State-Of-The-Art Hydrogen Sulfide Control For Geothermal Energy Systems: 1979

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STATE OF THE ART HYDROGEN SULFIDE CONTROL FOR
GEOHERMAL ENERGY SYSTEMS

ABSTRACT

This report has been prepared for the Environmental Control Technology Division, Office of Environmental Compliance and Overview, Assistant Secretary for Environment, of the Department of Energy (DOE).

Present efforts by the geothermal industry are directed toward developing economically viable hydrogen sulfide (H_2S) emission control technologies having efficiencies that satisfy federal and state emission requirements. This report discusses existing state-of-the-art technologies for removal of H_2S along with a comparative assessment of their efficiencies, reliabilities and costs. Other related topics include the characteristics of vapor-dominated and liquid-dominated resources, energy conversion systems, and the sources of H_2S emissions.

The report indicates that upstream control technologies are preferred over downstream technologies primarily because upstream removal of H_2S inherently controls all downstream emissions including steam-stacking. Two upstream processes for vapor-dominated resources appear promising; the copper sulfate (EIC) process, and the steam converter (Corry) process combined with an off-gas abatement system such as a Stretford unit. For liquid-dominated systems that produce steam, a process where the non-condensable gases are scrubbed with spent geothermal fluid appears to be promising. An efficient downstream technology is the Stretford process for H_2S removal from the non-condensable gas stream. In this case, partitioning in the turbine surface condenser will determine the overall abatement efficiency.

Recommendations for future environmental control technology programs include a) studies addressing H_2S emissions associated with steam stacking, b) examining the use of the Stretford process upstream, c) continuing studies of the steam converter (Corry) process, d) determining the feasibility of electrolytic processes for H_2S removal and, e) a follow-up program of the DOE sponsored Atmospheric Studies in Complex Terrain (ASCOT) study.

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EXECUTIVE SUMMARY

The report provides a review of the state of the art hydrogen sulfide (H_2S) control technologies presently applicable to geothermal energy sources, and identifies the most promising H_2S removal processes for future geothermal applications. Processes for H_2S abatement in both vapor-dominated systems and liquid-dominated systems are included.

Vapor-dominated systems, also known as dry-steam systems, are those where steam produced in underground resources is recovered at slightly superheated conditions. In these systems, the major component is steam containing CO_2 , H_2S , and other gases. Liquid-dominated systems are primarily made up of hot water containing dissolved solids as well as dissolved gases. When these resources are utilized for the generation of electric power, H_2S is released into the atmosphere and to various waste streams.

There are several release points of the H_2S emissions which include:

- Well--drilling emissions, standby venting, and bypass venting
- Fluid transmission--instrument vents, cyclone vents, and temperature equalizer vents
- Power plant (conversion process) emissions.

There are two main approaches for removing H_2S . These are upstream abatement (ahead of the turbine), and downstream abatement. Since there have been no commercially available upstream abatement processes successfully applied to geothermal uses, most of the technology presently used is directed toward downstream H_2S abatement methods. The downstream processes have been applied to the noncondensable off-gas stream and to the H_2S dissolved in the condensate/cooling-tower water.

The Stretford process has recently been applied to the noncondensable gas at The Geysers on Unit 15 with an abatement efficiency exceeding 99%. However, only 75-80% of the H_2S is partitioned into the noncondensable gas stream by the surface condensers on Unit 15. Therefore, overall abatement is limited to 75-80%. Recent experiments, however, indicate possible improvement to 90% overall abatement. The Stretford process involves scrubbing the H_2S -containing gas with an aqueous solution containing sodium carbonate, sodium metavanadate, and anthraquinone disulfonic acid (ADA).

The burner-scrubber process has also been used at The Geysers. In this process the noncondensable gas stream is burned to oxidize H_2S to SO_2 , which is scrubbed out of the gas stream with cooling water. Work on the process was suspended because only 50% H_2S abatement was achieved, and there were major maintenance problems.

Treatment of the condensate/cooling water using the iron-catalyst system is the main process now used at The Geysers. It has been modified to include the use of hydrogen peroxide for greater efficiency. Sodium hydroxide is used to maintain the pH of the circulating water between 7.4 and 7.8. Overall abatement of about 90% is now being obtained. However, because of corrosion and the high solids produced, this process causes high operating and maintenance costs, and an apparently reduced plant capacity factor.¹

Upstream abatement technologies are the best candidates for the control of H_2S emissions because they will, if successful, solve the steam stacking problem. Three processes appear to be promising: The EIC copper sulfate process, the steam converter with auxiliary H_2S removal, and the Dow oxygenation process.

Extensive pilot plant tests of the EIC process on Unit 7 at The Geysers have demonstrated 95% to 98% removal of H_2S . This pilot plant processes 100,000 lb of steam. A commercial scale (110 MW) facility will process two million lb/h of geothermal steam. Abatement is achieved by scrubbing the steam with a copper sulfate solution which reacts with the H_2S to precipitate copper sulfide. A pressure-leach unit regenerates copper sulfate from the copper sulfide, removing any free sulfur formed. The copper sulfate is then recycled to the scrubbing tower. The EIC process also removes ammonia, boron, and particulates from the steam. The process can be used to remove H_2S from steam obtained from vapor-dominated resources or from flashed steam derived from liquid-dominated sources.

The second promising candidate for upstream abatement is the steam converter to separate H_2S from steam, coupled with a Stretford unit to treat the H_2S . A pilot plant steam converter is being tested at the Geysers.

Although the Dow oxygenation process is somewhat costly and presents a potential corrosion problem, it is a candidate for use on liquid geothermal resources.

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I. INTRODUCTION

The use of geothermal energy for the production of electric power has been thought by many to be clean and nonpolluting. There are, however, many environmental issues to be considered in the expanding geothermal industry. These issues include emission of noncondensable gases and salts, subsidence and induced seismicity, liquid wastes, solid wastes, and noise. This report was written to complete work initiated in 1977 by Midwest Research Institute concerning state of the art abatement technologies to mitigate emissions of hydrogen sulfide (H_2S) from geothermal installations. It includes an update of H_2S control technologies. Some of these technologies have been tried and found economically or operationally inadequate; some are presently being used as abatement systems and are still being evaluated; some are in the experimental and pilot-plant stage for future applications. Of these, certain technologies are coming to the forefront as the best candidate technologies for the control of H_2S emissions for particular applications in geothermal power systems. Total abatement of H_2S emissions is not currently possible and may never be economically feasible. This report calls attention to those best candidate technologies for H_2S abatement and suggests additional areas for research.

The main requirement for the use of geothermal resources is that their use be environmentally and economically acceptable. It is the purpose of this report to provide the Department of Energy (DOE) and other concerned agencies with information that will help them to plan the accelerated development of geothermal resources in a manner that will meet environmental constraints and minimize attendant economic penalties.

BACKGROUND

Hydrogen sulfide abatement techniques are new to electric power generation and must be viewed as experimental or developmental even though similar processes are used in the chemical and petroleum industries. Most of the information in this report relating to applied abatement technology has been obtained from experiences at The Geysers in northern California, the only operating geothermal plant in the United States. This Known Geothermal Resource Area (KGRA) is presently producing 663 MW of electrical energy. Although a unique vapor-dominated resource, abatement experience gained at The Geysers can also be applied to other KGRAs that depend on liquid-dominated resources.

BEST AVAILABLE CONTROL TECHNOLOGY

The term "Best Available Control Technology" (BACT), as currently being applied to technologies that may be effective for H_2S abatement, can be misconstrued. It implies, to some, that a proposed technique will effectively control H_2S emissions in geothermal applications simply because it is effective in other industrial applications. This is not necessarily the case. Any technology must be researched, designed, developed, and then successfully applied to the particular plant process for perhaps one or two years before its applicability, efficiency, reliability, and costs can be evaluated. Therefore, the development of BACT for H_2S abatement in geothermal applications will require concerted effort by participants from both government and industry.

REPORT ORGANIZATION

To help the reader with a clear understanding of the H_2S release points in geothermal systems, Sections II and III are devoted to background information on the characteristics of geothermal resources and energy conversion processes. The actual release points are described in Section IV and some technical and legal requirements for the abatement of H_2S releases are discussed in Section V.

Abatement technologies to mitigate H_2S emissions are described in Section VI, with special emphasis on prime candidate methods presently known. Evaluation of the most likely candidates appears in Section VII with a brief discussion of cost estimates. Details of preliminary cost estimates are given in Appendix B.

The last section, Section VIII, offers recommendations for research and development for present and future environmental control technologies.

II. RESOURCE CHARACTERIZATION

Hydrothermal resources exist as vapor-dominated resources (steam) or liquid-dominated resources (hot water/brine). At the present time, the only power generation in the United States is taking place at The Geysers (a vapor-dominated resource) in Northern California. In the future, however, the major developments in geothermal power generation in the United States will most likely be in the area of liquid-dominated resources.

VARIABILITY OF RESOURCES

Geothermal reservoirs, both vapor- and liquid-dominated, are characterized by a significant lack of uniformity, even within the same well field over distances as short as a few kilometers. The emission of H_2S from geothermal power plants depends on several factors: the H_2S content in the geothermal fluid, the chemical and physical properties of the fluid, and the efficiency of conversion and abatement technologies. The total mass emission from a given KGRA depends on the size of the individual power plants and the total number of power plants throughout the area of development. There is considerable uncertainty in all of these factors, especially with liquid-dominated systems which are only in the initial stages of development.

The variability of geothermal fluids is illustrated in Table 1 by the range and average values of noncondensable gases found in several geothermal resources. The average values shown for The Geysers KGRA are fairly reliable because of the experience gained over many years of operation and the large number of analyses performed on samples from many wells. Hydrogen sulfide concentrations in the steam of individual Geysers units is shown in Table 2.⁸ Although many wells (10 to 20) supply each power generating unit, it can be seen that the spatial variations are significant. In addition, temporal variations are also fairly common; data from The Geysers KGRA reflect a two-fold variation over a period of a few months.¹² Data shown in Table 1 for various KGRA's in the Imperial Valley are the results from a limited number of samples taken from a few wells in each area. When actual power

TABLE 1. Ranges and average values of H₂S and other noncondensable gases found in geothermal fluids from wells in various KGRA's. Values are in mg/kg of fluid (ppmw).

Gas	Geysers ^a (steam)		Salton Sea ^b (brine)		East Mesa ^b (liquid)		Brawley ^c (brine)	Heber ^d (liquid)	Baca ^e (liquid)
	Range	Ave	Range	Ave	Range	Ave	Ave ^f	Ave ^f	Ave ^f
H ₂ S	5-1600	222	1.6-6.0	3.2	0.12-1.6	0.54	55.1	0.18	60.7
CO ₂	290-30600	3260	1100-3800	1700	270-2300	1100	23500	34.6	8410.0
CH ₄	13-1447	194	3.0-10	6.0	4.0-56	33	319	1.7	0.6
NH ₃	9.4-1060	194	20-41	35	1.3-8.1	4.5	51	-	-
N ₂	6-638	52	-	-	-	-	2900	10.6	16.7
H ₂	11-218	56	-	-	-	-	0.87	0.04	0.6

^aData from Ref. 2 Average value measurements from 61 producing wells. 1972-74.

^bData from Ref. 3 Measurements from 2 or 3 wells.

^cData from Ref. 4 Average of 2 wells: Veysey 2 and TOW 1.

^dData from Refs 5 & 6 Average of 2 wells

^eData from Ref. 7 (Baca Ranch, Sandoval County, New Mexico)

^fMeaningful range data not available.

TABLE 2. Hydrogen sulfide concentrations in the steam of individual Geysers units.^a

Unit	Rated net power (MW)	H ₂ S concentration (ppmw)
1	11	170
2	13	170
3	27	450
4	27	570
5	53	280
6	53	250
7	53	230
8	53	160
9	53	110
10	53	100
11 ^b	106	258
12 ^c	106	90
13 ^d	135	-
14 ^d	110	-
15 ^e	55	130

Note: Data for all units except 11 and 12 from Weinberg.⁹ Accuracy of the values $\pm 20\%$.

^aTable adapted from Ref. 8.

^bUnit 11 value from Ref. 10.

^cUnit 12 value from Ref. 11.

^dUnits not yet in existence.

^eUnit 15 coming on-line as of this writing.

production in the Imperial Valley becomes significant (hundreds of MWe) and operational experience and additional data are accumulated, the source measurements may show significantly different H_2S concentrations.

III. ENERGY CONVERSION TECHNOLOGIES AND PLANT DESIGN

CONVERSION TECHNOLOGIES

Several conversion technologies have been proposed to produce electricity from geothermal fluids. In general, these processes involve the use of a high-enthalpy fluid to drive a turbine/generator. In a vapor-dominated system such as The Geysers, geothermal steam is used directly in the turbine. Although there are no power plants now operating on liquid-dominated systems in the United States, processes are now being developed. These include: flashed steam, flashed-steam binary cycle, hot water binary cycle, and total flow. Geothermal fluids may also be used as a direct source of heat for nonelectrical applications such as space heating and process heating. Some of the processes in current use and under development for both direct use and electrical power generation are discussed below.

DIRECT STEAM POWER GENERATION

Vapor-dominated systems produce electrical power directly by expanding the geothermal steam through a turbine that is coupled to a generator (Fig. 1). A centrifugal separator, upstream of the turbine, removes particulate matter and water. The turbines are designed to operate on the relatively low temperatures and pressures of geothermal steam compared to the much higher temperatures and pressures of steam used with turbines in conventional fuel-fired power generating plants. The spent steam from the turbine is condensed in a direct-contact condenser or a surface condenser. This condensation reduces the pressure on the downstream side of the turbine to subatmospheric pressure and thus increases the turbine efficiency. The condenser is equipped with steam-jet ejectors to expel noncondensable gases

into the atmosphere. (Noncondensable, in this context, means not condensed under the existing operating conditions of temperature and pressure.) The condenser fluid (condensate and cooling water in the case of a contact condenser or simply condensate in the case of a surface condenser) is pumped to a forced-draft cooling tower. After cooling, the water is returned to the condenser to cool incoming steam. At The Geysers, cooling tower blowdown is deep injected for reservoir recharge.

The noncondensable gases contain part of the H_2S , but part is also present in the condensate. Partitioning of H_2S between noncondensable gases and condensate depends on the chemical characteristics of the fluid and the condenser design. Thus, it may be necessary to treat both the condensate and the noncondensable gases to provide effective H_2S abatement. Hydrogen sulfide release points are indicated in Fig. 1.

FIG. 1. Direct-steam process. *Hydrogen sulfide release point

FLASHED STEAM POWER GENERATION

Liquid-dominated resources require flashing of the geothermal fluid to produce steam, as shown in Fig. 2. Flashing is a process whereby the superheated well fluid is allowed to boil at a pressure that is lower than its equilibrium subterranean pressure. If the flashed liquid is hot enough, it can be flashed again in subsequent stages to produce additional steam. The flash chamber serves a dual purpose, also acting as a centrifugal separator to remove water and particulates from the steam. Once the steam is formed, it is then used for power generation as described above for direct-steam power generation. The spent liquid may be injected underground together with the cooling-tower blowdown fluid.

The lower pressure required for flashing decreases the solubility of the gases dissolved in the liquid. The result is that the hot fluid is transformed into two phases, a liquid phase containing some dissolved gases and a vapor phase containing steam plus most of the noncondensable gases including H_2S . Hydrogen sulfide release points are indicated in Fig. 2.

FIG. 2. Flashed-steam process. Separator discharge liquid can be flashed again if its temperature is sufficiently high.

*Hydrogen sulfide release point.

FLASHED BINARY CYCLE

This process uses the steam from flashed geothermal brine (as shown in Fig. 3) which, when passed through heat exchangers (boiler and superheater), vaporizes a low-boiling secondary fluid such as isobutane. The high-pressure secondary fluid is used to generate power by means of a turbine/generator unit as before. The secondary fluid (vapor) exhausted from the turbine is condensed and returned at high pressure to the heat exchanger. The spent steam from the heat exchangers is condensed and the noncondensable gases are removed. The steam condensate is then cooled in a cooling tower and recycled as a coolant for the condensers. Hydrogen sulfide release points are indicated in Fig. 3.

FIG. 3. Flashed binary cycle process. Flashed steam is used to heat a secondary fluid. * Hydrogen sulfide release point.

BINARY CYCLE

This process is similar to the flashed binary cycle except that the hot geothermal fluid is used directly to vaporize the secondary fluid (Fig. 4). The heat from the hot well fluid is transferred to the secondary fluid by a countercurrent flow through a boiler and superheater. After expanding through the turbine, the secondary fluid is condensed with water from a cooling tower and pumped to the heat exchangers at a high pressure. The cooling water used in this process must be supplied by an outside source since no steam condensate is generated for cooling purposes. The entire spent geothermal brine is injected underground.

It is generally believed that noncondensable gases are not emitted from binary cycle hot water systems because flashing is not required. However, if the resource contains two phases or if gases separate after leaving the well, venting of the gases may be necessary to protect pumps from cavitation erosion. Also, some plants may require separation of solids from the cooled spent brine to prevent plugging of the injection wells. This treatment could be a source of H_2S release.

FIG. 4. Binary cycle (hot water) process. Hot water is used to heat a secondary fluid.

TOTAL-FLOW POWER GENERATION

Total-flow systems are examples of the use of liquid geothermal resources that do not depend on the transfer of heat energy to another working fluid, but rather convert the thermal energy to kinetic energy. This process is shown in Fig. 5. The kinetic energy is utilized in two types of specially designed turbines: the impulse turbine and the reaction turbine. The impulse system obtains energy by impingement of vapor on the blades of a rotor, while the reaction system depends on the reaction of high velocity jets much as in pyrotechnic pinwheel displays. Lawrence Livermore Laboratory (LLL) has been working on both types of systems.¹³

FIG. 5. Total Flow Process. *Hydrogen sulfide release point

GEOTHERMAL UTILIZATION FOR ELECTRIC POWER

Except for The Geysers, there are no geothermal electric power facilities in the United States. A unit scheduled to come on-line this year is the Magma 10 MW plant in the Imperial Valley East Mesa KGRA. The facility will be operated by the San Diego Gas and Electric Company (SDG&E). This plant will use a binary cycle (hot water) process.

Several other geothermal facilities of SDG&E, Southern California Edison (SCE) and California Department of Water Resources (DWR) are proposed for electric power production in the near future. Forecasts for the period from 1979 to 1987 are assembled in Table 3. Several hundred megawatts of electric power production is projected. Estimates of electric power available from Imperial Valley geothermal sources by 1995 range from 500 to 8000 MW.¹⁵ 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.¹⁶

An assessment of the potential impact of geothermal development in the Imperial Valley on air quality has recently been published.³ Scenarios based on 3000 MW, 2000 MW, 500 MW, and 100 MW of power production are considered. Calculations predict that by the year 2010 at the 3000-MW level (with no abatement), the California 1-h standard for H_2S ($42 \mu\text{g}/\text{m}^3$) would be violated at least 1% of the time over an area of approximately 1500 km^2 (about 1/3 of the valley area).³ It is clear from this that H_2S abatement technologies must be planned during Imperial Valley development.

Violations of the California standard already exist at The Geysers at the present 663 MW production level.¹⁷⁻²⁰ Because of this, a major effort is being expended on abatement research in this KGRA. Three utilities, Pacific Gas and Electric (PG&E), Sacramento Municipal Utilities District (SMUD), and Northern California Power Association (NCPA), indicate that 2708 MW of electricity could be produced at The Geysers by 1990.

It is apparent that without sufficient preplanning for H_2S abatement procedures, the generation of electric power from geothermal resources can be (and is) a source of air pollution.

TABLE 3. Imperial Valley geothermal power projection to 1987 based on announced plans of utilities.^a

On-line Date	Utility	Developer	Location	MW	Cumulative Total
1979	SDG&E ^b	Magma	E. Mesa	10	10
1980	SDG&E ^b	RGI	E. Mesa	48	58
	SCE ^b	Union	Brawley	10	68
1982	SCE ^b	Chevron	Heber	50	118
	SDG&E ^b	Magma/NAPCO	Salton Sea	50	168
	SDG&E ^b	Chevron/EPRI	Heber	49	217
	SCE	Mono/Union/ Southern Pac. Land Co.	Salton Sea	10	227
1983	SCE	Union	Brawley	100	327
	SDG&E	RGI/MAPCO	Westmoreland	48	375
1984	DWR ^b	CUI Venture	S. Brawley	55	430
	DWR ^b	McCulloch	E. Salton Sea	55	485
			(Expanded)		
	SDG&E	Magma	E. Mesa	50	525
	SCE	Union	Brawley	100	625
1985	SCE	Chevron	Heber	55	680
	SCE	Union	Brawley	100	780
1986	SDG&E	Chevron	Heber	100	880
	SCE	Chevron	Heber	100	980
	SCE	Union	Brawley	100	1080
1987	SCE	Mono/Union/ Southern Pac. Land Co.	Salton Sea	40	1120
			(Expanded)		

^aFrom Ref. 14.

^bA commitment has been made between utility and developer.

In general, the geothermal energy for nonelectric use is provided by liquid resource fluids that have an enthalpy (heat content) too low for efficient electric generation. These fluids usually have their heat energy extracted in a closed system by heat exchangers (Fig. 6). If the spent fluid is then injected underground, H_2S can be injected with it. However, if the spent fluid is pure enough for surface disposal or use in irrigation or domestic consumption, H_2S could be released when it is exposed to the atmosphere.

In one application of geothermal energy for nonelectric use, a water desalination plant was planned by the Bureau of Reclamation for their East Mesa site.²¹ It is our understanding, however, that these plans have been cancelled because the capacity of the resource reservoir is inadequate to provide sufficient water for the project. If this project were to be carried out though, H_2S could be released because the process involves the production of steam.

The Direct Use of Geothermal Energy Symposium sponsored by the 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. Current applications include space heating, industrial process heating, crop drying, food processing, aquaculture, and greenhouse operations.

FIG. 6. Direct heating (closed system).

IV. HYDROGEN SULFIDE EMISSION SOURCES

Hydrogen sulfide has a characteristic odor, detectable with individual variations from 7 to 25 ppb (10 to 35 $\mu\text{g}/\text{m}^3$). This odor is often noticeable in The Geysers region and, at times, in nearby communities. Emission of H_2S is clearly a significant air quality problem that results from geothermal developments, although at the levels involved the problem is one of odor nuisance rather than verified health effects. If unabated, the amount of H_2S released per hour depends on the amount of H_2S in the resource fluid and the amount of the resource fluid required per megawatt-hour of electrical production. Table 4 shows the calculated "worst case" emissions based on these parameters and compares The Geysers KGRA, four Imperial Valley KGRA's, and the Baca⁷ KGRA in New Mexico. It can be seen that the magnitude of the problem of H_2S emissions is very site specific.

TABLE 4. A comparison of calculated "worst case" emissions for various KGRA's.

KGRA	Wt of resource Fluid ^a kg/MWh	H_2S in fluid, ^b mg/kg fluid	Unabated H_2S emissions, ^c g/MWh
Geysers (steam)	8,250	222.0	1,830
Salton Sea (brine)	50,000	3.2	160 ^d
Brawley (brine)	45,360	55.1	2,500 ^d
East Mesa (liquid)	200,000	0.54	108 ^d
Heber (liquid)	46,760	0.18	8.4 ^d
Baca (liquid)	26,216	60.7	1,652 ^e

^aValues from design data

^bFrom Table 1.

^cAssuming all H_2S in supply fluid is released to the atmosphere.

^dFor flashed-steam plants.

^eBased on 204 ppm H_2S in 892,000 lb/h of steam flashed from 3×10^6 lb/h well fluid.⁷

HYDROGEN SULFIDE RELEASE POINTS

The release points for H_2S can be divided into two categories: those which occur upstream of the turbine (pre-plant emissions) and those which occur downstream of the turbine (power-plant emissions). The pre-plant emissions include releases from well field construction and operations such as drilling, well testing, pipeline venting, steam stacking, and well bleeding while on standby. Sources of downstream emissions depend on the conversion process and include both the steam condensate and noncondensable gas streams. These major release points of H_2S for several conversion processes have been previously indicated in Figs. 1 to 5.

A VAPOR-DOMINATED PLANT - THE GEYSERS

Table 5 lists the approximate amounts of H_2S emitted to the atmosphere at The Geysers geothermal development for release points with and without downstream abatement. A brief description of the various points where H_2S is released during the construction and operation of a typical power plant at The Geysers is given below.²³ A more detailed description of The Geysers plant operations appears in Ref. 24.

Pre-plant Emission

The geothermal resource under development at The Geysers KGRA is rare because it consists of steam rather than hot water. The initial emissions occur when wells are drilled. During the first stages of drilling, mud is used to cool and lubricate the drill bit. However, when the drill reaches the geothermal stratum, the high temperatures encountered can cause caking of the mud which can plug the steam-producing formation. At this point the use of mud is discontinued and air-drilling techniques are used. During this drilling phase the geothermal fluid is released to the atmosphere. Releases during well drilling typically continue for 1 to 3 wk. Normally, only one well at a time will be at this stage of operation; occasionally, two or perhaps three wells are at this stage.

TABLE 5. Approximate amounts of H₂S emitted to the atmosphere at The Geysers geothermal development for various release points.

Release points	1976 unabated H ₂ S emissions, ^a kg/h	Without abatement		With 90% downstream abatement	
		kg/h	Percent of Total	kg/h	Percent of total
Total power plant emissions		1152 ^b	90.8	115 ^b	49.6
Pre-plant emissions					
Well drilling	4	5 ^c	0.4	5 ^c	2.2
Testing & clean-out	13	17 ^c	1.3	17 ^c	7.3
Well bleeds	3	4 ^c	0.3	4 ^c	1.7
Steam stacking	28	37 ^c	2.9	37 ^c	15.9
Pipeline vents	14	19 ^c	1.5	19 ^c	8.2
Uncontrolled well	33	33	2.6	33	14.2
Natural fumaroles	2	2	0.2	2	0.9
Total pre-plant		117	9.2	117	53.4
Total emissions		1269	100.0	232	100.0

^aFrom Ref. 22 (1976).

^bEstimated for 1979 @ 663 MW total generating capacity:
 $1.83 \times 663 \times 0.95 = 1152$.

where

1.83 = kg H₂S/MWh from Table 4,
663 = 1979^c capacity in MW,
and 0.95 = emission factor (H₂S in source fluid actually emitted).

^cValue from Ref. 22 multiplied by 1.33 to estimate 1979 value.

After a well-drilling operation is completed and valves have been installed, there is an initial 1 to 2 wk cleaning step to remove solids ("rock dust") accumulated in the reservoir during drilling. Then the well is flow tested. The purpose of the flow test is to determine production capacity. Flow testing may require from 4 to 24 h with flows ranging from 25 to 100% of full capacity. (Flow testing is required for all geothermal wells, regardless of the type of fluid, so H_2S control may be required at virtually all fields.)

When the flow test has been completed, the well is allowed to bleed (vent) through a bleed pipe. The purpose of such standby venting is to maintain a high temperature along the entire length of the well casing. A decrease in temperature would cause the casing to contract and separate from the grout that cements the casing to the wall of the rock formation. A fracture of the well casing could cause a blowout. Venting is therefore prudent because the cost for drilling and completion of a production well averages about one million dollars.²⁵ The well is allowed to bleed until a power plant is constructed; it may remain in this condition for several years, although most production wells are drilled during the latter stages of plant construction.

After a power plant is built and in operation, venting still routinely occurs at several locations along the steam supply lines. In an operating plant, however, most of these vents have been connected to a vent collection system, and the condensed geothermal fluid is now injected back into the ground. These vents are small (3/8 in. or less) and are located at particle separators that remove particles at the wellhead, at flow meters along the steam lines, at low spots along the line where condensate is periodically removed, and at the dust particle separator near the plant entrance. These vents are of relatively minor importance at present, but they do release all the geothermal fluid without removal of any pollutants.

The major release associated with the steam supply occurs when the power plant goes down. When a malfunction is detected in the plant, the supply of steam to the turbine is shut off; this causes pressure to build up quickly in the lines. This pressure build up in the transmission line actuates relief valves sequentially, and the full flow of geothermal fluid is vented directly into the atmosphere (steam stacking) through a muffler

to reduce noise. The Union Oil Company has developed procedures for use in the event of power plant outages to curtail production from the geothermal wells; such curtailment reduces emissions by throttling down wells and redistributing steam to adjacent operating power plants. These procedures are summarized in Table 6.

TABLE 6. Union Oil Co. guidelines for curtailing production from geothermal wells during plant outages.^a

Expected duration of unit shutdown	Action to be taken
Less than 2 h	Adjust steam apply to maximum vent pressure
2 to 24 h	Adjust steam supply to maximum vent pressure; throttle wells equipped with vee-ball valves in unit area to a wellhead flow pressure of 300 psig
24 to 96 h	Adjust steam supply to maximum vent pressure; throttle wells equipped with vee-ball valves in unit area to fully closed position (this will reduce flow from well to approximately 20% of capacity); adjust crossover piping to maximize steam transfer to adjacent unit areas; throttle wells equipped with vee-ball valves in adjacent unit area as required to balance steam supply with demand
More than 4 d	Same procedures as used for 24-96 h; in addition, wells will be shut-in as required in affected and adjacent unit areas to eliminate steam venting

^aData supplied by Warren Smith of Union Oil Company

Power Plant Emissions

Under normal conditions at The Geysers geothermal power plants, steam passes through the turbine that drives the generator. After passing through the turbine, the geothermal fluid moves into a direct-contact condenser (Units 1-12). The hot fluid that collects in the condenser is pumped to a cooling tower, while the noncondensable gases are pumped from the condenser by a gas ejector. The noncondensable gases were formerly emitted directly into the atmosphere; with recent modifications to the plants however, they are now injected into the cooling tower. In the cooling tower, about 80% of the condensed incoming steam is evaporated. The remaining 20% collects in the cooling tower basin and serves as condenser coolant and blow-down water for solids control. The blow-down is injected into the geothermal reservoir through an injection well.

Pacific Gas and Electric has taken samples from the steam inflow at each power plant unit and measured the concentrations of H_2S , ammonia (NH_3), and boron (B). In passing through the power plant, each of these substances undergoes processes that can affect their rates of emission. From its special measurements of the concentrations and flow rates in the inflow steam, the cooling-tower blowdown, and the cooling-tower exhaust, PG&E has obtained data on the fractions of the input substances that are emitted into the atmosphere. The data from these measurements are used to translate the routinely measured pollutant inflows into the reported emission rates. These data are summarized in Fig. 7. The fractional dispositions may be different for the various pollutants, however, depending on their physical characteristics and the pH of the condensate.

The special mass flow and balance measurements show that a normally operating, unabated plant emits about 95% of the input H_2S ; the remaining 5% is apparently oxidized or injected. Although this emitted fraction depends to a degree on atmospheric and operating conditions and on NH_3 concentrations in the fluid, it is always high. Therefore, the emission rates for unabated plants, which are reported as 95% of the measured inflow of H_2S , are accurate within about 15%.

FIG. 7. Typical flow of steam through an unabated power plant showing the distribution of H_2S , NH_3 and B .²³

A LIQUID-DOMINATED FLASHED STEAM PLANT

The description of a plant now under construction in the Imperial Valley of California will serve to illustrate the release points of H_2S from a liquid-dominated resource using a flash system for steam production. The plant is the 10 MW geothermal demonstration facility near Brawley which will be operated by SCE using steam supplied by the resource developer, the Union Oil Company. The information was obtained from Ref. 4.

Pre-plant emissions

As with The Geysers, initial emissions may occur when wells are drilled. These emissions will probably be negligible since air drilling is not used for this type of resource. Drilling is done with a viscous fluid called "mud" to carry cuttings to the surface, cool and lubricate the drill bit, and counteract reservoir pressures. A sump is used to contain the drilling mud and cuttings. Geothermal fluids acquired during drilling are stored onsite in steel Baker tanks. These stored fluids are then concentrated by evaporation, a minor source of H_2S release, and then taken to a Class I or Class II-1 disposal site (Appendix C).

After completion of the drilling phase, the well bore is cleaned out by allowing the well to flow into 50,000 ft³ (1,416 m³) Baker tanks. The cleanout operation is of short duration, involving only the time required to fill the Baker tanks.

The first venting of H₂S that may be of concern results from well production testing. The test is conducted by flowing the well fluid through a test system and injecting the produced fluid into a second well. In the test apparatus, the geothermal fluid flows from the well into water/steam separators, then continues through a device in which both steam and water flow rates are metered. Downstream from the flow meter is a primary flash separator (with muffler) through which any remaining steam from the hot water is flashed and vented, together with steam from the wellhead separators, into the atmosphere. The water travels on to surge tanks, and is then pumped into a nearby injection well where it reenters the geothermal reservoir. The duration of such a test may range from 12 h to several months. It is estimated that during testing, 9.1 kg/h of H₂S (218 kg/d) could result as a "worst case" release (Ref. 4, p. 146).

After well testing has been completed, up to four wells will be used to provide sufficient steam to the power plant. Fluid from each well will be connected to a common manifold that will convey the fluid to a steam production system. Figure 8 shows a schematic of the entire plant and includes projected flow balances, including H₂S. At the steam production system, the fluid will be processed to separate the steam phase from the liquid phase and to separate the bulk of the noncondensable gases from the steam. The noncondensable gases will be vented to the atmosphere through the cooling tower.

Power Plant Emissions

The production steam is piped to the turbine and the exhaust steam is condensed on the shell-side of a surface condenser. Noncondensable gases from the condenser are also vented to the atmosphere via the cooling tower. The "worst case" H₂S emissions from the 10 MW plant would include H₂S from both the steam production system (23.4 kg/h) and the condenser (1.6 kg/h), amounting to 25 kg/h.

FIG. 8. Schematic of a power plant utilizing a liquid dominated resource to produce flashed steam. (Adapted from Ref. 3, p. 37) *Assuming all gases emitted.

LIQUID-DOMINATED BINARY PLANTS

The only similarity of H_2S emissions between fields developed for flash system plants and those developed for binary system plants, is in the well drilling and testing phases. Since standard drilling procedures are used, the magnitude of the H_2S release will depend on the quantity of the gas in the liquid resource.

During normal binary plant operation, the geothermal fluid is passed through the tube side of a heat exchanger to transfer the heat energy to a secondary fluid such as isobutane. The heated secondary fluid is expanded through a turbine to turn a generator. The spent geothermal fluid from the heat exchanger is sent to injection wells for disposal. This fluid still contains the noncondensable gases including H_2S .

One possible perturbation to the injection process is the fact that precipitation may occur in the cooled spent fluid due to lower solubilities of the various dissolved solids. This is especially likely in those resources containing high Total Dissolved Solids (TDS). Precipitates in the injected fluid could cause plugging of the walls in the injection well and destroy the permeability of the injection strata, thus destroying the usefulness of the well. To prevent this, it may be necessary to pump the fluid into settling ponds or reactor-clarifiers to allow the precipitates to settle, and then filter and pump the clarified supernatant fluid into the well. Depending on the chemistry of the spent fluid, the H_2S would remain mostly in the fluid if the pH were high enough, or precipitate the sulfides of certain cations in the solution. If resources high in hydrogen sulfide were used, closed reactor-clarifier units rather than settling ponds may be required to suppress emission of the gas to the atmosphere.

STEAM STACKING

Steam stacking is a major source of H_2S emissions. This occurs (as described earlier) when emergency conditions require shutdown of the turbines and the plant steam is bypassed to the atmosphere. The increase in emissions caused by steam stacking at an abated plant can have a major effect on the total emissions of the development during the time of the release. An example to illustrate the effect of sudden steam stacking at The Geysers is described below.

Total emission data for all units (1-11), taken from tables in Ref. 12, show for 7 mo in 1977:

(1) Average emissions without abatement	= 865 kg/h
(2) Average emissions with 43.5% abatement	= 489 kg/h
(3) Unit 11 emissions without abatement	= 246 kg/h
(4) Unit 11 emissions with abatement	= 57 kg/h
(5) Unit 11 emissions due to stacking [(3)-(4)]	= 189 kg/h

From the above it can be shown that the increase in total emissions due to steam stacking Unit 11 would be 38.7%, and the overall abatement would be reduced from 43.5% to 21.6%. This is a significant change, and the effect on local ambient H_2S measurements could reveal violations of the California standard of 30 ppb (for 1 h) during the period of steam stacking.

Local Air Pollution Control Districts (APCD's) have set up tentative standards for total (absolute) amounts of H_2S emissions allowable based on the total electrical generating capacity of The Geysers development to the year 2000. The control requirements are covered in Section V.

Steam stacking at power plants using liquid-dominated resources will probably not be a problem of the same magnitude as it is at The Geysers. This is primarily because "shutting-in" a liquid resource well poses less threat of damaging the well since the fluid remains hot when flow is stopped. Also, if steam is not flashed off the fluid, the entire flow can bypass the plant and be injected back underground. There may be times of short duration when flashed-steam plants would resort to steam stacking during the period required to close down the producing wells. Flashed-steam plants that use upstream condenser-reboiler systems for separating noncondensable gases along with H_2S removal can stack production steam without serious environmental hazard.

V. HYDROGEN SULFIDE CONTROL REQUIREMENTS

Concentrations of H_2S less than $14,000 \mu g/m^3$ (10,000 ppb^{*}) are usually considered to be non-toxic²⁶. However, the odor is readily detectable for most people at concentrations of $35 \mu g/m^3$ (25 ppb)²⁷ and

^{*} parts per billion

can be detected by some at concentrations as low as $10 \mu\text{g}/\text{m}^3$ (7 ppb). Exposure to these low concentrations has little or no significance to human health,²⁷ but may be beneficial to some plant species. Nevertheless, the low odor detection threshold provides the basis for public antagonism to H_2S emissions from geothermal development.

Control of H_2S emissions from geothermal energy processes is necessary to minimize the odor nuisance and to avoid exceeding ambient air quality standards. The degree of control needed depends on the emission limitations imposed by the standards. Emissions and ambient concentrations are related but not definitely correlatable. It is not possible now to calculate an allowable emission rate based strictly on an ambient standard at the property line or some other point. Although emission limits must be stipulated, they cannot be completely definitive until the geothermal industry has been more firmly characterized with improved operational and environmental control technology, adequate field measurements, and sophisticated modeling studies.

MEASUREMENTS OF AMBIENT H_2S CONCENTRATIONS

At The Geysers, several measurement programs have been undertaken to determine the frequency of occurrences of ambient H_2S concentrations higher than the state standard of 30 ppb ($42 \mu\text{g}/\text{m}^3$). Several organizations have participated in collecting data using a variety of instruments and procedures. At the present time no extensive fixed site monitoring stations are operating. Lake County APCD, however, does operate two fixed site stations.

In 1976, SRI International established a data collection network of eight monitoring stations (Fig. 9) funded by PG&E, Union Oil Company, Aminoil U.S.A., and Thermogenics, Incorporated. Each of the monitoring sites was equipped to measure H_2S concentration, wind speed and direction, temperature, dew point, and precipitation. All data was collected automatically and transmitted to a central station for subsequent analysis.

FIG. 9. Locations of H₂S pollution roses and monitoring stations in the SRI network at The Geysers. Pollution roses are average concentrations in ppb associated with winds in a given direction. Data was presented by R. Ruff at the LLL geothermal workshop (Sept. 27-28, 1977) on air quality at The Geysers.

The SRI data obtained for 1976²⁸ indicate that the California state standard was, on the average, equalled or exceeded less than 0.5% of the time at the Cobb Valley stations. At these stations (3,4,5,6, and 7), the percent of days with at least one hourly average reading at or above 30 ppb were 6, 11, 8, 1, and 7 respectively. For the two stations on the ridge (1 and 2) the state standard was exceeded 7 and 10% of the time respectively, and just over half the days had at least one hourly average reading at or above 30 ppb.²³

Pacific Gas and Electric has also made numerous H₂S concentration measurements at approximately 30 sites in The Geysers area. Data indicate that H₂S concentrations are usually below 30 ppb outside The Geysers area. However, values of several hundred parts per billion were found within The Geysers complex. Average values of these measurements are shown by the circled figures in Fig. 10. Altshuler's²⁹ summary of the PG&E measurements shows the highest single H₂S concentration measured was 870 ppb just east of Units 3 & 4 cooling towers when west winds blew the cooling-tower plume directly towards the sampler.

Other organizations that have taken similar measurements include the Lake County APCD, Environmental Systems and Services (ES&S), and the California Air Resources Board (ARB). Their measurements have confirmed and supplemented the findings of SRI and PG&E.

In addition to H₂S measurements, extensive meteorological measurements have been made at the Geysers to establish a correlation between the geothermal plant emissions and ambient concentrations. These data may lead to predictions of when odor complaints will occur or when pollutant concentrations will exceed ambient air quality criteria. The extent of these measurements has been reported by Rosen and Molenkamp.²³

MODELING

The DOE is sponsoring a program for Atmospheric Studies in Complex Terrain (ASCOT) which is designed to develop the technology needed to perform air quality impact assessments for new energy sources in areas of highly complex terrain. The program will integrate theoretical research, mathematical model development, field measurements, and physical model experiments to improve fundamental knowledge and develop techniques for predicting pollutant transport and dispersion in terrain-dominated flows.

FIG. 10. Average H_2S concentrations (ppb) measured by PG&E at The Geysers power plant. Data taken from Ref. 2.

Although not a control technology per se, the program will aid in determining the degree of control needed to mitigate the effects of H_2S releases and other emissions from the geothermal area. Since The Geysers eminently qualifies as a complex terrain area, the study will be centered there. The main program goal during the first 3 y is to develop an improved capability for assessing the impact of geothermal power generation on air quality within typical valley drainage flow patterns. Results and techniques developed during the study can be applied to other regions where drainage winds are important in evaluating the air quality impact from power generating sources. The program officially began in October 1978.

In the Imperial Valley, limited air quality measurements have been made to establish baseline data for future geothermal development. A recent report by Ermak et al.³ contains predictions, based on modeling techniques, of ambient air quality concentrations for H_2S and other gaseous emissions from uncontrolled geothermal development as projected for the Imperial Valley. The main power level assessed in the study is 3000 MW. The siting pattern for 30 power plants at this level of development is shown in Fig. 11, with isopleths of the predicted annual ground level concentrations plotted in Fig. 12. Conclusions from this study indicate that with no abatement:³

- The California 1-h standard for H_2S ($42 \mu g/m^3$) would be exceeded at ground level a significant amount of time over a large fraction of the valley. The standard would be violated at least 1% of the time over an area of approximately 1500 km^2 surrounding the power plants in the Salton Sea area and extending over the power plants in the Brawley area. Similar episodes would probably occur over areas of approximately 5 to 10 km^2 surrounding the clusters of power plants in the Heber and East Mesa areas.
- The northern cities in the valley would receive the highest H_2S exposure. The standard would be exceeded 10% of the time in Calipatria on about 245 days each year, and Niland and Brawley would experience similar violations 2% of the time on about 73 days each year. In the cities of Heber, Calexico, and Holtville in the southern part of the valley, the standard would be exceeded on about

14 days each year, and in Mexicali, Mexico, a couple of days each year. No breaches of the H_2S standard are predicted for the central valley cities of El Centro and Imperial.

- Model calculations for a single power plant indicate that the H_2S standard is not exceeded beyond a distance of about 1 km when the emission rate is less than 0.8 g/s.
- The model predicts that nearly the entire valley--approximately 5000 km^2 --would experience concentration levels in excess of 10 $\mu g/m^3$ (the average odor threshold) at least 1% of the time.

It can be seen from the foregoing that the occurrences of H_2S concentrations above the state standard at The Geysers and predicted to occur in the Imperial Valley, demand that H_2S emissions be abated to levels that prevent air quality violations.

FIG. 11. Siting pattern for 30 power plant units in the 3000 MW scenario.

FIG. 12. Isopleth plot of the annual average ground level H_2S concentration in $\mu g/m^3$.

REGULATORY CONTROL ASPECTS

The existing ambient air standard for California is 0.03 ppm ($42 \mu\text{g}/\text{m}^3$) for a Time Weighted Average (TWA) of 1 h, not to be exceeded more than one time each year. A similar standard exists for New Mexico at 0.003 ppm. The New Mexico standard is below the olfactory detection threshold for most humans, and below the detection limits for most field analytical instruments. At these concentrations there are few, if any, adverse health effects. Hydrogen sulfide concentrations in the facility work environment (i.e. in or near the power plant) may be of greater health significance. Table 7 lists fairly recent suggested permissible concentrations of H_2S in workroom air.

TABLE 7. Suggested permissible concentrations of H_2S workroom air.

Organization	Permissible Concentrations
OSHA ^a	28 $\mu\text{g}/\text{l}$ (20 ppmv) acceptable ceiling concentration for an 8-h shift
	70 $\mu\text{g}/\text{l}$ (50 ppmv) acceptable maximum peak concentration for one 10-min period during the 8-h shift
ACGIH ^b	14 $\mu\text{g}/\text{l}$ (10 ppm) 8-h TWA
	21 $\mu\text{g}/\text{l}$ (15 ppm) short-term (15 min) exposure limit

^aOccupational Safety and Health Administration, U. S. Department of Labor. Ref. 28 (1974).

^bAmerican Conference of Governmental Industrial Hygienists. Ref. 24 (1975).

Proposed State of California regulations are discussed in a memorandum by Moyer and a paper by Joyce and Fontes (Appendix D).

To illustrate the regulatory requirements of a local authority, a regulation of the North Sonoma County Air Pollution Control District (NSCAPCD) is given:

- Rule 455 - a. No person shall discharge into the atmosphere from any geothermal operation sulfur compounds calculated as sulfur dioxide (SO_2), in excess of 1,000 ppm.
- b. No person shall discharge H_2S into the atmosphere at a rate which exceeds those set forth in Tables 8 and 9.
- c. A summary of the data required to determine compliance with applicable provisions of this rule shall be submitted to the Control Officer. This summary shall be presented in the manner, frequency and form as prescribed by the Control Officer.

TABLE 8. H_2S discharge rates for geothermal power plants^{a/}.

Effective Date ^{b/}	<u>In operation before January 1, 1980</u>		Any plant beginning operation after Jan. 1, 1980
	With direct contact condenser ^{c/}	With surface condenser (g/hr/GMW)	(g/hr/GMW)
Jan. 1, 1979	For Units 3, 4, 5, 6, 11, and 12 emit: no more than 10% of the H_2S in the supplied steam at full power plant load or 200 g/hr/GMW average using allocation method ^{h/}	-	-
Jan. 1, 1980	<u>i/</u>	100	100
Jan. 1, 1982	Units 3-6, 11, and 12: 200 g/hr/GMW ^{i/}	-	-
Jan. 1, 1985	<u>i/</u>	-	50 ^{j/}
Jan. 1, 1990	-	50 ^{j/}	-
Jan. 1, 2000	100 g/hr/GMW ^{j/}	-	-

TABLE 9. H₂S discharge rates from steam transmission lines^{a,g}

Effective date ^{b/}	Existing or permitted systems as of June 1, 1978	New systems	Other geothermal sources	
			Well drilling, reworking, and testing (kg/hr/well)	Small source emissions (kg/hr/source)
June 1, 1979	Upon an unscheduled outage an operator shall within 4 hr or less reduce H ₂ S emissions: (a) by 90% or more for dual units, or (b) by 50% or more for single units or when both units of a dual unit system have a simultaneous outage, or (c) to not more than 15 kg/hr. For scheduled outage the same emission standards shall be met within 1 hr or less.	Upon an unscheduled outage the operator shall within 4 hr or less reduce H ₂ S emissions: (a) by 90% or more, or (b) by 50% or more when both units of a dual unit system have a simultaneous outage, or (c) to not more than 15 kg/hr. For a scheduled outage the same emission standards shall be met within 1 hr or less.	5 ^{e/}	-
Jan. 1, 1980	<u>d/</u>	<u>d/</u>	2.5 ^{e/}	2.0 ^{f/}
Jan 1, 1982	To be promulgated by A.P.C.O. ^{g/}	To be promulgated by A.P.C.O. ^{g/}	-	1.0 ^{f/}
Jan. 1, 1985	-	-	-	0.5 ^{f/}
Jan. 1, 1990	-	-	-	-
Jan. 1, 2000	-	-	-	-

FOOTNOTES FOR TABLES 8 AND 9

- a/ All geothermal power plants, including new construction, must comply with future emission rate reductions as they become effective.
- b/ H₂S emission limitations for each category of emission source will become effective henceforth on the date indicated at the left of the Table.
- c/ "g/hr/GMW" shall equal "grams per hour per gross megawatt." The rates of emission may be equaled but not exceeded. Compliance shall be verified by the source testing method approved by the District for the applicable emission source.
- d/ The Air Pollution Control Officer shall after proper notice and public hearing promulgate on or before January 1, 1980, the emission standards commencing January 1, 1982, based upon a review of available control technology, air quality, emissions, and extent of development.
- e/ Individual well emissions shall be limited to 5 kg/hr/well (2.5 kg/hr/well after January 1, 1980) unless a higher rate was determined by new source review or unless applicant provides data which subsequently can justify a redetermination of the emission rate by the Air Pollution Control Officer.
- f/ Small sources include continuous well and pipeline bleeds. Allowable emissions are those shown in Table 9 unless otherwise determined by the Air Pollution Control Officer.
- g/ "Reduce H₂S by 50%" shall mean emit no more than 50% of the H₂S normally found in the supplied steam at full power plant load. "Dual units" shall refer to those steam transmission lines associated with two power plant units located in the same building and therefore such associated steam transmission lines shall be considered as one source.
- h/ Allocation method: If less than 200 g/hr/GMW is attained at one power plant unit, the reduction (in grams H₂S per hour) can be credited to another power plant unit or apportioned to other power plant units. For instance, a 10-MW plant can be allowed to emit 2,000 g H₂S/hr; but if a credit of 500 g H₂S were allocated, it could emit 2,500 g

H₂S per hour or 250 g/hr/GMW. The allocation should be modified no more than quarterly and only if needed based on new data. (The major purpose of the allocation method is for individual power plant unit compliance verification and credit for greater H₂S reduction than 90%.)

- i/ For Units 1, 2, 7, 8, 9 and 10, the Air Pollution Control Officer shall after proper notice and public hearing promulgate on or before January 1, 1980, the emission standards commencing January 1, 1982, and January 1, 1985, based upon a review of available technology, air quality, emissions, and extent of development.
- j/ The Air Pollution Control Officer, 1 year prior to each achievement date, shall, after review of air quality, extent of development, emissions, and available control technology, promulgate a new source emission standard if different than presently set forth after proper notice and public hearing.

TECHNICAL CONTROL ASPECTS

There are certain technical requirements desirable for an environmental control technology to be efficient in H_2S abatement:

- The process must be economical so that costs to the producer (and thus to the consumer) are not prohibitive.
- An abatement process should not increase hazards to plant workers or to the environment. Some processes require the use of hazardous chemicals such as hydrogen peroxide (H_2O_2) and concentrated sodium hydroxide ($NaOH$). These materials must be transported to the plant site and in so doing increase the opportunities for dangerous spills. Storage of chemicals may also present a hazard. Processes that regenerate the needed chemicals are preferred to those that require a continuous new supply.
- The process should not create or add to corrosion problems that may already exist. Corrosive situations markedly increase maintenance costs and operational difficulties, not only to the abatement equipment, but also to the power plant.
- The system should have a rapid response time to variations in H_2S content of the resource. Chemical systems should not be limited by slow kinetics in their reactions.
- The process should not cause excess reduced efficiencies in power conversion or other negative impacts such as excessive pressure or temperature reductions in the resource supply.
- Certain abatement processes are extremely dependent on the partitioning of H_2S in the condenser. The pH of the condenser fluid must be at an optimum value for the process in use.
- Processes must minimize the production of excessive solid wastes which may cause plugging of lines. These wastes also create a disposal problem and must be trucked to dumpsites.
- The process should not add to environmental problems because of chemicals used for abatement being emitted by the cooling tower drift.

VI. HYDROGEN SULFIDE CONTROL TECHNOLOGIES

The state of the art experience for the environmental control of H_2S from geothermal emissions has been gained by experimental techniques being developed and put into practice at The Geysers. The greatest efforts are being directed at the abatement of H_2S emissions from the major release points: the condenser vent gas ejection systems and the cooling towers. Any successful abatement technologies developed at The Geysers should be directly applicable to H_2S removal from flashed steam derived from liquid-dominated resources.

Some of the technologies for the control of H_2S in the geothermal industry have been adapted from other industrial processes such as the removal of sulfur from coal gas. Most of these are not suitable for geothermal application because of slow kinetics, high cost, or the chemical form of the sulfur waste product. Table 10 lists many of the commercial processes available. The systems that react chemically with H_2S , such as the Stretford process, seem to be better candidates for geothermal application than systems that depend on physical absorption phenomena. The end waste product of physical absorption processes is usually H_2S which requires final clean-up by a process such as Stretford.

HYDROGEN SULFIDE ABATEMENT DURING WELL DRILLING AND TESTING

Abatement of H_2S during well drilling and testing is routinely practiced at the Geysers. A system of H_2S abatement during well drilling using H_2O_2 and $NaOH$ is used effectively at the Geysers and has been described by Castrantas et al.³² A schematic taken from Ref. 32 is shown as Fig. 13. In this H_2S abatement process, $NaOH$ and H_2O_2 are spray injected into the steam as it leaves the wellhead and enters the Bloop line (exhaust line from the air drilling manifold). This procedure is used only during the air drilling phase of well completion which lasts for about 16 d.

TABLE 10. Sulfur removal systems^a

Process	Removal principle		End product	
	Absorption ^b	Chemical ^c	Sulfur	H ₂ S
Adip	x			x
Alkazid	x			x
Carl Still	x			x
Claus		x	x	
Benfield		x		x
MDEA	x			x
Purisol	x			x
Rectisol	x			x
SCOT	x			x
Selexol solvent	x			x
Stretford		x	x	
Sulfiban	x			x
Sulfinol	x			x

^aFrom Ref. 33.^bRemoval based on physical absorption.^cRemoval based on chemical reaction.

FIG. 13. A typical geothermal drilling/muffler setup.

FIG. 14. Hydrogen sulfide emissions during drilling.

Abatement is achieved by absorption of the H_2S into the NaOH spray (which is injected ahead of the H_2O_2) to form bisulfide (HS^-) and sulfide S^{-2} ions:

The intermediate ions are then oxidized by H_2O_2 to form bisulfate (HSO_4^-) and sulfate (SO_4^{-2}) ions:

It is important that NaOH be used so that HSO_4^- and SO_4^{-2} will be formed, because these products will not revert to H_2S if the condensate pond should become acid at a later date.

The process has been effectively used during air drilling at steam flows up to 68,200 kg/h (150,000 lb/h) with up to 98% abatement of H_2S . It is effective over a wide range of H_2S concentrations (several hundred parts per million) in the steam. Figure 14 indicates the efficiency of the process (Ref. 29).

The system has proved very reliable and is being used by Union Oil Company regularly. It has been assembled as a portable skid unit to be used wherever needed.

It has been estimated that the cost to achieve 83% to 98% abatement during the final 16 d of drilling is \$6,800 to \$9,000.³²

UPSTREAM ABATEMENT TECHNOLOGY FOR POWER PLANT EMISSIONS

The release of H_2S from power plants is of major concern because about 90% of the total releases can be attributed to the power conversion process itself. Depending on the conversion process, most of the emissions occur either from the cooling tower or from the noncondensable gas ejector system.

Figures 15 and 16 show that some of the same abatement technologies can be applied either upstream or downstream of the power plant.

FIG. 15. A logic diagram to indicate some abatement technologies for control of H₂S emissions from geothermal steam plants, and where they may be applied. *Secondary treatment of the condensate may be required.

FIG. 16. Logic diagram to indicate some abatement technologies for control of H₂S emissions from geothermal liquid resource plants. When steam is produced by flashing the resource fluid, the same abatement scheme shown in Fig. 15 can be used.

Upstream abatement has a main advantage that if the power plant goes down due to upset conditions, the steam can be stacked from impunity because the released steam is low in H₂S.

A second advantage of upstream abatement is that less costly direct-contact condensers can be used instead of surface condensers. The use of direct-contact condensers would allow the application of an efficient secondary treatment system on the cooling water/condensate for removal of residual H₂S if required. Also, the on-line availability of the secondary treatment system could serve as a backup abatement system

when the primary upstream system is upset or down for maintenance. An additional benefit of upstream removal of H_2S is the reduction of corrosion effects on the turbine and the condenser/cooling water equipment.

If upstream abatement is used, there are two possible routes that can be taken: (1) treat the entire fluid to destroy the H_2S , or (2) strip the fluid of noncondensable gases and use an off-gas abatement process to remove H_2S . Some processes with potential application to upstream abatement follow.

The EIC Copper Sulfate Process

Upstream absorption of H_2S by aqueous cupric sulfate ($CuSO_4$) solution has been investigated by the EIC Corporation of Newton, Massachusetts, with funding from both DOE and PG&E.^{33,34}

In the EIC copper sulfate process, the steam is contacted in a scrubber with a recirculating dilute solution of copper sulfate. Copper was selected because its sulfides are sufficiently insoluble, even at high temperature and acidity, to create favorable equilibrium and chemical kinetics. The initial chemical reaction taking place within the scrubber is approximately:

H_2S (in steam) + $CuSO_4$ (aqueous) $\rightarrow$ CuS (ppt) + H_2SO_4 (aqueous).
With extended residence time of the precipitated copper sulfide (CuS), sulfur is formed by the following reaction:

A simplified flow diagram of the scrubbing process is shown in Fig. 17. The scrubber is a simple tray-type tower, although Venturi scrubbers and packed towers have also been evaluated. Geothermal steam passes through the scrubber where H_2S and other pollutants (NH_3 and B) are removed. The scrubber solution containing insoluble precipitates is partly recycled to the scrubber, the remainder sent to the regeneration system. Ammonia is added to the scrubbing solution to maintain the pH within the range of 1.2 to 1.5.³⁰ The precipitate in the recycled slurry is a mixture of cuprous sulfide (chalcocite, Cu_2S), cupric sulfide (covellite, CuS), and

elemental sulfur. The cuprous sulfide fraction has a composition of from $\text{Cu}_{1.8}\text{S}$ to $\text{Cu}_{1.95}\text{S}$.³³

FIG. 17. Simplified flow chart of the EIC copper sulfate process.

Two methods of regenerating copper sulfate for recycling to the scrubber column can be used. Both are adaptations of methods used for production of copper metal from sulfide ores.

One is to use a "sulfating roast," which yields copper sulfate and drives off sulfur dioxide, which would have to be recovered by absorption or conversion to sulfuric acid. The reactions are as follows:

The other is acid pressure-leaching in which a slurry of copper sulfide in sulfuric acid solution is treated with air or oxygen under elevated pressure and temperature. Depending on the conditions used, the sulfide can be oxidized to sulfate or elemental sulfur. The possible reactions for copper sulfate regeneration are:

The possible reactions for elemental sulfur formation are:

In addition to H_2S , particulates and approximately 80 to 90% of the ammonia and boric acid are removed from the steam. Details of the theoretical considerations and laboratory research can be found in Ref. 34.

The above process is undergoing exhaustive testing by PG&E and EIC on Unit 7 at the Geysers as an upstream abatement technology. The pilot plant (shown in Figs. 18 & 19) is one-tenth scale (for a 55 MW plant) and processes 100,000 lb of steam/h. The results have been encouraging. Recent tests, after about 350 h of operation, have shown that 95 to 98% removal of H_2S from the steam is feasible. Copper sulfate is regenerated by the pressure-leaching method. It has been found that the kinetics of the regeneration process is better than that anticipated from laboratory experiments. If these promising results continue with additional testing, plans for a full-scale plant may be pursued.

One of the concerns of the EIC copper sulfate process has been the possible effects of entrained copper sulfate and elemental sulfur in the scrubbed steam. Analysis of the steam downstream of the pilot plant shows less than 1 ppm copper. It has been feared that even this small amount will eventually cause significant plating of copper on the turbine blades and other parts of the power conversion equipment, leading to corrosion by bimetallic coupling. Because of this, PG&E has not been returning the scrubbed steam to the turbine steam supply line. It is now thought, however, that copper entrained in the scrubbed steam will react with the residual H_2S in the steam to form copper sulfide particles and thus

FIG. 18. Photo of the EIC process pilot plant scrubbing tower on PG&E's Unit 7, The Geysers.

FIG. 19. Photo of the EIC pilot plant CuSO_4 regeneration unit.

eliminate the plating and bimetallic corrosion problems. On considering this hypothesis, PG&E will soon begin returning the scrubbed steam to the turbine supply line. The affect of elemental sulfur in the scrubbed steam on the turbine has not yet been determined.

Solid Sorbents

Battelle Pacific Northwest Laboratories of Hanford, Washington, has investigated several solid sorbents for the removal of H_2S from geothermal steam.³⁵ Two processes have been extensively studied: sorption (both physical and chemical) by solid sorbents, and catalytic oxidation in the presence of oxygen.

The solid sorbents studied were zinc oxide and a carbonaceous polymeric sorbent. Experiments showed that the materials were promising for their ability to remove H_2S from steam, but regeneration of the materials was difficult if not impossible. Regeneration of the spent carbonaceous polymeric sorbent required superheated steam in an amount equal to or more than the amount of steam treated. When zinc oxide was regenerated at $700^{\circ}C$, the sorption characteristics decreased markedly. It is believed that this decrease is due to the reduced surface area of the regenerated zinc oxide, which was 5% of the original surface area. The investigators concluded that regenerating the solid sorbents tested is either technically too difficult or too expensive for practical application.

Deuterium Process

The Deuterium Corporation of White Plains, New York, has installed and tested a device to remove H_2S from the geothermal fluid before it reaches the plant. A pilot test unit having an estimated capacity of 1,000 lb/hr (steam) was tested at the Geysers Unit 7. Early test results indicate a removal efficiency of at least 90%.⁸

The Deuterium process is believed to use a liquid absorption scrubber, but process details and the chemical reaction used are considered proprietary. Another process, the "GS Process" for heavy water, uses

H₂S, and the scrubbing process is intended as a component of a heavy water production facility. Development and marketing of the scrubber as a H₂S control process appears doubtful.

As shown in Fig. 15, the other route to upstream H₂S abatement is to separate the noncondensable gases from the steam and then apply an appropriate environmental control technology to remove H₂S from the off-gas stream. Steam converters are used to accomplish the separation and suitable control technologies would include the EIC copper sulfate system described above or the Stretford process to be described later. It should be pointed out here, however, that use of the Stretford process upstream instead of downstream would obviate the need for surface (tube and shell) condensers at the power conversion plant, and thus provide a substantial saving of capital costs.

Steam Converters

Although not a true H₂S abatement process, steam converters have the capability of separating H₂S and other dissolved gases from steam. Abatement controls to remove H₂S from the separated gases would be required to supplement this process.

A schematic of a typical steam converter is shown in Fig. 20. The enthalpy of the geothermal steam fraction is transferred in a heat exchanger (converter) to a secondary stream of condensate. The steam loses part of its heat, condenses, and gases are removed in a gas stripping column. The condensate is then reflashed in the secondary coils of the heat exchanger. The basic principle of the steam converter is that when steam is condensed by removing heat, the resulting condensate is relatively free of dissolved gases which remain mostly in the gas phase.⁸ The heat from the condensing steam is used to reboil the clean condensate producing relatively clean steam. The condensing and reboiling processes are the two sides of the heat exchanger.

The original steam converters used at Lardarello, Italy, were used to achieve separation of boric acid from steam. As shown in Fig. 20, a small

FIG. 20. Schematic of a typical steam converter unit.⁸

residual condensate stream remains after evaporation, and this contains most of the boric acid. The original steam converters which date back to pre-1940 were relatively inefficient, but more recent design concepts offer the promise of relatively high efficiency.

A small steam converter, processing only several hundred pounds of steam per hour, is being tested for proof-of-concept at the Geysers by PG&E and Coury Associates, Incorporated (Lakewood, Colorado). Preliminary information which is sparse at this time, indicates about 90% separation of H_2S from the steam. Additional tests are underway to determine the extent of scaling, corrosion, heat loss, and other operational problems.

The efficiency of steam converters for separating H_2S from the steam depends on its partitioning between the gas phase and the liquid phase. The partitioning depends on the pH of the condensate (which in turn depends on the composition of the gas phase, mainly the amounts of CO_2 and NH_3), the temperature and pressure conditions, the volume of the liquid phase, and the concentration of the H_2S in the raw steam.

Another concern with the use of steam converters is the loss of enthalpy of the steam, which will lower the ability of the steam to do work. Some of this loss of energy may be compensated for because upstream removal of the noncondensable gases will reduce the backpressure on the downstream side of the turbine, thus increasing the turbine efficiency. In addition, the diminished off-gas stream will require much smaller ejectors having much lower energy demands. Also, as mentioned before, upstream H_2S removal means that direct-contact condensers can be used instead of surface condensers. All these factors could offset most of the losses expected from reduced enthalpy of the steam.

Dow Oxygenation

The Dow oxygenation process³⁶ is an upstream technology for liquid-dominated resources. Gaseous oxygen is used for the removal of H_2S at the wellhead. Most of the experimental work (Ref. 36) has involved the treatment of simulated hot geothermal brine. The overall reaction which is believed to take place is as follows:

Lesser but significant amounts of sulfide and free sulfur are also formed by other reaction paths. Approximately 90% H_2S abatement was achieved in the laboratory at pH 7 and $171^\circ C$ at a 1.5 mole ratio of injected oxygen to H_2S . The oxygen is injected through a flow controller into a packed column.

Corrosion is a major problem if excess oxygen is injected. This requires very close monitoring and control of the oxygen injection system. A proposed design concept for the system is shown in Fig. 21.

FIG. 21. Conceptual design of Dow oxygenation processing using a packed column (design case II).³⁶

Reaction times with all-liquid resource fluid is about 1 min. However, the reaction with vapor is too slow to be feasible for steam or two-phase fluids. Two phases can be expected with high temperature liquid-dominated resources unless down-hole pumps are used to keep the fluid in an all-liquid state. The long term reliability of down-hole pumps has yet to be established. Because of these problems, work on this process has been discontinued.

SRI Electrolytic Oxidation Process

SRI International, under Environmental Protection Agency (EPA) funding is studying a direct electrolytic oxidation procedure for the removal of H_2S from saline solutions. The present laboratory-scale experiments are being performed in a single stage process using solutions that contain from 1 to 30 ppmw H_2S with salinities of 16 g NaCl and 200 g NaCl/l.

The oxidation reaction

takes place at a flow-thru vitreous carbon anode with a porosity of 95%; at a temperature of 200°C; and a pressure of 900 to 1000 psi. Early results indicate that better than 95% removal of H_2S can be achieved by the process. The system is precisely controllable, and the electrochemical aspects should be easy to scale-up. However, difficulties may be encountered with mechanical and physical scale-up.

DOWNSTREAM ABATEMENT TECHNOLOGY FOR POWER PLANT EMISSIONS

Condensers and Partitioning

When downstream technologies are used for the abatement of H_2S , the major concern is the partitioning of the H_2S between the gas phase and the aqueous phase in the turbine condenser. In addition to temperature, the pH of the condensate is a significant factor in the distribution of the H_2S . This is shown in Table 11: the lower the pH, the more the H_2S partitions into the gas phase. The pH of the aqueous phase depends on the quantities of H_2S , CO_2 , NH_3 , and boric acid in the steam. A discussion of condensate chemistry in contact condensers and surface condensers has been detailed by Weres et al. (Ref. 8, Sections S11.6 and S11.7).

It can also be seen that the type of condenser is important, since more H_2S is in the gas phase (at the same pH) when surface condensers are used. In a surface condenser, the steam is condensed on tubes and is in contact with only the relatively small amount of its own condensate. In a direct-contact condenser, the steam is condensed by contacting a spray of cooling tower water whose volume is about twenty times greater than that of the condensate. This large volume of water, and the more intimate contact provided by the spray, increases the amount of noncondensable gases that dissolve in the aqueous phase, and decreases the amount in the gas phase.

As previously shown in Fig. 15, the abatement technology employed to eliminate H_2S depends on the type of condenser used in the power conversion process. When a surface condenser is used, the abatement of H_2S is performed on the noncondensable off-gas stream. Units 13, 14, and 15 at the Geysers are designed with surface condensers, and the Stretford process is the abatement technology.

TABLE 11. Dependence of H_2S partitioning on pH and condenser^a.

	% H_2S in gas phase			% H_2S in aqueous phase		
(pH, aqueous phase)	(6.5)	(7.0)	(7.5)	(6.5)	(7.0)	(7.5)
Surface condenser	93	89	79	7	11	21
Contact condenser	40	30	16	60	70	84

^aAssuming 4000 ppmw noncondensable gases in steam (0.4%), the cubic feet of gas per pound of steam = $0.4/8 = 0.05$. The values in the table were estimated from the curves in Fig. A-2 (Appendix A).

Direct-contact condensers are used in all the other operating units at The Geysers (Units 1-12). On these units, abatement technologies that eliminate H_2S in the aqueous phase are applicable. The iron catalyst system is used extensively for this purpose.

Figures 22 and 23 illustrate conversion systems employing surface condensers with gas phase abatement (Stretford process), and systems using direct-contact condensers with aqueous phase abatement (iron catalyst process).

UOP Catalytic Oxidation

UOP catalytic oxidation (Sulfox^{*} process) utilizes a metal phthalocyanine compound supported by an activated carbon base to catalytically oxidize H_2S to sulfur, utilizing air as the oxidant.

^{*}Registered trademark of UOP Incorporated

FIG. 22. Schematic of geothermal steam power plant using surface condensers with Stretford H₂S abatement unit.

FIG. 23. Schematic of a geothermal steam power plant using direct-contact condensers with the H_2O_2 -supplemented iron catalyst H_2S control system.

The basic reaction may be written:

The oxidized sulfur products can vary considerably with the variations of reaction conditions. For example in an aqueous ammonical solution, the following oxidations to sulfur, thiosulfate, sulfite, and sulfate can occur:

This process was developed for use with hydrocarbon streams. A study has been recently funded by DOE to determine the applicability of this method to liquid- or vapor-dominated geothermal streams.

Any comments concerning the efficiency of this process must await the results of this study.

The Stretford Process

The Stretford process was originally designed for the removal of H_2S from synthetic fuel gases. Many Stretford units are operating throughout the world for this purpose. The process is very effective; it removes over 99% of the H_2S that enters the system. A Stretford unit under construction for Unit 13 at The Geysers is shown in Fig. 24.

The first operating application of the Stretford process in the geothermal industry is on Unit 15 at The Geysers for downstream H_2S removal. Recent tests confirm the performance of the Stretford process by abating over 99% of the H_2S that enters the unit. Initial tests indicated only about 75 to 80% of the H_2S was being partitioned into the off-gas stream. Later findings by PG&E reveal that by shifting the pH to between 6.5 and 7 approximately 91% of the H_2S was partitioned.¹

The Stretford process is a technique where the off-gas is scrubbed with a solution containing sodium carbonate, sodium metavanadate, and anthraquinone disulfonic acid (ADA).

FIG. 24. Photo of a Stretford plant under construction at PG&E's Unit 13, The Geysers.

A flow diagram of the Stretford process is shown in Fig. 25. The gas stream is scrubbed in a countercurrent flow. The H_2S is dissolved, forming bisulfide ion:

The bisulfide ion reacts with quinquivalent vanadium to form sulfur and quadravalent vanadium:

FIG. 25. Flow diagram of the Stretford process.³⁷

The reduced vanadium is regenerated to the +5 valent state through a mechanism involving oxygen transfer by the ADA:

Air passed through the solution in the oxidizer tank not only oxidizes the ADA, but also brings the elemental sulfur to the surface as a froth. The sulfur froth is removed to a skim tank; separated; washed; and melted to produce high quality sulfur.

Other processes have been considered for the abatement of H_2S in the off-gas stream of facilities that use either direct-contact condensers or surface condensers. They are less attractive than the Stretford process because of high costs, low performance characteristics, or unreliability and maintenance problems. Although not considered likely candidates at the present time, they are briefly described below.

Jefferson Lake Process

The Jefferson Lake process involves a variation of the Claus process commonly used in the petroleum industry. Gases containing H_2S are reacted with SO_2 in a catalytic reactor to form sulfur and water. Part of the sulfur is oxidized to form SO_2 , which is then recycled back to the reactor inlet.

This process is currently under investigation for use on a geothermal power plant at Cerro Prieto. Economics of the process are believed to be highly dependent on the recovery of by-product sulfur.

Burner-Scrubber Process

Noncondensable gases from geothermal fluids can be incinerated, but may require the addition of auxiliary fuel to support combustion. In the burner-scrubber process, the vent gases are incinerated, and the combustion products are scrubbed with water. Sulfur dioxide dissolved in the scrubbing liquid is returned to the condensate stream, lowering the pH in the condenser hotwell, thus causing more H_2S to be removed with the vent gases.

A full-scale prototype of the burner-scrubber concept was tested on the Geysers Unit 4.³⁸ The marginal flammability and pulsating nature of the gases from the ejectors posed some challenging engineering problems; however, these problems were overcome and the system became operational. The scrubbed SO_2 proved to have relatively little effect on the condensate pH because of the relatively large volume of cooling water required with the direct-contact condenser design--about 20 times the

volume of condensate. Therefore, much of the H_2S (40 to 60%) remained in the condensate, rather than being removed with the vent gases to the burner system. A maximum efficiency of only about 50% was achieved, based on the inlet concentration of H_2S .³⁸ For this reason, as well as unreliable operation and numerous equipment maintenance problems, work on this system has been discontinued by PG&E.

Catalyst-Scrubber Process

A variation of the burner-scrubber process is the catalyst-scrubber process developed by Union Oil Company. This process uses a catalyst to selectively oxidize H_2S to SO_2 . Since oxidation takes place without combustion, the system is potentially less complex and safer than the burner-scrubber process.³⁷ However, the efficiency of this process is not expected to be much greater than about 50%.

Ferrox Process

In the Ferrox process, the vent gas is compressed, cooled, then contacted with an aqueous alkaline solution of 3% sodium carbonate with 0.5% iron oxide suspended in the solution. The iron sulfide formed is air oxidized in the regeneration step to form a slurry of sulfur, sulfides, and insoluble oxides. The slurry is filtered to remove solids and then recirculated to the system. The sulfur-containing sludge is disposed of by landfill or other means.

The Ferrox process was, at one time, widely used in plants designed to sweeten gases containing moderate amounts of H_2S , but most such units have been long since converted to the Stretford process or shut down. Also, none of these units processed gases containing as much H_2S as is contained in geothermal effluents. Although it is probable that acceptable performance could be achieved by a multistage Ferrox unit, some development may be required. There are also some serious chemical hazards involved in the handling of the feed and waste products of a Ferrox unit.³⁹

Caustic Soda Process

The caustic soda process may be used to remove both H_2S and CO_2 from the vent gas stream. The gas is contacted with a solution containing caustic soda ($NaOH$) in a countercurrent packed tower. The spent caustic is then disposed of.

Caustic scrubbing does not appear to be an attractive process for use on most geothermal effluents since it consumes $NaOH$ on a once-through basis in removing both CO_2 and H_2S . Thus, chemical and waste disposal costs are expected to be extremely high. Dow Chemical Company has developed a caustic scrubbing process for removing H_2S selectively from streams containing CO_2 , but additional development work would be required to verify the applicability of this technique to the vent gases from any given geothermal facility.³⁹

Sodium Hypochlorite Process

In the sodium hypochlorite process, the gas is contacted with a 1 to 2% solution of sodium hypochlorite ($NaOCl$) in a Venturi scrubber to yield solid sulfur, sulfites, and chlorides. Fresh $NaOCl$ is continuously added to the solution, which is then recirculated back to the scrubber. There is no attempt to regenerate the solution. The pH is maintained at about 10.5 by the added $NaOCl$ and addition of caustic solution. When the solids content reaches about 15%, the slurry is pumped to disposal, while a fresh $NaOCl$ makeup solution is pumped into the top of the scrubber.

The literature contains very little information regarding the use of $NaOCl$ to remove large quantities of H_2S from a gas stream. Also, the manufacturers of $NaOCl$ do not have sufficient data to design such a process to treat the type of gas at the Geysers with reasonable confidence of its success. Therefore, before a unit based on this process is built, some development and pilot work would be required.³⁹

Potassium Permanganate Process

This process involves contacting the vent gas in a packed countercurrent tower with a 1 to 2% aqueous solution of potassium permanganate (KMnO_4). The H_2S is oxidized to sulfite ion with the formation of insoluble manganese dioxide (MnO_2). A blowdown stream is continuously withdrawn from the bottom of the packed tower and fresh KMnO_4 solution is added at the top.

Potassium permanganate has been successfully used to remove H_2S , mercaptans, unsaturated organic acids, and other sulfur compounds, in low concentrations from various gases. Although it has not been used to treat gases with H_2S concentrations as high as that expected for geothermal applications, it is believed that this process would be technically feasible. However, some development and pilot work would be required. There are also some serious chemical hazards associated with handling and use of KMnO_4 . Waste materials would require an appropriate disposal site. No cost information is currently available for this process.

Iron Catalyst Process

The iron catalyst system was developed by PG&E for removal of H_2S from the cooling-water/condensate stream. Units 1-12 at The Geysers are equipped with direct-contact condensers where the steam is condensed by sprays of very large volumes of circulating cooling-tower water. About two-thirds of the incoming H_2S dissolves in the water and returns to the cooling tower. About one-third is removed with the noncondensable gas stream, which is also injected into the cooling tower.

To abate H_2S emissions, ferrous sulphate is added to the circulating water upstream of the cooling tower. A ferric compound was formerly used, but the ferrous salt was found to be easier to dissolve and less corrosive to the metering system.¹¹ When the circulating water enters the cooling tower, the ferrous ion is oxidized by oxygen in the air to form ferric ion:

The ferric ion reacts with H_2S in the aqueous phase to form elemental sulfur:

The net reaction is:

Excess ferrous ion can react to form insoluble ferrous sulfide as follows:

The solid ferrous sulfide adds to the sludge loading which tends to block pipes and passageways in the cooling tower. Therefore, ferrous sulfate must be carefully metered into the cooling water.

To assure more complete oxidation of ferrous ion to ferric ion and maximize H_2S removal, the process has been modified to include the addition of H_2O_2 to the circulating water just before it enters the condenser. Sodium hydroxide is also added to maintain the optimum pH range (7.4 to 7.8).¹¹ This hydrogen peroxide-supplemented iron catalyst system is now being used on Units 3 & 4 with abatement efficiency improved to about 90%.

Corrosion is still a major problem with the iron catalyst system; as a result, mild steel fittings are being changed to stainless steel fittings. Also, carryover in the cooling-tower drift is indicated by a rust-colored coating on everything in the immediate vicinity of the plants.

The sulfur formed by the chemical reactions forms a sludge on the bottom of the cooling towers which is pumped off, filtered, and transported to a disposal site.

A schematic diagram of the H_2O_2 -supplemented iron catalyst H_2S removal system has been shown in Fig. 23.

Hydrogen Peroxide Process

The FMC Corporation has recently conducted laboratory experiments on oxidation of H_2S in samples of cooling-water/condensate streams taken from the Geysers power plant. The experiments were conducted with variations in the following parameters: H_2S solution concentration; pH; temperature; H_2O_2 to H_2S weight ratio; and ferric ion catalyst concentration.⁴⁰

Hydrogen peroxide reacts with H_2S in acidic or neutral solutions to form elemental sulfur and water:

In alkaline solutions, sulfide ion reacts with H_2O_2 to form sulfate and water:

These reactions proceed rapidly in the presence of iron catalyst in trace amounts (about 2 ppm), the reaction time being about 15 s. This is about the time normally taken for the circulating water to travel from the condenser to the cooling tower.

Results from FMC experiments indicate that the use of H_2O_2 for the oxidation of H_2S is feasible. Costs and handling problems may be significant. The oxidant is not regenerable.

Ozone

The use of ozone to oxidize H_2S in aqueous solutions has not been adequately investigated to evaluate its applicability for controlling emissions from geothermal sources. However, ozone has been used to oxidize H_2S in the gaseous phase. Elemental sulfur and sulfate are the most likely products of a H_2S ozone aqueous reaction.³⁷

The feasibility of this process will depend on which of the two reactions dominate since the second reaction requires four times as much ozone as the

first one. Therefore the cost of producing ozone will be a major factor in developing this process.

Wackenroder Reaction

The Wackenroder reaction is the liquid phase equivalent of a Claus reaction:

Laboratory experiments were performed at PG&E to determine the feasibility of SO_2 injection for H_2S control in condensate/cooling water. Such experiments evidently were successful in removing part of the H_2S .²⁴ No published reports of this work are available.

The Wackenroder reaction was part of the basis from which the burner-scrubber concept evolved, although measured rates of reaction between SO_2 and H_2S are very slow. No attempt has been made to use catalysts to accelerate the reaction rate.

Brine Scrubbing Process

A simple and inexpensive method for removing H_2S from noncondensable gas streams was identified and initially tested by LLL. When geothermal liquids are flashed to produce steam their pH increases. Hydrogen sulfide is much more soluble in the cool, higher pH fluid than in the original hot, lower pH fluid. Therefore, the spent fluid can be used to reabsorb H_2S from the noncondensable gas stream.

The method is particularly applicable for use with Salton Sea and Brawley geothermal field brines which are known to contain heavy metal ions. The H_2S absorbed in the brine reacts to form insoluble heavy metal sulfides which precipitate out and are removed prior to reinjection. At the Salton Sea geothermal field, the brines contain on the order of 65 ppm Pb, 280 ppm Zn, and 270 ppm Fe, far in excess of the stoichiometric

quantity necessary to react with all the H_2S . The reabsorption of H_2S in the spent brine is favorable because of the new equilibrium established between the gas and liquid at lower temperature and higher pH.⁴¹

The precipitation of metal sulfides is also the sulfide eliminating step in the EIC copper sulfate process.³⁴ But unlike that process, using spent geothermal fluid eliminates chemical feed costs, regeneration steps, and problems that may be associated with slurry pumping and recirculation.⁴¹

A brief test at the Geothermal Loop Experimental Facility (GLEF) by Magma Geothermal and SDG&E using the reaction chamber of a 30 gpm EIMCO clarifier as the contactor, indicated scrubbing efficiencies on the order of 97%.⁴² This adaptation of the brine scrubbing process combines H_2S abatement with preinjection clarification. There are minimal added plant costs as well as potential beneficial effects with respect to clarifier efficiency and mineral recovery from the sludge.⁴¹

In order to achieve high overall abatement of H_2S , a surface-type steam condenser will be required to minimize the volume of liquid in contact with H_2S in the gas phase, and thereby maximize the amount of gaseous H_2S to be ultimately scrubbed.⁴¹

Partitioning of the H_2S in the surface condenser will be a factor in the overall abatement efficiency. The amount of H_2S retained in the brine and subsequently desorbed in the lower flash stages and evolved with the low pressure steam, may still pose a problem.

This process may become the preferred H_2S abatement on liquid-dominated resources. It would be particularly applicable to resources such as those in the Salton Sea KGRA where heavy metal recovery may become an important by-product of power production, because H_2S is a valuable reagent for use in mineral processing.

Benfield

The Benfield (hot carbonate) process is a gas-liquid absorption process. Gas to be purified is introduced into an absorber column below a

packed section. It flows upward through the packed bed and is contacted with fresh potassium carbonate (K_2CO_3) solution flowing downward. Purified gas exits at the top of the absorber and spent solution is withdrawn at the base. The reaction is:

The spent solution is regenerated while passing downward through a second packed column, the stripper, against a rising flow of steam. Steam is condensed and separated from the acid gas and refluxed to the stripper. The H_2S then goes to a sulfur recovery unit such as a Stretford or Claus unit.

While the Benfield process is rather widely used to provide acid-gas free process streams (over 400 units are in use) the requirement of a separate sulfur recovery system severely limits its usefulness for H_2S control for geothermal energy.

VII. ANALYSIS AND ASSESSMENT OF ABATEMENT SYSTEMS

COSTS

Cost data for the control technologies described in the previous section are limited or in some cases not available. Recent published estimates are contained in Ref. 43. The cost estimates from Ref. 43 for four candidate technologies are presented as Appendix B. Table 12 compares those costs.

TABLE 12. Cost of four candidate technologies^a

Process	110 MW plant mills/kwh	Total annual cost, \$
Stretford	0.45 ^b	460,500
Iron catalyst	0.40 ^b	378,300 ^f
EIC copper sulfate	2.0 ^c	1,050,700
Dow oxygenation ^e	7.4 ^d	6,600,300

^aCost estimates from Ref. 43 (Appendix B) reflect the dollar as of the end of second quarter 1977.

^bBased on 220 ppm H₂S.

^cBased on 830 ppm H₂S.

^dBased on 500 ppm H₂S, packed column system.

^eFor a 98.2 MW plant.

^fWithout H₂O₂ supplemental treatment. If H₂O₂ supplemental treatment is used, the additional annual cost for H₂O₂ alone would be \$1,848,000 for a total of \$2,226,300. The additional cost/kWh would be 2.4 mills for a total of 2.8 mills/kWh. (Assumptions: \$0.60/lb for H₂O₂, 220 ppm H₂S, 80% plant operating factor, and 1:1 mole ratio H₂O₂:H₂S.)

TECHNICAL EVALUATION

A comparative analysis of six technical factors for H₂S control processes is shown as Table 13. These factors, related to the application of the processes to geothermal H₂S abatement, are discussed below.

(1) Potential for H₂S removal refers to the overall abatement efficiency that may be expected from the process. An exception is the value given for the Stretford process which is (as noted) for the unit itself; the overall efficiency will depend on partitioning efficiency.

(2) Status denotes the degree of development of the process. The code letters in the table are explained in the table footnotes.

TABLE 13. Evaluation of H₂S control processes for geothermal application.

Removal process	Potential H ₂ S removal, %	Status ^a	Ease of adaptability, (+,-)	Cross-media impacts	Estimated reliability	Negative factors
Upstream						
Steam converters	90+	cb	+	none	excellent	heat loss
EIC copper sulfate	98 to 99	P	+	sludge	excellent	entrainment?
Deuterium	90	P	+	unknown	unknown	proprietary
Solid sorbents	unknown	L	-	unknown	poor	costly
Dow oxygenation	90 to 100	L	+	none	good	corrosion
UOP catalytic oxidation	unknown	S	?	unknown	unknown	unknown
SRI electrolytic Oxidation	>95	L	+	unknown	unknown	unknown
Downstream						
Iron catalyst	80 to 90	U	+	sludge	good	corrosion
Hydrogen peroxide	80 to 90	L	+	unknown	unknown	costly ?
Ozone	unknown	S	?	unknown	unknown	costly
Wackenroder	unknown	L	?	unknown	unknown	unknown
EIC copper sulfate	98 to 99	S	+	sludge	unknown	unknown
Brine scrubbing	80 to 90	L	+	unknown	unknown	unknown
Off-gas stream						
Stretford	99+ ^c	U	+	none	excellent	none
Jefferson Lake	unknown	L	-	unknown	unknown	complex
Burner-scrubber	50	D	+	SO ₂	poor	many
Ferrox	unknown	A	?	sludge	unknown	unknown
Caustic soda	unknown	L	+	sludge	unknown	hazardous
Sodium hypochlorite	unknown	S	?	wastewater	unknown	hazardous
Potassium permanganate	unknown	S	?	sludge	unknown	hazardous
EIC copper sulfate	98 to 99	S	+	sludge	unknown	unknown
Benfield	unknown	S	?	unknown	unknown	produces H ₂ S

^aC - proof-of-concept pilot plant,
P - pilot plant scale,
L - laboratory scale,
U - in current use for geothermal H₂S abatement,
S - speculative,
A - abandoned,
D - discontinued.

^bTechnology to apply this process to a full scale unit has been demonstrated by Resources, Conservation Company (RCC).

^cStretford unit only; overall abatement efficiency depends on partitioning (see text).

(3) Ease of adaptability indicates whether the process can be adapted to geothermal application in a practical manner, based on its present state of development. A "+" means it may be practical, a "-" signifies it is not practical at this time, and a "?" means there is not enough information available to make a determination of the practicality of the process.

(4) Cross-media impacts indicate whether the process produces other environmental problem with its use. Examples are the production of toxic sludges or emissions.

(5) Estimated reliability refers to the "excellent", "good", or "poor" performance shown or estimated for the process, based on known actual use or pilot plant studies. As can be seen in the table, many of the processes are not advanced enough in development to make a judgment for this factor.

(6) Negative factors point out the most apparent negative factor for the process. Some are not serious concerns because the associated problems could probably be diminished by additional research or pilot plant studies. Some, denoted as hazardous, involve the handling and transportation of large quantities of hazardous chemicals, thus also qualifying as cross-media impacts.

CONCLUSIONS

The best candidate technologies for geothermal H_2S abatement are those that can be applied upstream of the conversion plant. Upstream application automatically provides H_2S abatement during steamstacking incidents.

At present one of the best candidates for upstream abatement is the EIC copper sulfate process for both vapor-dominated resources, and liquid-dominated resources using flashed steam. The EIC copper sulfate process has definitely established proof-of-concept status along with successful operational performance in moderate-scale pilot plant studies. It is one of the most promising state of the art technologies for future application to geothermal abatement of H_2S . Whether the process will be as effective in a full-scale upstream application remains to be determined. Indications are that it will, but scale-up problems can be significant.

The steam converter with a Stretford unit for H_2S abatement is another very promising candidate technology for upstream abatement. This process has been well demonstrated in other applications.

For liquid-dominated resources, the binary conversion system along with total spent fluid injection offers satisfactory H_2S abatement. At this time, the Dow oxygenation process is the best candidate for upstream treatment of the fluid itself. It is the only feasible laboratory proof-of-concept treatment for geothermal liquids. Corrosion control is the major problem, but computerized feedback for precise control of oxygen injection into the fluid may be the answer.

The Deuterium process has good potential for upstream H_2S abatement, but due to its proprietary status, is not a viable imminent possibility. It should however, remain as a consideration for future application.

The proposed method of scrubbing flashed steam off-gases with spent geothermal liquid is a promising candidate for liquid-dominated resources, provided condenser partitioning is favorable.

It has been previously stated that the best candidate technologies are those processes that can be applied upstream of the conversion plant. Until commercial upstream processes are available, the only alternative for the Geysers is to continue to apply the existing control technologies downstream of the conversion process. These are the commercially available Stretford process and the H_2O_2 supplemented iron catalyst process. Both are currently being used at the Geysers; the Stretford process on the off-gas stream at Unit 15, and the iron catalyst process on the condensate/cooling water of most of the other generating units.

VIII. RECOMMENDATIONS FOR FUTURE ENVIRONMENTAL CONTROL TECHNOLOGY

The following are recommendations for future environmental control technology programs:

(1) High priority should be given to a study addressing H_2S emissions associated with steam stacking and standby well bleeding. The study should include a systems level investigation to identify H_2S control technology options and assess their problems, needs, costs, and benefits.

(2) Examine the possibility of using the Stretford process applied upstream directly on the steam for H_2S removal in much the same manner as the EIC copper sulfate process. Both are scrubbing processes. As discussed in Section VI, the Stretford process oxidizes H_2S to sulfur by means of V^{+5} , which reduces to V^{+4} . Anthraquinone disulfonic acid is used as a regenerable catalyst to reoxidize V^{+4} . Anthraquinone disulfonic acid is used as a regenerable catalyst to reoxidize V^{+4} to V^{+5} in the presence of oxygen, so that the V^{+5} can be again used to react with additional H_2S when recycled to the scrubbing tower. One foreseen problem is the loss of ADA by steam distillation as the steam passes through the tower.

Instead of reoxidizing the V^{+4} through the ADA mechanism, it may be possible to reoxidize the V^{+4} electrolytically through the following reaction:

This would obviate the necessity of using ADA as a catalytic oxygen carrier. Laboratory experiments on Stretford solution could determine the feasibility and efficiency of this reaction scheme.

(3) Steam converter technology is a valuable upstream H_2S control process when combined with an off-gas abatement technique. Further work should be done on the steam converter for geothermal applications.

(4) The Dow oxygenation process needs additional research to determine the best method of monitoring and controlling the oxygen used to eliminate H_2S in geothermal liquid resources. The application of modern computer technology should be able to provide precise and almost instantaneous process control for maximum H_2S abatement, as well as minimum corrosion effects.

(5) It has been pointed out that Dow Chemical Company has developed a caustic soda NaOH process for selectively removing H_2S from streams containing CO_2 . The caustic solution must however, be disposed of, requiring transportation of large amounts of spent and fresh caustic solution.

Experiments could be undertaken to determine the feasibility of regenerating the caustic solution by an electrolytic process. The basic reactions for removal of H_2S are as follows:

and

the overall reaction being:

An electrolytic procedure may result in the following:

thus regenerating the caustic solution and greatly diminishing the caustic transportation hazard.

(6) Follow-up studies of the DOE-sponsored ASCOT program (see Section V) will be required to determine the degree of abatement actually needed in a given area. Where stringent controls are not needed, it may be possible to use more economical abatement systems and to avoid the use of systems requiring hazardous chemicals.

(7) Pilot plant studies on the EIC copper sulfate process should continue in order to aid designers of a full-scale plant. Many design parameters can be determined readily when an operating pilot plant is available to answer design questions.

(8) A study should be undertaken to develop reliable sampling and analysis methods for the quantification of H_2S in vented steam. Techniques for sampling turbulent flow in stacks, vent pipes, and other exhausts need to be examined, as well as the optimum analytical methods for H_2S .

(9) Since there are no existing viable processes for H_2S removal from liquid geothermal resources, promising techniques such as the SRI electrolytic oxidation experiments should continue to be investigated.

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APPENDIX A

METHODOLOGY USED FOR CALCULATION OF VAPOR-LIQUID EQUILIBRIUM DISTRIBUTION OF NONCONDENSABLE GASES-- H_2S , NH_3 , AND CO_2

This appendix presents a summary of methodology used for estimating the fractional distribution of three components--H₂S, NH₃, and CO₂--present in geothermal fluids. The fractional distribution is estimated for the vapor and liquid phases as a function of temperature, pH, vapor fraction, and liquid-to-condensate ratio. The methodology was patterned after a technique suggested by Dankwerts,^{A-1} and later implemented by PG&E in the design of H₂S removal equipment for their Geysers power plant facility.^{A-2,A-3}

The computational method is shown as a flowchart in Fig. A-1 and is described briefly below.

STEP 1. CALCULATE FRACTIONAL DISSOCIATION

The dissociation equilibrium constant for H₂S is determined for a given pH and temperature from information in Shih et al.^{A-4} For a pH less than 9, the second dissociation has only a negligible influence on the equilibrium.^{A-4} For CO₂, the dissociation equilibrium constant was determined from information given by Kent and Eisenberg.^{A-5} Ammonia was assumed to be 100% associated under the conditions encountered in geothermal brines (Table 1). Following Shih et al.,^{A-4} the fractional dissociation (α) of a given species in solution may be expressed in terms of hydrogen ion concentration as follows:

$$1 - \alpha \equiv (H^+)^2 / [(H^+)^2 + K_1 (H^+) + K_1 K_2] , \quad (A-1)$$

where H^+ = hydrogen ion concentration, g-ion/liter,

K_1 = the first dissociation equilibrium constant, g-ion/liter,

K_2 = the second dissociation equilibrium constant, g-ion/liter,

α = the fraction of a given species in solution which is dissociated.

STEP 2. CALCULATE MODIFIED HENRY'S LAW CONSTANT

Following Shih et al.,^{A-4} the modified Henry's Law constant may be expressed as:

$$H' \approx H (1 - \alpha), \quad (A-2)$$

FIG. A-1. Computational method flowchart used to determine the ratio of noncondensable gas components between vapor and liquid phases in two-phase brine flows.

where H = Henry's Law constant, mm Hg/g-mole-liter⁻¹,

H' = the modified Henry's Law constant, reduced by the fraction dissociated, mm Hg/g-mole-liter⁻¹,

= the fraction of a given species in solution which is dissociated.

Henry's Law constants for H_2S and CO_2 were determined from information given in Refs. A-4 and A-5, respectively. The Henry's Law constant for NH_3 was estimated from data given in Refs. A-6 and A-7.

STEP 3. CALCULATE DISTRIBUTION RATIO

Given the fractional dissociation of solute (Eq. (A-1)) and the modified Henry's Law constant (Eq. (A-2)), the distribution of a given component between the two phases can be determined from (a) vapor-to-liquid ratio,

(b) liquid-to-condensate ratio, and (c) initial solute concentration using methodology developed by PG&E. A-2, A-3. The equilibrium distribution ratio between vapor and liquid is directly proportional to the fraction of total fluid which is vapor. An example of the results obtained for H_2S is presented in Fig. A-2, showing the influence of vapor (noncondensable gas) fraction and liquid flow rates.

FIG. A-2. Calculated H₂S distribution ratios in vent gas for direct contact and surface condensers. *Cu ft/lb = (percent by weight noncondensable gas in steam)/8. Source: Pacific Gas and Electric Company. Ref. A-3)

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APPENDIX B

COST DATA

Most of the H₂S abatement systems have been utilized only on a limited scale or are still in experimental or pilot plant stages. The costs, therefore, must be considered preliminary judgments based primarily on the use of the technologies in related industries.^{B-1}

Published data on costs for H₂S control methods are limited or in some cases non-existent. Operation and maintenance cost estimates are based on a control system with stable operation and do not include major upset conditions or extended repair periods.^{B-1}

The costs have been standardized to the dollar value at the end of the second quarter, 1977. Capital costs have been amortized by the capital recovery factor over the estimated life of the control technology equipment at an annual interest rate of 8%.^{B-1}

Detailed cost estimates are given for four candidate control technologies:

- Stretford process

- Iron-Catalyst process

- EIC process

- Dow Oxygenation process.

These cost estimates, which follow, have been excerpted from Ref. B-1.

Stretford Process

Costs

Stretford process cost estimates are based on the process currently being designed for installation on the 117.5 MW, unit 14 power plant at the Pacific Gas and Electric Geysers facility in 1978 (Laszlo, 1976).

The installed capital cost of approximately \$2,432,000 was used as a basis for the Stretford cost estimates presented herein (Laszlo, 1976). The Geysers unit 14 will produce electrical power from a vapor-dominated resource with the following operating conditions:

- Steam quality: 180°C (355°F)
- Steam pressure: 7.8 atm (114 psia)
- Hydrogen sulfide concentration: 220 ppm average hydrogen sulfide concentration
- Steam enthalpy: 1200 Btu/lb
- Steam flow rate: 907,000 kg/hr (2,000,000 lb/hr)
- Scrubbing efficiency: 99 percent, or greater

All capital costs for the Stretford process include the differential investment required for a surface condenser in lieu of a direct contact condenser. Capital costs for units with hydrogen sulfide concentration or steam flow rates differing from those given for The Geysers unit 14 base case can be computed utilizing the following formulas obtained from Mark Griebe of the Ralph M. Parsons Company (Griebe, 1977):

$$IA = IB \left(\frac{SA}{SB} \right)^{0.4} \quad \text{for: } 0.5 < SA < 5 \text{ metric tons of sulfur per day}$$

$$IA = IB \left(\frac{SA}{SB} \right)^{0.5} \quad \text{for: } 5 < SA < 250 \text{ metric tons of sulfur per day}$$

SA = metric tons of sulfur produced per day in the desired case

SB = metric tons of sulfur produced per day by the base case (The Geysers unit 14) Stretford process.

I = Capital investment for the desired or base (A or B) Stretford process

Based on the above equations, the capital cost for a Stretford unit is assumed to be exponentially dependent upon the quantity of elemental sulfur produced. Ninety percent of the total sulfur entering the power plant as hydrogen sulfide is assumed to be removed by the Stretford process.

The following assumptions were used to estimate the annual capital and operating/maintenance costs for a Stretford unit:

- Amortization period: 15 years (SRI, 1977)
- Maintenance materials: 2 percent of the installed capital cost (Griebe, 1977)
- Maintenance labor: 10 percent downtime, requiring a two-man maintenance crew, earning approximately \$30 per hour per person
- Electrical power usage: 66 operating BHP per metric ton of sulfur produced per day (Griebe, 1977)
- Chemical cost: \$35 per metric ton of sulfur produced per day (Griebe, 1977)
- Sulfur credit: \$20 per metric ton
- Construction site: The Geysers

The accepted market value of commercial grade elemental sulfur is approximately \$40 per metric ton. However, the market value is dependent upon the demand in the vicinity of the geothermal site, and in some areas could be as low as \$3 to \$4 per metric ton (Griebe, 1977). Since geothermal sites are likely to be located in remote areas, a market value of \$20 per ton was used to compensate for transportation and other costs. A credit for the elemental sulfur produced by the Stretford process was deducted from the annual operation and maintenance cost.

The Stretford annual costs as a function of steam flow rates ranging from 100,000 kg/hr to 907,000 kg/hr for a constant hydrogen sulfide concentration are presented in Table 3. Costs as a function of hydrogen sulfide concentration varying between 220 ppm and 10,000 ppm at a constant steam flow rate are given in Table 4. Table 3 is based on a hydrogen sulfide concentration of 220 ppm, equivalent to that normally found at The Geysers. Table 4 is based on a steam flow rate of 907,000 kg/hr, equivalent to that of The Geysers 117.5 MW unit 14. Normalized total, capital, and operation/maintenance annual costs, based on the estimates given in Table 3 and 4, are presented in Figures 8, 9, and 10. The costs are based specifically on the design conditions for The Geysers unit 14 power plant and do not apply to geothermal energy conversion systems in general. At other geothermal sites, greater or lesser quantity of steam may be required to produce the same amount of electrical energy. Since the cost of a Stretford process is a function of the sulfur mass flow rate, costs will vary from those presented for other geothermal applications.

Figure 8 gives the costs, in dollars per kg/hr of steam, for steam flow rates varying from 100,000 kg/hr to 907,000 kg/hr and a hydrogen sulfide concentration of 220 ppm. Costs, in mills per KWH, for power generation capacities ranging from 12.95 MW to 117.5 MW and a hydrogen sulfide concentration of 220 ppm are presented in Figure 9. The dependency of the Stretford process costs, in mills per KWH, on hydrogen sulfide concentration in the steam is shown in Figure 10. Costs were estimated for hydrogen sulfide concentrations ranging from 220 ppm (0.022 percent) to 10,000 ppm (1.0 percent). A cost estimate for a 5.0 percent (50,000 ppm) hydrogen sulfide concentration and 907,000 kg/hr steam flow rate is not presented because the resultant sulfur production rate is beyond the valid range of the cost equation.

TABLE 3. STRETFORD ANNUAL COSTS VS. STEAM FLOW RATE.
(220 ppm H₂S)

Costs (\$)	Steam Flow Rate (kg/hr)			
	100,000	400,000	700,000	907,000*
Annual Capital	122,800	213,700	267,400	284,200
Maintenance Material	21,800	36,600	45,800	48,700
Maintenance Labor	50,000	50,000	50,000	50,000
Electrical Power	7,200	28,700	50,200	58,500
Chemicals	5,500	21,800	38,200	44,500
Sulfur Credit	-3,100	-12,500	-21,800	-25,400
Total O & M Cost	80,600	124,600	162,400	176,300
Total Annual Cost	203,400	338,300	429,800	460,500

NOTE: *Based on The Geysers unit 14 steam flow rate (Laszlo, 1976)

TABLE 4. STRETFORD ANNUAL COSTS VS. HYDROGEN SULFIDE CONCENTRATION IN STEAM
907,000 kg/hr STEAM FLOW RATE

Costs (\$)	ppm H ₂ S		
	220	2000	10,000
Annual Capital	284,200	857,400	1,916,700
Maintenance Material	48,700	146,800	328,100
Maintenance Labor	50,000	50,000	50,000
Electrical Power	58,500	531,900	2,658,300
Chemicals	44,500	405,300	2,025,500
Sulfur Credit	-25,400	-231,600	-1,157,400
Total O & M Cost	176,300	902,400	3,904,500
Total Annual Cost	460,500	1,759,800	5,821,200

NOTE: A 50,000 ppm (5% by weight) H₂S concentration at the given steam flow rate, results in a sulfur production rate beyond the range of this cost estimate.

Figure 8. Stretford annual cost vs steam flow rate

Figure 9. Stretford annual cost vs power generation

Figure 10. Stretford annual cost vs H₂S concentration

Iron Catalyst Process

(The cost analysis for this process does not include the peroxide supplement currently used at The Geysers. If the peroxide modification was taken into account, the cost estimates would be significantly higher. See note below Table 13 of main text.) - F.B.S.

The installed capital cost of The Geysers unit 11 iron catalyst system is \$1,718,000 and was used as a basis for the cost estimates presented (Laszlo, 1976). The installed capital cost includes a differential estimated investment of \$300,000 for sludge thickeners in lieu of sand filters (Galeski, 1977). The operating conditions of the unit 11 power plant are as follows:

- o Steam quality : 180°C (355°F)
 - : 7.8 atm (114 psia)
 - : 220 ppm average hydrogen sulfide concentration
 - : 1200 Btu/lb
- o Steam flow rate : 907,000 kg/hr (2,000,000 lb/hr)

Capital costs for iron catalyst systems with steam flow rates differing from that given above can be calculated using the following formula:

$$IA = IB \left(\frac{STA}{STB} \right)^{0.6}$$

STA = Steam flow rate of desired case

STB = Steam flow rate of base case (907,000 kg/hr)

I = Capital investment for the desired or base (A or B) case.

The above equation assumes that the capital investment depends exponentially on the steam flow rate according to the Williams sixth-tenths rule (Hesketh, 1973). The cost of the iron catalyst system is a function of the cooling water/condensate flow rate, which is directly proportional to the steam flow rate. Therefore, the steam flow rate is an acceptable variable in the cost equation. Capital costs were assumed not to be affected by variations in hydrogen sulfide concentration. Operation and maintenance costs for electrical power and chemical usage were assumed to be linearly dependent upon: steam flow rate (with constant hydrogen sulfide concentration) and hydrogen sulfide concentration (with constant steam flow rate). Operation and maintenance costs are difficult to estimate due to the operational problems encountered at The Geysers (Allen, 1977).

The following assumptions were used for the iron catalyst annual capital and operation/maintenance cost estimates:

- o Amortization period: 15 years
- o Maintenance materials: 1 percent of the installed capital cost
- o Maintenance labor: 10 percent down time, requiring a two man crew, earning approximately \$30 per hour per person

- Electrical power usage: 68 KW per hour (Galeski, 1977)
- Ferric sulfate usage: 0.5 kg ferric sulfate per kg of hydrogen sulfide, with a loss factor of 20 percent (Laszlo, 1976)
- Ferric sulfate cost: \$0.05 per lb or \$0.11/kg (Galeski, 1977)
- Removal efficiency: 90 to 92 percent

Construction site: The Geysers

The annual costs for the iron catalyst system as a function of steam flow rate ranging from 100,000 kg/hr to 907,000 kg/hr for a constant hydrogen sulfide concentration, and as a function of hydrogen sulfide concentration varying from 220 ppm to 50,000 ppm for a constant steam flow rate, are given in Tables 5 and 6, respectively. Table 5 is based on a hydrogen sulfide concentration of 220 ppm, equivalent to that normally found at The Geysers. Table 6 is based on a steam flow rate of 907,000 kg/hr equivalent to that of The Geysers 110 MW unit 11. Based on these tables, normalized total, capital and operation/maintenance annual costs are shown in Figures 12, 13 and 14. Generation capacities are based specifically on the operating conditions for The Geysers unit 11 power plant and cannot be applied to geothermal energy conversion systems in general. Figure 14 shows the costs, in mills per KWH, for a 907,000 kg/hr steam flow rate and hydrogen sulfide concentrations varying from 220 ppm (0.022 percent) to 50,000 ppm (5.0 percent).

TABLE 5. IRON CATALYST ANNUAL COST VS. STEAM FLOW RATE. (220 ppm H₂S)

Costs (\$)	Steam Flow Rate (kg/hr)			
	100,000	400,000	700,000	907,000*
Annual Capital	53,400	122,800	171,800	200,700
Maintenance Material	4,600	10,500	14,700	17,180
Maintenance Labor	50,000	50,000	50,000	50,000
Electrical Power	2,100	8,400	14,700	19,000
Chemicals	10,200	40,800	71,300	92,400
Total O & M Cost	66,900	109,700	150,000	178,600
Total Annual Cost	120,300	232,500	322,500	379,300

NOTE: * Based on The Geysers unit 11 steam flow rate (Laszlo, 1976)

TABLE 6. IRON CATALYST ANNUAL COST VS. HYDROGEN SULFIDE CONCENTRATION IN STEAM. (907,000 kg/hr STEAM FLOW RATE)

Costs (\$)	H ₂ S ppm			
	220	2000	10,000	50,000
Annual Capital	200,700	200,700	200,700	200,700
Maintenance Material	17,200	17,200	17,200	17,200
Maintenance Labor	50,000	50,000	50,000	50,000
Electrical Power	19,000	19,000	19,000	19,000
Chemicals	92,400	923,800	4,199,800	21,999,800
Total O & M Cost	178,600	1,010,000	4,286,000	21,086,000
Total Annual Cost	378,300	1,210,700	4,486,700	21,286,700

Figure 12. Iron catalyst cost vs. steam flow rate

Figure 13. Iron catalyst annual cost vs power generation

Figure 14. Iron catalyst annual cost vs. H_2S concentration

EIC Process

Installed capital cost and operation/maintenance costs are summarized in the EIC Corporation Annual Status Report (EIC, 1976) for a 50 MW geothermal power plant with the following design parameters:

Steam to be treated : 17,100 kg/hr (37,700 lb/hr) steam
: 53,900 kg/hr (118,900 lb/hr) inerts
: 830 ppm H₂S
: 150°C (300°F)
: 11.9 atm (160 psig)
Scrubbing efficiency : 97.5 percent, or greater
Regeneration process : Leaching
Construction site : Well-developed site, adjacent to existing facilities

The above steam conditions are based on those encountered for vent gases at the Niland geothermal loop experimental facility, located in Imperial Valley, California. The estimated installed capital cost of an EIC process removing hydrogen sulfide from steam utilized in a 50 MW geothermal power plant, operating with the above conditions, is \$4,400,000 (EIC, 1976). Total annual operating cost, including capital, is given in the EIC Annual Status Report as 1.5 mills per KWH for a 500 MW power plant.

Capital costs for EIC units with hydrogen sulfide concentrations differing from that given above for the Niland facility can be computed utilizing the following formula:

$$IA = 0.85 IB \left(\frac{HA}{HB} \right)^{0.6} + 0.15 IB$$

HA = Hydrogen sulfide concentration of the desired case

HB = Hydrogen sulfide concentration for the base case (830 ppm)

I = Capital investment for the desired or base (A or B) case

Eighty-five percent of the capital investment for the EIC process involves reactors, tanks, vessels, heat exchangers, filters, pumps, and other associated process equipment. The remaining 15 percent of the capital investment is allocated for the scrubbing tower. It is assumed that the capital investment for equipment associated with the liquid/solid separation and regeneration operations (85 percent of total) vary exponentially with hydrogen sulfide concentration according to William's sixth-tenth rule (Hesketh, 1973). The capital investment for the scrubbing tower (15 percent of total) is assumed to depend upon steam flow rate and is relatively independent of hydrogen sulfide concentration.

Assumptions used to estimate the annual capital and operation/maintenance costs for an EIC unit are (EIC, 1976):

- Amortization period: 10 years
- Maintenance materials: 2 percent of the installed capital cost
- Maintenance labor: 4 operators at \$18,000 per year per person
1 maintenance man at \$20,000 per year
1 supervisor at \$22,000 per year
- Electrical power usage: 2,200,000 KWH per year
- Water usage: 10,000,000 gallons (37.85×10^6 liters) per year at \$0.50 per 1000 gallons (3785 liters)
- Chemical and process materials:
 - sulfuric acid - 300 tons (273 metric tons) per year at \$33 per ton (\$36.30/metric ton)
 - limestone - 250 tons (227 metric tons) per year at \$8 per ton (\$8.80/metric ton)
 - precipitated copper - 37.5 tons (34 metric tons) per year at \$1600 per ton (\$1760/metric ton)
 - detinned scrap - 45 tons (41 metric tons) per year at \$200 per ton (\$220/metric ton)
 - miscellaneous - \$19,000

The EIC process annual costs for a 50 MW and 500 MW geothermal power plant are given in Table 7. The annual costs for a 50 MW power plant with hydrogen sulfide steam concentrations varying from 830 ppm to 50,000 ppm are presented in Table 8. The cost estimates given in Table 7 were derived from the basic EIC data given for a 50 MW power plant with a hydrogen sulfide concentration in the steam of 830 ppm. Capital costs as a function of increased hydrogen sulfide concentration were calculated, based on the formula given previously. Operation and maintenance costs for electrical power, water, chemicals, and process materials were assumed to increase linearly with an increase in hydrogen sulfide concentration. Normalized total, capital and operation/maintenance annual costs given in Tables 7 and 8 are shown in Figures 17, 18 and 19. The cost estimates presented for the EIC process were developed from the specific set of operating conditions previously outlined, and may not necessarily apply to geothermal resources with different operating conditions.

Figure 17 gives the cost, in dollars per kg/hr, for steam flow rates of 71,000 kg/hr and 7,100,000 kg/hr (corresponding to 50 MW and 500 MW) and a hydrogen sulfide concentration of 830 ppm. Costs, in mills per KWH, for power generation capacities ranging between 50 MW and 500 MW and a hydrogen sulfide concentration of 830 ppm are given in Figure 18. Costs, in mills per KWH, estimated for a generating capacity of 50 MW and hydrogen sulfide concentrations from 830 ppm (0.083 percent) to 50,000 ppm (5.0 percent), are shown in Figure 19.

TABLE 7. EIC ANNUAL COST FOR 50 MW AND 500 MW PLANTS (EIC, 1976). 830 PPM H₂S

Costs (\$)	Plant Generating Capacity (MW)	
	50	500
Annual Capital	655,700	3,725,800
Maintenance Material	88,000	--
Maintenance Labor	114,000	--
Electrical Power	88,000	--
Water	5,000	--
Chemicals and Process Material	100,000	--
Total O & M Cost	395,000	3,413,000 *
Total Annual Cost	1,050,700	7,138,800

NOTE: * Derived from EIC cost data for total annual operating costs (EIC, 1976)

TABLE 8. EIC ANNUAL COST FOR 50 MW PLANT VS. HYDROGEN SULFIDE CONCENTRATION IN STEAM

Costs (\$)	H ₂ S ppm			
	830	2000	10,000	50,000
Annual Capital	655,700	1,040,300	2,573,000	6,613,700
Maintenance Material	88,000	170,300	631,700	2,451,600
Maintenance Labor	114,000	114,000	114,000	114,000
Electrical Power	88,000	211,200	1,056,000	5,297,600
Water	5,000	12,000	60,000	301,000
Chemicals and Process Material	100,000	240,000	1,200,000	6,020,000
Total O & M Cost	395,000	747,500	3,061,700	14,184,200
Total Annual Cost	1,050,700	1,787,800	5,634,700	20,797,900

Figure 17. EIC annual cost vs. steam flow, rate

Figure 18. EIC annual cost vs. power generation

Figure 19. EIC annual cost (mill/KWH) vs. H₂S concentration

Dow Oxygenation Process

Preliminary capital cost estimates for both the in-line and packed column systems have been developed by The Dow Chemical Company based on the results of the laboratory investigation and the following process conditions (Dow, 1977):

- o Brine to be treated: 3785 liters per minute (1000 gpm)
 - : 40 ppm H_2S
 - : 177°C (350°F)
 - : 11.2 atm (150 psig)
- o Brine phase : single-phase liquid
- o Oxygen : hydrogen sulfide mole ratio: 1.25 : 1.0
- o Construction site : Imperial Valley, California

The preliminary installed capital cost estimates for an in-line and for a packed column system, with the above operating conditions, are \$373,600 and \$216,500, respectively. Over 31 percent of the capital cost investment for the in-line system is required for instrumentation. Ten in-line mixer trains are required due to the 100 gpm (378 lpm) mixer capacity limitation; thus necessitating a duplication of instrumentation. Capital costs would be significantly reduced if larger capacity mixers could be utilized to minimize duplication.

Capital cost for an in-line system was assumed to depend linearly on brine flow rates. This is due to the required duplication of equipment, negating any possible savings resulting from economies of scale. Capital costs for a packed column system with differing brine flow rates can be computed utilizing the following formula:

$$IA = IB \left(\frac{BA}{BB} \right)^{0.85}$$

BA = Brine flow rate of desired case

BB = Brine flow rate of base case (1000 gpm or 3785 lpm)

I = Capital investment for the desired or given (A or B) case

The capital cost of a packed column system is therefore assumed to be exponentially dependent upon the brine flow rate. The exponential factor was based on that for stainless steel packed towers, 36 to 100 inches in diameter (Hesketh, 1973). The Dow preliminary cost estimate was based on a Carpenter 20 alloy column, packed with teflon pall rings. The exponent utilized in the cost calculation applies to these materials of construction. Capital costs for the in-line and packed column systems were assumed to be independent of the hydrogen sulfide brine concentration. Operation and maintenance costs for electrical power usage and cryogenic oxygen consumption were assumed to be linearly dependent upon the hydrogen sulfide brine concentration.

The following assumptions were utilized to estimate the annual capital and operation/maintenance costs for the in-line and packed column Dow oxygenation systems:

- Amortization period: 15 years
- Maintenance materials: 1 percent of the installed capital cost
- Maintenance labor: 10 percent down time, requiring a two-man crew, earning approximately \$30 per hour per person
- Electrical power usage: 5 horsepower oxygen compressor required for 1000 gpm (3785 lpm) system (Galeski, 1977)
- Cryogenic oxygen usage: Calculated for an oxygen/hydrogen sulfide mole ratio of 1.25 : 1.0, an additional 20 percent required to account for system losses.
- Cryogenic oxygen cost: \$0.65 per 100 cubic feet (\$0.23 per cubic meter).

The annual cost of maintenance materials was taken as 1 percent of the installed capital cost because of the relative simplicity of equipment and design for the Dow process.

The annual costs of the in-line and packed column Dow oxygenation processes as a function of brine flow rates ranging from 15,000 to 350,000 l/min, with a hydrogen sulfide concentration in the brine of 40 ppm, are given in Tables 9 and 10. Annual costs for the Dow processes for a 100,000 l/min brine flow rate and hydrogen sulfide concentrations of 40 ppm, 500 ppm and 1000 ppm are presented in Tables 11 and 12. Figures 22 through 27 are graphs of the normalized total, capital and operation/maintenance costs given in Tables 9 through 12. Cost estimates for the Dow oxygenation in-line and packed column systems have been developed from specific data and conditions, thus cannot be applied to geothermal resources in general.

Figures 22 and 23 give the cost, in dollars per l/min, for brine flow rates from 15,000 l/min to 350,000 l/min with a hydrogen sulfide concentration of 40 ppm for the in-line and packed column systems. Costs, in mills per KWH, for power generation capacities varying from 14.9 MW to 347 MW and with a 500 ppm hydrogen sulfide concentration are shown in Figures 24 and 25. Generation capacities were computed based on a double flash energy conversion system with 8 percent overall efficiency, operating with brine conditions given previously. Figures 26 and 27 represent the costs, in mills per KWH, of the Dow processes as a function of hydrogen sulfide brine concentration at a 100,000 l/min flow rate (98.2 MW).

TABLE 9. DOW OXYGENATION ANNUAL COST* FOR IN-LINE SYSTEM VS. GEOTHERMAL BRINE
FLOW RATE 40 ppm H₂S

Costs (\$)	Brine Flow Rate (l/min)			
	15,000	100,000	225,000	350,000
Annual Capital	173,100	1,154,600	2,597,800	4,041,000
Maintenance Material	14,800	98,800	222,400	345,900
Maintenance Labor	50,000	50,000	50,000	50,000
Electrical Power	2,000	13,300	30,000	46,700
Oxygen	71,300	475,200	1,070,000	1,664,500
Total O & M Cost	138,100	637,300	1,372,400	2,107,100
Total Annual Cost	311,200	1,791,900	3,970,200	6,148,100

NOTE: * Derived from Dow Chemical Co. cost data for 1000 GPM in-line system (Dow, 1977)

TABLE 10. DOW OXYGENATION ANNUAL COST* FOR PACKED COLUMN SYSTEM VS.
GEOTHERMAL BRINE FLOW RATE 40 ppm H₂S

Costs (\$)	Brine Flow Rate (l/min)			
	15,000	100,000	225,000	350,000
Annual Capital	81,500	409,000	814,900	1,186,400
Maintenance Material	7,000	35,000	69,800	101,600
Maintenance Labor	50,000	50,000	50,000	50,000
Electrical Power	2,000	13,300	30,000	46,700
Oxygen	71,300	475,200	1,070,000	1,664,500
Total O & M Cost	130,300	573,500	1,219,800	1,862,800
Total Annual Cost	211,800	982,500	2,034,700	3,049,200

NOTE: * Derived from Dow Chemical Co. cost data for 1000 GPM packed column system.
(Dow, 1977)

TABLE 11. DOW OXYGENATION ANNUAL COST FOR 100,000 1/MIN IN-LINE SYSTEM VS. HYDROGEN SULFIDE CONCENTRATION IN GEOTHERMAL BRINE

Costs (\$)	ppm H ₂ S		
	40	500	1000
Annual Capital	1,154,600	1,154,600	1,154,600
Maintenance Material	98,800	98,800	98,800
Maintenance Labor	50,000	50,000	50,000
Electrical Power	13,300	166,300	332,500
Oxygen	475,200	5,940,000	11,880,000
Total O & M Cost	637,300	6,255,100	12,361,300
Total Annual Cost	1,791,900	7,409,700	13,515,900

TABLE 12. DOW OXYGENATION ANNUAL COST FOR 100,000 1/min PACKED COLUMN SYSTEM VS. HYDROGEN SULFIDE CONCENTRATION IN GEOTHERMAL BRINE

Costs (\$)	ppm H ₂ S		
	40	500	1000
Annual Capital	409,000	409,000	409,000
Maintenance Material	35,000	35,000	35,000
Maintenance Labor	50,000	50,000	50,000
Electrical Power	13,300	166,300	332,500
Oxygen	475,200	5,940,000	11,880,000
Total O & M Cost	573,500	6,191,300	12,297,500
Total Annual Cost	982,500	6,600,300	12,706,500

Figure 22. Dow oxygenation - in-line system annual cost vs. brine flow rate

Figure 23. Dow oxygenation - packed column system annual cost vs. brine flow rate

Figure 24. Dow oxygation - in-line system annual cost vs. power generation

Figure 25. Dow oxygation - packed system annual cost vs. power generation

Figure 26. Dow oxygenation - in-line system annual cost vs. H₂S concentration

Figure 27. Dow oxygenation - packed column annual cost vs. H₂S concentration

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APPENDIX C

DEFINITION OF A CLASS I AND CLASS II-1 DISPOSAL SITE

DEFINITION OF A CLASS I DISPOSAL SITE*

Class I disposal sites are those at which complete protection is provided for all time for the quality of ground and surface waters from all wastes deposited therein and against hazard to public health and wildlife resources. The following criteria must be met to qualify a site as Class I:

(a) Geological conditions are naturally capable of preventing vertical hydraulic continuity between liquids and gases emanating from the waste in the site and usable surface or groundwaters.

(b) Geological conditions are naturally capable of preventing lateral hydraulic continuity between liquids and gases emanating from wastes in the site and usable surface or groundwaters, or the disposal area has been modified to achieve such capability.

(c) Underlying geological formations which contain rock fractures or fissures of questionable permeability must be permanently sealed to provide a competent barrier to the movement of liquids or gases from the disposal site to usable waters.

(d) Inundation of disposal areas shall not occur until the site is closed in accordance with requirements of the regional board.

(e) Disposal areas shall not be subject to washout.

(f) Leachate and subsurface flow into the disposal area shall be contained within the site unless other disposition is made in accordance with requirements of the regional board.

(g) Sites shall not be located over zones of active faulting or where other forms of geological change would impair the competence of natural features or artificial barriers which prevent continuity with usable waters.

(h) Sites made suitable for use by man-made physical barriers shall not be located where improper operation or maintenance of such structures could permit the waste, leachate, or gases to contact usable ground or surface water.

(i) Sites which comply with a,b,c,e,f,g, and h but would be subject to inundation by a tide or a flood of greater than 100-year frequency may be considered by the regional board as a limited Class I disposal site.

*From Title 23, Chapter 3, Section 2510, California Administrative Code

DEFINITION OF A CLASS II-1 DISPOSAL SITE*

Class II disposal sites are those at which protection is provided to water quality from Group 2 and Group 3 wastes. The types of physical features and the extent of protection of ground water quality divides Class II sites into the two following categories.

Class II-1 sites are those overlying usable groundwater and geologic conditions are either naturally capable of preventing lateral and vertical hydraulic continuity between liquids and gases emanating from the waste in the site and usable surface or groundwaters, or the disposal area has been modified to achieve such capability.

Class II-2 sites are those having vertical and lateral hydraulic continuity with usable groundwater but for which geological and hydraulic features such as soil type, artificial barriers, depth to groundwater, and other factors will assure protection of the quality of usable groundwater underneath or adjacent to the site.

The following criteria must be met to qualify a site as Class II:

(a) Disposal areas shall be protected by natural or artificial features so as to assure protection from any washout and from inundation which could occur as a result of tides or floods having a predicted frequency of once in 100 years.

(b) Surface drainage from tributary areas shall not contact Group 2 wastes in the site during disposal operations and for the active life of the site.

(c) Gases and leachate emanating from waste in the site shall not unreasonably affect groundwater during the active life of the site.

(d) Subsurface flow into the site and the depth at which water soluble materials are placed shall be controlled during construction and operation of the site to minimize leachate production and assure that the Group 2 waste material will be above the highest anticipated elevation of the capillary fringe of the groundwater. Discharge from the site shall be subject to waste discharge requirements.

*From Title 23, Chapter 3, Section 2511, California Administrative Code

APPENDIX D

PROPOSED STATE OF CALIFORNIA REGULATIONS FOR H₂S ABATEMENT AT THE GEYSERS

Proposed California regulations concerning H₂S control at The Geysers are presented in the following.

(1) A July 1978 memorandum from the California Air Resources Board (ARB) regarding the status of The Geysers geothermal H₂S control strategy.

(2) A July 1978 paper, "Air Quality as the Limiting Factor on Development of the Geysers Geothermal Resources," presented at the Geothermal Resources Council Annual Meeting, Hilo, Hawaii, July 1978. The paper has been reproduced from Transactions, Vol. 2 (1978) pp. 345-349, with permission from the Geothermal Resources Council.

Memorandum

To : William H. Lewis, Jr.
Executive Officer

Date : July 19, 1978

Subject: Status of Geysers
Geothermal H₂S
Control Strategy

Neil A. Moyer, Technical Assistant
to Executive Office

From : Air Resources Board

At the April 26, 1978 Board meeting, the Board accepted the staff's control strategy and the requirements it encompassed. The Board directed the staff to consider some appropriate modifications in the steam supply requirements to reflect some additional industry concerns. Also, the APCOs and APCD Board representatives from Lake County and NSAPCD* were to meet with the Executive Officer and ARB staff to accelerate the process of both APCD's adopting and enforcing the same requirements for geothermal electric power development in the two counties.

Prior to the 4/26/78 meeting, the NSAPCD had since December 1977 been attempting to improve its geothermal regulations and adopt new ones. During this period and subsequently, the ARB staff has discussed and met with the NSAPCD on implementing the control strategy. On June 27, 1978, the NSAPCD Board adopted new geothermal requirements.

The staff is unaware of any effort by the Lake County APCD up to this time to adopt the elements of the control strategy.

Discussion of Control Strategy Concept

1. The control strategy is meant to apply equally in both counties throughout the Geysers KGRA. The probability of developing an alternative strategy based on extensive airshed simulation modeling seems small. The data collection efforts will be extraordinarily costly and time consuming and would further impede (unnecessarily) geothermal development.
2. Based on current information, the minimum required emission limits are feasible and necessary to generally abate H₂S and achieve and maintain the standard where it is now being violated and causing a problem.
3. Inherent with the adoption and enforcement of the control strategy are three criteria by which new geothermal projects should be compared:
 - a. Will the project meet the requisite emission limits?

*Northern Sonoma Air Pollution Control District

- b. Will the project's emissions cause a violation of the H₂S standard? (Due to location, topography, meteorology, source size, proximity of receptors, etc. A new project may need to emit less than the minimum emission limits in order to not violate the H₂S standard. However, if due to these same conditions a new project could emit more without a violation, the limits should not be relaxed since the emission limits are necessary to mitigate an areawide problem caused by many contributing sources.
- c. If the new project's applicant is already operating sources at the Geysers, are those sources in compliance with the requisite emission limits?

Implementation of the control strategy requires that new geothermal operators (i.e., DWR, NCPA, Dow) meet criteria A and B while existing operators meet all three criteria before a new project can be approved.

With these three criteria, the current NSR process is not necessary. Approval of new sources need not be tied to the performance of existing sources through "trade offs". As long as the three criteria are met and the control strategy and its emission limits are correct, "trade offs" are not necessary.

4. Presently, both APCDs require the steam production wells and the power plant to be permitted separately. This is unnecessary and unreasonably divides the project in two parts which cannot exist without each other. Also, this dual permitting further contributes to the current resolution of responsibility for H₂S released during steam "stacking" caused by a power plant outage or shutdown. PG&E currently accepts no responsibility and the steam supplier (Union Oil, now) is limited in options to fully abate this H₂S source. Complementary power plant design (i.e., dual power plant units as with Units 3 and 4, 5 and 6, 7 and 8, 9 and 10 as opposed to single units like Units 11, 12, 13, 14, 15, etc.) with well throttling to 50-65% of full steam flow and extensive steam transmission pipeline interconnections can minimize to a great extent the need to chemically abate H₂S during power plant outages. However, due to the artificial division of responsibilities between the steam supplier and user, optimum total system design is generally not being considered for future electric power development. By combining the permits, the APCO can bring the two parties together and joint responsibility can be established for H₂S released during steam "stacking".

The following is a staff comparison of the recently adopted (6/27/78) NSAPCD geothermal requirements:

Comparison of NSAPCD and ARB Requirements for
Geothermal Power Plants

<u>Effective Date</u>	<u>NSAPCD</u>	<u>ARB</u>
Jan 1, 1979	For Units 3, 4, 5, 6, 11 and 12 (equipped with direct contact condensers and Ferrifloc H ₂ S control) Emit no more than 10% of H ₂ S at full steam flow or 200 g/hr/GMW average using allocation method.	Each emit no more than 200 gm/MwHr of H ₂ S
Jan 1, 1979	None	New units constructed after this date emit no more than 175 gm/MwHr of H ₂ S
Jan 1, 1980	New units in operation after this date emit no more than 100 g/hr/GMW; for Units 1, 2, 7, 8, 9 and 10 the APCO will determine based on need requirements effective 1/1/82 and 1/1/85	New units constructed after this date emit no more than 100 gm/MwHr
Jan 1, 1982	For Units 3-6, 11 and 12, each emit no more than 200 g/hr/GMW.	
Jan 1, 1984		Units 1-12 each emit no more than 200 gm/MwHr of H ₂ S
Jan 1, 1985	New units operating after this date emit no more than 50 g/hr/GMW (not implemented until APCO hearing 1 year in advance-1/1/84)	
Jan 1, 1986		New units constructed after this date emit no more than 50 gm/MwHr of H ₂ S

Effective
DateNSAPCDARB

Jan 1, 1990

Units with surface condensers operating prior to 1/1/80 emit no more than 50 g/hr/GMW (not implemented until APCO hearing 1 year in advance-1/1/89).

All units constructed after 1/1/79 (except Unit 12) emit no more than 50 gm/MwHr.

Jan 1, 2000

Units with direct contact condensers operating prior to 1/1/80 (Units 1-12) emit no more than 100 g/hr/GMW (not implemented until APCO hearing 1 year in advance-1/1/99).

Units 1-12 emit no more than 100 gm/MwHr.

Comments on Power Plant Requirements

1. Staff is apprehensive about the NSAPCD 1/1/79 requirement for Units 3, 4, 5, 6, 11 and 12 since it may not cause the power plant operator to seriously consider permanent, effective H₂S controls for these units. The allowance for quarterly changes in allocating emission reductions between units inject considerable uncertainty in determining the actual power plant performance levels.

The following tables indicate the emissions and control requirements impacts:

<u>Unit</u>	<u>Power Rating (gross Mw)</u>	<u>Unabated Emissions Kg/Hr</u>	<u>gm/MwHr</u>
3	27.5	93.9	3415
4	27.5	84.0	3055
5	55	106	1927
6	55	143	2600
11	110	261	2373
12	110	123	1118
	385	810.9	2106 (average)

July 19, 1978

Unit	NSAPCD Requirements		ARB Requirements	
	90% reduction or 200 g/hr/GMW Emissions Kg/hr	(average)	Each to 200 gm/MwHr Emissions Kg/hr	Reduction
3	9.39	--	5.5	(94%)
4	8.4	--	5.5	(93%)
5	10.6	--	11.0	(90%)
6	14.3	--	11.0	(92%)
11	26.1	--	22.0	(92%)
12	12.3	--	22.0	(82%)
	81.09	200 g/hr/GMW avg	77.0	
	(210.6 gm/MwHr average and 729.81 kg/hr reduction)	(77.0 kg/hr total emissions and 733.9 kg/hr reduction)	(733.9 kg/hr reduction)	

The power plant operator (PG&E) has consistently indicated it does not know if any of these requirements can be met on time. Recent field studies using hydrogen peroxide and sodium hydroxide have shown considerable improvement in the dissolving of H_2S and removal in the condensate return line on power plants equipped with the Ferrifloc ("iron catalyst") process. If PG&E moves rapidly, these six units could be equipped for $H_2O_2/NaOH$ treatment by 1/1/79. Otherwise, PG&E will violate the emissions requirement and variance or abatement order actions will be necessary.

If an abatement order is enforced, up to 385 Mw of geothermal electric capacity could be lost, but only temporarily until the emissions requirement is met. PG&E contends the replacement power would come from fossil fuel-fired power plants causing increased emissions. During the winter, air quality in Northern California may not be adversely impacted by the incremental increase, and in the spring additional hydropower reserves (including Pacific Northwest intertie) are generally available. This was the case this spring and the Geysers units were substantially curtailed at night.

If a variance is enforced, staff believes the best approach would be to require supplemental $H_2O_2/NaOH$ treatment at Units 1, 2, 7, 8, 9 and 10 to the extent that the total H_2S reductions from all units operating is at least 733.9 kg/hr. Temporary addition of the Ferrifloc process to these currently uncontrolled units should not be required unless PG&E demonstrates the H_2S removal effectiveness, costs and operational efficiencies are superior to $H_2O_2/NaOH$ treatment alone.

July 19, 1978

2. The ARB requirement for new power plants on January 1, 1979 may be redundant if the construction schedules for new Units 13, 14 and 15 (equipped with surface condensers and Stretford units) continue to slip. However, NSAPCD has no requirements for new units until January 1, 1980 and at least one of the new units could be finished and not have to control its H₂S until January 1, 1980.
3. NSAPCD has yet to establish control requirements for the existing uncontrolled Units 1, 2, 7, 8, 9 and 10. Staff believes it has demonstrated the need to control these units as an integral part of the control strategy (4/26/78). The 1/1/84 effective date of the control requirement reflects a time schedule with sufficient allowance for demonstration of new control technologies (upstream abatement - EIC or Coury processes), further development and application of existing technologies (Ferrifloc with supplemental H₂O₂/NaOH treatment), and the possible retrofit with surface condensers/Stretford and supplemental H₂O₂/NaOH, if needed.

Unless existing units are controlled permanently, there will not be adequate allowance for new units and their controlled emissions.

4. NSAPCD has not fully adopted the most stringent future requirements (1/1/85 50 gm/MwHr for new units, 1/1/90 50 gm/MwHr for existing Stretford units, and 1/1/2000 100 gm/MwHr for Units 1-12) pending future determinations by the APCO. The staff believes it has demonstrated the need and to the extent possible at this time the feasibility of these limits in the 4/26/78 report to the Board. As such, these requirements serve as minimum design objectives for future developments and should focus the necessary research and development efforts. The inherent ambiguity of the NSAPCD approach will lessen this focus. Also, the APCO already has the authority and responsibility to reexamine future control requirements. Until there is unambiguous evidence that the current H₂S problems are being mitigated and future developments are proceeding without exacerbating H₂S air quality levels, these future limits appear necessary.

July 19, 1978

Comparison of NSAPCD and ARB Steam "Stacking" Requirements

NSAPCD

June 1, 1979 - existing steam transmission systems (permitted as of 6/1/78)

"scheduled" outage - if expected 4 hours or less, no abatement
if expected more than 4 hours, reduce H_2S
released within 1 hour by 90% of H_2S in the
total steam flow for dual unit power plants
and by 50% of total steam flow for single
unit power plant or when both units of a
dual power plant have a simultaneous outage
or reduce H_2S emissions to not more than
15 kg/hr.

"Unscheduled" outage - same limits as above except accomplish
within 4 hours or less

-- new systems

"unscheduled" outage - within 4 hours or less, reduce H_2S released
by 90% of the H_2S in the total steam flow
for dual units, by 65% for single units or
for simultaneous outage of both units at a
dual plant or reduce H_2S emissions to not
more than 15 kg/hr.

"scheduled" outage - same limits as above except accomplish
within 1 hour.

ARB

Jan. 1, 1980 - reduced H_2S from "stacked" steam to no more than 35% of the
 H_2S at full steam flow within 15 minutes of the outage

NSAPCD

Jan. 1, 1980 - determine need for more stringent requirements for existing
(pre 6/1/78) systems

Jan. 1, 1982 - new systems

"unscheduled" outage - same limits as 6/1/79 except kg/hr limit
to be determined by 6/1/81

"scheduled" outage - same as above, except accomplished within
1 hour, and no abatement of 4 hour or less
outage.

ARB

Jan. 1, 1986 - reduce H_2S from "stacked" steam to no more than 10% of the H_2S at full steam flow within 15 minutes of the outage.

COMMENTS

1. Through separate discussions with industry representatives and the NSAPCD, the staff has received information indicating one hour response time on outages is both reasonable and feasible. However, there appears to be no substantial reason for distinguishing between "scheduled" and "unscheduled" outages. The staff believes the NSAPCD requirements should be changed to reflect the intent of the Control Strategy that the field-wide emissions be substantially the same whether there is an outage or not. The model requirements would be:

Jan. 1, 1980 -

- A. At dual unit power plants for outages of 4 or more hours, the combined H_2S emissions of the operating unit and the H_2S from the "stacked" steam shall not exceed 110% of the maximum allowable H_2S emissions from both units allowed during normal operation and this is to be reached within 1 hour of the start of the outage.
- B. At dual unit power plants with simultaneous outage of both units expected to last 4 or more hours, the H_2S emissions shall be reduced within 1 hour of the start of the outage to no more than 50% of the H_2S present with full steam flow to both units.
- C. At single unit power plants for outages of 4 or more hours, the H_2S emissions shall be reduced within 1 hour of the start of the outage to no more than 50% of the H_2S present with full steam flow.

Jan. 1, 1981 - All new units constructed after this date, for outage of 4 or more hours, H_2S emissions released during steam "stacking" shall not exceed 110% of the maximum allowable power plant H_2S emissions allowed during normal operation and this is to be achieved within 1 hour of the start of the outage.

July 19, 1978

Jan. 1, 1986 - All units constructed prior to 1/1/81,

For outages of 4 or more hours H₂S emissions released during steam "stacking" shall not exceed 110% of the maximum allowable power plant H₂S emissions allowed during normal operations (for dual units - this is the total H₂S from "stacking" and the remaining operating unit or the total H₂S from steam "stacking" if both units are out.)

From now to January 1986, existing steam transmission system need to be upgraded through interties so power plant outages at existing units do not need to cause unnecessary steam releases. As new power plants are proposed, siting will be an important consideration if interties with existing units (like Units 13, 14, and 15) are to be made. Design of new power plants as dual units can lessen the need to intertie with other power plants to abate H₂S releases caused by power plant outages.

Comparison of NSAPCD and ARB Requirements for Other
Geothermal H₂S Sources

Well Drilling, Reworking and Testing

NSAPCD

June 1, 1979 - H₂S limited to 5 kg/hr/well unless a less restrictive limit is approved by the APCO.

Jan. 1, 1980 - H₂S limited to 2.5 kg/hr/well unless a less restrictive limit is approved by the APCO.

ARB

Jan. 1, 1980 - H₂S limited to 2.5 kg/hr/well under any conditions.

Comments: The technology (H₂O₂/NaOH) for effectively abating H₂S emissions from well drilling has been demonstrated as practical and feasible. As the geothermal resource is developed, well drilling testing, reworking, etc., will increase as the number of production wells increases and the need for make-up wells and wells for new projects increases. In order to moderate the development of an areawide H₂S source from well drilling activities, a limit of 2.5 kg/hr/well is needed. Regulation of this activity on a case-by-case basis will become unnecessarily burdensome to these two small APCDs.

Small Sources (well and pipeline bleeds, valves, meters)

NSAPCD

Jan. 1, 1980 - 2.0 kg/hr per source unless a less restrictive limit is approved by the APCO.

Jan. 1, 1982 - 1.0 kg/hr per source unless a less restrictive limit is approved by the APCO.

Jan. 1, 1985 - 0.5 kg/hr per source unless a less restrictive limit is approved by the APCO.

ARB

Jan. 1, 1980 - (Including well drilling, reworking, testing) 5 kg per 1000 Mw of electric power (5 gm/MwHr).

July 19, 1973

Comments: The staff believes the separation of well activities from other sources is an excellent idea. The NSAPCD limits seem reasonably achievable. The NSAPCD limits for other sources also seem feasible. In the long term, pipeline vents may be eliminated and steam management practices can adjust to this occurrence. However, no regulation seems warranted at this time.

Thermal 4 ("Wild Well")

NSAPCD (no requirements)

ARB

Jan. 1, 1982 - H₂S shall not exceed 1.5 kg/hr.

Comments: This source of unabated H₂S has existed since the early 1960s due to a well blowout. Thermal power (well owner) is slowly proceeding with a plan to generate some power and cause some H₂S abatement at this source. Progress has been excruciatingly slow and favorable results may not occur. Unless favorable action occurs soon, the NSAPCD well drilling limits should be applied to this source or the Division of Oil and Gas should be petitioned to cause the well owner to permanently shut in this well as part of its abandonment.

cc: Marjorie Evans
Al Gordon
Tom Austin
Ron Kukulka
Ray Tuvell

AIR QUALITY AS THE LIMITING FACTOR ON DEVELOPMENT OF THE GEYSERS GEOTHERMAL RESOURCES

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Staff Members of the Supply Assessment Office
CALIFORNIA ENERGY COMMISSION

Abstract

An air quality problem exists at the Geysers California as a result of hydrogen sulfide (H_2S) emissions from geothermal power generation. In this report the policy and legal issues engulfing the air quality problem and efforts to mitigate the problem are examined. Estimates are made of the air quality impacts of future generation capacity based on utility electricity supply plans as submitted to California Energy Commission (CEC). The status of current and developing H_2S abatement technologies is examined for availability and technical characteristics. Analysis is provided on the prospect and consequences of inadequate control of H_2S emissions. H_2S control efficiencies of less than 95 percent may ultimately be ineffective if full field development is to be achieved at the Geysers.

Introduction

Geothermal energy, although not benign, is a desirable alternative to dependency upon other finite and relatively more environmentally harmful power generation cycles. It is the "preferred" source of the CEC for the generation of electric power but H_2S emissions have caused air quality problems.

The Geysers Known Geothermal Resource Area (KGRA) has been estimated by the Jet Propulsion Laboratories to have a full field potential electric generation capacity of approximately 6200 MW. To date 502 MW (11 Units) of generation capacity has been installed by Pacific Gas and Electric Company (PG&E) and planned expansion has been slowed by H_2S problems.

Hydrogen sulfide is a noncondensable gas, usually associated with geothermal steam, which has a distinct, powerful odor affecting humans at levels of approximately .02 or .03 ppm (the latter figure being the California Ambient Air Quality Standard). Loss of the sense of smell can occur at about .06 ppm with eye irritation and fatigue resulting at H_2S levels of .06-.07 ppm. Respiratory irritation from H_2S begins after one hour of exposure to levels of 100-200 ppm and death occurs at 600-900 ppm.

Emissions and Air Quality Impacts

Measurements of the net H_2S emission from the 11 units at the Geysers have been made by the North Sonoma County Air Pollution Control District (APCD). In September 1977, a total of 1174 lb/hr of H_2S was emitted by the power plants. The use of H_2S abatement equipment, which had only been retrofit on three units at the time the measurements were taken, has proven undependable. These iron catalyst H_2S control systems have been only 40 to 70 percent effective at reducing H_2S emissions at full scale operation.

Calculations and estimates of H_2S emissions from other geothermal developmental activities were also made and nonpower plant sources of H_2S (including, well drilling, testing, well bleeds, a currently uncontrolled well, pipeline vents and natural fumerals) were estimated to emit 63 lbs/hr. Currently, about 1237 lb/hr H_2S is emitted to the atmosphere from geothermal development at the Geysers.

The meteorological and topographical conditions of the Geysers region are such that it is extremely difficult to directly correlate H_2S emissions from the power plant and air quality impacts. The general pattern has been for H_2S emissions released at the Geysers in Sonoma County to be transported to and affect the populated areas of Lake County a few miles downwind to the east.

Prevailing meteorological conditions combined with the complexity of the local mountainous terrain result in violations of the California ambient air quality standard for H_2S (.03 ppm) in Lake County. During the one-year period from October 1976 to September 1977 hourly average hydrogen sulfide levels equal to or in excess of .03 ppm were measured 1092 times by the eight station air quality monitoring network maintained in the area by Stanford Research Institute. The California Air Resources Board (ARB) estimates that it is necessary to reduce H_2S emissions by a factor of three (to about 391 lb/hr) for attainment of the air quality standard.

The Legal Framework

The Warren-Alquist Act of 1974 (AB 1575) placed the ultimate permitting responsibility for thermal power plants in California with the CEC. This means that future geothermal power plants (beginning with Unit #17) will go through the CEC Notice of Intent/Application for Certification (NOI/AFC) screening process.

The stated Commission policy is to consider geothermal as a "preferred" source for meeting electricity supply. Policy and guidance, intended to maximize the use of geothermal resources, and to support the rapid expansion of geothermal power production is being implemented. Only site specific and environmental issues will demand resolution in the siting process due to newly adopted Commission policy. Through interagency action (CEC, ARB, North Sonoma County APCD and Lake County APCD) it is anticipated that existing and future H₂S air quality problems, as well as the legal requirements and needs of each agency, can be satisfied in the Commission's common regulatory forum.

The ARB in response to the Federal Clean Air Act has drafted "model" New Source Review (NSR) regulations and requires that all APCD's in California adopt similar regulations. These regulations ensure that a new stationary source for which an air quality permit is issued shall not prevent or interfere with the attainment or maintenance of any applicable air quality standard. Both national and state air quality standards are required to be considered by the ARB guidelines. Lake and North Sonoma County APCD's have adopted an NSR regulation in response to the guidelines established by ARB.

Both the ARB and the North Sonoma County APCD are presently proposing regulations to further restrict H₂S emissions from existing and future geothermal development. In proposed amendments the North Sonoma County APCD regulations would require that existing geothermal power plant units emit no more than 350 lb/hr or 290 lb/hr of hydrogen sulfide (to be determined by the district). Also, any unit constructed after January 1, 1978, shall emit no more than: (a) three percent of the H₂S produced by that units steam; or (b) 0.1 lb. H₂S/hr/MW to the atmosphere; or (c) 10 lbs/hr to the atmosphere; or (d) a level which is feasible by the use of best available control technology (BACT). The proposed North Sonoma County APCD regulations will also place restrictions on non-power plant sources of H₂S.

ARB has held public workshops and has collected background information in order to draft model air pollution regulations for H₂S from geothermal operations. The ARB staff report

Table 1 ARB PROPOSED MODEL RULE ON H₂S*
CONTROL STRATEGY

YEAR	CONDITIONS TO BE MET	APPROXIMATE DEGREE OF CONTROL
1979	1. Power plant units number 3, 4, 5, 6, 11, and 12 to emit no more than 200 gm H ₂ S/MWH (.44 lb/MWH).	90
	2. Power plant units equipped with surface condensers to emit no more than 175 gm H ₂ S/MWH (.39 lb/MWH).	85
1980	1. Power plant units equipped with surface condensers to emit no more than 100 gm H ₂ S/MWH (.22 lb/MWH).	90
	2. All power plant units constructed or commencing construction during 1980 shall emit no more than 100 gm H ₂ S/MWH (.22 lb/MWH) when completed.	90
	3. H ₂ S emissions resulting from "stacking" operations shall be reduced by 65 % (from levels associated with unabated steamflow) within 30 minutes.	65
	4. H ₂ S emissions from drilling 60-90 operations shall not exceed 5 kg/hr (11 lb/hr) for every 1000 MW of electrical power generated.	
1982	1. The uncontrolled geothermal, well known as Thermal 4 (or the "Wild Well") will have its H ₂ S emissions reduced by 90% over its abated conditions.	90
1984	1. All power plant units utilizing direct contact condensers will emit no more than 200 gm H ₂ S/MWH (.44 lb/MWH).	90
1986	1. H ₂ S emissions resulting from "stacking" operations shall be reduced by 90% (from levels associated with unabated steam flow) within 30 minutes.	90
	2. All power plant units completed after 1985 shall emit no more than 50 gm H ₂ S/MWH (.11 lb/MWH).	95
1990	1. All power plant units equipped with surface condensers shall emit no more than 50 gm H ₂ S/MWH (.11 lb/MWH).	95
2000	1. All power plant units equipped with direct contact condensers shall emit no more than 100 gm H ₂ S/MWH (.22 lb/MWH).	95

*Adopted by ARB April 26, 1978.

and recommendations are expected to be presented to the full board in April 1978. A summary of the ARB proposed model rules to control H_2S is presented in Table 1.

Projected Growth

In an effort to develop an integrated, state-wide electricity supply strategy the Energy Commission has required that all California utilities' provide planning documents prescribing the manner in which each utility would meet future forecasted electricity demand for its service area. Table II lists all of the development currently being planned by electric utilities for the Geysers KGRA.¹⁰ Three utilities, Pacific Gas and Electric Company (PG&E), Sacramento Municipal Utilities District (SMUD) and Northern California Power Association (NCPA) indicate that 2708 MW of electricity could be produced at the Geysers by 1990. The only other generation capacity now planned for the Geysers is 165 MW by the California Department of Water Resources.

It should be noted that H_2S control efficiencies were not indicated for iron catalyst control systems on units 1-11. These systems are not presently on all of PG&E's existing units, although it does appear as though PG&E expects to retrofit with iron catalyst and attain 90 percent abatement efficiency on these units.

The expected Geysers cumulative H_2S emissions utilizing various levels of control efficiency and assuming development proceeds as planned, are presented by year in the columns on the right in Table II. Expected cumulative emissions and the net relationship to current emissions levels at the Geysers is presented in Figure 1. Although the utilities have indicated that up to 90 percent control of H_2S is expected, the ultimate degree to which H_2S must be controlled at the Geysers has not yet been established. Since ambient air quality standards are currently being violated, logic would indicate that net future emissions over 1174 lb/hr would cause continuing violations. Even 95% control of H_2S may not be sufficient if a reduction down to one third of current emission levels is required. Control efficiencies of 96-99 percent appear to be required if ultimate compliance with standards and full field development is desired.

The proposed ARB regulations (Table 1) call for 95 percent of all units completed after 1985. It is unclear at this time whether this degree of control can be technically achieved or is ultimately sufficient to prevent violations of the ambient air quality standard for H_2S .

H_2S Abatement Technologies

A substantial amount of money and time has been expended (primarily by PG&E) in efforts to control the releases of H_2S to the atmosphere by geothermal operations. Several different

approaches to H_2S control have been investigated and the three most promising are: (1) Iron Catalyst; (2) Stretford; and (3) EIC Upstream. Information is provided in Table III regarding the H_2S abatement technologies currently being tested by PG&E. By mid-1979 more precise operational characteristics will be available on all these systems.

Of the systems under consideration, only the Iron Catalyst system has been in full-scale operation, with rather unsatisfactory results (40 to 70 percent efficiency). The Stretford system is expected to provide high control efficiencies on new units using surface condensers (as opposed to direct contact condensers on units 1-12). The Stretford system is presently unproven, however, because there is no operating experience to indicate the degree of H_2S partitioning which will occur in the surface condenser. The EIC Upstream system is in the very early stages of development but appears to be promising. If successful it would enable removal of H_2S from the geothermal steam resource before it enters the power plant.

FIGURE 1: PROJECTED INCREASES IN H_2S EMISSIONS FROM PLANNED POWER PLANT UNITS AT THE GEYSERS

1 1977 Emission level.

2 ARB estimated roll back requirement.

Conclusion

The limit to which geothermal development can occur at the Geysers presently seems to be restricted by two factors: (1) the ultimate size of the resource, (which has yet to be definitively established); and (2) more immediately, by the failure to maintain the state ambient air quality standard for H_2S .

TABLE II
PROJECTED GEOTHERMAL POWER PRODUCTION AND H₂S EMISSIONS IN THE GEYSERS KGRA

UNIT DATA							CUMULATIVE TOTAL CONTROLLED H ₂ S (lb/hr)					
UNIT #	YEAR ON LINE	SIZE (MW)	HEAT RATE (BTU/KWH)	H ₂ S EMMIS- SION FACTOR (LBS/BTUx10 ⁶)	CONTROL DEVICE ²	CONTROL EFFICIENCY	H ₂ S EMISSION TOTAL (LBS/HR)	(MW)	As Re- ported	90% CON- TROL	95% CON- TROL	99% CON- TROL
PG&E 1	1960	11	22,000	.076	IC	1	18.3					
PG&E 2	1963	13	22,000	.076	IC	1	21.7					
PG&E 3	1967	27	22,000	.076	IC	1	45.1					
PG&E 4	1968	27	22,000	.076	IC	1	45.1					
PG&E 5	1971	53	22,000	.027	IC	1	31.5					
PG&E 6	1971	53	22,000	.033	IC	1	38.5					
PG&E 7	1972	53	22,000	.016	IC	1	18.7					
PG&E 8	1972	53	22,000	.011	IC	1	12.8					
PG&E 9	1973	53	22,000	.005	IC	1	5.8					
PG&E 10	1973	53	22,000	.005	IC	1	5.8					
PG&E 11	1975	106	22,000	.028	IC	1	65.3	502				
PG&E 12	1978	106	21,376	.0138	IC	90%	31.3					
PG&E 15	1978	55	22,881	.0373	STRET	90%	46.9	663	386.8	386.8	193.4	38.7
PG&E 14	1979	110	22,000	.0142	STRET	90%	34.6					
PG&E 13	1979	135	22,000	.00885	STRET	90%	26.3	908	447.7	447.7	233.9	44.8
PG&E 16	1981	110	22,000	.00684	STRET	90%	16.6					
PG&E 17	1981	110	22,000	.0353	STRET	90%	85.4					
NCPA 1	1981	32	23,000	.22 ³	1	90%	161.9					
NCPA 1	1981	53	23,000	.22 ³	1	90%	268.2	1213	979.8	592.7	296.4	59.3
PG&E 18	1982	110	22,000	.0224	STRET	90%	54.2					
PG&E 19	1982	110	22,000	.0224	STRET	90%	54.2					
NCPA 1A	1982	32	23,000	.22 ³	1	90%	161.9					
NCPA 2A	1982	53	23,000	.22 ³	1	90%	268.2	1518	1518.3	744.2	372.1	74.4
PG&E 20	1983	110	22,000	.0224	STRET	90%	54.2					
PG&E 21	1983	110	22,000	.0224	STRET	90%	54.2	1738	1626.7	852.6	426.3	85.3
PG&E 22	1984	110	22,000	.0224	STRET	90%	54.2	1848	1680.9	906.8	453.4	90.7
PG&E 23	1985	110	22,000	.0224	STRET	90%	54.2					
SMUD 1	1985	100	24,000	.167	4	4	400.8	2058	2135.9	1001.1	500.6	100.1
PG&E 24	1986	110	22,000	.0224	STRET	90 %	54.2					
SMUD 2	1986	100	24,000	.167	4	4	400.8	2268	2590.9	1095.4	547.6	109.5
PG&E 25	1987	110	22,000	.0224	STRET	90%	54.2	2378	2645.1	1149.5	574.6	115.0
PG&E 26	1988	110	22,000	.0224	STRET	90%	54.2	2488	2699.3	1203.8	601.5	120.4
PG&E 27	1989	110	22,000	.0224	STRET	90%	54.2	2598	2753.5	1258.0	629.0	125.8
PG&E 28	1990	110	1	.0224	STRET	90%	54.2	2708	2807.7	1312.2	656.1	131.2

1. Information not provided by utilities.

2. Control Devices: IC= Iron Catalyst, STRET = Stretford Process.

3. The NCPA Emission Factor appears to be representative of an uncontrolled state.

4. SMUD did not indicate any control.

5. The location of Unit #28 was not given, it may or may not be in the Geysers KGRA.

TABLE III
Hydrogen Sulfide Abatement Technologies

	Iron Catalyst	Stretford	EIC Upstream
Abatement Efficiency	Actual 40-70% Potential 90%	80-98% 90+X from Condensate	90-97%
Expected Downtime	10%	5%	5%
Estimated Capital Cost	\$3 million	\$5.84-6.7 million	Similar to STRET.
Estimated Annual cost	\$995,000	\$1,350,000 \$2,275,000 with Con- densate Treatment	\$1,245,000
Expected Availability	90% Abatement Full scale end of 1978	Fullscale on Unit 15 Early 1979	Pilot July 1979 Fullscale Mid-1982

If it cannot be demonstrated that geothermal power plants can operate without causing violations of the .03 ppm hydrogen sulfide standard and comply with proposed hydrogen sulfide regulations of the ARB and local APCD's, it would be imprudent to expect unrestricted development at the Geysers. No agency has yet established precisely what level of H₂S control (or emissions) will be required to allow full field development. Although most proposed regulation is presently in the range of 90-95 percent control, more stringent controls may be necessary if thousands of megawatts of electricity are to be produced at the Geysers.

Achieving the goal of full field development remains hypothetical. Uncertainties presently associated with development of geothermal H₂S control technologies are numerous. It is possible that a level of H₂S control sufficient to eliminate H₂S as an environmental problem may not be available soon. Should adequate H₂S control prove unavailable planned geothermal development at the Geysers may be seriously hindered and eventually curtailed. Every effort should be made to ensure against such an eventuality. This analysis is intended to communicate the status of an eminent regulatory problem and encourage expanded research and planning to resolve the issue.

The views and conclusions contained in this report are those of the authors and should not be interpreted as necessarily representing the official policies of either the California Energy Commission or the State of California.

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