DOE/SF/12203--T1

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REPORT ON HAWAII
GEOTHERMAL POWER PLANT
PROJECT

Prepared by
THE RESEARCH CORPORATION OF THE UNIVERSITY OF HAWAII

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MASTER

JUNE 1983

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HGP-A PROJECT
FINAL REPORT

THE EXECUTIVE SUMMARY

The Hawaii Geothermal Generator Project is the first power plant in the State of Hawaii to be powered by geothermal energy. This plant, which is located in the Puna District on the Island of Hawaii, produces three (3) megawatts of electricity utilizing the steam phase from the geothermal well. This project represents the climax of the geophysical research efforts going on for two decades in the Hawaiian Islands which resulted in the discovery of a significant reservoir of geothermal energy which could be put to practical use. The first well was named after Dr. Abbott (deceased), who was a key figure in the selection of the site for the Hawaii Geothermal Project (HGP). In honor and memory of his contribution, the well is known as HGP-A, the "A" standing for Abbott. In 1978 the Department of Energy, in conjunction with the State of Hawaii, entered into negotiations to design and build a power plant.

The purpose and objective of this plant was to demonstrate the feasibility of constructing and operating a geothermal power plant located in a remote volcanically active area. A contract was signed in mid 1978 between the Research Corporation of the University of Hawaii (RCUH) and the Department of Energy (DOE). To date, the DOE has provided 8.3 million dollars with the State of Hawaii and others contributing 2.1 million dollars.

The cost of the project exceeded its original estimates by approximately 25%. These increases in cost were principally contributed to the higher cost for construction than was originally estimated. Second, the cost of procuring the various pieces of equipment exceed their estimates by 10 to 20 percent, and third, the engineering dollar per man hour rose 20 to 25 percent.

The consultant in this project, Rogers Engineering, Inc. of San Francisco assisted by Hirai and Associates of Hilo, Hawaii, performed the engineering design and construction management. The Environmental Analysis Lab (EAL) of Richmond, California, was selected to perform the environmental monitoring task both prior to the operation of the plant to the present time.

The design effort and other project efforts were interrupted for two major reasons: (1) it was concluded that the existing data regarding the mass flow and gas content were not adequately defined and (2) the well casing required rework.

In late 1979 a well test program was conducted to resolve the uncertainty of the mass flow and gas content. Construction of the steam-liquid separator and its associates piping and controls were completed to assure the data obtained from the well test could be properly interpreted. The well test was conducted in the last two weeks of December 1979 and the first week in January 1980. The results of this testing indicated both the gas content and mass flow were different than originally determined from previous two phase flow tests.

Subsequent to the completion of the flow test, the well static pressure levels increase above the previous plateau of approximately 120 PSI to a level in excess of 500 PSI. The well was evaluated with instrumentation to determine any changes in the temperature profile. The results suggested circulation had developed in the well. Subsequently, a log test indicated that the casing cement had either deteriorated or had been damaged by past operations of the well. In any event, it was concluded that the well was unsafe and required reworking to improve the integrity of the casing. Subsequent testing of the well and its reduced static pressure condition confirmed that the defects which were causing circulation were corrected by the rework.

The program continued with power plant construction and tests. The procurement of equipment was performed throughout the period and the major equipment was received during the period of January through April 1981.

Construction was essentially completed in May 1981 during which time the Hawaii Electric Light Company (HELCO) initiated a training program for the personnel who would be operating the plant. This training program provided both classroom and hands-on operation experience for the HELCO personnel. The well was opened on June 12, 1981, and initial power was generated on July 18, 1981. These events did not take place without significant difficulties including the failure of the speed control and trip valves and the unsatisfactory performance of a number of components, both electrical and mechanical, and the subsequent failure of the turbine. In late August 1981, the well was shut-in for a period of approximately three months while the turbine was reworked.

In December 1981 the plant was brought back on line. However, another delay developed when rebalancing of the generator was required by the manufacturer because of deficiencies noted in other generators of this type at other locations. Rebalancing continued into January and February 1982. In addition to these problems, a significant effort was extended to bring the hydrogen sulfide abatement systems, both the primary and by-pass systems, up to operating efficiently at the required 98% removal rate. Subsequent efforts resulted in the primary system providing 99.9%, abatement and the by-pass system providing 98%. In March 1982, HELCO put the plant in commercial operation and assumed responsibility for the day to day management and operation of the plant. An initial revenue rate of 49 mills per kilowatt-hour net generated was based on HELCO's average cost of purchase power for 1981. HELCO improved the efficiency and effectiveness of the power plant operation such that in August 1982 it was able to reduce the manned shifts from three to one. The day shift is manned with one operator and during the other shifts the plant is in full automatic operation and only a security guard is at the power plant. Since September 1982 the plant has operated at a net profit of approximately \$30,000 per month. It is expected that the plant will continue to operate throughout the calendar year of 1983 with an anticipated need to shut down the plant prior to the end of the year for a maintenance program.

From the inception of the program, various organizations conducted environmental baseline studies to assure that when the new plant came on line the baseline condition would be understood so that any additions of pollutants

to the environment by the power plant would be clearly recognized. During the 1979/1980 well test, Lawrence Livermore Labs sent a technician and equipment to the site to measure both background and emissions during the well test. The results indicated there were no significant addition of H_2S to the environment.

In March 1981, Environmental Analysis Lab activated the environmental monitoring program. The network of monitoring equipment indicates that there were periods when the plant emitted H_2S above its design level. However, H_2S levels never approached the OSHA limit of 10 ppm at the plant. Since March 1982, the emissions from the plant have essentially been well within the design requirement of 98% removal. Other analysis shows no indication of any addition of lead, arsenic or mercury, or other potentially harmful elements to the environment from the operation of the power plant.

OBJECTIVES AND ORGANIZATION

Within the State of Hawaii, the HGP-A Geothermal Power Plant was managed by the HGP-A Development Group (DG) which consisted of a representative from the State of Hawaii Department of Planning and Economic Development (DPED), the University of Hawaii, and the County of Hawaii. This organization was charged with the development of geothermal energy in the State of Hawaii when it was determined that the HGP-A could produce significant quantities of steam producing up to five (5) megawatts of electricity and that a significant geothermal reservoir existed in the area. The DG, in conjunction with the Department of Energy (DOE), reached an agreement to construct a geothermal power plant to demonstrate the feasibility of producing electricity in an active volcanic rift zone in an environmentally acceptable manner. DOE technical management and contract administration was carried out by the San Francisco Area Office of the DOE, located in Oakland, California. Negotiations during 1977 and 1978 resulted in a cost-sharing contract for an estimated total cost of \$6,268,256 of which \$400,000 was contributed by the State of Hawaii, \$100,000 by the County of Hawaii, and \$25,000 by Hawaiian Electric Company (HECO) and the remainder by the DOE.

The contracting agency for the DG was The Research Corporation of the University of Hawaii (RCUH). The RCUH entered into the contract with the DOE in June 1978. A full-time project manager was hired to coordinate the organizational elements and project tasks.

Rogers Engineering Corporation of San Francisco was selected as the engineering consultant for the program. This company was experienced in the engineering and construction of one of Iceland's geothermal plants.

Construction contracts were awarded on a competitive fixed-price bid basis. The construction work was accomplished in three phases: the "front end" equipment, including the well head valves, liquid/vapor separator, and the steam bypass to the rock muffler was built during late 1979; the site work, involving grading, equipment foundations, and the turbine generator building was constructed in 1980; the final phase of work included the installation of all the electrical, mechanical and instrumentation equipment, including piping and wiring, was completed in mid 1981.

The other major element of the project involved environmental monitoring. Environmental Analysis Laboratory of Richmond, California was selected as the environmental monitoring firm. Their contract provided for equipment procurement and installation, air and water sampling and analysis. This element of the project was to provide assurance that the emissions and effluents for the reservoir were properly abated and that there were no adverse effects on the environment.

The funds provided to date are as follows:

Department of Energy	\$8,314,000
Department of Planning and Economic Development	1,906,000
University of Hawaii	48,000
County of Hawaii	100,000
Hawaiian Electric Company	25,000
Private Contributions	30,000

SECTION II

HGP-A DESIGN

Prepared by

Edward Baughman
Hawaiian Electric Company

II. HGP-A DESIGN

1. Mechanical:

This 3000 KWe gross R&D plant is equipped with a 6-stage, 5800 RPM turbine driving through a reduction gear to a 1800 RPM, 4 pole, 4160V, 3Ø generator.

Output from the generator is fed to a station transformer, a 34.4 KV stepup transformer and into the local power company system.

The steam supply from a single well is processed through a flash separator which separates the high silica brine water from the steam. The 100,000#/hr flow consists of approximately 48,000# steam at 366°F/175PSIG and 52,000# of water at 365°F. The flash separator delivers 99%+ purity steam to the 10" carbon steel main steam line. Final moisture separation to 99.9+% is accomplished prior to delivery to the turbine by an inline moisture separator. A constant steam line pressure of 175 PSIG is maintained by a back pressure control valve. Excess steam is spilled over to the rock muffler silencer. A 10% by volume sodium hydroxide solution is sprayed into the muffler line for reaction with the H₂S contained in the steam. A abatement level of 95% is accomplished in the rock muffler.

Normal operation is to flow the entire well steam flow to the turbine with "0" flow to the muffler. The original flow of 60,000#/hr steam dropped to 48,000#/hr after the last well restart in December 1981. The well had been shut down in August 1981 when vibration damage to the turbine required a factory rebuild of the rotating portion.

The turbine is designed for a flow of 50,968#/hr at 145 PSIG and 364°F for 3000 KWe gross at a PF of 80%. Approximately 1000#/hr is needed for the air ejectors and another 500#/hr for the steam seals. With this present 9.6% reduced flow to the turbine, we are able to maintain a gross output of 2780 KWe or only a 7+% loss.

The turbine is mounted with its gear reducer and generator on a steel skid at floor level.

Steam flow for load control is through either of two 8" parallel butterfly valve arrangements. Trip valves are also of butterfly design.

A main steam line butterfly valve is also incorporated as a backup during overspeed conditions. A trip for any other reason will not shut down the ejector steam supply, consequently an auto vacuum breaker was installed which opens on any turbine trip.

The turbine is equipped with six inner stage drains. These are regulated by orifice type hand valves which are gradually closed down as the turbine is warmed up and loaded. Stages 1 and 2 are shut off and 3, 4 and 5 are left one-half turn open above 2000 KW output. These drains are collected in a pit cond. tank and pushed to the condenser by a steam eductor.

The turbine exhaust is overhead through a 40"O stainless steel line to a stainless steel four-pass surface condenser to 2 PSIA exhaust pressure. The condenser hot well level is maintained by a recirculation system and surplus condensate is pumped into the cooling water system as make up for the two element cooling tower. Sufficient condensate is generated to make up evaporation loss plus about 20 gpm to overboard flow.

The vertical cooling tower has two sections with a 50 HP fan for each section. The tower is of wood construction, sits on a 20,000 gal. concrete basin and is packed with PVC filler. Two 65 HP cooling water pumps provide flow to and from the condenser via two carbon steel 12" lines. Cooling water for the generator, NCG ejectors, lube oil and NC Gas cooler is from taps off these main lines. Total flow requirements of 3,330 GPM can be met by either cooling water pumps.

The brine water level is maintained in the flash separator by a level controller operating a flow control valve. This brine water, 104 GPM, is released to atmospheric pressure in a separate muffler. About 10% flashes to steam and the remaining liquid is percolated into the porous lava rock. Some plugging of the rock has occurred due to precipitation of a portion of the SiO_2 .

A small portion of the H_2S , 30ppm, is contained in the steam plume. This level meets all EPA requirements when diluted by the steam plume.

The NC Gas stream contains CO_2 and H_2S in equal volumes of 37.2% measured at the condenser exit. The balance is N_2 , H_2 , O_2 and water vapor. Prior to oxidization, the major water vapor is condensed out. The balance is sent to a surge tank and then to a thermal oxidizer operating at 1600°F. The H_2S and H_2 are oxidized to water vapor and SO_2 plus a small quantity of SO_3 . The nitrogen and CO_2 are left primarily unreacted.

The oxidizer exhausts into a scrubber tower where the reactive gases contact a sodium hydroxide solution and the SO_3 and SO_2 are reacted to HSO_3 and enters the solution. The scrubbed gas is routed to the cooling tower for final washing. The oxidizer is 99+% effective and the cooling tower removes all final traces of SO_2 . The spent scrubber tower solution are disposed of in a percolation pond.

2. Electrical:

The plant electrical system consumes approximately 220 KW of load or 8% of the gross capability.

The main electrical control center, contained in a 8' x 8' x 30' transportable container, contains all breakers for 4160 V. and 480 V. 3Ø plus 120/240 V-1Ø systems, metering and generation power relays. All through wall connections are vapor-tite connectors on the exterior side. Only the generator 4160 volt wiring is wired through.

The electrical control center is air conditioned and maintained at a positive pressure to exclude H_2S gases. All incoming air is filtered through a charcoal media to react out the H_2S .

The electrical control center also contains the solid state battery charger and a large bank, 96 cells, of nickel-cadmium batteries provide D.C. backup power.

A small 3Ø-480 volt engine generator set provides charging power plus 3Ø AC power for the caustic injection pumps.

The plant is equipped with four 400 KW force cooled resistance load banks. These are used to automatically partially load the generator when the plant is separated from the local utility.

3. Instrumentation and Control:

The operators control room is similar in construction to the electrical control center but is only 20' long. It contains the electronic turbine governor system, the extensive electronic vibration detection equipment plus all pneumatic controllers and trips/recorders. The generator exciter control system is also housed in this module.

All tubing - electronic and electrical connections are made on the exterior walls.

All exterior plant steam and water system flow controls are pneumatic and, therefore, the use of stainless steel tubing is extensive. PH sensing, pressure vessel liquid high level alarms and trips are electric sensing with relay trips or alarms.

Turbine roll is made from an exterior startup control module. When turbine speed has reached governor control the system is transferred to the operator control room where voltage matching and synchronization are performed.

The plant is normally manned only on the day shift. When unmanned, gen. ver., load, trip and auto sync controls are transferred to the local utility system dispatcher.

The plant can safely separate from the system and maintain its own auxiliary plus loading of the resistance bank. Upon reestablishment of system power, the dispatcher can call for auto sync. Although this feature is incorporated in the unit, the local utility has not used it. They prefer to send a man out to the plant who checks out the system and then hand synchronizes the unit. A security guard is maintained during other shifts and he may call the dispatcher if he detects an alarm which is not transmitted to the dispatcher. The main reason for the security guard is due to the remoteness of the station and local vandalism.

Miscellaneous Equipment:

Two full capacity non-lub air compressors are provided for pneumatic control power. This skid set of compressors included two 100% silica regenerative air dryers. The compressors are connected to a common inlet silencer and H₂S reactive filter.

Two 100% control oil pumps, skid mounted, were provided including a duplex strainer set. Oil supply is common to the turbine reservoir.

The turbine lube oil system utilizes the base skid for a reservoir. A startup and shutdown aux. AC oil pump is provided with auto on in the event of lube oil pressure loss.

Shutdown of the aux. AC oil pump requires a manual action. The main oil supply pump is driven from the low speed shaft of the gear reducer and supplies oil to the turbine generator via a large duplex filter. Oil reservoir air ventilation is via an exhaust fan and inlet air is filtered and purged of H_2S by activated charcoal.

All turbine generator and miscellaneous equipment are housed in a control building with a full capacity bridge crane capable of lifting the generator and the turbine skid.

The major equipment items, i.e. the turbine, generator, control room, and switchgear, were designed for ease of removal in the event a volcanic eruption threatens the plant. The well head is protected against damage from lava by a concrete enclosure that can be filled with loose aggregate material and covered with a concrete lid.

The components, the mechanical control center and the electrical control center were designed for removal in a 48 hour period in the event of a threatening volcanic flow.

Except for the major turbine outage during the 1981 startup phase, this station has performed with an availability in excess of 90% since it was considered firm in May of 1982.

Figures 2-1 thru 2-6 are as built P & I diagrams, electrical schematic and plant layout.

- CONTROL SYMBOLS & ABBREVIATIONS**
- (S) STREAM NUMBER
 - (C) CONTROL CIRCUIT NUMBER
 - (I) INSTRUMENT
 - (S) SOLENOID OPERATOR
 - (D) DIAPHRAM OPERATOR
 - (M) MOTOR OPERATOR
-
- AI ANALYZER INDICATOR
 - FS: FLOW SWITCH
 - FCV FLOW CONTROL VALVE
 - LC: LEVEL CONTROL
 - LAL LEVEL ALARM LOW
 - LAM LEVEL ALARM HIGH
 - NC NORMALLY CLOSED
 - RC: RATIO CONTROL
 - PDI PRESSURE DIFFERENTIAL INDICATOR
 - PC PRESSURE CONTROL
 - PSV PRESSURE SAFETY VALVE
 - PI PRESSURE INDICATOR
 - FC FAIL CLOSE
 - FO FAIL OPEN

STREAM No.	3	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33
FLOW IN LB/HR																											
STEAM	52684	51475	180	460	374	8	51475	51475	375	13.9		513	20														
NON CONDENSABLE GAS	106	104	0.3	0.9	0.8	87.1	103.6	103.6	0.7	104.3		105.1	105.1														
AIR LEAKAGE						29		29		29		29	29														
COOLING TOWER WATER																											
COOLING TOWER BLOWN WATER																											
FLASH WATER																											
DISSOLVED SOLIDS																											
SODIUM HYDROXIDE																											
HYDROGEN PEROXIDE																											
CONDENSATE																											
TOTAL FLOW LB/HR	52280	51579	180.3	460.9	374.8	122.1	51376.6	51602.6	375.7	272.3		547.1	154.1	480	17400	18400	1575200	38030	20500		52678	493		52678	474		
TEMPERATURE °F	371		371	371	371	105		125		100		247	100	104	115	115	115	92	89	121	130	85	1144	140	85	371	270
PRESSURE PSIA	175	167	168	168	168	16.7	160	2		1.5		4.9	4.7														
PRESSURE INCH Hg AM																											
DENSITY LB/FT³																											
TOTAL MOLS / HR	2930	2866				4.3																					
ENTHALPY BTU/LB	1196	1196					1196	5972																			

Figure 2-2

ROBERTS ENGINEERING CO., INC. ENGINEERS - ARCHITECTS 111 FINE STREET, SAN FRANCISCO, CALIFORNIA 94101		RESEARCH CORPORATION OF THE UNIVERSITY OF HAWAII APPROVALS		HCP-A WELLHEAD GENERATOR PROOF-OF-FEASIBILITY PROJECT FLOW & CONTROL DIAGRAM POWER PLANT	
SCALE: NONE DATE: NOV-3-1978 DESIGNED BY: [Signature] CHECKED BY: [Signature] APPROVED BY: [Signature]		DATE: NOV-3-1978 DESIGNED BY: [Signature] CHECKED BY: [Signature] APPROVED BY: [Signature]		JOB NO. E-02-102 SHEET 1

NOTES

1. CALCULATED COMPOSITION OF THE INLET DISCHARGE GAS IS AS FOLLOWS:

LINE NO.	LB/HR	NO.	LB/HR	NO.	LB/HR
1	33.8	3	48.5	103	
2	1.6	4	3.2	224	364
3	0.4	5	0.4	0.64	
4	176.2	6	29	40.6	(NOTE 2)

2. MAXIMUM CONDITION IF 100% OF N.C. GAS COMES FORWARD FROM AFTER CONDENSER DATA CALCULATED BY JOHN ZINK.

STREAM No.	10	30	50	55	56	58	59	60	61	62	63	64
FLOW IN LB/HR												
STEAM	6					176.2						
NON CONDENSABLES	87.1					276.7						
AIR	29		258			0.4						
SO ₂ EFFLUENT LB/HR MAX.						117.40	720	138	26490	720	1772.7	
WATER		2583		2560	38122	(B)						
WYS EFFLUENT (PPM)					138	1780	143.2	5	120	80	196.8	
SOLIDS												
NaOH												
TOTAL FLOW LB/HR	122.1	2583	258	2570	38260	454.9	13900	863.2	138	26640	800	136.9
TEMPERATURE OF	103	85	85	187	209	182	182	182	84	187	104	104
PRESSURE PSIA	16.7	14.4	16.4		14.4	14.4	45	35				
DENSITY LB/FT ³	4.3											
WOLS/HR												
pH										8.5		
NOTE 1												

INTERMITTENT ONLY

Figure 2-3

ROBERTS ENGINEERING CO., INC. ENGINEERS - ARCHITECTS 111 PINE STREET, SAN FRANCISCO, CALIFORNIA 94111		RESEARCH CORPORATION OF THE UNIVERSITY OF HAWAII		HGP A WELLHEAD GENERATOR PROJECT OF FEASIBILITY PROJECT FLOW & CONTROL DIAGRAM 425 ABATEMENT	
ISSUED FOR DESIGN 425 ABATEMENT 11/1/78		DATE NOV. 3, 1978		APPROVALS DATE 11/1/78	
REVISION 1. 11/1/78 2. 11/1/78		REVISION 1. 11/1/78 2. 11/1/78		P. 108 NO. 12009 E-02-103 2

Figure 2-5

HAWAIIAN ENGINEERING CO., INC. ENGINEERS - ARCHITECTS 111 PINE STREET, SAN FRANCISCO, CALIFORNIA 94111				RESEARCH CORPORATION OF THE UNIVERSITY OF HAWAII				HGP A WELLHEAD GENERATOR PROOF OF FEASIBILITY PROJECT			
SCALE: 1"=20' DATE: 5/14/80				APPROVED: _____ DATE: _____				SHEET NO. 57030 KEY PLAN MECHANICAL			
ISSUED FOR CONSTRUCTION DATE: 5/14/80				ISSUED FOR BID DATE: 5/14/80				E-41-001			
REVISION NO. 1 DATE 5/14/80 BY J. H. H. H.				REVISION NO. 2 DATE 5/14/80 BY J. H. H. H.				REVISION NO. 3 DATE 5/14/80 BY J. H. H. H.			
REFERENCE DRAWINGS NO. 1 DATE 5/14/80 BY J. H. H. H.				REFERENCE DRAWINGS NO. 2 DATE 5/14/80 BY J. H. H. H.				REFERENCE DRAWINGS NO. 3 DATE 5/14/80 BY J. H. H. H.

Figure 2-6

SECTION III

EQUIPMENT LIST

HGP-A EQUIPMENT LIST

3-2

<u>ITEM</u>	<u>MANUFACTURER</u>	<u>ACQUISITION COST</u>
FCV-160, Model 29120 - 1"		
FCV-161, " " - 1"		
LV-511, " 29210 - 1"		
AV-901, " " - 1"		
LV-526, " 29121 - 1"		
LV-524, " 35-35102 - 1"		
LV-521B, " 35-35202 - 3"		
LV-521A, " 35-35102 - 1"		
LV-531, " 35-35202 - 1"		
PV-687, " 29111 - 1"		
Specifications: MR 40-111	Masoneilan International, Inc.	\$8,898.00
Process Analyzers (PH)		
Specifications: MR 40-125	The Foxboro Co.	\$1,022.00
Safety Relief Valves		
Specifications: MR 40-118B	Teledyne Farris, C/O Belilove Company -Engineers	\$ 510.00
Rupture Disk and Assembly		
10" - 150 ANSI - Insert G Assembly		
316 SST Base Carbon		
10" hov rupture disc burst pressure		
12 PSIG at 239 degrees F 316 SST		
top/teflon seal/316 SST Vacuum		
support		
Specifications: MR 40-118A	Fike Metal Products	\$1,418.00

<u>ITEM</u>	<u>MANUFACTURER</u>	<u>ACQUISITION COST</u>
Steam Water Separator		
Specifications: MR 10-101	Peerless MFG. Co.	\$36,350.00
Pressure Relief Valve Teledyne-Farris Model 26 PB 1240		
Specifications: MR 40-101	Belilove Co.	\$ 3,652.00
Steam Pressure Control Valve PV-1 Water Level Control Valve LV-1		
Specifications" MR 40-102	Steam Specialties Co.	\$ 7,640.00
TI-12, TI-21 TI16, 17, 18, 19, 20 TI-10A, 10-B TI-13, 114, 15, TI-11		
Specifications: MR 40-107	Associated Process Controls	\$ 1,480.65
Venturi Type Flow Elements		
Specifications: MR 40-105	Flow Tech Corp.	\$ 2,815.00

<u>ITEM</u>	<u>MANUFACTURER</u>	<u>ACQUISITION COST</u>
400 KW, 480 Volt, 3-phase load bank, fan cooled weather proof		
Specifications: MR-17-104B	Montgomery Brothers	\$26,288
Secondary Substation Transformer 1500/1680/1932va 4160 - 480/277 volts, 3-phase 55/65 C Rise, Standard no-load taps, ANSI standard accessories, with air filled junction boxes		
Specifications: MR 17-104A	H. K. Porter Co.	\$21,500
3,000 x 9 5/8" S.O. Casing Head Flanged with (2) 3" Flanged 2,000 lb. Nozzles		
3,000 x 7" S.O. Casing Head Flanged 2,000 Nozzles		
R-53 Ring Gasket 1 3/8" x 9 1/2" Studs @\$7.04 ea		
1 3/8" Nuts Double Stud Adaptor Flanges 3" 2,000 lb x 2" 5,000 lb.		
R-31 Ring Gaskets		
R-24 Ring Gaskets	W-K-M Wellhead Systems, Inc.	\$7,134.69

<u>ITEM</u>	<u>MANUFACTURER</u>	<u>ACQUISITION COST</u>
Waste Acid Gas Incinerator and Absorber		
Specifications: S 13-101	John Zink Company	\$155,635.00
Air Compressor Worthington Model 7-1/2 x 5 BVV		
Specifications: MR 16-101	Power Machine Company	\$ 41,131.00
Air Dryer		
Specifications: MR 16-102	Power Machine Company	\$ 20,857.00
Gas Chromatograph (part 8704) Microcell detector Column	Carle Instruments Inc.	\$ 2,067.40
Vertical pump electric motor driver		
Specifications: MR 14-103	Goulds Pump Company	\$ 55,924.00
Condensing and Gas Removal Equipment		
Specifications: MR 12-101	Zeman Sales Company	\$166,032.00
Peerless 24" O.K. 215 psig LS	Peerless Manufacturing Co.	\$ 18,810.00
Condensate Pump vertical type Model D1132 3x2x8 in. 316 Stainless Steel		
Specifications: MR 14-104	Worthington Pump Corporation	\$ 5,156.00

<u>ITEM</u>	<u>MANUFACTURER</u>	<u>ACQUISITION COST</u>
Lube Oil Centrifuge Sharples-Stokes		
Specifications: S-18-003	Elliott Company	\$14,805.00
Control Valves: FV-161, LV-511, LV-526 LV-521B, LV-521A, LV-531, PV-687, AV-951		
Specifications: MR 40-111	Masoneilan International, Inc.	\$ 9,429.00
Venturi Flow Tubes: FE-111, Fe-121, FE-122		
Specifications: MR 40-115	Flow Tech Corp.	\$ 4,550.00
Control Valve: PV-601		
Specifications: MR 40-112	Redwood Controls	\$ 2.308.00
Turbine Exhaust Ducting		
Specifications: MR-20-110	Hyspan Precision Products, Inc.	\$24,3330.00
Control Module Instrumentation and Control Panel		
Specifications: MR 40-110	Engineered Control Systems, Inc.	\$80,464.00
Heat Exchanger for Compressor Cooling		
Specifications: MR 12-102	Westland Engineering Co.	\$ 7,000.00

<u>ITEM</u>	<u>MANUFACTURER</u>	<u>ACQUISITION COST</u>
Caustic Tank Mixers		
Specifications: MR 19-101	Milton S. Frank Co., Inc.	\$4,506.00
Turbine Generator Unit		
Specifications: S-18-101, Rev.1	Elliott Company	\$656,699.00
S&C Catalog No. 15731-BIT, 34.5kv, 1200 ampere Circuit Switcher, Mark V, Outdoor 3-pole one-gap Vertical Break Style with Shunt trip device, Bypass Accessory Upright mounted on customer furn- ished steel structure.		
S&C Catalog No 38846R3, 125 Volt DC, Switch Operator Type CS-1A with Shunt trip, Solenoid Switch and Redundant Relay, Position Indicating Lamps and Remote Control Blocking Switch.		
Specifications: MR-17-101B	S&C Electric Co.	\$ 18,893.00
Transformer, 2500/2800/3500kva 34 400-4160Y/2400 volts with ANSI standard no-load tape changing 10% above and 10% below, with reverse power feature, standard impedance and accessories, lightning arresters, and cooling fans	H. K. Porter Co.	\$ 60,425.00

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<u>ITEM</u>	<u>MANUFACTURER</u>	<u>ACQUISITION COST</u>
Switchgear/Motor Control Center Unit with 4KV Switchgear, 480 Volt motor control center, 125V batteries and dc system, and load bank controller in accordance with: Specifications: MR 17-102 Control Unit with electrical control panel in accordance with: Specifications: MR 17-103	Gould-Brown Bovari	\$361,490
W-K-M Pow-R-Seal Gate Valve; 2"-1500 FE RTJ W/G-008 Trim for Geothermal Service W-K-M Pow-R-Seal Gate Valve; 10"-900 FE RTJ W/G-008 Trim for Geothermal Service Adapter Flange; 10"-900x10" -600 Double Studded, RTJ, Studs and Nuts included Flange Cross; 10" -600 RTJ Limitorque Operators for W-K-M Pow-R-Seal Gate Valves 10"-600 Model "D" Adaptor Kits Reducer Spool; 10"-600 x 4" -200; Flanged End 10" High W-K-M Pow-R-Seal Gate Valve; 4"-2000 FE RTJ W/G-008 Trim for Geothermal Service (Description continued next page)		

ITEMMANUFACTURERACQUISITION
COST

(Description continued)

Lubricator Spool; FE RTJ 4"-2000 x 4"-2000,
10ft. long (Sch. 80 Pipe)

4"-600 LB Blind Flange RTJ

7/8" x 6" Studs; Double End,
RC-22 Mac

7/8" Nuts; RC-22 Max

Ring Gasket; R-24 (2"-5000)

Ring Gasket; R-37 (4"-2000)

1-1/4" x 8-3/4" Studs; Double End
RC-22 Max

1-1/4" Nuts; RC-22 Max

Ring Gaskets; R-53 (10"-2000; 10"-3000)

1-3/8" x 9-1/2" Studs; Double End

RC-22 Max

1-3/8" Nuts; RC-22 Max

W-K-M Wellhead Systems

\$ 30,980.70

APPENDIX A

WELL TEST REPORT

HGP-A
WELLHEAD GENERATOR PROJECT

WELL TEST REPORT
JANUARY 3 - 18, 1980

Department of Energy Contract
DE-AC03-78ET28420

HGP-A JANUARY 3-18, 1980 WELL TEST REPORT
Engineering Group
University of Hawaii Hawaii Geothermal Project

I. Introduction

The HGP-A well at Puna, Hawaii underwent a two-week flow test in January, 1980:

- 1) To verify the quantity of steam flow for a 3-MW power plant.
- 2) To verify the quantity of non-condensable gases and percentage of H_2S , which are critical in the design of condensers and H_2S abatement system.
- 3) To prove out the effectivenesses of the caustic/peroxide H_2S abatement system and the noise abatement system of the rock pit.
- 4) To check out the steam collection system which will be used in the final power plant operating system.

The test is judged to be a success because it has accomplished most of our objectives. The following summarizes the Engineering Group's effort of the well test. Separate reports will cover the results of the reservoir fluid chemistry and H_2S abatement experiments.

II. Responsibilities of the Hawaii Geothermal Project

The Hawaii Geothermal Project (HGP) staff was responsible for the operation of the well test under the direction of the well test manager. Figure 1 shows the organization of the well test.

Specifically the Engineering Group of the HGP was responsible for:

- A. Providing a test supervisor and a test data recorder 24 hours per day throughout the test period. The test supervisor had the overall responsibility of maintaining the operation of the well test under the direction of the well test manager.

- B. Maintaining a record of all well flow, pressure and temperature data.
- C. Maintaining a well test log including any complaints from the residents.
- D. Maintaining a chemical injection log including caustic dilution records.
- E. Checking the performance of the separator by steam calorimeter.
- F. Implementing the safety plan.
- G. Conducting downhole temperature and pressure measurements prior to the well test and after the well test.
- H. Monitoring the noise level to measure the effectiveness of the rock pit muffler.

III. Results

A. Well flow vs. wellhead pressure

Due to the incorrect sizing of the steam control valve, it was not possible to control a steady flow much beyond 161 psig at the separator, therefore we were not able to obtain meaningful data beyond that point. Table 1 summarizes the well flow data vs. the separator pressure. Table 2 is an abbreviated version of the well flow data performed in 1977 duplicated here for comparison purposes.

In general, the wellhead pressure is approximately 10 to 15 psi higher than the separator due to line loss and higher separator elevation. Notice that the steam flow rate does not differ much from the previous flow test but water flow rate is much higher. This is due partially to the improper design of the weir measuring methods employed in the previous test measurements.

The final plant design calls for approximately 160 psig at the separator. The metered steam flow will adequately generate 3 MW of electricity.

B. Calorimeter

An Ellison U-Path Steam Calorimeter was used to check the effectiveness of the separator by measuring the steam quality of the separated steam. Due to the placement of the calorimeter, there was a 10 ft. length of inlet pipe between the steam line and the calorimeter. It was very difficult to insure adiabatic condition in the inlet pipe even though the pipe was insulated.

Nevertheless, calorimeter measurements were attempted and no better than 96% quality was consistently obtained. These data do not match up to the results of the chemistry chloride method employed by the HGP Chemistry Group. Their measurements consistently show very little chloride in the steam and showed better than 99.9% steam quality. Thus, we feel that the separator is performing adequately and the performance of 99.9% separation is satisfactory.

C. Chemical Injection Rates

Throughout the test, we were able to maintain very constant peroxide injection rate but were unable to maintain very constant caustic injection rate without constant adjustment. The caustic metering pump and its air actuator must be repaired. A separate report covers the results of the H₂S abatement experiments.

D. Noise

Sound level measurements were taken to test the efficiency of the newly installed rock muffler system. The measurements were taken at various stations around the well site, 1/2 mile up and

down the adjacent Pohoiki Bay Road and 1/2 mile up into the Leilani Estates area. Initial measurements were obtained with the well flashing through the twin stacks only. Later sound level measurements were obtained with the rock muffler in operation.

The muffler system consisted of an earthen pit upon which rocks were placed. Steam from the H₂S treatment system was discharged into the pit. Some of the steam condensed in the earthen pit and emptied into the percolation pond. The uncondensed steam rose up through the rock pile and disbursed into the atmosphere.

The rock muffler proved to be an effective noise abatement system. At many stations over 30% noise level reductions were experienced. Figure 2 is a diagram of the well site and indicates the stations at which noise level readings were taken. Table 3 lists the noise level measurements obtained at each station. As added information, noise level readings of previous flashings are included in Table 3.

E. Temperature and Pressure Profiles

Prior to the start of the two week flow test at HGP-A in January 1980, a temperature-pressure profile was taken where the temperature profile showed high temperatures at 4300 and 6250 feet -- in the order of 320°C. The temperature and pressure plots are shown in Figures 3 and 4. No other downhole tests were conducted during the flow test until after the well was shut-in.

The HGP-A well was reworked in September, 1979 to restore the casing cement competency. The original 9 5/8" casing was set from the surface to ~2200 ft. below casing head flange. Before the repair work the well temperature profile showed high temperatures all the way up to ~1500 ft. During rework several attempts were

made to squeeze off zones around 2200 ft. and 1500 ft. The cement bond logs showed only approximately 80% bond at best. Subsequently, a new string of 7" casing was run from surface to 3000 ft. The temperature peaks at 1500 ft. and 2200 ft. on the temperature profile prior to flashing reflect the zones where the conduction of heat from outside of the casing exists.

Since the well shutdown, five temperature profiles have been conducted. Two profiles taken immediately after shutdown have shown the flashing profile characteristics (semi-vertical straight-line), while five days later, the temperature profile started to show similarities to the preflash profile. The ten and thirty-one day profiles display, in general, cooling in the upper sections and heating in the lower sections. These plots are presented in Figure 3.

F. Water Level Recovery

Water level recovery after the two week flow test followed similar patterns of other recoveries after production flow. This is shown in Figure 5. Approximately twenty-three days after shutdown, the water level was at ground level. This recovery was faster than previous recoveries following production flows of similar time length. It is thought that the lengthening of the casing of HGP-A to 3000 feet, thus closing the suspected cooler water influx, may have increased the recovery rate.

G. Other Results

1. During the two-week test, Hawaii was hit by a severe storm and the well site suffered numerous and long power outages. During these periods, it was not always possible to chemically treat the steam to remove hydrogen sulfide and to operate the equipment

in the normal noise suppression mode. The final power plant must have adequate stand-by power for noise and odor suppression in the event of power outages.

2. During these periods where noise and odor were not suppressed, we received several complaints from the nearby residents. However, after the power was restored and the normal test operation with full odor and noise abatement resumed, no further complaints were received.
3. During the two-week test, several weaknesses in the instrumentation were discovered. These are:
 - a. Defective separator water level indicator and level controller.
 - b. Continuous plugging of the venturi pressure sensing ports.
 - c. Defective badgemeters for mixing caustics.
 - d. Lack of weatherproofing of instruments and gages.
4. The maximum growth of the wellhead during flow is approximately 5 inches.

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Figure 1

FIGURE 2 DIAGRAM SHOWING STATIONS FOR NOISE LEVEL READINGS

33 ○ (Property Line)

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WIND DIRECTION

12/28/79

1/3/80

10:00 - 10:30A

11:00 - 11:30A

2:25 - 2:55P

6:00 - 6:30P

11/3/76

1/26/77

1/7/80

(diagram is not to scale)

Figure 3

Figure 4

Figure 5

Table I
Throttled Flow Data 1/3/80-1/18/80

Separator Pressure (PSIG)	Total Mass Flow Rate (Klb/hr)	Steam Flow Rate (Klb/hr)	Water Flow Rate (Klb/hr)	Steam Quality (%)
56	111.5	70.9	40.6	63.6
110	110.3	64.7	45.6	58.7
132	108.0	61.0	47.0	56.5
161	105.9	56.6	49.3	53.4

Table 2
Throttled Flow Data 1/26/77-2/10/77

Wellhead Pressure (PSIG)	Total Mass Flow Rate (Klb/hr)	Steam Flow Rate (Klb/hr)	Water Flow Rate (Klb/hr)	Steam Quality (%)
54	99	65	34	66
100	93	57	36	64
165	89	54	35	60

TABLE 3
NOISE LEVEL READINGS ON DBA SCALE

STATION	NO ABATEMENT			PARTIAL ABATEMENT		PREVIOUS FLASHING		ABATEMENT
	12/28/79	1/3/80		1/3/80		11/3/76	1/26/77	1/7/80
		10:00-10:30A	11:00-11:30A	2:25-2:55P	6:00-6:30P			
1	93	91	94	75	73	100	96	57
2	99	100	99-100	82	78	104	100	66
3	84	83	82	65	75	98	93	51
4	75	--	84-85	70	70	98	96	64
5	86	--	--	--	--	97	--	--
6	79	--	76	64	63	98	89	50
7	88	--	82	67	64	96	90	52
8	75	83	78	63	80	98	91	46
9	82	--	76-78	67	67	99	93	52
10	81	--	91	71	80	98	94	57
11	86	--	--	--	--	99	96	--
12	88	--	--	--	--	100	90	--
13	100	--	100	84	82	107	100	69
14	101	--	102	85	83	110	103	60
15	98	96	98-99	81	79	107	100	56
16	100	98/99	103	--	--	106	102	--
17	102	100	103	83	82	104	101	71
18	102	--	--	84	80	110	103	68
19	104	--	--	--	--	110	101	--
20	99	--	--	--	--	--	--	--
21	98	94	--	--	--	103	99	--
22	98	--	96	82	80	104	98	67
23	93	--	92	73	71	100	94	63
24	91	94	94	76	75	99	95	69
25	97	--	99	82	80	106	95	74
26	94	--	94	74	73	106	93	58
27	93	--	--	--	--	100	96	--
28	97	--	96	81	--	106	100	68
29	98	97	97	80	--	110	102	70
30	96	92	83	77	--	96	91	72
31	94	--	93-94	75	--	108	101	66
32	79	83	83	60-62	--	87	80	44
33	--	94-95	94	73	--	--	--	56
34	--	41-42	42	41	--	--	--	37
35	--	50	48	40	--	--	--	34
36	--	40-42	38	36	--	--	--	42

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WATER AND GAS CHEMISTRY FROM HGP-A GEOTHERMAL WELL: JANUARY 1980 FLOW TEST

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Hawaii Institute of Geophysics, Honolulu, Hawaii 96822

ABSTRACT

During January 1980, a two-week production test was conducted on the geothermal well HGP-A. Brine chemistry indicates that approximately six percent of the well fluids are presently derived from seawater and that this fraction will probably increase during continued production. Reservoir production is indicated to be from two chemically distinct aquifers: one having relatively high salinity and low production and the other having lower salinity and producing the bulk of the discharge.

INTRODUCTION

During January 1980, a two-week production test was conducted on the geothermal well HGP-A. This well is located on the east rift zone of Kilauea volcano, on the island of Hawaii, and was completed in 1976. This effort was the final flow test of HGP-A preliminary to the installation of a 3.5 MWE well head generator and, as such, was conducted in order to obtain data on steam quality, production rate, non-condensable gas concentration and composition, and brine chemistry. The present report is concerned with the results obtained to date from water and gas chemistry analyses conducted during and immediately following the test. Further chemical and isotopic analyses are currently underway in an effort to confirm some of the preliminary conclusions drawn from the presently available data.

Water Chemistry

Figure 1 presents a plot of chloride concentration in the weirbox water (and well head pressure) versus time through the duration of the well test. The trend of increasing chloride is apparent and shows no significant break point at which the chloride concentrations level off. Previous flow tests of HGP-A have also produced similarly increasing chloride concentrations with time, although the most recent results indicate a somewhat more rapid rise to slightly higher chloride values than were previously observed (Kroopnick et al., 1978). The data presently available strongly suggest that the source of the chloride ion, as well as most of the other major ions, is derived from seawater intrusion into the geothermal reservoir. Although the rate of chloride increase during the test was quite high, tritium

data (see below) on the discharge water suggests that the natural rate of increase under continuous production will be substantially less rapid.

The short term variations observed in the chloride chemistry can be correlated with changes in well head pressure as plotted in Figure 1. Although both the chloride and pressure curves have been considerably smoothed it is apparent that a decrease in flow rate, and consequent increase in well head pressure, results in a decrease in the chloride concentrations observed. All the chloride values plotted are from the weirbox samples, and thus were obtained at the same temperature and pressure. When these chloride data are calculated back to constant temperature and pressure flash in the well head separator the chloride concentrations in the effluent water are somewhat lower at the high discharge pressure than can be accounted for simply by changes in the percentage of flash from a constant chloride reservoir fluid. It is possible that the small differences observed are the result of changing production rates from different aquifers at the higher and lower pressures. However, at present, more precise pressure-temperature and chloride concentration data are necessary before any definite conclusions can be drawn.

The remainder of the brine chemistry is summarized in Table 1 and Figure 2. If one

Table 1. Separator Brine Chemistry (mg/Kg brine)

Date	"Pretreatment"	Press Psig	Cl	Na	K	Ca	Mg	SO ₄	SiO ₂
01/10/80	Untreated	88	2390	1430	200	16.3	<10	50	865
01/11/80	Untreated	154	2450	1463	211	33.2	<10	60	792
01/12/80	Untreated	155	2350	1405	204	25.9	<10	62	
01/14/80	Untreated	156	2450	1440	205	30.5	<10	60	796
01/16/80	Untreated	130	2600	1530	216	33.2	<10	67	832
01/17/80	Untreated	52	2920	1713	247	17.9	<10	59	875
01/18/80	Untreated	55	2930	1700	248	17.9	<10	73.6	873
=====									
Seawater			19,500	9600	398	450	1290	2200	4
15% Seawater			2925	1440	60	68	194	330	0.6

assumes that the chloride ion concentration is representative of the seawater mixing it is apparent that there has been a slight enrichment in the sodium ion concentrations and a much greater enrichment in potassium whereas calcium and sulfate have been heavily depleted and magnesium removed almost completely. These trends are virtually identical to those observed in earlier production tests of HGP-A and present no significant deviations from its earlier behavior.

One question of importance to the future productivity of the well is the mechanism for the depletion of some of the seawater ions. It is generally understood that magnesium is removed through the formation of the hydrothermal alteration mineral chlorite which is abundant in cores from the deeper parts of HGP-A (Stone, 1977). The removal of calcium ion can be effected in two ways: by the formation of calcite and by precipitation of anhydrite. Both of these minerals have been identified in small amounts in cores and cuttings from near the bottom of HGP-A and in grab samples of material scraped from the inside of the well bore. Anhydrite has a retrograde solubility product and it is not known at present whether the increased concentrations of calcium and sulfate brought about by flashing of the reservoir fluid exceeds the higher solubility product of anhydrite in the adiabatically cooled brine. We are presently attempting to acquire the data necessary for the solubility calculations in the original reservoir fluids and in the flashed brine.

Figure 2 presents plots of the chloride, sodium, calcium, and potassium concentrations in the separator brine as well as the separator pressure at the time of collection. It is apparent that all the ions plotted respond to changes in separator pressure as would be expected for different flashing fractions of the well fluid, however, the calcium ion concentration responds in the opposite manner to the other ions plotted. This behavior suggests that the calcium carbonate-dissolved CO₂ equilibrium is controlling the calcium concentration in the liquid phase. At higher separator pressures the dissolved CO₂ concentration in the brine can maintain a CaCO₃

concentration of approximately 0.85 millimolar at approximately 0.45 millimolar. We are presently in the process of acquiring additional data in an effort to determine whether calcite solubility is controlling the dissolved calcium concentrations at the higher separator pressures. If the calcium concentrations in the brine are at the calcite: carbon dioxide equilibrium concentrations then it must be assumed that calcite is being deposited either in the aquifer or in the well bore.

Figure 2
Major Ion Concentrations
Normalized to Percent Seawater

Calculation of the reservoir temperature through application of the silica and sodium-potassium-calcium geothermometer was attempted. In every case the calculated temperature was at least 50°C below the observed reservoir temperature confirming the inapplicability of these geothermometers in the Hawaiian environment.

Non-Condensable Gas Composition

Table 2 presents a selected set of the most reliable analytical results obtained for the non-condensable gas compositions during the January test. Comparisons between earlier data on HGP-A

non-condensable gases (Kroopnick et al., 1978) and those obtained during the January test strongly suggest that the total non-condensable gas content may have decreased substantially. It should be noted, however, that the earlier samples were taken using considerably less elaborate equipment and the analytical techniques used on those samples were not as accurate as those applied in the recent test.

Table 2. Non-condensable Gas Analyses
(expressed in mg/Kg of steam)

Date Sampled	H ₂ S	CO ₂	N ₂	H ₂	Separator Pressure
01/10/80†	704	825			88
01/11/80†	782	864			154
01/13/80†	766				156
01/14/80†	837	930			156
01/15/80*	825	900	195	10.9	155
01/16/80†	760	1010	169	11.0	155
01/17/80*	750	1000	168	11.0	96
01/18/80*	690	783	117	8.9	56
01/18/80*	900	760	108	6.4	56

† field analysis

* laboratory analysis

Although there are several potential explanations for the apparent decrease in non-condensable gas content, the one which is most consistent with the data is that gases are being preferentially mined from the reservoir during production. Whether the source of the non-condensable gases being withdrawn are in the form of dissolved carbonate and sulfide or whether they are from the remobilization of carbonate and sulfide minerals cannot be determined at present. Although New Zealand geothermal reservoirs have shown a similar trend of decreasing non-condensable gas concentrations (Ellis, 1962; Mahon, 1962), the proposed mechanism does not appear to be applicable in the Hawaiian geologic environment. Whether the trend of decreasing non-condensable gas content will continue in the future cannot be determined with the presently available data. Although there are also apparent changes in the relative ratios of the non-condensable gases, we have found that the differences observed are artifacts of the earlier analytical techniques and that the more recent analyses are more representative of the non-condensable gas compositions present.

It is apparent from the data presented in Table 3 that there is a substantial variation in the gas compositions and concentrations through the duration of the test. This can, in large part, be attributed to changes in steam quality at the different separator pressures; as the separator pressure is increased the steam fraction is decreased substantially whereas there is relatively little change in the total amount of gas discharged. The net result is that at higher separator pressures (and lower steam fractions) the relative amount of non-condensable gas in the steam phase increases. Although it is theoretically possible to use the gas compositions at different separator pressures to determine the fluid enthalpy as well as several other down-hole geochemical and production parameters, we will not be able to perform this type of

analysis until further analytical data have been obtained.

In addition to the major components of the non-condensable gas fraction, minor amounts of several other gases were also found to be present. The trace gases detected in the steam discharge included helium, argon, carbon monoxide, and possibly methane. None were present in concentrations greater than 2-3 ppm of the steam phase. Although ammonia and mercury were analyzed for, neither were present at the detection limits for the technique applied. Further analyses are being pursued for these species.

Isotope Chemistry

Table 2 presents tritium analyses performed on selected samples of the well discharge water through the duration of the test as well as a few samples taken prior to the extended well discharge.

Tritium analyses done on discharge water from earlier production tests of HGP-A have yielded values of approximately 0.2 TU or less thus indicating that the reservoir water for HGP-A is older than approximately thirty years (pre-bomb). It can be concluded then that the tritium present in the recent discharge water is derived entirely from water pumped into HGP-A prior to the well test; the activity of the quench water was approximately 7.93 TU (Fire Hydrant Sample). Several hypotheses are suggested by the tritium data:

1. Discharge samples collected from the silencer overflow immediately after the well rework had an activity of 4.0 TU, however, samples collected after a long period of shut-in had a substantially higher activity. This suggests that two aquifers were being produced during the 10/17 discharge: a "high tritium" aquifer which received the bulk of the quench water and a "low tritium" aquifer. The increase in tritium following the three-week shut-in can probably be attributed to circulation within the well bore between the two aquifers. Downhole water chemistry samples taken subsequent to the January 18 shut-in also suggest that this type of circulation pattern is continuing and that the "high tritium" reservoir

Table 3. Isotope Analyses of HGP-Discharge

Sample Source	Date Collected	Tritium Act. (T.U.)
Well head	11/09/79	6.48 ± 0.91
Fire Hydrant	11/09/79	7.93 ± 0.97
Weirbox	10/17/79	4.00 ± 0.56
Weirbox	12/28/79	2.31 ± 0.40
Weirbox	01/03/80	2.08 ± 0.37
ANX-2	01/12/80	1.32 ± 0.42
ANX-2	01/18/80	0.50 ± 0.38
Sample Source	Date Collected	¹⁴ C Age
Well head	05/08/77	12,800 ± 200 years
Well head	05/08/77	13,600 ± 200 years
ANX-1	01/18/77	12,203 ± 142 years

is of a lower salinity than the "low tritium" reservoir. If this is the case, it can be concluded that the majority of the HGP-A production is from a low salinity aquifer and that a somewhat lower pressure/less permeable saline aquifer is producing at a shallower level.

2. Samples taken during the January discharge have a substantial amount of tritium still present. This would suggest that circulation within the reservoir is relatively slow relative to the fluid withdrawal rate during production from the HGP-A reservoir.

3. The correlation between decreasing concentrations of high tritium-low salinity quench water and the increasing chloride concentration in the discharge fluids strongly suggests that the rate at which the chloride ion was increasing during the initial part of the production test was somewhat higher than its natural rate would have been had there been no quench water present. It is highly probable that the rate at which the chloride ion concentration was increasing would have abated had the test been continued.

Carbon dioxide samples were also obtained for ^{14}C analysis of the gases being discharged from HGP-A. The results of these analyses are puzzling at best. Carbon-14 is present at a level equivalent to 20% of modern activity which corresponds to a maximum average carbon age of approximately 12,000 years. This age assumes no contribution from magmatic carbon dioxide; if one assumes magmatic carbon is present then the actual age of the non-magmatic component would be younger by the assumed proportion of magmatic carbon. The apparent ages of the carbon dioxide samples taken during the January 1980 test are virtually identical to an earlier ^{14}C analysis of HGP-A gases done in June of 1977. Although there are several possible sources of carbon in the well, there are only two which could reasonably supply the biogenic carbon in the well: organic material pumped into the well during drilling operations or calcite which has been deposited from groundwater circulated through the rift zone. Whether either of these sources could provide the seemingly constant proportion of ^{14}C to the well fluids is questionable. Continued monitoring of the ^{14}C in the fluids during production will be required before a more definite source for the carbon in the well discharge can be identified.

CONCLUSIONS

The conclusions which can be drawn from the presently available results of this production test of HGP-A are as follows: 1) The chloride and total dissolved solids concentration in the HGP-A fluids will continue to increase during production from the HGP-A reservoir although it is highly probable that a plateau will be reached as production stabilizes. 2) The non-condensable gas fraction in the HGP-A discharge has decreased substantially from earlier production concentrations. 3) Carbonate scaling within the piping network during production is unlikely to occur if the well production pressure is maintained above 150 psi. 4) the rate of circulation through the

reservoir is on the order of at least years but is probably no more than a few thousand years. 5) Production from the HGP-A reservoir is withdrawn from at least two reservoirs; one is more saline than the other and, under shut in conditions, the less saline aquifer circulates water into the well bore and thus must be at a higher pressure.

ACKNOWLEDGMENTS

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APPENDIX B

WELL REWORK

HGP-A WELLHEAD GENERATOR FEASIBILITY PROJECT
WELL WORKOVER COMPLETION REPORT

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INTRODUCTION

The HGP-A Well on the Big Island of Hawaii was drilled by the University of Hawaii's Hawaii Geothermal Project in 1976 (Ref. 1). After setting the 20" surface casing and the 13-3/8" anchor casing, the 9-5/8" production casing was set from the surface to about 2200 ft. below surface, and a 7" slotted liner was set off bottom from a total depth of about 6400 ft to 2100 ft. below surface. Prior to the well workover, the wellhead pressure during shut-in periods was approximately 140 psig and the temperature profile inside the casing (See Fig. 1) was low until it reached the 9-5/8" casing shoe at about 2200 ft. below surface.

However, after the well flow test in November, 1978, the static wellhead pressure began to increase gradually to over 500 psig by January 1979, and the temperature profile in the casing showed a dramatic rise, especially in the section from to the bottom of the 9-5/8" casing shoe. Furthermore, a gas cap formed in the wellbore during static condition, which was not observed prior to November 1978. These phenomena led to the speculation that there was either a break in the casing which permitted hot fluids to circulate inside of the wellbore, or that the cement anchoring of the casing to the formation had deteriorated, allowing well fluids to migrate upward on the outside of the casing.

After consultation with Mr. Anthony Adduci, Mr. Martin Scheve and Mr. Bennie DiBonna of the Department of Energy (DOE), a casing caliper log and a cement bond log were run in May, 1979 to determine whether there was a break in the casing and/or that the cement bond had deteriorated. No apparent break in the casing was detected, however, substantial deterioration of the cement bond was confirmed, and the fact that high temperature cement had not been used in the original cementing program prompted the project to propose to U.S. DOE that a casing perforation and cement squeeze job be performed to insure the integrity of the HGP-A Well. Subsequently, DOE approved the proposal in June, 1979, and a geothermal well modification permit was issued by the State Department of Land and Natural Resources in September, 1979.

Rogers Engineering Inc., of San Francisco was retained as the drilling consultant to the project and Mr. James Kuwada of Rogers was designated as the technical consultant. Specifications for the workover were prepared by Rogers and invitations to bid were sent to potential drilling companies, in addition to general advertising in June. Two bids were received in July and after evaluation of the bids, Water Resources International, Inc. was declared as the low bidder. To further assist the project, Mr. Sheldon Hopkins of Global Geothermal was hired to serve as the drilling manager to supervise the daily workover operations. Mr. Anthony Adduci of DOE/SAN will be the technical director for all technical decisions.

Several meetings were held among the drilling manager, the drilling supervisor and the drilling contractor regarding tools, services and workover program in August. The rig was moved to the site in early September and the workover program commenced on September 15, 1979. This report describes the procedures followed and equipment used in the completion of the workover.

In the contract with DOE, the project was directed to perform the following tasks:

1. Acquire a workover rig to be placed at HGP-A with necessary blow-out preventing devices.
2. Pressure test the casing for leakage.
3. Perforate, cement and restore cement bond.
4. Set 7" casing down to 3000 feet if deems necessary and/or economical.
5. Run cement bond logs to insure competency.
6. Cement the upper portion of the 7" slotted liner to tie down the liner and to block off the cold water zone.
7. Perform mechanical caliper run inside the 7" slotted liner.
8. Ream out the inside of the slotted liner and obtain samples for analysis.
9. Remove junk at the bottom hole and restore the hole to 6455 feet.
10. Obtain all permits, waivers, and inspections required by governmental agencies having jurisdiction.
11. Report all efforts as part of the reporting requirements presently provided on the original contract and the revisions thereto.

After several meetings among the project staff, the drilling manager and the technical consultant, the following program was tentatively agreed upon subject to change as the workover progressed.

1. Keeping well dead, rotate master valve to desired position to accommodate set up of drilling rig, blow-out-preventer stack-mastergate, cross over spool, double gate, Hydrill and rotating head.
2. Keeping well dead run temperature survey & caliper log (Otis).
3. Run in hole with 7" casing scraper & jars to 3200 ft.
4. Run and set HOWCO 7" 23# EZSV #1 @ $\pm$ 3150 ft.
5. Unsting from EZSV and spot spearhead of flow check pill @ bottom of slotted section.

6. Pullout of hole and pick up EZSV #2.
7. Run in hole and set @ $\pm$ 2950 ft.
8. Pump spear head of flow check and cement as follows; Mix 20 ft³ 1-1-1 "G" cement + 1 ft³ perlite + 1 ft³ sand + 0.5% CFR-2 + retarders as needed.
9. Pull out of hole with stinger and wait on cement.
10. Run in hole with stinger and stab into EZSV #2.
11. Pressure test with 1000 psig.
12. Resqueeze if necessary as many times as necessary.
13. After bridge is established, run in hole with 9-5/8" scraper. Then 9-5/8" RTTS and retrieve bridge plug combined or separately if necessary.
14. Set bridge plug @ $\pm$ 2,100 ft.
15. Set RTTS @ $\pm$ 1000 ft. and test both sides. Isolate any leaks.
16. If no leaks are found run cement bond log on top 400 ft. of hole, perforate and squeeze to surface if possible.
17. Clean out, cement, recover retrievable Bridge plug in top part of hole.
18. Decision may be made to cut 7" slotted liner and recover same, as follows:
19. Run in hole OE and change over to mud and loss circulation material.
20. Run in hole with casing cutter and cut casing below collar @ $\pm$ 2925 ft.
21. Run in hole with casing spear and jars and recover casing.
22. Underream 8-1/2" hole to 10".
23. Run in hole with 7" casing and casing bowl.
24. Cement to surface.
25. Install 10"x7" casing head and new master gate.
26. Run casing bond log.
27. If decision is made to cement existing slotted 7" liner proceed as follows:
28. Set RTTS Packer (with 2 joints tailpipe) above each section of slotted liner and cement. Wait on cement between jobs as needed.

29.

30. If OK drill out EZSV Bridge Plugs and continue to top of junk and push to bottom.

31. Flow well (supervised by University staff).

32. Rig down.

It is further agreed upon between the project and DOE that Mr. Anthony Adducci shall be the technical director in DOE for all technical decisions.

Approximately three weeks prior to the commencement of the workover, large amounts of cold water at approximately 150 gpm were pumped into the HGP-A well to kill the well pressure. Subsequently, about 80 gpm of cold water is pumped into the well constantly to maintain the water level in the wellbore at approximately 400 ft. below ground level. The drilling rig and its supporting equipment were mobilized and ready to go by September 15, 1979 with all necessary blowout preventing equipment installed.

Repeated pressure testing of the 9-5/8" casing with retrievable plug at approximately 2000 ft. below rotary table (BRT) and RTTS tool at different depths above the plug failed to reveal any significant leaks in the casing. A decision was made then to set a cement plug at approximately 3000 ft. BRT to prevent well fluids from producing into the wellbore so that the casing perforation and cement squeeze job can be performed. The top section of the original 7" liner was also removed from 2161 to 2921 ft. BRT.

A HOWCO retrievable bridge plug was set at about 2000 ft BRT and a series of perforation and cement squeeze job were performed at intervals 2150 to 2152, 2110 to 2112, 1650 to 1652, 1250 to 1252 and 970 to 972 ft. BRT. (See Appendix D). It is evident from the formation breakdown pressure that the cement outside of the casing has deteriorated so that well fluids have migrated upward on the outside of the casing. After the hole was cleaned to the HOWCO plug, the casing was pressure tested for apparent leaks and no leaks were found.

Difficulty was experienced in retrieving the HOWCO plug at about 2200 ft. It appeared that the 9-5/8" casing has come apart and gone out of alignment at about 2147 ft. BRT. After considerable amount of drilling, milling and rolling efforts, the plug was retrieved.

A cement bond log was run to check on the effectiveness of the squeeze job. It was discovered that all of the squeeze operations have improved the bonding substantially except at about 1650 ft. A decision was made to perforate and squeeze again at

1420 to 1422 ft. which was approximately half way between the two previous squeeze operations at 1250 and 1650 ft. BRT. This squeeze operation has improved the bonding substantially between 1200 and 1500 ft. as evidenced from later cement bond log.

A decision was made to run the 7" casing all the way from surface to the 7" liner stub at 2921 ft. BRT. 70 joints of 26-16 K55 buttress casing with stage-cementing tools was run in and was stage-cemented to the surface and the rig was shut down for the Discover's Day weekend to wait on cement.

After the break, cement bond logs were run to check the cementing job. It was discovered that from 2500 to 2900 ft. the cement bond was not competent. Squeeze jobs were then performed at 2963 to 2975 ft. and at 2530 to 2533 ft. A final cement bond log was run from surface to 2990 ft. and over 80% bonding was shown on almost the entire string.

A new wellhead was completed on the 7" casing and cement plug was drilled out, cleaned out hole to 6430 ft. and drove junk to 6343 ft. BRT. A banjo box was installed and flow test equipment was attached to prepare for a brief flow test. The well was flowed for 4-1/2 hours on October 17th and the production was approximately the same as before the workover. The rig was subsequently released on October 18, 1979.

DAILY DRILLING REPORTS

Sept. 15, 1979 Start rig time at 12:00 noon. Install blowout preventing equipment (BOE) and Grant rotating head. Pressure test BOE to 1000 psi.

Sept. 16, 1979 Scrape 7" liner to 3225 ft. below rotary table (BRT). Scrape 9-5/8" casing to top of liner at 2161 ft BRT. Tight spots at 1996 - 2034 ft. and 2150 ft. BRT. Set 9-5/8" RTTS at 360 ft. BRT, pressurize between 360 ft. and surface to 1000 psi. Pressure declined 500 psi in 2 minutes. Pull RTTS out of hole.

Sept. 17, 1979 Set HOWCO retrievable bridge plug at 1958 ft BRT. Set RTTS at 175 ft. BRT. Pressurize between RTTS and plug. Pressure declined 500 psi in 3 minutes. Reset RTTS at 865 ft BRT. Pressurize between RTTS and plug again to 1000 psi. Pressure declined 350 psi in 15 minutes. Retrieve RTTS and run cement bond log from 500 ft to 20 ft BRT. Retrieve HOWCO bridge plug. Set 7" EZSV at 3140 ft BRT. Prepare for cementing.

Sept. 18, 1979 With drill pipe at 3136 ft BRT. Inject 10 bbls of 10% calcium chloride brine, 2 bbls water, 5 bbls Flochek and 2 bbls water. Follow immediately with 32 cu. ft. of API Class G cement with 40% silica flour and 0.5% CFR-2. Displace cement with 24 bbls of water. Wait on cement (WOC) 13 hours. Run in hole to tag cement. No cement. With drill pipe at 3136 ft BRT, re-inject 10 bbls of calcium chloride brine, 1 bbl water, 5 bbls of Flochek and 1 bbl water. Follow immediately with 24 cu ft API class G cement with 40% silica flour and 0.5 % CFR-2. Displace cement with 19 bbls of water. WOC 6-1/2 hrs. Run in hole and tag top of cement at 3088 ft BRT at midnight.

Sept. 19, 1979

With drill pipe above the top of cement plug, inject 10 bbls water, follow by 32 cu ft of API class G cement with 40% silica flour and 0.5% CFR-2 and displace with 17 bbls of water. WOC 2 hrs. Cut 7" slotted liner at 2921 ft. BRT. Spear liner at 2161 ft. BRT and recover and lay down 7" casing.

Sept. 20, 1979

Scrape casing to 2190 BRT. Pick up 8-1/2 " bit to clean out fill with mud to 2898 ft BRT. Circulate to clean out fill.

Sept. 21, 1979

Set HOWCO retrievable bridge plug at 2196 ft BRT. Dump 10 sacks of sand on plug with drill pipe. Wait on sand 2-1/2 hrs. Tag sand at 2179 ft BRT. Perforate casing from 2150 to 2152 ft BRT with 8 1/2"-holes. Set RTTS at 2165 ft BRT. Pressurize to 1000 psi. No leaks. Set RTTS at 2075 ft BRT. Pump 20 cu ft per minute water at 200 psi. Squeeze with 52 cu ft of API class G cement with 40% silica flour and 0.5% CFR-2. Displace cement with 117 cu ft of water. W.O.C.

Sept. 22, 1979

W.O.C. till 10:00 am. Perforate casing at 2110 to 2112 ft BRT with 8 1/2"-holes. Set RTTS at 2015 ft BRT. Pressurize to 1500 psi and obtain breakdown with 20 cu ft/min water rate. Squeeze with 178 cu ft of API class G cement with 40% silica flour and 0.5% CFR-2. Displace with 21 bbls of water. W.O.C. 6 hrs. Perforate casing from 1650 to 1652 ft BRT with 8 1/2" holes. Set RTTS at 1545 ft BRT. Obtain breakdown pressure at 200 psi with 20 ft³/min water rate. Squeeze with 162 cu ft of API class G cement with 40% silica flour and 0.5% CFR-2. Displace with 22 cu ft water. W.O.C.

Sept. 23, 1979

W.O.C. till 6:00 am. Perforate casing from 1250 to 1252 ft BRT with 8 1/2-inch holes. Set RTTS at 1167 ft BRT. Breakdown at 200 psi with 20 cu ft/min water rate. Squeeze with 87 cu ft

of API class G cement with 40% silica flour and 0.5% CFR-2.

Displace with 15 bbls of water. W.O.C. 6 hrs. Perforate casing from 970 to 972 ft. BRT with 8 1/2"-holes. Set RTTS at 880 ft.

BRT. Breakdown at 2500 psi with 20 cu. ft./min. water rate. Squeeze with 87 cu. ft. of API Class G cement with 40% silica flour and 0.5% CFR-2 displaced with 11 bbls of water. W.O.C. till midnight.

Sept. 24, 1979

W.O.C. till 5:00 am. With 8-1/2" bit drill out cement and clean hole to 2147 ft. BRT. Bad spot in casing at 2147 ft. Trip out of hole and change bit.

Sept. 25, 1979

Drill on bad spot in casing at 2147 ft. BRT. Continue to drill out cement and sand to 2186 ft. BRT. Pressure test 9-5/8" casing. Pressure declined 600 lb in 3 minutes. Trip out and return in hole with retriever tool to retrieve HOWCO bridge plug. Succeed in latching on the plug after three tries. Unsuccessful in pulling through the casing bad spot at 2147 ft. BRT. Reset bridge plug at 2172 ft. BRT. Return with 8-1/2" in casing roller to work on the bad spot. Unable to pull out of hole.

Sept. 26, 1979

Try to pull casing roller out. Stuck at 1794 ft. BRT. Run two back-off shots at 1793 ft. BRT and backed off at 1793 ft. BRT. Return in hole with drill collar, bumper sub and jars. Screw into fish and retrieved the casing roller. Return in hole with 8-1/2" casing swedge to drive through bad spot to 2151 ft. BRT. Pull out of hole and build tungston carbide face on bottom of swedge.

Sept. 27, 1979

With the rebuilt swedge, mill through bad spot in 9-5/8" casing at 2147 ft. BRT. Retrieve the HOWCO bridge plug after two tries. With 8-1/2" casing scraper, scrape to 2205 ft. BRT. Run cement bond log.

Sept. 28, 1979

Continue with cement bond log. Drill out cement and dill, condition hole and clean out to 3000 ft. BRT.

Sept. 29, 1979 Attempt to run inside 7" slotted liner stub at 2920 ft. BRT was unsuccessful. Run in with 6" tapered will and will out top of 7" to 2931 ft. BRT. Attempt to run inside 7" slotted liner stub at 2920 ft. BRT was again unsuccessful. Run in with 6" tapered will and tagged fill at 2987 BRT.

Sept. 30, 1979 Attempt to run inside 7" slotted liner with perforation gun failed. Pick up 7" sizing tool and bumper sub to dress up 7" liner. Tools can not pass 2147 ft. BRT.

Oct. 1, 1979 With hard facing 8-5/8" swedge and two 8-1/4" stubs, mill out bad spots from 2145 to 2155 ft. BRT. Attempt to dress up 7" slotted liner with 7" dressing tool failed again. Set 9-5/8" retrievable bridge plug at 1563 ft. BRT.

Oct. 2, 1979 Place 10 cu ft of sand on plug. Perforate casing from 1420 to 1422 ft. BRT with 8 1/2-inch holes. Set RTTS at 1458 ft. BRT and pressure test to 1000 psi. Pull up and reset RTTS at 1260 ft. BRT and pumped 20 cu ft of water per min. at 200 psi. Cemented with 162 cu ft of API class G cement with 40% silica flour, 0.5% CFR-2. Displaced with 76 cu ft of water. W.O.C. 10 hours. Drill out cement and retrieve bridge plug.

Oct. 3, 1979 Mill on 7" slotted liner stub with 8-1/2" pilot mill to 2921 ft. BRT. Clean out fill from 2990 to 3000 ft. BRT with 6" tapered mill. With perforating gun and sinker bar shot 10 1/2-inch holes from 2963 to 2975 ft. BRT. Set 7" RTTS at 2930 ft. BRT and break down formation at 2000 psi.

Oct. 4, 1979 Dress up 7" stub with dressing tool at 2921 ft. BRT. Change BOP blind ram to 7". Run cement bond log inside 9-5/8" casing. Run in 70 joints 26 1/2 K55 buttress casing with stage-cementing tools (See Appendix C).

Oct. 5, 1979 Attempt to circulate at 7" stub failed. Dropped D.V. opening plug and circulate at 2492 ft. BRT with 200 psi. Pumped 50 cu ft

mud flush, 25 cu ft water, 147 cu ft flochek and 25 cu ft water. Cemented with 162 cu ft of API class G cement with 40% silica flour, 0.5% CFR-Z and 0.3% HR7. Displaced with 536 cu ft of water. Dropped DV opening plug and circulated DV collar at 2163 ft and got good cement. WOC till midnight.

Oct. 6, 1979 Circulate through top DV collar at 2163 ft BRT. Pumped 50 cu ft mud flush and 25 cu ft water. Cemented with 446 cu ft of API Class G cement with 40% silica flour, 0.5% CFR-2 and 0.3% HR7. Displaced with 476 cu ft water. W.O.C. and shut rig down at 4:00 pm.

Oct. 7 & 8 Rig shut down

Oct. 9, 1979 Start up rig. Run bond log to find top of cement at 19 ft below surface. Flush and fill cement with 1" pipe until good return to surface. Cut off 7" casing and weld on 7" casing head.

Oct. 10, 1979 Dug out cement inside 30" conductor, cut off 20" pipe 14" below cellar floor, 13-3/8" pipe 10" below cellar floor and 9-5/8" pipe 4" below cellar floor. Bottom of 7" well head is flush with cellar floor.

Oct. 11, 1979 Drill out cement and DV collars to 2877 ft BRT. Pressure up on 7" weld. small leak on upper weld.

Oct. 12, 1979 Continue to drill out float collar and clean out to 3000 ft BRT. Run cement bond log from 2968 ft to 2000 ft BRT. Perforate 6 1/2-inch holes from 2530 to 2533 ft BRT. Set 6" RTTS at 2576 ft BRT. Pumped 20 cu ft/min at 1200 psi into perforations at 2963 to 2975 ft. Opened circulation collar and pumped 20 cu ft/min into 2530 to 2533 ft. No communications established. Reset RTTS at 2510 ft BRT and tested casing to 500 psi with no leakage.

Oct. 13, 1979

Set 6" EZSV at 2573 ft. Pumped 20 cu ft/min water into perforations at 2963 to 2975 ft at 1200 psi. Cemented with 162 cu ft of API class G cement with 40% silica flour, 0.5% CFR-2 and 0.3% HR7. Displaced with 185 cu ft of water. Set RTTS at 2385 ft and pumped 20 cu ft/min of water at 1500 psi in perforations at 2530 to 2533 ft BRT. Cemented with 81 cu ft of API Class G cement with 40% silica flour, 0.5% CFR-2 and 0.3% HR7. Displaced with 125 cu ft of water. W.O.C. Reweld 7" casing head and X-rayed.

Oct. 14, 1979

Drill out cement from 2348 ft to 2552 ft BRT. Test casing to 500 psi with no leakage. Drill out EZSV and cement from 2765 to 2993 ft BRT. Test casing to 500 psi with no leakage. Run cement bond log on entire 7" casing.

Oct. 15, 1979

Drill out cement and EZSV and clean out hole to 6340 ft BRT.

Oct. 16, 1979

With 6" flat bottom mill, mill and drive junk to 6343 ft BRT. Install banjo box and build flow test line to muffler. Run Kuster temperature survey.

Oct. 17, 1979

Bail out water till well flashed and flowed well for 4-1/2 hours. Shut in and run Kuster temperature survey.

Oct. 18, 1979

Lay down drill collars and drill pipes. Release rig at midnight.

V. Conclusion

The HGP-A workover effort accomplished all of the objectives as planned. It secured the cement bonding of the casing and prevented the geothermal fluids from migrating up the annulus of the 9-5/8" casing.

Currently, after almost a year after the workover, the wellhead pressure has stabilized to approximately 140 psig which was the same as the shut-in pressure prior to November 1978. This further demonstrated that the workover effort was successful

HGP-A Casing Record
Hole Size 8-1/2 inch
Casing Size 7 inch OD 26 lbs/ft
Grade K55 Buttress Thread

Appendix A

<u>Joint No.</u>	<u>Measured Length (ft)</u>	<u>Cumulative Length (ft)</u>
1	41.06	41.06
2	43.44	84.50
3	43.51	128.01
4	42.24	170.25
5	43.81	214.06
6	43.01	257.07
7	40.61	297.68
8	43.35	341.03
9	40.06	381.09
10	42.00	423.09
11	42.43	465.52
12	36.84	502.36
13	39.25	541.61
14	42.62	584.23
15	42.75	626.98
16	42.36	669.34
17	38.12	707.46
18	40.96	748.42
19	40.01	788.43
20	41.36	829.79
21	42.94	872.73
22	41.48	914.21
23	43.01	957.22
24	42.48	999.70
25	36.84	1036.54
26	43.72	1080.26
27	43.62	1123.88
28	42.96	1166.84
29	43.38	1210.22
30	41.12	1251.34
31	40.04	1291.38
32	42.94	1334.32
33	43.29	1377.61
34	43.38	1420.99
35	43.04	1464.03
36	43.18	1507.21
37	42.81	1550.02
38	41.02	1591.04
39	43.05	1634.09
40	42.07	1676.16
41	42.60	1718.76
42	40.28	1759.04
43	42.70	1801.74
44	40.20	1841.94
45	29.04	1870.98
46	43.35	1914.33
47	41.38	1955.71
48	43.31	1999.02
49	43.32	2042.34
50	43.23	2085.57

Joint No.Measured Length (ft)Cumulative Length (ft)

51	42.86	2128.43
52	43.68	2172.17
53	43.26	2215.37
54	40.98	2256.35
55	41.98	2298.33
56	40.57	2338.90
57	40.91	2379.81
58	43.52	2423.33
59	41.15	2464.48
60	38.72	2503.20
61	42.42	2545.62
62	41.66	2587.28
63	43.18	2630.46
64	35.98	2666.44
65	42.15	2708.59
66	39.16	2747.75
67	41.16	2788.91
68	44.02	2832.93
69	42.31	2875.24
70	43.60	2918.84

BIT RECORD

<u>Bit No.</u>	<u>Size</u>	<u>Type</u>	<u>Serial</u>	<u>Purpose</u>
1	8 1/2"	S4TJ	555280	Clean out fill
2	8 1/2"	S4TJ	881474	" " cement
3	6"	SEC	596581	" " cement
4	6"	S4J	828136	Drill out EZSV & cement
5	6"	S4J	827063	" " " " "
6	6"	S4J		" " " " "

RECORD OF
HPG-A CASING CEMENTING EQUIPMENT

Casing Bowl = 1.20	Top @ 2919.80
Float Collar = 1.73	Top @ 2877.01
Bottom DV Collar = 3.21	Top @ 2491.77
Top DV Collar = 3.10	Top @ 2163.34

Cement Baskett # 1 2537

Cement Baskett # 2 2453

Cement Baskett # 3 2207

Cement Baskett # 4 2086

Record of Perforation and Testing

Date	Perforated at (ft BRT)	RTTS at (ft. BRT)	Formation Breakdown Pressure (psig.)
9/21/79	2150 to 2152	2165	1000/no leaks
		2075	200
9/22/79	2110 to 2112	2015	1500
	1650 to 1652	1545	200
9/23/79	1250 to 1252	1167	200
	970 to 972	880	2500
10/ 2/79	1420 to 1422	1260	200
10/ 3/79	2963 to 2975	2930	2000
10/12/79	2530 to 2533	2576	1200

Record of Logging Operations

Date	Type of Log	Interval	Comments
4/25/76	Cement Bond	0 - 2200 ft.	Original bond record
5/20/79	Temperature	100 - 2400 ft.	
5/20/79	Casing Caliper	0 - 2100 ft.	No apparent breaks
5/20/79	Cement Bond	350 - 2106 ft.	Substantial deterioration
9/17/79	Cement Bond	20 - 500 ft.	
9/28/79	Cement Bond	100 - 2200 ft.	
9/29/79	3-arm Caliper	2100 - 2914 ft.	
10/ 3/79	Temperature	200 - 2906 ft.	
10/ 4/79	Cement Bond	100 - 2200 ft.	
10/12/79	Cement Bond	2000 - 2968 ft.	
10/14/79	Cement Bond	20 - 2990 ft.

HGP-A Wellhead Valve Arrangement B-23

APPENDIX C

ENVIRONMENTAL MONITORING PROGRAM

A comprehensive environment monitoring program was included in the HGP-A Project to measure the impact on the environment surrounding the HGP-A power plant. The monitoring program focused on the effects of untreated hydrogen sulfide emission from the plant on the ambient air. Other hazards such as mercury and arsenic were also monitored. The monitoring program demonstrated that no significant hazards to the environment resulted from operation of the HGP-A plant.

Figure 1 shows the location of the four H₂S monitoring stations in the vicinity of the HGP-A plant. The Gilman, Hess and Schroeder stations are located downwind of the plant and the Woods station is upwind. The closest station, Gilman, is about 0.7 miles from the plant and Wood is 1.6 miles away. Table 1 provides a summary of H₂S data at each of the stations during 1983. These data show there were no concentrations greater than the 30ppb California 1-hour standard. (The State of Hawaii did not have a standard).

Table 2 provides data which is typical of the data subsequently obtained. The values for both Hg and As are generally the same as background levels measured in the Puna area leading to the conclusion that the HGP-A is not affecting the air quality of the region.

The reader is referred to EAL Technical Progress Reports for more extensive and detailed data obtained both prior to and during HGP-A operation.

TABLE 1*

Summary of the Statistical Computer Results for Monitoring Sites
at Schroeder, Gilman, Hess and Wood Residences for the Period
Extending from January 1 to December 31, 1983.

<u>Station</u>	<u>Highest Value ppb</u>	<u>Lowest Value ppb</u>	<u>Mean Value ppb</u>	<u>No. of Values Greater Than 10 ppb</u>	<u>% Data Recovery</u>
Schroeder	8	0	1.43	0	89.46%
Gilman	11	0	1.32	1	93.73%
Hess	8	0	1.18	0	94.11%
Wood	<u>13</u>	<u>0</u>	<u>1.17</u>	<u>5</u>	<u>91.89%</u>
Total/Average	10	0	1.27	6	92.30%

*For "An Analysis of Atmospheric Hydrogen Sulfide Concentration
to Determine the Effects of the HGP-A Geothermal Plant on Air Quality
In the Puna District" by Linnie Sue Cartor, April 12, 1984 for
Hawaii Lung Association.

TABLE 2**

AIR SAMPLING ANALYTICAL RESULTS

Date Sampled	TURBINE BUILDING					FENCELINE			
	CO ₂ ppm(vol)	SO ₂ ppb(vol)	Hg(tot) μg/m ³	As(tot) μg/m ³	SO ₄ ⁼ (tot part) mg/m ³	SO ₂ ppb(vol)	Hg(tot) μg/m ³	As(tot) μg/m ³	SO ₄ ⁼ (tot part) mg/m ³
6/3	248	-- (1)	< 0.09	-- (2)	< 0.10	65	< 0.09	-- (2)	< 0.10
6.10	278	-- (1)	< 0.08	< 0.17	< 0.17	60	< 0.08	< 0.17	< 0.17
6/17	334	20	< 0.08	< 0.17	< 0.17	-- (1)	< 0.08	< 0.17	< 0.17
6/24	370	55	*	*	*	75	*	*	*
7/1	340	95	< 0.08	< 0.10	< 0.17	120	0.15	< 0.10	< 0.17
7/8	282	25	0.12	< 0.10	< 0.16	95	0.11	< 0.10	< 0.16

(1) SO₂ measurement only made at fenceline or turbine building due to misunderstanding.

(2) Filter sample entirely used during sulfate analysis.

* Sample shipment lost in mail.

** From EAL Corporation Technical Progress Report June 1, 1981 - July 31, 1981.

• APPENDIX D

CHEMICAL MONITORING AND GEOCHEMICAL HISTORY

A Geochemical Case History of the HGP-A Well 1976-1982

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ABSTRACT

The Hawaii Geothermal Project Well-A, located on the Island of Hawaii, was completed in 1976 to a depth of 1966 meters. The bottomhole temperature, under shut-in conditions, is 360°C and at full discharge is capable of producing about 45,500 kg/hr of a mixed fluid composed of 48% steam and 52% liquid. The major element chemistry of the fluids suggests that recharge to the reservoir is largely fresh meteoric water with no more than 10% to 15% of the recharge being from sea water. Extensive water-rock equilibration has occurred; however neither Na-K-Ca nor silica geothermometry calculations have been able to yield reasonable reservoir temperatures. Isotopic data suggest that the circulation rate and residence times of fluids in the reservoir are on the order of a few thousand years. Helium isotopic data also indicate that the heat source for this reservoir is very young or very large.

INTRODUCTION

The Hawaii Geothermal Project Well-A (HGP-A) is located on the lower East Rift Zone of Kilauea Volcano on the Island of Hawaii and was completed in April of 1976. The well penetrates to a depth of 1966 m and has a bottomhole temperature under shut-in conditions of approximately 360°C.

The first flow test of HGP-A occurred on July 2, 1976 and, after it was determined that the well could maintain spontaneous flow for more than a few hours, an extensive well testing program was initiated to determine the sustainable flow rate, wellbore permeability and fluid chemistry. Flow testing of the well indicated that it was able to produce a total flow of approximately 40,000 kg/hr, of which about 48% was steam, and thus was capable of producing commercial quantities of steam. On this basis, a 3MW wellhead electrical generator facility (jointly sponsored by the U.S. Department of Energy, the State of Hawaii, the County of Hawaii and Hawaiian Electric Company) was installed on the well to demonstrate the technical feasibility of power production from this resource and thus to stimulate the development of a commercial geothermal industry in Hawaii. Initial start-up operations for this facility began in June 1981

and the power plant began producing electrical power on a continuous basis in March 1982. The present generating capacity of the facility is approximately 2.8 MWe.

WELL TESTING

Testing of HGP-A can be divided into two phases: preliminary testing conducted primarily to determine the basic engineering and geoscientific parameters of the well and developmental testing to define the production and process chemistry requirements for the design and construction of a generator facility.

RESERVOIR ENGINEERING ANALYSIS

Reservoir testing of the well initially consisted of pumpdown tests and short duration flow tests followed by pressure and temperature recovery analyses. Results of this work suggested that the wellbore had suffered some skin damage from mud caking during drilling and completion operations and that the reservoir permeability was low (about 1 millidarcy) (Yuen, et. al., 1978). The sustainable production rate from the well tended to increase with each flow test and stabilized at about 41,000 kg/hr at a wellhead pressure of 1100 kpa after an extended (40 day) flow test in 1977. Down hole temperature and pressure profiles obtained during and after production tests indicated that, during production, a mixed phase was present throughout the wellbore (steam flashing was occurring in the formation) and that at least three aquifers were providing fluid to the well. Production zones were located at depths of 1800 to 1860m, 1160 to 1250 m, and 670 to 700 m (Yuen et. al., 1978).

RESERVOIR CHEMISTRY

Fluid sampling and analysis have been conducted on an intermittent basis throughout testing and production from HGP-A. The early testing phase was intended to define the basic parameters of the reservoir penetrated by the well whereas more recent analysis has monitored changes in fluid chemistry arising from long term production.

CHLORIDE DATA

The chloride ion concentration in the HGP-A brines has been monitored very closely since the completion of the well as a means of determining the source fluids for the reservoir as well as for identifying changes in reservoir recharge (eg. cold water breakthrough into the production aquifers).

Table 1. Chemical Analysis of HGP-A Brines (mg/kg)

	Cl ⁻	Na	K	Mg	Ca	SiO ₂
11-8 -76	2190	1200	212	<0.5	81.9	
11-17-76	2520	1320	223	0.5	78.8	
1-29-77	2590	1260	225	0.5	78.2	
4-11-77	3050	1460	266	0.1	77.3	710
6-15-78	2420	1500	250	0.08	56.6	
1-14-80	2450	1440	216	0.1	33.2	
6-12-81	1593	806	154	0.02	18.5	1200
9-4 -81	3700	2190	250	0.1	72	800
12-22-81	3261	1745	281	0.04	58.3	1100
3-22-82	5050	2655	431	0.080	121.	
4-19-82	5293	2792	472	0.134	123.	799
5-17-82	5489	3066	508	0.060	124	802
6-14-82	5677	3200	513	0.070	149	818
7-12-82	6044	3300	536	0.073	157.	

During initial well testing the chloride concentration (Table 1) in the brines produced was found to be substantially lower than that in sea water (Kroopnick, et. al., 1978). This result was unexpected since the well penetrates to a depth substantially below that expected for the bottom of the Ghyben-Herzberg lens in this area. The initial interpretation of the low chloride concentrations was that drilling water was being cleared from the producing aquifers. However, more recent production from the well has indicated only a very gradual increase in the chloride concentrations in the geothermal fluids. Thus it is presently believed that the total dissolved solids content in the reservoir fluids under equilibrium conditions is on the order of 6000 mg/kg.

The low salinity of the reservoir fluids may be the result of isolation of the interior of the rift zone from ocean water intrusion by the impermeable dike system within the rift zone. High rates of meteoric recharge from the surface coupled with rapid mixing within the dike compartments could thus maintain a uniformly low salinity within the individual compartments.

Comparison of observed chloride concentrations in the brine versus time (Fig. 1) (all values have been corrected to 1200 kPa flash pressure) for three separate production periods suggests that the changes in chloride concentration with time follow a reproducible trend. Although it is possible that the gradual chloride increase is the result of increasing sea water influx into the reservoir, it is more likely that the change in chloride ion reflects migration of the flash front out into the formation thereby allowing the liquid phase to mine progressively more heat, and thus form more steam from the rock matrix between the flash front and the wellbore. This interpretation is substantiated to some degree by the change in steam quality observed during production; during the first 300 to 400 hours of

well flow, the steam quality increases substantially but the rate of increase gradually declines with time. It is suggested that the sudden breaks in the slope of the chloride concentration curve reflect the migration of the flash front into areas of the formation that have not been produced from before and therefore have a higher temperature.

General Brine Chemistry

The remainder of the dissolved solids in the HGP-A brines have been analyzed in an effort to further define the characteristics of the reservoir recharge fluids as well as attempt to calculate reservoir temperatures. The data acquired indicate that if sea water does make up a portion of the reservoir recharge it has, in most cases, been substantially altered by interaction with the reservoir rock. The ratios of the sodium and potassium ion concentrations to chloride ion are about 5% and 450% above the corresponding sea water ion ratios whereas the calcium ion ratio is depleted by about 65% and both magnesium and sulfate ion ratios are reduced by more than 99% relative to sea water. The mechanism for the modification of the ion ratios is largely through the alteration of potassium containing minerals (primarily plagioclase or interstitial glass) and the formation of chlorite and anhydrite for the removal of magnesium ion and calcium and sulfate ions respectively (Bischoff and Dickson, 1975). Both chlorite and anhydrite have been identified in the deeper cores from HGP-A; the former as an alteration product and the latter as a vein filling mineral (Stone, 1977). Even though the cation concentrations have been substantially altered by interactions with the reservoir rocks, attempts to calculate reservoir temperatures using the cation geothermometers have been uniformly unsuccessful. Depending on the assumptions made, calculated reservoir temperatures have ranged from 80°C to 120°C below the static (nonproducing) bottom-hole temperature in HGP-A. Calculations of the reservoir

Fig. 1 Plot of Chloride Concentration versus time in HGP-A brines

temperatures using silica geothermometry have similarly been unsuccessful. Although the silica concentrations are high in the HGP-A brines, the calculated temperatures using the silica concentrations are well below the static bottom-hole temperature. Evaluation of silica concentrations during well start-up operations indicates that the concentrations peak a short time after production begins and then rapidly decline as the wellbore is cleared of fluids. This suggests that the dissolved silica in the brine phase is rapidly re-equilibrating to the much lower bottom-hole temperatures brought about by production of steam from the well.

The deposition of hydrothermal minerals in the formation or the wellbore during production is of major concern to the potential for long term production from this reservoir. If the above mechanism for silica concentration control is valid, it follows that silica must be depositing in the formation around the wellbore. Although silica scaling in the surface piping of the power plant has proceeded at a relatively slow rate, during the last twelve months it is highly probable that deposition is considerably more rapid in the reservoir. Comparison of the ratios of the individual cation concentrations to chloride ion can also indicate

whether deposition of other minerals is occurring. If, for example, calcium carbonate were being deposited, one would expect a gradually increasing Cl/Ca ratio in the brines produced. The chemical data obtained to the present time indicate that all of the cation to chloride ratios in the brines have been relatively constant and do not exhibit any distinct trends. The absence of a trend of this sort for the cation concentrations suggests that silica is the only mineral that is presently being deposited at an appreciable rate as a result of the flashing process.

The concentrations of the trace transition elements in the geothermal brines has been monitored on an intermittent basis in order to evaluate the potential environmental impacts of the geothermal fluids being produced. The presently available data (Table 2) indicate that the concentrations of many of these elements are well below those found in fluids from most other geothermal environments. The low transition element concentrations in the HGP-A fluids almost certainly arise from the low concentrations of these elements found in Hawaiian basalts.

Table 2. Trace element concentrations in the HGP-A brines

Date	Hg	Cd	Pb	Tl	As	Cu	Zn	B
6/16/77	0.41	<10	<1	≤1	<0.5	<10	≈35	-
6/13/81	≤1.0	<1	-	<1	50	<100	≈40	1.3
1/27/82	<0.5	-	-	-	<100	-	-	2

Table 3. Down-hole water chemistry for HGP-A

Date	Depth (meters)	Cl	Na	K	Mg	Ca
12/2 /76	690	910	500	77.5	1.9	21
12/2 /76	1310	920	480	85	0.7	17.3
12/3 /76	1770	980	500	223	0.6	22.6
2/14/77	690	4800	2160	248	14.7	465
2/14/77	1070	1030	600	82.5	0.4	39.3
2/14/77	1770	2330	1080	160	2.0	161
2/14/77	1920	1310	620	87.5	1.9	95.7

DOWNHOLE WATER CHEMISTRY

During early testing of the well a number of downhole profile water samples were obtained as a means of identifying and defining the production chemistry of the different aquifers in the well (Kroopnick, et. al., 1978a). The chemical data from these samples (Table 3) initially indicated a relatively uniform composition in the wellbore, suggesting that only one production zone was providing fluids to the well or that multiple zones were producing fluids of similar chemical composition. But, subsequent sampling profiles identified three different production zones (Fig. 2, Fig. 3) having distinctively different compositions. The upper production zone, at about a 670 m depth, had substantially higher chloride, magnesium, and calcium concentrations than the deeper aquifers. The ratios of magnesium and calcium ion concentrations to the chloride ion suggest that fluids from this aquifer had not been thermally altered to the same degree as the fluids entering the well at deeper levels. On this basis it was hypothesized that this aquifer was injecting low enthalpy fluids into the well during production; a recasing program necessitated by a leak in the surface casing subsequently sealed off this aquifer. The second production zone at a depth of 1158 m is also indicated to have a significantly higher salinity than the bottom hole. The loss of calcium and magnesium from the fluids in this aquifer suggests that higher enthalpy fluids are being produced at this depth. The data indicate that the third production zone at bottom hole has a lower salinity and total dissolved solids than those above it. The gradual development of these aquifers with time tends to substantiate the engineering analysis that the wellbore had suffered substantial

skin damage during drilling and completion operations; several flow tests were apparently necessary to clear the drilling mud and debris from the major production zones in the well.

NON CONDENSIBLE GAS COMPOSITIONS

The concentration and composition of non-condensable gases in the HGP-A steam phase have been determined on a frequent basis since the completion of the well. The earlier data (Table 4), acquired during short term flow tests, indicated quite variable compositions having total concentrations ranging from 750 mg/kg to 5900 mg/kg in the steam phase. Although some of the observed variability is undoubtedly the result of sampling and analytical errors, more recent analysis of the gas compositions during longer term flow tests indicates that the non-condensable gas concentrations and compositions change radically during the first few hundred hours of production and then gradually stabilize. The observed changes are probably due, in part, to the development and migration of the flash front into the reservoir however, other chemical processes are undoubtedly involved as well. Analysis of the non-condensable gases from the most recent production period indicates that the gas compositions have stabilized and are likely to remain at a concentration of about 2400 mg/l for the immediate future.

Analysis of the steam phase for other volatiles have not found ammonia at detectable levels whereas mercury, boron and arsenic are present only at trace levels.

ISOTOPIC ANALYSES

Stable and radio-isotopic analyses have been performed on the geothermal fluids from HGP-A on

Fig. 2 Plot of Chloride Concentration versus depth for downhole profile samples.

an intermittent basis since flow testing of the well began both as a means of determining the reservoir recharge characteristics as well as to monitor environmental impacts of the well discharge. Radioisotopic analyses were done for tritium, carbon - 14, and radon isotopes in the geothermal fluids during the early testing phase as well as more recently. Tritium concentrations in the brine under extended flow (i.e. uncontaminated conditions) are at background levels (0.1 TU) indicating that the bulk of the recharge for the well is at least 30 years old. Brine samples analyzed from an earlier test, (Thomas, 1980) conducted approximately five months after a substantial quantity of surface water had been pumped into the well indicated that all of the water pumped into the reservoir ($\sim 8 \times 10^6$ kg) was discharged over a period of 12 to 14 days. This would suggest that the fluid circulation and residence times within the immediate vicinity of the wellbore are on the order of years.

Analysis of carbon-14 in carbon dioxide produced by the well during early testing yielded an apparent age of about 12,000 years (Thomas and Kroppnick, 1978). This value was considered to be a maximum age since magmatic carbon dioxide (having zero carbon-14 activity) is expected to make a significant (if not substantial) contribution to the carbon present in the well fluids. Thus it was originally hypothesized that carbonaceous materials used in the drilling process (bagasse, cotton seed hulls, etc.) was a

Fig. 3 Plot of Magnesium Ion Concentration versus depth for downhole profile samples.

Table 4. Non-Condensable Gas Compositions in HGP-A. (expressed in mg/kg of steam)

Date	CO ₂	H ₂ S	Na	H ₂
2/ 9/77	4431	1435	131	46.3
5/ 8/77	2378	878	375	15.1
7/19/77	445	112.	116.	2.3
1/19/80	1000	750	168	11.0
5/31/82	1238	886	129	11.0
=====				

substantial contaminant in the carbon dioxide in the well discharge. More recent analyses, however, have confirmed the earlier data suggesting that the hydrologic circulation rate within this reservoir is substantially more rapid than that within larger continental reservoirs.

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The concentrations of radon in the geothermal fluids have ranged from 1.16 nano curie per kilogram of steam condensate (nCi/kg) during early flow testing to approximately 3.7 nCi/kg during more recent longer-term production (Kruger, personal communication). The concentration of radon in the total well flow for the later samples is calculated to be about 1.65 nCi/kg. This compares with values averaging approximately 20 nCi/kg in the Geysers geothermal field. The lower radon concentrations found in Hawaii are considered to be largely due to the lower uranium concentrations present in Hawaiian basalts relative to the more silicic volcanic and sedimentary rocks found in continental environments.

A very limited number of stable isotopic analyses have been performed for carbon, oxygen, hydrogen, and helium in the HGP-A fluids. Carbon-13 isotopic values ranged from -1.97‰ to -3.6‰ versus PDB. These values are somewhat heavier than expected since the primary sources for the carbon present in these fluids would be biogenic carbon and magmatic carbon which are presumed to have ratios of approximately -20‰ and -7‰ respectively. Although isotopic fractionation processes are almost certainly controlling the C-13 ratios observed in the well discharge, the data are presently inadequate to attempt even a preliminary evaluation of the reactions governing the carbon isotopic ratios.

A limited number of hydrogen and oxygen isotopic analyses were conducted on fluids obtained during the early testing of HGP-A. The isotopic ratios determined for these samples ranged from -6.4‰ to -8.2‰ and from -3.6‰ to -4.6‰ relative to standard mean ocean water (SMOW) for deuterium and oxygen-18 isotopes respectively. These values suggest that the fluids analyzed were of local meteoric origin and that oxygen isotopic exchange with the reservoir rock had not occurred to an appreciable degree. On this basis, it is considered highly probable that these fluids were comprised largely of water pumped into the reservoir during the drilling and completion operations. Unfortunately no more recent analyses have been conducted for the hydrogen and oxygen isotopes from HGP-A.

Helium isotopic analyses for the fluids from HGP-A have yielded $^3\text{He}/^4\text{He}$ ratios of approximately 1.7×10^{-5} (Thomas and Kroopnick, 1978), nearly a factor of ten above atmospheric helium isotope ratios. These values are similar to those observed in fumarolic gases at the Kilauea summit, suggesting that there is a substantial component of magmatic helium present in the geothermal fluids. This, in turn, implies that the magma bodies from which the reservoir derives its helium (and its heat) are relatively young or are very large.

SUMMARY

In summary, the geochemical data obtained from HGP-A suggest the following tentative conclusions regarding the Puna geothermal resource:

1. The total dissolved solids content of the fluids produced by HGP-A is well below that of seawater indicating that parts of the reservoir have minimal direct communication with the normal Ghyben-Herzberg lens adjacent to the rift zone. This implies that there is strong compartmentalization within the reservoir.
2. The total dissolved solids content of the fluids produced by the well is likely to increase as the flash front migrates out into the formation. The rate of increase in the dissolved solids content of the fluids over the production life of the well is expected to be relatively constant until such time as the flash front stabilizes.
3. Steam production occurring in the formation is inducing silica deposition within the production aquifers.
4. The toxic transition element concentrations in the fluids from HGP-A or other geothermal wells in the reservoir are likely to remain relatively low compared to continental geothermal systems.
5. The non-condensable gas concentration in the well fluids will probably remain at a nearly constant level for the immediate future.
6. The circulation rate and residence time of fluids within the reservoir produced by HGP-A are greater than 30 years but almost certainly less than a few thousand years.
7. Helium isotopic data suggest that the heat source for the well is a relatively young and/or large magma body still out-gassing its primordial rare gases.

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PROCESS CHEMISTRY MONITORING AT THE HGP-A POWER PLANT:
ANALYTICAL RESULTS, PROCESS PROBLEMS AND MODIFICATIONS

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ABSTRACT

The HGP-A generator plant began operations on June 12, 1981 and came on-line on a continuous basis on March 1, 1982. During this period process problems were identified and, in most cases, plant modifications have eliminated the difficulties. Silica in the brine was stable at a pH 7.5, however, at a pH above 9.5 deposition of silica was triggered in a brine disposal system and required abandonment of the hydrogen sulfide abatement process originally proposed for the brine system. The steam phase sulfide abatement system for standby conditions was 90% effective, although superheat in the treatment system reduced abatement efficiency. Brine carryover through the separator was very low; however, scale deposition on the turbine blades resulted in substantial damage to the turbine. Non-condensable gases in the condenser were weakly partitioned into the liquid phase, and about 99% were carried into the off-gas treatment system which was found to be approximately 99% effective.

INTRODUCTION

Start-up operations at the HGP-A generator facility on the island of Hawaii were initiated on June 12, 1981; the power plant began providing power to the utility grid on a continuous basis on March 1, 1982. During this shakedown period and continuing to the present, a number of mechanical and process problems have arisen from the geothermal fluid characteristics or from proposed operational procedures that were incompatible with the geothermal fluids. Most of the initial problems have been resolved and modifications are continuing on the plant facility to correct those that remain.

BRINE PROCESS MONITORING

The HGP-A well, which powers the generator facility, has an output capacity of approximately 23,000 kg/hr (50,000 lb/hr) of brine and 23,000 kg/hr (50,000 lb/hr) steam. The total fluid flow from the well is directed into a centrifugal separator/demistor vessel (Fig. 1) where the steam

Fig. 1 HGP-A Geothermal Generator Project steam supply process.
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and brine flows are separated at approximately 1,200 kPaa (175 psia). The observed major element chemical composition from the separator is summarized in Table I. Although a detailed interpretation of the fluid chemistry has not been completed, several general observations can be made. The total dissolved solids content has increased substantially since flow was initiated in June 1981. This increase may be the result of increased seawater intrusion into the production aquifers or, alternatively, it may reflect an increasing fraction of steam formation from the single phase reservoir fluid as the flash front migrates away from the wellbore. It is also noteworthy that silica concentrations in the brine have decreased, rather than increased, since the early production flow. The decrease is thought to result from rapid reequilibration of the reservoir silica concentrations to lower temperatures encountered in the flash zone and in the wellbore. If reequilibration is controlling the silica concentrations, it is probable that substantial silica precipitation is occurring both within the flash zone and in the wellbore; this situation may, in the long term, reduce the output capacity of the HGP-A well.

TABLE I. MAJOR ELEMENT CHEMISTRY OF HGP-A FLUIDS (mg/kg)

	Cl ⁻	Na	K	Mg	Ca	SO ₄ ⁼	SiO ₂
6/17/81	1593	806	148	.061	15.9	50	1233
9/4/81	3700	2190	250	0.1	72.	63	795
Well Shut In	--	--	--	--	--	--	--
12/22/81	3261	1745	281	0.038	58.3	ND	1004
2/5/82	4226	2253	364	0.054	84.4	ND	850
4/5/82	5119	--	--	--	--	--	--

From the separator, the brine is passed through a pressure reduction valve into an atmospheric flash tank. The remaining liquid fraction is passed through a silica settling tank and then into a percolation pond. The steam phase formed is presently being emitted to the atmosphere. The brine phase fed into the low-pressure flash tank contains approximately 30 ppm hydrogen sulfide and approximately 60 ppm carbon dioxide; about 90% to 98% of these gases are partitioned into the steam phase formed in the flash tank, resulting in an appreciable pH change in the brine (from about 7.4 to 8.5). The steam discharge, as a result of the gas loss from the brine, becomes a small but significant source of hydrogen sulfide emissions from the plant. The increase in brine pH occasioned by the gas loss also has significant impact on the silica present in the liquid phase. Whereas the dissolved silica in cooled (non-flashed) samples of brine appeared to be stable indefinitely, the increased pH of the flashed brine triggered silica polymerization resulting in the formation of a moderately stable colloidal suspension of silica polymers. Under these conditions, silica precipitation in the silica settling tank is very slow; after nearly five months of flow, the silica cake on the walls of the pond is less than 2 cm thick.

The hydrogen sulfide emissions in the steam phase from the flash tank were considered sufficiently large to justify the application of abate-

ment procedures. The proposed process was an adjustment of the brine pH to approximately 10 pH units immediately downstream of the pressure reduction valve. This procedure was effective in reducing the sulfide emissions from the brine. However, it also destabilized the colloidal silica formed at pH 8.5; the colloidal suspension rapidly flocculated to form a moderately viscous sludge having a water content of approximately 95% to 99%. The sludge formed was sufficient to fill the silica settling tank in approximately 48 to 72 hours and, if passed through the settling tank, caused an immediate and drastic reduction in the performance of the percolation ponds. Although a number of procedures for handling the silica sludge were investigated, none proved to be economically workable, and thus direct caustic injection into the brine as hydrogen sulfide abatement procedure was abandoned. Work is currently under way to construct a hood and treatment stack for the hydrogen sulfide emissions from the brine flash tank.

STEAM PROCESS MONITORING

The steam fraction from the separator, during plant stand-by conditions, is diverted through a pressure reduction valve and into a rock muffler. The non-condensable gas concentrations present in the steam phase are summarized in Table II. The sulfide production rate from this well amounts to approximately $\frac{1}{2}$ a metric ton per day in the steam phase; thus it was necessary to apply hydrogen sulfide abatement procedures to the geothermal steam emitted to the atmosphere. The abatement technique applied was to inject a 10% solution of sodium hydroxide into the low-pressure steam line upstream of a static mixer spool. This procedure was found to be about 90% effective at a mole ratio of 3 sodium hydroxide to 1 hydrogen sulfide. Although this may not be the peak efficiency for this system, we did find that substantially increased caustic injection rates provided only a minimal improvement in the abatement efficiency.

TABLE II. GAS CHEMISTRY IN HGP-A STEAM

	CO ₂	H ₂ S	N ₂	H ₂	CO
6/14/81	670	609	130.5	9.	~1
2/8/82	964	1297	125.	12.9	~1

The degree of superheat in the steam was found to be a very important factor in the efficiency of the hydrogen sulfide abatement procedure. During the initial start-up period, insufficient water was added to the steam line downstream of the pressure reduction valve and as a result, caustic was being injected into a superheated steam. Under these conditions, the efficiency of the caustic abatement procedures was reduced by 30% to 50% and substantial back pressures were created (due to solids deposition) throughout the low-pressure system. The latter effect may have precipitated the failure of a temporary port in the rock muffler box. Further work with the system indicated that sulfide abatement and system back pressures were optimized with a slight excess (10%-20%) of desuperheat water being injected. Additional testing of this abatement system is planned.

Fig. 2 HGP-A Geothermal Generator Project output and heat rejection.

The steam phase from the separator, under normal conditions, passes through a secondary demistor vessel and into the turbine through trip and control valve manifolds (Fig. 2). To determine the fraction of brine carried past the separator and demistor, the chloride concentration in the steam phase was tested immediately downstream of the plant separator and downstream of the demistor. Silica concentrations were tested there as well. The chloride levels observed in the steam samples were generally between 0.3 ppm and 0.7 ppm; sample blank levels (using distilled water) for the analytical procedures were generally about 0.1 ppm to 0.2 ppm. These chloride levels corresponded to about 0.01% to 0.02% brine carryover in the steam phase.

In spite of the low brine carryover observed in the steam phase, scale material was discovered on the turbine blades during the initial start up period of the facility. The turbine scale material was discovered subsequent to a generator start-up procedure that resulted in excessive turbine vibration that inflicted substantial damage to the turbine rotor and shaft assembly. Removal of the turbine casing revealed that significant amounts of scale material had been deposited on the turbine blades and on the internal components of the turbine housing. Analysis of the scale material indicated that it was primarily a mixed iron oxide with smaller amounts of iron sulfides. An evaluation of the plant chemistry and operating procedures up to the excessive vibration incident suggests that the source of the scale was the piping and manifold section between the turbine inlet and the block valve upstream of the demistor vessel. During the start up, this section of pipe, which is constructed of mild steel, had been exposed alternately to both sulfide-bearing steam and to the atmosphere a number of times due to

required modifications on the control valve assembly. This treatment of the pipe had allowed substantial quantities of iron oxide scale to form, which was subsequently carried into the turbine and mechanically deposited on the blades. To alleviate this problem during future turbine starts, the plant piping was modified to allow the entire steam manifold, down to the turbine inlet, to be blown clear after any extended period of turbine shutdown. The effectiveness of this modification has not been determined; turbine vibration at critical speed has not increased substantially during subsequent turbine start-up procedures.

The spent steam from the turbine is passed through the exhaust duct into a stainless steel surface condenser maintained at a pressure of about 0.8 kPaa (6 in. Hg abs.). Analysis of the steam condensate formed indicated that the liquid had a pH of about 4.5 and that approximately 0.6% of the hydrogen sulfide present in the steam was carried into the liquid phase. This latter value contrasts sharply with steam plant performance at Geysers where as much as 30% of the hydrogen sulfide remains in the steam condensate. The virtual absence of ammonia in the steam from HGP-A probably accounts for the observed difference in hydrogen sulfide solubilities.

The condensate liquid is pH-adjusted to approximately 9 and then pumped into the cooling water return line as make-up water for the cooling tower. The pH of the cooling water was found to be extremely important in minimizing corrosion of the mild steel piping used in the cooling water lines and to inhibiting emission of hydrogen sulfide from the cooling tower.

The non-condensable gases from the condenser are removed through a two-stage ejector assembly

and are injected into an incinerator backed by a packed column scrubbing tower. The hydrogen sulfide fraction of the gases is incinerated to sulfur dioxide, which is subsequently removed by sodium hydroxide treatment in the packed column. During the initial start-up of this abatement system, insufficient air flow into the incinerator resulted in an incomplete reaction of the hydrogen sulfide to sulfur dioxide, leading to the following reaction: $2\text{H}_2\text{S} + \text{SO}_2 \rightarrow 3\text{S}^\circ + 2\text{H}_2\text{O}$. Elemental sulfur formed very rapidly, reduced the scrubber column flow capacity, and required a shut down of the system for removal and replacement of the tower packing. Modification of the air blower system to provide an excess mole ratio of oxygen in the incinerator apparently has eliminated this problem.

Although the abatement efficiency of the incinerator scrubber was quite high (>99%), the gaseous emissions from the column were found to carry a significant quantity of sulfur particulates. Because this was considered to be a source of visual pollution, piping was installed to transmit the stack gases to the air intake of the cooling tower. Passage of the gas through the cooling water cascade removed a substantial fraction of the sulfur particulate and diluted the remainder to the point that it was not visible in the cooling tower plume. No adverse effects on the cooling tower water from this procedure have been observed.

PRESENT OPERATION

At the present time the power plant is operating at a capacity of about 2.8 MWE with an overall plant hydrogen sulfide abatement efficiency of approximately 98%. Work is currently under way to reduce the condenser back pressure to 0.5 kPaa (4 in. Hg abs.) or less in order to bring the plant capacity up to 3 MWE. Modifications are also under way on the brine steam emission system that will attempt to improve the total hydrogen sulfide abatement efficiency of the facility to better than 99%.

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SAMPLING AND ANALYTICAL METHODS DEVELOPMENT AT THE HGP-A GENERATOR FACILITY

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ABSTRACT

During shakedown operations for the HGP-A generator plant sampling and analytical problems were encountered during the process chemistry monitoring effort. Acid-preservation of brine for cation analysis required the use of nitrous oxide-acetylene flame for accurate A-A analysis of calcium. Analysis of gases for carbonate and sulfide was by specific ion electrode and alkalinity titration, respectively. Sulfide caused substantial interferences with the alkalinity method and corrections for sulfide were required. Sulfide also interfered with chloride analyses in the steam phase requiring removal of the sulfide by boiling. Analysis of dissolved silica in the brine was complicated by the presence of colloidal silica which produced erratic analytical results. An accurate evaluation of the hydrogen sulfide abatement system was possible only when the hydrogen sulfide concentrations in the treated and untreated steam were compared with a second component in the steam phase that was unaffected by caustic injection.

INTRODUCTION

Construction of the HGP-A turbine generator facility on the island of Hawaii was completed in June of 1981 and operations for start up of the plant were initiated on June 12, 1981. Beginning then, and continuing to the present, the chemical compositions of a number of process streams throughout the plant have been monitored.

PLANT PROCESS

The HGP-A generator facility (Figs. 1 and 2) is fed by a single geothermal well with an output capacity of approximately 23,000 kg/hr (50,000 lb/hr) of steam and 23,000 kg/hr (50,000 lb/hr) of water. Mixed fluid from the well is piped to a centrifugal separator/demistor vessel where the brine fraction is removed from the steam phase at 1,200 kPaa (175 psia). The brine stream is passed through a pressure reduction valve to atmospheric pressure and, after passing through a muffler box and silica settling pond, it is allowed to percolate into the ground.

Fig. 1 HGP-A Geothermal Generator Project steam supply process.

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Fig. 2 HGP-A Geothermal Generator Project output and heat rejection.

The steam phase from the separator, under normal operating conditions, passes through a second mist eliminator and the power plant trip and control valve manifolds to the turbine. The turbine exhaust is piped to a stainless steel surface condenser and the steam condensate, after pH adjustment, is pumped into the cooling water return line as make-up water for the forced draft cooling tower. The non-condensable gases are ejected from the condensate into a thermal oxidizer where the hydrogen sulfide fraction is incinerated to form sulfur dioxide that is subsequently scrubbed with caustic soda in a packed column. The tail gas from the scrubber column is piped to the air intake of the cooling tower where, as a final treatment, the cooling water cascade removes sulfur particulates from the gas stream.

When the power plant turbine is not operating at full capacity, part or all of the steam from the plant separator is diverted to a pressure reduction valve where it is passed to the atmosphere through a caustic abatement system and rock muffler.

PROCESS MONITORING

The locations at which the process chemistry was monitored, and the species for which analyses were made, are as follows.

(1) The high pressure brine discharge line immediately downstream of the plant separator was monitored for major element compositions including SiO_2 , Cl^- , H_2S , Na, K, Ca, Mg, SO_4 . Silica was monitored to indicate the changes in reservoir temperatures; chloride, to determine the stability of the production aquifers; and H_2S to determine sulfide emission rates from the brine discharge

point. The other species were analyzed as a check on scale formation within the production zone of the well.

(2) The high-pressure steam line immediately downstream of the plant separator was monitored for non-condensable gases, chloride, and silica. The N-C gases were used to evaluate the gas load and air requirements of the incineration system, and chloride was used to determine the fraction of brine particulate that was being passed by the plant separator/demistor vessel.

(3) The condensate discharge line from the plant condenser was monitored for pH and N-C gas content and for chloride concentrations. The former data were used to evaluate partitioning of the N-C gases between the condensate and gas phase, and the latter to check on the chloride measurements upstream of the turbine.

(4) The incinerator column gas discharge line was monitored for hydrogen sulfide and sulfur dioxide to evaluate the abatement efficiency and compliance with emission requirements for the plant.

(5) The silica precipitation tank was monitored for silica concentration to check the effectiveness of the pond in removing dissolved silica.

(6) The rock muffler discharge was monitored for hydrogen sulfide to check the effectiveness of the abatement system and compliance with emission regulations, and for pH to ensure that the steam discharge was not emitting significant quantities of the caustic soda injected into the steam line for hydrogen sulfide abatement.

SAMPLING AND ANALYTICAL PROCEDURES

The sampling procedure for the pressurized brine was essentially that described by Kindle and Woodruff (1981). Although their recommended

on-site analytical procedures for chloride, silica and dissolved gases were satisfactory, later analysis of the major element chemistry did encounter one significant problem. The sample preservation and analytical method recommended for cation samples was acidification of raw and filtered samples and later analysis by atomic absorption spectroscopy. Using this method, we found that the calcium concentrations in the acidified samples were indicated to be approximately 30% of those in the non-acidified samples for both filtered and unfiltered splits. Subsequent analysis indicated that a nitrous oxide/acetylene flame was required to obtain accurate concentration values for calcium ion. This situation suggests that silica polymerization or complexing is in some way binding the dissolved calcium ions. It is not presently known whether a similar effect is occurring for the trace elements in the brine; however, this possibility is being investigated.

Initially, steam samples were obtained from a 1/2-inch insulated line attached to a port on the side of the main steam line. This sampling procedure was found to be unacceptable because of condensation in the sampling line. Subsequent experimentation found that, lacking sample probe access directly into the steam line, an acceptable alternative was a steam jacketed 1/8-inch probe (Fig. 3). The steam samples obtained were condensed into a cooling water-jacketed evacuated bottle containing 4 N sodium hydroxide.

Fig. 3 Steam Jacket Sample Line.

Analysis of the samples for non-condensable gases was by gas chromatography for the non-absorbable gases (N_2 , H_2 , CO) and by specific ion electrode and alkalinity titration for H_2S and CO_2 , respectively. Sulfide concentrations in the samples were high enough to result in substantial interferences from HS^- ion in the carbonate determinations. Precipitation and oxidation of the sulfide were attempted, but the results were inconsistent; the only reliable method found for overcoming the sulfide interferences was to perform the alkalinity titration over a pH range of 11.5 to 3.5 and then correct the acid volume used by that required for a similar titration (over the same pH range) of a carbonate blank having a sulfide concentration identical to that of the sample.

Chloride analyses of the steam condensate also encountered interferences from dissolved sulfide ion even for raw condensate taken without caustic. Precipitation of the sulfide by nickel

nitrate or lead nitrate did not reduce the sulfide concentration sufficiently to eliminate the interference. The only method effective for eliminating the interference was to acidify and boil the sample down to one-tenth its original volume to drive off the sulfide and concentrate the chloride in the remaining liquid. Another method presently being investigated is pre-concentration of the chloride and removal of sulfide through the application of ion exchange resins.

The condensate discharge sampling procedures for non-condensable gases were straightforward provided that the liquid was introduced directly into a caustic medium (Kindle and Woodruff, 1981). Without this precaution, dissolved H_2S and CO_2 were rapidly lost to the atmosphere. The analytical procedures were identical to those described above for carbonate, sulfide and chloride ions.

The incinerator packed-column gas discharge was monitored with a lead acetate tape continuous monitoring system. Under normal operating conditions this method was successful; however, under flame-out of the incinerator, the sulfide levels in the column gases were sufficiently high to affect the entire tape spool in the instrument and render it useless. Sulfur oxides from the column effluent were initially sampled intermittently by disposal gas detection tubes; however, absorption of a measured volume of effluent into a caustic impinger is presently believed to yield more reliable results for total sulfur emission rates.

Analysis of silica concentration in the silica precipitation pond proved to be an intractable problem. Whereas the silica present in the high-pressure brines seemed stable enough to allow dilution before polymerization occurred, the change in pH of the liquid phase from 7.5 to 8.5, brought about by the atmospheric flashing of the hot pressurized brine, induced the rapid formation of colloidal silica in the brine phase. Filtered and diluted (10:1) brine samples yielded inconsistent results with the molybdate blue method even after several days of reequilibration. Later analysis of these samples by nitrous oxide/acetylene atomic absorption provided better results, although the variations in the data suggest that there still may be analytical problems to be resolved.

A precise evaluation of the sulfide concentration present in the steam emissions from the rock muffler was a relatively straightforward procedure. Steam condensate and non-condensable gases were drawn into a caustic solution through an evacuated flask. The major requirement with this procedure is the exclusion of air from the sample solution; the introduction of atmospheric oxygen into the sample allows oxidation of sulfide to sulfate to occur in the basic medium.

Although the above procedure yields an accurate representation of the sulfide present in the atmospheric steam emissions, an evaluation of the efficiency of the abatement system, in terms of

percent removal of the original sulfide present, required a further step. As the hydrogen sulfide-to-water vapor ratio in the steam phase is altered by the addition of de-superheat water to the steam line downstream of the pressure reduction valve, it is necessary to ratio the H_2S concentration in the emitted steam to another component in the steam phase that is unaffected by caustic treatment. In the present case, the hydrogen concentration in the steam emissions was used as the second component. Comparison of the $H_2S:H_2$ ratios in the steam before and after caustic treatment yielded the required abatement efficiency values.

SUMMARY OF CURRENT DATA

A summary and discussion of the plant process chemistry data acquired during this monitoring program is presented elsewhere in this volume (Thomas, 1982). However, in general terms the following observations have been made during the first nine months of operations of HGP-A:

1. The HGP-A well fluid chemistry is following a slow but predictable trend of increasing chloride concentration.
2. The non-condensable gases make up about 0.2% of the steam phase.
3. Brine carryover through the separator/demistor system is about 0.03%.
4. Less than 1% of the non-condensable gases are partitioned into the exhaust steam condensate from the exhaust steam condenser.
5. The turbine off-gas hydrogen sulfide abatement system is operating at better than 99% efficiency.
6. The abatement efficiency of hydrogen sulfide in the turbine standby (rock-muffler) system is about 90% at a mole ratio of 3 NaOH to 1 H_2S .
7. Silica precipitation in the silica settling pond is occurring at a very slow rate.

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APPENDIX E

CORROSION TESTS

Note: This material was abstracted from the thesis by Kam-Fai Raymond Lam and has not been edited.

CORROSION TESTS IN HAWAIIAN GEOTHERMAL FLUIDS

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ABSTRACT - Exposure tests were conducted in binary geothermal brine on the island of Hawaii. The steam which flashes from the high pressure, high temperature water as it is brought to ambient pressure contains substantial amounts of H_2S . In the absence of oxygen this steam is only moderately aggressive but in the aerated state it is highly aggressive to carbon steels and copper alloys. The liquid after flashing is intermediately aggressive. The Hawaiian fluid is unique in chemistry and corrosion behavior; its corrosiveness is relatively mild for a geothermal fluid falling close to the Iceland-type resources.

INTRODUCTION

The energy crisis of the early 1970's fostered development of alternate energy sources in many parts of the world. Geothermal energy received special attention in certain areas because its feasibility had been proven many years ago, because no major technological break-throughs were needed, and because location of the resources was fairly well known.

At first glance the island of Hawaii with its active volcanoes would seem to be a perfect site for geothermal energy development. Closer inspection reveals, however, that most of the rock is porous and does not allow the build up of steam pressure and there are no geysers or active hot springs on the island. This was long thought to rule out the presence of usable geothermal reservoirs and a small drilling program carried out in the mid- to late 1950's seemed to confirm this - it did not hit any steam or pressurized hot water. In hindsight that drilling operation, which was a commercial venture, appears to have been ill-conceived and poorly planned. With the reawakening of interest after 1972 a careful geological survey was made and a successful well was drilled.

The well was finished in 1976, to a depth of 1970 m (1780 m below sea level) and a bottom hole temperature of $360^\circ C$ was measured, making this one of the hottest geothermal wells in the world. A pilot power plant was constructed in 1980-81. It has operated since then and generates 3 MW of electric power. Geological exploration has demonstrated that a very large resource exists in the area and additional drilling is in progress.

The resource is liquid-dominated and produces a mixture of steam and liquid. At present, energy is extracted only from the steam, which accounts for 55-65% of the mixture while the hot liquid is discarded. This liquid has a temperature of around $180^\circ C$. It represents a significant thermal resource and when larger plants are built on the site

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it will be very desirable to utilize this liquid for secondary power generation or for industrial or agricultural heating.

From other geothermal systems, such as Lardarello in Italy (1), Krafla in Iceland (2), Wairakei in New Zealand (3), Cerro Prieto in Mexico (4), Matsukawa in Japan (5) and Geysers in California (6), it is known that the geothermal fluids can be very corrosive; careful materials selection is necessary for any secondary use systems, based on corrosion tests in the actual medium.

The purpose of this study was to make an initial assessment of the corrosiveness of Hawaiian geothermal fluids, in particular the fluid at the Hawaii Geothermal Project's well A (HGP-A).

EXPERIMENTAL

Location of the well is shown in Fig. 1. The site is in a volcanic rift zone on fairly level land with good access from the main port of Hilo. A sketch of the pilot plant is shown in Fig. 2. The wellhead fluid enters a separator in which flashing takes place; the steam portion with non-condensable gases is here separated from the liquid and passes through an H_2S abatement chamber on to the turbine. In order to dispose of the liquid, it must first be brought to ambient pressure. This takes place in the brine flash chamber and is accompanied by a second flashing. The steam from this flashing passes through another hydrogen sulfide abatement chamber before it is released to the atmosphere. The liquid flows through a settling pond, in which most of the suspended silica particles settle out, before it flows into the porous ground rock.

The tests were conducted during the period August 1981 - November 1982. Racks of test specimens were exposed in the settling pond and in the steam at the second flashing for various periods of time. In the initial steam tests there was free access of air while in later tests the chamber had been enclosed for hydrogen sulfide control and the steam was air free.

Fig. 1 Location of well site on the island of Hawaii

Fig. 2 Sketch of the HCPA pilot power plant. Sample strings were exposed in the flash chamber (A) and in the silica settling pond (B).

The liquid typically had a flow rate of 400 l/min, a temperature of 76°C, a pH of 7.45-8.8 and the following contents of dissolved salts and gases (ppm): H₂S - 20; Cl - 7230; Na - 3750; K - 620; Ca - 150; SiO₂ - 650; O₂ - 1.6 (7).

The aerated steam contained about 20% air. Its pH was 4-4.5 and it contained 100 ppm of CO₂ and 80 ppm of H₂S. The non-aerated steam had the same pH, only a trace of CO₂, and 100 ppm of H₂S. Trace gases in the steam (< 3 ppm) were He, A, CO, and possibly methane but, unlike most other geothermal systems, no ammonia was present (7). The temperature at the test site was 100°C and the steam was flowing at a rate corresponding to 75 l/min of water.

Test coupons were prepared from thin sheet or plate material or from tubes and rods, as available. Each coupon was finished with 120 µm silicon carbide abrasive paper, cleaned in acetone and weighed. Flat exposure coupons were 7.5x7.5 cm and the rod shaped samples were 9 cm long. A 1.3 cm diameter hole was drilled through the center of each for use in making up the sample string. A threaded, Tygon coated rod of stainless steel 316 was inserted through the holes and 2.5 cm long pieces of PTFE tubing were used as spacers between the coupons. Some U-bend specimen were added to each string to provide SCC data and also to put the string assembly under some compression. The U-bend samples were 22x4 cm strips of sheet with a hole near each end. They were bent to a 2.5 cm opening and strung on the rod of the assembly. A sample string typically contained 25-30 coupons.

Sample strings in the steam flash chamber were located horizontally on top of the rocks in the chamber. Sample strings in the silica settling pond were hung vertically in the water. Exposure times varied from 14 to 50 days in the steam and from 38 to 130 days in the liquid.

After exposure the samples were studied by optical and electron microscopy. Pit and crevice depths were measured by the depth of focus technique using an optical microscope. Corrosion products and silica scale could generally be removed by gentle brushing but for some materials the silica scale adhered quite strongly. In some of those cases the scale would flake off when the specimen was flexed. In other cases it was necessary to dip the specimen for a few seconds in 50% HF or to use the electrolyte cleaning method suggested by Braithwaite and Lichti (8). Corrosion products were removed by the usual ASTM methods (9) before the weight loss was determined.

RESULTS

The corrosion results are summarized in Table 1. The depths of pitting and crevice corrosion attacks varied from test run to test run and for these types of damage the largest values have been listed.

Some alloys were completely resistant: titanium, Hastelloys C-3 and C-276, and high-alloy stainless steels. The composition of these alloys is listed in Table 2.

The more common stainless steels are generally subject to substantial pitting in some of the environments but not in others. These steels include the austenitic 18/8 (304) type and the martensitic 431. The composition of this group of apparent borderline alloys is given in Table 3.

The pure nickel shows pitting and crevice corrosion only in the aerated steam, but as copper is added, to form monel 400, general attack is also experienced. The pure copper shows very severe uniform attack in the aerated steam, to 1.5 mm/yr, while the attack is only 2.5 µm/yr in the non-aerated steam and less than 50 µm/yr in the liquid. The 70:30 Cu:Zn brass shows similar relative values but at lower total rates while the pure zinc is attacked only by severe pitting. The zinc coating on galvanized steel performs in a similar manner, though the depths of attack are only 20-30% of those for the pure zinc.

The low carbon steel shows quite high general corrosion rates - 85 µm/yr in the aerated steam, 200 µm/yr in the non-aerated steam and up to 65 µm/yr in the liquid. In the latter environment the attack under the washer was even greater - up to 230 µm/yr. The high strength low alloy steels AISI 4140 and 4340 show generally good resistance except for crevice corrosion attacks in the liquid which are nearly as severe as for the low carbon steel.

The aluminum alloys tested generally show remarkably high rates of pitting - to 11 mm/yr. The most severe attack is shown by the aluminum-zinc alloy 7075 but very substantial pit and crevice attacks are found also for the aluminum-magnesium alloys 5052 and 5086 and the aluminum-magnesium-silicon alloy 6061. The coating on aluminized steel behaves in the same general way as the straight aluminum alloys. The attacks on the aluminum alloys are severe in all three environments with non-aerated steam as possibly the worst environment, followed by the aerated steam and the liquid.

The nominal compositions of the alloys which show substantial attack are listed in Table 3.

No stress corrosion or hydrogen cracking was observed on any of the low carbon steel U-bend specimens.

DISCUSSION

It is difficult to make a direct comparison of the three different environments because test conditions were not always constant. For example, during some of the tests in aerated steam the flow conditions in the chamber changed somewhat, so that some splashing to liquid onto the samples may have occurred. It is also difficult to compare with results from other geothermal sites around the world because, again, test conditions vary considerably and complete information is not always available. For these reasons the following discussion is rather general and qualitative.

Data on uniform corrosion in various geothermal liquids are summarized in Table 4. It is seen that the secondary fluid from the Hawaiian site is

generally intermediate in its corrosiveness, as compared with other sites, falling between the New Zealand, Iceland and Central American sites on the milder side and the mainland U.S.A. sites on the severe side. The water chemistry data available do not, unfortunately, permit a more detailed analysis. It should be mentioned, however, that the very high corrosiveness towards steels of the Salton Sea fluids most probably is due to their very high salinity.

Data on uniform corrosion in steam are presented in Table 5. The values from the Hawaiian site should probably be compared only with literature data for flashed steam. However, insufficient information is available for a good study. In a general comparison with steam from other sites it is seen that the Hawaiian site is intermediate in aggressiveness towards carbon steels, mild towards low alloy steel, aggressive towards brass, and extremely aggressive towards copper and Monel 400. The sites which have steam aggressive to copper and Monel 400 all have 100 ppm or more of H_2S in combination with oxygen in the aerated steam, while the same steam free of oxygen is quite benign to copper and the 70 Ni 30 Cu Monel. An exception is the Matsukawa, Japan data which may represent both aerated and non-aerated steam environments. The Matsukawa site has an extremely high H_2S level (1500 ppm) and so do the other two sites which are somewhat aggressive to Monel in the nonaerated steam: Cerro Prieto (1500 ppm) and Ahuachapan (130 ppm).

Data for the carbon steel follow similar lines - heavy attack where H_2S and oxygen act together, moderate attack where the oxygen is excluded.

Little information is available in the literature on the behavior of aluminum alloys in geothermal fluids. The available data all show severe pitting. On the steam side this includes alloy 1100 in aerated and non-aerated steam at Wairakei, New Zealand (3) and in aerated steam at Cerro Prieto, Mexico (4,20); alloys 1100 and 5052 in non-aerated steam at Matsukawa, Japan (22); and alloy 5005 in flashed steam at East Mesa, U.S.A. (15). In the liquid, pitting has been found for alloys 1100, 5052 and 6063 at Raft River, U.S.A. (13) and for alloy 5005 at East Mesa, U.S.A. (15). There appears to be no reports of geothermal fluids which do not attack aluminum alloys by pitting corrosion.

The data for the severely pitted aluminum alloys do not clearly indicate that any one of the three environments tested in this study is more aggressive than any other. The other metals and alloys tested do, however, clearly show that the aerated steam is the most aggressive of the three environments, the non-aerated steam the least, and the liquid falls somewhere in between. This ranking is in agreement with findings from other sites around the world.

A study of the primary steam was not included in the present work. It was noticed during turbine overhaul, however, that no serious corrosion takes place in this environment, possibly because

virtually all of the H_2S has been removed upstream.

Attempts have been made to classify the corrosiveness of low temperature geothermal fluids on a global scale. Ellis (23) has proposed that geothermal sites can be divided into two different categories: Iceland-like resources and Madison-like resources. The classification is based on fluid chemistry parameters: pH, total alkalinity, bicarbonate, H_2S , chloride and sulfate and on the corrosion rate of carbon steel. The HGP-A fluid chemistry does not fit into the classification system while the corrosion rate for low carbon steel (7.5-65 $\mu m/yr$) places it closer to an Iceland-like resource (< 41 $\mu m/yr$) than to a Madison-like resource (120-450 $\mu m/yr$). A comparison on fluid chemistry alone also shows that the Hawaiian site appear to be somewhat unique, though not very different from some Icelandic wells (24).

CONCLUSIONS

The tests have shown that compared to geothermal sites world wide the Hawaiian geothermal fluid is a moderately aggressive geothermal resource. Of the three environments tested the aerated flashed steam was the most aggressive followed by the liquid after flashing. The non-aerated flashed steam was least aggressive. Aluminum alloys suffered severe pitting attack in all three environments while the high alloy stainless steels were fully resistant. Carbon steel and copper alloys suffered severe general corrosion in the aerated steam, moderate damage in non-aerated steam and considerable general or crevice corrosion damage in the liquid. Nickel, zinc and Monel 400 were attacked by severe pitting, especially in the aerated steam and in the liquid.

The results are preliminary in nature. Longer term tests must be conducted before materials selection guidelines can be firmly established for this geothermal fluid.

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Table 1

Corrosion Data, $\mu\text{m}/\text{yr.}$

Alloy	Aerated Steam	Non-aerated Steam	Liquid
Titanium, Gr. 2	R	R	R
Hastelloys C-3, C-276	R	R	R
High-alloy Stainless	R	R	R
SS 316 L	-	R	R
SS 304	P-6860/CC-1700	R	R
SS 303	-	R	P-145/CC-168
SS 431	-	R	P-56/CC-330
Ni 270	P-2286/CC-762	R	R
Monel 400	G381-762/P-2185	R	P-381/CC-330
Cu	G762-1524	G2.5	G46-48
70:30 Brass	G152-254	R	G20-41
Zn	P-3886/CC-889	P-406/CC-432	P-356/CC > 1525
Galv. Steel	P-1016/CC-432	P-152	P-229/CC-117
Low Carbon St.	G 84	G 0-203	G 716-64/CC-229
AISI 4140 St.	(R)	(R)	CC-196
AISI 4340 St.	(R)	CC-8	CC-183
Aluminized St.	P/CC-1829	P-76/CC-330	P-178/CC-229
Al 2024	P	P-2970	R
Al 7075	P-2160/CC-4520	P-7214/CC-152	P-11230/CC-2670
Al 5052	P-2440/CC-6705	P-7365/CC-6705	CC-890
Al 5086	P	-	CC-1015
Al 6061	P-3405/CC-8130	P-4725/CC-3275	CC-1145

P - pitting; CC - crevice corrosion; G - general attack; R - resistant

Table 2

Composition of Fully Resistant Stainless Steels

	C	Cr	Ni	Mo	Mn	Si	N	Cb	Cu
AL-6X	0.08m	20	24	6.0	8.25				
Jessop 700	0.025	21	25.6	4.5	1.8	0.5	0.02	0.3	
Jessop 777	0.025	21	25.6	4.5	1.4	0.5	0.03	0.3	2.2
Avesta 254SMO	0.014	20	18	6.1	0.5	0.3	0.22		0.7
Nitronic 50	0.035	21	12.5	2.1	4.8	0.4	0.23	0.13	
Ferralium 255	0.02	25.6	5.5	3.0	0.8	0.4	0.25		1.75
Avesta 223 FAL	0.03m	22	5.5	3.0			0.12		
Avesta 3 RE 60	0.03m	18.5	5	2.8	1.2	1.5			
316 L	0.01	17.2	13	2.7	1.75	0.6			0.12

Table 3

Nominal Composition of Corroding Alloys

304 Stainless Steel	C:0.08 max, Cr:19, Ni:10
303 " "	C:0.15 max, Cr:18, Ni:9, S:0.15 min.
431 " "	C:0.2 max, Cr:17, Ni:2
Nickel 270	Commercially pure nickel
Monel 400	Ni:63-70; Fe:2.5 max, Cu:rem.
Copper	99.99% Cu. min.
70:30 Brass	Cartridge brass, Cu:68.5-71.5, Zn rem.
Zinc	99.9% Zn min.
Low Carbon Steel	ASTM A366: C 0.06
AISI 4140 Steel	C:0.4, Mn:1.0, Cr: 0.8-1.1, Mo:0.15-0.25
AISI 4340 Steel	C:0.4, Mn 0.8, Cr:0.7-0.9, Ni:1.65-2, Mo:0.2-0.3
Al 2024	Cu:3.8-4.9, Mg:1.2-1.8
Al 7075	Zn:5.1-6.0, Mg:2.1-2.9, Cu:1.2-2.0
Al 5052	Mg 2.2-2.8; Cr:0.15-0.35
Al 5086	Mg 3.5-4.5; Cr:0.05-0.25
Al 6061	Mg 0.8-1.2; Si:0.4-0.8

Table 4

Literature Corrosion Data for Geothermal Liquids, $\mu\text{m}/\text{yr}$

Location	Reference	Carbon Steel	4130/ 4140	Monel 400	Cu	Brass
<u>Separated Water:</u>						
Wairakei, N.Z.	3	< 25		25-250	25-250	
Broadland, N.Z.	8	2.5-7.5 ^x	2.5 ^x			
Krafla, Iceland	10	10				
Ahuachapan, El Salvador	11	10		46	700	41
Brady Hot Springs, U.S.A.	11			76		
<u>Well Water:</u>						
Diamond Ring, U.S.A.	12	389		11	86	
Raft River, U.S.A.	13	46 ^x	20 ^x	2030		4165
<u>Flashed Fluid:</u>						
Bara, U.S.A.	14	813		76		76
East Mesa, U.S.A.	15	84 ⁺	30 ⁺			
Salton Sea, U.S.A., 1976-7	16/17	1220 ^x	56/262 ^x			
Same, 1978	18	1905 ^x	584			

Hawaii HGP-A	This Study	7.6-64 ⁺	0 ⁺	0 ⁺	48	203-406

x - Pits

+ - Crevice Corrosion

Table 5

Literature Corrosion Data for Geothermal Steam, $\mu\text{m}/\text{yr}$.

Location	Reference	Carbon Steel	4130/ 4140	Monel 400	Cu	Brass
<u>Aerated Steam:</u>						
Wairakei, N.Z.	3,19	508	< 25	255	1015	1015
Broadland, N.Z.	8	965 ^x	865 ^x			
Ahuachapan, El Salvador	11	183	137	213	691	602
Cerro Prieto, Mexico	4,20,21	110			569	
<u>Non-aerated Steam:</u>						
Broadland, N.Z.	8	17 ^x	23 ^x		15	
Hachobaru, Japan	11	86	46			11
Otake, Japan	11	41	43		15	~ 0
Cerro Prieto, Mexico	4,20,21	38		99		
Matsukawa, Japan	22	635 ⁺		25-255 ⁺	255-1524	255-1270
Ahuachapan, El Salvador	11	34	7	83	16	7
<u>Flashed Steam:</u>						
Salton Sea, U.S.A. '76-77	16,17	635 ^x	208 ^x			
Salton Sea, U.S.A. '78	18	432 ^x	279 ^x			
Baca, U.S.A.	14			51		127
East Mesa, U.S.A.	15	81 ⁺	64 ⁺			

HGP-A, Hawaii, aerated	This Study	84	~ 0	381-762	762-1524	152-254
" " , non-aerated	"	0-203	~ 0 ⁺	0 ^x	2.5	~ 0

x - Pits + - Crevice Corrosion