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IDENTIFICATION OF ENVIRONMENTAL CONTROL TECHNOLOGIES FOR GEOTHERMAL DEVELOPMENT IN THE IMPERIAL VALLEY OF CALIFORNIA

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CONTENTS

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ABSTRACT

This interim report discusses control technologies to manage environmental impacts from geothermal developments in California's Imperial Valley from development to 1985. Included are descriptions of methods for managing land subsidence by fluid injection; for preventing undesirable induced seismicity or mitigating the effects of seismic events; for managing liquid wastes through pretreatment or subsurface injection; for controlling H_2S by dispersal, reinjection, and chemical treatment of effluents; and for minimizing the impact of noise from power plants by setting up buffer zones and exclusion areas.

INTRODUCTION

This is an interim report for the Imperial Valley Environmental Project: Assessment of Environmental Control Technologies, one of several projects conducted by the Lawrence Livermore Laboratory (LLL) for the U.S. Department of Energy (DOE) in support of geothermal energy development. Early and major development of the Imperial Valley's geothermal resources is expected (Fig. 1). At present, resource and technology development work is proceeding at several Valley KGRA's (known geothermal resource areas).

A predevelopment or "baseline" study, the Imperial Valley Environmental Project (IVEP), is more than half complete. Power plant and direct heat utilization systems are at proposal and feasibility study stages, respectively. The risk of unacceptable environmental impacts impeding the commercialization of geothermal energy and the need for timely development of required controls are recognized. Liquid wastes, gaseous emissions, and subsidence and induced seismicity are primary concerns. The DOE programs underway include state-of-the-art evaluations of environmental control technologies (ECT's) and development of specific ECT's.

The purposes of the project for assessment of environmental control technologies are to:

- Provide independent assessments of the effectiveness and practicability of environmental control technologies for federally supported geothermal developments in the Imperial Valley.

- Provide descriptions of these technologies for inclusion in environmental impact statements and assessments prepared by DOE pursuant to the National Environmental Policy Act of 1969 (PL91-190).

- Confirm performance criteria for these technologies.

The project has been planned in two phases. Phase I includes identification, description, and assessment of the environmental control technologies. Phase II includes performance assessment during the period facilities are operating.

This report is on Phase I. It includes identifications and descriptions of environmental control technologies as well as a summary of prior work characterizing the Imperial Valley environment, the geothermal resource, effluents from development, projected development to 1985, control needs, and abatement needs.

Comments regarding applicability of control measures for development in the Imperial Valley are not intended as assessment. The final report on Phase I will provide assessments.

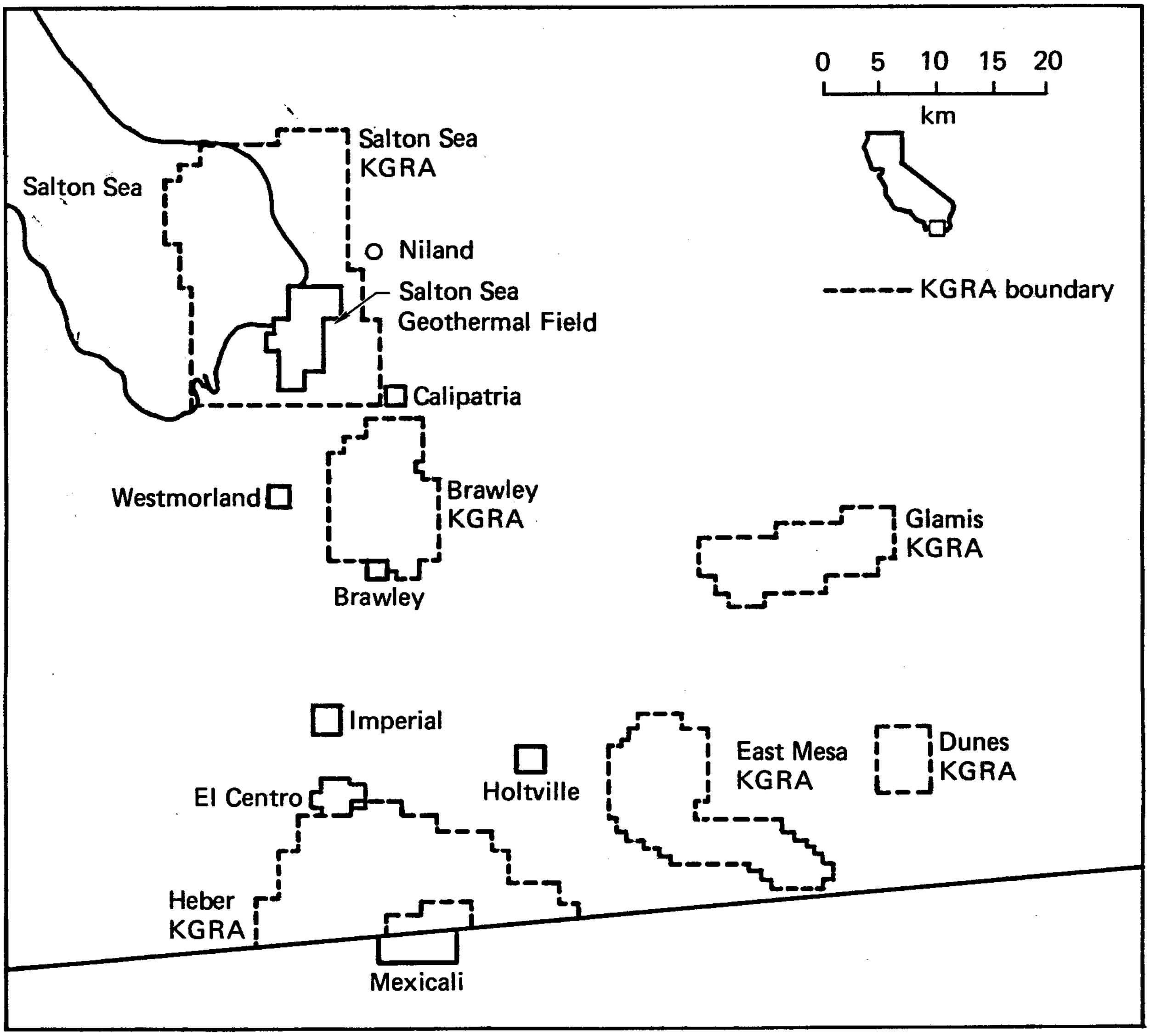

Fig. 1. Map of Imperial Valley showing Known Geothermal Resource Areas (KGRA's) and Salton Sea Geothermal Field.

IMPERIAL VALLEY GEOTHERMAL RESOURCES AND ENVIRONMENT

This section summarizes selected information from publications on the Imperial Valley geothermal resource, the present quality of the air and water in the Valley, and the seismic history of the Valley. These summaries are very brief and are intended to provide only the broadest sort of background information on conditions in the Imperial Valley as now known

Energy Resources

The Imperial Valley contains six KGRA's.[1] Four of these areas — the Salton Sea, Heber, East Mesa and Brawley — are considered potentially suitable for electric power generation. Approximately 60% of the total resource is estimated to be in the Salton Sea KGRA. Only a small percentage has been explored by well drilling, but the size of the total resource has been estimated by indirect methods. Recent estimates place the potential for electric power production between 3,000 and 5,000 MW for a 30-yr period (90,000–150,000 MW-yr).

Fluid Characterization [1,2]

The average downhole temperature of the geothermal fluids ranges from 285°C in the Salton Sea KGRA to 180–200°C in the other KGRA's. While fluids in the Salton Sea KGRA are of a higher quality from a temperature standpoint, they have an extremely high total dissolved solids (TDS) content: 200,000 ppm on the average. (For comparison, this is approximately eight times the TDS of sea water.) The high TDS content of these fluids contributes to extensive problems with corrosion, scaling, solids deposition, and plugging which require major development of energy conversion and environmental control technologies before commercial production of electrical power can be expected from the Salton Sea KGRA. Fluids from KGRA's in the southern part of the valley have a much lower TDS content, approximately 14,000 ppm at Heber and 7,600 ppm at East Mesa, and therefore present much less severe problems to developers.

Characteristics of fluids from wells in the Salton Sea, Heber, and East Mesa KGRA's are shown in Appendix D. These data should not necessarily be considered typical or representative of the sites.

Air Quality[3]

Air quality in the Imperial Valley is in keeping with its rural, desert environment. Results obtained from six air-monitoring stations during the first half of 1977 indicate low ambient air concentrations of gaseous pollutants. Concentrations of H_2S, SO_2, NO, and NO_x were generally less than 10 ppbv*, while ozone (O_3) concentrations averaged about 30 ppbv. The primary air pollutants are particulates whose concentrations ranged from 18 to 420 $\mu g/m^3$ during the six-month period of investigation and regularly exceeded the California air quality standard of 100 $\mu g/m^3$.

*Parts per billion by volume.

Water Quality[4]

The main source of water for the Imperial Valley, nearly 3 million acre-feet per year, is the Colorado River. At present this water contains about 850 ppm TDS. Water from shallow aquifers contains from a few hundred ppm to over 10,000 ppm TDS. In surface waters the TDS content ranges from about 900 ppm in the All American Canal to over 39,000 ppm in the Salton Sea.

Subsidence and Seismicity[4]

Subsidence measurements taken in the Imperial Valley between 1931 and 1941 reveal downward movements as great as 20 cm in some areas. The valley is also known to be an area of high seismic activity. Twelve earthquakes with Richter magnitudes of 6.0 or higher have occurred this century in the Salton Trough. In addition, multiple earthquakes with magnitudes less than Richter 5.0 frequently occur in long series of shocks called earthquake swarms.

The magnitude as measured by the Richter Scale is commonly used to report earthquakes. However, damage caused by an earthquake with a given Richter magnitude and a shallow epicenter may be greater than damage associated with a higher Richter magnitude and a deep epicenter. The Modified Mercalli Intensity Scale is sometimes used to relate intensity to damage. Although there is no direct relationship between the two scales, an approximate comparison for earthquakes with shallow epicenters is shown in Table 1.

Table 1. Modified Mercalli Intensity scale showing approximate relationship with magnitude of shallow local earthquakes. (Adapted from D. Linehan, "Geological and seismological factors influencing the assessment of a seismic threat to nuclear reactors" in *Seismic design for nuclear power plants* (M.I.T. Press, Cambridge, Massachusetts, 1970) pp. 69-90).[a]

Intensity (Modified Mercalli Scale)	Effect	Magnitude (Richter Scale)
I	Not felt except by very few under especially favorable conditions.	
II	Felt only by a few persons at rest, especially on upper floors of buildings. Delicately suspended objects may swing.	
III	Felt quite noticeably indoors, especially on upper floors of buildings, but many people do not recognize it as an earthquake. Standing motor cars may rock slightly. Vibration like passing of truck. Duration estimated.	3
IV	During the day felt indoors by many, outdoors by few. At night some awakened. Dishes, windows, doors disturbed; walls make creaking sound. Sensation like heavy truck striking building. Standing motor cars rock noticeably.	4
V	Felt by nearly everyone; many awakened. Some dishes, windows, etc., broken; a few instances of cracked plaster; unstable objects overturned. Disturbance of trees, poles and other tall objects sometimes noticed. Pendulum clocks may stop.	5
VI	Felt by all; many frightened and run outdoors. Some heavy furniture moved; a few instances of fallen plaster or damaged chimneys. Damage slight.	
VII	Everybody runs outdoors. Damage negligible in buildings of good design and construction; slight to moderate in well-built ordinary structures; considerable in poorly built or badly designed structures; some chimneys broken; noticed by persons driving motor cars.	6
VIII	Damage slight in specially designed structures; considerable in ordinary buildings with partial collapse; great in poorly built structures. Panel walls thrown out of frame structure. Fall of chimneys, factory stacks, columns, monuments, walls. Heavy furniture overturned. Sand and mud ejected. Changes in well water. Cars disturbed.	
IX	Damage considerable in specially designed structures; well designed frame structures thrown out of plumb; great in substantial buildings, with partial collapse. Buildings shifted off foundations. Ground cracked. Pipes broke.	7
X	Some well-built wooden structures destroyed; most masonry and frame structures destroyed with foundations, ground badly cracked. Rails bent. Landslides from river banks and steep slopes. Shifted sand and mud. Water splashed (slopped) over banks.	8

[a]Reproduced with permission from M.I.T. Press.

GEOTHERMAL RESOURCE UTILIZATION

Present geothermal resource utilization in the Imperial Valley is carried out in relatively small experimental facilities. A 10-MW Geothermal Loop Experimental Facility (GLEF), funded by DOE, to investigate the flashed binary conversion process is operated by San Diego Gas and Electric Company in the Salton Sea KGRA. A Geothermal Component Test Facility is operated by Westec for DOE at the East Mesa site previously used by the Department of Interior Bureau of Reclamation for an experimental water desalination plant. This facility provides actual geothermal fluids under field conditions for tests of various geothermal energy conversion equipment and materials. The Union Oil Company (at the Brawley KGRA) and Chevron Oil Company (at the Heber KGRA) also operate field stations for experimental work.

Utilization for Electric Power

Several geothermal facilities are proposed for electric power production in the near future. Forecasts for the period to 1985 are assembled in Table 2. Several hundred megawatts of electric power production is projected. Estimates of electric

Table 2. Assembled geothermal development forecasts to 1985 in Imperial Valley, California.[5-9]

Location	Principals	MW	Project and process	Government support	Date in use	Comments
Salton Sea KGRA	San Diego Gas and Electric Co.	10	GLEF, Flashed Binary[a]	DOE/DGE	Currently	R&D
	Union Oil, S.P. Land Co., Southern California Edison		Well Completion and Extraction Technology Test Facility	DOE	'79[b]	R&D
		50			'82[c]	
		50			'84[c]	
		50			'85[c]	
Westmorland	Republic Geothermal, Inc., and MAPCO	55	Westmorland Development Project.[d] Process choice is geothermal fluid and design dependent: Flashed Steam,[f] Binary,[g] Flashed Binary.[a]	Proposed: DOE/SAN/GLGP[e]		
Heber KGRA	San Diego Gas and Electric Co., Los Angeles Department of Water and Power, Imperial Irrigation District, Southern California Edison	45	Proposed Demonstration Plant, Binary		'81[h]	
	Union Oil?	50			'84[h]	
Brawley KGRA	Union Oil	10			'79[j]	Commercial
	Union Oil	50	Flashed Binary?		'83 or '84[i]	
	Union Oil	50	Flashed Binary?		'85[i]	
East Mesa KGRA	Department of Interior/USBR		Geothermal Resource Investigations, East Mesa Test Site		'74–	Desalination
	DOE/WESTEC/USBR		Geothermal Component Test Facility	DOE	Currently	
	Magma Power Co.	10	East Mesa Project, "Magmamax," Binary-type, two secondary fluids		'78[i]	R&D "Magmamax" Process Test
	Republic Geothermal, Inc.	10	East Mesa Development Project, Flashed Steam	Proposed: DOE/SAN/GLGP	'78-'79[8]	Expansion to 48 MW
		48	East Mesa Geothermal Project Flashed Steam		'82[9]	

[a] In this system, steam is flashed off the brine in one or more separators and used to vaporize a secondary working fluid which is used to drive the turbine.

[b] See Ref. 5, pp. 3-21.

[c] See Ref. 5, pp. 3-32.

[d] See Ref. 6.

[e] Geothermal Loan Guarantee Program.

[f] In this system, steam is flashed off the brine in one or more separators and fed directly into a steam turbine.

[g] In this system, the heat brine is used to vaporize a secondary working fluid in a heat exchanger which is used to drive the turbine.

[h] See Ref. 5, pp. 3-24.

[i] See Ref. 5, pp. 3-34.

[j] See Ref. 5, pp. 3-28, 13.

power available from Imperial Valley geothermal sources by 1995 range from 500 to 13,000 MW.[1] The wide range reflects uncertainties in the size of the resource and the technological problems associated with utilization of brines from the Salton Sea KGRA. Other factors such as alternate power development and political decisions, may also affect development.

Nonelectric Utilization

The *Direct Use of Geothermal Energy Symposium* sponsored by DOE on January 31 to February 3, 1978, in San Diego, California, indicated that there is considerable interest in the nonelectric uses of geothermal energy. Possible applications include space heating, industrial process heating, crop drying, food processing, aquaculture, and greenhouse operations. Although we are not aware of any current nonelectric applications of geothermal energy in the Imperial Valley, future usage can be expected because of constraints on the use of fossil fuels.

A water desalination plant was formerly planned by the Bureau of Reclamation for their East Mesa site.[10] It is our understanding that these plans have been cancelled however, because the capacity of the reservoir is inadequate to provide sufficient water for the project.

UTILIZATION SYSTEMS—FLUID PRODUCTION AND EFFLUENTS

Effluents from Well Drilling and Operation

Geothermal well drilling in the Imperial Valley is done with drilling muds, typically, heavy bentonite clay mixes with additives. These are designed to seal the bore hole to prevent influx of fluid. They also limit release of gases. No quantitative measurements are available on H_2S emissions during drilling operations, but they are said to be almost nonexistent.[11, 12] The drill cuttings are the primary material requiring disposal, and are ordinarily removed from the mud, deposited in a pit, and buried.

After completion, the well is allowed to discharge in order to conduct a brief flow test and to remove residual drilling mud and cuttings. The discharged fluid is collected in holding ponds or Baker tanks, and then either transported to a disposal well for injection or allowed to evaporate. If it is allowed to evaporate, the resultant solids are deposited in a pit and buried. The production test on a new well is not made until it is connected to a disposal well so that the fluid can be injected.

Nongeothermal wastes, i.e., garbage and used drilling mud, associated with drilling operations, are similar to those for conventional oil well drilling. Garbage is collected and hauled to conventional garbage dumps and drilling mud may be collected in tanks and hauled to other drilling sites for reuse. Nontoxic drilling muds are disposed of in conventional land fill dumps, while toxic drilling muds are hauled to sites designated for toxic waste disposal.

Effluents from Power Plants

The temperature, pressure, and chemical composition of geothermal fluids found in the Imperial Valley differ considerably from one location to another, so any one power conversion process is not optimum for all locations. Simplified schematic diagrams of four applicable types of processes are shown in Figs. 2–5. Conversion processes eventually installed will produce effluents similar to those shown here (Figs. 1–4). Liquid wastes such as spent brine, steam condensate, and cooling tower blowdown, as well as the solid wastes, scale, sludge, and suspended solids, will require disposal. Effluents that may require treatment for H_2S abatement are spent brine, steam condensate, and noncondensable gases. In addition, it may be necessary to control the drift of mist from cooling towers to prevent the deposition of entrained salts on adjacent vegetation and soils.

Unlike steam wells at The Geysers, Imperial Valley geothermal wells can be routinely shut in (valved off) and restarted conveniently with no apparent damage to the well, e.g., when a power plant is shut down for repairs.

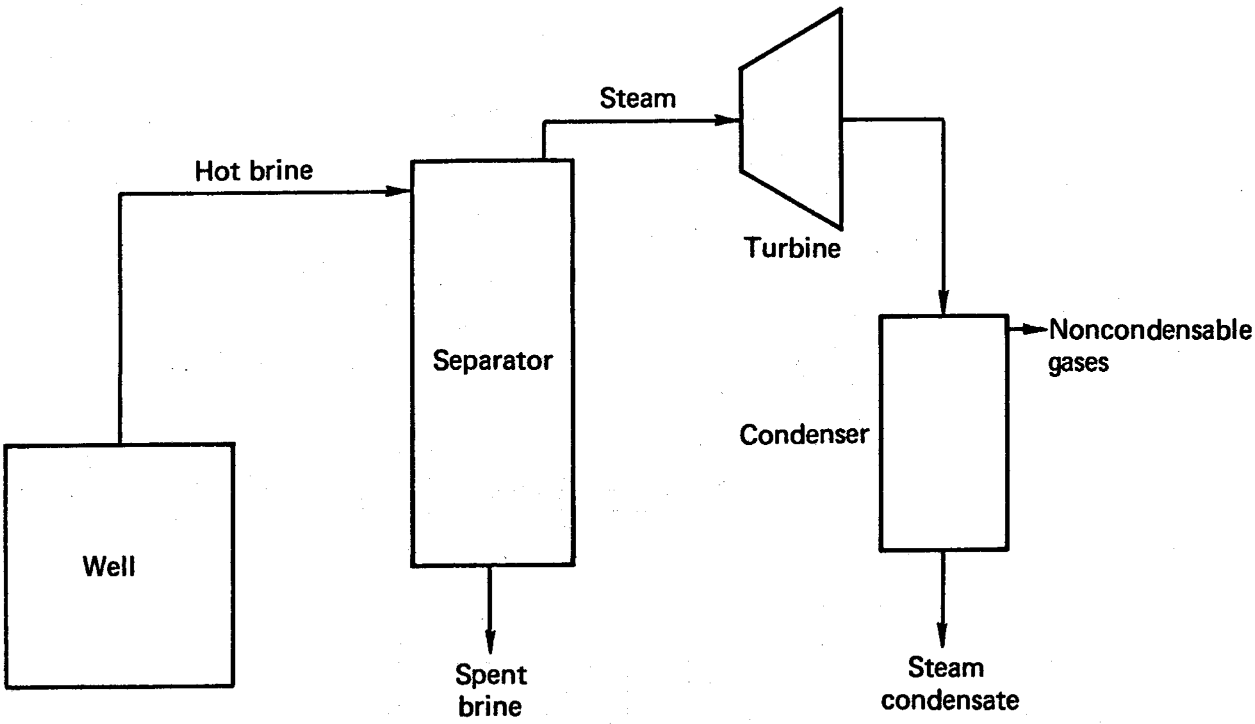

Fig. 2. Simplified schematic for process to generate power from geothermal brines using flashed steam separation.

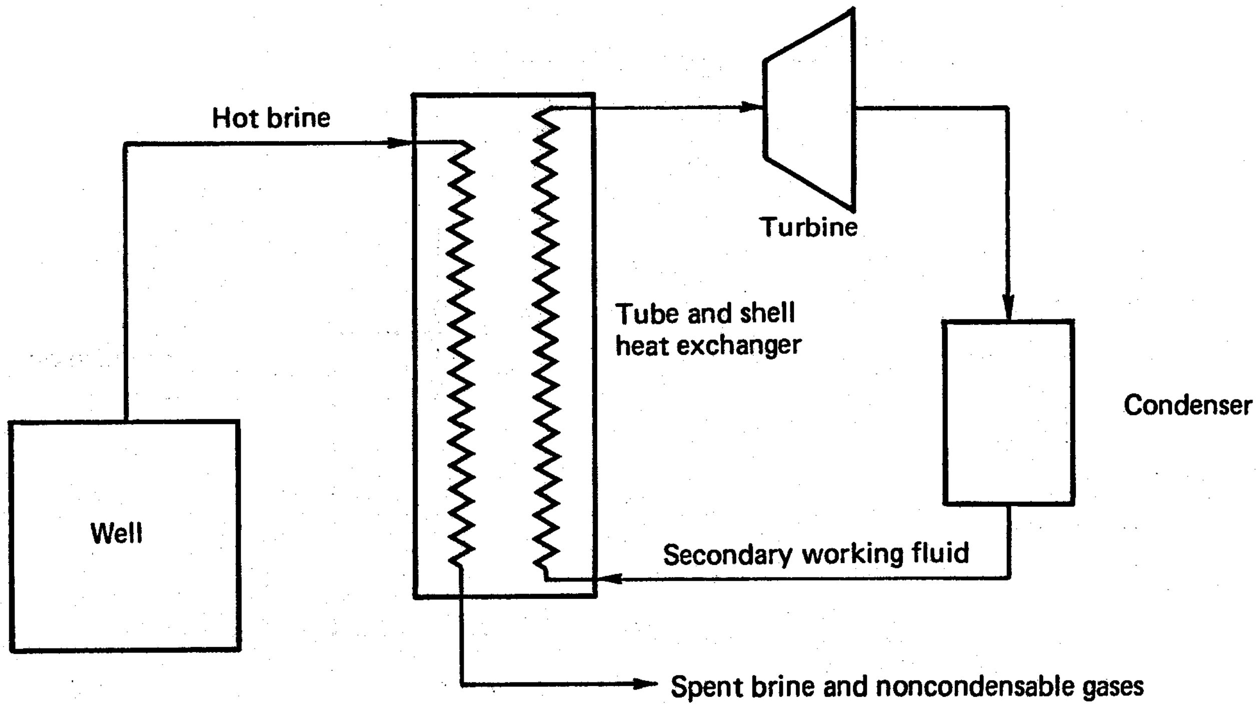

Fig. 3. Simplified schematic for process to generate power from geothermal brines using tube and shell heat exchanger to vaporize secondary working fluid. In this process, there is a single effluent stream containing both spent brine and noncondensable gases.

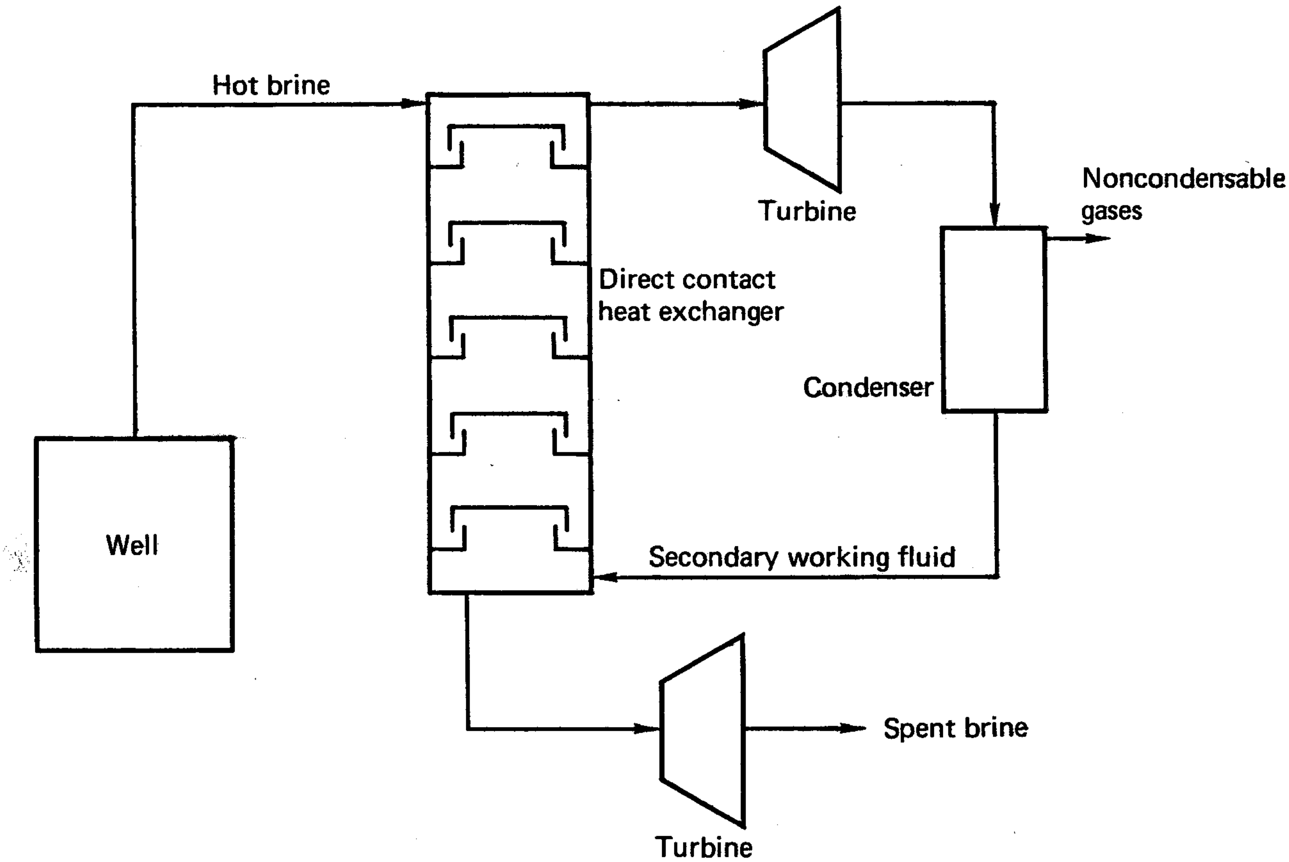

Fig. 4. Simplified schematic for process to generate power from geothermal brines using direct contact heat exchange to vaporize a secondary fluid.

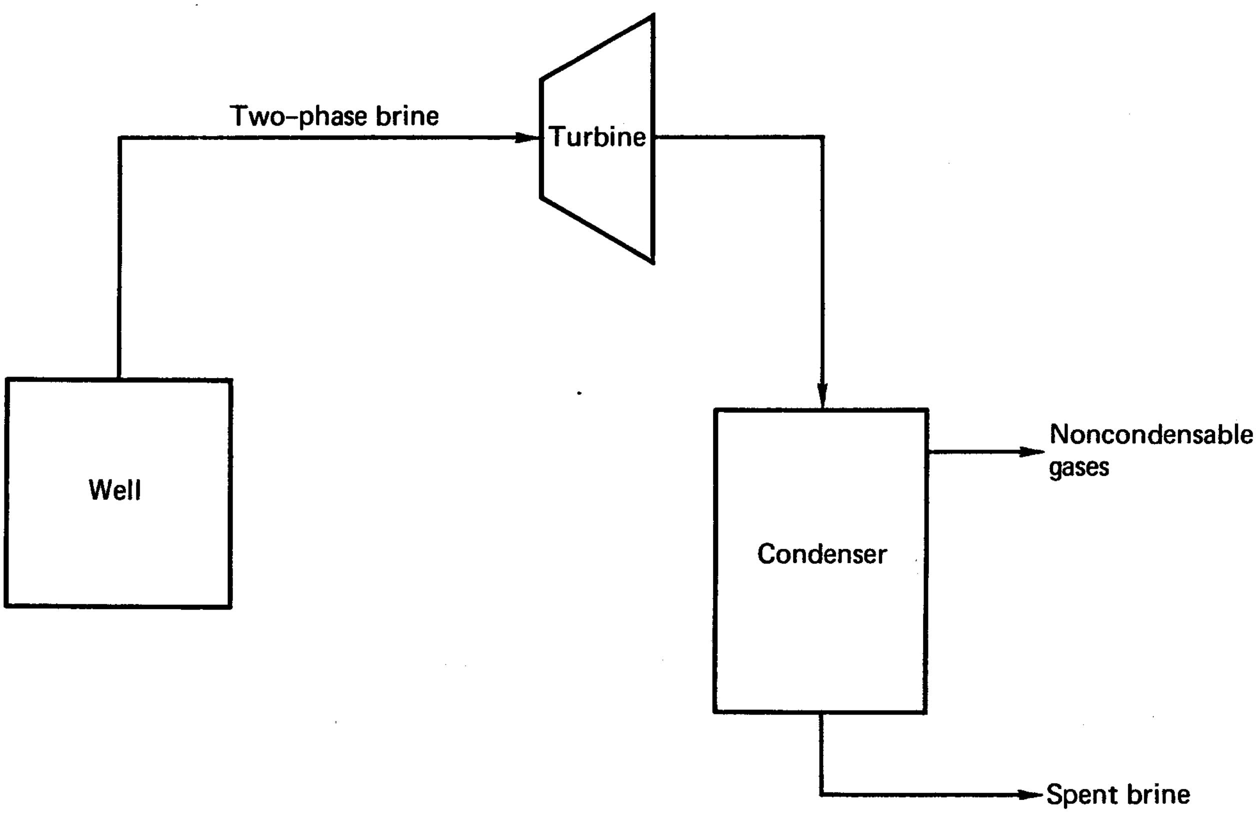

Fig. 5. Simplified schematic for process to generate power from geothermal brines using two-phase, liquid and steam, to drive a turbine.

ANTICIPATED ENVIRONMENTAL CONTROL PROBLEMS AND CONTROL NEEDS

Approximate quantities of effluents which may be produced by Imperial Valley power plants operating at an average power level of 100 MW are shown in Table 3. These values are approximate because the characteristics of geothermal brines are different in each well and can change over a period of time as fluid is produced from a well.

Evaluation of these characteristics together with environmental issues caused substantial concerns of subsidence and seismicity, management of liquid and gaseous wastes, and abatement of noise.[3, 4, 13, 14] Liquid waste disposal and H_2S control need priority attention. Preliminary estimates indicate that development of approximately 500 MW in the Imperial Valley would not result in valley wide average H_2S concentrations in excess of the ambient standard. Simple controls such as a tall stack could be used to disperse H_2S emissions from temporary facilities which could be phased out before development beyond 500 MW.

In FY 1978, the IVEP is expected to provide further definition of control needs for H_2S concentrations near emission points, subsidence effects and their significance, and cooling tower drift. Ongoing EPA studies on geothermal fluid compositions, projected new EPA emission (source) standards, and expected regulations relating to protection of water systems and disposal of toxic materials also will provide better definition of control needs.

Table 3. Characteristics of Imperial Valley power plants.[1]

Characteristic	Salton Sea KGRA	Other KGRA's
Power plant size		
• Capacity, MW	110	110
• Operation factor, %	90	90
• Average power level, MW	100	100
Land area per power plant for geothermal facilities, mi^2	0.03	0.03
Average downhole resource temperature, °C	285	190
Net power plant efficiency, %	14	10
Well field area per power plant, mi^2	1.25	2.50
Geothermal brine required, kg/kW–h	30	60
Geothermal brine injected, kg/kW–h		
• Flashed steam	21	45
• Confined flow	30	60
Steam condensate, kg/kW–h		
• Flashed steam	9	15
• Confined flow	0	0
Cooling water requirements, acre-ft/MW-yr	60	90
• Cooling water evaporation losses to the atmosphere	50	75
• Cooling water blowdown	10	15
Hydrogen sulfide emissions to the atmosphere,[a] g/kW–h		
• Flashed steam	1.2	2.4
• Confined flow	0	0

[a]Based on 20 ppm (wt) of H_2S in the brine.

ENVIRONMENTAL CONTROL TECHNOLOGIES: IDENTIFICATION

In this and following sections, those environmental control technologies under consideration or possibly applicable in the period covered in the forecast of developments are listed and described. Some information is included on control technologies in development.

Approaches now being developed for management of subsidence and induced seismicity include the following:

Subsidence Monitoring

- Establish baseline elevations, station by station, and their rates of change before development.

- Determine physical properties of subsurface formations for use in forecasts of the extent of subsidence.

• Monitor downhole changes in formation thickness or compaction to obtain an early warning, and forecast the possible extent of surface subsidence.

• Monitor surface subsidence to confirm forecasts and determine further control or remedial measures. This includes recognition and distinction between natural and man induced effects.

Subsidence Control

- Reduce fluid production.
- Increase fluid injection.
- Suspend production.
- Repair damage.

Seismicity Monitoring

- Establish baseline before development.
- Monitor to determine seismicity induced by development.

Seismicity Control

- Change the rates of fluid production.
- Change the rates of fluid injection.
- Suspend production.
- Repair damage.
- Build structures resistant to damage by earthquakes.

The major measures being considered for prevention and mitigation of environmental impacts in the areas of liquid waste control, H_2S control, and noise control are as follows:

Liquid Waste Control

- Inject total geothermal fluid into the geothermal reservoir for disposal.
- Inject residual brine from flashing operations into the geothermal reservoir for disposal.
- Inject combined effluents, residual brine, cooling system purge or blowdown, and condensate, into the geothermal reservoir for disposal.
- Evaporate accumulated geothermal fluid and/or blowdown in ponds.
- Dispose of cooling tower or spray pond blowdown water of acceptable quality into surface water draining to the Salton Sea.

H_2S Control

- Inject untreated total geothermal fluid into the geothermal reservoir for prevention of release of H_2S.
- Disperse atmospheric effluent gas, or "non-condensables," containing H_2S via a stack.
- Burn in air or flare effluent gas containing H_2S.
- Apply the Stretford Process (see Appendix C) for control of H_2S in effluent gas.

Noise Control

- Use insulating baffles or blankets during drilling.
- Zone-to-space noise sources sufficiently far from critical areas.

ENVIRONMENTAL CONTROL TECHNOLOGIES: SUBSIDENCE AND SEISMICITY

The occurence of subsidence following the withdrawal of fluids from underground reservoirs is well documented.[13, 15, 16] Two approaches for management of subsidence are recognized. One is to regulate the withdrawal of fluids so that subsidence is uniform and tolerable over a very large area. The second is to return fluids to appropriate formations to maintain pressure and thus minimize subsidence. However, quantitative relationships and modes for subsidence control are not well established. At the present time, some geothermal developers in the Imperial Valley are contemplating the use of closed-cycle binary power plants to provide, in part, full return of withdrawn fluid. This appears prudent as long as the potential for subsidence damage remains an uncertainty. However, return of less than the withdrawn amount may prove adequate and steam condensate from flashed geothermal fluid could be used for process cooling, i.e., cooling tower makeup, or otherwise.

There is a developing consensus that subsidence will not be a problem in the Imperial Valley for several years because of low early development. The reasoning follows: Pilot production, even at rates of 50 to 100 MW, requires little fluid relative to volume associated with the "reservoir" and average reservoir pressure changes will be small. It will also take time for compaction effects to be translated to the surface. However, the amounts and rates of subsidence must be monitored so that remedial action can be taken if required.

Tests of cores from geothermal wells are needed to determine the strength and porosity of materials in the formation. Selective placement of extensometers, casing collars, or radioactive bullets in geothermal wells is needed to measure compaction

(Brandt, Appendix A). This information would be useful in preparing computer models to predict subsidence and in making comparative or empirical predictions of subsidence.[16] Compaction measurements could provide early warning of excessive subsidence. Atherton *et al.* have prepared an extensive discussion of subsidence prediction.[15] Operators are now required to install benchmarks at each geothermal well and to tie them into the regional survey network used to monitor surface subsidence.[17,18]

The effect of fluid injection on earthquake activity can be judged from the history of liquid injection in oil fields and waste wells. Although there are thousands of oil field and waste injection wells, only two instances of fluid injection triggering earthquakes are reported in the literature.[19] One of these occurred following the injection of waste at Rocky Mountain Arsenal near Denver, and the other occurred near Rangely, Colorado, as a result of water injection into an oil field. In both of these cases the injection pressure was very high and probably exceeded the lithostatic pressure in the receiving formation. The geology and rock properties in these two areas are considerably different from those in the Imperial Valley. The reservoirs in the Imperial Valley are essentially at hydrostatic pressure and therefore accept fluids at low injection pressures, 500 psi measured at the surface. Therefore, the experience at these two sites is not likely to apply to the Imperial Valley.

The Imperial Valley has a long history of seismic activity which is known to correlate with the geothermal anomalies there.[4] Measurements are now being made to develop data about this natural pattern which would allow regulators to distinguish between the natural activity and activity which may be caused by development of the geothermal resources. In 1973, the United States Geological Survey (USGS) installed a 16-station telemetered network to record earthquake activity and establish its relationship to geothermal phenomena. In 1976, this network was augmented by six additional stations installed as part of the IVEP. This network has provided considerable data to establish the baseline of naturally occurring seismic events.

The Bureau of Reclamation has also installed a microseismic monitoring network on East Mesa to monitor microearthquake activity before and during production and injection operations. Up to April 1977, their data showed no relationship between microearthquake activity and well operations.[10]

As the Imperial Valley resources are developed, continued monitoring and assessment will be needed to determine if development causes any change in seismic activity. The USGS network seems to provide excellent information. However, it will probably have to be modified and expanded as development proceeds.

Proposed methods to control induced seismicity or mitigate the effects of seismic events include changing the rate of production or injection, suspending production, repairing damage, and building structures to withstand earthquakes.[18,20]

ENVIRONMENTAL CONTROL TECHNOLOGIES: LIQUID WASTE DISPOSAL

Disposal of Liquid Wastes from Power Plants

There are several techniques which might be considered for the disposal of liquid wastes from power plants operating on Imperial Valley brines.

Evaporation. Geothermal fluid and/or cooling water blowdown can be evaporated in ponds. Based on the brine requirements for a power plant generating 100 MW per year[1] and the evaporation rate of the Salton Sea[4] an evaporation pond with an area of 12 x 10^6 m^2 (3000 acres) would be required for a power plant operating on brines from the Salton Sea KGRA. In the other Imperial Valley KGRA's where brine temperatures are lower, the ponds would have to be twice as large for the same size power plant. In addition, from 4.2 x 10^8 kg (460,000 tons) to 8 x 10^9 kg (9,000,000 tons) of solids would be produced at plants operating off East Mesa (7,600 ppm TDS) and Salton Sea (300,000 ppm TDS) brine respectively. Disposal of these solids would also constitute a major problem. The estimates given above are based on the assumption that all of the brine is discharged to the evaporation pond. However, the actual size of the pond will also depend to some extent on the source of the cooling water, e.g., steam condensate, Colorado River, or spent irrigation water, used for the plant. Evaporation ponds have the disadvantage that they may spring leaks which would contaminate adjacent areas. There is particular danger that dikes and seals on ponds may be ruptured by seismic activity in the Imperial Valley. Therefore, evaporation does not seem to be an attractive method to dispose of the bulk of the waste fluids from large facilities operating in the Imperial Valley.

Cooling Water Discharge. Cooling water blowdown can be discharged to surface waters flowing to the Salton Sea. This technique seems acceptable for experimental facilities using irrigation water or steam condensate. However, for large-scale development requiring the use of agricultural waste water, water quality standards will prevent the discharge of cooling water blowdown to the Salton Sea. The feasibility of this disposal technique will depend to a large extent on the amount of steam condensate available for cooling water makeup and on the composition of the resulting blowdown

Injection into Underground Reservoir. This technique seems to be the most practical method to dispose of liquid wastes from geothermal power plants. Its advantages are as follows:

- It isolates the liquid waste from the surface environment and thus prevents pollution of the surface environment.
- It minimizes subsidence caused by the production of geothermal fluids.
- It minimizes the decline in reservoir pressure which occurs when geothermal fluids are produced. Failure to replenish reservoir fluid by injection causes the reservoir pressure to decline unless there is rapid natural recharge, which is not always the case. A decline in reservoir fluid pressure will cause a decline in the productivity of wells.
- It provides a mechanism to recover additional heat from the reservoir. The injected waste is a working fluid which scavenges heat from the reservoir rocks as it migrates through the formation on its way back to the production wells.

Some liquid wastes will require pretreatment to ensure compatability with other wastes on mixing and with the well and the underground formations. In most cases, this treatment will have to be tailored to the chemistry of the wastes produced at each specific site. If solids are removed prior to injection, they must be disposed of. However, these solids contain valuable minerals[21] which might be recovered to offset disposal costs. A more detailed discussion of injection techniques is presented in Appendix B.

Current Subsurface Injection and Liquid Waste Disposal Practices in Imperial Valley KGRA's

Salton Sea. Fluid for the San Diego Gas and Electric Company's GLEF was drawn from either Magmamax No. 1 well or Woolsey No. 1 well since July 1976, and spent brine from this facility disposed of by injection into two disposal wells, Magmamax No. 2 and No. 3, mainly No. 3. Steam condensate was either injected with the spent brine or used as cooling water makeup. Cooling water blowdown is discharged to the Salton Sea or injected with spent brine.

Magmamax No. 1 brine contains about 180,000 ppm TDS and has a wellhead temperature of about 220° C. Woolsey No. 1 brine contains about 160,000 ppm TDS and has a wellhead temperature of about 190° C. When brine is flashed to produce steam in the GLEF, the brine temperature drops to about 100° C, causing the precipitation of an iron-rich amorphous silica and other sparingly soluble metallic salts.[22-25] These solids have plugged Magmamax No. 3 injection well several times, probably by depositing in the slots of the well casing and in the pores of the adjacent formation. It is possible to inhibit the precipitation of amorphous silica solids by acidifying the brine to pH <4.5.[23,24] However, if this acidified brine is injected, it can react with limestone ($CaCO_3$ and $MgCO_3$) in the formation. In the presence of excess $CaCO_3$, the pH of the brine will increase to about 5.6.[26] At that pH amorphous silica and other solids can form[22-25] and plug pores in the formation.

The steam condensate from the GLEF contains CO_3^{2-} and has a high pH, 8.5–9.0. When this condensate is mixed with the spent brine for disposal, sparingly soluble carbonates and hydroxides precipitate to increase the suspended solids load of the spent brine. Because these additional solids increase the plugging problem encountered during injection, most of the steam condensate is now used for cooling water makeup.

Irrigation water taken from the Colorado River is the primary source of cooling water for the GLEF. This water contains about 350 ppm of SO_4^{2-}, which concentrates in the cooling water blowdown. If the cooling water blowdown is mixed with spent brine, SO_4^{2-} will react with Ba^{2+} and Ca^{2+} in the brine to form $BaSO_4$ and $CaSO_4$ precipitates. These precipitates, which are very difficult to redissolve, can also plug the disposal well and the adjacent formation during injection. Therefore, the cooling water blowdown is drained to the Salton Sea for disposal.

East Mesa, U.S. Bureau of Reclamation (USBR) Portion. The geothermal fluid in the portion of the East Mesa Field varies widely in quality from well to well.[10] The range of TDS in the fluid ranges from 1,600 to 26,000 ppm. The USBR has used a polyethylene lined holding pond to store waste brine prior to injection. They used well No. 5-1 as an injection well for several years.[10]

East Mesa, Magma Power Company Portion. It is reported that Electrohydraulics Corporation has installed a portable geothermal waste treatment facility for Magma Electric, Inc.[27] The wellhead geothermal fluid is subjected to a high voltage spark-generated shockwave that reportedly precipitates soluble constituents, which are then removed by microstrainers. No injection test has been reported in this part of East Mesa.

East Mesa, Republic Geothermal Portion. Republic Geothermal injected fluid from wells No. 38-30 and No. 16-29 into well No. 18-28 from July through October 1977. After the fluid was flashed in a separator, the liquid waste was passed through a settling pond and a 50 μm filter to remove solids. Initial well plugging problems caused by $CaCO_3$ were overcome by acid treatment and the installation of finer 19-μm filters. Further experiments to prevent plugging by using inhibitors and acidifying the waste to pH 6 are currently under way.

Injection appears to be successful as a liquid waste control technique in the limited tests so far. Republic anticipates that the three injectors to be used for the 10 MW plant, including well No. 18-28, should be able to handle the residual 1,800,000 kg/h, about 300,000 bbl/day, of fluid at very low wellhead injection pressures due to the high permeability sands present in the 600–1,500 m injection zone.

Heber. Injection of the liquid waste, together with dissolved gases, is proposed for pollution control at Heber. Chevron Oil Company, the resource producer, expects to produce at least 200 MW net electricity from the Heber field. Chevron plans to drill at least 50 production and 25 injection wells for the 200 MWe capacity. The production wells are to be located in an approximately circular array about 610 m in diameter in the center of the geothermal anomaly. The injectors will be located in a large circular array of about 6.4 km in diameter and concentric with the production well array. Several wells will be drilled directionally from each surface location, called a production or injection island. For the 50 MWe demonstration plant, Chevron intends to have 13 production and 7 injection wells. At present there are 10 geothermal wells at Heber on which production and injection tests were made.

In a 10-month test conducted during 1974–1975, geothermal fluid produced from the wells Holtz No. 1 and Nowlin No. 1 was injected into the Holtz No. 2 well. The production-to-injection path was a closed system. The fluid was cooled to as low as 88°C before injection because of heat loss in the wellbore and surface plumbing. During 1976, Chevron injected cooled geothermal water in Holtz No. 2 well for short periods. In January 1978, Chevron intends to start producing from the well J. D. Jackson No. 1 and injecting into the Holtz No. 1 well, and to monitor the injection performance. This test is expected to be a well-instrumented, long-term test. In the injection tests carried out so far, no severe scaling, corrosion, or loss of injectivity in wells has been experienced.

ENVIRONMENTAL CONTROL TECHNOLOGIES: HYDROGEN SULFIDE

Control Upstream from Power Plant

Removal of H_2S from the geothermal fluid before it reaches the power plant may be the best control method. Advantages are that upstream removal eliminates the need to treat separate effluent streams, eliminates scaling caused by heavy metal sulfides, prevents corrosion caused by H_2S, and allows the power plant design and operation to be independent from the H_2S abatement process. However, it does involve the treatment of large amounts of fluid which requires that any reagents used must be either very cheap or effective in very small quantities.

Although there has been little development work done on upstream abatement processes to date, oxidation of H_2S to free S seems to be the most promising method to remove the gas from the hot brine.[28, 29] There are many potentially good oxidizing processes for the job including the addition of O_2 as proposed by Dow Chemical Company.[30, 31] One disadvantage of this technique is that the oxidation of H_2S can form SO_4^{2-}. The SO_4^{2-} can then react with Ca^{2+} and Ba^{2+} in the brine to form scale composed of $CaSO_4$ and $BaSO_4$. This reaction can be minimized by selecting the proper oxidizing agent and by controlling the concentration of oxidant in the brine. Another disadvantage is that oxidation will also increase corrosion rates in equipment located downstream.

Control in Power Plants

Plants designed to generate electrical power from geothermal brines found in the Imperial Valley will have three main types of effluents which contain H_2S. These are spent brine, steam condensate, and noncondensable gases. The optimum control technique to be used on each of those effluents will depend to some extent on the source of the brine, the design of the power conversion process, and the subsequent use of the effluent. Applicable techniques for each effluent are as follows:

Spent Brine. The most applicable technique for H_2S control is injection as discussed under liquid waste control technology.

Steam. H_2S in steam can be removed by precipitation. If the EIC Corporation (EIC) $CuSO_4$ process proves to be feasible for use on steam at The Geysers, it should also be applicable to steam flashed from brines when modified to compensate for differences in chemical composition, flow capacities, and operating temperatures and pressures. A description of the EIC $CuSO_4$ process is given in Appendix C.

Steam Condensate. H_2S in steam condensate can be disposed of by injection as discussed under liquid waste control technology, or by direct oxidation. The second technique would be particularly applicable if the condensate is used for cooling water makeup, irrigation or domestic consumption. Some oxidation processes which may be applicable are:

- Injection of Cl_2.
- Injection of SO_2 to oxidize H_2S to S by the Claus reaction.
- Injection of SO_2 and air or oxygen.
- Injection of air or oxygen with or without a catalyst.
- Controlled potential electrolysis.

Noncondensable Gases. Among techniques for removing H_2S from noncondensable gases, the following four are particularly appropriate.

1. *Dispersal by tall stack.* This is the technique now employed at the GLEF and should be adequate for small (<10 MW) experimental facilities where the noncondensable gases are separated from the brine. However, more sophisticated techniques may be required for large power plants, particularly in the Salton Sea KGRA.

2. *Reinjection of the total noncondensable gas fraction together with or separate from the spent brine.* This process would be particularly applicable to closed binary systems where the noncondensable gases are completely soluble in the spent brine.

3. *Burning the noncondensable gas stream.* In this process, H_2S would be oxidized as follows:

$$2\,H_2S + 3\,O_2 = 2\,SO_2 + 2\,H_2O$$

This process has the disadvantage that it may present a secondary disposal problem if SO_2 concentrations exceed ambient air quality standards. Also, fuel would have to be supplied to the noncondensable gas stream because the noncondensable gases from Imperial Valley brines are primarily CO_2 (>90%), which does not burn.

4. *Reaction in scrubber system.* Several such processes might be considered:

- Reaction with a base as shown by the following equations

$$H_2S + OH^- = HS^- + H_2O$$

$$HS^- + OH^- = S^{2-} + H_2O$$

This process does not seem practical because of the high CO_2 concentrations found in the noncondensable gas fraction from Imperial Valley brines. The CO_2 would react as follows:

$$CO_2 + H_2O = H_2CO_3$$

$$H_2CO_3 + OH^- = HCO_3^- + H_2O$$

$$H_2CO_3(\text{excess}) = H^+ + HCO_3^-$$

These reactions consume base, lower the pH of the solution, and thus decrease the efficiency of the H_2S reactions.

- Reaction with a metal ion to form an insoluble sulfide. The EIC $CuSO_4$ process being developed for use on steam at The Geysers is probably applicable to noncondensable gas streams.
- Reaction with oxidizing agents. Processes incorporating the use of oxidizing agents (SO_2, Cl_2, O_2, etc.) might be applicable. At present, the Stretford process described in Appendix C looks particularly promising.

Controls Presently Used in Imperial Valley

Geothermal brines in the Imperial Valley contain hydrogen sulfide in concentrations ranging from one ppm to about 50 ppm.[10,19,22,32,33] Therefore, only minimal H_2S abatement has been required on the experimental facilities operating to date. At East Mesa, reported H_2S concentrations average <2 ppm in the brines.[10] At the Bureau of Mines desalination plant and DOE's Geothermal Component Test Facility, this H_2S was either vented directly to the atmosphere with the noncondensable gases or discharged into a holding pond with the liquid effluents.

At the San Diego Gas and Electricity Company GLEF, H_2S concentrations up to 30 ppm have been reported in brine from Magmamax No. 1 Well.[22] The three effluent streams which contain H_2S are spent brine, steam condensate, and noncondensable gases. At this facility the spent brine is injected underground. The steam condensate is sometimes injected with the spent brine and sometimes used for cooling water makeup. When the condensate is used for cooling water makeup, the H_2S present is discharged into a spray pond with the condensate. Part of this H_2S is oxidized to other sulfur compounds in the spray pond while the remainder is discharged to the atmosphere via the spray nozzles. The H_2S in the noncondensable gases is discharged to the atmosphere through a 130 ft stack. Concentrations of H_2S up to 3,500 ppm have been measured in the stack gases. However, quantitative data on either the rate of H_2S emission or on the total emissions are not available at this time. The odor of H_2S is frequently detectable in the immediate vicinity of the facility. However, at an air monitoring station approximately one kilometer away, and intermittently downwind, the H_2S concentration has never exceeded 10 ppb. For comparison, the California Ambient Air Quality standard is 0.03 ppm, one hour average.

ENVIRONMENTAL CONTROL TECHNOLOGIES: NOISE

Noise levels in power plants proposed for the Imperial Valley are expected to be similar to those in power plants now operating at The Geysers, as shown in Table 4.[34]

The impact of the noise from power plants can be minimized by isolating the plants from urban areas as proposed in three Imperial County documents[1] that place limitations on the siting of geothermal operations. The county also has a "Geothermal Element" to the Imperial County General Plan which presents county goals and policies concerning geothermal development.

Table 4. A-weighted sound levels, dBA, from various noise sources at The Geysers, for typical power plant at normal operation and full load.

Noise source description	Distance, ft	Sound level, dBA (re 20 MPa)
Cooling tower	5-10	81-85
Outside turbine/generator building	25	70-75
Steam jet gas ejector (SJGE)[a]	3-10	88-93
Around turbine/generator unit inside building	3-5	92-94
Random locations on turbine/generator floor	–	90-94
At plant fence line, distance from noise producing surfaces	20-70	67-83
Total plant noise[a]	500	60 ± 5

[a]Total noise from plant at distances greater than ≈200 ft is primarily cooling tower only. The noise from SJGE falls off rapidly as a function of distance from source because of small radiating surface area and high frequency content.

The zones in which geothermal operations would be permitted according to the Imperial County Current Zoning Plan and the Ultimate Land Use Plan are mainly agriculture, industry, and recreation zones. The Imperial County department of public works document *Terms, Conditions, Standards, and Application Procedures for Initial Geothermal Development,* lists minimum separation distances, or buffer zones, between a geothermal well and various facilities, e.g., hospital, 1 mi; school, 1/4 mi. Buffer zones for commercial geothermal power plants have not been established but are expected to be similar to those for geothermal wells.

The institutional criteria included in the siting documents are:

- Power plant operations are not located in the wildlife refuge and critical habitat areas.
- Power plant operations are sited in accordance with the Imperial Valley Current Zoning Plan and Ultimate Land Use Plan.
- Power plant operations are excluded from buffer zones surrounding the following facilities:

Facility	Buffer distance (mi)
Hospital	1.0
School	0.5
Municipal boundary	0.5

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APPENDIX A. RECOMMENDATIONS FOR SUBSIDENCE EVALUATION OF GEOTHERMAL RESERVOIRS

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The following are recommendations for the evaluation of subsidence that may result from the development of subterranean, geothermal reservoirs. More detailed and more specific recommendations can be developed for particular sites. The recommendations can be carried out with state-of-the-art technology.

Any withdrawal from a subterranean zone of fluid that causes a decrease in interstitial fluid pressure causes subsidence of that zone. The subsidence may range from a small amount to a large one depending on the pressure change of the interstitial fluid, the strength properties of the rock formations of the producing zone, the temperature change of the producing zone, and the initial stress state of the producing zone. Formations that lie above the producing zone may follow the movement of the producing zone or they may partially or fully bridge it. In general, then, the subsidence at ground level is less than the subsidence of the producing zone and at worst is not more than the subsidence of the producing zone.

Injection of fluid under pressure into the producing zone to maintain interstitial fluid pressure may partially offset subsidence. However, once the interstitial fluid pressure in the producing zone has been decreased from an initial value, it is not possible to recover all the subsidence of this zone by bringing the pressure of the interstitial fluid back to its initial value.

To develop a geothermal reservoir successfully, we need to determine how much subsidence can be expected to take place during the life of the reservoir. Since an accurate evaluation of the subsidence potential of a reservoir is an expensive activity it is recommended that the evaluation of the subsidence potential be divided into different levels of accuracy. For example, the maximum subsidence of a producing zone would be obtained if all the interconnected pore spaces of the zone would collapse. Furthermore, if the overburden does not have significant strength, this maximum subsidence of the producing zone would be translated to ground level.

If the maximum subsidence calculated in this way is tolerable then the subsidence problem eliminates itself. On the other hand, if the maximum subsidence that is calculated in this manner is too large, more accurate calculations will need to be made. In this connection, it is necessary to consider the location of the geothermal site. In the cases where damage due to subsidence has been severe, the site usually has been above an oil producing zone located close to an ocean or other water bodies and is in developed areas. Usually, the producing zones have been thick so that even a small amount of subsidence per foot of vertical depth could cause large ground level changes. On the other hand, if a geothermal site were located far from bodies of water and if there were few buildings or aqueducts in the area, a substantial subsidence could be tolerated without significant damage. Thus, subsidence that might cause severe damage at one location might cause no damage at all at an entirely different location. Consequently, before a large-scale geothermal project is undertaken, it is recommended that the amount of subsidence that can be tolerated be determined in advance. If the amount of subsidence that can be tolerated is greater than the maximum possible subsidence, the problem resolves itself and only a modest amount of expenditure may need to be taken to monitor such subsidence during the life of the geothermal reservoir.

A more accurate evaluation of subsidence may be required. Even in the above mentioned case we may wish to obtain a more accurate prediction of subsidence to prove that indeed we can make accurate predictions. However, if we do wish to obtain accurate subsidence predictions and measurements, the cost to make these measurements and predictions would be substantial.

Geothermal reservoirs may be located in areas that are seismically active. Consequently, the problem of accurately measuring subsidence is made more difficult because we need to distinguish between subsidence caused by the development of a geothermal reservoir and subsidence from natural causes. Ground movement resulting from the natural causes has taken place over geologic time, and in principle, we are already too late to obtain a sound data base from which we can predict naturally occurring subsidence. Unfortunately historical data for the yearly ground movement of the area where there would be geothermal development are nearly nonexistent.

We may have ground surface measurements that were made over a period of years, and in some places, decades, but we do not have long-term measurements spanning a century or more. Thus, we should not be surprised if during the geothermal development of a reservoir we suddenly have ground movement from natural causes that is larger than originally anticipated. Furthermore, we need to develop the capability to discriminate this ground level change from ground level changes caused by reservoir subsidence.

Because we most likely will be able to make only a limited number of ground movement measurements, it becomes important to locate the measuring stations at optimum places. During the past few years improvements have been made in the theory for optimizing the location, and number of stations and for the frequency of measurements. For example, Professor J. Brewer at the University of California at Davis, has done considerable work in the development of optimization theory for data gathering. It is recommended that optimization theory be integrated at an early date with the field measurements to insure that data are gathered in an optimum fashion.

The next level of accuracy in our estimate of subsidence would make use of published data of the bulk modulus of formations similar to the formations from which we withdraw the hot reservoir fluids. Using, for example, the theory developed by Geertsma, we can calculate the subsidence of the producing zone from the relation between the bulk modulus of the formation and the changes in the interstitial fluid pressure. Here again, we can take the worst possible value and see if it is below our acceptable level of subsidence. If it is, the problem may resolve itself at relatively low cost because the calculations can be made in a few days. However, if we need more accurate data, we need to obtain either bulk modulus data or triaxial strength test data of the actual formations that are being produced. From a technical point of view, if we do need to predict subsidence accurately, then we need to obtain rubber sleeve cores of the producing formations. We should have cores from the formations that are being produced from two or three holes in the geothermal reservoir. Even cores from two to three holes represents a modest amount of data if one considers that a geothermal reservoir may have considerable aerial extent. It is clear that if there are large geological changes in various portions of the reservoir, then rubber sleeve cores from three test holes would not really be sufficient to determine subsidence accurately.

In addition to obtaining cores from the producing zone, it is highly desirable to obtain core material from the formations overlaying the geothermal reservoir. If the formations above the geothermal reservoir are strong, the subsidence produced in the producing zone may not be translated to ground level. On the other hand, if these formations have low strength, the subsidence of the producing zone may be observed also at ground level. Thus, the strength properties of the formations above the producing zone need to be taken into account in an accurate evaluation of subsidence.

Often considerable expenses are layed out in obtaining cores while fewer funds are earmarked for proper handling, packaging and shipping of cores from the drilling site to the laboratory where the samples will be tested. Sometimes cores are so damaged during transportation and storage that the tests lose much of their meaning. It is recommended that prior to the coring, a coordinated program be set up for coring the formations, packaging the cores, transporting the cores and testing the cores. This means that the test equipment needs to be operable with trained personnel who have been informed under what conditions the tests will need to be made. Meaningful tests most likely will be by triaxial tests under simulated overburden and interstitial pressures as well as simulated temperature changes of the cores. The tests need to be made relatively slowly so that we get deformation data that resemble the conditions of subsidence. This means that the tests may have to range from about one-half day to several days to insure that the cores are strained slowly. Dynamic tests that make use of acoustic measurements are not expected to give valid results for subsidence measurements because of the difference between the strength characteristics of rocks under dynamic and static conditions.

When the strength properties of the rocks are obtained, the subsidence of the reservoir can be calculated with different levels of accuracy depending on the model that is used for the reservoir. The most important reservoir variation is the decrease of the reservoir pressure as a function of aerial extent and of time. A second variable is the change in temperature of the reservoir. A simplistic model of the producing zone assumes that the formations move only vertically when the interstitial fluid pressure is decreased. More sophisticated models would take into account the aerial extent of the reservoir with different subsidence levels at different locations in the reservoir. A still more sophisticated model would take into account the effect of the possible bridging action of the formations that are above the producing zone.

Any subsidence modeling program also should have as an objective the determination of the accuracy of the model and the sensitivity of the model to material properties and pressure changes.

Eventually we should like to use these models for the calculation of subsidence prior to the development of a geothermal field. Such predictions might be helpful in the development of environmental impact studies and in the construction of any facilities that may be necessary during the life of a geothermal field.

It is recommended that the accuracy of the various predictions be checked against actual field measurements. Measurements of the ground surface level need to be taken because they are the most direct measurements that affect buildings, structures and canals that may be present in the geothermal development area. However, ground surface measurements are not the most valuable measurements to understand the subsidence behaviour of a reservoir. Downhole measurements that measure the deformation of the producing zone are far more helpful because they give us the deformations of particular zones rather than a single value that a ground level measurement gives.

The process of obtaining good quality downhole measurements is expensive. Ideally, measurement holes should be available with extensometers placed at various depths to measure the subsidence of the various formations. Such measurements would be helpful in evaluating the accuracy of the subsidence models. If it is too costly to install special holes with extensometers for subsidence measurements, then cheaper, but less accurate methods are available. For example, in the completion of a geothermal well, the space between the slotted liner and the formation probably will be filled by a gravel pack or a graded sand pack to enable formation fines to bridge. Further up the hole, the casing may be cemented or packed. By proper selection of the packing of the producing string in the well bore and by having external upset collars on the liner, a strong bond can be obtained between the formations and the producing string. Most, or all of the subsidence of the producing formations would then be translated to the producing string by shortening of the string. By making measurements of the location of the collars we can measure the subsidence at various depths through the life of the reservoir. These measurements can be improved by proper design of the collars.

Another method is to place radioactive bullets in the formation prior to casing the hole. The dostances between the radioactive bullets would then be determined at various times throughout the producing life of the reservoir.

Measurement of the changes in distance between casing collars is not a foolproof method to measure subsidence. Nevertheless, with some foresight the method is sufficiently cheap that there appears to be no good reason not to make the measurements.

In conclusion, the above recommendations can be carried out with present state-of-the-art technology. Several areas of research can be pursued to delineate more accurately the various factors affecting subsidence. In proceeding with the development of geothermal reservoirs in the near future, it appears prudent to use at least present state-of-the-art methodologies to predict subsidence.

APPENDIX B. INJECTION OF LIQUID WASTES

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Injection is a well established technique for disposing of liquid wastes.[35] In practice, the liquid waste is injected through wells into a permeable subsurface formation by pumping or gravity flow. Injection wells may be converted production wells or wells drilled solely for injection. Unless the reservoir rock is very competent, a cased hole is used with a slotted liner in the injection zone. The waste can be injected back into the geothermal reservoir from which it was produced or to any other reservoir.

Injection seems to be the only practical method to dispose of liquid wastes from geothermal power plants operating in the Imperial Valley. It has several advantages over other disposal techniques.

- It isolates the liquid waste from the surface environment and thus prevents pollution of the surface environment.
- It minimizes subsidence caused by the production of geothermal fluids.
- It minimizes the decline in reservoir pressure which occurs when geothermal fluids are produced. Failure to replenish reservoir fluid by injection causes a decline in reservoir pressure unless there is a rapid natural recharge which is not always the case. Any decline in reservoir fluid pressure causes a decline in the productivity of wells.
- It provides a mechanism to recover additional heat stored in the reservoir. The injected waste is a working fluid which scavenges heat from the reservoir rocks as it migrates through the formation on its way back to the production wells.

Fluid injection into subsurface reservoirs is well established in the petroleum industry where it has been practiced for many decades. However, waste disposal is not always the main reason for reinjection in a petroleum reservoir—reservoir pressure maintenance, sweeping of oil towards the producing wells, improving well productivity, increasing overall recovery from the reservoir, etc., may be the primary reasons. Besides ordinary water and gas, hot water, steam and various chemicals are often injected into petroleum reservoirs. Besides the petroleum industry, many other industries have adopted subsurface injection of liquid wastes for preventing water pollution. Reinjection into geothermal reservoirs was first attempted in the early 1960s. Since then significant improvement has taken place in the technology of reinjection, particularly in the treatment of injection fluid to prevent formation plugging.

Successful tests of injection of geothermal wastes have been performed in a number of geothermal fields in the United States and abroad, for example, The Geysers, East Mesa, Heber and Niland fields in California; Valles Caldera field in New Mexico; Ahuachapan field in El Salvador; Wairakei field in New Zealand; Matsukawa and Otake fields in Japan.

There are a number of criteria that need to be evaluated before implementing an injection scheme including the cost of injection versus other methods of disposal, the pressure required to inject at a certain rate, and the decline of injectivity with time. It is also necessary to determine the geological suitability of the reservoir for injection. The reservoir must have a relatively impermeable cap rock, which can prevent the waste from moving upward and polluting ground water aquifers. Fracture zones and faults may cause upward mobility of the waste and consequent pollution.

The optimum reinjection scheme should involve injection sites and rates such that the travel path and time for the flow of water from injectors to producers is maximized. This allows maximum reheating of the injected waste before it reaches the production wells. At the same time, liquid wastes should be injected close to the producing reservoir so that the decline in reservoir pressure with time is minimized. The key factor which determines the optimum injection plan is the variation, both areal and vertical, of the water temperature and the permeability in the reservoir.

During injection if the pore fluid pressure exceeds the hydrostatic pressure for the area, it is possible to induce seismic activity in preexisting faults or major fracture zones near the injection zone. Only two such incidences have been reported in the literature[36]: at Rangely, Colorado, a number of earthquakes occurred as a result of water injection in an oil field; and at Denver, Colorado, earthquakes were caused as a consequence of subsurface injection of waste from the Rocky Mountain Arsenal. However, so far no earthquake activity has been linked to injection in any geothermal field. Possibility of earthquakes can be minimized by not exceeding the original pore pressure of the fluids, particularly if there is a fault near the injection area.

An injection well should be completed carefully so as to isolate the injection well from shallow, fresh water aquifers. A poor cement job behind casings can result in upward migration of water from geothermal reservoirs into the shallow aquifers. Any abandoned well near an injection well may provide a pathway allowing the waste to migrate to shallow fresh water aquifers. Corrosion of liners and uncemented or poorly cemented portions of the casing in an injection well may provide pathways for the waste to flow into the ground water aquifers.

Cooling and pressure decline around the injection wellbore cause formation plugging due to the deposition of some of the dissolved and suspended solids present in the water. This reduces injectivity. In order to maintain the injection rate, pressure has to be increased. Increase in injection pressure increases operating cost and technical difficulties. If the injection system reaches its maximum pressure capacity, more injection wells may need to be drilled or the old wells stimulated to maintain the total injection rate. This escalates the field development cost. There is no simple way as yet to estimate such gradual loss of injectivity with time. The only sure means of assessing injection potential is to inject continuously in a reservoir for an extended period, at least for a few months, and monitor wellhead injection pressure versus flow rate.

Efficiency of any injection operation depends on the physical, chemical and thermodynamic characteristics of the waste fluid, the reservoir fluids and the reservoir rock. There can be various types of plugging of the porespaces around the injection well bore due to the interaction between the waste and the formation or the waste and the reservoir fluid. The problems of formation plugging, scaling in the injection lines and well bore, and corrosion of pipes are essentially chemical in nature.

Scaling and formation plugging can be caused by precipitation of minerals, water-formation incompatibility such as swelling of clays, and bacterial growth. Scaling can be caused by one or more of the following reactions[37,38]: precipitation and polymerization of silica and silicates; precipitation of alkaline earths as insoluble carbonates, sulfates and hydroxides; precipitation of heavy metals as sulfides; and precipitation of redox reaction products. Silica and calcium carbonate are the principle constituents likely to cause pipe scaling and formation plugging.

To ensure success of a subsurface disposal operation, surface pretreatment of the waste water is required. Generally the pretreatment operation can be categorized as follows[37]:

- Solids separation which may involve processes such as oxidation, reduction, precipitation, pH control, addition of coagulants, settling, and filtration.
- Corrosion control which may involve pH control, deaeration, H_2S removal, and use of inhibitors.
- Degassification which may involve pH control, deaeration, oxidation, and precipitation.
- The addition of bactericides and application of an electrical potential may also help to control corrosion and the formation of solids.

One of the major deposits from geothermal effluents is silica. However, monomeric silica in solution will not precipitate nor adhere until it starts to polymerize. A reduction in polymerization can be achieved in several ways:

- By maintaining a sufficiently high temperature to keep the solubility of silica above the supersaturation level.
- By reducing turbulence in order to avoid increments in the velocity gradients and collision of particles which may cause increased polymerization.
- By lowering the pH of the solution. A reduction in pH below 6.5 causes a substantial decrease in polymerization.

Silica-laden discharge waters have been successfully treated with slaked lime to precipitate silica and any arsenic, if present.[39] The waste water in the Otake geothermal field in Japan is ponded for about one hour during which time formation of colloidal silica takes place. After this polymerization ceases, the water can then be disposed of without serious silica scaling problems.[40] Various scale inhibitors, polyelectrolytes, esters of phosphoric acid, phosphorates, etc. have been used to slow down the precipitation rate of calcium carbonate.[41] A glassy phosphate called Calgon has been used to prevent scale and control corrosion.[42]

While prevention of scaling can be achieved by proper treatment of the waste, it is also possible to remove scales. Silica scale has been successfully removed from a wellhead in the Matsukawa field in Japan by allowing the scale to react with concentrated NaOH.[43] The scale was completely removed in 30 minutes although it was necessary to maintain a high temperature and pressure. Shock treatment has been reported to be successful in resolving the plugging problem. It consists of subjecting the formation to an almost instantaneous applied pressure differential, implosion, for the purpose of loosening the material plugging the formation and sustaining this differential for a period of time.[44]

Corrosion rates in the reinjection system are a function of temperature, flow rate, well depth, pressure, brine chemistry, pH, and the concentration of dissolved gases such as O_2, CO_2, H_2S, and NH_3. Also, high salinity tends to accelerate electrolytic corrosion by increasing the conductivity of the medium. Although corrosion will occur in reinjection systems, it can probably be controlled using conventional techniques which involve the use of resistant alloys, inhibitors, and protective coatings, and also the control of pH, oxidation potential, and dissolved gas content in the brine.

Reinjection seems to be the most practical way to dispose of liquid wastes produced by power plants operating on geothermal brines produced in the Imperial Valley. Also, there seem to be no insurmountable problems associated with the implementation of this disposal technique. However, each reinjection system will have to be site specific to some extent because the chemistry of the brine varies extensively from one KGRA to the next and also from well to well. In addition, each power conversion system, i.e., flashed steam, binary, total flow, etc., produces slightly different effluents.

APPENDIX C. STRETFORD PROCESS AND EIC SULFATE PROCESS

The Stretford Process

The most promising technique for removing H_2S from a noncondensable gas stream seems to be the Stretford process which was originally developed by the North Western Gas Board and the Clayton Aniline Company, Ltd. of Great Britain to remove H_2S from coal gas.[45] Subsequently this process proved to be applicable to the desulfurization of a variety of other gas streams such as natural gas, synthetic gas, and various refinery gases. At present there are about 80 Stretford plants operating in Europe and North America. The first application to geothermal power production is planned for Geysers Units 13, 14, and 15 which are scheduled to start up in 1978 and 1979.

In the Stretford process, H_2S is absorbed in an aqueous solution of Na_2CO_3 then oxized to free S with VO_3^-. The VO_3^- is regenerated by oxidation with air using 2,7- anthraquinone disulfonic acid (ADA) as a catalyst. Simplified equations for the reactions are as follows:

$$H_2S + CO_3^{2-} = HS^- + HCO_3^-$$

$$2HS^- + 4VO_3^- + 4HCO_3^- = 2S + V_4O_9^{2-} + 3H_2O + 4CO_3^{2-}$$

$$V_4O_9^{2-} + O_2 + H_2O + 2CO_3^{2-} \overset{(ADA)}{=} 4VO_3^- + 2HCO_3^-$$

When air is bubbled through the Stretford solution to regenerate the VO_3^-, the sulfur rises to the surface in a froth. This froth is then filtered or centrifuged to separate the sulfur which can be melted to form a high quality commercial product.

In present applications,[45–48] this process is over 99 percent efficient which means that virtually all of the H_2S delivered to the plant is abated. The only effluent from the plant itself is a small stream of Stretford solution which must be constantly removed and replaced with fresh solution because of the slow buildup of undesirable byproducts such as sulfate and thiosulfate. This effluent may present an additional disposal problem. If it is mixed with Imperial Valley brines for reinjection, the SO_4^{2-} can react with Ba^{2+} and Ca^{2+} in the brine to form insoluble $BaSO_4$ and $CaSO_4$. This effluent could be disposed of by ponding and evaporation which would also allow the vanadate to be recovered for recycling.

The primary disadvantage of this process may involve the high CO_2 concentrations present in the noncondensable gas fraction of Imperial Valley brines. This CO_2 could cause excessive consumption of Na_2CO_3 in the Stretford solution by the following reaction:

$$CO_2 + CO_3^{2-} + H_2O = 2HCO_3^-$$

A simplified schematic of the Stretford process is shown in Fig. C-1.

The EIC Copper Sulfate Process

In the EIC $CuSO_4$ process,[49, 50] H_2S in steam or noncondensable gases is reacted with a solution of $CuSO_4$ to form insoluble copper sulfides. Simplified equations for the reactions which occur are as follows where equation No. 1 shows the primary reaction:

$$Cu^{2+} + H_2S = CuS + 2H^+$$

$$2\,Cu^{2+} + 2H_2S = Cu_2S + S + 4H^+$$

$$8Cu^{2+} + 5H_2S + 4H_2O = 4Cu_2S + 18H^+ + SO_4^{2-}.$$

The insoluble mixed sulfides are separated from the solution and oxidized by roasting or pressure leaching to regenerate $CuSO_4$ which is then recirculated through the system. Acid generated in the above reactions is neutralized by the addition of base.

A pilot test was used to investigate the efficiency of the scrubbing system on geothermal steam at The Geysers. In this test, steam was scrubbed in a 20-cm (8-in.) scrubbing column containing a single counterflow sieve tray. An average removal efficiency of 98.9 percent was reported for a run of 30-h duration. During this run the initial H_2S content of the steam was approximately 230 ppm. The steam flow rate was about 454 kg/h (1000 lb/h). The average H_2S content of the cleaned steam was 2.6 ppm. Additional experimental work is planned for a 45,400 kg/h (100,000 lb/h) field test facility.

For use in the Imperial Valley, this process has the advantage that it could be used on either steam or noncondensable gases as required by the power plant design. One disadvantage of this process could involve Cu^{2+} entrained in steam from the scrubber. Although Cu^{2+} was not detected at the 0.05 ppm level in scrubbed steam from the 20-cm scrubber column, it could be entrained in steam from larger units. If so it would plate out on steel components downstream by the following reaction:

$$Cu^{2+} + Fe = Cu + Fe^{2+}.$$

This copper plate would create a bimetallic couple with the steel and thus cause electrochemical corrosion. Corrosion of this kind would be particularly undesirable in turbine components.

Most of the secondary wastes from this process will probably be generated during the oxidation of copper sulfides to regenerate $CuSO_4$. These wastes cannot be identified for certain until the specific regeneration process is established. However, disposal of potential wastes such as S, SO_2, SO_3, and H_2SO_4 should be fairly straightforward.

A simplified schematic diagram of this process is shown in Fig. C-2.

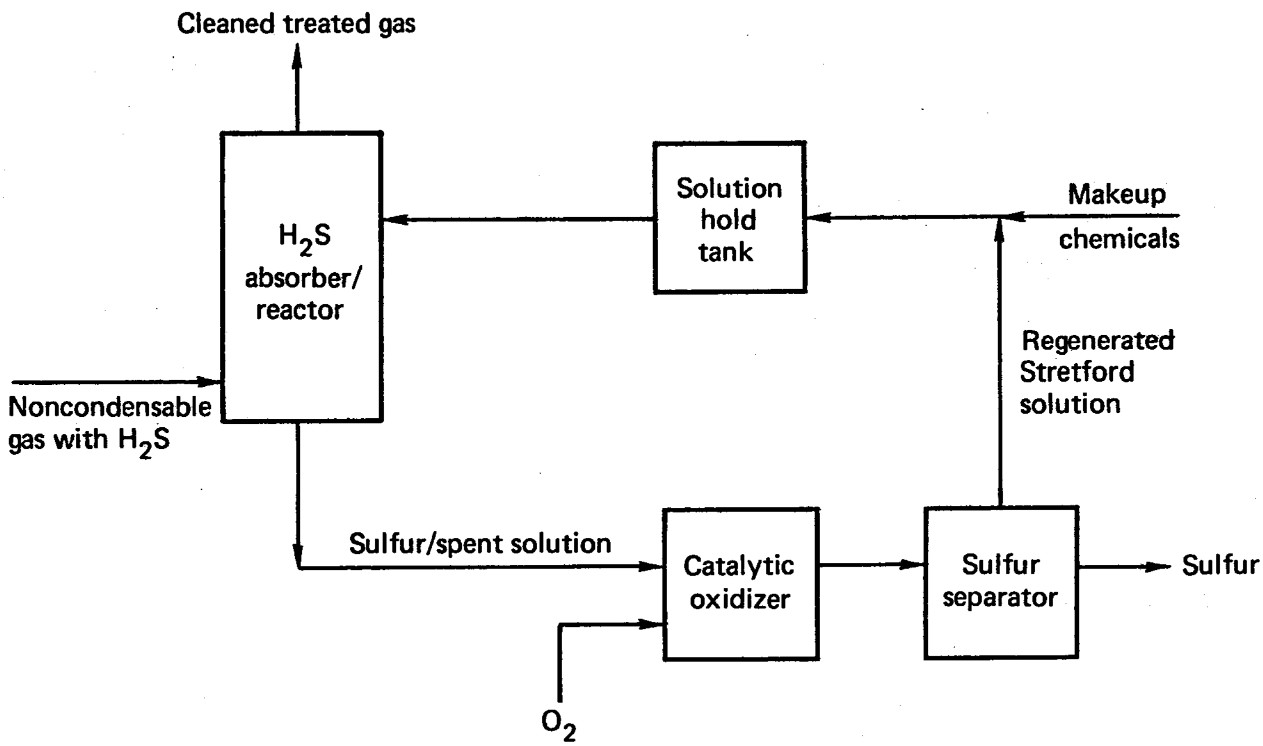

Fig. C-1. Simplified schematic showing Stretford process for H_2S removal.

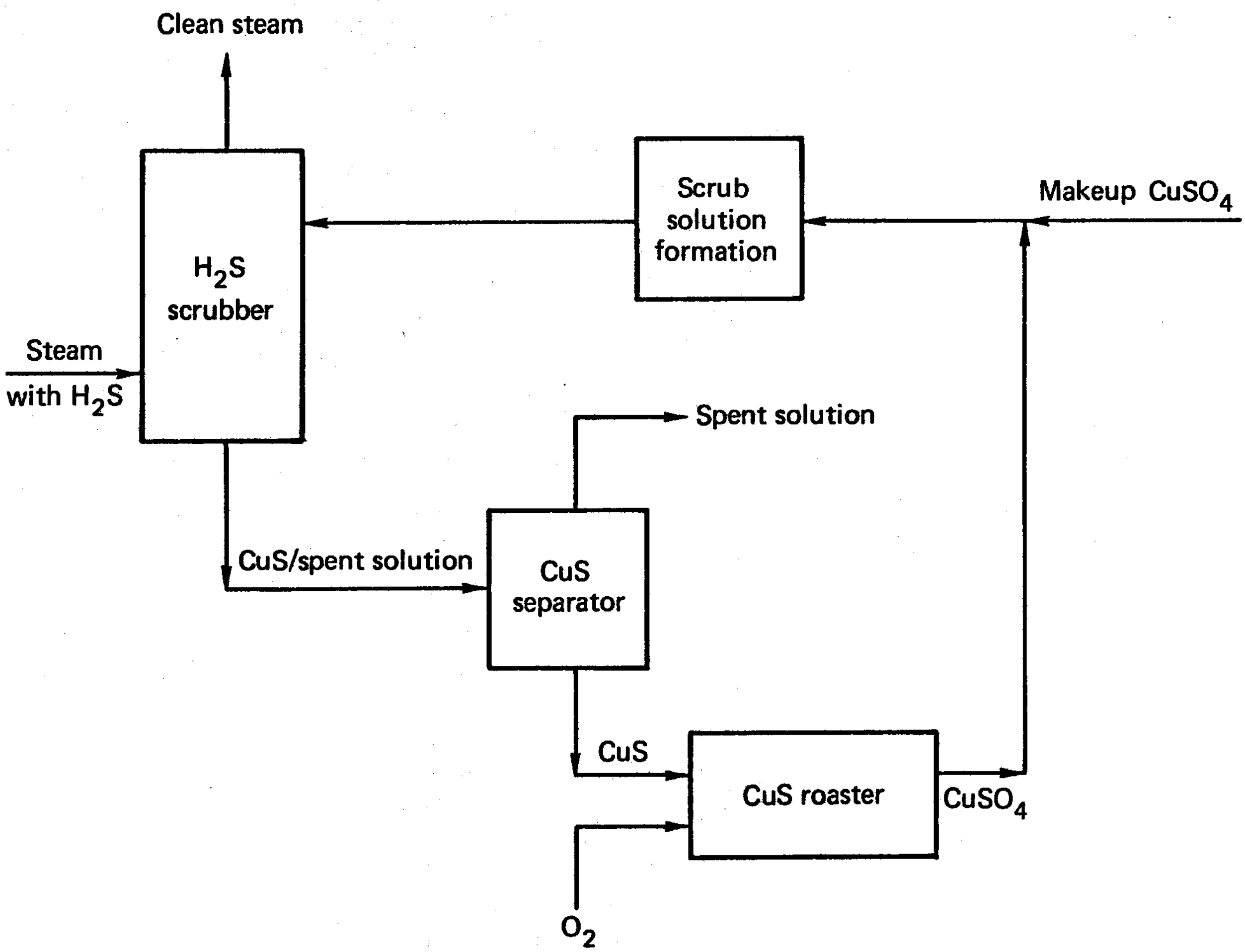

Fig. C-2. Simplified schematic showing EIC $CuSO_4$ process for H_2S removal.

APPENDIX D. CHARACTERISTICS OF GEOTHERMAL FLUIDS FROM IMPERIAL VALLEY KGRA'S

The Salton Sea, Heber, and East Mesa KGRA's are each characterized in respect to TDS and individual ions and elements. Table D-1 contains the characteristics of three wells in Salton Sea KGRA, Table D-2 of five wells in Heber KGRA, and Table D-3 of three wells in East Mesa KGRA. (See Fig. 1 for location of KGRA's.)

Table D-1. Characteristics of fluid from three wells in the Salton Sea KGRA[22,24]

Parameter[a]	Sinclair No. 4	Magmamax No. 1	Magmamax No. 2
Date	4-23-75	8-10-76	3-18-76
Temperature, °C	255	215	195
Pressure, psig	445	235	~200
Density, g/cm^3	1.18	1.15	1.19
Total dissolved solids, g/liter	290	208	244
Composition, mg/l			
Lithium (Li)		141	192
Sodium (Na)	70,000	42,000	53,600
Silicon (Si)	249	202	410
Potassium (K)	15,800	8,600	16,600
Iron (Fe)	1,450	256	1,910
Copper (Cu)	3	1	8
Rubidium (Ru)		64	98
Barium (Ba)		118	258
Boron (B)			4
Magnesium (Mg)	71	80	148
Zinc (Zn)		361	
Strontium (Sr)		388	
Aluminum (Al)	2	<1	
Fluoride (F^-)			22
Chloride (Cl^-)		121,000	142,000
Calcium (Ca)	29,000	20,000	27,200
Silver (Ag)	0.5		
Manganese (Mn)	1,230	690	1,290
Lead (Pb)	101	78	102
Ammonium (NH_4^+)		350	
H_2S		10-30	
CO_2, wt%		1-2	

[a]With the exception of the noncondensable gases, the concentrations shown were obtained on the liquid phase of the fluid and are not corrected for flashing. Estimated steam quality is 10 percent.

Table D-2. Characteristics of fluid from five wells in the Heber KGRA.[51]

Parameter	Nowlin No. 1	Holtz No. 1	Holtz No. 2	C.B. Jackson No. 1	J.D. Jackson No. 1
pH	7.1	NA	7.4	5.8	6.5
Total dissolved solids, ppm	14,100	13,168	16,330	15,430	15,275
Composition, ppm					
Silica (SiO_2)	120	268	187	267	268
Lithium (Li)	6.6	4	4.1	2.8	3.4
Sodium (Na)	3,600	5,500	4,720	4,688	4,563
Potassium (K)	360	220	231	181	197
Calcium (Ca)	880	1,062	1,062	891	781
Magnesium (Mg)	2.4	5.6	23	4.7	3.8
Chloride (Cl^-)	9,000	7,420	8,242	8,320	8,076
Sulfate (SO_4^{2-})	100	100	148	152	150
Carbonate (CO_3^{2-})	4	NA	NA	NA	NA
Bicarbonate (HCO_3^-)	20	NA	NA	NA	NA
Fluoride (F^-)	1.6	1.7	1.5	0.9	0.6
Boron (B)	4.8	4.1	8	4.8	5.2
Iron (Fe)	0.9	15	5	20	10
Manganese (Mn)	NA	0.9	0.9	1.3	1.9
Lead (Pb)	0.1	1.6	0.6	0.6	0.9
Zinc (Zn)	0.68	0.3	0.1	0.4	0.5
Copper (Cu)	0.2	0.5	0.4	0.4	0.4
Barium (Ba)	NA	6	3	3	3
Strontium (Sr)	NA	37	42	32	36
Aluminum (Al)	0.04	15	12	0.5	18
Silver (Ag)	NA	NA	NA	NA	NA
Uranium (U)	<4	NA	NA	NA	NA

Table D-3. Characteristics of fluid from three wells in the East Mesa KGRA.[10]

Parameter	Mesa No. 6-1	Mesa No. 6-2	Mesa, No. 8-1
Date	6-9-76	6-76	6-22-76
Conductivity, μmhos, 25°C	40,000	6,000	3,200
pH	5.45	6.12	6.27
Total dissolved solids, mg/liter	26,300	5,000	1,600
Composition, mg/liter			
Chloride (Cl^-)	15,850	2,142	500
Titanium (Ti)	<0.10	<0.10	<0.10
Lithium (Li)	40.0	4.0	1.1
Copper (Cu)	<0.10	<0.10	< 0.10
Molybdenum (Mo)	<0.005	<0.005	<0.005
Manganese (Mn)	0.95	0.05	0.05
Barium (Ba)	14	0.25	0.15
Carbonates (CO_3^{2-})	0.0	0.0	0.0
Fluoride (F^-)	0.99	1.23	1.60
Phosphate (PO_4^{3-}) total	ND[a] <0.01	<0.2	ND <0.1
Ammonium (NH_4^+)	40.75	14.7	4.95
Cesium (Ce)	2.75	0.38	0.14
Mercury (Hg)	ND <0.002	ND <0.002	0.014
Selenium (Se)	ND <0.1	ND <0.1	0.5
Tantalum (Ta)	0.14	0.17	0.12
Sodium (Na)	8,100	1,700	610
Strontium (Sr)	320	6.4	2.1
Indium (In)	ND <0.1	ND <0.1	0.024
Palladium (Pd)	ND <0.1	ND <0.1	0.02
Cobalt (Co)	0.06	ND <0.01	1.60
Tungsten (W)	ND <0.1	ND <0.1	ND <0.01
Boron (B)	9.75	7.45	<0.50
Lead (Pb)	0.5	<0.5	0.005
Silver (Ag)	0.013	<0.010	<0.010
Sulfide (S^{2-})	3.0	1.5	1.0
Silica (SiO_2)	320	269	389
Iron (Fe)	8.8	<0.10	<0.10
Potassium (K)	1,050	150	70
Magnesium (Mg)	17.2	0.24	<0.05
Zing (Zn)	0.07	<0.01	<0.01
Nickel (Ni)	0.10	<0.10	<0.10
Bicarbonate (HCO_3^-)	202	560	417
Sulfate (SO_4^{2-})	42.8	156	173
Nitrate (NO_3^-)	Trace, <0.02	0.1	0.34
Cadmium (Cd)	ND <0.01	ND <0.01	Trace, <0.01
Beryllium (Be)	ND <0.02	ND 0.02	ND <0.02
Bismuth (Bi)	3	ND <0.005	ND <0.005
Arsenic (As)	0.26	0.22	0.053
Antimony (Sb)	5.5	0.90	1.2
Niobium (Nb)	0.40	0.40	0.40
Calcium (Ca)	1,360	16.4	8.5
Germanium (Ge)	ND <0.1	ND <0.1	ND <0.1
Gold (Au)	ND <0.1	ND <0.01	
Platinum (Pt)	ND <0.1	ND <0.1	
Iridium (Ir)	ND <0.1	ND <0.1	ND <0.1
Aluminum (Al)	0.04	0.03	ND <0.01
Chromium (Cr)	ND <0.01	ND <0.01	ND <0.1
Vanadium (V)	0.005	<0.005	ND <0.1

[a]ND = Not Detected.

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