Rogers

RECORD COPY -- RETURN TO
Project Library

**A FEASIBILITY STUDY
OF
H₂S ABATEMENT BY INCINERATION OF NONCONDENSABLE GASES
IN
VENTED STEAM FLOW**

FROM

DAVIES-STATE 5206-1 GEOTHERMAL STEAM WELL

**GEYSERS GEOTHERMAL STEAM FIELD
LAKE COUNTY, CALIFORNIA**

Prepared for

**NATOMAS ENERGY COMPANY
SAN FRANCISCO, CALIFORNIA**

Prepared by

**ROGERS ENGINEERING CO., INC.
SAN FRANCISCO, CALIFORNIA**

AUGUST 25, 1981

S-81009-00

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

ROGERS ENGINEERING CO., INC.
ENGINEERS & ARCHITECTS
111 PINE STREET
SAN FRANCISCO, CALIF. 94111, TEL. (415) 986-6546

In reply refer to:
S-81009-00

25 August 1981

Natomas Energy Company
601 California Street
San Francisco, California 94108

Attention: Mr. J. M. Rudisill
Geysers Project Manager

Subject: A Feasibility Study of H₂S Abatement by
Incineration of Noncondensable Gases in
Vented Steam Flow From Davies/State 5206-01
Geothermal Steam Well

Gentlemen:

Transmitted herewith are five copies of the final report of the subject study for your use. The report incorporates comments and additional data requested by Natomas subsequent to review of the preliminary draft.

This submittal completes our work on this project; however, if we can be of further assistance please contact us at your convenience.

We have enjoyed having the opportunity to be of service to you and trust we can look forward to working with you on future projects.

Very truly yours,

ROGERS ENGINEERING CO., INC.

F. D. Dunn
Vice President

FDD:bg

Enclosures: As Noted Above

Rogers

TABLE OF CONTENTS

1.0	BACKGROUND
2.0	PURPOSE AND SCOPE
3.0	CRITERIA
4.0	CONCLUSIONS
5.0	INCINERATION SYSTEM DESCRIPTION
6.0	COST ESTIMATE
7.0	DISCUSSION

APPENDIX

I	TEST DATA
II	LETTER INFORMATION CRITERIA
III	BLEED STEAM-GAS CONDENSING COOLING CHART
IV	PROCESS FLOW DIAGRAM
V	COST ESTIMATE

Rogers

1.0

BACKGROUND

On January 28, 1981 the Lake County Air Pollution Control District (LCAPCD) staff issued a Notice of Violation to Natomas Energy Company (Natomas) indicating that the Davies-State Well 5206-1 while on bleed steam flow was in violation of LCAPCO rules, section 421 A & B. LCAPCO has stated that no further action will be taken provided Natomas investigates, among several other conditions, the potential of using an incineration-type device to lower H₂S levels while on bleed to meet the requirements of the LCAPCO.

Natomas has sampled the well extensively under "bleed" and full flow test conditions. The data on the noncondensable gases obtained during the sampling have been analyzed qualitatively and quantitatively for the various flow conditions and provide the basis for this feasibility study. The test data obtained are included in Appendix I for reference.

Rogers

2.0 PURPOSE AND SCOPE

2.1 Purpose

Determine feasibility of using an incineration-type device to accomplish the required reduction in vent steam H_2S content to meet LCAPCO rules. This approach is to be the only method considered in this feasibility study.

2.2 Scope

2.2.1 Determine combustibility of noncondensable gas present in well bleed vent steam at an established vent steam flow rate needed to minimize or eliminate condensation in well production casing.

2.2.2 Prepare process flow diagram, with materials and heat quantities to define an acceptable conceptual incineration-type H_2S abatement system. The conceptual system is to have turn-down capability to handle vent steam from one up to a total of three identical wells at this well pad location.

2.2.3 Develop budgetary capital and operating costs of the conceptual incineration system.

Rogers

3.0 CRITERIA

3.1 Sulfur Emissions Limitation

The incineration system for H_2S abatement is to be designed to satisfy the requirements of Sections 421A and B of the Lake County Air Pollution Control District Regulations with the following interpretation provided to Natomas by the LCAPCO:

With respect to Section 421B, possible SO_2 emissions will not be included under the 24 pounds per day total sulfur emission limitation.

Refer to Thermal Power Company Memorandum dated 11 May 1981 in Appendix II.

3.2 Test Data and Noncondensable Gas Characteristics

Source test summary for Davies State 5206-1 indicated that initial well bleed testing was started on 17 October 1980. A full flow test was initiated on 16 December 1980 and completed on 17 December 1980. Following the full flow test the well has been on a continuous bleed

Rogers

program using various sized bleed orifices and has been sampled to ascertain H_2S content at the various bleed steam rates. The results of these tests were used to establish the design bleed steam flow for the proposed incinerator-type H_2S abatement system. These data are included in Appendix I.

3.3 Vent Steam Flow Rate

The vent steam bleed flow rate required to prevent well bore condensation as determined by Natomas and agreed to by the LCAPCO is 1998.5 pounds per hour using a 3/8" diameter orifice in the vent steam bleed line. Additional data on this test condition is in Appendix I.

3.4 Incineration System Capability

The incineration system is to be capable of incineration of the non-condensable gas flow from a minimum of one well or a maximum of three wells identical in flow and bleed steam characteristics to Davies-State 5206-1 Well, all located at the same well pad.

Rogers

3.5

Site

A level site is available at the well pad location for installation of required equipment and is adjacent to the well drilling sump for condensate disposal.

Rogers

4.0

CONCLUSIONS

4.1

Noncondensable Gas Combustibility

Calculations based on the data obtained by LFE for the noncondensable gases in the bleed steam from the Davies-State Well 5206-1 show a heat value of 285 Btu/SCF (dry gas basis). This is well above the approximate minimum calculated value for combustibility of 160 Btu/SCF and therefore the noncondensable gas is considered capable of sustained combustion.

4.2

Noncondensable Gas Temperature

To prepare the noncondensable gas for combustion the bulk of the steam must be removed. However it is desirable that the condensate temperature be at least 160°F to lessen the solubility of H_2S in the condensate. Based on calculation of gas heating value at a condensate gas separation condition of 20 psia and various design conditions, a temperature of 160°F was selected for the conceptual design which provides a calculated wet gas heat values of 217 Btu/SCF. At a temperature of 160°F any possibility of flame-out during changes in gas composition will be avoided.

Rogers

4.3

Bleed Steam Rate

Measurements have been taken using bleed steam orifices with bores of 1/4", 3/8", 1/2" and 3/4". Well production flow has also been measured using a 4" i.d. bore orifice. The test using a 3/8" bore orifice has been determined to be satisfactory for maintaining noncondensing conditions in the well-bore by Natomas and agreed to by the LCAPCO. The values shown for the 3/8" bleed orifice are 1,998.5#/hr. steam and 904 ppm H₂S, corresponding to 1.8#/hr. H₂S in bleed steam.

4.4

Proposed Incineration - Type H₂S Abatement System

Analysis of the selected bleed steam vent flow conditions and the composition of the noncondensable gases from Davies-State Well 5206-1 combined with a study of incinerator equipment and hardware available on the market substantiates the conclusion that H₂S abatement by incineration of the noncondensable gases in the bleed steam vent stream from the well is technically feasible.

The conceptual design of the proposed incineration-type abatement system is defined on Drawing No. E-02-001 "Flow and Control Diagram - Incineration System" and described in detail in Section 5 of this report.

Rogers

Major elements of the proposed system are:

- a. A series connected air cooled heat exchanger and water cooled heat exchanger with cooling tower for steam condensation.
- b. A gas/condensate separator for collection and separation of the noncondensable gases and the condensate from the well bleed steam.
- c. An incinerator for burning the noncondensable gas stream, arranged for propane fired light-off pilot burner.
- d. A condensate neutralizer station with tank, mixer, dry chemical feeder and pH controller.
- e. A treated (neutralized) water surge tank and transfer pump for cooling tower water source.
- f. An instrument air compressor for control systems.
- g. An electric supply from nearby PGandE power lines to provide power for pumps and fans, etc.

Rogers

4.5 Estimated Installed Cost

The proposed incineration H_2S abatement system is estimated to require an installation budget of approximately \$292,610 middle 1981 basis. A detailed breakdown of the cost estimate is included in Appendix V.

4.6 Operating Cost

The incineration H_2S abatement system is estimated to require an operating budget of \$7,700 per month for three wells on bleed. Normally the plant will be expected to require minor maintenance and check of chemical feed systems six times per week. Design is based on automatic shutdown and manual restart. A propane pilot is required for each start-up. This heat duty is estimated at 500,000 Btu/Hr. when in use. A detailed breakdown of the operating cost is included in Appendix V.

Rogers

5.0 INCINERATION SYSTEM DESCRIPTION

5.1 Description of Conceptual Plant

The incineration system consists of an air cooled heat exchanger and a water cooled heat exchanger and cooling tower in series to condense the bulk of the well bleed steam flowing into the noncondensable gas and condensate separator. The gas-condensate separator discharges the noncondensable gas to the induced draft gas-air burner of the gas incinerator. The separator operates under sufficient pressure (20 psia) to operate the induced draft gas-air burner. The gas-air incinerator is designed for induced draft burner operation using a 45 foot high stack. A propane pilot burner is provided for start-up light-off and will also be used for curing of the refractory prior to initial operation. The incinerator and gas burner are capable of burning the gas from one, two or a total of three identical wells. Propane will be supplied under a rental-supply contract.

The gas-system condensate is not cooled below 160°F in order to reduce the amount of H_2S and CO_2 present in the liquid condensate. The condensate from the gas/condensate separator is discharged to a 730 gallon neutralizer tank complete with mixer and a pH controlled chemical feeder to neutralize the H_2S in the condensate.

Rogers

The treated condensate effluent from the neutralizing station is discharged into a 730 gallon neutral water surge tank which is the treated water source for the cooling water for the water cooled heat exchanger via the cooling tower. Excess water is discharged by overflow to the existing sump.

An instrument air compressor will provide dry air for air-operated instrumentation and controls. Capacity required is 3.2 SCFM @ 30 psig.

Plant operation will require electric power to operate pumps, fans, blowers and an instrument air compressor. In addition, the pH controller and burner flame management and shutdown controls will require electric power at 120V, 1 ϕ , 60 Hz. The connected power load is estimated at 28.5 hp. This study considers that the required power will be supplied by a diesel engine driven 50 kW, 480 Volt, 3-phase generator on the site as opposed to a power line extension from PGandE's 12 kV line on Highway 175. Although the power costs are higher from the generating unit, the lower initial cost and the ultimate salvage value of the unit are basic decision factors favoring the selection.

Rogers

5.2

Description of Operation

Pre-start Requirements

- a) The cooling water tower and the neutral water surge must be filled with fresh water.
- b) The Na_2CO_3 system and feeder must be checked and be operable.
- c) All auxiliary items, i.e., instrument air, control power supply, propane supply and all pumps and motors prechecked for proper rotation and operability.
- d) The incinerator controls, flame scanner, etc. all checked for operability.

Start Up

The propane fired pilot is lighted and the refractory curing is started. The vent gas can then be started through the heat exchanger train and the noncondensable gas vented to the emergency vent gas silencer. The condensate is sent into the neutralizer. Condensate from the noncondensable gas-condensate separator will

Rogers

contain some dissolved H_2S and CO_2 . To avoid adding H_2S into the water cooled heat exchanger cooling tower vent air system it will be necessary to react the H_2S with Na_2CO_3 (aqueous) and yield Na_2S which will not be volatilized into the air from the water cooled exchanger exhaust air flow. This neutralization of the H_2S will be done by controlling the pH of the neutralizer effluent. The pH controller will modulate the feed rate of dry Na_2CO_3 into the neutralizer.

The total heat in the well steam will be absorbed partly by the air cooled heat exchanger so that the water evaporated in the water cooled section will be less than the total condensate produced. The small excess of condensate will contain Na_2S and $NaHCO_3$ and other chemicals from the condensation of the geothermal steam. Therefore, the ponded excess will require disposal in a designated geothermal waste site.

When the refractory is cured the separator gas may be then sent into the burner and the incinerator placed in automatic firing condition. The burner induced air control is ratio controlled depending on vent gas flow (one, two or three wells) so that the combustion temperature is correct for the conversion of the H_2S into SO_2 and water vapor. Should the flame go out due to a transient disturbance the

Rogers

unit will be automatically shutdown and the bleed steam will be vented directly to the air.

Restart After Flame Out

Relight pilot and bring incinerator up to operating temperature per manufacturer's instructions. Restart bleed steam through heat exchanger train and send noncondensable gas into burner and condensate into neutralizer. Line out all sub-systems.

5.3

Operating Cost Estimate

The estimated system operating costs are based on automatic operation with manual restart and minimal maintenance. The estimate considers a requirement for an operator in the field six days per week on a four hour per day basis for minor maintenance and operating services such as checking chemicals, feeder systems, and diesel generator operation, pH sensor replacement, and occasional incinerator restarts (assumed at two per month). Other costs include cost of chemicals, propane, fuel for electric generation, miscellaneous materials, and the cost for disposal of the chemically treated contaminated steam condensate at a licensed waste dump. A detailed breakdown is included in Appendix V.

Rogers

Following is a summary of the budgetary operating cost estimate.

	<u>\$/Month</u>
Field Man	2,400
Propane	40
Na ₂ CO ₃ Chemical	170
Miscellaneous Supplies	140
Pond Liquid Waste Disposal	<u>3,490</u>
Total	7,700

Rogers

6.0

COST ESTIMATE

The preliminary specification for the conceptual incinerator was submitted to John Zink Co. for the major plant component cost. The balance of the equipment was estimated from telephone quotes or from built up equipment cost developed by the Guthrie or Richardson estimating system. All costs have been estimated in mid-1981 dollars. A detailed breakdown is included in Appendix V.

Following is a summary of the budgetary cost estimate:

	<u>Item</u>	<u>Cost</u>
6.1	Air Cooled Heat Exchanger	\$ 5,650
6.2	Water Cooled Heat Exchanger	8,380
6.3	Pumps	10,800
6.4	Mixer	4,660
6.5	Tanks	8,200
6.6	Separator	4,220
6.7	Cooling Tower	16,500
6.8	Incinerator	106,600
6.9	Instrumentation, Control Valves including Compressor	20,100
6.10	Diesel Electric Unit	<u>21,000</u>
	Subtotal	\$206,110
	Engineering 15%	30,900
	Contractors 12%	24,700
	Contingency 15%	<u>30,900</u>
	Total Installed Budget Estimate	\$292,610

Rogers

7.0 DISCUSSION

7.1 Noncondensable Gas Combustibility

A preliminary test for combustibility can be made by calculating the heat available in Btu per standard cubic foot the gas utilizing the net heat of combustion of each component. If the value calculated is well above a value of about 160 Btu/SCF, the gas can be considered capable of sustained combustion. If the calculated value is near 160 Btu/SCF or less a more rigorous check of flammability limits must be made to determine if the gas mixture will burn without application of additional heat from a large pilot burner flame. Using the data obtained by LFE on the Davies-State Well 5206-1 noncondensable gas, a calculated value of 285 Btu/SCF is obtained (dry gas basis). To prepare the noncondensable gas for combustion the bulk of the steam must be removed. However it is desirable that the condensate temperature be at least 160°F to lessen the solubility of H_2S in the condensate. Calculation of gas heating value at a condensate gas separation condition of 20 psia and various conceptual design conditions gives wet gas heat values as follows:

Temperature °F	190	180	170	160
Calculated Wet Gas Heat Value Btu/SCF	152	178	199	217

Rogers

The conceptual design point used is 160°F. This probably could be raised to 175°F without a flameout condition. After plant start up, if the H_2S in the condensate proves to be too high, condensation temperature could be increased to bring the value closer to the conceptual design point and avoid increased cost for the required dosage of neutralization agent.

7.2

Heat Balance During Steam Condensation

Because the bleed steam has a high value of pressure at the underground source point, the steam contains a large amount of heat content. It is not possible to obtain the required condensation heat balance without rejecting some of the heat to an air cooled heat exchanger. See Appendix III for Bleed Steam-Gas Condensing-Cooling, °F vs Heat Duty.

The conceptual design allows for rejecting the steam superheat and a portion of the condensation heat so that the evaporation in the water cooling tower will be such that there is small net blowdown of condensate into the wellhead pond. This is required to carry away the geothermal steam mineral component and the neutralization chemicals.

Rogers

7.3 Advantages of the Proposed Incineration System

7.3.1 The application of the proposed incineration system to abate the H_2S present in the noncondensable gas present in the well bleed steam is dependent on the acceptance of an equivalent stream of sulfur dioxide (SO_2) in the incinerator off gas. The SO_2 will not be as evident as the smell of H_2S fumes. If the SO_2 and water vapor present in the incinerator combustion gas can be vented directly, a low cost induced draft unit can be used. This is the basis of the conceptual design.

Based on the acceptance of the foregoing the following advantages of the proposed incineration system exist:

- (i) a scrubber quench section is not required. Instead a simple stack may be used;
- (ii) combustion air input required can be met by an induced draft incinerator burner;
- (iii) disposal costs for scrubber effluent is not required;
- (iv) consumption of neutralizing agent is reasonably low.

Rogers

- 7.3.2 If it should be ruled that this new point source containing SO_2 would need to be reduced to less than 24 lbs./day of equivalent H_2S , a reduction in the vent SO_2 would be required. This can be done by including a caustic scrubber system to neutralize the off gas. With this requirement all the above advantages which obtain for the proposed incineration abatement system would be negated and additional equipment and operating costs would be experienced.

7.4 Basic Requirements for H_2S Abatement by Incineration

Applying incineration for abatement of H_2S in the well bleed steam entails the following basic requirements:

- 7.4.1 The bleed steam cannot be burned directly without using an additional amount of heat provided by a large pilot gas preheater-burner system. The bulk of the steam must therefore be condensed and the noncondensable gas separated prior to incineration.
- 7.4.2 The steam condensation must be temperature controlled to give a wet gas (containing water vapor) which can sustain combustion and at the same time avoid accumulation of H_2S and CO_2 into the condensate.

Rogers

7.4.3 The bulk of the H_2S dissolved in the condensate must be neutralized so that the H_2S will not be stripped in the water cooled heat exchange system and result in an H_2S gas vent from the cooling water tower above the desired abatement level.

APPENDIX I

TEST DATA

FINAL REPORT
GEOHERMAL WELL TEST

For: Mr. Jake Rudisill
Natomas Co.

By: Mr. David R. Fielder
LFE Corp., Environmental Analysis Laboratories

Date: January 5, 1980

LFE W.O. No. 06316-0001

I. INTRODUCTION

Steam from Davies State Well Number 5206-1 was sampled on December 17, 1980. The well was at full flow, with a four inch orifice plate installed, for approximately 36 hours prior to the test. The sampling point was located approximately twenty feet downstream from the wellhead and approximately ten feet upstream from the orifice plate.

II. SAMPLING PROCEDURES AND PHYSICAL PARAMETER MEASUREMENTS

A stainless steel sampling tube was connected directly to the well line using a 0.5 inch high-temperature valve. Pressure measurements were made at the sampling point using a Weiss pressure gauge. Well temperature measurements were obtained from Exlog Smith's thermocouple gauge located at the wellhead. Subsequently, the tubing was passed through two non-contact condensers in series. The first was a water bath (boiling) and the second was an ice-water bath. The condensed steam and gases passed through a teflon line to a two liter pyrex bottle where condensate was collected. Non-condensable gases passed out of the bottle to flow measurement and analytical devices.

The non-condensable gas/condensate ratio was determined by taking repeated volumetric flow measurements of the condensate while simultaneously measuring the non-condensable gas flowrate using a one liter bubble meter. All physical parameter and flow rate results are listed in Table I.

Flow was maintained through the sampling train for approximately one half hour prior to start of sample collection to insure representative samples.

III. ANALYTICAL PROCEDURES

A. Non-condensable Gas Phase

Hydrogen (H_2), carbon dioxide (CO_2), oxygen (O_2), nitrogen (N_2), methane (CH_4), and hydrogen sulfide (H_2S) were analyzed on-site using a Carle AGC-311 gas chromatograph (GC) with thermistor detector. Certified gas mixtures from Scott Specialty Gases were used for calibration as well as standards prepared using pure gases

and a Precision Sampling, Inc. gas-tight syringe.

Non-condensable gas samples for determination of non-methane organic compounds were collected in aluminized mylar bags from Calibrated Instruments, Inc. These samples were returned to LFE for analysis by gas chromatography.

Non-condensable gas samples for determination of ammonia and mercury were collected by passing the gas through impinger trains containing sulfuric acid and acidified potassium permanganate absorbing solutions respectively. The mercury samples were preserved using hydroxylamine hydrochloride and analyzed at LFE using cold vapor atomic absorption. The ammonia samples were analyzed at LFE using a selective ion electrode.

- B. Samples of condensate were collected and titrated on-site for H₂S/ sulfide using an iodometric procedure with zinc acetate preservation. Both pH and specific conductance were also determined. Additional samples were collected, preserved as necessary, and returned to LFE for analysis as follows:

<u>Analyte</u>	<u>Analytical Procedure</u>
Metals (Ca, Fe, As, Pb, Cd)	Atomic Absorption (A.A.)
Carbonate, bicarbonate, chloride	Titration
Sulfate	Turbidimetric
Fluoride, ammonia	Selective Ion Electrode
Boron, Nitrate	Colorimetric
Mercury	Cold Vapor Atomic Absorption
Total Dissolved Solids/ Total Suspended Solids (TDS/TSS)	Gravimetric

IV. RESULTS DISCUSSION

All results are listed in Tables 1-3. Although the well underwent a pressure drop from 1300 to 1318 hrs., as indicated in Table 1, the steam conditioning train was thoroughly purged for one hour before sampling. The non-condensable gas/condensate ratio remained essentially the same before the pressure drop (8.2) until after the one hour purge as indicated in Table 1.

TABLE 1
Physical Parameters

TIME	AMBIENT PRESSURE (in Hg)	AMBIENT TEMPERATURE (°F)	CONDENSATE TEMP. AT SEPARATOR BOTTLE (°F)	WELL PRESSURE (psig)	WELL TEMPERATURE (°F)	NON-CONDENSIBLE GAS FLOW (Lpm)	CONDENSATE FLOW (Lpm)	NON-CONDENSIBLE GAS RATE (L/Kg atm)
1247	--	--	81	118	--	4.6	0.56	8.2
1300 ²	---(WELL PRESSURE UNSTABLE)---			90	---(WELL PRESSURE UNSTABLE)---			
1306	: . : . : . ↓			80	↓			
1308				50				
1310				30				
1318	---(WELL PRESSURE STABLE)---			115	---(WELL PRESSURE STABLE)---			
1500	27.7 (day ave)	62 (day ave)	82	115	365 (ave)	3.1	0.39	7.9
1530	--	--	82	115	--	3.2	0.39	8.2
1700	--	--	83	110	--	3.2	0.39	8.2

¹Calculation of this ratio assumes a density of 1.0 grams per milliliter for the condensate and neglects the density of the non-condensable gas.

²Well pressure began dropping as well head outlet simultaneously emitted a significant amount of water.

TABLE 2
Non-Condensable Gas Analytical Results

ANALYTE	CONCENTRATION (% by vol.)			CONCENTRATION (% by wt.)			
	Run	1	2	AVE.	1	2	AVE.
H ₂		2.6	2.4	2.5	0.2	0.2	0.2
CO ₂		55.6	54.6	55.0	75.8	75.8	75.2
O ₂		0.06	0.06	0.06	0.06	0.06	0.06
N ₂		8.2	7.8	8.0	7.1	6.8	6.9
CH ₄		28.5	27.1	27.9	14.1	13.4	13.8
H ₂ S		2.0	2.0	2.0	2.1	2.1	2.1
H ₂ O ⁽¹⁾		3.1	3.1	3.1	1.7	1.7	1.7
<u>Total of major Constituents</u>		100.0%	97.0%	98.6%			100.0%
Aliphatic Hydrocarbons C1-C10 (as CH ₄)		25.6	26.1				
Aromatic Hydrocarbons (as Benzene)		(ppm vol)	(ppm vol)				
Ethane		175	177				
Propane		21	24				
Butane		5	5				
Pentane		3	7				
Hexane		<1	<1				
NH ₃		198	192				

(1) Lange, Handbook of Chemistry, "Mass of Water Vapor in Saturated Air", pg.1424
McGraw-Hill, 1969.

J. M. Rudisill/SSW
February 17, 1981

FLOW RATE DURING DECEMBER 16TH, 1980 TEST
DAVIES STATE 5206-1

Time		Elapsed Time (hrs)	Temp. (°F)	p, (PSIA)	Specific v, Volume $\frac{\text{lbs}}{\text{ft}^3}$	Flow = $11,435.34 \sqrt{\frac{P}{v}}$ lb/hr	
12/16	9:30 AM	0	370	171.5	2.68	91,477.39	K ₁
	9:40	0:10	407	265.2	1.74	141,176.11	622
	9:45	0:15	407	263.2	1.74	140,642.77	624
	9:50	0:20	404	254.2	1.81	135,518.18	
	10:00	0:30	394	225.0	2.04	120,095.09	
	10:30	1:00	390	209.4	2.20	111,564.51	
	10:40	1:10	387	203.0	2.28	107,902.02	
	10:55	1:15	384	194.0	2.36	103,679.75	626
	11:30	2:00	382	191.6	2.41	101,961.99	
	11:40	2:10	381	184.0	2.43	100,850.22	
	12:40 PM	3:10	376	177.0	2.61	94,170.63	
	1:40	4:10	373	169.0	2.70	90,471.24	
	2:40	5:10	371	164.0	2.79	87,673.61	
	3:40	6:10	368	162.0	2.83	86,519.37	
	4:40	7:10	370	167.3	2.73	89,519.10	
	5:40	8:10	368	163.4	2.80	87,356.67	
	6:40	9:10	366	158.9	2.88	84,940.49	
	7:40	10:10	364	154.9	2.93	83,145.93	
	8:40	11:10	362	151.3	3.00	81,209.70	
	9:40	12:10	360	148.9	3.05	79,899.95	
	10:40	13:10	360	147.5	3.08	79,135.21	
	11:40	14:10	360	149.5	3.02	80,457.44	
12/17	12:40 AM	15:10	358	145.3	3.14	77,788.80	
	1:40	16:10	356	141.3	3.23	75,634.32	
	2:40	17:10	355	140.2	3.24	75,222.99	
	3:40	18:10	354	138.0	3.27	74,287.33	
	4:40	19:10	353	137.4	3.28	74,012.58	
	5:40	20:10	352	135.8	3.32	73,135.78	
	6:40	21:10	351	133.2	3.39	71,680.55	
	7:40	22:10	350	131.0	3.45	70,465.28	
	8:40	23:10	350	132.2	3.41	71,201.25	
	9:40	24:10	349	129.5	3.47	69,858.50	
	10:40	25:10	348	124.1	3.66	66,587.76	
	11:40	26:10	346	118.0	3.85	63,308.16	
	12:40 PM	27:10	345	116.0	3.97	61,813.43	
	1:40	28:10	348	118.0	3.85	63,308.16	
	2:40	29:10	346	121.0	3.75	64,957.03	
	3:40	30:10	345	122.0	3.75	65,224.89	
	4:40	31:10	344	121.0	3.73	65,130.94	
	5:40	32:10	343	120.0	3.73	64,861.25	624

606
6

Environmental Analysis Laboratories

2030 Wright Avenue
Richmond, California 94804
(415) 235-2633

CORPORATION (TWX) 910-382-8132

RECEIVED
FEB 11 1981
TPC

February 11, 1981

Mr. Jake Rudisill
Natomas Company
601 California Street
San Francisco, CA 94108

Reference: EAL Work Order
Number 06316-0001

Dear Mr. Rudisill:

The enclosed sequence of equations details the determination of the percent non-condensable portion of the total steam by weight as measured during the geothermal testing we completed for you on December 17, 1980.

If you have any further questions, please do not hesitate to call me.

Sincerely,

Philip A. Bumala
Air Pollution Specialist
Environmental Science Department

PAB/zlm

Enclosure

RECEIVED
FEB 17 1981
TPC

NON-CONDENSIBLE PERCENT BY WEIGHT

- (1) The molecular weight of the non-condensable gas equals 32.2 grams/mole, calculated from determining the percent by volume of the major gas constituents multiplied by their individual molecular weights.

- (2) Given: Flow measurements of:

3.2 Liters/min non-condensable

0.39 Liters/min condensable

Solve for 1 minute of flow:

$$\frac{3.2 \text{ Liters/min}}{24.45 \text{ Liters/mole}} = \frac{0.13 \text{ moles non-condensable}}{\text{min}}$$

Recall non-condensable molecular weight of 32.2 grams mole:

$$\text{grams non-cond/min} = \left(\frac{0.13 \text{ moles non-cond}}{\text{min}} \right) \left(\frac{32.2 \text{ grams non-cond}}{\text{mole}} \right) =$$

4.19 grams non-cond/min

Condensable flow rate = 0.39 Liters/min

390 mls or 390 grams

(assuming condensate density of 1 gram/ml)

- (3) Total steam sampled in one minute equaled:

$$\begin{array}{r} 4.19 \text{ grams non-cond} \\ + 390. \text{ grams condensate} \\ \hline 394.19 \text{ grams total} \end{array}$$

- (4) Finally:

$$100 \times \frac{4.19 \text{ grams non-cond}}{394.19 \text{ grams total}} = 1.06\% \text{ non-condensable (by weight)}$$

Rogers

PROJECT CONFERENCE NOTE

Number 2
ROGERS Job No. S-81009-00
Date 11 May 1981
Place San Francisco
By F. D. Dunn

CONFIRMATION OF CONFERENCE (Telephone X Meeting)

F. D. Dunn

ATTENDING: Thermal Power Rogers
Roy Skinner F. D. Dunn

SUBJECT: H₂S Incineration for Vent Steam

Roy Skinner of Thermal Power called to advise on the following:

1.	<u>Orifice Size</u>	<u>Pressure</u>	<u>Steam Flow</u>	<u>H₂S Amount</u>	<u>Ratio</u> <u>H₂S/1000</u> <u>CO</u> <u>HR.</u>
	3/8" ϕ	420 psig	1998.5 #/hr.	904 ppm 1.81 #/hr.	0.91
	1/2" ϕ	-	3612 #/hr.	614 ppm 2.18 #/hr.	0.60
	3/4" ϕ	400 psig	6586.5 #/hr.	500 ppm	0.50
	4"		62.000	3.29 #/hr. 251 ppm	
	1/4" ϕ	-	1085 #/hr.	15.56 #/hr. - 1200 ppm 1.3 #/hr.	0.25 1.2
2.	Above missing data to be supplied later in documented form.				
3.	Bob Reynolds of Lake County Air Pollution Control District advised Thermal Power that SO ₂ emissions will not be a problem. Rogers requested a copy of letter from LCPCD to Thermal Power for Rogers' report purposes.				

Page 1 of 1

Distribution: ROGERS

CLIENT

OTHERS

FDD
→BF
File: S-81009-00

J. M. Rudisill (Natomas - S. F.)
Roy Skinner (Thermal Power - S. F.)

**SOURCE TEST SUMMARY
DAVIES - STATE 5201-1**

	<u>TEST DATE</u>	<u>BLEED STATUS</u>	<u>SAMPLE LOCATION & REMARKS</u>	<u>AVERAGE TOTAL H2S (ppmw)</u>
(1)	10/17/80 - 1100 hrs	1" Bleed	Off 3" valve on casing head 180° opposite bleed line.	814
(2)	10/17/80 - 1300 hrs	1" Bleed	Same as above except sample line vented for 10 min. before grabbing sample.	702
(3)	10/20/80 - 1700 hrs	K" Bleed	As in (1).	3,097
(4)	10/27/80	K" Bleed	Same as in (2). P=428 psi. Draeger tubes at 5' from mouth of bleed had 130 ppm; at 10 ft., 60 ppm.	1,126
(5)	11/05/80 - 1600 hrs	K" Bleed	Same as in (2); took 2 Drager samples at well head fence in plume (7' from mouth) - 40 ppm avg.	1,338
(6)	11/05/80 - 1100 hrs	K" Bleed	Bleed Line, up-stream of K" orifice.	1,409
(7)	12/16/80 - 1055 hrs	4" Orifice	P=181 psigs, T=389°F. Full flow started at 0940 hrs.	342
(8)	12/16/80 - 1540 hrs	4" Orifice	P=149 psig, T=368°F. Full flow for 6 hrs.	298
(9)	12/17/80 - 0800 hrs	4" Orifice	P=119 psig, T=350°F after 22 hrs. of flow.	251
(10)	12/17/80 - 1400 hrs	4" Orifice	After 28 hrs. of flow, & less than 1 hr. after water slug.	261
(11)	01/15/81 - 1000 hrs	K" Bleed	Almost 1 month after flow test; sampled as in (6).	1,904

JMR/lam

APPENDIX II

LETTER INFORMATION CRITERIA

COUNTY OF LAKE

Air Pollution Control District
Courthouse — 255 N. Forbes Street
Lakeport, California 95453
Telephone 707/263-2391
Laboratory: 707/263-2392
Burn Info: 707/263-3121

ROBERT L. REYNOLDS
Air Pollution Control Director

RECEIVED

28 January 1981

JAN 28 1981

TTC

Ms. Beckee Beemer
Natomas Company
601 California Street
San Francisco, California 94108

Dear Beckee:

On January 15, 1981 the LCAPCD staff, accompanied by your representative (Mr. Dwight Walters of Exlog-Smith) tested the Natomas 5206-1 exploratory well (permit #A/C 17-78-130) which is being vented through a $\frac{1}{4}$ " orifice. The H_2S content of the vented steam was determined as 1800 ppm_w. The total H_2S vent rate is estimated at 1.35 lbs H_2S per hour (assuming a minimum 750 lb/hr bleed).

The test results indicate the well is in violation of LCAPCD rules, section 421 A & B. Depending on the research and monitoring efforts of the developer, the APCO is allowed discretion in allowing an excess of 24 lbs H_2S per day, but not in the 1000 ppm_w limitation.

As you are aware, the H_2S at the levels measured are of special concern and danger. Enclosed is a Notice of Violation which requires a written response within ten (10) days. I suggest we set up an office conference to discuss this violation and if possible, identify a course of action to resolve the violation.

At your request, I have included the condensables/noncondensables ratio measured and NH_3 content as determined by the District. This particular well, fortunately, represents an anomaly.

Sincerely,

Robert L. Reynolds

RLR:ko

Encl: NOV #55

1-15-81 data

NOTICE OF VIOLATION
Air Pollution Control District
Lake County

#55

Date Issued 1-22-81 Time Issued ---

Name Plumas Energy Company, Redwood Falls

Address 601 East St., San Francisco, CA 94104

Method of Issuance: ☒ mail ☐ by hand.

Offense(s): (Regulation, Section)

CAPED, Rules & Regulations, Section

421 HEP

Description of Offense(s):

SEE ATTACHED MEMO

Location Offense(s) Committed: Plumas Division

State 3205-1

Issuing Officer

Without admitting guilt, I acknowledge receipt of this
NOTICE OF VIOLATION.

ACTION ON VIOLATIONS is outlined on the reverse side
of this NOTICE.

ACTION ON VIOLATIONS

Receipt of a Notice of Violation from the Lake County Air Pollution Control District should result in the following actions on your part:

1. Prompt correction of excessive or prohibited emissions by appropriate operational changes, and
2. File a plan of corrective action with the Lake County Air Pollution Control District that will eliminate future violations. You have ten (10) working days to file a plan.

In the event that operational procedure change is inadequate to correct excessive or prohibited emissions, you should either:

1. Cease operations which are causing excessive or prohibited emissions, or
2. Within twenty-four (24) hours, file a petition for a Hearing Board review of the specified violation. Petition forms are available at the District Office, 5440 Live Oak Drive, Kelseyville. Phone 279-4842.

Second Notice of Violation may be cause for Citation to Justice Court.

AMMONIA DETERMINATION

WELL NUMBER
SCRUBBER NUMBER

1970-795 5206-1
1-A

DATE
WELLHEAD TEMPERATURE
WELLHEAD PRESSURE
FLOWRATE
ORIFICE SIZE

1-15-81

1/4"

I. SAMPLING

- (A) Weight of scrubber
(B) Weight of scrubber and solution
(C) Weight of scrubber and sample

152.5
187.5
241.8

DILUTION FACTOR - $DF = \frac{B+C}{C} = 1.8$

II. ANALYSIS

A. STANDARD VALUES

1.0×10^{-2}

MV

-80

1.0×10^{-3}

-24

1.0×10^{-4}

+032

Unknown

S1

-037

S2

-045

MOLAR VALUE

5.9×10^{-4}

4.5×10^{-4}

$\bar{x} = 5.2 \times 10^{-4}$

III. CALCULATIONS

A. Molar value and dilution factor

Molar value (X) $DF = NH_3$ con in steam (molar value).

$$(5.2 \times 10^{-4}) \times 1.8 = 9.36 \times 10^{-4}$$

B. NH_3 molar value converted to ppm

NH_3 con (X) $1.7 \times 10^4 = ppm NH_3$

$$(9.36 \times 10^{-4}) \times (1.7 \times 10^4) = 15.9 \times 10^0$$

15.9 ppm

H. E. H. H. H.
SIGNATURE

1-16-81
DATE

P. Term 5206-1
1-15-81

$\times 10^{-2}$

$\times 10^{-3}$

$\times 10^{-4}$

**CONDENSIBLE
NON-CONDENSIBLE
GAS RATIO**

Date 1-15-81

Well number NATUMAS 5206-1

Well head temp. _____

Well head pressure _____

Flow rate _____

Orifice size 1/4"

THIS TYPE See Level

= 29.47 mm Hg

STD AT 7.0
pH 5.8
Calorimeter _____

- A) Barometric pressure 29.95 = 748.75" 14.47 PSIA • Well Pad is 710 mm Hg if
B) Condensate temp. 16°C = 289.16 Sea level reading is 760 mm
C) Amount of non-condensate gas flowed 27L
D) Amount of condensate collected 340 ml
E) Weight of condensate 564.3
F) Tare weight of collection vessel 239.6
G) Total weight of condensate collected 324.7

$$V_B = \frac{273.16}{B} \times \frac{A}{760} \times C = \text{corrected volume of gas measured.}$$

$$(II) V_B = \frac{273.16}{289.16} \times \frac{748.75}{760} \times 27L = 25.1 \text{ Liters}$$

Condensible/non-condensable ratio

$$\frac{\text{corrected volume (II) } 25.1}{\text{weight (G) in Kg of condensate } 325} = 77.2 \text{ liters/Kg}$$

Date 1-15-81

Harry E. Peterson Jr.
Signature

H₂S DETERMINATION IN STEAM

WELL NUMBER NATOMAS 5706-1
SCRUBBER NUMBER HIGH VCL GW BOTTLE

DATE 1-15-81
WELL HEAD TEMPERATURE _____
WELLHEAD PRESSURE _____
FLOWRATE _____
ORIFICE SIZE 1/4"

I. SAMPLING

- (A) Weight of gas washing bottle
(B) Weight of bottle and NH₄OH
(C) Weight of bottle and NH₄OH sample

360.2 <1.15>
403.6
700.4

II. TITRATION

	Sample #1	Sample #2	Sample #3
Wt. of beaker and sample	<u>102.1</u>	<u>72.3</u>	<u>70.9</u>
Wt. of beaker	<u>41.2</u>	<u>41.2</u>	<u>41.2</u>
Wt. of sample	<u>60.9</u>	<u>31.1</u>	<u>29.7</u>
Final buret reading	<u>43.4</u>	<u>44.07</u>	<u>47.08</u>
Initial buret reading	<u>0</u>	<u>0</u>	<u>0</u>
Total AgNO ₃ used	<u>43.4</u>	<u>44.07</u>	<u>47.08</u>
H ₂ S (ppmw)	<u>1763.7</u>	<u>1814.5</u>	<u>1823.0</u>

III. CALCULATIONS

$$\text{H}_2\text{S (ppmw)} = \frac{\text{Vol of AgNO}_3 \times \frac{\text{C-A}}{\text{C-B}} \times 1000}{\text{weight of sample titrated}}$$

AVG. 1800.4 ppmw

$$\begin{aligned} 43.4 \times 1.15 \times 10^3 / 60.9 &= 1763.7 \text{ ppmw} \\ 44.07 \times 1.15 \times 10^3 / 31.1 &= 1814.5 \\ 47.08 \times 1.15 \times 10^3 / 29.7 &= 1823.0 \end{aligned}$$

1/15/81
SIGNATURE

1-15-81
DATE

meson-1803

December 20, 1971.

Section 411 Other Sources: Particulate matter discharged into the atmosphere from other than combustion sources shall not exceed:

- A. Two-tenths (0.2) grain per standard cubic foot of gas, or
- B. The total process emission from a single premise source for any dust, condensed fume, or other particulate matter, as given in Table IV. The more stringent of A or B shall apply.

Section 412 Sulfur Recovery Units: A person shall not discharge into the atmosphere from any sulfur recovery unit producing elemental sulfur, effluent process gas containing more than:

- A. 300 parts per million by volume of sulfur compounds calculated as sulfur dioxide.
- B. 10 parts per million by volume of hydrogen sulfide.
- C. 100 pounds per hour of sulfur compounds calculated as sulfur dioxide. Any sulfur recovery unit having an effluent process gas discharge containing less than 10 pounds per hour of sulfur compounds calculated as sulfur dioxide may dilute to meet the provisions of Section 412 A.

Article III Geothermal Operations

Section 421 Geothermal Wells Sulfur Emissions:

- A. A geothermal well operation may not emit total sulfur compounds expressed as hydrogen sulfide in excess of 150 PPM by weight unless:
 - 1. The developer has installed an operable control system capable of achieving a 75% or greater reduction in H_2S emission, or
 - 2. The developer documents that it is engaged in an active program of research and development of technology for abating H_2S emissions from geothermal well drilling acceptable to the APCO, and
 - 3. The emissions from such operation do not cause the 1-hour ambient air standard for H_2S to be exceeded.

The APCO may waive the requirements of this Section 421 provided that the developer installs and maintains an approved H_2S ambient air monitoring system in the prevailing downwind direction and provided that the ambient air standard is not exceeded. In no case may the APCO waive the requirements of this section if total sulfur compounds expressed as hydrogen sulfide exceed 1000 PPM by weight.

- B. No geothermal well operation shall emit total sulfur expressed as hydrogen sulfide in excess of twenty-four (24) pounds/day during the lowest bleed rate consistent with keeping the well potentially productive unless monitoring evidence is being and has been collected and convinces the APCO that the incremental sulfur emissions by wells of various developers is not likely to cause a violation or make a measureable contribution to an existing violation of the ambient air standard.

Section 421.1 Geothermal Wells
Particulate Emissions

- A. All geothermal well operations shall abide by rule 411 of the Rules and Regulations of the Air Pollution Control District except that during the air drilling phase of the operation, the particulate emission rate may reach a level of 100 lbs/hr. for a time period not to exceed 16 days.
- B. In no case may the ambient particulate air standard be exceeded or caused to be exceeded during any phase of the geothermal well operation.

Sec. 421.2 Geothermal Power Plant Operations

A. Power Plants

- 1) All Geothermal Power Plants for which an Authority to Construct Permit is initially issued before January 1, 1979 shall emit no more than 175 grams of hydrogen sulfide per gross megawatt hour until January 1, 1990.
- 2) All Geothermal Power Plants for which an Authority to Construct Permit is initially issued on or after January 1, 1979 shall emit no more than 100 grams of hydrogen sulfide per gross megawatt hour until January 1, 1990.
- 3) All Geothermal Power Plants for which an Authority to Construct Permit is initially issued on or after January 1, 1983 shall emit no more than 50 grams of hydrogen sulfide per gross megawatt hour until January 1, 1990. The APCO shall, after reviewing air quality data, the extent and rate of geothermal development, and the availability of control technologies, suggest that this rule be confirmed or modified by the Board at a properly noticed public hearing to be held in 1981.
- 4) All Geothermal Power Plants shall by January 1, 1990 emit no more than 50 grams of hydrogen sulfide per gross megawatt hour. However, this rule shall be subject to confirmation at a properly noticed public hearing to be held in 1987.

NATOMAS
COMPANY

2 June 1981

Mr. Robert Reynolds
Lake County Air Pollution Control District
Courthouse - 225 W. Forbes Street
Lakeport, California 95453

Dear Bob:

With regards to our telephone conversation of 8 May 1981, we have contracted Rogers Engineering to conduct the feasibility study for the incineration device without an SO₂ scrubber downstream of the unit. It is our understanding that under rule 421B, SO₂ emissions as a result of the incineration of H₂S at our Davies State Well 5206-1 will not constitute a violation or contribute to an existing violation of the ambient air standard. Furthermore, it is our understanding that you feel sufficient air monitoring has been done to substantiate this. The study is expected to take about 5 weeks and therefore, should be completed sometime in mid-June. Please contact us if your views are contrary to this.

Although our misunderstanding of Rule 421B may be a special case, to avoid this type of situation in the future, you may want to regulate SO₂ and other sulphur compounds separate from H₂S. This could avoid complications in the late stages of this type of research program.

Thank you for the clarification of the rule and please contact me if you have any comments or questions regarding this project.

Very truly yours,

Roy C. Skinner
Geothermal Operations

RCS/ikl

APPENDIX III

BLEED STEAM-GAS CONDENSING COOLING CHART

APPENDIX IV

PROCESS FLOW DIAGRAM

- * BURNER FLAME
CONTROL SAFETY
SHUTDOWN SYSTEM
BY INCINERATOR
SUPPLIER

APPENDIX I

TEST DATA

FINAL REPORT
GEOTHERMAL WELL TEST

For: Mr. Jake Rudisill
Natomas Co.

By: Mr. David R. Fielder
LFE Corp., Environmental Analysis Laboratories

Date: January 5, 1980

LFE W.O. No. 06316-0001

I. INTRODUCTION

Steam from Davies State Well Number 5206-1 was sampled on December 17, 1980. The well was at full flow, with a four inch orifice plate installed, for approximately 36 hours prior to the test. The sampling point was located approximately twenty feet downstream from the wellhead and approximately ten feet upstream from the orifice plate.

II. SAMPLING PROCEDURES AND PHYSICAL PARAMETER MEASUREMENTS

A stainless steel sampling tube was connected directly to the well line using a 0.5 inch high-temperature valve. Pressure measurements were made at the sampling point using a Weiss pressure gauge. Well temperature measurements were obtained from Exlog Smith's thermocouple gauge located at the wellhead. Subsequently, the tubing was passed through two non-contact condensers in series. The first was a water bath (boiling) and the second was an ice-water bath. The condensed steam and gases passed through a teflon line to a two liter pyrex bottle where condensate was collected. Non-condensable gases passed out of the bottle to flow measurement and analytical devices.

The non-condensable gas/condensate ratio was determined by taking repeated volumetric flow measurements of the condensate while simultaneously measuring the non-condensable gas flowrate using a one liter bubble meter. All physical parameter and flow rate results are listed in Table I.

Flow was maintained through the sampling train for approximately one half hour prior to start of sample collection to insure representative samples.

III. ANALYTICAL PROCEDURES

A. Non-condensable Gas Phase

Hydrogen (H_2), carbon dioxide (CO_2), oxygen (O_2), nitrogen (N_2), methane (CH_4), and hydrogen sulfide (H_2S) were analyzed on-site using a Carle AGC-311 gas chromatograph (GC) with thermistor detector. Certified gas mixtures from Scott Specialty Gases were used for calibration as well as standards prepared using pure gases

and a Precision Sampling, Inc. gas-tight syringe.

Non-condensable gas samples for determination of non-methane organic compounds were collected in aluminized mylar bags from Calibrated Instruments, Inc. These samples were returned to LFE for analysis by gas chromatography.

Non-condensable gas samples for determination of ammonia and mercury were collected by passing the gas through impinger trains containing sulfuric acid and acidified potassium permanganate absorbing solutions respectively. The mercury samples were preserved using hydroxylamine hydrochloride and analyzed at LFE using cold vapor atomic absorption. The ammonia samples were analyzed at LFE using a selective ion electrode.

- B. Samples of condensate were collected and titrated on-site for H₂S/ sulfide using an iodometric procedure with zinc acetate preservation. Both pH and specific conductance were also determined. Additional samples were collected, preserved as necessary, and returned to LFE for analysis as follows:

<u>Analyte</u>	<u>Analytical Procedure</u>
Metals (Ca, Fe, As, Pb, Cd)	Atomic Absorption (A.A.)
Carbonate, bicarbonate, chloride	Titration
Sulfate	Turbidimetric
Fluoride, ammonia	Selective Ion Electrode
Boron, Nitrate	Colorimetric
Mercury	Cold Vapor Atomic Absorption
Total Dissolved Solids/ Total Suspended Solids (TDS/TSS)	Gravimetric

IV. RESULTS DISCUSSION

All results are listed in Tables 1-3. Although the well underwent a pressure drop from 1300 to 1318 hrs., as indicated in Table 1, the steam conditioning train was thoroughly purged for one hour before sampling. The non-condensable gas/condensate ratio remained essentially the same before the pressure drop (8.2) until after the one hour purge as indicated in Table 1.

TABLE 1
Physical Parameters

TIME	AMBIENT PRESSURE (in Hg)	AMBIENT TEMPERATURE (°F)	CONDENSATE TEMP. AT SEPARATOR BOTTLE (°F)	WELL PRESSURE (psig)	WELL TEMPERATURE (°F)	NON-CONDENSIBLE GAS FLOW (Lpm)	CONDENSATE FLOW (Lpm)	NON-CONDENSIBLE GAS RATE (L/Kg atm)
1247	--	--	81	118	--	4.6	0.56	8.2
1300 ²	---(WELL PRESSURE UNSTABLE)---			90	---(WELL PRESSURE UNSTABLE)---			
1306	↓			80	↓			
1308				50				
1310				30				
1318	---(WELL PRESSURE STABLE)---			115	---(WELL PRESSURE STABLE)---			
1500	27.7 (day ave)	62 (day ave)	82	115	365 (ave)	3.1	0.39	7.9
1530	--	--	82	115	--	3.2	0.39	8.2
1700	--	--	83	110	--	3.2	0.39	8.2

¹Calculation of this ratio assumes a density of 1.0 grams per milliliter for the condensate and neglects the density of the non-condensable gas.

²Well pressure began dropping as well head outlet simultaneously emitted a significant amount of water.

TABLE 2
Non-Condensable Gas Analytical Results

ANALYTE	CONCENTRATION (% by vol.)			CONCENTRATION (% by wt.)			
	Run	1	2	AVE.	1	2	AVE.
H ₂		2.6	2.4	2.5	0.2	0.2	0.2
CO ₂		55.6	54.6	55.0	75.8	75.8	75.2
O ₂		0.06	0.06	0.06	0.06	0.06	0.06
N ₂		8.2	7.8	8.0	7.1	6.8	6.9
CH ₄		28.5	27.1	27.9	14.1	13.4	13.8
H ₂ S		2.0	2.0	2.0	2.1	2.1	2.1
H ₂ O ⁽¹⁾		3.1	3.1	3.1	1.7	1.7	1.7
<u>Total of major Constituents</u>		100.0%	97.0%	98.6%			100.0%
Aliphatic Hydrocarbons C1-C10 (as CH ₄)		25.6	26.1				
Aromatic Hydrocarbons (as Benzene)		(ppm vol)	(ppm vol)				
Ethane		175	177				
Propane		21	24				
Butane		5	5				
Pentane		3	7				
Hexane		<1	<1				
NH ₃		198	192				

(1) Lange, Handbook of Chemistry, "Mass of Water Vapor in Saturated Air", pg.1424
McGraw-Hill, 1969.

J. M. Rudisill/SSW
February 17, 1981

FLOW RATE DURING DECEMBER 16TH, 1980 TEST
DAVIES STATE 5206-1

Time	Elapsed Time (hrs)	Temp. (°F)	P _r (PSIA)	Specific v, Volume	$\frac{\text{lbs}}{\text{ft}^3}$	Flow = $11,435.34 \sqrt{\frac{P}{v}}$ lb/hr	
12/16 9:30 AM	0	370	171.5	2.68		91,477.39	K ₁
9:40	0:10	407	265.2	1.74		141,176.11	622
9:45	0:15	407	263.2	1.74		140,642.77	629
9:50	0:20	404	254.2	1.81		135,518.18	
10:00	0:30	394	225.0	2.04		120,095.09	
10:30	1:00	390	209.4	2.20		111,564.51	
10:40	1:10	387	203.0	2.28		107,902.02	
10:55	1:15	384	194.0	2.36		103,679.75	626
11:30	2:00	382	191.6	2.41		101,961.99	
11:40	2:10	381	184.0	2.43		100,850.22	
12:40 PM	3:10	376	177.0	2.61		94,170.63	
1:40	4:10	373	169.0	2.70		90,471.24	
2:40	5:10	371	164.0	2.79		87,673.61	
3:40	6:10	368	162.0	2.83		86,519.37	
4:40	7:10	370	167.3	2.73		89,519.10	
5:40	8:10	368	163.4	2.80		87,356.67	
6:40	9:10	366	158.9	2.88		84,940.49	
7:40	10:10	364	154.9	2.93		83,145.93	
8:40	11:10	362	151.3	3.00		81,209.70	
9:40	12:10	360	148.9	3.05		79,899.95	
10:40	13:10	360	147.5	3.08		79,135.21	
11:40	14:10	360	149.5	3.02		80,457.44	
12/17 12:40 AM	15:10	358	145.3	3.14		77,788.80	
1:40	16:10	356	141.3	3.23		75,634.32	
2:40	17:10	355	140.2	3.24		75,222.99	
3:40	18:10	354	138.0	3.27		74,287.33	
4:40	19:10	353	137.4	3.28		74,012.58	
5:40	20:10	352	135.8	3.32		73,135.78	
6:40	21:10	351	133.2	3.39		71,680.55	
7:40	22:10	350	131.0	3.45		70,465.28	
8:40	23:10	350	132.2	3.41		71,201.25	
9:40	24:10	349	129.5	3.47		69,858.50	
10:40	25:10	348	124.1	3.66		66,587.76	
11:40	26:10	346	118.0	3.85		63,308.16	
12:40 PM	27:10	345	116.0	3.97		61,813.43	
1:40	28:10	348	118.0	3.85		63,308.16	
2:40	29:10	346	121.0	3.75		64,957.03	
3:40	30:10	345	122.0	3.75		65,224.89	
4:40	31:10	344	121.0	3.73		65,130.94	
5:40	32:10	343	120.0	3.73		64,861.25	624

205
60

TABLE 3
Condensate Analytical Results

Run	1	2		1	2
Analyte	(mg/liter)	(mg/liter)	Analyte	(mg/liter)	(mg/liter)
Boron	3.6	3.3	Arsenic	<0.01	<0.01
Chloride	83	78	Cadmium	<0.004	<0.004
Fluoride	<0.1	<0.1	Iron	0.19	<0.05
Ammonia	121	134	Lead	<0.03	<0.03
Nitrate	0.3	0.3	Calcium	<0.2	<0.2
Total Dis- solved Solids	30	45		($\mu\text{g/liter}$)	($\mu\text{g/liter}$)
			Sulfate	3.2	2.7
Total Sus- pended Solids	<3	<3	Mercury	11	10
	$\frac{\text{mgCaCO}_3}{\text{liter}}$	$\frac{\text{mg/CaCO}_3}{\text{liter}}$		(μmhos)	(μmhos)
Alkalinity	240	240	Conductivity	710	770
pH					
	5.25	5.20

Environmental Analysis Laboratories

2030 Wright Avenue
Richmond, California 94804
(415) 235-2633

CORPORATION (TWX) 910-382-8132

RECEIVED
FEB 16 1981
TPC

February 11, 1981

Mr. Jake Rudisill
Natomas Company
601 California Street
San Francisco, CA 94108

Reference: EAL Work Order
Number 06316-0001

Dear Mr. Rudisill:

The enclosed sequence of equations details the determination of the percent non-condensable portion of the total steam by weight as measured during the geothermal testing we completed for you on December 17, 1980.

If you have any further questions, please do not hesitate to call me.

Sincerely,

Philip A. Bumala
Air Pollution Specialist
Environmental Science Department

PAB/zlm

Enclosure

RECEIVED
FEB 17 1981
TPC

NON-CONDENSIBLE PERCENT BY WEIGHT

- (1) The molecular weight of the non-condensable gas equals 32.2 grams/mole, calculated from determining the percent by volume of the major gas constituents multiplied by their individual molecular weights.

- (2) Given: Flow measurements of:

3.2 Liters/min non-condensable

0.39 Liters/min condensable

Solve for 1 minute of flow:

$$\frac{3.2 \text{ Liters/min}}{24.45 \text{ Liters/mole}} = \frac{0.13 \text{ moles non-condensable}}{\text{min}}$$

Recall non-condensable molecular weight of 32.2 grams mole:

$$\text{grams non-cond/min} = \left(\frac{0.13 \text{ moles non-cond}}{\text{min}} \right) \left(\frac{32.2 \text{ grams non-cond}}{\text{mole}} \right) =$$

4.19 grams non-cond/min

Condensable flow rate = 0.39 Liters/min

390 mls or 390 grams

(assuming condensate density of 1 gram/ml)

- (3) Total steam sampled in one minute equaled:

$$\begin{array}{r} 4.19 \text{ grams non-cond} \\ + 390. \text{ grams condensate} \\ \hline 394.19 \text{ grams total} \end{array}$$

- (4) Finally:

$$100 \times \frac{4.19 \text{ grams non-cond}}{394.19 \text{ grams total}} = 1.06\% \text{ non-condensable (by weight)}$$

Rogers

PROJECT CONFERENCE NOTE

Number 2
 ROGERS Job No. S-81009-00
 Date 11 May 1981
 Place San Francisco
 By F. D. Dunn

CONFIRMATION OF CONFERENCE (Telephone X Meeting)

ATTENDING: Thermal Power Rogers
Roy Skinner F. D. Dunn

SUBJECT: H₂S Incineration for Vent Steam

Roy Skinner of Thermal Power called to advise on the following:

- | 1. | <u>Orifice Size</u> | <u>Pressure</u> | <u>Steam Flow</u> | <u>H₂S Amount</u> | <u>Ratio</u>
<u>H₂S/1000</u>
<u>CO</u>
<u>40</u> |
|----|---------------------|-----------------|-------------------|---------------------------------------|--|
| | 3/8" ϕ | 420 psig | 1998.5 #/hr. | 904 ppm
1.81 #/hr. | 0.91 |
| | 1/2" ϕ | - | 3612 #/hr. | 614 ppm
2.18 #/hr. | 0.60 |
| | 3/4" ϕ | 400 psig | 6586.5 #/hr. | 500 ppm
3.29 #/hr. | 0.50 |
| | 4" | | 62.000 | 2.51 ppm | 0.25 |
| | 1/4" ϕ | - | 1080 #/hr | 15.56 #/hr.
- 1200 ppm
1.3 #/hr | 1.2 |
- Above missing data to be supplied later in documented form.
 - Bob Reynolds of Lake County Air Pollution Control District advised Thermal Power that SO₂ emissions will not be a problem. Rogers requested a copy of letter from LCPCD to Thermal Power for Rogers' report purposes.

Page 1 of 1

Distribution: ROGERS

CLIENT

OTHERS

FDD
 →BF
 File: S-81009-00

J. M. Rudisill (Natomas - S. F.)
 Roy Skinner (Thermal Power - S. F.)

**SOURCE TEST SUMMARY
DAVIES - STATE 5201-1**

<u>#</u>	<u>TEST DATE</u>	<u>BLEED STATUS</u>	<u>SAMPLE LOCATION & REMARKS</u>	<u>AVERAGE TOTAL H2S (ppmw)</u>
(1)	10/17/80 - 1100 hrs	1" Bleed	Off 3" valve on casing head 180° opposite bleed line.	814
(2)	10/17/80 - 1300 hrs	1" Bleed	Same as above except sample line vented for 10 min. before grabbing sample.	702
(3)	10/20/80 - 1700 hrs	¾" Bleed	As in (1).	3,097
(4)	10/27/80	¾" Bleed	Same as in (2). P=428 psi. Draeger tubes at 5' from mouth of bleed had 130 ppm; at 10 ft., 60 ppm.	1,126
(5)	11/05/80 - 1600 hrs	¾" Bleed	Same as in (2); took 2 Draeger samples at well head fence in plume (7' from mouth) - 40 ppm avg.	1,338
(6)	11/05/80 - 1100 hrs	¾" Bleed	Bleed Line, up-stream of ¾" orifice.	1,409
(7)	12/16/80 - 1055 hrs	4" Orifice	P=181 psigs, T=389°F. Full flow started at 0940 hrs.	342
(8)	12/16/80 - 1540 hrs	4" Orifice	P=149 psig, T=368°F. Full flow for 6 hrs.	298
(9)	12/17/80 - 0800 hrs	4" Orifice	P=119 psig, T=350°F after 22 hrs. of flow.	251
(10)	12/17/80 - 1400 hrs	4" Orifice	After 28 hrs. of flow, & less than 1 hr. after water slug.	261
(11)	01/15/81 - 1000 hrs	¾" Bleed	Almost 1 month after flow test; sampled as in (6).	1,904

APPENDIX V

COST ESTIMATE

CONSULTING ENGINEERS

DWG. NO. E-02-001

PRELIM. ☐ % FINAL ☒[illegible]

CONSULTING ENGINEERS

North. MIYAN GAS & COND. Sep. & CW. TOWER PRELIM. ☐ % FINAL ☒

CONSULTING ENGINEERS

PRELIM. ☐ % FINAL ☒

CONSULTING ENGINEERS

PRELIM. ☐ % FINAL ☒

ACCOUNT NO.	DESCRIPTION	QUAN.	UNIT	UNIT LABOR	LABOR	UNIT MATERIAL	MATERIAL	OTHER	TOTAL
	EMER. VENT VALVE						900-		
	RESTRICTION ORIFICES & UNIONS	3	-			300	900-		
	WATER EXCH TIC						1200-		
	TIC VALVE 3PORT 2WAY all IRON						1800-		
	GAS & LIQ. SEPARATOR PSV						800-		
	LIC all SS 316L						1600-		
	LIC VALVE SS BODY & TRIM						900-		
	Neutralizer 1/4HP Na ₂ CO ₃ feeder WITH CONTROLS & STORAGE BLDG						8000-		
	AIR pH CONTROLLER with electrodes						1800-		
	Naut. Water Surge LIC - COND. TYPE						900-		
	LIC. VALVE all IRON						600-		
	INST. AIR COMP - LOW PRESSURE								
	OIL LESS PISTON - DUAL AUTO START (2 UNITS)					350	700-		
	3.2 SCFM @ 30 PSIG								
	ca 1/2 HP - 120 V - 60 cyc - 1 phase								
GE-001	C-3 SUB TOTAL						20100-		

ROGERS ENGINEERING CO., INC.
CONSULTING ENGINEERS

JOB NO. S-81009-00 COST ESTIMATE DATE 6 JULY 81 REVISED 20 AUG 81
FOR NATOMAS ITEM TITLE INCINERATOR TYPE SYSTEM SHEET C-4 OF _____
PROJECT BLEED STEAM ABATEMENT PREPARED BY BF CHECKED BY 700
DWG. NO. E-02-001 INSTALLED COSTS PRELIM. ☐ % FINAL ☒

ACCOUNT NO.	DESCRIPTION	QUAN.	UNIT	UNIT LABOR	LABOR	UNIT MATERIAL	MATERIAL	OTHER	TOTAL
	EQUIPMENT INSTALLATION COSTS								
	USING GUTHRIE BARE MODULE FACTOR ADJUSTED X BASE EQUIPMENT (CARBON STEEL)								
	AIR COOLED EXCHANGER = $3,800 \div 1.85 = 2,050$ C.S. BASE								
	$2,050 \times 1.9 = (3,900) + (3,800 - 2,050) =$								5,650
	WATER COOLED EXCHANGER = $4,300 \div 1.78 = 2,400$ C.S. BASE								
	$2,400 \times 2.7 = (6,480) + (4,300 - 2,400) =$								8,380
	COOLING WATER CIRC PUMP 2,300 } all iron 4,000 C.S. BASE								
	NEUTRAL WATER TRANS PUMP 1,700 }								
	$4,000 \times 2.7 =$								10,800
	MIXER $2,800 \div 1.8 = 1,550$ C.S. BASE								
	$1,550 \times 2.2 = (3,410) + (2,800 - 1,550) =$								4,660
	TANKS $(2,300 + 1,800) \times 2.0 =$								8,200
	GAS & CONDENSATE SEP = $2,300 \div 1.3 = 1,280$ C.S. BASE								
	$1,280 \times 2.5 = (3,200) + (2,300 - 1,280) =$								4,220
	SMALL C.W.T. = $5,500 \times 3.0 =$								16,500
	DIESEL-ELECTRIC UNIT BUDGET $19,700 \times 1.12$								21,000
	SUB TOTAL								79,410

ROGERS ENGINEERING CO., INC.
CONSULTING ENGINEERS

JOB NO. 5-81009-00

FOR NATOMAS

PROJECT BLEED STEAM ABATEMENT

DWG. NO.

COST ESTIMATE

ITEM TITLE INCINERATOR TYPE SYSTEM

DATE 7 JULY 81 REVISED 20 AUG 81

SHEET C-5 OF 1

PREPARED BY BF CHECKED BY ZDD

PRELIM. ☐ % FINAL ☒

INSTALLED COST BUDGET TOTAL

[illegible]

CONSULTING ENGINEERS

...% FINAL ☒

7700-