. However, intermittent sampling of the brine clearly under estimates the average solids content because the "spikes" are usually missed.

Table 8.1 provides more detail of particulate production related to heat exchanger warmup and cleanup during startup. From January 29, through February 1, 1980, about 90% of the brine was being passed through the heat exchangers. During this time, the suspended solids content remained low (0.19 to 1.50 mg/l throughout the plant), with the outlet (PC-2) generally remaining higher. On February 2, 1980 the plant was started up after being down that night. As the brine was being recirculated through the heat

TABLE 8.2. Suspended Solids Measurements at Magma Geothermal Power Plant

<u>Filter Location/ Sample History</u>	<u>Total Suspended Solids, mg/l</u>	<u>Major Size Ranges, μ</u>	<u>Major Chemical Components</u>
Supply Well SW2 Well Just Turned On	11.0	---	Silicate Minerals
Supply Well SW2/ Well-Flow Stabilized	1.4	1 to 10	Silicate Minerals
Supply Well SW3/ Well-Flow Stabilized	2.2	3 to 15	Silicate Minerals
Supply Well SW4/ Well-Flow Stabilized	1.9	0.22 to 0.45, 8.0 up	Silicate Minerals
Supply Well SW5 Well-Flow Stabilized	0.8	1 to 10	Silicate Minerals
Plant Inlet/Normal HX	0.7	0.22 to 0.45, 5.0 up	Silicate Minerals
Plant Outlet/Normal HX	1.1	5.0 up	Silicates/Fe-S
Plant Outlet/ Recirculation	180.0	Silghtly Favoring 5.0 up	Fe-S

exchangers with small quantities of fresh brine added in order to slowly warm them, large quantities of suspended solids were being produced (180 mg/l). These suspended solids have been analyzed and are primarily Fe-S scale fragments (from the scale deposited on pipes and heat exchangers) removed during turbulent flow. As can be seen in Table 8.1, on February 2, 1980, as less brine is being recirculated through the heat exchangers and larger amounts of fresh brine are added, the concentrations of suspended solids decreases. From 10:00 am to 11:11 am the quantity of suspended solids rapidly decrease from 180.0 mg/l to 16.67 mg/l, and finally at 3:10 pm down to the normal operating range of 0.48 mg/l.

Suspended solids were also measured during normal plant operating conditions using laser light scattering techniques. As Table 8.3 shows, there appears to be an increase in the total quantity of suspended solids after the brine passes through the heat exchangers, which agrees with the filter data. In each case the quantity of particles between 1 to 5 μ decreased, while the

FIGURE 8.3. Brine Turbidity at Plant Outlet Injection Line and Injection Line Temperature

TABLE 8.3. Suspended Particles/ml at Magma, Ca Determined by Laser Light Scattering

Date	Time	PC-1 (inlet spool)	PC-2 (outlet spool)	Bypass (bottle)	Bypass (window)	Plant Operation
01/30/80	10:20 am	----	1335(a)	----	----	Flow initiated through HX
			220			
			114			
			99			
	11:25 am	----	1500	----	----	90% brine—10% HX
			267			
			284			
			209			
	02:00 pm	1590	1380	----	----	90% through HX
			304			
			332			
			222			
	4:40 pm	1270	1550	----	----	90% through HX
			735			
			366			
			135			
01/31/80	02:30 pm	1360	1580	1520	1680	90% through HX
		872	514	531	642	
		350	466	403	431	
		80	255	242	124	

(a) First number = total between 1 to 80 μ
 second number = total between 1 to 5 μ
 third number = total between 5 to 10 μ
 fourth number = total between 10 to 15 μ .

quantity of particles between 5 to 10 and 10 to 15 generally increased. These larger particles were collected on filters and were determined to be Fe-S scale fragments.

Suspended solids from four of the five producing wells were also studied to determine what particulates they each contributed. It was not surprising that the four wells are very similar in the kinds of mineral fragments they produce (Table 8.4). Well SW5 did have the largest amount of quartz to feldspar ratio. The production wells suspended solid chemistry was also studied by XRF to determine their bulk elemental chemistry (Table 8.5). The two southern wells, SW4 and SW5, are very similar. The ratio of S:Fe:As and Si:Ca are almost the same, although Well SW5 does have a greater quantity of Si per S than Well SW4. The northern supply well, SW2, is very chemically distinct chemically from the southern wells. There is more Fe than S, and a larger percentage of Si. This suggests the most particles are iron-silicate.

At the Bypass inlet, while the south supply wells were flowing, a size distribution of the suspended solids in the brine was determined using a filter chain (shown in Figure 8.2). These filters were then analyzed to determine the chemistry of the suspended solids for various sizes. The elements Fe, As, Sb, and S were more common as the pore diameter of the filter increased. This implies that they are metallic sulfides, most likely the source of the yellow color observed on the filters. Also Si was most predominant on the largest filter (8.0 μ), suggesting that Si exists in a compound that is $>8.0 \mu$. Barium had an opposite trend. It was most predominant on the finest filter (0.22 μ m), suggesting that Ba exists as a compound (most likely BaSO_4) with the diameter range of 0.45 to 0.22 μ m.

After establishing the nature of the particulates which enter the power plant from the production wells, the brine particulates were again studied at the plant outlet (PC-2). This was to establish to what extent the particulate population was being altered by heat extraction from the brine during power production. Samples of suspended solids were collected simultaneously at the plant inlet (PC-1) and plant outlet (PC-2) during normal heat exchanger operation. Comparing the electron microscopy scans of each typical area of the filters (Figures 8.3 and 8.4) an increase in Fe and S in the particulate matter

TABLE 8.4. Compositions of Suspended Particles at Magma

Filter Number	Location	Operation	Major Particle Compositions
MA-37	PC-2	During circulation (taken after ~2 hr of brine circulation through HX)	Fe-S Fe oxide Fe-S-Si Minor Ba-S Fe-S-Ca Fe-Ca
No. 3	PC-1	Normal HX operation	quartz K-feldspar Minor Fe oxide scale pieces Na-Al-Si Ca-plagioclase Ba-S
No. 11	PC-2	Normal HX operation (take simultaneous with No. 3)	K-feldspar Fe-S Minor-Fe oxide Ca-plagioclase Cu-Fe-S Fe-S-Si quartz scale piece
MA-24	SW2	---	Si-Al-K-Fe quartz Minor-Si-Fe Si-Al Si-Fe-Al-Cd Si-Fe-S
No. 10	SW3	---	quartz Si-Al-K-Fe Minor-Si-Fe-Al Cd
NM	SW4	---	quartz Si-Al-K-Fe Minor-Fe-Si Si-Fe-S Ba-S Cu-S Fe-S-Si-Cd
MA-1	SW5	---	quartz Minor-Si-Fe Cd-S Si-Al-K-Fe

TABLE 8.5. XRF Results of Suspended Solids Collection on Filters at Magma

Location	Filter Number	Pore Size (μ)	l of Brine	(concentration in $\mu\text{g}/\text{cm}^2$)							
				Si	S	Cl	Ca	Fe	As	Sb	Ba
Bypass Inlet (So. wells flowing)	M-6	8.0	5.0	84	75	30	0.23	27	3.7	9.2	1.0
	M-16	5.0	5.0	<10	14	16	<0.2	0.63	1.5	1.5	<3.43
	M-26	1.2	5.0	4.4	9.4	18	<0.2	0.21	1.2	<0.8	<3.54
	M-36	0.45	5.0	<16	15	9	<0.2	0.20	1.2	<0.8	<3.47
	M-56	0.22	5.0	5.5	17	20	<0.2	0.17	0.9	<0.9	2.2
Concentrations corrected to 1 l of brine for comparison											
Well SW4	NW	0.45	3.0	13	5	9	0.5	4	0.06	2	<3.3
Well SW5	MA-1	0.45	10.0	19	3	4	0.7	3	0.03	<0.1	<0.1
Sell SW2	MA-33	0.45	0.545	500	28	10	14	72	0.2	<1.3	0.9

FIGURE 8.4. SEM Analysis of Suspended Particles at Plant Inlet (PC-1) Filter No. 3

occurs. This trend was reflected in the chemistry of the individual particles, at PC-1 quartz and feldspar predominate and at PC-2 K-feldspar and Fe-S predominate (Table 8.4). Suspended solids were sampled again at PC-2, but during recirculation while warming up the heat exchangers. The electron microscopy area scan (Figure 8.5) of the filters shows the large relative increase in Fe and S. Figure 8.6 shows the scan of particles during warmup of the HX-bank. The individual particles are mostly iron-sulfides with no apparent silicates. (The antimony—Sb—was due to a grease used in the heat exchanger seals.) It was also observed that the particles are larger at the plant outlet under both operating conditions.

Mineral fragments with minor amounts of pipe corrosion products enter the plant, and as the brine cools in the heat exchangers insoluble sulfides form on the pipe wall as scale and deposit on the mineral fragments. Thus, the particles at PC-2 are a mixture of the initial particles (mineral fragments, corrosion products) plus coated mineral fragments and scale from the heat

FIGURE 8.5. SEM Analysis of Suspended Particles at Plant Outlet (PC-2), Filter No. 11

FIGURE 8.6. SEM Scan of Particles Collected During Recirculation While Warming Up HX-Bank

exchanger removed due to the turbulent brine flow. This explains the near absence of silicates observed during warmup where the brine was recirculated many times through the heat exchangers and mineral fragments were diluted with the larger quantity of scale particles.

8.1 REFERENCE

Shannon, D. W. et al. 1980. "Field Evaluation of Sampling Methods for Pressurized Geothermal Liquids, Gases, and Suspended Solids." Pacific Northwest Laboratory, PNL-3412.

8.14

9.0 OBSERVATIONS ON REINJECTION WELLS

9.1 INTRODUCTION

At Magma's Geothermal Binary Power Plant over one million pounds/hour of brine is pumped through the heat exchangers during electrical energy production. An assured deliverability of brine from the production wells and the continued acceptance of spent brine by the reinjection wells is essential for the successful operation of the power plant. By monitoring the performance of production and reinjection wells during varying plant conditions, factors which show potential to cause degradation of the wells can be isolated.

9.2 BACKGROUND

Magma's Geothermal Power Plant is located in Imperial Valley, California, in the fault bounded Salton Trough. The strata which the wells transect are nonmarine Colorado River delt sediments. The subsurface of the area near the wells is displayed in Figure 9.1. It is interesting to note the southerly dip of the strata towards Production Well 48-7. Reinjection Well 46-7 was added to the figure to demonstrate the depth separation between the reinjection interval (2070 to 3072 ft) and the typical production interval (5800 to 6900 ft).

Samples of the strata as rock chips from well drillings have been collected and analyzed optically and by X-ray fluorescence and X-ray diffraction. The data are reported in Tables 9.1 and 9.2 for Reinjection Well 46-7A depths 2200 to 2230 ft, 2530 to 2560 ft, and 3130 to 3160 ft plus two other samples from the Magma area from 2880 to 2910 ft and 3421 to 3433 ft (well not identified). These samples can be characterized primarily as mudstone or shale due to their fine grain size. This data will also be used as a baseline to determine the amount of water-rock alteration that occurs during reinjection simulations at the Bypass Test Facility. This will aid in determining the magnitude of aquifer degradation that can be expected due to reinjection of spent brine. Comparing the elemental concentrations of the Magma rocks with the elemental concentration of a typical shale (Table 9.2), rock chips closely resemble a typical shale with the exception of Ca and Si. In the case of these two elements, Ca and Si, the Magma rocks contain much higher quantities. This appears

FIGURE 9.1. South to North Cross-Section Subsurface Map Including Magma's Production and Reinjection Wells. Isothermal surfaces at 300° and 330°F plus seismic reflectors, blue, orange, and yellow markers on wells are Magma's 6-2 (U.S. Government)

TABLE 9.1. XRD Results from Core Chips from the Magma Site

Well	Sample Depth	Minerals Identified						
		Dolomite	Calcite	Feldspar	Quartz	Smectite	Kaolinite	Mica
46-7A	2200 to 2230	X	X	X	X	X	---	---
46-7A	2530 to 2560	X	X	X	X	X	X	X
---	2880 to 2910	---	X	X	X	X	X	---
46-7A	3130 to 3160	---	X	X	X	X	X	X
---	3421 to 3433	X	X	X	X	X	X	X

TABLE 9.2. XRF Results of Core Chips from the Magma Site

Well	Sample Depth	Elemental Concentration, ppm									
		Al	Ba	Ca	Fe	K	Mn	S	Si	Ti	Zr
46-7A	2200 to 2230	73,200	640	50,200	29,400	21,600	390	<1,600	264,000	3,250	134
46-7A	2530 to 2560	64,700	430	53,900	47,600	22,400	710	1,800	233,000	3,180	124
---	2880 to 2910	76,500	370	42,000	34,900	24,500	400	<1,600	256,000	3,430	116
46-7A	3130 to 3160	59,700	1,210	31,200	23,000	29,600	300	2,000	306,000	2,640	95
---	3421 to 3433	84,600	320	55,400	31,900	27,300	460	<1,700	266,000	3,730	124
	Typical Shale ^(a)	80,000	580	22,100	47,200	26,600	850	2,400	73,000	4,600	160
	Typical Sandstone ^(a)	25,000	50	39,100	9,800	10,700	50	240	268,000	1,500	200

(a) Elemental averages from many localities (Turekian and Wedgeohl 1961).

to be due to hydrothermal alteration producing calcite and silica cement as observed under the petrographic microscope. There are some interesting chemical trends with depth (Figure 9.2); K increases with depth and for just Well 46-7A samples, both Al and Ca decrease with depth.

The well drilling samples have very similar mineralogy, as shown in Table 9.1. The predominant minerals are dolomite, calcite, feldspar, quartz, smectite, kaolinite, and mica. It is of interest to note that none of these minerals have a large tendency to swell due to changes in salinity of the ground water.

9.3 INJECTION WELL PERFORMANCE DATA

Test methods to simulate the down-hole behavior of injection wells have been developed by the oil industry. Field tests employing these methods were undertaken at the Magma Geothermal Power Plant to determine the plugging potential of the spent brine to the injector formations. The apparatus designed for this test is shown in Figure 9.3. The brine was cooled to $\sim 50^{\circ}\text{F}$ by an ice bath; the brine then flowed through a filter housing containing a $0.45\text{-}\mu\text{m}$ filter where most of the suspended particles collected and formed a filter cake. With a graduated cylinder and stopwatch the cumulative volume of brine with time was determined. A constant pressure differential across the filter and filter cake of 50 psig was maintained by using a backflow regulator.

Two simulation injector tests were performed during typical heat extraction from the brine on two different occasions. The field conditions which varied slightly, and a record of the data taken during these tests are shown in Table 9.3. The brine sampling point was located at the outlet valve (PC-2) from the heat exchangers. This location was the closest to the reinjection wells that could be sampled. Considering the high brine flow rates, one can easily assume that the brine characteristics did not vary between the sampling point and the injection wells.

FIGURE 9.2. Chemistry of Rock Chips from Magma's Wells with Depth

FIGURE 9.3. Apparatus for Simulating Behavior of Spent Brine on Rejection Wells

TABLE 9.3. Simulation Injector Tests

Date/Time: May 7, 1980, 10:20 am
Location: Magma Geothermal Plant, outlet valve from heat exchangers (PC-2)
Brine Conditions: Brine cooled by heat exchangers to 152°F at 350 psig
Pressure Drop Across Filter: 50 psig
Filter Pore Size: 0.45 μ m

<u>Time (sec)</u>	<u>Cumulative Volume (ℓ)</u>
15	0.2
25	0.3
33	0.4
44	0.5
95	0.75
108	0.8
138	0.9
173	0.95
187	0.99
247	1.0
265	1.3

Date/Time: October 30, 1980, 11:00 am
Location: Magma Geothermal Plant, outlet valve from heat exchangers (PC-2)
Brine Conditions: Brine cooled by heat exchangers to 170°F at 610 psig,
all 5 wells producing
Pressure Drop Across Filter: 45 psig
Filter Pore Size: 0.45 μ m

<u>Time (sec)</u>	<u>Cumulative Volume (ℓ)</u>
12.5	0.2
25	0.5
36	0.7
68	1.2
98	1.6
152	2.2
199	2.6
274	3.1
354	3.5
453	3.9
560	4.2

Using Darcy's Law (Equation 9.1) the permeability of the filters (pore size 0.45 μ m) which simulated the formation's surface were 0.014 and 0.015 millidarcy. Not only do the two tests agree well, but they also compare well (0.003 to 0.078 md) with another simulation injector test during June 1978 of

EQUATION 9.1

$$K \text{ (permeability, darcy)} = \frac{(\text{flow rate, cc/sec}) (\text{thickness of filter and cake, cm}) (\text{liquid viscosity, centipoise})}{(\text{X-sectional flow area, cm}^2) (\text{pressure drop across filter, atm})}$$

$$K = \frac{(5 \text{ cc/sec}) (0.014 \text{ cm}) (0.4 \text{ centipoise})}{-(13.65 \text{ cm}^2) (3.4 \text{ atm})}$$

$$K = 1.4 \times 10^{-5} \text{ darcy}$$

$$K = 0.014 \text{ millidarcy}$$

brine that was cooled then "aged" (Jorda 1980). Assuming a formation permeability between 10 and 1000 millidarcy with a filter cake-permeability measured around 0.014.

Figure 9.4 predicts that the suspended solids in the re-injected fluid will not be retained on the formation's surface, but will all pass through. Thus, reinjector well degradation should not occur due to the normal state of fine particulates. Unfortunately, well injectability has been reported to decrease with time (Jorda 1980) and back-flushing is necessary to restore the well's performance.

Another method to view the acceptability of the spent brine to the receiving formation is to compare the diameter range of suspended solids to the typical formation particle diameter. By microscopic examination of rock chips from the receiving formations, the grain size was determined to be between 5 to 50 μm . Locating the area bounded by 5- to 10- μm dia in Figure 9.5, surface retention (Region 1) appears to have the most likely affect on the receiving formations of the suspended solids greater than one micron. Particles with diameters between 0.4 and 1 μm should exhibit both retention and deep invasion properties. While particles less than 0.4 μm should pass through the formation without forming a filter cake.

As discussed in Section 8.0, a typical quantity of suspended particles with diameter $>1 \mu\text{m}$ at the plant outlet (PC-2) is 1300 particles/ml of brine. With this large quantity, it appears (by the method of diameter comparison) that well degradation should occur due to suspended particles being retained on the surface of the formations.

We suspect the discrepancy between the two predictions is due to not collecting all the suspended solids during sampling. Particles in the large size range 0.01 to 0.3 mm have been collected in low points in the line and do enter the reinjection wells. If these larger particles are not represented in the sampling fluid, the filter cake would be more compact (thus lower permeability) than the potential filter cake in the well bore. The lower permeability value of the filter cake results in the conclusion that the particles will all pass through the formation.

FIGURE 9.4. Relationship Between Filter Cake and Formation Permeabilities in Flow or Particle-Laden Fluid Through Porous Media (Jorda 1978)

FIGURE 9.5. Particle Distribution in Systems Where Particles in Fluid and Reservoir Particles are Spheroids (Jorda 1978)

During June 20, 1980, when Reinjection Well 46-7A was back-flushed, we had an opportunity to sample the slurry that was being flushed from the well. The chemical analysis of the particles in the slurry are reported in Table 9.4. The predominate elements in order of concentration were Si, Al, Fe, S, Ca, Cu, and Ba. The mineral phases identified by XRD were quartz, feldspar, pyrite and a trace of mica. This composition differs from the suspended solids sampled at Port PC-2 which is located in the brine line before entering the reinjection well. As can be seen in Table 9.4, the slurry obtained during back-flushing was higher in silicate minerals and much lower in scale particles (Fe + S). The presence of the scale particles, which originated on the heat exchanger surfaces, were still a major component of the slurry and implies that these particles are being retained in the well (Region 1, Figures 9.4 and 9.5). There are several possible schemes which could account for the higher percentage of silica obtained during back-flushing. One source is the large quantities of silicates (sand) that are produced during the start-up of a well. This period of well activity is usually not represented in sampling, and in particular, not during the collection of suspended solids on Comparative Filter No. 12 (Table 9.4). Another scheme to explain the higher silicate concentrations would be infiltration of mineral grains through the slotted liner of the injection well itself, during well inactivity or back-flushing. Or perhaps, a larger quantity of silicates are actually entering the well bore than determined during random sampling. Most likely each of these schemes contributed to the higher silicate mineral content is the particles collected during back-flushing versus reinjection.

In summary, analysis of the suspended solids in the back-flush slurry flags a potential major concern: a significant portion of the suspended solids which are being reinjected into the reinjection well are remaining in the well bore itself. With the addition of pressure gauges at each well head and a record of the injected brine flow rates, injectability variations for each injector can now be monitored with respect to plant operation, such as well startup. These data are given in Table 9.5. Analysis of the data in Table 9.5 do not establish a statistically significant reduction in flow during this time period although the wells differ in their performances. The surface pressure

TABLE 9.4. Comparison of Particulate Chemistry During Back-Flushing and Normal Activity

Filter Number	Location	Conditions	Particulates mg/	Chemical Composition of Particulates											
				Al	Si	S	Ca	Fe	Cu	Zn	As	Sr	Ag	Sb	Ba
				(µg/cm ²)											
12	PC-2	Normal HX Activity	0.34	NA	<16	32	0.44	16	0.69	3.6	1.3	0.11	NA	<1.1	<0.5
				(wt%)											
109	Well 46-7A	Back-Flushing	1.82	5.5	23	0.74	0.57	4.4	0.20	0.10	0.05	0.04	0.04	0.06	0.48
110	Well SW3	Back-Flushing	2.33	5.0	24	0.69	6.6	5.6	0.09	0.57	0.03	0.27	0.01	0.004	0.5

NA--Not Analyzed.

TABLE 9.5. Injection Well Flow and Surface Pressure Data

Date	Time	Injection Line Pressure (psi)	Well 46-7		Well 46-7A		Well 46-7B	
			psi	gpm	psi	gpm	psi	gpm
09/26/80	07:00am	370	275	787.5	380	551.3	360	1193
09/29/80	12:15pm	360	310	843.8	365	495	355	1148
09/30/80	08:30am	360	310	832.5	360	416-641	340	1136
10/01/80	09:30am	360	320	832.5	360	484	345	1114
10/03/80	08:30am	345	303	900	350	562.5	170	315
10/06/80	07:30am	345	145	NF	355	585	335	1294
10/07/80	07:30am	350	142	NF	360	562.5	345	1272
10/08/80	07:45am	350	140	NF	360	562.5	340	1283
10/09/80	07:45am	350	130	NF	350	585	340	1260
10/10/80	01:00pm	350	125	NF	350	540	330	1181
10/14/80	01:00pm	350	130	NF	360	551.5	315	1193
10/17/80	09:45am	355	110	NF	360	663.8	215	608
10/21/80	07:30am	360	115	NF	360	675	215	608
10/23/80	07:30am	360	120	NF	360	652.5	215	630
10/29/80	08:30am	490	155	NF	490	945	420	1935
10/30/80	07:50am	490	165	NF	495	945	420	1845
11/01/80	09:40am	450	160	NF	460	877.5	380	1653
11/12/80	07:30am	367	95	NF	365	787.5	150	450
11/13/80	02:00pm	350	130	NF	350	630	335	1395
11/14/80	08:00am	345	135	NF	340	596.3	325	1383
01/13/81	08:35am	255	50	NF	260	405	245	787
01/22/81	09:30am	230	57	NF	235	450	185	697
01/23/81	08:00am	250	80	NF	245	382.5	200	652
01/26/81	08:30am	235	90	NF	240	371.3	195	652
03/13/81	09:40am	253	187	247.5	240	315	240	585
03/21/81	07:45am	350	114	NF	345	607.5	310	1237
03/21/81	06:45pm	280	225	315	270	247	265	517
03/22/81	06:45am	260	115	NF	260	427.5	140	382
03/22/81	01:30pm	385	307	1102.5	380	585	370	1552
03/24/81	08:20am	380	365	990	375	495	375	1327
03/25/81	08:40am	435	335	720	430	562.5	425	967
03/27/81	10:00am	355	355	1080	354	551.3	350	945
03/27/81	04:15pm	400	395	1170	400	652.5	395	1282
03/28/81	12:00pm	375	325	1282.5	375	663.8	380	1260
03/30/81	02:05pm	360	355	1260	365	630	355	1305
04/02/81	11:00am	375	137	157.5	375	810	365	1732
04/02/81	02:40pm	380	300	855	390	776.3	380	1575
04/03/81	08:45am	415	343	675	405	663.8	395	1676
04/03/81	03:25pm	410	350	697.5	410	675	400	1777
04/04/81	11:15am	415	355	652.5	410	630	400	>1136
04/06/81	08:30am	425	373	607.5	425	562.5	420	1642
04/06/81	03:45pm	425	370	663.8	425	596.3	410	1530
04/07/81	10:45am	400	208	225	400	596.3	395	1563
04/08/81	08:30am	390	210	225	390	551.3	380	1563
04/08/81	01:00pm	390	205	225	395	540	380	1575
04/09/81	09:15am	390	200	225	395	540	380	1598

TABLE 9.5. (contd)

Date	Time	Injection Line Pressure (psi)	Well 46-7		Well 46-7A		Well 46-7B	
			psi	gpm	psi	gpm	psi	gpm
04/09/81	01:30pm	390	200	225	395	540	390	1575
04/10/81	09:00am	380	197	225	390	517.5	370	1575
04/11/81	10:00am	460	210	247.5	460	663.8	445	1924
04/17/81	10:30am	420	190	528.8	410	765	400	1991
04/18/81	10:00am	425	265	483.8	420	630	420	1924
04/24/81	08:00am	305	112	225	290	495	300	1260
04/24/81	03:20pm	445	150	112.5	445	765	425	2328
04/25/81	01:15pm	425	425	1170	420	585	410	1260
04/30/81	08:40am	240	240	540	240	281		
05/01/81	03:50pm	470	150	NF	465	742.5	445	2182
05/05/81	01:45pm	250	253	742.5	250	427.5	240	945
05/06/81	08:00am	280	270	607.5	275	405	260	1057
05/06/81	04:00pm	280	283	596.3	280	405	265	1091
05/07/81	08:00am	280	283	562.5	280	393.8	265	1080
05/07/81	03:15pm	280	287	573.8	285	382.5	270	1068
05/08/81	08:00am	290	287	562.5	290	393.8	275	1023
05/11/81	08:00am	313	310	585	310	382.5	295	1113
05/11/81	03:00pm	310	310	618.8	315	382.5	290	1113
05/12/81	11:30am	315	315	596.3	320	382.5	300	1091
05/13/81	08:00am	375	380	753.8	375	472.5	370	1473
05/13/81	02:15pm	490	180	NF	495	753.8	420	1946
05/14/81	08:00am	265	255	225	260	112.5	250	472
05/19/81	08:10am	250	180	438.8	260	315	240	1271
05/26/81	08:30am	375	155	NF	380	697.5	370	1102
05/26/81	12:00pm	370	150	NF	370	697.5	345	1102
05/28/81	11:00am	360	145	NF	360	708.8	345	1383
05/28/81	02:45pm	360	145	NF	360	708.8	345	1383
06/05/81	03:30pm	470	150	NF	455	1260	440	1665
06/07/81	09:00am	450	155	NF	445	1012.5	430	1642
06/29/81	08:00am	320	308	585	315	393.8	305	1046
06/30/81	09:00am	320	310	562.5	320	382.5	305	1080
07/01/81	08:45am	320	310	540	310	360	305	1125
07/02/81	10:30am	370	135	NF	370	472.5	360	1552
07/13/81	08:00am	365	374	765	360	483.8	240	821
07/14/81	08:00am	375	375	753.5	370	472.5	240	798
07/16/81	10:30am	395	140	NF	385	562.5	360	1327
07/24/81	02:45pm	360	137	NF	360	630	345	1620
07/27/81	08:00am	370	125	NF	370	472.5	360	1552
07/27/81	03:00pm	370	125	NF	370	472.5	365	1552
07/28/81	08:00am	365	130	NF	360	450	355	1530
07/28/81	03:00pm	375	133	NF	370	461.3	360	1518
07/29/81	09:15am	370	130	NF	370	450	360	1530
07/31/81	10:00am	370	133	NF	365	427.5	350	1507

is a poor measure of the pressure drop in the formation, since well depth and brine density (temperature) need to be considered in a detailed analysis of reservoir injection performance. This expanded study was outside the scope of this project.

Production Well SW3 was back-flushed on June 18, 1980, and a sample was collected of the slurry. The elemental analysis is given in Table 9.4. The major mineral phases identified by XRD were quartz, calcite, feldspar, mica, illite, chlorite, kaolinite, and pyrite. The purpose for back-flushing SW3 was to remove a calcite plug that was suspected to have formed. Since calcite was found in the slurry, one can assume that a calcite plug did form. The source of the other minerals could only be infiltration from the formations along the slotted liner.

Collection and analysis of the particles contained in the slurry produced during back-flushing of the wells does add insight into what is taking place down in the well bore itself.

9.4 REFERENCES

Jorda. 1978.

Turekian and Wedgeohl. 1961. Bull. Geol. Soc. Am. 72:175.

9.16

10.0 FUTURE WORK

We expect that the Magma Plant and the East Mesa KGRA will be used for many years to come. There are a number of areas where future work will be useful.

10.1 ISOBUTANE SYSTEM CORROSION

Our monitoring program did not include measuring corrosion in the isobutane system. We observed significant corrosion on several occasions when the isobutane system was open for maintenance. Leaks developed in the heat exchanger seals which let geothermal brine into the isobutane piping. This chloride contamination caused subsequent corrosion and buildup of corrosion product sludge in the system. At this time we are planning a future program to instrument the isobutane system.

10.2 GEOTHERMAL WELL CHEMISTRY

During the period we monitored the wells no significant chemistry changes were observed. It would be useful to continue this periodic sampling over a longer time.

10.3 INJECTION WELL PERFORMANCE

The data on injection well performance given in Chapter 9 show no obvious degradation with time. However the data are widely scattered. Further analysis of the data is needed to correct for the hydrostatic pressure of the column of water in the well, this pressure or the formation also changes with water density caused by temperature changes. Also the permeability of the formation itself appears to be temperature dependent.

10.4 HEAT EXCHANGER CORROSION

The relatively high corrosion rates on the 0.035-in. well heat exchanger tubes suggest these tubes will have a short life. If tube bundles become available a destructive analysis of the corrosion on both brine and isobutane sides would be useful.

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