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Strategies for Steam Handling and H₂S Abatement at Geothermal Power Plants in The Geysers Area of Northern California

W. F. Morris
F. B. Stephens

MASTER

August 5, 1981

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CONTENTS

Abstract	1
Introduction	1
Steam Supply Systems and Geothermal Power Plants	5
Environmental Regulations	10
Background	10
Regulations	10
The Clean Air Act and Best Available Control Technology	12
The H ₂ S Abatement Systems for Geothermal Power Plants	13
Upstream H ₂ S Abatement Systems	14
The EIC Copper Sulfate Process	14
Steam Converter	15
The Sulfox Process	15
Downstream H ₂ S Abatement Systems	16
The H ₂ O ₂ Supplemented Iron Catalyst Process	16
The Combined Surface Condenser, Stretford and H ₂ O ₂ Catalyst Process	16
Steam Handling During Power Plant Outages	17
Precautions Required in Steam Handling	17
Optional Approaches for Handling Steam During Plant Outages	18
Current Strategies for Steam Handling and H ₂ S Abatement	22
Description of Strategies	22
Evaluation of Strategies	22
Strategy Costs and Projected Performance	26
Summary and Conclusions	31
Steam Flow Control and Rerouting	31
Downstream H ₂ S Abatement Technology	32
Upstream H ₂ S Abatement Technology	32
Conclusions	33
References	34

Appendix A. The H ₂ S Emission Limitations of the Northern Sonoma County Air Pollution Control District	37
Appendix B. Lake County Air Pollution Control District Determination of Compliance for the Department of Water Resources Bottle Rock Geothermal Power Plant	40
Appendix C. Lake County Air Pollution Control District Determination of Compliance for the Pacific Gas and Electric Company Geysers Unit 16 Geothermal Power Plant	49
Appendix D. Forced Outages at PG&E Unit 15	56
Appendix E. Suggested Measures for the Control of H ₂ S Emissions from Geothermal Operations at The Geysers Known Geothermal Resources Area	59

STRATEGIES FOR STEAM HANDLING AND H₂S ABATEMENT
AT GEOTHERMAL POWER PLANTS IN THE GEYSERS AREA OF
NORTHERN CALIFORNIA

ABSTRACT

Strict limitations on the emission of H₂S from new geothermal power plants in The Geysers area of northern California have been imposed by Lake and Northern Sonoma County Air Pollution Control Districts. Lake County, under new source review rules, has stipulated that specific technologies shall be utilized to limit H₂S emissions to 5 lb/h as a condition for determination of compliance. The status of these technologies as well as other ongoing technology development efforts to conserve steam and abate H₂S are evaluated. Although projections indicate that it may be possible to meet the 5 lb/h limit, there is no firm assurance of achievement at this time because of the unproven, full-scale performance status of some key technologies specified by the air pollution control districts.

INTRODUCTION

Effective steam handling practices and abatement of H₂S are issues of major concern in the development of geothermal energy in The Geysers area of northern California. The issues affect both the steam supply industry and the power plant operators. Because geothermal power plants in this area utilize large amounts of steam (2×10^4 lb/MW·h) containing relatively high levels of H₂S ranging from approximately 60 to 450 ppm (210 ppmw, average), various degrees of control are necessary to abate H₂S emission to avoid violating local H₂S emission regulations and the State of California ambient air quality standard (AAQS). Two courses of action are possible. The H₂S can be removed from steam or process stream gases before they are vented to the atmosphere or steps can be taken to prevent the release of steam from the pipelines or the power plant.

To date, the steam suppliers at The Geysers have not removed H₂S from steam piped to the power plants. Only after the steam has entered the plant have steps been taken to remove it. For example, Pacific Gas and Electric

(PG&E) has utilized in-plant H_2S abatement technology for several years and has instituted numerous changes aimed at lowering H_2S emissions consistent with effective power plant operation.

As the number of power plants at The Geysers has increased, local H_2S emission regulations have become increasingly more stringent and time schedules have been imposed within which the regulations must be met. To meet these new regulations and schedules, new technologies are being proposed and tested and, as a rule, are lacking in full-scale and long-term operational performance data. Despite this shortcoming, commitment to the not fully proven technologies is being urged. This situation is not unique and is exemplified by the problems encountered in the use of the iron catalyst H_2S abatement system at the older PG&E power plants utilizing direct contact condensers. In the course of using the iron catalyst for several years, changes were necessary to overcome difficulties that were not uncovered in the initial limited tests of the process. Although the H_2O_2 -supplemented version of the iron catalyst process is now capable of removing over 90% of the total incoming H_2S , it is plagued with other problems associated with corrosion of the condenser cladding, fouling, degradation of the capacity factor of the power plant, and the necessity for disposing of secondary waste material.

The newer PG&E power plants utilize the Stretford process for removal of H_2S from the noncondensable gases ejected from the power plant surface condenser. The Stretford process is a proven technology for removing greater than 99% of H_2S from gas streams. Its overall effectiveness in new power plants incorporating surface condensers depends upon the partitioning of H_2S between the condensate and the noncondensable gas phases. Recent findings indicate that partitioning between the two phases is strongly influenced by the concentration of NH_3 in the incoming steam. When the NH_3 level is relatively high, as much as 35% of the H_2S can partition into the condensate. This phenomenon was not rigorously studied prior to installation of Stretford units in the newer power plants at The Geysers. Fortunately, H_2S can be removed from the condensate by means of the H_2O_2 -supplemented catalyst process that has been modified for effective, relatively trouble-free use on the condensate stream before it enters the cooling tower.

Work has been underway for several years to develop a process for removing H_2S from steam before it enters the power plant. The EIC copper sulfate process is one approach that has been demonstrated successfully in tests at

one-tenth of full plant scale on the PG&E Unit 7 power plant at The Geysers. Although there is much optimism regarding the use of this process in geothermal power generation systems, full-scale plant tests have not been run and are not expected to be completed for 2 y. Also, long-term operational data will not be forthcoming until some time later.

Efforts by the steam suppliers to prevent the discharge of steam from steam gathering systems that supply the power plants have been reasonably successful in spite of the size and complexity of the systems. However, one major difficulty persists--disposition of steam during power plant outages. The usual action taken on shutdown of a power plant is to vent steam at a reduced flow through a noise silencer or muffler to the atmosphere. The process is commonly referred to as steam stacking and is less than satisfactory from both environmental and resource conservation points of view (Fig. 1). Ordinarily the steam supplier does not incorporate process equipment for removing H_2S from steam supplied to the power plant. Thus when steam is stacked by the supplier, H_2S is released unabated to the atmosphere. The effect of steam stacking on air quality will depend on the concentration of H_2S in the steam, the amount of steam being vented, and atmospheric conditions at the time of release. To ensure that H_2S emissions do not exceed regulated levels, measures are necessary either to remove H_2S from the stacked steam or to handle the steam in such a way that it will not be vented to the atmosphere. Strategies planned for future plants include removal of H_2S from steam before it enters the power plant by means of the EIC abatement process; diversion of steam around the power plant turbine (turbine bypass) to the condenser and the downstream Stretford and H_2O_2 -supplemented catalyst processes; rerouting of steam to another power plant; and construction of dual, parallel power plants supplied with steam from a single steam gathering system.

It is our intent to examine how these strategies are to be used in future power plants and to assess their feasibility. To augment the study, steam supply and power plant operations and the physical constraints on these operations will be described. Pertinent environmental regulations will be reviewed and optional approaches for handling steam supplies and abating H_2S will be presented.

Fig. 1. Steam stacking at The Geysers PG&E Unit 15.

STEAM SUPPLY SYSTEMS AND GEOTHERMAL POWER PLANTS

To understand the difficulties involved with steam handling, it is necessary to take into account the size and complexity of the steam gathering facilities and the designs of newer geothermal power plants.

The steam gathering system of Aminoil, USA, located in the Lake County section of The Geysers supplies 2.7×10^6 lb/h of steam to PG&E Unit 13. The system is composed of 22 wells located in hilly terrain ranging from 2200 to 3400 ft in elevation. The more distant wells in the system are located nearly 1 mi. from the power plant. The pipelines that convey steam to the plant vary in diameter from 10 in. near the wells to 48 in. at the main trunk line leading to the plant. The different pipe diameters are calculated to provide optimum control of pressure and temperature, and the pipes are insulated with aluminum- or vinyl-covered fiberglass blanketing to reduce heat loss. The pipelines expand and contract with changes in temperature. For example, in a 1 mi section the pipeline can increase in length by about 14 ft as the temperature is raised to 400°F by the flow of steam to the power plant (CEC, 1980a).

The pipeline sections constituting the steam gathering system vary in length from the wellheads to the main trunk lines and to the power plant. The traverses of the various sections change in slope and elevation according to the rise and fall of the rugged terrain that characterizes the area (Fig. 2). Despite thermal insulation, condensation takes place within the pipes and flows to the various low points in the pipeline system, where it is removed by means of traps that are vented to a common vent collection system. The collected condensate is discharged and disposed of by subsurface injection.

The steam gathering system for Unit 13 incorporates distributed microprocessor controls to monitor and control every well in the system, regulate delivery of steam to the power plant, and control the condensate injection system (Kumataka and Bayard, 1981). The flow of steam is remotely controlled by electrically actuated vee ball valves located downstream of the master and working valves, and the rock separator at each wellhead. The system is currently being operated in remote manual mode from a central control building. Conversion to automatic control will be implemented when sufficient experience and information have been obtained from remote manual operations. A remote control system that can be operated automatically or

FIG. 2. Steam pipelines in The Geysers geothermal area.

manually is also being developed by Union Oil for the steam supply to PG&E Unit 17 (Smith, 1981). The system eventually will be retrofitted on most of the existing Union Oil steam gathering systems supplying PG&E units at The Geysers. Compared to the older, manual methods of control, these new systems provide more precise and timely control of steam flow and venting during power plant operations and are particularly effective during plant start-up and shutdown.

A schematic of the Unit 13 power plant is shown in Fig. 3. The components of the plant are typical of PG&E Units 13 through 18. In this 135-MW power plant design, 2.7×10^6 lb/h of steam drive the turbine. The H_2S is removed downstream of the turbine-surface condenser system. The major fraction of H_2S is partitioned into the noncondensable gases that are ejected from the condenser and removed by means of a Stretford H_2S abatement unit. Processing equipment for adding the H_2O_2 -supplemented iron catalyst is also provided in the condensate line between the condenser and the cooling tower. This equipment can be used to remove excessive amounts of H_2S that partition to the condensate.

More recent power plant designs such as the Sacramento Municipal Utility District SMUDGE #1 plant are incorporating turbine bypass facilities. The bypass is a mechanism for diverting steam around the turbine to the power plant condenser during plant start-up and shutdown. In Fig. 4 a preliminary design schematic of SMUDGE #1 shows the turbine bypass pipelines and valves. Both remote manual control and automatic operation of the turbine bypass are provided. Steam is bypassed on closure of the turbine stop valves (E/H) and opening of the bypass valves (M). Remote manual control allows the plant operator to activate the system valves during plant start-up. Automatic operation of the bypass is effected through connections with the turbine generator control system and is initiated by a turbine trip signal. To date, these systems have not been operated on full-scale geothermal power plants.

In recent years, Union Oil has interconnected many of its steam gathering systems at The Geysers (Weres, et al., 1977). Crossover pipelines have been installed connecting Units 5 and 6 to Units 1 and 2, 3 and 4, and 7 and 8. Also, Units 7 and 8 have been connected to Units 11 and 12, and Units 9 and 10 have been connected to Unit 14. Crossover pipelines are also planned for the interconnection of Units 13, 16, and 18. These interconnections are intended primarily for efficient use of the steam resource and to assist in meeting air

FIG. 3. The Geysers PG&E Unit 13 Power cycle.

FIG. 4. Preliminary design schematic Sacramento Municipal Utility District SMUDGE #1 power plant.

quality regulations for H_2S . Even though many crossover pipelines are in place for rerouting steam between power plants, their effective use is impaired because manual controls are the only means available for adjusting steam flow.

ENVIRONMENTAL REGULATIONS

BACKGROUND

To provide safeguards for the environment while producing electricity from geothermal resources, steam suppliers and electric energy producers are required to limit the emission of various pollutants in order to be in compliance with specific air quality regulations and conditions. The major concern in The Geysers area is the release of H_2S to the atmosphere in amounts that would violate the State of California AAQS. The standard, established by the California Air Resources Board (CARB), states that H_2S in ambient air cannot exceed $42 \mu g/m^3$ (30 ppbv) averaged over a 1-h period (CARB, 1970). The standard is based on odor-threshold detection tests performed by the California Department of Public Health (CDPH) on chemists and laboratory technicians (CDPH, 1962; Dechant and Sanders, 1956). Anspaugh and Leitner (1980) compared the California AAQS with that of other states and countries and found lower standards ranging from 3 to 9 ppbv. This range agreed with the findings of six odor-threshold studies conducted on more diverse subjects able to detect lower concentrations of H_2S than those of the CDPH study. The California AAQS and those cited by Anspaugh and Leitner (1980) are clearly intended to avoid an odor nuisance problem from H_2S . The concentrations are well below toxic levels and contrast with the occupational health standard that suggests a maximum concentration of H_2S in work room areas of 20,000 ppb for 8 h (OSHA, 1974).

REGULATIONS

The H_2S emission limitations for geothermal power plants under regulatory jurisdiction of the Northern Sonoma County Air Pollution Control District (NSCAPCD) are contained in Regulation 1 of the California North Coast Air Basin Air Quality Control Rules revised on October 21, 1980. The

regulations listed in Appendix A are expressed in mass emission rates of H_2S as g/GMW•h and kg/h. For plants coming onstream after January 1, 1980, H_2S emissions are limited to 100 g/GMW•h. After January 1, 1985, the emission level will be lowered to 50 g/GMW•h. As a result, the larger geothermal power plants (110 MW) in Sonoma County cannot emit H_2S at levels greater than 11 kg/h (24.2 lb/h) through 1984. After that time, the maximum allowable level will be 5.5 kg/h (12.1 lb/h). For the SMUDGE0 #1 power plant, proposed for construction in the Sonoma County sector of The Geysers, NSCAPCD has chosen to regulate H_2S emissions under new source review rules that are intended to limit multiple plant H_2S emissions to levels that will not be in violation of the AAQS. In exercising this authority, NSCAPCD has established an H_2S emission limit for SMUDGE0 #1 at 5 lb/h negotiable to 8 lb/h depending on future air monitoring data. All of the above limits apply to the emission of H_2S from an operating geothermal power plant. When a plant outage occurs and steam stacking takes place, NSCAPCD requires that the flow of steam be throttled back to 35% of full flow within 15 min of stacking initiation.

Lake County Air Pollution Control District (LCAPCD) also has jurisdiction in The Geysers area. However, only one geothermal power plant, PG&E's Unit 13, has operated in Lake County. This plant operates under a LCAPCD regulation limiting H_2S emission to 10% of the H_2S content of the incoming steam. Steam containing 60 ppm of H_2S is supplied to Unit 13 at a rate of 2.7×10^6 lb/h, resulting in a total incoming load of 162 lb/h H_2S .

More specific and stringent conditions under new source review rules have been promulgated by LCAPCD for new power plants that have applied for certification in Lake County. A total of 23 conditions listed in Appendix B are stipulated in the determination of compliance for the 55-MW Department of Water Resources (DWR) Bottle Rock power plant (DWR, 1980). Some of the more pertinent conditions are described here. For example, condition 1 limits the release of H_2S to 5 lb/h for the combined steam gathering system and power plant not only during operation of the plant, but during plant outages as well. Condition 2 requires specific multiple H_2S control technologies to attain compliance with condition 1. In recognizing that releases of H_2S above the 5 lb/h limit are sometimes unavoidable, LCAPCD allows, in condition 6, untreated steam venting at a flow rate of 25,000 lb/h, equivalent to 2.3%

of normal flow. Steam supplied to the DWR Bottle Rock plant is expected to contain 450 ppm H_2S (DWR, 1980); thus under condition 6, H_2S may be released at a rate of 10 lb/h.

There are 16 conditions for determination of compliance for PG&E's Unit 16 in Lake County. Just for the DWR power plant, H_2S release is limited to 5 lb/h. Other conditions for the PG&E plant differ from those of the DWR plant and may be compared in Appendix C.

The H_2S emission standards are based on the assumption of a direct relationship between H_2S emission and ambient H_2S levels (CARB, 1978). Because of the complex terrain and meteorological conditions at The Geysers, it is extremely difficult, if not impossible, to directly correlate H_2S emissions and air quality impacts at the present time (Joyce and Fontes, 1978). The Department of Energy (DOE) is sponsoring the program Atmospheric Studies in Complex Terrain (ASCOT) to develop the technology to correlate H_2S emissions and air quality impacts by energy sources in areas of highly complex terrain (Dickerson and Gudiksen, 1980). The study is being carried out at The Geysers.

THE CLEAN AIR ACT AND BEST AVAILABLE CONTROL TECHNOLOGY

The Environmental Protection Agency (EPA) does not provide emission regulations nor specify ambient air standards for H_2S . However, under certain sections of the Federal Clean Air Act regarding the prevention of significant deterioration (PSD) of air quality, EPA regulations can require the use of best available control technologies (BACT) for certain new industrial source categories for which new source performance standards (NSPS) will be developed. The EPA's definition of BACT is as follows.

The term "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of "best available control technology" result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to Section 111 or 112 of this Act.

State and local districts, on a case-by-case basis, can define BACT in a manner much more restrictive than the EPA definition. For example, CARB states that

BACT is defined as "the maximum degree of control for air contaminant emitting equipment taking into account what is known to be practical but not necessarily in use," (CARB, 1981).

As pointed out in the CARB report this definition could be interpreted as an H_2S emission limit of nearly 0 using the Stretford and H_2O_2 control technology, provided larger quantities of chemicals are injected into the condensate.

The proposed CARB control measure for H_2S emissions at The Geysers is presented in Appendix E. The suggested measure is designed to expedite permits for new geothermal plants by limiting H_2S emissions to values approaching 0 (5 lb/h) and thus avoid new source review procedures. The objective is to avoid the added costs, uncertainties, and disagreements associated with air quality measurements, tracer tests, meteorological interpretations, and complex modeling studies by eliminating the need for such exhaustive studies on a case-by-case basis.

For new plants greater than 50-GMW electrical (GMWe), the suggested measure shows an H_2S emission limit beginning July 1, 1981 of 5 lb/h or 40 g/GMW•h, whichever is greater. This means that a 55-GMWe plant would be limited to 5 lb/h while a 120-GMWe plant would be limited to about 11 lb/h. Beginning July 1, 1985, all new plants greater than 50 GMWe will be limited to 5 lb/h regardless of size. Emission limits for new plants during stacking will be the same as those for the plants at all other times. Limits for existing plants are also given in the control measure (Appendix E).

The suggested control measure was drafted by the CARB to be considered for adoption by the Northern Sonoma County, Lake County, and Mendocino County Air Pollution Control Districts.

THE H_2S ABATEMENT SYSTEMS FOR GEOTHERMAL POWER PLANTS

Extensive efforts by the geothermal industry are being made to develop effective and economic H_2S control technologies that satisfy both the local emission and state AAQS. Most of the applied technology has been developed at The Geysers.

A report describing state-of-the-art technologies for H_2S removal and evaluating their efficiency and reliability has been published by Stephens et al. (1980). The technologies, as they are used in geothermal power plants, are generally divided between upstream systems that remove H_2S from steam before it enters the power plant turbine and downstream systems that remove H_2S from the condenser off-gas and condensate streams.

UPSTREAM H_2S ABATEMENT SYSTEMS

The advantages of upstream H_2S abatement have been enumerated by Stephens et al. (1980). A major advantage of removing H_2S from steam before it enters the power plant turbine is that steam can be stacked with minimum risk of violating local and state compliance limits. Unfortunately, full-scale upstream abatement has not yet been implemented in geothermal power plants.

Nevertheless, development of the technology is underway, with most of the emphasis directed toward chemical separation by the EIC copper sulfate process. Other processes have been proposed such as the Coury Associates steam converter and the UOP Sulfox process. However, tests of their application to geothermal power plants have not advanced as far as those for the EIC process.

The EIC Copper Sulfate Process

I IC copper sulfate process, steam upstream of the power plant turbine is scrubbed with a recirculating dilute solution of copper sulfate. H_2S in the steam undergoes the following reaction:

The precipitated cupric sulfide (CuS) then converts to cuprous sulfide and sulfur as follows:

Sulfur is removed and copper sulfate is regenerated for recirculation back to the scrubber. The reactions are:

and

The EIC process has been tested at one-tenth of full plant scale on PG&E's Unit 7 at The Geysers (Brown, 1980). The tests have demonstrated H_2S removal efficiencies averaging 97%. Full-scale, long-term tests of the process are needed to establish process parameters, reliability, and compatibility with the power plant turbine. The estimated fixed capital investment costs for a commercial-scale EIC plant capable of servicing a 110-MW power plant are \$10.2 million (Brown, 1980).

Steam Converter

In a steam converter, incoming steam is condensed in a heat exchanger where noncondensable gases are separated. The condensate is flashed back to purified steam in the secondary coils of the heat exchanger. Used upstream of the power plant turbine, the reflashed steam entering the turbine should then be free of a major fraction of H_2S originally present in the incoming steam.

Small-scale tests of a steam converter intended to establish proof-of-concept have been run by PG&E and Coury Associates. As much as 90% separation of H_2S has been achieved; however, much more testing is required to determine the feasibility of this process. Consideration must be given to abatement of H_2S in the steam converter off-gas, partitioning of H_2S into the condensate, and enthalpy loss in the incoming steam.

The Sulfox Process

The UOP Sulfox process uses a highly stable, proprietary catalyst to oxidize H_2S to elemental sulfur using air as the oxidant. It has been applied in pilot-plant tests on mock-up geothermal streams of water-saturated steam at 430°F containing H_2S (Urban, 1981). Results show that the system is capable of complete sulfide conversion at H_2S concentrations typical of geothermal steam at The Geysers. Depending on oxygen stoichiometry, alkaline conditions produced mainly water soluble thiosulfate and sulfate compounds

(88%), and acid conditions produced mainly elemental sulfur (75%). Because of the possible effects of contaminants, an onsite field test pilot-plant study should be undertaken.

DOWNSTREAM H_2S ABATEMENT SYSTEMS

To date, virtually all H_2S abatement technology related to steam utilization in geothermal power plants has taken place in the power plant complex using downstream processes. The term downstream signifies that the abatement technology is incorporated in the power plant downstream of the turbine. Unlike upstream abatement, H_2S is not removed until after the steam has passed through the turbine. Thus, when the turbine is tripped, untreated steam must be diverted and, as in current practice, stacked to the atmosphere.

The principal downstream abatement technologies that have been used and are expected to be used on future power plants in The Geysers are the combined technologies incorporating surface condenser facilities, the Stretford process, and the H_2O_2 -supplemented iron catalyst process.

The H_2O_2 Supplemented Iron Catalyst Process

The H_2O_2 -supplemented iron catalyst process evolved from the iron catalyst process used in PG&E power plants equipped with direct contact condensers (PG&E Units 1 to 12). To be able to process higher levels of H_2S and meet regulatory requirements, the iron catalyst was supplemented with NaOH and H_2O_2 to enhance the reaction of H_2S in the condensate and the regeneration of ferric iron. The H_2O_2 -supplemented iron catalyst process is now developed to a point where approximately 90% of the total incoming H_2S can be removed. However, it is a relatively complex process, requires careful balancing of process reagents, and has created problems of corrosion, fouling, and waste disposal when used in power plants equipped with direct contact condensers (Weinberg, 1980).

The Combined Surface Condenser, Stretford, and H_2O_2 Catalyst Process

The newer geothermal power plants at The Geysers employ surface condenser technology that favors partitioning of H_2S to the noncondensable gases that

are ejected from the condenser and processed by a Stretford H_2S abatement unit. Original estimates projected 80 to 90% partitioning of H_2S to the noncondensable gas phase. However, in practice, it has been found that this high value is not achieved unless the NH_3 content of the incoming steam is low. For example in steam containing a low concentration of NH_3 , such as that supplied to PG&E Unit 14, 90% of the H_2S goes to the noncondensable gases. In contrast, it is 65% for Unit 15 where the NH_3 content is relatively high.

The degree of partitioning of H_2S in the surface condenser determines the complexity of downstream chemical abatement (Weinberg, 1981). For example on PG&E Unit 14, since most of the H_2S is partitioned to the gas phase, the Stretford unit alone is capable of sufficiently abating H_2S emission to meet air pollution control district requirements. However on PG&E Unit 15, in addition to the Stretford unit for processing the noncondensable gas stream, H_2O_2 -supplemented iron catalyst and hydroxyacetic acid (H_2O_2 -HAA-Fe) must be added to process H_2S in the condensate stream before it enters the cooling tower. Treatment by the H_2O_2 -HAA-Fe catalyst process is effective in removing H_2S and does not suffer from the same problems encountered with the use of iron catalyst in systems with direct contact condensers. However process chemical costs are relatively high, ranging between 3 and 4 dollars per pound of H_2S removed (Weinberg, 1981).

STEAM HANDLING DURING POWER PLANT OUTAGES

PRECAUTIONS REQUIRED IN STEAM HANDLING

Improvements have been made over several years in virtually all of the steam gathering control systems at The Geysers. In the newer facilities, remote manual and automatic controls have been installed to facilitate better control during plant start-ups and rapid reduction of steam flow when conditions require it. Even though improvements have been made, the problem of handling and disposition of steam during power plant outages persists. The problem arises because of the variable steam quality, the nature of the steam gathering facilities, and certain precautions that are necessary to avoid damage to wells, pipelines, and other components (Angwin and Toy, 1980). The following guidelines give some insight to the problem.

- Steam flow at the power plant inlet should not be shut off too rapidly, otherwise physical damage to the steam gathering system will occur.

- Steam flow at the wellheads should not be closed off completely (well shut-in), and cycling of temperature and pressure within the wells should be minimized. If care is not exercised, the integrity of the well casings and the exposed walls of the wells may be jeopardized.

- Steam flow and pipeline temperature should be maintained at appropriate levels (usually 35% of full flow) to prevent condensation buildup in the steam gathering systems. If steam condensation takes place, then upon power plant start-up, slugs of condensate will have to be vented from the system to avoid damage to the pipelines and turbine.

These precautions suggest that some level of steam flow should be maintained during power plant outages. Although a number of options have been proposed to handle the situation, only one has been routinely exercised to date--namely, controlled stacking. The following section describes alternative approaches and evaluates each in relation to the others.

OPTIONAL APPROACHES FOR HANDLING STEAM DURING PLANT OUTAGES

Five optional approaches for handling steam during power plant outages are listed below.

- (1) The flow rate of steam from the wells can be gradually reduced to the limit of vee ball-valve throttling, which is 10 to 20% of full flow. This residual flow of steam can be stacked to the atmosphere.

- (2) The flow rate of steam from the wells can be gradually reduced to 30 to 40% of full flow to maintain pipeline temperature at a level sufficient to avoid condensation. The residual flow of steam can be sent through a standby H_2S abatement system before stacking.

- (3) The steam can be diverted around the turbine by means of a bypass and sent through the power plant condenser and downstream H_2S abatement system.

- (4) The steam supply can be processed by a preplant, upstream H_2S abatement system and then stacked to the atmosphere.

- (5) The steam supply can be rerouted to another power plant.

Each of the approaches has problems associated either with condensation, wasteful venting of steam, emission of H_2S , or expenditure of capital funds for the development and implementation of control technology.

Repeated reduction of steam flow to minimum levels ranging between 10 to 20% of full flow (approach 1) is not considered good practice because of possible well damage. In well fields where the H_2S concentration is high, processing equipment for the removal of H_2S will be required before the residual flow of steam can be stacked.

In the practical operation of steam gathering systems, steam flow should not be reduced below 30 to 40% of full flow to avoid condensation in the pipelines (approach 2). Unfortunately, because relatively large amounts of residual steam must be stacked in this mode of operation, H_2S removal is essential.

If approaches 1 or 2 are utilized in power plants equipped only with downstream abatement units, then standby H_2S abatement facilities will be needed during a plant outage to process steam before it is stacked. Both approaches therefore may be costly, not only in terms of standby equipment and reagents, but in operational expenditures as well.

Bypassing steam around the turbine to the condenser (approach 3) allows the steam to be condensed and subsequently treated for removal of H_2S by the inplant, downstream off-gas and condensate treatment systems. Thus the bypassed steam will not be detrimental to the environment. Turbine bypass systems are usually designed to handle full-flow of steam for up to 24 h and reduced flow for approximately 96 h (CEC, 1980b). If longer plant outages are expected, alternative measures such as gradual closure of the steam supply wells will be necessary and the residual steam will have to be dealt with as described for approaches 1 and 2. It should also be noted that turbine bypass cannot be used if the power plant outage is caused by a failure in the condenser or cooling tower units. In data accumulated for PG&E Unit 15 (Appendix D), over 70% of the power plant forced outages were caused by failures that would render a turbine bypass system inoperable.

It is likely that some of the types of forced outages discussed in Appendix D may not necessarily rule out the use of turbine bypass. For example, during incidents of low steam pressure it is possible that the off-gas steam ejectors could remain operative provided the pressure is maintained above 80 psig. The condensers would then remain functional, allowing the use of turbine bypass. Similarly, some of the forced outages caused by inappropriate water levels in the condensers or cooling tower sump

may be prevented by more timely warning systems such as proposed in condition 7 of the LCAPCD determination of compliance for the DWR Bottle Rock plant (Appendix B), in addition to presently used monitors and alarms. It is probable, therefore, that the incidents of forced outages could be substantially reduced. Whether turbine bypass will be a significant and practical factor in H₂S abatement technology will be demonstrated by its performance at the DWR Bottle Rock plant.

If a preplant, upstream abatement system such as the EIC copper sulfate process is utilized to process steam before it enters the power plant (approach 4), then in the event of a power plant outage steam can be diverted after passing through the abatement unit and sent to the stack. This approach provides a relatively simple solution to the problem. However, it is wasteful of steam unless steam throttling is used. In addition, the technology is not yet fully tested and proven for use in geothermal power plants.

Rerouting of steam to an alternate user, for example to a nearby power plant (approach 5), utilizes steam efficiently and avoids emission of H₂S to the atmosphere during power plant outages. However, this approach requires a relatively sophisticated level of steam parameter monitoring and flow control. The technological problems are magnified by the size and characteristics of the steam gathering systems and the distances between power plants.

Choice of the appropriate approach or combination of approaches for handling steam and abating H₂S emission is influenced primarily by steam quality (such as superheat, H₂S, and NH₃ content), environmental regulations, the availability and status of technologies capable of implementing the approaches, and economic factors. Table 1 summarizes the status of steam flow control and H₂S abatement technologies described earlier. Combinations of these technologies are being included in the steam handling and H₂S abatement strategies for several new power plants in The Geysers area. The strategies have evolved primarily to satisfy specific conditions for determination of compliance required by LCAPCD and regulations imposed by NSCAPCD.

TABLE 1. Status of technologies for steam handling and H₂S abatement.

Technology	Positive Aspects	Negative Aspects
EIC-copper sulfate process	<ul style="list-style-type: none"> • Upstream technology • Preliminary 1/10-scale tests successful • Regenerative chemical process • 97% H₂S removal efficiency 	<ul style="list-style-type: none"> • Liquid and solid waste handling and disposal • Unknown factors <ul style="list-style-type: none"> • Demisting procedure • Entrainment of Cu • Long-term reliability • Full-scale process parameters not established
Turbine bypass	<ul style="list-style-type: none"> • Handles full flow of steam (up to 24 h) • Activated quickly 	<ul style="list-style-type: none"> • Handles ~60% of all plant outages
Surface condenser	<ul style="list-style-type: none"> • Proven technology 	<ul style="list-style-type: none"> • More expensive than direct contact condenser • Relatively large amounts of H₂S can partition into condensate depending on steam constituents
Stretford process	<ul style="list-style-type: none"> • Proven Technology • Removes 99% of H₂S from noncondensable gases • Regenerative chemical process • Close control not required • Handles large range of H₂S levels • Waste sulfur is a marketable by-product 	<ul style="list-style-type: none"> • Requires maximum partitioning of H₂S into noncondensable gas phase to be effective
H ₂ O ₂ -HAA-Fe catalyst process	<ul style="list-style-type: none"> • Proven Technology 	<ul style="list-style-type: none"> • Nonregenerative chemical process • High operating cost due to manpower and chemicals
Remote steam flow control and throttling	<ul style="list-style-type: none"> • Remote manual control is proven technology • Can reduce steam flow to <35% of full flow in <15 min • Ability to monitor steam supplies 	<ul style="list-style-type: none"> • Automatic control not fully tested • Possible well casing damage from frequent steam pressure reduction
Steam rerouting	<ul style="list-style-type: none"> • Crossover lines are installed in most Union Oil systems 	<ul style="list-style-type: none"> • Automatic control not developed

CURRENT STRATEGIES FOR STEAM HANDLING AND H₂S ABATEMENT

DESCRIPTION OF STRATEGIES

Strategies for steam flow control and H₂S abatement planned for five new power plants expected to be completed in The Geysers area in 1983 and 1984 are shown in Table 2. The mix of technologies for each strategy demonstrates the diversity of approaches that prevails in efforts to meet H₂S emissions limitations established by the LCAPCD and NSCAPCD.

Of the five plants listed in Table 2, four are single power plant configurations. They contrast with the NCPA-2 dual, parallel power plant of the Northern California Power Association (NCPA), which is supplied with steam from a single steam gathering system. The dual configuration provides for continued utilization of steam in the event that one of the dual units is shutdown. The configuration does not entirely avoid the necessity to vent steam when one unit trips, but the duration of venting can be greatly reduced from that of a single-unit power plant. Understandably, a highly responsive control system is needed to detect power plant trips, sense pressure changes, and facilitate optimum adjustment of valves to avoid upsetting the second power plant.

Seven different technologies can be identified in Table 2. Three are chemical abatement systems comprised of the EIC copper sulfate, Stretford, and H₂O₂-HAA-Fe catalyst processes. Three are steam flow control technologies including turbine bypass, steam supply and throttling control systems, and steam rerouting. The dual, parallel power plant configuration constitutes the seventh technology.

EVALUATION OF STRATEGIES

In condition 2 for the determination of compliance for the DWR Bottle Rock power plant, LCAPCD requires the utilization of an atmospheric emissions control system (AECS). This consists of the EIC copper sulfate process, a turbine bypass system, surface condenser technology, and the Stretford and H₂O₂-HAA-Fe catalyst processes. In addition to the AECS, steam flow control and throttling technology is provided by the steam supplier as an integral part of the steam gathering and supply system. In determining if the

TABLE 2. Planned H₂S abatement strategies for proposed geothermal power plants.

Power plant	County	Configuration	H ₂ S concentration, ppmv	H ₂ S emission limit, ^a lb/h	Abatement required, %	Strategies ^b						
						EIC	STRET	H ₂ O ₂	BYPASS	THRTL	RERTE	DUAL
DWR		Single plant										
Bottle Rock	Lake	55-MW unit	450	5	98.9	X	X	X	X	X	--	--
PG&E		Single plant										
Unit 16	Lake	110-MW unit	60	5	95.8	--	X	X	X	X	X	--
PG&E		Single plant		24								
Unit 18	Sonoma	110-MW unit	65	(100 g/MW·h)	81.5	--	X	X	--	X	X	--
SMUD-		Single plant										
GEO #1	Sonoma	72-MW unit	60	5-8	93.6 to 89.8	--	X	X	X	X	--	--
NCPA ^c		Dual plant		24								
2	Sonoma	2,55-MW units	90	(100 g/MW·h)	86.7	--	X	X	--	X		X

^a Refer to Appendices A, B, and C for details on regulations and conditions for determination of compliance.

^b Technologies incorporated in strategies:

EIC--copper sulfate process; upstream abatement technology.

STRET--surface condenser Stretford process; downstream abatement technology.

H₂O₂--H₂O₂-HAA-Fe catalyst process; downstream abatement technology.

BYPASS--turbine bypass pipeline and controls technology.

THRTL--steam flow control and throttling technology; remote manual and automatic control.

RERTE--steam rerouting technology; interplant crossover pipelines with remote manual and automatic control.

DUAL--dual, parallel power plant, steam flow control system.

^c NCPA--Northern California Power Association.

AECS constitutes the BACT, LCAPCD draws the conclusion by definition that all components of the system are available and when used concurrently are capable of achieving the emission limitation of 5 lb/h set forth in condition 1 for the determination of compliance.

To date, the combination of technologies constituting the AECS has never been assembled and tested concurrently to demonstrate that the above emission limitation can be achieved. Also the EIC copper sulfate process and the turbine bypass system have not been implemented and performance tested on a full-scale geothermal power plant. On the other hand the remaining components of the system, that is, surface condenser technology and the Stretford and H_2O_2 -HAA-Fe catalyst processes have proven effective for controlling H_2S emissions well within current limitations (100 g/MW·h) for PG&E Units 13, 14, and 15 during power plant operation.

However, these performance tested technologies alone are not capable of meeting the 5 lb/h limitation for the DWR power plant. The best overall abatement that can be expected is 96.3% and an emission of 16.7 lb/h for the DWR plant. This assumes H_2S partitioning to the off-gas and condensate phases in the ratio of 70 to 30 and abatement efficiencies of 99 and 90% for the off-gas and condensate treatment systems respectively. The 96.3% overall abatement not only does not meet the degree of abatement needed (98.9%), but it is also doubtful whether such abatement would be available 99% of the time (excluding maintenance) as required in condition 3 for the determination of compliance.

It is important to point out that control of emissions for PG&E Units 13, 14, and 15 in plant outage situations is handled by the steam flow control and throttling systems operated by the steam supplier. The Aminoil, USA system for Unit 13 is capable of limiting steam flow to currently required levels within the allowed time frame set by LCAPCD (100 g/MW·h within 15 min). However, this type of system will not be effective in meeting the limitation of 5 lb/h established for the DWR power plant. This is not because of a shortcoming in the capability of the control system, but rather on a reluctance to throttle back on steam flow so rapidly and to such an extent that the wells and pipelines would be damaged or accumulate condensate. The dilemma points out the need for abatement technology to handle plant outage situations and explains, to some extent, the current emphasis on the EIC process and turbine bypass systems.

It appears that the rationale for determining that the EIC process and turbine bypass in combination with the surface condenser, Stretford, and H_2O_2 -HAA-Fe catalyst processes constitute BACT is based on successful performance tests of the EIC process at one-tenth of full plant scale and the assumption that the turbine bypass system is composed of pipeline, valve, and control components that have been demonstrated in other uses and consequently can be expected to work for the bypass system.

If, as planned for the DWR plant, a full-scale EIC process that achieves 97% H_2S abatement in the incoming steam as demonstrated in one-tenth scale tests is used concurrently with the other technologies of the AECS, then indeed the 5 lb/h H_2S emission limit can be achieved. Again projecting from one-tenth scale tests, the EIC process can be expected to meet the 5 lb/h limitation during plant outages as well, provided the flow of steam is reduced to 35% of full flow.

It is assumed that the need for turbine bypass, in addition to the EIC process in the AECS for the DWR plant, is based on the requirement for 99% availability of technology to meet the 5 lb/h emission limitation (condition 3). The turbine bypass, therefore, may be considered a backup to divert steam to the downstream abatement system if the upstream EIC process is inoperable. However, turbine bypass itself may be unusable during some plant outages as pointed out earlier.

The conditions for determination of compliance for PG&E Unit 16 are not as demanding with regard to H_2S abatement technology as those for the DWR power plant, largely because of the expected low concentration of H_2S in the supply steam (60 ppmv). The combined surface condenser, Stretford, and H_2O_2 -HAA-Fe catalyst processes when applied to Unit 16 conditions are capable of limiting H_2S emissions to 4.4 lb/h, assuming an overall abatement efficiency of 96.3%. Turbine bypass is included in the strategy to provide access to the downstream facilities during plant outages. Just for the DWR plant, turbine bypass may not be usable during some plant outages. Steam flow control and throttling technology applied to Unit 16 could be used to limit steam venting to 35% of full flow with a corresponding H_2S emission level of 42 lb/h if turbine bypass is inoperable.

The three remaining power plants listed in Table 2 are scheduled for construction in Sonoma County. The downstream abatement technologies included in the strategies for these plants are expected to meet H_2S emission

limits. The calculated emission levels based on an overall efficiency of 96.3% are 4.8 lb/h for PG&E Unit 18, 2.9 lb/h for SMUDGE #1, and 6.7 lb/h for NCPA-2. Turbine bypass is included in the strategy for SMUDGE #1 to meet the 5 to 8 lb/h emission limit required during plant outages.

As previously stated, the NCPA-2 dual power plant configuration provides for steam utilization when one of the two units is tripped. Some venting will take place immediately after the trip occurs, but this can be controlled and gradually shut off as the control system adjusts pressure levels throughout the gathering system to provide appropriately balanced steam conditions for single unit operation.

The strategies for PG&E Units 16 and 18 include steam rerouting technology composed of crossover pipelines and controls that will be operated in remote manual or automatic mode. This technology is currently under development and has not yet been demonstrated at the full plant scale level. Though monitoring and control instrumentation are available, the ultimate success of a controlled rerouting system will depend on the ability to specify the well and piping flow dynamics. As discussed at the Workshop on Environmental Control Technology for The Geysers-Calistoga KGRA, the problems stem from the size of the steam gathering and power plant systems and the volumes of steam that are handled (Hill and Phelps, 1980). As stated by Kuwada of Rogers Engineering at the workshop:

Research is needed to develop a predictive dynamic computer model to aid in designing automatic control systems for steam gathering pipeline networks that handle large volumes. Computer modeling and expandable mathematical representation of such a system would allow suppliers to determine in advance the heat transfer losses, optimize heat insulation, minimize system warmup and startup times, and maintain constant stable pressures at the point where steam transfers to the power plant. Controller design and settings predicted by such a model would assist the suppliers in minimizing an otherwise prolonged design and operational startup time (Hill and Phelps, 1980).

STRATEGY COSTS AND PROJECTED PERFORMANCE

Table 3 lists estimated costs of individual technologies that constitute the current strategies for steam flow control and H₂S abatement as well as the costs incurred by each power plant complex for the abatement strategies indicated in Table 2. The economic generation of power from these plants will depend substantially on effective and reliable operation of specified H₂S abatement systems. Appropriate abatement technologies should be chosen on the

TABLE 3. Estimated costs for steam flow control and H₂S abatement technology.

Technology or power plant	Capital, \$10 ⁶	Operation and maintenance, \$10 ⁶ /y
EIC process	12	2
Surface condenser, Stretford, and H ₂ O ₂ processes	9.5	2.2
Turbine bypass	4	--
Remote control of steam flow	2 to 3.5 ^a	<0.1
Steam rerouting technology	>0.5 ^b	<0.1 ^b
Dual power plant configuration	14 ^c	--
DWR Bottle Rock	29	4.2
PG&E Unit 16	17.5	2.2
PG&E Unit 18	13.5	2.2
SMUDGE #1	17	2.2
NCPA-2	27	2.2

^a Includes one time computer costs and does not consider possible use of the system in multiple plants.

^b Costs per plant will vary depending on interplant distances.

^c Based on cost differential of 20%. Dual 55-MW turbogenerator system and ancillary equipment will cost more than a single turbogenerator system designed to produce the same output (110 MW).

basis of proven performance and reasonable cost. Moreover, the establishment of environmental standards and regulations should reflect the availability of such technology.

It is not unreasonable to conclude that steam flow control and H_2S abatement strategies planned for the PG&E Unit 18 and NCPA-2 power plants will be effective in meeting NSCAPCD emission regulations. The 24 lb/h H_2S emission limitation for the 110-MW operating plants can be met using performance-tested surface condenser technology in combination with the Stretford and H_2O_2 -HAA-Fe catalyst processes. Also, in the event of plant outages, state-of-the-art steam throttling controls such as the Aminoil, USA system will be capable of the required reduction of steam venting to 35% of full flow within 15 min of an outage.

The potential effectiveness of steam flow controls and H_2S abatement strategies for the PG&E Unit 16, SMUDGE #1, and DWR Bottle Rock power plants is less certain. The problem centers around the strict H_2S emission limits of LCAPCD, uncertainties regarding the utility of turbine bypass during power plant outages, and projected performance of the EIC process.

Table 4 summarizes the projected H_2S emission levels for the three plants under various modes of operation. Mode 1 defines conditions prevailing in an on-line plant. The conditions assume design-level flow of steam for power generation and utilization of the required H_2S abatement strategies listed in Table 2. In mode 1, all three plants are expected to meet the H_2S emission limitation of 5 lb/h if optimal performance of the abatement units is achieved. When a forced outage occurs and it is one in which turbine bypass can be utilized (mode 2), the emission limitation again can be met. However in outages where turbine bypass cannot be utilized (mode 3), the emission limitation probably will be exceeded in both the PG&E Unit 16 and SMUDGE #1 power plants as a result of steam stacking at 35% of full flow. Even with maximum controlled throttling of steam to 10% of full flow (mode 4), the H_2S emission level will remain above the 5 lb/h limit.

The utility of the turbine bypass may not be as important for the DWR power plant during forced outages. The reason for this is the incorporation of the upstream EIC process. In a DWR plant outage (mode 3) the EIC process can conceivably remove sufficient H_2S to just meet the emission limit, assuming 97% process efficiency and 35% flow of steam. If the EIC process is inoperable and the outage is one in which turbine bypass can be utilized (mode 4), then the emission level of 5.8 lb/h exceeds the limit by only a

TABLE 4. Projected H₂S emissions for proposed geothermal power plants.

Plant	Mode	Steam flow under plant conditions, %			Abatement technology ^a			H ₂ S emissions, lb/h	
		100	35	10	EIC	BYPASS	STRET- H ₂ O ₂	Projected ^b	Limit
PG&E Unit 16	1	X	--	--	--	NA	OP	4.4	5
	2	--	X	--	--	OP	OP	1.6	5
	3	--	X	--	--	NOP	NOP	42	5
	4	--	--	X	--	NOP	NOP	12	5
SMUD GEO #1	1	X	--	--	--	NA	OP	2.9	5 to 8
	2	--	X	--	--	OP	OP	1.0	5 to 8
	3	--	X	--	--	NOP	NOP	27.5	5 to 8
	4	--	--	X	--	NOP	NOP	7.9	5 to 8
DWR Bottle Rock	1	X	--	--	OP	NA	OP	0.5	5
	2	--	X	--	OP	OP	OP	0.2	5
	3	--	X	--	OP	NOP	NOP	4.7	5
	4	--	X	--	NOP	OP	OP	5.8	5
	5	X	--	--	OP	NA	NOP	13.5	5
	6	X	--	--	NOP	NA	OP	16.7	5
	7	--	X	--	NOP	NOP	NOP	158	5
	8	--	--	X	NOP	NOP	NOP	45	5

^a EIC--EIC copper sulfate process.

BYPASS--Turbine bypass.

STRET-H₂O₂--Stretford process and H₂O₂-HAA-Fe catalyst process.

NA--not applicable; OP--operating; NOP--not operating.

^b Projected H₂S emission assuming efficiencies of 96.3% for STRET-H₂O₂ and 97% for EIC.

small amount. Inoperability of both the EIC process and turbine bypass during a plant outage (mode 7) leads to excessive emission of H_2S (158 lb/h) in the steam being stacked at 35% of full flow. Maximum throttling to 10% of full flow (mode 8) will only reduce H_2S emission to 45 lb/h, a level still well above the LCAPCD emission limitation. It would appear that a more drastic step involving complete well field shutdown is the only recourse if this situation were to occur at the DWR facility. This would involve time-consuming manual closure of the master wellhead valves throughout the steam gathering system.

Other modes of operation are possible for the DWR plant because of multiple technologies included in the H_2S abatement strategy. Plant operation in modes 5 and 6 reflects the exclusive use of either the EIC process or the combined Stretford and H_2O_2 -HAA-Fe catalyst processes. Although the respective, projected emission limits of 13.5 lb/h and 16.7 lb/h are greater than the 5 lb/h limit stipulated in condition 1 for determination of compliance, they are close to or below the 12 lb/h and 24 lb/hr limitations established as the minimum performance standards for 55-MW and 110-MW geothermal power plant operations.

Abatement of H_2S at the DWR plant is especially difficult because of the high concentration of H_2S in the incoming steam. The proposed, multiple technology strategy should be looked on as an intensive design approach for reducing H_2S emission to a potentially achievable level of 5 lb/h. The strategy should not be considered BACT that will ensure the limitation of H_2S emission to the above specified level. The proposed abatement technology represents a relatively high capital investment and commitment to high accumulated costs for the operation and maintenance of three chemical systems. These costs could be substantially decreased if a proven upstream abatement process alone could be substituted for the technology presently proposed in the DWR power plant strategy.

Efficient upstream abatement such as the EIC process could significantly change design strategies not only for the DWR plant but for many others as well, in addition to considerably reducing the cost of abatement technology. Substitution of the EIC process in strategies proposed for the PG&E Unit 16 and SMUDGE #1 power plants, for example, would eliminate the need for turbine bypass, require less-expensive direct contact condensers instead of surface condensers, and replace the more costly reagent-intensive, downstream chemical

processes. However, such design decisions cannot be made at this time because of the unproven status of the EIC process. It is imperative, therefore, that full-scale plant tests be expedited to better resolve strategy decisions for future plants.

Because steam flow control systems and rerouting facilities are integral components of steam gathering systems and provide for efficient steam utilization, it is reasonable to assume that the capital investment in such facilities would be made regardless of the need for H_2S abatement. Continued development of controls for rerouting steam during plant outages is expected to provide capabilities to alleviate outage situations exemplified by mode 7 in Table 4. More importantly, development of effective rerouting facilities will provide alternate means for handling steam if upstream abatement technology and turbine bypass do not perform as anticipated.

SUMMARY AND CONCLUSIONS

Abatement of H_2S remains a critical issue affecting the expansion of geothermal electrical power plants in The Geysers area of northern California. Central to the issue are LCAPCD and NSCAPCD regulations and conditions limiting H_2S emissions and requiring specific abatement technologies in proposed power plant designs. Certification of each proposed plant requires a favorable determination of compliance with air quality standards by the county air pollution control district APCD and is contingent upon inclusion of the specified technologies in the plant design.

We have reviewed the required technologies as well as others that are being developed and are to be included in currently proposed power plants and steam gathering facilities. The status of these technologies is summarized below.

STEAM FLOW CONTROL AND REROUTING

- Remote, manual steam flow control systems have been developed and can be utilized effectively in a variety of geothermal power plant operations. They are especially useful during plant start-up and shutdown and are capable of throttling steam flow to 35% of full flow within 15 min. Throttling to

lower flow rates in shorter time intervals are within the capabilities of the systems but are not expected to be utilized because of possible damage to wells and pipelines. Hardware is built into the systems that enables automatic operation. This will be implemented using data and experience from remote manual operations.

- Turbine bypass, in principle, may be regarded as an effective way to divert steam to downstream abatement facilities during plant outages. However, some outages may render either the bypass or the downstream abatement facilities to which steam is being diverted inoperable. To date, turbine bypass has not been operated on a full-scale geothermal power plant.

- Steam rerouting pipelines and control valves are installed on most of the steam gathering systems supplying PG&E power plants at The Geysers. Effective rerouting of steam and overall reduction of steam stacking will not be realized until remote manual and automatic steam flow control systems have been installed and performance tested on multiple steam gathering facilities and power plants at The Geysers. This development is actively underway.

DOWNSTREAM H_2S ABATEMENT TECHNOLOGY

- Downstream H_2S abatement consisting of surface condenser technology and the Stretford and H_2O_2 -HAA-Fe catalyst processes has been utilized and proven effective at full plant scale. At the present time it constitutes BACT capable of 96.3% (or greater) H_2S removal efficiency depending upon the partitioning of H_2S between the noncondensable gases and the condensate exiting the surface condenser.

- Downstream H_2S abatement technology is relatively expensive because of the need for surface condenser facilities and the reagent-intensive H_2O_2 -HAA-Fe catalyst process.

UPSTREAM H_2S ABATEMENT TECHNOLOGY

- The upstream EIC process for abatement of H_2S has not been performance tested at full plant scale. Tests at one-tenth plant scale have been used to project future performance.

- If the EIC process proves effective at full scale, it may obviate the need for turbine bypass and downstream abatement and thereby provide a relatively economic technology for abating H_2S .

CONCLUSIONS

Although projections here show that achievement of the 5 lb/h H_2S emission limitation may be possible with specific technology strategies, there is no assurance that in fact this will occur. This is primarily because of the unproven status of the EIC process at full plant scale and uncertainty regarding the utility of turbine bypass during power plant outages. There is no doubt that full-scale performance tests of both technologies should proceed as quickly as possible. However, it should be borne in mind that steam flow control systems and steam rerouting facilities are being developed concurrently. The outcome of these tests will greatly influence the choice of abatement strategies for future geothermal power plants. Until such time as the results are complete, prudent judgement should be exercised in the choice of technologies and establishment of H_2S emission limitations based on specific technologies.

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APPENDIX A. THE H₂ EMISSION LIMITATIONS OF THE NORTHERN SONOMA COUNTY AIR POLLUTION CONTROL DISTRICT

The following is taken from Regulation 1 of the California North Coast Air Basin Air Quality Control Rules (revised October 21, 1980).

TABLE A-1. Emission limits for geothermal power plants.

Effective date ^a	In operation before January 1, 1980		Any plant beginning operation after Jan. 1, 1980 (g/hr/GMW) ^b
	With direct contact condenser	With surface condenser (g/hr/GMW) ^b	
Jan. 1, 1979	For Units 3, 4, 5, 6, 11 and 12 emit: no more than 10% of the H ₂ S in the supplied steam at full power plant load or 200 g/hr/GMW average using allocation method ^c	--	--
Jan. 1, 1980	-- ^d	100	100
Jan. 1, 1982	Units 3-6, 11, and 12: 200 g/hr/GMW ^d	--	--
Jan. 1, 1985	-- ^d	--	50 ^e
Jan. 1, 1990	--	50 ^e	--
Jan. 1, 2000	100 g/hr/GMW ^e	--	--

NOTE: All geothermal power plants, including new construction, must comply with future emission rate reductions as they become effective.

^a The H₂S emission limitations for each category of emission source will become effective henceforth on the date indicated at the left of the table.

^b "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.

^c 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%).

^d 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.

^e 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.

TABLE A-2. Geothermal power plant emission during unscheduled outages.

Effective date ^a	Existing or permitted systems as of June 1, 1978.	New systems	Other geothermal sources	
			Well drilling, reworking and testing ^b (kg/hr/well)	Small source emissions ^c (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, ^d or (c) to not more than 15 kg/hr. For a scheduled outage greater than 4 hr 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 65% 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 greater than 4 hr the same emission standards shall be met within 1 hr or less.	5 ^e	--
Jan. 1, 1980	-- ^e	--	2.5 ^e	2.0
Jan. 1, 1982	To be promulgated by APCO ^e	Same as above except (b) is 50%.	--	1.0
Jan. 1, 1985	--	--	--	0.5

NOTE: All geothermal power plants, including new construction, must comply with future emission rate reductions as they become effective.

^a The H₂S emission limitations for each category of emission source will become effective henceforth on the date indicated at the left of the table.

^b 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.

^c Small sources include continuous well and pipeline bleeds. Allowable emissions are those shown in table A-2 unless otherwise determined by the Air Pollution Control Officer.

^d "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.

^e 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.

APPENDIX B: LAKE COUNTY AIR POLLUTION CONTROL DISTRICT DETERMINATION OF COMPLIANCE FOR THE DEPARTMENT OF WATER RESOURCES BOTTLE ROCK GEOTHERMAL POWER PLANT.

The following is taken from the decision on the Department of Water Resources' Application for Certification for the Bottle Rock Geothermal Project, California Energy Commission, Sacramento, CA, October 1980, 79-AFC-4.

REQUIRED CONDITIONS

Condition 1

Hydrogen sulfide (H_2S) emissions from the DWR/Bottle Rock power plant shall be limited to a maximum of five (5) pounds per hour during power plant generation and all possible generation outages. All untreated steam or condensate shall be returned to a treatment or re-injection point to ensure this level of emissions is maintained.

Condition 2

The atmospheric emissions control system (AECS) described in the AFC and revisions to the AFC, April 18, 1980, shall be utilized. The system as described, which constitutes the best available control technology, shall consist of the following concurrently available major components:

- (a) An EIC system to reduce H_2S and other emissions prior to entering the power plant;
- (b) A surface condenser to facilitate the partitioning of H_2S into the noncondensable gas phase;
- (c) A Stretford unit as specified in the AFC to reduce the H_2S concentration in the noncondensable gases to 10 parts per million by volume (ppmv) or less;
- (d) Secondary condensate treatment which includes sufficient hydrogen peroxide (H_2O_2) and catalyst injection and reaction time to ensure the power plant will comply with the emission limitation specified in Condition #1;

- (e) A turbine by-pass system sufficiently sized to accept 100% of full steam flow during generating outages so that the power plant emission control system can be utilized to treat steam normally stacked during the outage.

In addition,

- (f) The air emissions control system specified above shall be properly winterized.
- (g) If a solids removal system is necessary as a result of solids formation in the condensate, such facility shall be incorporated into the system.
- (h) In the event of Bottle Rock generation loss, an alternate source of power to enable the continued use of the air emissions control system specified above shall be available.
- (i) A stand-by generator capable of sustaining the EIC system shall be available and fueled with low sulfur fuel of 0.5% or less.

Condition 3

The major components of the air emissions control system (EIC, Stretford, and condensate abatement) shall incorporate a design to enable a 99% availability excluding scheduled maintenance on these individual major components. If such design criteria cannot be established, abatement systems shall be retrofitted as necessary to achieve performance at this level.

Condition 4

Upon failure of H_2S abatement equipment, DWR shall curtail to a level necessary to comply with the five (5) lbs/hr H_2S emissions limitation or provide for a mechanism allowing an immediate determination of prevailing atmospheric conditions to enable the LCAPCO to make a decision as to whether it is acceptable to continue operation at a higher emissions level.

Condition 5

The cooling towers shall have a guaranteed drift rate of no more than 0.00002 as described in the AFC.

Condition 6

The off-gas vent to the atmosphere shall be used only during legitimate emergencies and to enable the cold start-up of the power plant turbine. Steam flows shall not exceed 25,000 lbs/hr to the power plant during direct venting of untreated noncondensable gases in the steam. The turbine by-pass shall be used if possible to avoid direct venting into the atmosphere of undiluted noncondensables. The LCAPCD shall be notified when cold start-ups in excess of 5 lbs H_2S /hr are to occur and may cancel such activity if deemed necessary.

Condition 7

DWR shall install alarms and switches on the following units to ensure immediate corrective action is initiated to prevent outages and potential stacking. Alarm/trip conditions noted with an asterik have a separate alert and trip alarm function and those alarm/trip conditions without an asterisk are coincident alarm/trip functions.

Turbine Generator Unit.

1. Excessive vibration switch, alarm and trip.
2. Lateral motion switch on the turbine shaft, alarm and trip.
- 3.* High lube oil temperature switch, alarm and trip.
- 4.* Low lube oil pressure switch with indicating light in control room.
- 5.* Low lube oil sump level switch, alarm.
6. Overspeed switch, alarm and trip.
- 7.* High hydrogen gas temperature and low purity hydrogen alarm and trip.
- 8.* Seal oil level switch and alarm.
- 9.* Differential pressure switch to prevent low differential pressure between the seal oil and hydrogen pressure, alarm and trip.
- 10.* Generator moisture detector and alarm.
- 11.* Vacuum switch to prevent low vacuum in the seal oil detaining tank, alarm and trip.
- 12.* Turbine bearing metal temperature alarm and trip.

Condensers.

- 1.* Pressure switch to prevent condenser pressures from exceeding design levels, alarm and trip.
- 2.* Condensate level switches to start and stop pump, prevent excessively high condensate levels in hot well.
- 3.* High or low condensate levels alarms.

Cooling Towers.

- 1.* Float switches and indicators to start and stop the pump in the cooling tower overflow basin and provide alarms.
2. Vibration switches and alarms on each cooling tower fan.

Electrical System.

1. Generator differential current trip and alarm.
2. Generator over-current trip and alarm.
3. Generator ground fault trip and alarm.
4. Generator anti-motoring trip and alarm.
5. Generator field ground trip and alarm.
- 6.* Generator stator over temperature alarm and trip.
7. Loss of excitation trip and alarm.
8. System negative phase sequence trip and alarm.
9. Transformer differential current trip and alarm.
10. Transformer over-current trip and alarm.
11. Transformer ground fault trip and alarm.
12. Transformer sudden pressure trip and alarm.
- 13.* Transformer winding temperature alarm.
- 14.* Transformer oil temperature alarm.

Condition 8.

The LCAPCD shall be notified within one hour following any power plant outage or malfunction resulting in emissions in excess of five (5) pounds per hour H_2S at (707) 263-2391, 263-3121, or a number to be provided by the LCAPCD. DWR shall maintain a log of power plant outages along with explanations for the outages and malfunctions. In the event that power plant outages recur because of equipment malfunctions that are not indicated by

alarms, DWR shall retrofit alarms on the malfunctioning equipment as possible. The log shall be available for inspection upon the request of the staffs of the LCAPCD, ARB, CEC, and EPA.

Condition 9

The power plant abatement system shall have an operator on site at all times. The operator must be able to immediately take necessary corrective action in the event of power plant outage or equipment malfunction in order to meet the conditions of this Determination of Compliance. DWR shall provide a telephone number at which the Bottle Rock operator or a representative can be reached to ensure LCAPCD entry for inspection purposes within one (1) hour of notification. If for considerations of safety, DWR can not comply with such a specific request, DWR shall forward, in writing within one week, a letter explaining the reasons entry within one hour could not be allowed the LCAPCD staff.

Condition 10

DWR's approved-for-construction drawings or other drawings acceptable to the LCAPCD of the EIC system, Stretford unit, turbine by-pass, and secondary abatement (condensate treatment) system shall be submitted to the LCAPCD and CEC for comment and review at the earliest possible date. DWR shall not be required to submit proprietary information unless specifically requested by the LCAPCO pursuant to section 91010, Title 17, California Administrative Code.

Condition 11

DWR shall submit to the LCAPCD, ARB, and CEC the results of the pilot test program performed by Bechtel National Inc., no later than February 1, 1982, or within one month before finishing the final design of the hydrogen peroxide/catalyst abatement system.

Condition 12

Before the start-up of the power plant, DWR shall submit to the LCAPCD certification by EIC Corporation that DWR's operators have been trained to operate and maintain the EIC system in accordance with EIC's approved procedures.

Condition 13

Although the applicant is to be licensed upon the use of BACT as described in Condition #2, DWR may use other means to comply provided the LCAPCD, ARB, and CEC are provided performance data indicating the other means are capable of achieving the same emissions limitations and reliability as those defined in Condition #2. Any such changes shall be decided at a properly noticed public hearing to be convened jointly by the LCAPCD and CEC, no later than two years prior to anticipated power plant operation at which the ARB and all intervenors shall be invited to participate. The LCAPCD concurrence upon any changes must be given.

Condition 14

The access road from Bottle Rock road to the power plant shall be paved to ensure that the generation of fugitive particulate matter is minimized.

Condition 15

Within sixty (60) days after initial power production, DWR shall demonstrate that the applicable emissions limitations are being maintained during normal power plant operations. DWR shall submit a detailed performance test plan to the LCAPCD at least thirty (30) days prior to such tests. Such plans shall also be designed to determine the particulate emissions rate and components of particulate emitted. DWR's proposed test plan must receive LCAPCD and CEC staff approval before such tests may be conducted to determine compliance.

Safe sampling access and ports to enable the LCAPCD to gather samples from the freshly treated condensate, cooling tower stack, treated gas from the Stretford system, and treated steam from the EIC system shall be provided.

Condition 16

Reports shall be issued quarterly to the LCAPCD detailing: (a) hours of operation; (b) any periods for which abatement equipment malfunctioned and the action taken; (c) chemicals utilized for treatment of condensate; (d) periods of scheduled and unscheduled outages and the reasons for such outages; and (e) summary of the output of continuous emissions monitors with explanations of any irregularities.

Condition 17

Within ninety (90) days after commercial operation DWR shall file with the LCAPCD an application for a Permit to Operate together with all appropriate information to ensure compliance with the certification and submit permit fees.

Condition 18

DWR shall take all reasonable measures to comply with any future air emittent or ambient standard or guideline adopted for present non-criteria pollutants (i.e., mercury, boron, arsenic, radon²²², etc.) by responsible State or Federal agencies and/or comply with guidelines established as part of DWR/Bottle Rock's certification by the California Energy Commission.

Condition 19

DWR shall promptly fund reasonable studies or tests as required by the LCAPCD to ascertain the impact of DWR/Bottle Rock when operating, specifically at the residence located approximately 1900 ft east of the Francisco pad, should the resident in good faith file complaints with the LCAPCO indicating the air quality is worsening or becoming a nuisance or unhealthful as a result of Bottle Rock's operation. These studies shall include, but not be limited to, monitoring at the residence to determine H₂S levels and particulate or other components which are believed or known to be in geothermal steam, tracer tests, or source tests. Such studies shall be approved by the LCAPCO prior to initiation. Reasonable mitigation steps shall be applied upon request of the LCAPCO to attempt to remedy any unlawful impacts caused by the Bottle Rock power plant.

Condition 20

The incoming steam to the power plant shall be analyzed quarterly and reported to the CEC and LCAPCD for radon²²² and its daughters, mercury, arsenic, silica, boron, benzene, ammonia, and total suspended solids for the first two years of operation. The results of these tests shall be reviewed by the LCAPCO to determine if thereafter annual testing will suffice. DWR may join with the steam supplier in performing such tests. Results of any tests performed upon the cooling tower sludge shall also be forward to the LCAPCD.

Condition 21

H₂S emissions shall be monitored continuously by measuring total volume/flow rates and H₂S concentrations at the following locations: (a) outlet of the EIC system; (b) outlet of the Stretford unit; and (c) in the condensate. A log of such monitoring shall be maintained and be made available to LCAPCD staff upon request. The devices must have accuracies of +1 ppm, provide measurements at least every 15 minutes, and be accessible to LCAPCD staff. Flow rate measuring devices must have accuracies of +5% at 40% to 100% of the total flow rate and calibrations must be performed at least quarterly. Calibration records must be made available to LCAPCD staff upon request. Monitoring shall be required pursuant to Section 42303 of the California Health and Safety Code.

In the event that acceptable continuous monitors are not available, DWR shall conduct testing no less than once every thirty (30) days to ensure the efficiencies of the H₂S abatement systems are being maintained. The testing procedure used to determine compliance must be approved by the LCAPCO. A log of such testing shall be maintained and be available to LCAPCD staff upon request. The Applicant shall on an annual basis after the date of the decision submit for approval by the LCAPCD, CEC, and ARB a summary of the Applicant's efforts to develop, research, let for contract to research, or let for contract to implement use of equipment, that is to be a likely candidate for a continuous condensate and noncondensable gas monitor for hydrogen sulfide.

In either case, a summary of the monitoring and/or testing shall be forwarded to the LCAPCD every three (3) months.

Condition 22

DWR shall, at the request of the APCO, install, operate and maintain an on-site meteorological station capable of determining wind direction, wind speed, standard deviation of the direction, and temperature. Such data shall be furnished to the LCAPCD on a monthly basis in an hourly/day format and quarterly in a summary format acceptable to the APCO.

Condition 23

Compliance monitoring shall be conducted for a minimum one (1) year period before initial operation and one (1) year period after initial operation. Constituents to be monitored include arsenic, boron, mercury, radon²²², benzene, silica, and particulates in addition to H₂S. Constituents shall be measured both as suspended aerosols and fall-out. Monthly composite samples of fall-out shall be collected using a wet/dry collector. Constituents other than H₂S may be measured every sixth day, per the ARB particulate sampling schedule. DWR, CEC, and LCAPCD shall agree upon methods used in sampling and analysis. At the end of the indicated period, the monitoring program will be reviewed by the APCO and the feasibility and necessity for continuance determined. The site for such monitoring shall be in the Cobb Valley area unless DWR and the LCAPCD agree upon a mutually acceptable alternative site.

If DWR enters into a combined effort with other developers of an alternative monitoring program acceptable to the LCAPCD and CEC, this condition shall not be exercised.

APPENDIX C: LAKE COUNTY AIR POLLUTION CONTROL DISTRICT DETERMINATION OF COMPLIANCE - PACIFIC GAS AND ELECTRIC COMPANY GEYSERS UNIT 16 GEOTHERMAL POWER PLANT

The following is taken from the Lake County Air Pollution Control District Determination of Compliance for Geysers Unit 16, Lake County Air Pollution Control District, Lakeport, CA.

REQUIRED CONDITIONS

Condition 1

Pacific Gas and Electric Company (PG&E) shall use equipment and/or procedures expected to be capable of maintaining the emissions of hydrogen sulfide (H_2S) from the power plant at 5 pounds per hour.

Condition 2

PG&E shall operate the abatement systems in the manner expected to limit the emissions of H_2S from the power plant to 5 pounds during each hour the plant is operating. Within 30 days of completion of the performance test required by Condition 12, PG&E shall submit, for approval, an operating procedure expected to limit the emissions of H_2S from the power plant to 5 pounds per hour. The Lake County Air Pollution Control Officer (LCAPCO) shall approve or disapprove the procedure within 30 days of receipt. Upon approval, compliance with the procedure shall be deemed compliance with the Condition 2, provided that, in no case, shall the H_2S emissions from the power plant exceed 7.5 lbs/hr for more than a total of 72 hours each year. These 72 hours are intended to allow for reported unforeseen outages of air pollution abatement equipment. Nothing in this condition shall relieve PG&E from compliance with Section 510 of the Rules and Regulations of the Lake County Air Pollution Control District (LCAPCD).

In the event that the emissions exceed 5 pounds per hour, PG&E shall immediately report to the LCAPCO; (1) the reason why the power plant emissions exceeded 5 pounds per hour of H_2S ; and (2) the action taken or proposed to be taken in accordance with the approved operating procedure to reduce the H_2S emissions to 5 pounds per hour.

Condition 3

The hydrogen peroxide/catalyst and Stretford/surface condenser system as proposed in the AFC shall be the equipment used to satisfy the requirements of Condition 1. In the event that PG&E seeks to change the equipment to control H₂S emissions, PG&E shall request that the LCAPCD Hearing Board and California Energy Commission (CEC) determine whether the alternate technology satisfies the requirements of Conditions 1 and 2. PG&E may use the alternate technology only if the LCAPCD Hearing Board and CEC determine that it will comply with Conditions 1 and 2.

Condition 4

Not later than two (2) years prior to the scheduled operation date of any alternative abatement technology to be installed at the Unit 16 power plant, PG&E shall submit to the LCAPCD and the CEC the conceptual design of the alternative technology which will be installed to satisfy the requirements of Conditions 1 and 2.

Condition 5

Not later than 30 days prior to the scheduled start of construction of the alternative technology, PG&E shall submit to the LCAPCD and the CEC data from a full scale or pilot 5-day test (similar to that conducted for the hydrogen peroxide/catalyst process at Unit 13 in 1980) demonstrating that any proposed alternative technology is expected to be capable of maintaining emissions of H₂S from the power plant at the levels specified in Conditions 1 and 2. If PG&E proposes to change the H₂S abatement technology, PG&E shall not commence construction or installation of any alternative technology until the LCAPCO concurs in writing that such alternative technology is expected to comply with the emissions limitations specified in Conditions 1 and 2. The LCAPCO shall either concur or deny concurrence within fifteen (15) days of receipt of the data submitted by PG&E. Failure to submit data from the above specified test demonstrating compliance with Conditions 1 and 2 may be a basis for the denial of concurrence by the LCAPCO. The type of data and format shall be similar to that contained in PG&E's Department of Engineering

Research Report 420-80-.179. In no event shall PG&E operate the Geysers Unit 16 power plant at this site without either H₂S control technology specified in Condition 3 or alternative H₂S control technology approved by the LCAPCO.

Condition 6

PG&E, with the steam supplier, shall develop a plan to limit H₂S emissions during power plant outages to the H₂S emission limitation specified in Conditions 1 and 2 within 15 minutes, or as close to 15 minutes as is obtainable, but in no case later than 60 minutes after cessation of power generation. Said plan shall specifically consider the use of a turbine bypass system consisting of the following components: valving, tubing, and sparger enabling 50% of the full steam flow to be treated using the power plant surface condenser and abatement equipment to control H₂S emissions during power plant outages. If such a system is not proposed, said plan shall include a justification for the decision.

Said plan shall be submitted, within 120 days of issuance of PUC certification, to the Executive Office of the Air Resources Board (ARB) for approval and shall: (1) identify the technology proposed to control H₂S emissions during power plant outages (stacking emission control system); (2) provide general operating procedures for the stacking emission control system specifying the duties of PG&E and the steam supplier; and (3) include the development of performance data to submit to the LCAPCO and Executive Officer of the ARB demonstrating that the stacking emission control system can comply with the H₂S emission limitation specified above. Within 30 days of receipt of the plan the Executive Officer shall determine whether the plan satisfies this Condition 6 and, if satisfactory, shall approve the plan. The plan shall be approved only if H₂S emissions are controlled as specified in Conditions 1 and 2 within 15 minutes, or as close to 15 minutes as is obtainable, but in no case later than 60 minutes after cessation of power generation. PG&E shall not commence installation of the power plant H₂S control technology prior to receiving approval of the plan. Upon approval of said plan it shall become a part of the terms and conditions of the Determination of Compliance and shall be incorporated into any certification and any Permit to Operate issued for Geysers Unit 16 at this site.

Condition 7

The direct off-gas vent to the atmosphere shall be used only during cold start-up of the power plant turbine and failures of the cooling tower fans or the direct off-gas system to the cooling towers. PG&E shall notify the LCAPCO at least one hour prior to each cold start-up involving direct venting. Within normal operating constraints, PG&E shall use best efforts to avoid cold start-ups under adverse meteorological conditions (e.g., strong drainage and limited downward mixing). Cold start-up shall not involve direct venting of the untreated noncondensables for steam flows exceeding 25,000 pounds per hour.

Condition 8

The cooling towers shall have a guaranteed drift rate of no more than 0.002%. "Drift" shall be defined as it was in PG&E Report #7485.16-74.

Condition 9

The components of the air pollution abatement systems shall be properly winterized.

Condition 10

PG&E shall submit approved-for-construction drawings of the power plant secondary H₂S control technology to the LCAPCD and the CEC at least 30 days prior to commencing construction of the technology.

Condition 11

- (A) PG&E shall continue to pursue development of continuous H₂S monitoring devices to meet the following requirements: H₂S shall be monitored by measuring parameters indicating total volume flow rates and H₂S concentrations at the following locations:
- (a) outlet of the Stretford unit; and (b) in the treated condensate or in the circulating water upstream of the cooling tower. A log of such monitoring shall be maintained and made available to LCAPCD and CEC staff

upon request. The H_2S monitoring devices must have an accuracy of plus or minus 1 ppm, provide measurements at least every 15 minutes, and be readily accessible to LCAPCD staff. Flow rate measuring devices must have accuracies of plus or minus 5% at 40% to 100% of the total flow rate and calibrations must be performed at least quarterly. The monitor shall not require more than 16 hours of maintenance per month. Calibration records must be made available to LCAPCD staff upon request. PG&E shall submit a copy of the continuous monitoring development plan to the LCAPCD and the CEC.

One year after the commencement of commercial operation, PG&E shall submit a final report to the LCAPCO on the availability of acceptable continuous monitors which satisfy the above criteria. Within 30 days of receipt of the report, the LCAPCO shall determine whether or not such monitors are available and should be installed at Unit 16. Until such monitors are installed or in the event that the LCAPCO determines that monitors meeting the above specifications are not commercially available within one year of commencement of commercial operation, PG&E shall conduct testing no less than once every thirty (30) days to ensure compliance with Conditions 1 and 2. The testing procedure used to determine compliance shall be submitted to the LCAPCD for approval. A log of such testing shall be maintained and available to the LCAPCD and CEC upon request.

In all cases, a summary of the monitoring and/or testing shall be forwarded to the LCAPCD every three (3) months.

- (B) The incoming steam to the power plant shall be analyzed for H_2S , ammonia, arsenic, boron, mercury, and radon²²². These components (except H_2S) shall be monitored every quarter for a period of two (2) years after the scheduled date of commercial operation and annually thereafter. The H_2S shall be monitored at least every 30 days for the life of the power plant, unless a continuous monitoring system as described in Condition 11.A. is used to monitor emissions. Reports summarizing the results of such analyses shall be submitted to the LCAPCD and the CEC quarterly.
- (C) PG&E shall operate or participate in the operation of a monitoring station to be located at the Anderson Springs Recreation Center. Such monitoring shall be conducted for one (1) year prior to and one (1) year

after the scheduled date of commercial operation. The constituents to be monitored shall be H_2S , boron, mercury vapor, radon²²² and its daughters, and particulate matter. Particulate matter shall be analyzed for silica, boron, vanadium, and mercury solids. The frequency, method of collection, and the testing methods shall be approved by the ARB and the LCAPCO. Quarterly reports summarizing the results of such monitoring shall be submitted to the LCAPCD, the ARB, and the CEC.

- (D) PG&E shall provide safe access to sampling ports that enable representatives of the LCAPCD or ARB to collect samples from the treated condensate or the circulating water upstream of the cooling tower, cooling tower stacks, the noncondensable exit gas from the Stretford unit, and the direct off-gas vent.

Condition 12

At least 60 days prior to scheduled commercial operation, PG&E shall submit, for approval, a detailed plan for testing the performance of The Geysers Unit 16 abatement system at normal full load operation. Normal full load is defined as operating Geysers Unit 16, at a minimum of 80% of the gross electricity generating capacity, and the abatement system. This one-time test shall incorporate tests for emissions from the cooling tower of components of potential concern in geothermal steam.

PG&E shall complete the performance test plan approved by the LCAPCO within 90 days or as soon as possible following the date of commercial operation. The LCAPCO shall approve, disapprove, or modify the plan within 30 days of receipt.

Condition 13

PG&E shall file an application for a Permit to Operate with the LCAPCD within 90 days after the commercial operation date or as soon as possible thereafter and submit appropriate permit fees. The application shall include the results of the performance test plan in Condition 12.

Condition 14

PG&E shall issue quarterly reports to the LCAPCO detailing; (a) hours of operation; (b) any periods of abatement equipment malfunction, reasons for malfunctions, and the corrective action; (c) types and amounts of chemicals used for condensate treatment; (d) periods of scheduled and unscheduled outages and the cause of the outages if known; (e) a summary of any irregularities that occurred with the continuous emissions monitors, if used; and (f) the dates and hours in which Unit 16's H₂S emission rate was in excess of the emissions limitations specified in Conditions 1 and 2.

Condition 15

PG&E shall allow authorized representatives of the LCAPCD and ARB to enter the premises where the source is located, within one hour of notification, to inspect the plant for compliance with the conditions of this Determination of Compliance.

Condition 16

PG&E shall comply with all applicable Federal, State, and local laws, standards, and ordinances in the operation of Geysers Unit 16.

APPENDIX D: FORCED OUTAGES AT PG&E UNIT 15

The following was taken from information supplied by the Pacific Gas and Electric Company.

TABLE D-1. Summary of causes of forced outages.

Year	Start		End		Total		Cause	Turbine bypass utilization
	Mo.	Day	Mo.	Day	Mo.	Day		
1979	5	26	11	5	26	14	3.1 Steam supply problem	No
		26	18		27	12	18.3 Turbine bearing high temp.	Yes
	6	22	9	6	22	10	0.7 Exciter ^a	Probable
		22	12		22	14	1.9 Exciter	Probable
		22	15		22	16	0.8 Exciter	Probable
		26	9		26	12	2.8 Exciter	Probable
	7	15	18	7	16	18	24.6 Hydrogen seal	Yes
		18	8		18	9	1.4 Low steam pressure ^b	No
		18	9		18	20	10.8 Low hydraulic oil pressure	Yes
		19	12		19	14	2.0 Broken drain line ^c	No
		23	9		23	11	1.7 Condenser high water level	No
		25	15		25	18	3.1 Low steam pressure	No
		25	18		25	20	1.5 Low condenser vacuum	No
	8	2	7	8	2	12	5.3 Turbine bearing high temp.	Yes
		9	15		9	17	1.8 Low steam pressure	No
		10	15		11	5	14.0 Broken drain line	No
		11	15		11	21	6.3 Low steam pressure	No
		13	11		13	14	3.5 Steam Line Pressure tap failure ^d	No (3)
		14	12		14	15	2.5 Blowdown reinjection line	No
	9	10	16	9	10	18	1.9 Circulating water pump trip ^e	No
		26	19		27	19	24.2 Cooling tower over-flow	No
		28	9		2	0	87.5 Bus damage--480-V motor ^f	No
	10	2	5	10	3	14	32.7 Condenser level control ^g	No
		4	15		4	21	6.0 Condenser level control	No
		13	17		13	21	3.5 Unknown	Unknown
		16	16		16	18	1.8 Unknown	Unknown
		17	23		21	13	830.2 Bus damage--fire	No

TABLE D-1. (Continued.)

								Turbine			
Start			End			Total		bypass			
Year	Mo.	Day	Hr.	Mo.	Day	Hr.	Hours	Cause	utilization		
1979	11	21	13	11	21	14	0.8	Low hydrogen purity	Yes		
		21	17		21	17	0.7	Water carryover in steam	No		
	12	1	20	12	1	23	3.0	Steam lead drain valve	No		
		1	23		2	2	2.8	Low steam pressure	No		
		5	10		5	15	5.8	Generator trip	Yes		
		6	11		6	13	1.6	High lube oil temp.	Yes		
		6	13		6	15	1.9	Low condenser vacuum	No		
		11	15		11	16	1.6	115-kV transmission line	No		
	1979	12	14	13	12	14	16	3.1	Turbine drain flange leak	No	
			19	15		19	20	5.0	Turbine drain leak	No	
20			1	20		4	3.5	Low steam pressure	No		
21			14	21		15	1.6	Low condenser vacuum	No		
21			18	21		22	3.8	Low condenser vacuum	No		
22			15	23		1	10.1	Broken steam line drain	No		
23			1	23		19	18.3	Low steam pressure	No		
1980			1	12		2	1	12	5	3.1	Low steam pressure
	18	16		2	18	19		3.1	External--thermogenics	N/A ^h	
	2	29	14	2	29	16	2.5	Low condenser vacuum	No		
		3	5		15	3	5	23	8.6	Circulating water pump breaker	No
			6		11		6	14	3.2	Circulating water pump breaker	No
		23	13		24	17	28.3	Switchgear (relay)	No		
24	17	29	2	105.3	Steam release to building	No					
Total yes, Probable or Unknown									13		
Total no									35		
Total not applicable									1		
Total Forced Outages									49		

NOTE: Scheduled outages are not included in this listing since they would not normally result in stacking. For May 1979 to March 1980 there were only five scheduled outages.

^a Exciter, generator, generator hydrogen coolers - turbine bypass possible.

^b Steam pressure inadequate to run the condenser steam-jet air ejectors.

^c All drain lines to the condenser and condenser vacuum would be lost during drain line repairs.

^d Line must be cleared for repair.

^e Condensate pump trip, circulating water pump trip, cooling tower overflow--cooling system not available for use in a turbine bypass mode.

^f Transmission, switchgear, bus, or load center--no electric power available for operation of auxiliaries (includes secondary abatement chemical feed pumps, Stretford air blowers, etc.).

^g Low condenser vacuum, high condenser water level, condenser level control--condenser not available for steam condensation.

^h Turbine bypass not applicable since outage was caused by steam supplier.

APPENDIX E. SUGGESTED MEASURES FOR THE CONTROL OF H₂S EMISSIONS FROM
GEOTHERMAL OPERATIONS AT THE GEYSERS KNOWN GEOTHERMAL RESOURCES AREA

The following was taken from the State of California Air Resources Board suggested control measure for the control of hydrogen sulfide emissions from geothermal operations at The Geysers known geothermal resources area, California Resource Board, Sacramento, CA (1981).

I. Applicability

This rule shall apply to hydrogen sulfide emissions in The Geysers Known Geothermal Resources Area from existing geothermal power plants, new geothermal power plants, and stacking.

For the purposes of this rule, power plants which receive a permit to construct from an Air Pollution Control District or a certificate from the California Energy Conservation and Development Commission on or after July 1, 1981, are deemed new power plants.

II. Definitions

A. Geothermal power plant means any thermal power plant which uses geothermal resources as the principal energy source for the generation of electrical power.

B. Gross megawatt (GMWe) means the total rated electrical generating capacity of a geothermal power plant as specified on the name plate of the turbine.

C. Stacking means the venting of steam into the atmosphere during power plant shutdowns or outages, both scheduled and unscheduled.

D. Dual units means two or more electrical power generating turbines which are located within or part of the same structure and which may be operated independently.

E. Single units means all electrical power generating turbines not defined as dual units.

III. Emissions Limitations

No person shall cause or allow the discharge into the atmosphere of hydrogen sulfide (H_2S) from new geothermal power plants, existing geothermal power plants, or stacking at a rate which exceeds those set forth in Table E-1 of this rule.

IV. Exemption from New Source Review Rule

The H_2S emissions from new geothermal power plants, including stacking, which comply with the emissions limitations specified in Section III of this rule shall be exempt from those sections of the district's new source review rule which require offsets, best available control technology, and air quality impact analyses.

V. Operating Protocol

Each permit to operate shall include an operating protocol which specifies the manner in which the power plant and related facilities will be operated to meet the emissions limitations set forth in Table E-1 of this rule.

A. General Requirements

1. Each operating protocol shall include a requirement that a log be kept indicating for each power plant outage the date, the duration, and the estimated amount of H_2S emissions. This log shall be made available, upon request, to the district or the Air Resources Board.

2. The operating protocol for each power plant shall specify the frequency and method of source tests, the frequency and method of sampling the H_2S concentration in the incoming steam, the predicted relationship between H_2S sulfide emissions and chemical feed rates, the location of the record of all source tests, and a requirement that source tests will be performed with the power plant operating at a minimum of 80% of rated capacity.

3. The operating protocol for stacking emissions controls shall specify the steam flow rates, chemical feed rates, and all other parameters which determine the degree of H_2S control.

TABLE E-1. Summary of suggested measures for control of H₂S emissions.

Effective Date	New Geothermal Power Plants		Existing Geothermal Power Plants		Stacking	
	Less than 50 GMWe	50 GMWe or greater	Direct Contact Condenser	Surface Condenser	New Power Plants	Existing Power Plants
<u>July 1, 1981</u>	50 grams/gross megawatt-hour	five (5) pounds per hour or 40 grams/gross megawatt-hour, whichever is greater	Units 3, 4, & 11: 90% reduction of the H ₂ S in the incoming steam to each unit. Units 5,6,&12: 200 grams/gross megawatt-hour for each unit.	--	Same emissions limitations as power plant, at all times	--
61 <u>July 1, 1985</u>	--	five (5) pounds per hour	Units 1 & 2: 50% reduction of the H ₂ S in the incom- ing steam to each unit. Units 3,4,5,6,7, 8,9,10,11, & 12: 200 grams/gross megawatt-hour for each unit.	Units 13, 14 15,17 & NCPA #2: 50 grams/ gross/mega- watt-hour	--	Same emissions limitations as the power plant, within two hours of the outage
<u>July 1, 1990</u>	--	--	Units 1 & 2: 50% reduction of the incoming steam to each unit. Units 3,4,5,6,7, 8,9,10,11, & 12: 100 grams/gross megawatt-hour for each unit.	--	--	--

B. Procedures

1. New facilities: each applicant for a permit to operate for a new power plant shall submit an operating protocol. The steam supplier for a new power plant shall submit an operating protocol for stacking emissions from facilities it operates.

2. Existing facilities: each operator of an existing power plant shall submit an operating protocol for each unit, including all facilities operated by the same person, to the Air Pollution Control Officer within 60 days after the adoption of this rule. The steam supplier for each existing power plant shall submit an operating protocol for stacking emissions from all facilities it operates within 60 days after the adoption of this rule. The Air Pollution Control Officer shall approve, disapprove, or modify the operating protocols.

VI. Enforcement

Compliance with the operating protocol approved by the Air Pollution Control Officer shall be deemed compliance with the H₂S emissions limitations of this rule.

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