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PROJECT DEVELOPMENT DESERT PEAK
9 MW POWER PLANT

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ABSTRACT

In late 1982 Phillips Petroleum Company began preliminary design of a power plant for Desert Peak in Churchill County, Nevada. Like all geothermal resources and projects Desert Peak is unique and required careful consideration of existing process schemes and design technologies. This paper is limited to discussing the evolution of surface facilities design and will not attempt to review geological aspects of the resource. Although specific conclusions may not be applicable to other projects, process and design considerations discussed in this paper should be reviewed to ensure maximum conversion efficiency for any new facility.

INTRODUCTION

Phillips Petroleum Company has obtained approximately 24,000 acres of Federal and Southern Pacific Railroad leases in the Brady-Hazen Known Geothermal Resource Area (KGRA), an area commonly referred to as Desert Peak. This medium temperature hot water dominated resource is located in arid rolling desert of the Hot Springs Mountains, 65 miles northeast of Reno, Nevada. After preliminary evaluations of the resource, Phillips began in late 1982 a comprehensive study of alternatives which ultimately resulted in the current 9 MW facility design.

Process Parameters

Table 1 shows process parameters utilized for Desert Peak.

Table 1

Production Well Characteristics

Average flowrate per well	500,000 lbm/hr.
Average wellhead temp	326°F
Average wellhead pressure	97 PSIA
Average resource temp	400°F
Average resource enthalpy	384 BTU/lb
Steam flash by mass	9.9%

Because of the desert conditions, temperature fluctuations were rapid and had a great range from day to night and summer to winter. Fourteen years of weather data from Fallon, Nevada (approximately 20 miles S.E. of site) were reviewed and are summarized in Table 2.

Table 2

Average Mean Temperature Summary
(January 1949 to January 1963)

	Summer July	Winter January
Dry bulb temp		
Daytime high	92°F	42°F
Nighttime low	60°F	22°F
Day to night range	32°F	20°F
Wet bulb temp		
Daytime high	62°F	35°F
Nighttime low	51°F	20.5°F
Day to night range	11°F	14.5°F

Studies

The design philosphy stated the facility should, at a reasonable cost, convert geothermal energy to electricity at the highest conversion rate; provide a means to develop resource data and utilize an existing conversion technology. In order to implement this philosophy several detailed studies were required. Each study was based upon existing conditions at Desert Peak.

Cooling Towers vs. Air Fin Exchangers

Two criteria were selected to evaluate cooling systems. The first criteria was cost. Operating costs were evaluated as KWH required during operations. Water treatment costs were not considered significant unless a non-condensing turbine or a binary process was used. These costs were more applicable to the selection of a process than to the selection of a cooling system. Table 3 shows design criteria for a cooling system.

Table 3

Summer Conditions

Ambient air temperature	92°F
Wet bulb temperature	62°F
Fluid to be cooled	Water
Process heat load BTU/hr	180,000,000
Difference between inlet and outlet of cooling unit	40°F

Table 4 reflects design and cost data developed for both systems. Air fin exchangers were designed and costs estimated by Phillips Petroleum Company. Design specifications for the cooling tower were developed by Phillips while the final design and costs were provided by Marley Cooling Tower Company.

Table 4

Air Fin/Cooling Tower Cost Comparison

	Capital Cost	Operating Cost KWH
Air Fins (14 Sections)	$1,300,000	920 - Air fin fans
		409 - Reinjection pumps
		180 - Spray condenser pumps
		1,509 - Total KWH
Cooling Tower (2 cells)	$390,000	118 - Cooling tower fans
		341 - Reinjection pumps
		157 - Spray condenser pumps
		140 - Cooling tower pumps
		756 - Total KWH

The second criteria was the impact of a cooling system on process performance. For a given process, air fin exchangers and cooling towers will respond to ambient air conditions differently. Air fin exchangers can return a fluid to the process at T = dry bulb ^oF + 15^oF. Cooling towers will respond differently returning a fluid to the process at T = wet bulb ^oF + 5^oF. Table 5 shows the effects of different cooling systems for Desert Peak as calculated by Desert Peak Simulator Series F (DPSIMF).

Table 5

Air Fin/Cooling Tower Electrical Power Production Comparison

Conditions	Air Fin	Cooling Tower
Ambient air temp	92^oF	92^oF
Wet bulb temperature	NA	62^oF
Approach temperature	15^oF	5^oF
Cooling water to process	107^oF	67^oF
Cooling water from process	147^oF	107^oF
Electrical Power		
Gross Power Output KWH	7279	10022
Parasitic KWH	1509	756
Net Power for Sale KWH	5770	9266
Difference	(3496)	
Effectiveness	62%	

Cooling towers would also be more effective for a binary system at Desert Peak because the lower cooling water temperatures would allow condensing of the binary fluid at a lower pressure thus providing greater expander output. When a binary system is utilized, the cooling water make up can be a problem; therefore, additional costs of water treating must be considered.

Two Phase Flow vs Wellhead Separation

A drop in the high pressure steam pressure will reduce power generated. Two phase flow and well head separator systems were studied to determine which could provide the lowest pressure drop at the lowest investment and operating costs. Program P0038 utilizing the Taitel-Duckler correlation indicated wave flow in large diameter pipes was the best method of conserving limited wellhead pressure. Large diameter pipe (24 in and 30 in) also allowed intermittent operation of wells without changing flow regimes. Wellhead separation with individual brine and steam lines could be designed for a minimum pressure drop, however, line sizes were in the 14 in to 16 in range. When lines were reduced to a more economical size, 12 in., the pressure drop exceeded that calculated for a two phase system. Two phase flow was selected because operating and investment costs were reduced by eliminating wellhead separators. By locating the plant downhill of the production wells and insuring there were no pockets in the line; damage due to slug flow was eliminated. Large diameter pipes also assisted in separating fluids.

Floating Power

At Desert Peak, daily and annual temperature ranges as indicated in Table 2 are great; therefore, a study was initiated to determine the effects of "floating power". Floating power means that equipment is sized to take advantage of temperature ranges. As the cooling system responds to lower temperatures more horsepower can be developed by the turbine or expander and more power can be generated. Floating power can be demonstrated by the following example:

Floating Power

Determine the net output and percentage increase in output when a facility designed for a constant 10 MW is allowed to float. To assure 10 MW at all times the system must be designed for summer conditions shown in Table 3. When floating power is considered, the production rate remains constant; however, temperature fluctuations are reflected by annualized mean termperatures. Table 6 summarizes design conditions and power output.

Table 6

Constant Power/Floating Power Comparison

Conditions	Constant Power	Floating Power
Production rate lbm/hr	1,086,000	1,086,000
Cooling Water to Process	$67^oF^{(1)}$	$53^oF^{(2)}$
Cooling Water from Process	$107^oF^{(1)}$	$93^oF^{(2)}$
Electrical Power		
Net Power KWH	10,000	11,050
Percent increase		10.5%

(1) Summer conditions
(2) Mean annual

The incremental increase in capital and operating costs associated with floating power for Desert Peak was less than the benefits derived from a 10.5% increase in net power available.

Process Selection

Simultaneous with the previously-discussed studies, a comparison of existing processes was conducted. First binary and Biphase were compared for initial Desert Peak premises. Among these premises was an increased flow rate of 1,500,000 lbm/hr from three production wells. This increased the power generated to nearly 14 MW gross and required two injection wells.

Binary Process

Figure 1 shows the process schematic which evolved from review of three configurations. Wellhead separation with a single heat exchanger train located at the plant was selected because of lower capital cost, maintenance considerations and operational advantages. The other configurations were wellhead separation with individual heat exchanger trains for each production well and central separation (two phase gathering system) with a single heat exchanger train. A cooling tower was used to take advantage of low wet bulb temperatures. To increase the conversion efficiency of the cycle both steam and brine were utilized in the vaporizer train and condensate produced was used as cooling tower make up. Because of the chemical composition of the brine, the remainder of the required make up water was obtained by cooling brine in a multiple pond system. Additional studies revealed a blend of hydrocarbons would improve cycle efficiency over the use of pure isobutane.

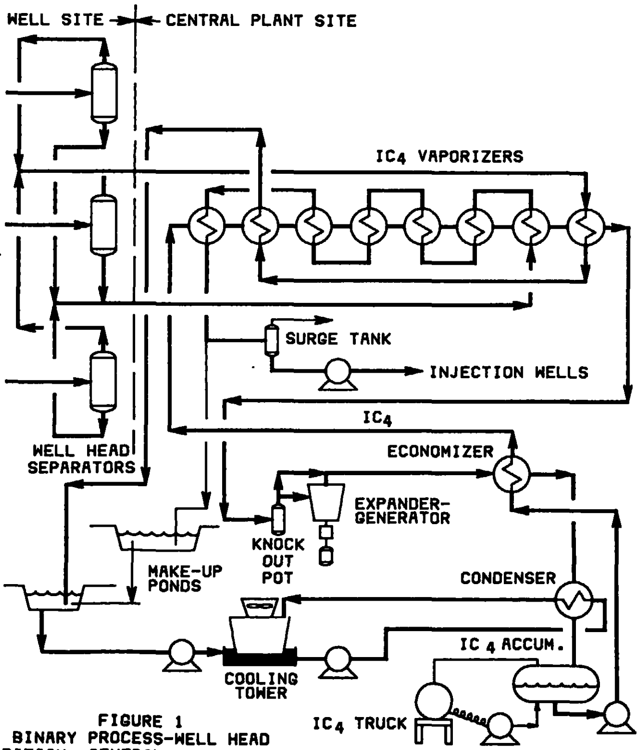


FIGURE 1
BINARY PROCESS-WELL HEAD SEPARATION, CENTRAL HEAT EXCHANGER

Biphase Process

Figure 2 shows the process schematic for the Biphase system which consisted of wellhead separation, two Rotary Separator Turbine (RST) power skids and a cooling tower. Two RST power skids were required to accommodate 1,500,000 lbm/hr of production. Because one production well was located downhill of the plant, wellhead separation was required to achieve the lowest gathering system pressure drop.

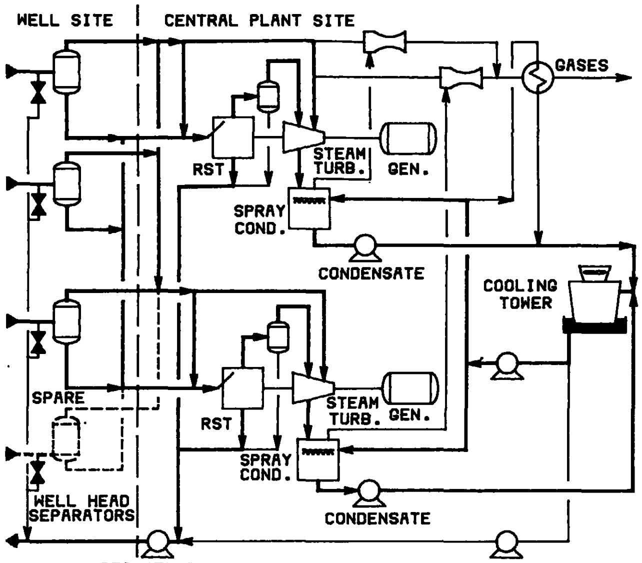


FIGURE 2
2 MODULE BIPHASE
PROCESS FLOW DIAGRAM

Binary vs Biphase

The Biphase process was selected at Desert Peak primarily because it produced more net power at a lower capital cost. Table 7 summarized both processes.

Table 7

Binary/Biphase Comparison

	Binary	Biphase
System Characteristics		
Well flow lbm/hr	1,500,000	1,500,000
Isobutane flow lbm/hr	2,026,000	
Cooling water circulation rate lbm/hr	12,865,000	6,488,620
Electrical Power		
Gross MW	15.08	13.46
Parastic MW	4.10	1.40
Net for sale MW	10.98	12.06
Conversion Efficiency		
Net	7.09%	7.32%
Estimate Cost Differential (1982 costs)	$ 7,200,000	-0-

Other advantages of the Biphase system included:

1. Lower expected maintenance costs.
2. No fire hazard associated with hydrocarbons.
3. Less potential for silica scaling.
4. No concern for cooling water make up chemistry because it was all condensate.

Biphase vs Dual Flash

A brief review of a dual flash process indicated the Biphase system would always produce more power. This power is directly related to the energy dissipated by the inlet control valve of the low pressure separator. At Desert Peak this was approximately equal to the parasitic power.

Current Design

The current design is the result of implementing the conclusions of previously discussed studies and several premise changes. One of the major premise changes was the reduction in the number of production wells from three to two which limited the process flow rate to 1,000,000 lbm/hr. Figure 3 shows the 24 in. and 30 in. two phase gathering system with the plant located at the lowest elevation. As shown by Figure 4 geothermal fluids are separated into high pressure steam and brine in the high pressure separator. High pressure steam flows through a knock out vessel to the steam turbine inlet. Brine from the high pressure separator is divided between the RST and the low pressure separator. Because of low system pressure, the RST cannot process all brine produced in the high pressure separator. Excess brine is flashed in the low pressure separator. Low pressure steam from the RST and low pressure separator enters the steam turbine after any excess moisture is removed by a knock out vessel. Steam at less than atmospheric pressure is discharged from the steam turbine into

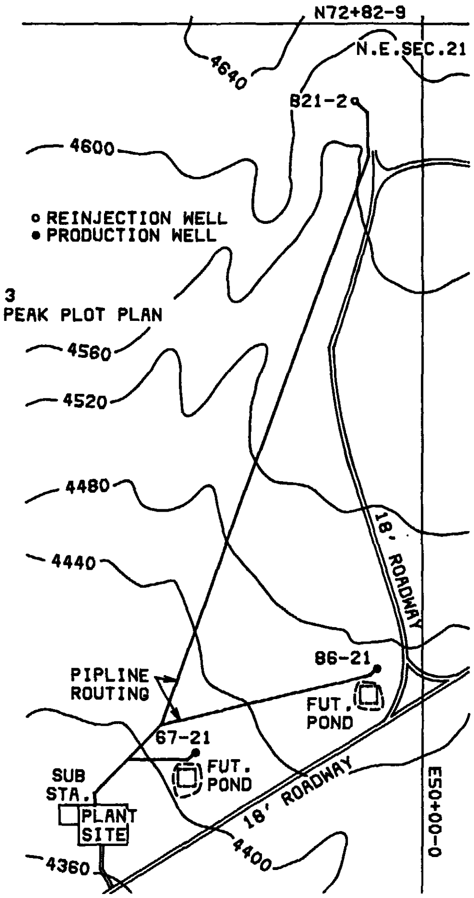
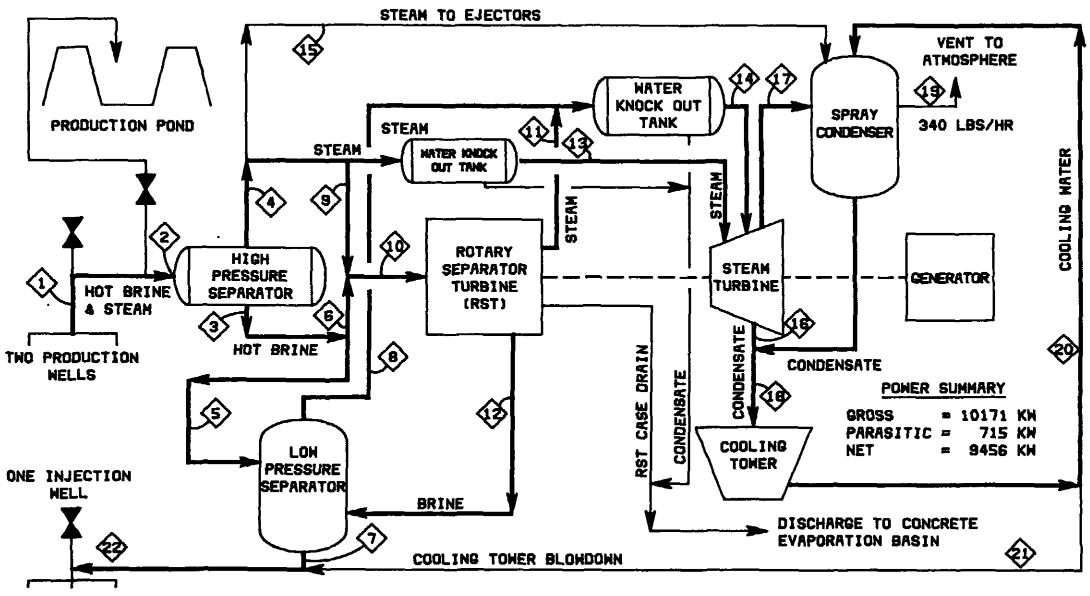


FIGURE 3
DESERT PEAK PLOT PLAN



DESCRIPTION	GEOTHERMAL RESOURCE	FEED	H.P. SEPARATOR LIQUID	H.P. SEPARATOR STEAM	FEED TO L.P. SEPARATOR	LIQUID TO RST	L.P. SEPARATOR LIQUID	L.P. SEPARATOR VAPOR	H.P. RST CONTROL STEAM	TOTAL FEED TO RST	RST OUTLET STEAM	RST OUTLET LIQUID	H.P. STEAM TO TURBINE	L.P. STEAM TO TURBINE	H.P. STEAM TO EJECTORS	LIQUID FROM STEAM TURBINE	VAPOR FROM STEAM TURBINE	LIQUID TO COOLING TOWER	COOLING WATER TO SPRAY COND.	COOLING TOWER BLOWDOWN	RE-INJECTION LIQUID
STREAM NUMBER	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	21	22
LIQUID LBS/HR $(X10^3)$	901	894.4	894.4		84.1	810.3	809.2			807.2		733.3				21.5		3548	3357	24.1	833.3
STEAM LBS/HR $(X10^3)$	99	105.6		105.6				8.2	13.4	16.5	90.4		87.2	98.6	5.0		164.3				
PRESSURE (PSIA)	97	89	89	89	89	89	20	20	89	85	20	41	89	20	89	1.1	1.1				
TEMPERATURE (°F)	326	319.5	319.5	319.5	319.5	319.5	228	228	319.5	316	228	228	319.5	228	319.5	105	105	105	53	53	224

FIGURE 4
9 MW PROCESS FLOW AND MATERIAL BALANCE

a direct contact spray condenser where vacuum is provided by steam ejectors. Heat is rejected through a cooling tower and make up for the system is condensate. Brine from the RST flows to the low pressure separator. The injection system includes the discharge from the second stage separator, cooling tower blow down, injection pumps and an injection well. Figure 5 shows the plant layout.

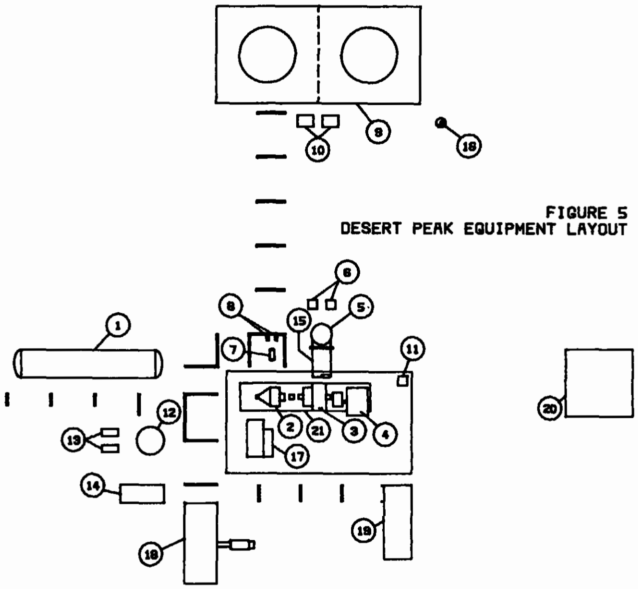


FIGURE 5
DESERT PEAK EQUIPMENT LAYOUT

1. HIGH PRESSURE SEPARATOR
2. ROTARY SEPARATOR TURBINE
3. DUAL STAGE STEAM TURBINE
4. ELECTRICAL GENERATOR
5. DIRECT CONTACT SPRAY COND.
6. CONDENSATE C.W.PUMPS
7. TURBINE DRAIN TANK
8. DRAIN TANK PUMPS
9. COOLING TOWER
10. COOLING TOWER WATER PUMPS
11. NEUTRAL GROUNDING RESISTORS
12. LOW PRESSURE SEPARATOR
13. REINJECTION PUMPS
14. PACKAGED INST. & TOOL AIR SKID
15. TURBINE EXHAUST DUCT
16. VENT STACK
17. LUBE OIL SKID
18. POWER HOUSE & SWITCHGEAR BLDG.
19. CONTROL ROOM & OFFICE
20. RST DRAIN POND
21. PACKAGE POWER GENERATION SKID

Rotary Separator Turbine Power Skid

The conversion of wellhead flow enthalpy to electrical power is performed on the power skid. The power skid is a self contained assembly of the Transamerica Delaval Biphase Energy Systems' rotary separator turbine, steam turbine and electrical generator. These components are mounted on a 13 by 56 foot structural steel skid which weighs 260,000 lbs. The skid can be split between the turbine and generator for ease of shipment and assembled in the field by means of a doweled and machined joint. Installed on the power skid is piping which distributes liquid from high pressure separator to four inlet nozzles of the rotary separator turbine. The RST shaft power output of 656 KW at 1020 rpm is transmitted through a speed increasing gear to a 3600 rpm steam turbine. The combined shaft power of 10171 KW is transmitted through a second gear type speed reducer to the 1800 rpm generator. The generator is an induction type unit rated at 11 megawatts, 138 KV, 3 phase 60 HZ.

The rotary separator turbine is of the design previously tested at Roosevelt Hot Springs, Utah in a program jointly supported by EPRI, Utah Power and Light Company and Phillips Petroleum Company. The results were reported in Reference 3 for a 4000 hour test completed in March 1983. The test was conducted with a design flowrate of 515,000 lbm/hr, a two-phase input of 400 psia and 8 percent inlet steam quality. The internal configuration of the five primary RST components is shown in Figure 6. There are four nozzles which expand inlet flow from wellhead pressure to steam turbine inlet pressure. Nozzle flow impinges on the separator rotor resulting in centrifugal separation of steam and liquid. Steam spirals into the 24-inch diameter exit duct. Liquid flow on the separator rim is removed by the liquid turbine which converts flow kinectic energy to shaft torque. The liquid is discharged from the liquid turbine with sufficient kinetic energy to drive the liquid transfer rotor. This rotor, with a stationary diffuser flow pickup converts remaining liquid kinetic energy to pressure.

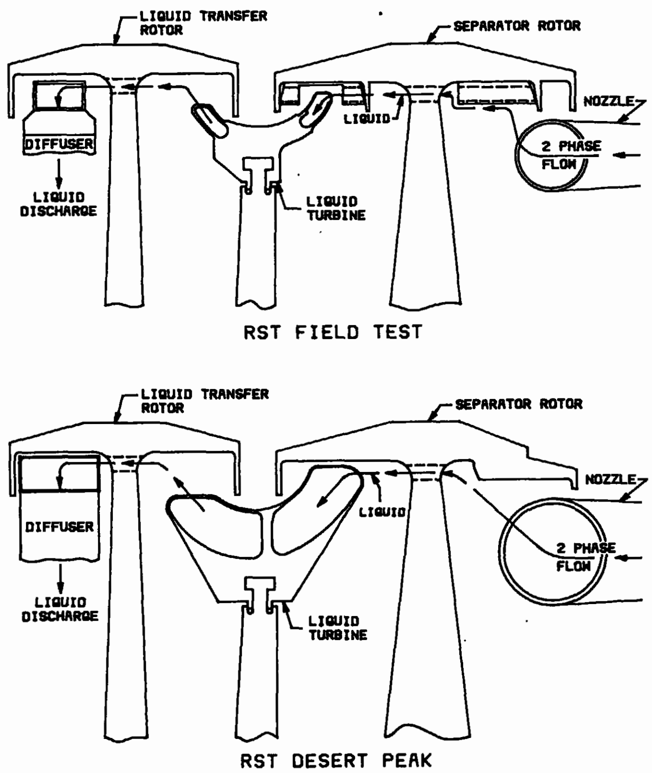


FIGURE 6
RST DESIGN

For Desert Peak the rotary separator turbine flow capacity was increased from 550,000 to 830,000 lbm/hr by replacement of the interchangeable nozzles, liquid turbine element and diffuser as shown in Figure 6. With this configuration the two-phase jet leaves the nozzles at 520 ft/sec and drives the separator rotor at 1766 rpm. Liquid coalesces to form a film depth of 1.0 inches on the separator rim due to centripetal acceleration of 2300 g's. The liquid layer submerges the inlet of the liquid turbine to a depth of one inch. The liquid turbine is constrained to rotate at 1020 rpm by the generator connection to the grid. Liquid enters the liquid turbine with an absolute velocity of 416 ft/sec which is 187 ft/sec relative to the turbine and leaves with a reduced velocity of 159 ft/sec due to losses after a 180 degree flow direction reversal within the liquid turbine element. The absolute velocity of the liquid leaving the liquid turbine is 70 ft/sec. This liquid jet causes the liquid transfer rotor to rotate at 270 rpm. The liquid layer develops to a depth of 1.5 inches and submerges a stationary diffuser. The diffuser picks up the liquid through a sharp edged inlet apperature which is 1.65 inches high by 3.75 inches wide. The flow channel diverges with a 7.5 degree angle to a flow area of 28 square inches. This flow divergence within the diffuser serves to convert remaining liquid kinetic energy to static pressures up to 90 psia.

The horizontally split upward exhaust steam turbine is an induction-condensing type with high pressure steam inlet of 89 psia, low pressure steam inlet of 20 psia and exhaust pressure of 1.1 psia. The steam flow path consists of four impulse and five reaction stages with interstage moisture removal. Bearings are of the tilting pad type, pressure lubricated and installed in the horizontally split housing. The turbine is rated at 9515 KW at 3600 rpm with inlet flowrates of 87,200 lbm/hr at 89 psia and 98,600 lbm/hr at 20 psia.

Control of the power plant is provided by operators in a control room adjacent to the power skid. There are five primary control loops provided to achieve proportional process control. The process controls provide the capability of establishing and maintaining wellflow through the separators independent of the power train. In the event of loss of generator load, the control system closes the inlet valves on the RST and steam turbine. In addition, steam is vented through a control valve to maintain constant flowrate while the liquid out of the low pressure separator is diverted to the injection system under control of the liquid level controller.

A throttle valve is installed on the high pressure inlet to the steam turbine to control speed during turbine start up and limits flow above the maximum power rating. In normal operation, the RST and steam turbine are expected to operate base loaded with wide open throttles. For off design operation a control provision is included to adjust steam pressure between the RST and steam turbine induction port in order to adjust RST separator rotor speed.

Estimates of wellhead powerplant performance have been prepared to cover a range of geothermal resources or more specifically wellhead enthalpies from 320 to 500 Btu/lbm. Assumptions used pure liquid thermodynamics properties with noncondensible loading of .5% of total flow and steam turbine exhaust pressures at the condenser inlet of 2.5 in. hg. For the RST system with a dual admission steam turbine operating on one million lbm/hr total flow the power increases from 4.8 megawatts to 15 megawatts for a resource enthalpy increase from 320 to 500 Btu/lbm. For Desert Peak with a 384 BTU/lbm enthalpy, net output power is 10.03 megawatts per 10^6 lbm/hr. Figure 7 compares these performance predictions to conventional optimized single-stage flash systems and shows a performance advantage of 20 to 35 percent.

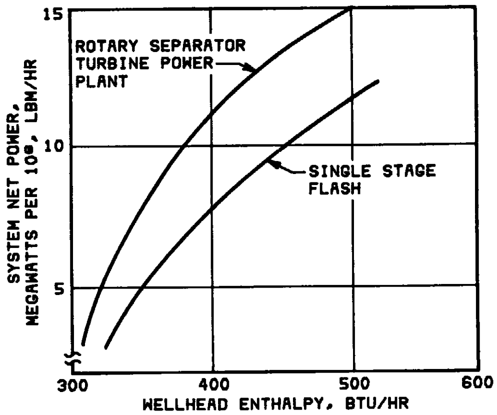


FIGURE 7
RST AND SINGLE FLASH POWER OUTPUT

SUMMARY

At Desert Peak, studies indicated cooling towers, a two phase gathering system and a Biphase process utilizing floating power would produce the most power per pound of geothermal fluid. In order for Geothermal to be competitive with other forms of energy, power plant design must convert wellhead enthalpy to electricity with the highest efficiency. To accomplish this, careful consideration should be given to cooling system selection; plant layout, production well locations, floating power potential and process selection. These criteria should be reviewed before negotiations for sale of electricity or geothermal fluids are complete.

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