EPRI-TC-80-907-7

# Proceedings of the Fourth Annual Geothermal Conference and Workshop

EPRI TC-80-907
TC-80-907
Conference Proceedings
December 1980

Keywords:
Geothermal
Research Projects
Power Plants

MASTER

Prepared by
Altas Corporation
Santa Cruz, California

ELECTRIC POWER RESEARCH INSTITUTE

## DISCLAIMER

# A HEAT EXCHANGER PROCESS FOR REMOVAL OF $H_2S$ GAS

CONTRACT NO. RP1197-2

Glenn E. Coury, Robert A. Babione, and Robert J. Gosik
Coury and Associates, Inc.
7625 West 5th Avenue
Lakewood, CO 80226 (303)-232-3823

I. Introduction A heat exchanger process has been developed for the removal of $H_2S$ and other noncondensable gases from geothermal steam. The process utilizes a heat exchanger to condense water from geothermal steam while allowing $H_2S$ and other noncondensable gases to pass through in the vapor phase. The condensed water is evaporated to form a clean steam from which over 90 percent of the $H_2S$ and other noncondensable gases have been removed.

Some of the important advantages of the heat exchanger process are shown in Table 1. The system can be located upstream of a power plant turbine which eliminates much of the potential for corrosion, as well as the requirement for removing $H_2S$ from water collected in the main condenser. Since almost all noncondensables are removed, much less steam is needed for air ejector operation. The heat exchanger process is simple: it has no chemical addition requirements or sludge by-products and utilizes standard equipment found in many power plant applications. The regular power plant operators and maintenance crews can easily understand and run the system with minimal attention. Capital and operating costs are competitive with those for currently available $H_2S$-abatement technology, although significant economic advantages over downstream abatement processes may result due to the use of clean steam in the turbines.

Table 1. Advantages of the Heat Exchanger $H_2S$ Removal Process

Upstream Abatement
- Clean steam to turbine
- Reduced air ejector requirements
- No treatment needed for main condenser water

Simple Operation
- No chemicals
- No sludge
- Minimal operator attention

Reasonable Costs
- Competitive with downstream abatement techniques
- Reduction in overall power plant costs with clean steam

Under the contract to EPRI, a 1000-lb steam/h heat exchanger test unit was designed and constructed at Unit 7 of The Geysers Power Plant. Operation began in March 1979. The test unit was run under widely varying conditions to demonstrate $H_2S$ removal, heat transfer properties, and related process characteristics.

Based on data from the test unit and other EPRI-sponsored studies, alternative conceptual designs for the heat exchanger process were developed for a 55-MW power plant. Design criteria and equipment requirements were determined for a selected design. Capital and operating costs for a large-scale system were also estimated.

II. Heat Exchanger Test Unit

A. Description The test unit is located at The Geysers Power Plant, Unit 7. Wellhead steam at Unit 7 varies from saturated to superheated conditions, with typical temperatures of about 340°F to 350°F. $H_2S$ concentrations are commonly 200 to 300 ppm with total noncondensable gas concentrations ranging from 2000 to 5000 ppm. About 80 percent of the noncondensable gas is $CO_2$. Besides $H_2S$ and $CO_2$, other constituents include $NH_3$, $N_2$, $H_2$, $CH_4$, and boron. Figure 1 shows the test unit configuration.

Geothermal steam enters the shellside of the heat exchanger, where it is selectively condensed at its saturation pressure. The condensate will dissolve some of the noncondensable gases contained in the steam, but about 98 percent of all gases, including $CO_2$, $NH_3$, $H_2$, and $N_2$, will remain in the vent gas stream. Depending on steam compositions and process operating conditions, 90 to 99 percent of $H_2S$ will remain in the vent stream.

The condensate is reduced to a lower pressure and allowed to flash in the tubeside sump of the heat exchanger. This provides the necessary temperature driving force across the heat exchanger. The condensate within the tubes is partially vaporized to clean steam which discharges from the sump. The clean steam from the sump and the vent gas exiting the top of the shellside of the heat exchanger are released into the Unit 7 cooling tower basin.

B. Test Objectives The testing program for the 1,000 lb/h test unit was set up to accomplish both primary and secondary objectives. The primary objectives of the test program were to demonstrate $H_2S$ removal capabilities and heat transfer performance of the heat exchanger. The secondary objectives of the program were to

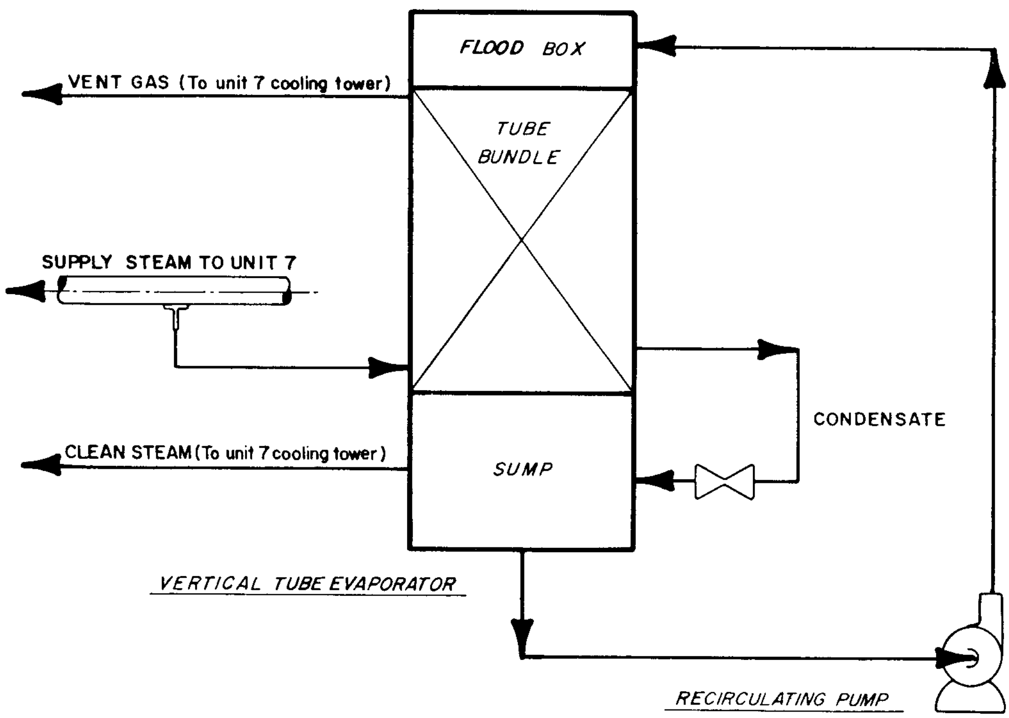


**FIGURE 1.** HEAT EXCHANGER TEST UNIT CONFIGURATION AT THE GEYSERS POWER PLANT, UNIT 7.

develop data for use in the design of larger heat exchangers.

C. <u>Test Results</u> The test unit has operated since March of 1979. Data have been collected for approximately 68 days, during which time the unit has been in operation on a continuous basis for as long as 10 to 15 days. Besides $H_2S$ removal and heat transfer performance , the pilot plant was tested for total noncondensables removal, transient response, gas injection, and parametric evaluations of $\Delta T$ and vent rate.

Removal of $H_2S$ is determined by how much $H_2S$ enters the liquid phase as the steam condenses on the outside of the tubes. The amount of $H_2S$ absorbed at equilibrium is controlled by three factors: the partial pressure of the gas in the vapor phase, the mass ratio of vapor to liquid in contact with each other, and the pH of the liquid solution. The pH, however, depends in a complex way on the amount of gases that dissolve. As $CO_2$ and $H_2S$ are dissolved the pH decreases due to hydrolysis of $CO_2$ and $H_2S$ in the liquid phase:

$$CO_2 + H_2O = H^+ + HCO_3^- \tag{1}$$

$$H_2S = H^+ + HS^- \tag{2}$$

while the dissolution of ammonia leads to the capture of hydrogen ions and an increase in pH:

$$NH_3 + H^+ = NH_4^+ \tag{3}$$

As a result, the major variables that affect $H_2S$ removal are temperature, pressure, gas composition, and the percent of inlet steam vented. The only variable that could be controlled effectively within the limitations of the test unit was the percent vent rate.

Figure 2 shows $H_2S$ removal as a function of percent vent rate. The $H_2S$ removal varied from 90 to 99 percent with an average value of 94 percent. There is a slight trend showing increased $H_2S$ removal with increased vent rate; this is predicted since increasing the vent rate reduces the partial pressure of $H_2S$ in the vapor phase. On the other hand, the data in Figure 2 show a high degree of scatter. The scatter is attributed mostly to highly variable concentrations of $H_2S$, $NH_3$, and other gases in the inlet steam. Based on recent field tests at The Geysers, changes in concentration by a factor of three or more can occur within a short period of time.

The heat transfer properties of the test unit were evaluated by calculating an overall heat transfer coefficient (HTC), under various conditions. The coefficient is defined by the following relationship:

$$HTC = \frac{Q}{A\Delta T} \tag{4}$$

where $Q$ = heat load defined by the amount of steam condensed
$A$ = heat transfer area
$\Delta T$ = temperature difference between the tubeside and shellside

The major factors expected to affect HTC measurements are the noncondensable gas concentrations, mass flow rate, presence of scale, and the percent vent rate. The effect of changing the percent vent rate was extensively tested in the unit. It was expected that the HTC would increase with vent rate since higher vent rates result in increased sweep velocities across tubes, thus minimizing the blanketing effects of noncondensables.

Figure 3 shows the variation in the HTC with percent vent rate. In general, values ranged from 300 to 1000 Btu/(h·ft$^2$·°F) with an average of about 576 Btu/(h·ft$^2$·°F). Large variations in the HTC values were experienced and no consistent correlation between HTC and vent rate was apparent. This may be explained by highly variable noncondensable concentrations and possible leakage across the bottom tubesheet. No effects attributed to fouling of tubes were noted.

The predicted HTC value for the test unit was about 900 Btu/(h·ft$^2$·°F). Lower values may have been calculated for the test unit for a number of reasons. First, the test unit was too small to be designed for proper sweep velocities. As discussed previously, higher sweep velocities are necessary to minimize the effect of blanketing of tubes. Second, due to physical limitations, $\Delta T$ measurements were between inlet and clean steam lines. These $\Delta T$ values would be higher than actual tubeside-shellside $\Delta T$'s. Lower calculated HTC values would result. Finally, two of the 50 heat exchanger tubes were crushed, possibly blocking flow and reducing heat transfer area. Reduced heat transfer area would also result in lower calculated HTC values.

Other major test results for noncondensables, transient conditions, gas injection and parametric tests are summarized in Table 2. Total noncondensables removal in the test unit was found to be greater than 99 percent for all conditions. This is based on field test methods which compare gas to liquid volume ratio in condensed inlet and clean steam samples. Transient tests were done to simulate conditions that could be experienced if the heat exchanger was installed upstream of a turbine generator. The tests, which included startup, sudden decreases and increases in clean steam flow, sudden increase and decrease in vent gas flow resulted in stable, predictable operation of the heat exchanger. Only the sudden increase in the clean steam flow caused a shutdown and this could be solved by using a standard control scheme for commercial

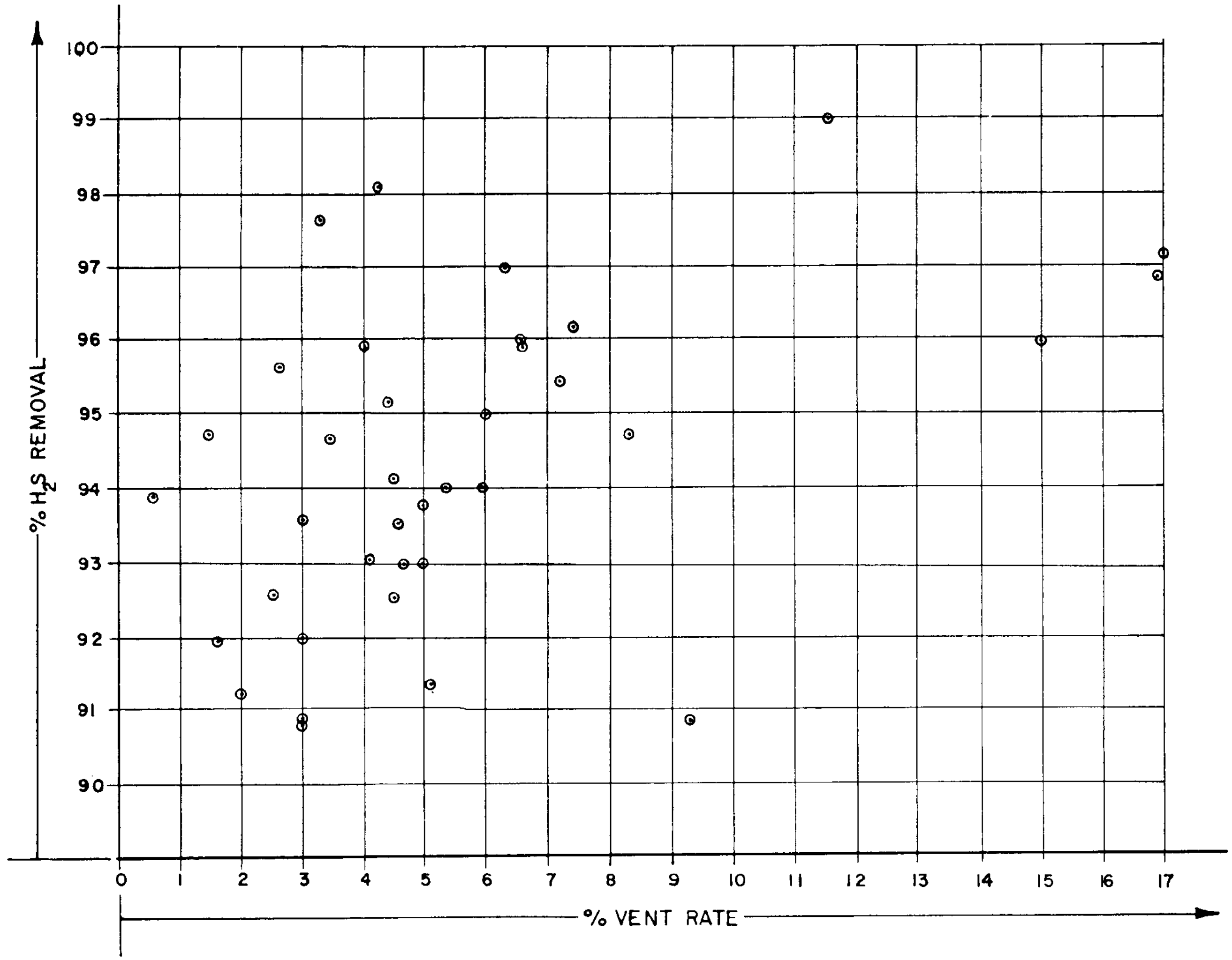


**FIGURE 2.** TEST UNIT PERFORMANCE: $H_2S$ REMOVAL vs. VENT RATE.

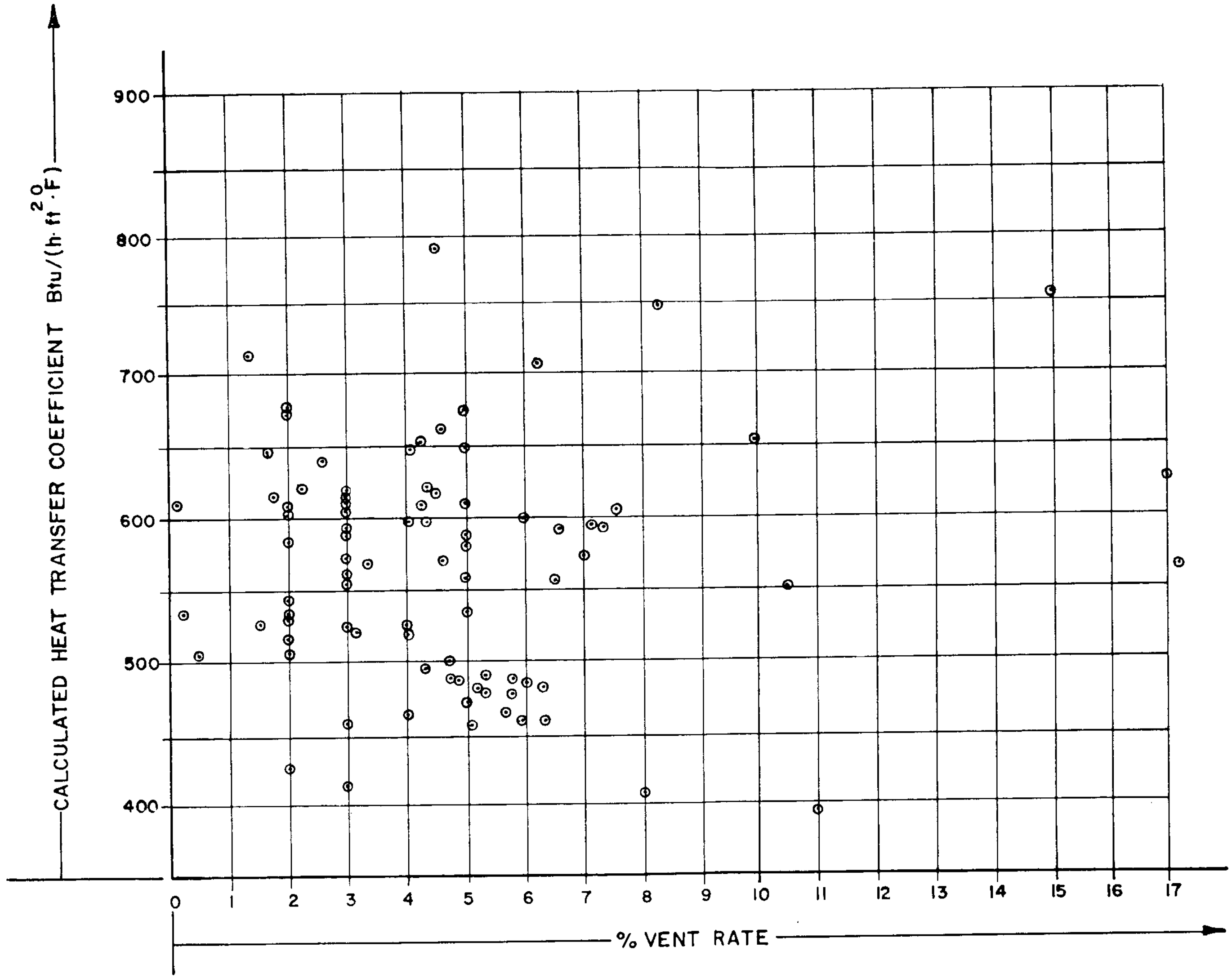


**FIGURE 3.** TEST UNIT PERFORMANCE: COEFFICIENT of HEAT TRANSFER vs. VENT RATE.

power plant operations. Increasing the inlet concentrations of $NH_3$ and $H_2S$ by up to four times their normal concentrations had little effect on $H_2S$ removal or heat transfer; however, the limited runs made under these inlet conditions, which could vary significantly with time, do not allow conclusions to be made here. The parametric tests varying $\Delta T$ were consistent with predictions. Data showed that increasing $\Delta T$ from $5^oF$ to $10^oF$ doubled the clean steam produced but had negligible effect on $H_2S$ removal or heat transfer properties. Parametric tests involving percent vent rates have been presented previously.

Table 2. Other Major Test Results

Noncondensables Removal

- Greater than 99 percent under all conditions

Transient Effects

- Tested conditions simulating startup, sudden opening and closing of clean steam valve, sudden opening and closing of vent gas valve, sudden closing of inlet steam valve, pump trip.
- No unpredictable results
- Smooth heat exchanger response in all cases except sudden opening of clean steam valve.

Gas Injection

- Increased $NH_3$ and $H_2S$ up to four times
- No significant effect on $H_2S$ removal or heat transfer properties
- Limited number of runs

$\Delta T$ Effects

- $\Delta T$ tested between 5 and $10^oF$
- Clean steam flow rates changed as predicted
- No effect on $H_2S$ removal or heat transfer properties.

III. Commercial-Scale Design The most effective way of utilizing this heat exchanger process in a full-scale power generation application similar to The Geysers would be to use an upstream, multistage heat exchanger system. Figure 4 shows one possible scheme for such an application. The well steam first enters the first-stage heat exchanger where most of the $H_2S$ and other noncondensables are removed from the steam. Approximately 95 percent of the incoming flow leaves the first-stage heat exchanger as clean steam, supplying steam to a turbine generator unit. The vent stream from the first-stage condenser (which includes approximately 5 percent of the total incoming steam and almost all of the incoming $H_2S$ and other noncondensables) is processed by a second-stage heat exchanger. The clean steam from this second stage is used to drive a second turbine generator unit. Almost all of the $H_2S$ and other noncondensables and a very small percent of the steam entering the first-stage heat exchanger are in the second-stage vent stream. This vent stream can be treated for ultimate disposal of the $H_2S$ by some process such as the Stretford process. The Stretford process is a proven commercial process which can easily convert highly concentrated streams of $H_2S$ into elemental sulfur. The second-stage vent stream could possibly be used to drive a third turbine generator unit located upstream of the $H_2S$ conversion process. This turbine would have to be constructed of materials suitable for the high concentrations of $H_2S$ in this flow stream.

Figure 5 shows another possible scheme for an upstream, multistage heat exchanger system in a power generation application. In this scheme the clean steam from the first-stage heat exchanger is used to drive the turbine generator unit. The clean steam from the second-stage unit is used to drive the condenser vacuum system and also provides process heat, if required, for the $H_2S$ conversion process. The vent stream from the second-stage unit goes directly to an $H_2S$ conversion process such as the Stretford process. The scheme shown in Figure 5 can more easily be used in a retrofit application for power plant designs similar to those at The Geysers; however, both schemes could be utilized in new plant design applications.

IV. Estimated Costs for Commercial-Scale Application The estimated costs of a commercial-scale heat exchanger system were determined in a recently completed study. The cost model was based on a system that would be compatible with a typical Pacific Gas and Electric Company (PG&E) 55-MW power plant unit at The Geysers. The design scheme in Figure 5 was used in developing the cost model. This scheme includes a two-stage heat exchanger system with the first stage supplying clean steam to the turbine generator unit and the second stage supplying clean steam to the condenser vacuum system and for use as process heat in the Stretford plant. The second-stage vent stream is processed by a Stretford plant which converts this highly concentrated stream of $H_2S$ into elemental sulfur. Tables 3 and 4 present the design criteria and the performance factors used in developing this cost model. The design criteria were provided by PG&E. The performance factors were based on detailed theoretical studies related to this heat exchanger process and the results of experimental field tests.

The major equipment items are the first- and second-stage heat exchangers and the recirculating condensate pumps. The total required first-stage surface area was 155,400 $ft^2$, which

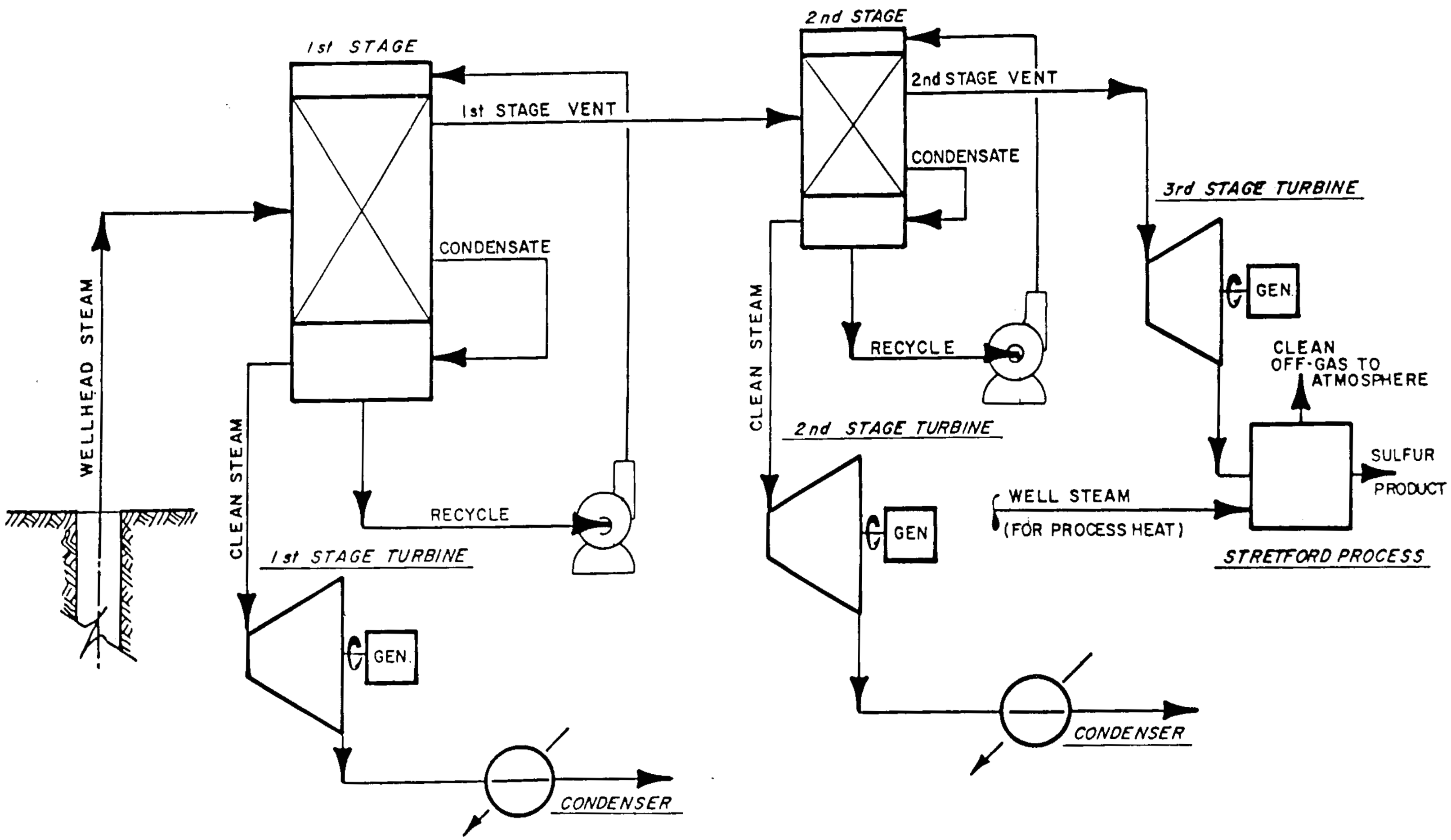


**FIGURE 4.** MULTISTAGE UPSTREAM APPLICATION OF THE $H_2S$ REMOVAL HEAT EXCHANGER PROCESS.

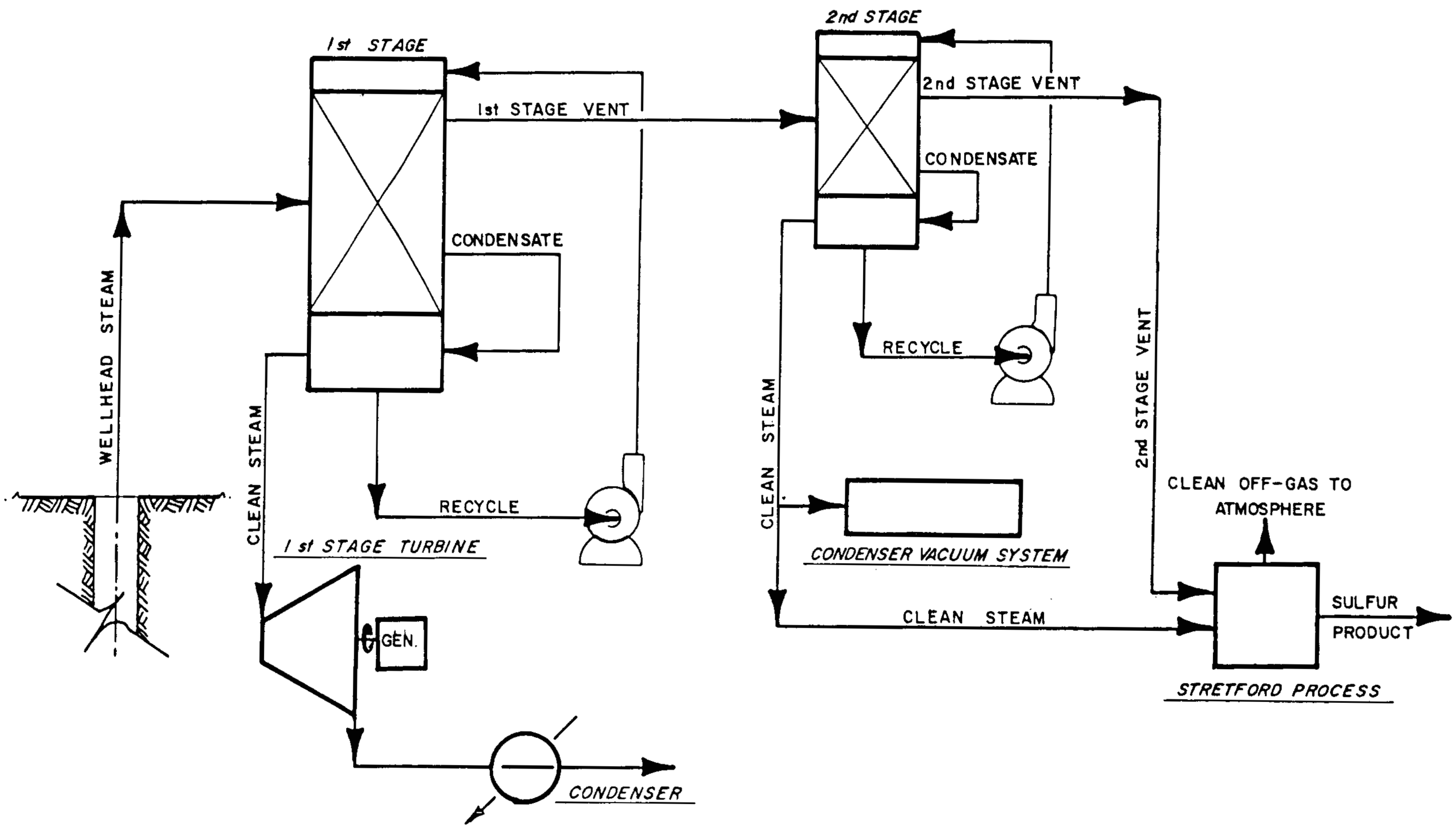


**FIGURE 5.** ALTERNATE MULTISTAGE UPSTREAM APPLICATION OF THE $H_2S$ REMOVAL HEAT EXCHANGER PROCESS.

Table 3. Design Criteria

| | |
|---|---|
| Well steam conditions: | |
| pressure | 115 psig |
| temperature | 350°F |
| noncondensable loading | 0.5% |
| Turbine inlet steam conditions: | |
| pressure | saturation |
| temperature | 338°F minimum |
| noncondensable loading | 0.01% maximum |
| full load flow rate | 1,100,000 lb/h |
| Maximum heat exchanger tube bundle size: | |
| 40 feet long by 12 feet diameter (Shipping constraint due to remote location of The Geysers) | |
| Condenser vacuum system requirements: | |
| pressure | 90 psig |
| flow rate | 20,000 lb/h |
| Process steam to Stretford unit: | |
| flow rate | 5,000 lb/h |

Table 4. Performance Factors

| | |
|---|---|
| Overall heat transfer coefficient | 600 Btu/(h·ft$^2$·°F) |
| First-stage vent rate | 5 percent |
| Second-stage vent rate | 60 percent |
| Tubeside flow rates | 1 1/2 gpm/tube |

resulted in three first-stage heat exchangers, each with a tube bundle 37 feet long and 11 feet in diameter. The total required second-stage tube surface area was 3638 ft$^2$, which resulted in one second-stage heat exchanger with a tube bundle 19.5 feet long and 4 feet in diameter. The first-stage pumping configuration was assumed to be four pumps in parallel servicing the three heat exchangers, with one of these pumps being a spare. The pumping power requirements for each pump was 64 hp. The second-stage pumping configuration was assumed to be two pumps in parallel, with one of these pumps being a spare. The pumping power requirements for each pump was 5.2 hp. 304 stainless steel was selected as the material of construction for the heat exchangers, pumps, and related piping.

In addition to the heat exchangers and pumps, the other items included in the cost model were insulation, piping and valves, support structures and foundations, electrical equipment, instrumentation and controls, engineering costs, and a Stretford plant sized for this application. Table 5 summarizes the cost model.

The estimated system costs based on the developed cost model are summarized in Table 6. The estimated heat exchanger system capital cost is 5.6 million dollars. The estimated Stretford plant capital cost is 2.6 million dollars.

Table 5. Cost Model Summary

| | |
|---|---|
| First-stage heat exchangers: | |
| Number of heat exchangers | 3 |
| Tube surface area per heat exchanger | 51,800 ft$^2$ |
| Tube bundle height | 37 ft |
| Tube bundle diameter | 11 ft |
| Material | 304 stainless steel |
| Second-stage heat exchangers: | |
| Number of heat exchangers | 1 |
| Tube surface area | 3638 ft$^2$ |
| Tube bundle height | 19.5 ft |
| Tube bundle diameter | 4 ft |
| Material | 304 stainless steel |
| First-stage pumps: | |
| Number of pumps | 4 (3 operating, 1 spare) |
| Required pumping power per pump | 64 hp |
| Material | 304 stainless steel |
| Second-stage pumps: | |
| Number of pumps | 2 (1 operating, 1 spare) |
| Required pumping power per pump | 5.2 hp |
| Material | 304 stainless steel |
| Piping and valves: | |
| Material | 304 stainless steel |
| Instrumentation and controls: | |
| Control valves, level controllers, flow controllers, and instrumentation | suitable for process requirements |
| Stretford plant: | |
| $H_2S$ processing requirement | 240 lb/h |

The total capital cost, including the Stretford plant, is 8.8 million dollars. The total estimated annual cost, including annual capital cost payments and operating and maintenance costs, is 1.9 million dollars.

Table 6. Estimated Cost Summary of 55-MW Heat Exchanger $H_2S$ Removal System

| | |
|---|---|
| Capital cost of heat exchanger system | $5,600,000 |
| Capital cost of Stretford plant | 2,600,000 |
| Total capital cost | $8,200,000 |
| Annual operation and maintenance cost | $ 400,000 |
| Annual capital cost payment | 1,500,000 |
| Total annual cost | $1,900,000 |

Notes for Table 6.

1. All costs are ±25 percent.
2. Heat exchanger system capital cost includes heat exchangers, shipping, erection, pumps, valves, piping, instrumentation, insulation, foundations, and engineering.
3. Annual operation and maintenance costs include 2 percent of heat exchanger system capital cost, 10 percent of Stretford plant capital cost, pump energy costs based on $0.03 kWh, and an assumed on-line time of 8000 h/yr.
4. The annual capital cost payment is assumed to be 18 percent of the total capital cost.