Geysers Advanced Direct Contact Condenser Results

J. Henderson and Tom Bahning,
Pacific Gas and Electric Co.

Introduction

The world's first geothermal application of the Advanced Direct Contact Condenser (ADCC) technology developed by the National Renewable Energy Laboratory (NREL) is now operational at The Geysers Power Plant Unit 11. This major research effort was supported through the combined efforts of NREL, The Department of Energy (DOE), and Pacific Gas and Electric (PG&E).

The project was the first geothermal adaptation of an advanced condenser design originally demonstrated at the Ocean Thermal Energy Conversion (OTEC) plant in Kona, Hawaii. PG&E expects this technology to improve power plant performance and to help extend the life of the steam field by using steam more efficiently. Successful application of this technology at The Geysers will provide a basis for NREL to continue to develop this technology for other geothermal and fossil power plant systems.

Geysers Unit 11 was selected for installation and demonstration of the NREL technology. The Unit 11 condenser was an excellent test case due to a high non condensable gas load and a high amount of steam carryover to the gas removal system. The technology has provided a 3.5 megawatt increase in power production to date as a result of improved direct contact condensation in the main condenser. An additional 2 megawatts may be possible pending the resolution of a venting limitation. The technology has also yielded a 50% reduction in abatement chemicals.

The project involved the development of a computer simulation model used as a predictive tool to determine expected process conditions and flows for the conceptual design. The results from the model were used to arrive at the final detailed engineering design. The final design included improvements to the main condenser and the gas removal system.

Process Description - Original

The original Unit 11 direct contact condensation scheme is presented in Figure 1. The original main condenser relied on a single pass, cross flow mixing design. A series of perforated trays were used to mix the cooling water and steam. The condensate and cooling water mixture is then pumped out to the cooling tower to be recycled as circulating water. Cooling water is drawn into the condenser by the vacuum. The noncondensable gas was removed from the condenser by a two stage steam jet condenser system as shown in Figure 2. The inter and after condensers were both open vessels with a single spray nozzle. Both vessels drained back to the main condenser, the inter condenser via a loop seal and the after condenser via a level control valve.

Past studies by PG&E confirmed poor cooling water and steam mixing with the existing perforated trays. Temperature probes positioned in the trays indicated that there was very little heat transfer between the water inlet chamber and the first (upper) tray which was close to the original gas removal baffle. Consequently, steam vapor carryover was large because the temperature of the vent gas leaving the main condenser was roughly equivalent to the hotwell temperature.

Process Description - Modified

The new main condenser interior design, developed from the NREL model, is depicted in Figure 3. The new design utilizes a two pass, co current and counter current scheme. The perforated trays were removed and replaced with plastic structured packing as the contact media. The packing is standard counter flow cooling tower packing. New stainless steel cross wise water distribution headers were also installed. Each header is equipped with a series of plastic spray nozzles that were originally designed for counter flow cooling tower applications. Stainless steel baffles separate the co current and counter current sections.

NREL worked closely with PG&E to arrive at the best internal configuration. The final design was arrived at after a number of iterations. Several designs were studied and rejected for either performance or constructability reasons.

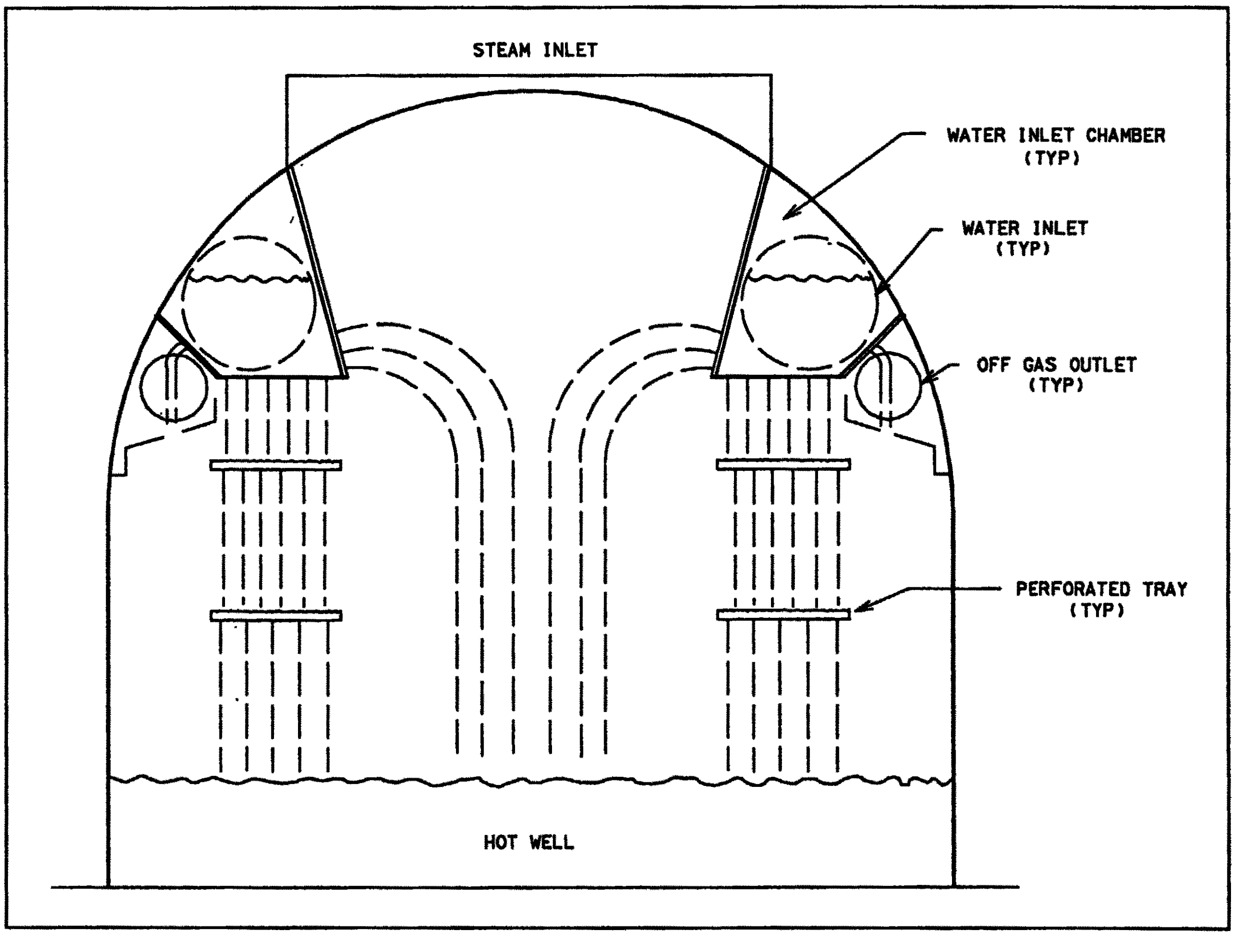

Figure 1. End view of original main condenser flowpath.

Several features were installed to protect the main condenser plastic structured packing from high temperature. High temperature can result if steam is entering the main condenser when there is not enough vacuum to draw in cooling water. This is mainly a danger during unit start up and shut down. The protection features include:

1) An air operated main steam shut off valve (AOV): This 42" valve stops all steam flow to the plant within 6 seconds. Compressed air is used instead of a motor driven actuator to ensure operation following a station black out.

2) Main condenser shell side temperature probes: An array of fast response probes monitor temperatures within the condenser. A "high temp" signal will start the existing turbine exhaust hood spray system. A "high high temp" signal will trip the new AOV closed.

3) Vacuum breaker time delay: The vacuum breaker valves are delayed several seconds from opening following a unit trip. Main condenser cooling water flow will then continue long enough to ensure condensation of the steam trapped between the trip valves and the condenser.

The gas removal system, as shown in Figure 4, was changed from a two stage system to a three stage system to better utilize the steam resource in conjunction with the new main condenser modification. The principle changes included the following:

- All new steam jets.
- A new second inter condenser vessel (Inter Condenser 2).
- Metal structured packing in all inter and after condensers.
- Inter Condenser 2 and After Condenser tailpipes rerouted to the cooling tower.
- A steam turbine driven gas compressor at the third stage.

The steam turbine driven gas compressor or turbine compressor (TC) was designed and built by the Barber Nichols Company of Arvada, Colorado. It lowers auxiliary steam use even further than a three stage ejector scheme and provides greater flexibility in meeting future noncondensible gas loads. Spent steam from the turbine section supplies the shaft steam seals on the power turbine. Excess spent steam is dumped into the after condenser. A bypass third stage steam jet air ejector is used when the TC is unavailable for service.

Although the TC system was installed at the same time as the ADCC system, it is a separately funded project. Participants include Pacific Gas and Electric Co., The Dept. of Energy, Barber Nichols, and UNOCAL Geothermal.

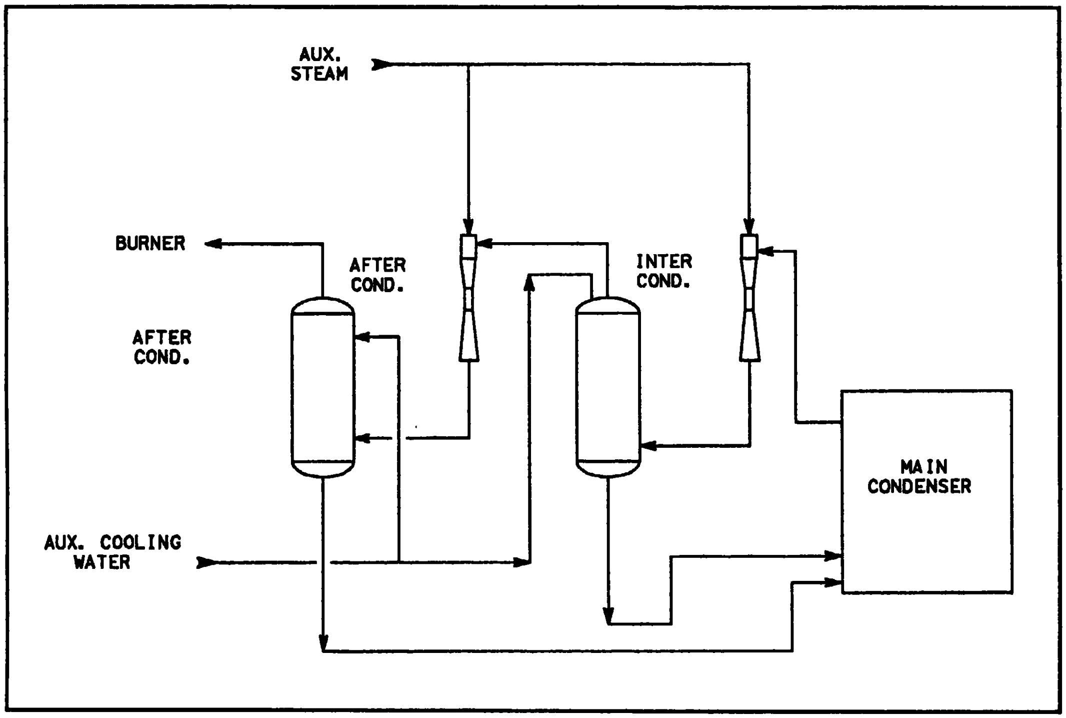

Figure 2. Flow diagram-original gas removal system.

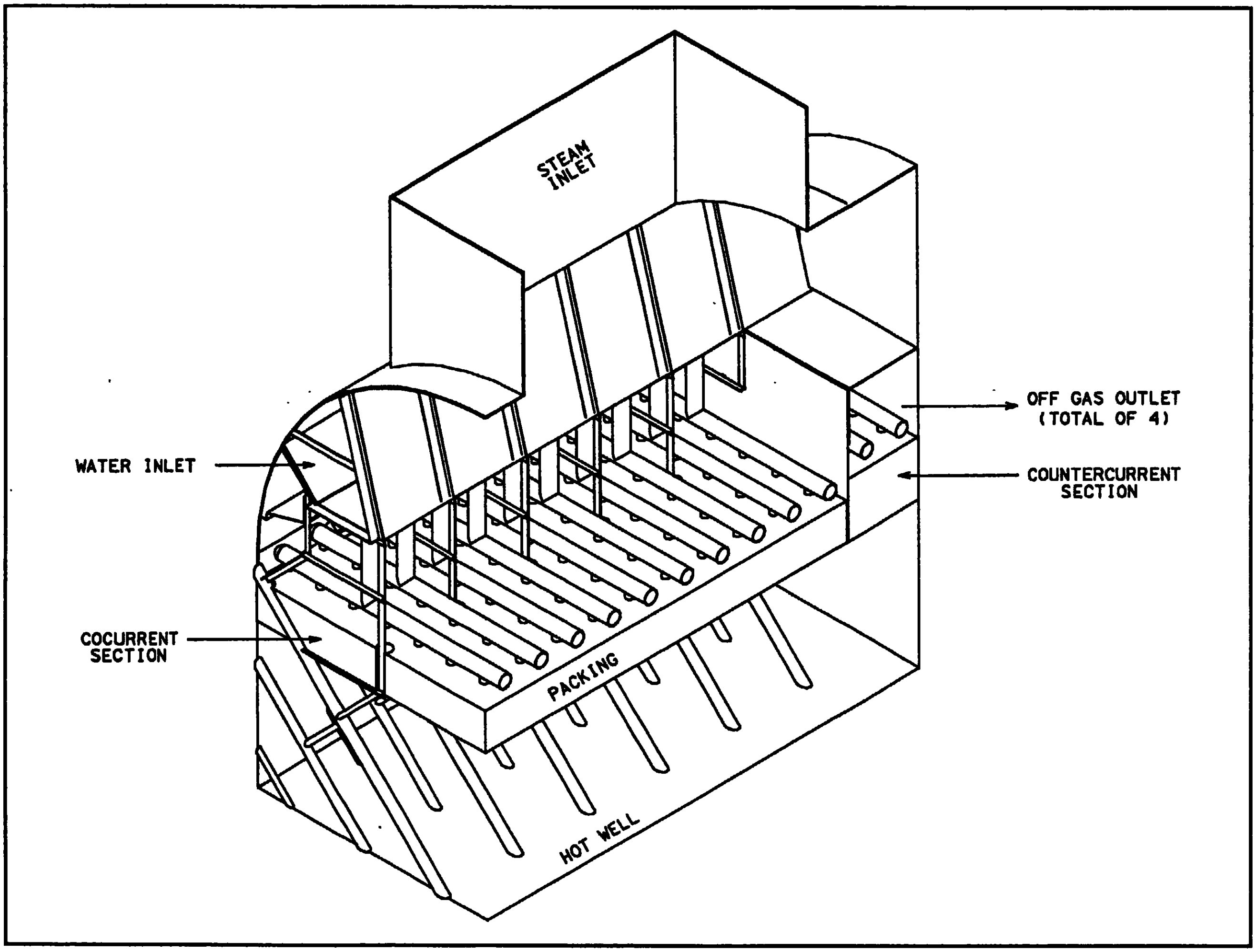

Figure 3. Quarter section view of modified main condenser.

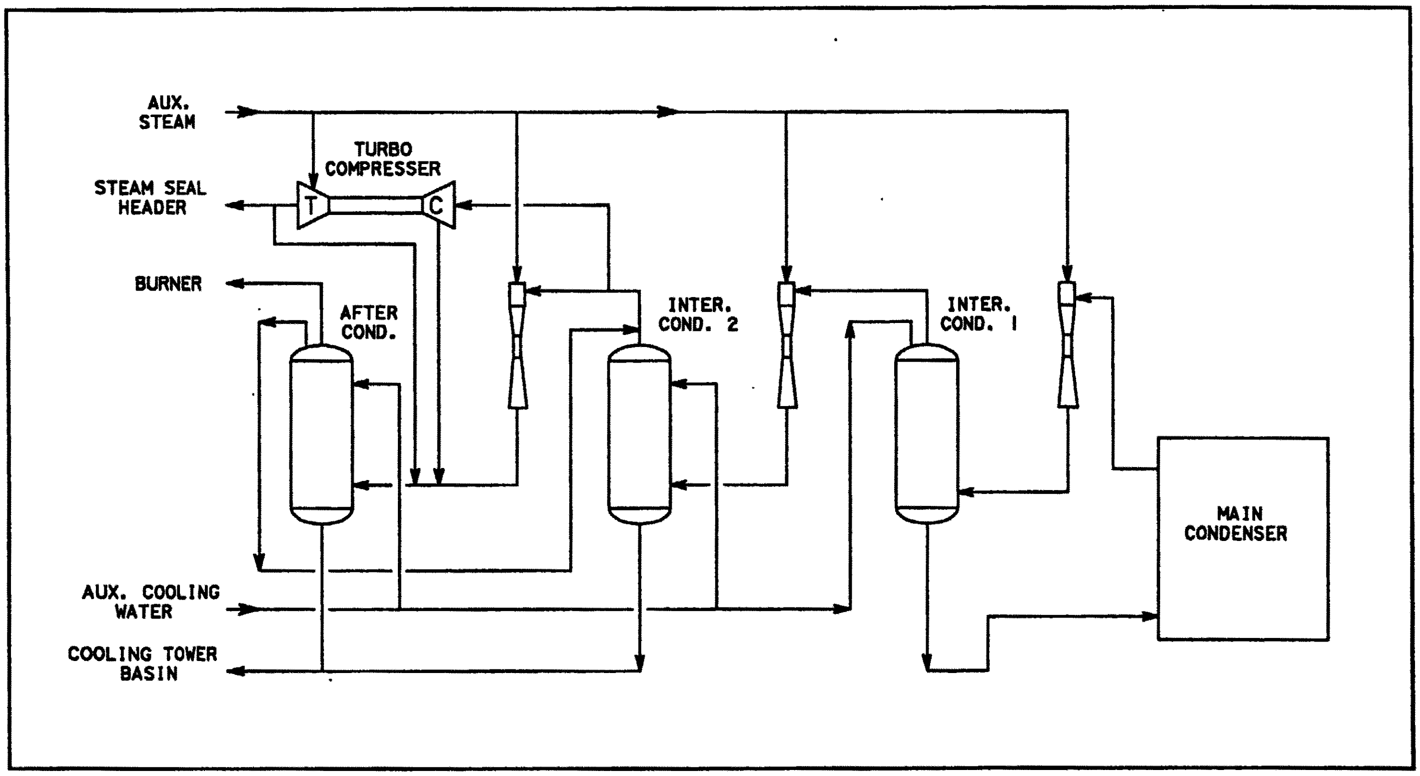

Figure 4. Flow diagram-modified gas removal system.

Model Development

A computer simulation model for the ADCC technology was developed by NREL to evaluate the conceptual design and to provide a predictive tool for determining thermal and chemical performance. The model incorporates a computer code designed to take into account the high amounts of noncondensable gas loading unique to geothermal units. Geothermal chemistry is included in the model, particularly H_2S partitioning in the condenser and associated aqueous chemical reactions that affect H_2S abatement. NREL currently has a patent pending on this technology.

The model is configured to calculate each condensation section independent from the other. The program uses an iterative method to solve the equations for twenty three variables as a function of packed bed depth. Convergence is achieved by mass balance and charge neutrality. Once convergence is achieved, sixteen tables of data is output for each condenser. The data includes gas and liquid temperatures, composition of liquid and gas streams, concentrations of all chemical species in both liquid and gas, and mass flow rates at specified depths through the packing.

The input files for the model were based on existing plant operating data adjusted for the expected changes in the steam supply. The design steam flow to the unit was 1.32 million lbs/h. The incoming noncondensable loading was estimated to be 19,000 lbs/h. Gas composition (mole %) is 70% CO_2, and 5% H_2S, with the remainder made up of hydrogen, nitrogen, and methane.

Model Results -Thermal

The model was used to size the new three stage gas removal system. Predicted suction conditions for each stage were used to purchase new air ejectors and to coordinate with Barber Nichols.

Model Results - Chemical

The NREL model predicted significant changes in H_2S absorption with the modified condenser design. These changes impacted the amount and location where H_2S is absorbed within the condenser system. The model predicted that 95% of the incoming H_2S in the main condenser partitions into the noncondensable gas stream. Typical pre modification partitioning values were 65 %. Also, the greatest amount of H_2S absorption is no longer expected to be in the main condenser but in the second inter condenser and the after condenser. Less than 48 lb/h of H_2S, which is less than the Unit 11 regulatory compliance value, was predicted to accumulate in the main condenser condensate.

The increased H_2S concentration in the second intercondenser and after condenser condensate presented the opportunity for a more effective approach to H_2S abatement. The combined condensate from the second inter condenser and the after condenser is piped halfway down the length of the cooling tower through a submerged header in the cooling tower basin. The condensate is released into the basin near the point where quench water from the vent gas incinerator is returned to the basin. New baffling in the basin redirects the flow of the H_2S rich condensate and the SO_2 rich quench water toward the back of the cooling tower where it is mixed with circulating water. The circulating water containing iron chelate is also saturated with oxygen which helps to drive the reaction chemistry towards completion. Piping the combined condensate in this manner increased the residence time by a factor of 10. The net effect is that the H_2S abatement can be accomplished with less iron because the increased residence times allows the iron to be used multiple times.

Test Results - Thermal

A pre modification performance test was run in February 1996 with data taken at six power levels. A similar four point post modification test was run in May 1997 with the turbine compressor in service. Table 1 compares some of the critical parameters. Only three of the six pre modification test points are shown for clarity. The design column lists values that were input to or calculated by the NREL model. It should be noted that Unit 11 typically has enough steam avalable for 76 to 80 megawatts of load when all neighboring units are operating. The 87 megawatt test point was reached because several adjacent units were shut down for maintenance during the post modification test.

Significant reductions in backpressure, steam rate, vapor carryover, and auxiliary steam consumption were realized. Of particular interest is the large reduction in vapor carryover to the gas removal system due to the installation of the counter flow gas cooler sections. The vent gas approach temperature (VGA) reflects this improvement, with vent gas temperature typically only 9 degrees F above the cooling water temperature. Prior to the modification, vent gas temperature would typically be within 3 to 4 degrees of the hotwell temperature.

However, condenser performance was found to be limited due to an off gas flow restriction at the turbo compressor. Condenser backpressure and terminal temperature difference (TTD) would be even lower were it not for this restriction.

Figure 5, a plot of main condenser backpressure versus off gas volume flow leaving the condenser, illustrates the condenser venting situation. The following curves are included on the figure:

- **Ejector Design Curves:** Old (pre modification) and new (post modification) first stage ejector suction volume flows are shown. They were derived from manufacturer's curves at constant design suction temperature.
- **Pre modification vent characteristic curve:** At high backpressure, this curve approaches the effective volumetric capacity of the old ejectors. The fall off at lower backpressure is due to piping losses between the main condenser and the first stage suction. This curve is based on the six pre modification test points. The three test points closest in load to three of the four post modification test points are shown on this curve for reference.
- **Post modification potential vent flow curves:** These four curves show potential volume flow as a function of condenser pressure at the particular post modification test conditions (gas flow, water vapor flow, and mixture temperature). Post modification test points indicate the actual

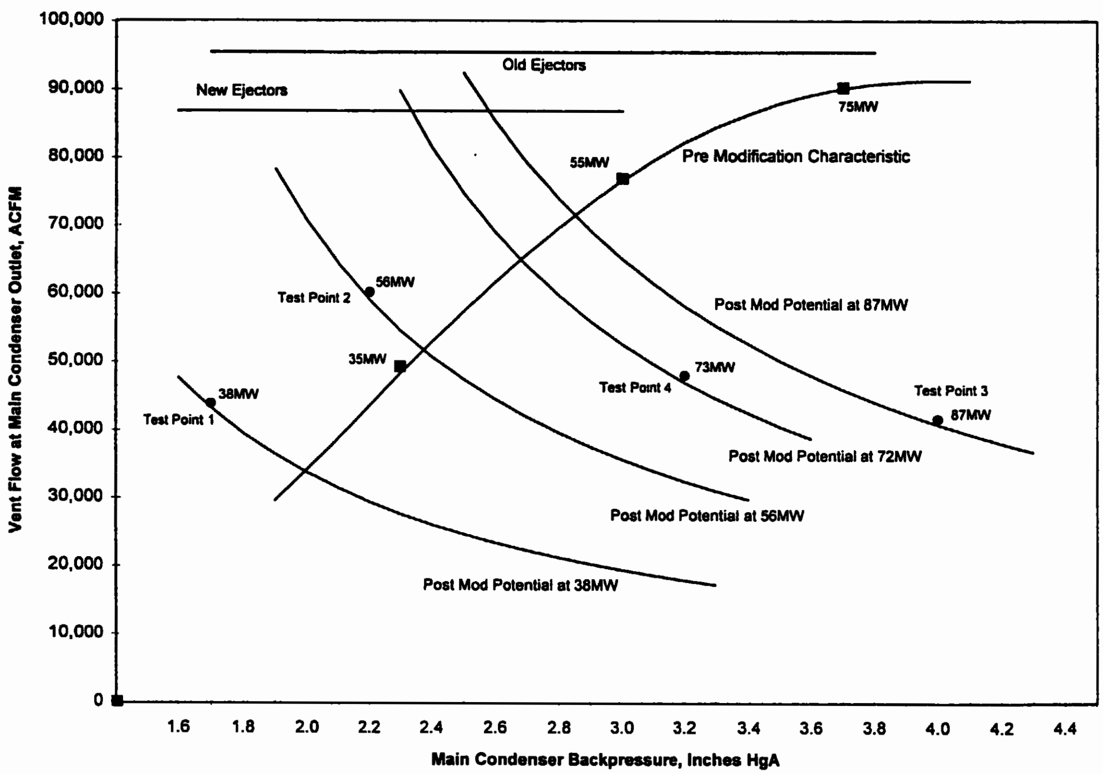

Figure 5. Unit 11 main condenser vent curves.

volume flow leaving the main condenser. They are labeled according to plant load.

In all cases, the water vapor carryover flow was calculated using the partial pressures of the water vapor and gas mixture. Pre modification potential vent flow curves are not shown for clarity

The relative locations of test points 1 and 2 (38 and 56 MW) versus test points 3 and 4 (87 and 73 MW) on their respective potential curves illustrates the venting limitation. Test points 1 and 2 approximate the pre modification vent characteristic. Test points 3 and 4 have slid down their potential curves, indicating a vent flow problem. Consequently, the exact shape of the post modification characteristic curve is unknown.

Even with the existing vent limitation, the condenser and gas removal modifications have significantly improved plant efficiency. The reduction in auxiliary steam use has yielded an equivalent of 3 megawatts of additional generation. Of this 3 megawatts, approximately 1 megawatt can be attibuted to the turbine driven condenser. Improved backpressure has resulted in an additional 1.5 MW at the 73 MW (test point 4) load point.

Figure 5 can be used to estimate additional load due to improved backpressure if the vent limitation did not exist. At the 73 MW load point (test point 4 on Table 1) the potential vent curve and the vent characteristic intersect at 2.7 "HgA. At this backpressure, an additional 2 MW would be realized.

The vent limitation is centered at the third stage turbo compressor. The most probable cause is high water vapor carryover from the upstream direct contact inter condenser. PG&E and Barber Nichols are currently investigating this situation. Also, the compressor speed was limited to 17,000 rpm during the post modification test due to high bearing vibration. Typical operating speed is 18,000 rpm. This reduced speed also contributed to the vent limitation.

Table 1. Unit 11 Condenser Retrofit Summary.

Line	Parameter	Units	Test Data				Design	Comments
1	Pre modification Test Number		6	5	7			
1a	Post modification Test Number		1	2	4	3		
2	Unit Gross Load	MW	35.1	54.8	74.6			
2a			38.3	55.8	73.4	87.4		
3	Condenser Backpressure	"HgA	2.32	2.95	3.71			
3a			1.68	2.25	3.17	3.96	2.4	
4	Gross Steam Flow	klb/hr	785	1,091	1,415			
4a			665	1,022	1,298	1,609	1,320	
	Non Condensable Gas Flow	klb/hr	8.4	12.5	16.7			Based on net steam flow to turbine
5			8.1	12.6	14.8	18.3	19.0	
6	Vapor Carryover	lbH2O/lbgas	0.6	0.9	1.1			
6a			0.3	0.4	0.4	0.3	0.5	
7	Cooling Water Temperature (Tcold)	Deg F	68.6	72.5	75.2			
7a			64.6	72.0	77.4	78.7	72	
8	Terminal Temperature Difference	Deg F	15.4	12.3	11 0			TTD = Tsaturation@backpressure - Thotwell
8a			12.4	8.2	7.9	8.9		
9	Vent Gas Approach	Deg F	15.6	26.3	33.3			VGA = Toffgas - Tcooling water
9a			0.5	6.1	9.7	9.3	11.0	
10	Unit Steam Rate	lb/kwhr	22.4	19.9	19.0			Gross Stm / Gross MW
10a			17.4	18.3	17.7	18.4		
11	Auxiliary Steam Flow	klb/hr	165	166	152			Wedge meter reads high: Deltas OK
11a			85	87	79	84		
12	Turbine Steam Rate	lb/kwhr	17.7	16.9	16.9			Net Steam Flow / Gross MW
12a			15.1	16.8	16.6	17.4		
13	Turbine Stm Rate (corrected to 4"hg)	lb/kwhr	20.1	18.2	17.3			Adjusted with Turbine Curves
13a			19.1	18.9	17.6	17.5		
14	Load from Aux Steam Reduction	MW			3.1			(Delta Aux Stm / Turb Stm Rate) x 0.7
15	Load from Lower Backpressure	MW			1.5			Based on turbine curves with adjustments for cooling water temp and net stm flow
16	Est. Additional Load w/o vent limitation	MW			2.0			Same as line 15 plus Figure 5

Test Results - Chemical

PG&E has been able to reduce iron chelate consumption by approximately 50% to date. Additional Iron chelate optimization tests are planned in order to determine under what conditions iron chelate consumption may be further reduced.

As of the publication date of this paper, PG&E has not been able to verify the amount of H_2S absorbed in to the circulating water at each of the condensing vessels. However, the 50% iron chelate reduction would suggest that the NREL model is accurate in this regard. These tests are planned for the near future at which time the test results will be compared to the NREL model.

Conclusion

The condenser modifications have improved plant conversion efficiency and reduced H_2S abatement chemical costs. Improved efficiency due to lower backpressure at a given steam and gas load plus lower auxiliary steam consumption has reduced the plant steam rate by 6%. The NREL model has accurately predicted the amount of vapor carryover from the modified condenser. The shift in H_2S absorption location plus the improved treatment of the H_2S rich condensate in the cooling tower basin has allowed a 50% reduction of iron chelate concentration in the circulating water.

The authors wish to thank Desikan Bharathan of NREL for his work during the modeling phase and his support and advice during the construction phase of the project.