

CHAPTER 7

Energy Conversion Systems – Options and Issues

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7.1 Introduction

This section presents energy conversion (EC) systems appropriate for fluids obtained from Enhanced Geothermal Systems (EGS). A series of EC systems are given for a variety of EGS fluid conditions; temperature is the primary variable and pressure is the secondary variable.

The EC systems used here are either directly adapted from conventional hydrothermal geothermal power plants or involve appropriate modifications. In certain cases, ideas have been borrowed from the fossil-fuel power industry to cope with special conditions that may be encountered in EGS fluids.

Several applications are considered. These range from existing “targets-of-opportunity” associated with the coproduction of hot aqueous fluids from oil and gas wells to very hot, ultra-high-pressure geofluids produced from very deep EGS reservoirs. Although electricity generation is our principal goal, we also discuss direct-heat applications and cogeneration systems, which use the available energy in the EGS fluid for electricity generation and direct heat.

Thermodynamic analyses are carried out, sample plant-flow diagrams and layouts are presented for typical applications at both actual and hypothetical sites, and estimates are made for the capital cost of installing the power plants.

7.2 Electric Power Generation

To cover a wide range of EGS fluids, we consider five cases of a geofluid at the following temperatures:

(1) 100°C; (2) 150°C; (3) 200°C; (4) 250°C; (5) 400°C.

In most – but not all – cases, pressures are assumed sufficient to maintain the geofluid as a compressed liquid (or dense, supercritical fluid) through the EGS reservoir and well system, and up to the entry to the power-generating facility.

For each case, we have:

- (a) Identified the most appropriate energy conversion system.
- (b) Determined the expected net power per unit mass flow in kW/(kg/s).
- (c) Determined the mass flow required for 1, 10, and 50 MW plants.
- (d) Estimated the installed cost of the power plants.

Table 7.1 summarizes the preferred energy conversion systems for the five cases. Note that the first two cases are relatively low-temperature applications, which may not apply to a high-temperature EGS system, but would apply instead to one of the “targets-of-opportunity” – namely, coproduced aqueous fluids from oil and gas operations. The last case is that of a supercritical dense fluid that could present engineering and economic challenges owing to the high pressures involved, necessitating expensive heavy-duty piping and other materials.

Although we suggest using a binary cycle with a recuperator for the 150°C resource, we did not incorporate a regenerator in the cycles we examined. It may be more beneficial to allow the geofluid to cool to as low a temperature as possible, if the binary plant is to be used with an EGS reservoir. This will enhance the gravity head through the well-reservoir system and improve the natural circulation.

The 200°C case lies on the border between the binary and flash systems, and we show both as possibilities. If a binary cycle is chosen, the working fluid should be operated at supercritical pressure to obtain the optimum performance.

Table 7.1 Summary of energy conversion systems.

Geofluid temperature, °C	Energy conversion system	Typical application	Working fluid	Cooling system
100	Basic binary	O&G waters	R-134a	Water (evaporative condenser)
150	Binary w/recuperator	O&G waters	Isobutane	Air
200	Binary or Single-flash	EGS	Isobutane or Geofluid	Air or water
250	Double-flash	EGS	Geofluid	Water
400	Single or triple expansion	Supercritical EGS	Geofluid	Water

7.2.1 Electricity from coproduced oil and gas operations

It has been suggested recently that there is an enormous untapped hydrothermal energy resource associated with coproduced hot waters from oil and gas operations (McKenna and Blackwell, 2005; McKenna et al., 2005). Those authors estimated that the resource potential could range from about 985 to 5,300 MW_e (depending on the water temperature), using the fluids currently being produced in seven Gulf Coast states.

Binary power plants are a well-established technology for utilizing low- to moderate-temperature geothermal fluids (DiPippo, 2004; DiPippo, 2005). Figure 7.1 shows a typical binary plant in simplified form. This type of plant is ideally suited for energy recovery from coproduced fluids.

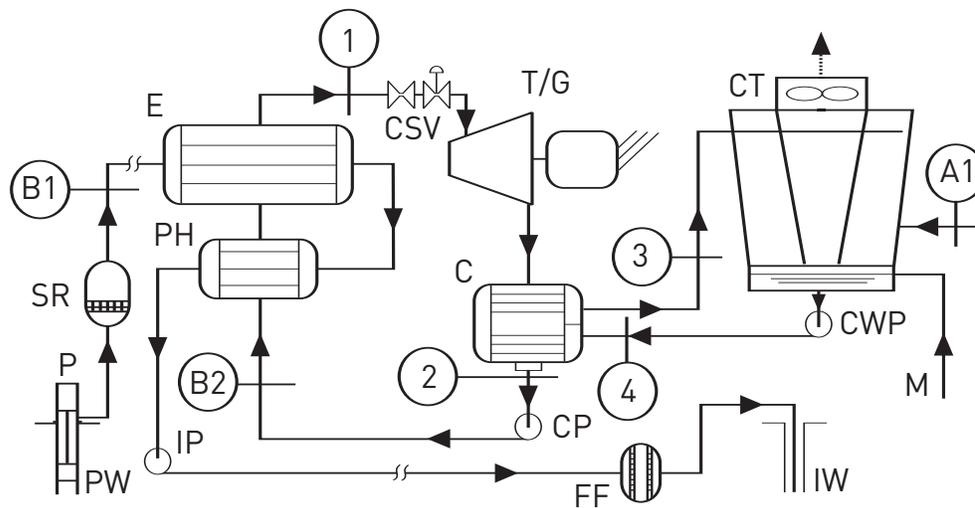


Figure 7.1 Basic binary power plant in simplified schematic form (DiPippo, 2005).

For this study, we examined this resource, beginning with a survey of current binary power plant performance, to determine the effect that geofluid temperature has on the cycle thermal efficiency. Once we found this dependency, we applied it parametrically to the known coproduced fluids in the seven Gulf Coast states included in McKenna et al. (2005), plus California. The results are presented as a function of fluid temperature because the coproduced fluids vary in temperature from field to field. Once the flow rate and the temperature are known for any site, our analysis allows an easy calculation of the electric power that can be installed. Thus, for each state, we have calculated the expected total power potential, in MW, as a function of the fluid temperature.

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This analysis is based on a correlation for the thermal efficiency derived from several actual binary plants. The thermal efficiency is defined in the standard way as the ratio of the net power output to the rate of heat input, i.e., input thermal power (Moran and Shapiro, 2004). The plants used in the correlation are shown in Table 7.2, and the data are plotted in Figure 7.2 with the correlation equation for thermal efficiency as a function of geofluid temperature. All of the plants are organic Rankine cycles (ORCs), with the Húsavík plant being a Kalina-type plant using a water-ammonia mixture as the working fluid. The data used for the efficiencies come from various sources and may be found in DiPippo (2004).

There is considerable scatter in the efficiency data because of the variety of plant configurations represented by the data. The pinch-point temperature difference in the brine-working fluid heat exchangers is an important factor in determining the plant thermal efficiency, and this value is not reported in the literature. However, for the purposes of this study, the efficiency correlation is considered accurate enough to show the dependence of binary plant efficiency on the geofluid temperature.

Table 7.2 Cycle thermal efficiencies for several binary power plants.

Plant name	Location	Brine inlet temperature, °C	Efficiency, %
Amedee	CA	103	5.8
Wabuska	NV	105	8
Brady	NV	109	7
Húsavík	Iceland	122	10.6
Otake	Japan	130	12.9
Nigorikawa	Japan	140	9.8
Steamboat SB-2 & SB-3	NV	152	8.2
Ormesa II	CA	157	13.5
Heber SIGC	CA	165	13.2
Miravalles Unit 5	Costa Rica	166	13.8

The cycle net thermal efficiency is found from the temperature of the coproduced fluid using the correlation equation shown in Figure 7.2, namely

$$\eta_{th} = 0.0935 T - 2.3266, \quad (7-1)$$

where T is in °C and the efficiency is in percent. Then, the net power output can be calculated from the geofluid inlet temperature, the geofluid outlet temperature, and the geofluid mass flow rate.

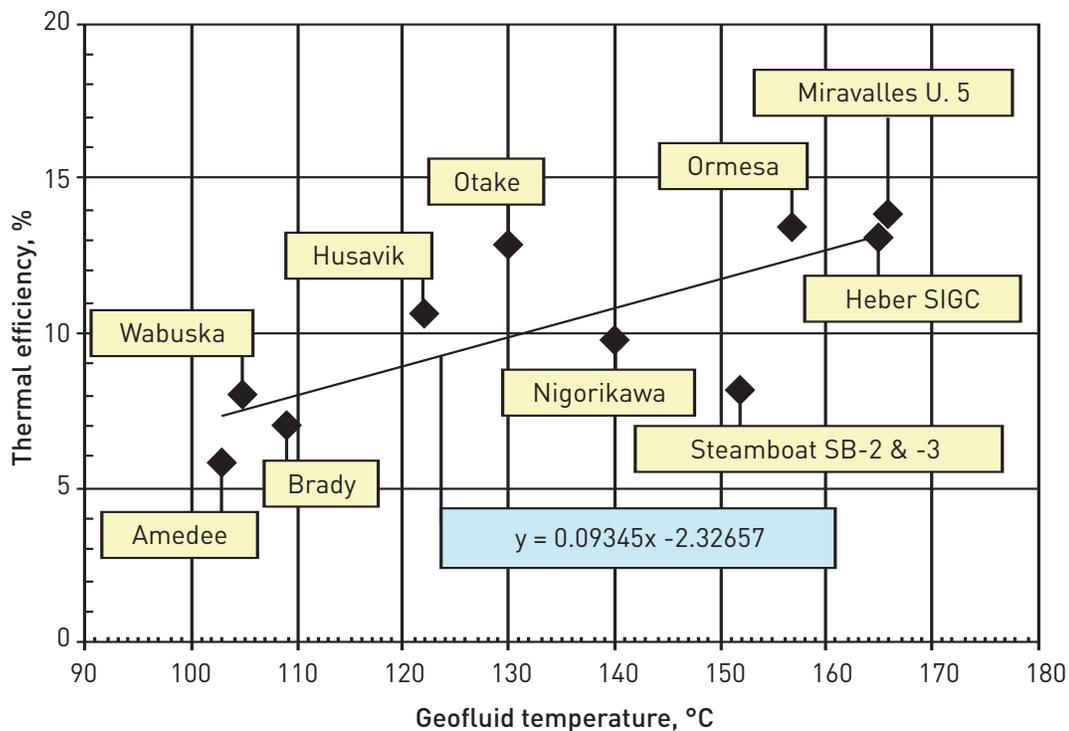


Figure 7.2 Correlation of binary plant cycle thermal efficiency with geofluid temperature in degrees Celsius (°C)

The results are presented in the form shown in Figure 7.3, where T_2 is the geofluid temperature leaving the plant. If one knows the inlet (T_1) and outlet (T_2) geofluid temperatures, the power output (in kW) for a unit mass flow rate of one kg/s can be read from the graph. The total power output can then be obtained simply by multiplying this by the actual mass flow rate in kg/s. For example, a flow of 20 kg/s of a geofluid at 130°C that is discharged at 35°C can be estimated to yield a power output of 800 kW (i.e., 40 kW/(kg/s) times 20 kg/s).

Finally, using the data from McKenna and Blackwell (2005) for the flow rates of waste water from petroleum production wells in the Gulf Coast states, plus the data for California (DOGGR, 2005), we can estimate the power that might be obtained if all the waste water were used in binary plants. The results are shown in Table 7.3 for an assumed outlet temperature of 40°C. To correct the power (\dot{W}) totals for an outlet temperature other than 40°C, one can use the following equation:

$$\frac{\Delta \dot{W}}{\Delta T_2} = 0.098701 - 0.0039645 T_1. \quad (7-2)$$

This equation was obtained from a simple fit to the calculated data and gives the change in the power output per degree Celsius change in outlet temperature as a function of the inlet temperature. Then the actual power output can be found from:

$$\dot{W}_{actual} = \dot{W}_{T_2=40C} + \frac{\Delta \dot{W}}{\Delta T_2} \times (T_2 - 40). \quad (7-3)$$

As an example, let $T_1 = 100^\circ\text{C}$. From Table 7.3, the estimated power from Alabama's waste water is 16.6 MW at $T_2 = 40^\circ\text{C}$. If $T_2 = 50^\circ\text{C}$, then from Eq. (7-2), the power gradient is negative 0.29775, and from Eq. (7-3), the actual power would be reduced to 13.6 MW. If the outlet temperature were 25°C, the power gradient would be the same, but the actual power would be increased to 21.1 MW.

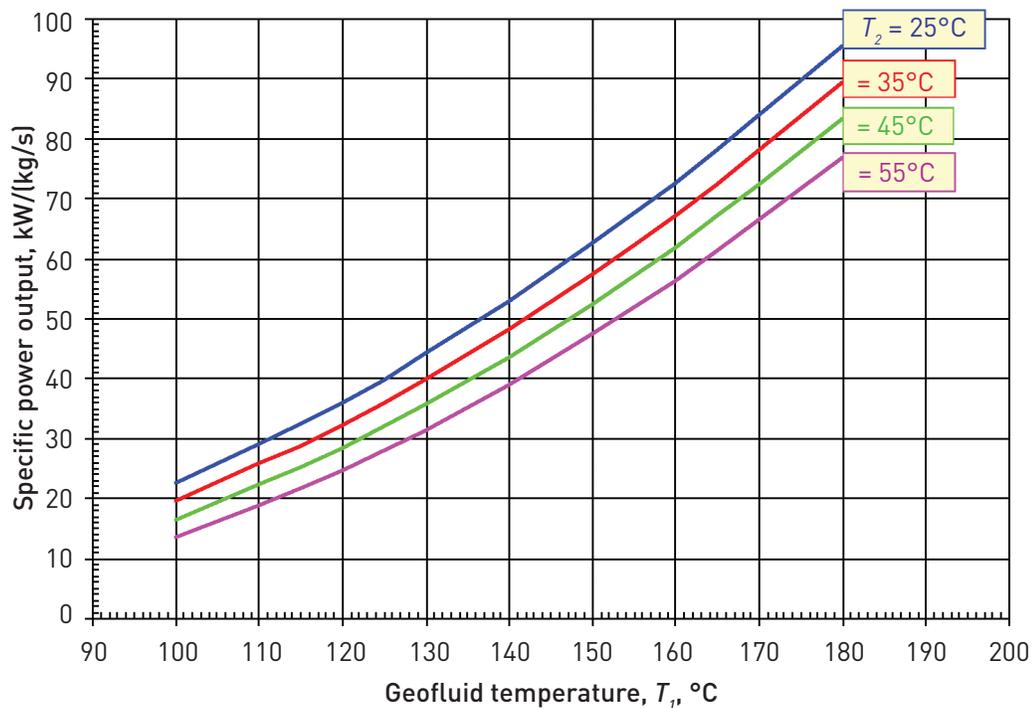


Figure 7.3 Specific power output (in kW/(kg/s)) for low- to moderate-temperature geofluids as a function of inlet (T_1) and outlet temperatures (T_2) shown in degrees Celsius ($^\circ\text{C}$).

Adopting the middle of the temperature range, we see that about 6,000 MW might be obtained today using standard binary-cycle technology from hot waters that are currently being reinjected without any energy recovery. This estimate could very well be higher because there are several other states with coproduced fluids, but we do not have sufficiently reliable data that allows us to include them in our survey.

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Finally, another case of combined use of petroleum and geothermal energy resources may be considered. The use of so-called geopressured geothermal resources was extensively studied beginning in the 1970s by the U.S. Department of Energy (DOE), the Electric Power Research Institute (EPRI), and others (see, for example, DiPippo, 2005; Swanson, 1980; and Campbell and Hatter, 1991).

A nominal 1 MW pilot plant was installed to exploit the very high-pressure, high-temperature, methane-saturated fluids that were obtained along the Gulf Coast. The plant ran from 1989-1990, and generated 3,445 MWh of electricity over 121 days of operation. This came to an average power output of 1,200 kW. The plant captured the thermal energy in the geofluid using a binary cycle, and the chemical energy in the dissolved methane by burning it in a gas engine equipped with a waste heat-recovery system. The hydraulic energy represented by the high-pressure geofluid was not recovered for power generation.

Table 7.3 Estimated power from California and Gulf states coproduced waters; outlet temperature assumed to be 40°C.

State	Flow rate, kg/s	MW @ 100°C	MW @ 140°C	MW @ 180°C
Alabama	927	16.6	42.3	79.9
Arkansas	1,204	21.6	54.9	103.7
California	2,120	37.9	96.7	182.5
Florida	753	13.4	34.3	64.8
Louisiana	9,786	175.2	446.3	842.6
Mississippi	2,758	49.4	125.8	237.5
Oklahoma	59,417	1,064	2,709	5,116
Texas	56,315	1,008	2,568	4,849
TOTALS	131,162	2,348	5,981	11,293

Although the plant performed well, such plants were not economical at the time. Recently, Griggs (2004) re-examined this subject and concluded that the time is still not appropriate for this resource to become economic, but that under the right conditions of prices for competing fuels, geopressed resources might once again be considered for power production. In 50 years, when conventional petroleum resources may be close to exhaustion, the economic conditions should be favorable for the exploitation of geopressed resources.

Coproduction from the Naval Petroleum Reserve No. 3. As an example of a resource that is currently under production for oil, we consider the case of the Naval Petroleum Reserve (NPR) No. 3, and develop a binary plant that could operate with the hot water that is now being discharged to the surface. The flow diagram is represented in Figure 7.1. The plant has been designed to conform to the resource conditions as given by Myers et al. (2001). The most appropriate cycle working fluid is R134a. The key state-point parameters for a nominal 1 MW (net) power plant using a 100°C fluid are listed in Table 7.4. The actual coproduced fluid temperature is not known with certainty but may be as low as 82-93°C. In such a case, the required flow rate to achieve the nominal 1 MW would be greater than the 88 kg/s (48,000 bbl/day) shown in the table. We estimate that the flow rate would range from 160 kg/s (87,000 bbl/day) for the 82°C temperature to 103 kg/s (56,000 bbl/day) for the 93°C temperature. We estimate the installed cost for this plant would range from \$2,180/kW (for 100°C) to \$2,326/kW (for 93°C) and \$2,540/kW (for 82°C).

Table 7.4 Cycle parameters for 1 MW binary plant at NPR No. 3 (see Figure 7.1).

State-point (description)	Temperature, °C	Mass flow rate, kg/s
B1 (brine inlet)	100	88
B2 (brine outlet)	60	88
1 (turbine inlet)	71	77
2 (condenser outlet)	26	77
3 (cooling water outlet)	21	380
4 (cooling water inlet)	13	380
A1 (air wet-bulb)	7.2	---

Design of 1 MW binary plants for low-to-moderate temperatures. The results of an engineering design exercise for a series of binary plants operating on low- to moderate-temperature geofluids are presented in Figure 7.4. Shown are two curves as a function of the geofluid temperature: (1) the specific installed plant cost in \$/kW and (2) the specific power output in kW/(kg/s). All the systems represented by the points on these curves have been designed as nominal 1 MW power plants, but we think that the results would apply reasonably well to units up to 5 MW in capacity. The working fluid is R134a for the three low temperatures, and they are subcritical cycles. Isobutane is the working fluid for the two higher-temperature cases. The 150°C case is slightly subcritical, while the 200°C case is supercritical. The geofluid discharge temperature is 60°C for all the cases, except for the 200°C supercritical case. For the lower-temperature cases, 60°C is necessary to maintain reasonable pinch-point temperature differences in the heat exchangers. The supercritical case does not experience a sharp pinch point between the preheater, and the vaporizer and the fluid can be cooled to 50°C.

Notice that the specific plant cost approaches \$1,500/kW at the highest temperatures considered, and that the specific power or utilization effectiveness increases dramatically as the geofluid temperature increases.

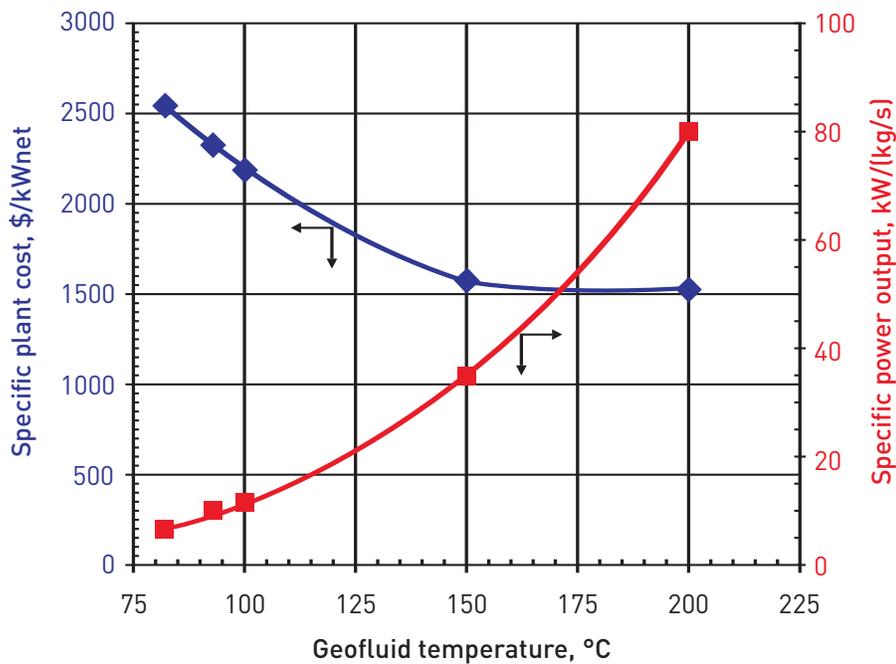


Figure 7.4 Cost and performance of 1 MW binary power plants as a function of geofluid temperature in degrees Celsius (°C).

7.2.2 Electricity from high-temperature EGS resources

It is expected that EGS reservoirs will be created in deep granitic basement rocks where the *in situ* temperatures will range from about 250°C to more than 500°C in special circumstances such as near magma intrusions. The fluids produced from such reservoirs may range in temperature from about 200°C to values well in excess of the critical temperature for pure water, i.e., 374°C.

In this section, we consider energy conversion systems for fluids at the subcritical temperatures of 200°C and 250°C; in the next section, we treat the supercritical case at 400°C. As shown in Table 7.1, we selected a single-flash plant for the 200°C case and a double-flash plant for the 250°C case. Figures 7.5 and 7.6 show these plants in simplified schematic form (DiPippo, 2005).

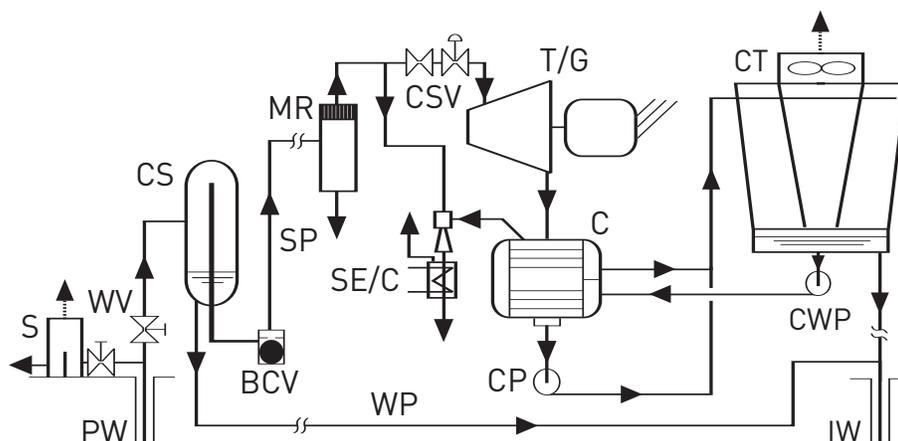


Figure 7.5 Single-flash power plant in simplified schematic form (DiPippo, 2005).

Table 7.5 Results for thermodynamically optimized single- and double-flash plants.

Geofluid temp., °C	Energy conversion system	Separator temp., °C	Flash temp., °C	Specific turbine power, kW/(kg/s)	Mass flow rate in kg/s needed for		
					1 MW	10 MW	50 MW
200	Single-flash	121	N.A.	53.9	19.5	195.2	975.9
250	Double-flash	185	122	123.5	8.52	85.2	426.2

It should be recognized that the maximum reasonably sustainable mass flow rates from EGS reservoirs to-date have been in the neighborhood of 20-22 kg/s. This would be sufficient to generate 1 MW from a 200°C fluid, and about 2.4 MW from a 250°C fluid.

Estimated power plant costs for 1- and 2-flash systems. In this section, we estimate the cost to install plants of the 1- and 2-flash type for use at EGS resources. The costs are based on the work of Sanyal (2005). He postulated that the cost of a power plant (including the cost of the initial wells and associated piping gathering system, but not replacement wells) would follow an exponentially declining curve as the capacity of the power unit increases. His cost equation is:

$$C = 2500 \times \exp(-0.003(\dot{W} - 5)) \quad (7-4)$$

where C is in \$/kW and \dot{W} is the unit capacity in MW. This formula was calibrated at \$2,500/kW for a 5 MW plant and \$1,618/kW for a 150 MW plant, the largest size considered in Sanyal's study.

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Our purpose is somewhat different in that we want to estimate the cost of power units when several of them will be constructed in a large EGS field. Thus, we need to account for both economy of scale (i.e., larger-size plants will be less expensive, per kW, than smaller ones) and a learning curve (i.e., the unit cost of many units of identical design will be less than a one-off designed plant). We expect that a lower cost limit will be reached, for which the cost of a plant will remain constant no matter the size of a given unit or the number of common units constructed.

One other important difference exists in our case: We need the cost of the power plant alone because the well and field costs to create an EGS reservoir will be estimated separately in this report. To this end, we have assumed that 75% of the total cost from Eq. (7-4) is for the plant itself. Given the current uncertainty in estimating the cost to create an EGS reservoir, we believe this percentage is a reasonable estimate for the present purpose.

Thus, we adapted Sanyal's equation to suit the present needs and used the following formulation:

$$C = 0.75 \times [1000 + 1500 \times \exp(-0.006115(\dot{W} - 5))] \quad (7-5)$$

or

$$C = 750 + 1125 \times \exp(-0.006115(\dot{W} - 5)). \quad (7-6)$$

This equation gives \$1,875/kW for the plant cost, exclusive of initial wells, for a 5 MW plant; and \$1,213/kW for a 150 MW plant (the same as Sanyal's equation), but includes an asymptotic plant cost of \$750/kW for large units or for very large numbers of common units. This limit cost is our judgment, based on experience with actual, recently constructed plants.

We want to show how the temperature of the EGS resource affects the cost of the plant. For this purpose, we calculated the exergy of the geofluid coming from the EGS reservoir at any temperature. This value was multiplied by the utilization efficiency for optimized 1- and 2-flash plants to obtain the power output that should be attainable from the geofluid. This power was then used in Eq. (7-6) to obtain the estimated cost of the power unit.

The results are shown in Figures 7.7 to 7.10, which cover the range of temperatures expected from EGS systems. Figures 7.7 and 7.9 show the optimized power output, and Figures 7.8 and 7.10 show the plant costs, for 1- and 2-flash plants, respectively. The dramatic reductions in cost per kW for the higher flow rates are evident, which, of course, mean higher power ratings.

A nominal 50 MW plant can be obtained from 1,000 kg/s at 200°C using a 1-flash plant at an estimated cost of \$1,600/kW. The same power output can be obtained from a 2-flash plant using 1,000 kg/s at 180°C for \$1,650/kW.

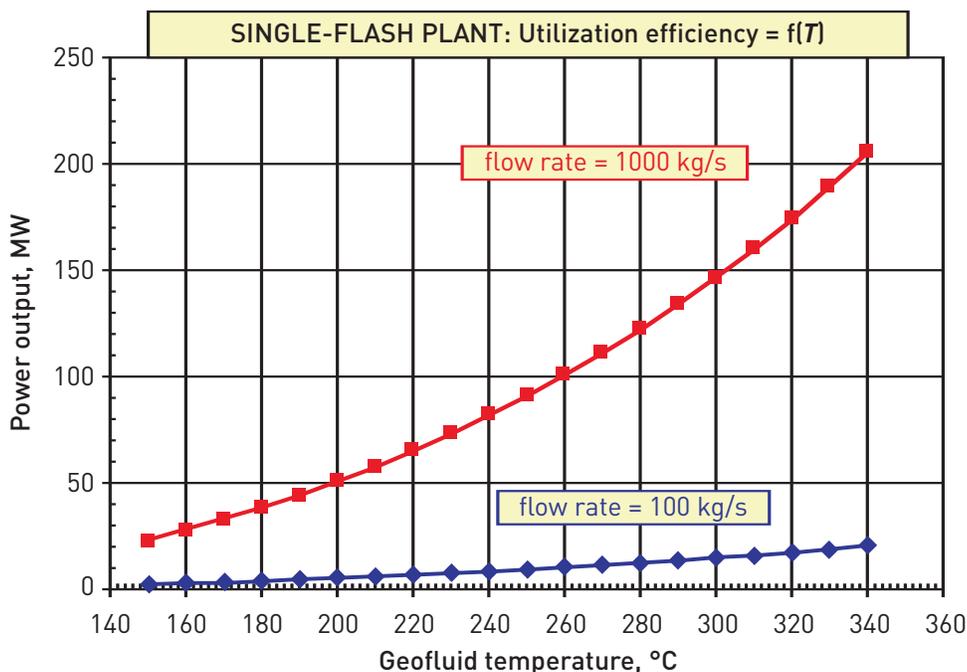


Figure 7.7 Optimized power output for a 1-flash plant as a function of geofluid temperature in degrees Celsius (°C) for geofluid flow rates of 100 and 1,000 kg/s.

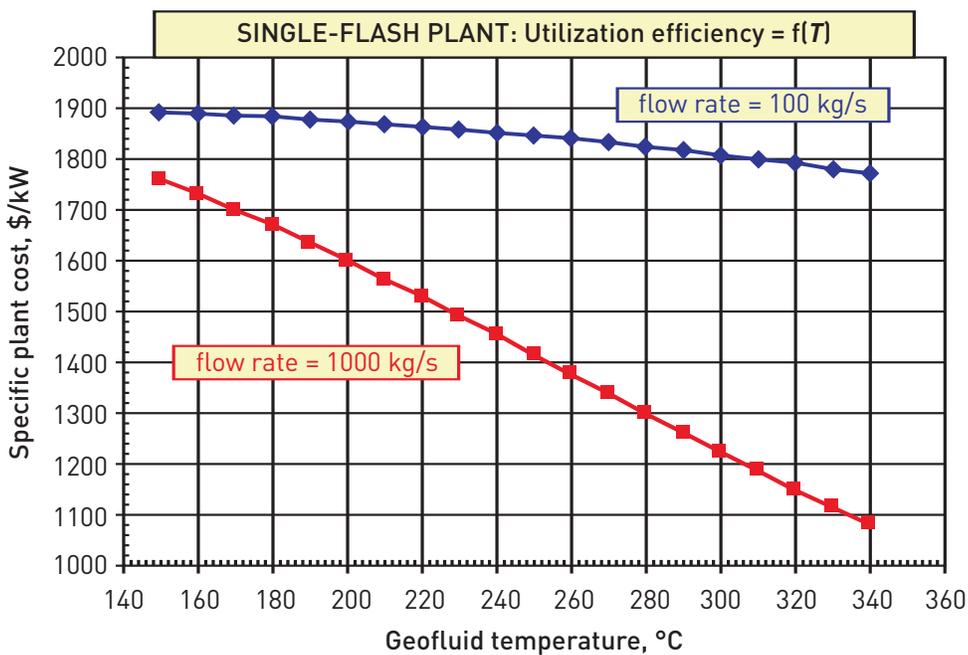


Figure 7.8 Estimated plant cost (\$/kW) for a 1-flash plant as a function of geofluid temperature in degrees Celsius (°C) for geofluid flow rates of 100 and 1,000 kg/s.

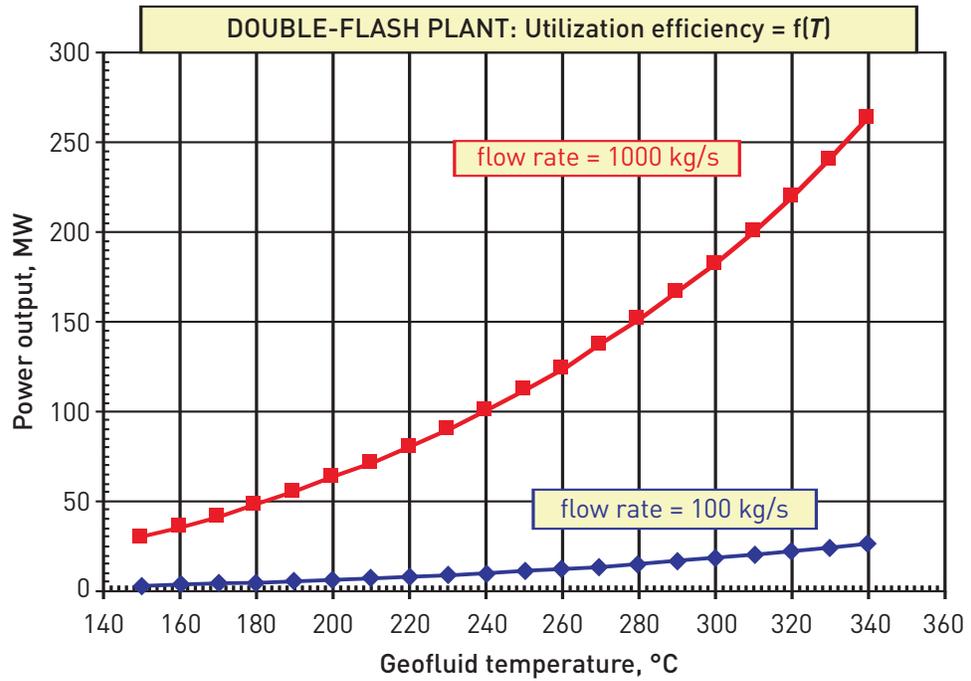


Figure 7.9 Optimized power output for a 2-flash plant as a function of geofluid temperature in degrees Celsius (°C) for geofluid flow rates of 100 and 1,000 kg/s.

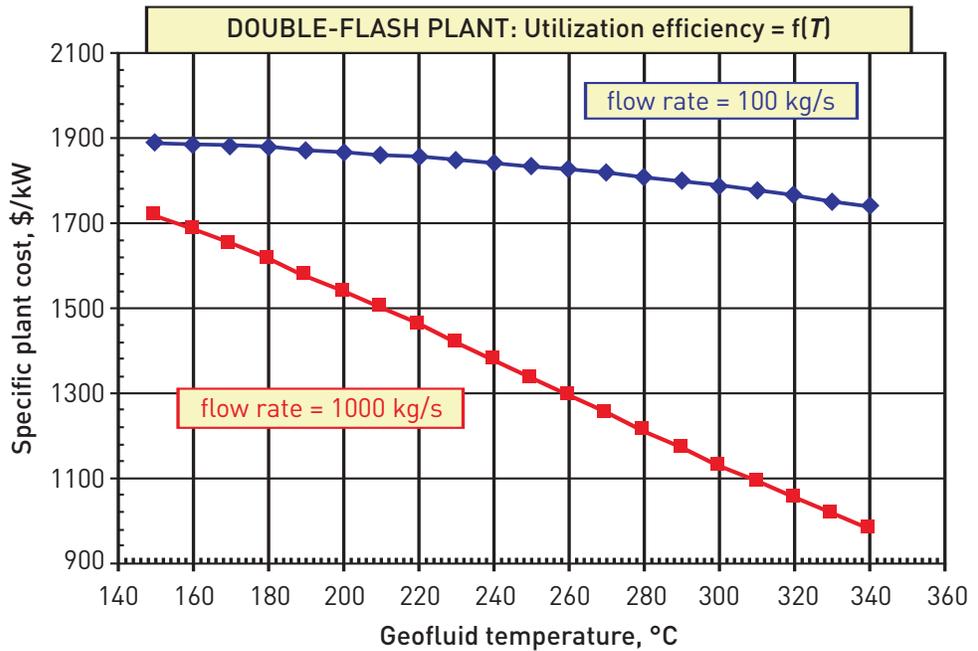


Figure 7.10 Estimated plant cost (\$/kW) for a 2-flash plant as a function of geofluid temperature in degrees Celsius (°C) for geofluid flow rates of 100 and 1,000 kg/s.

7.2.3 Electricity from EGS resources at supercritical conditions

A novel energy conversion system was developed to handle the cases when the EGS geofluid arrives at the plant at supercritical conditions, i.e., at a temperature greater than 374°C and a pressure greater than 22 MPa. For all situations studied, the temperature was taken as constant at 400°C . The plant is called the “triple-expansion” system; it is shown in simplified schematic form in Figure 7.11, and the thermodynamic processes are shown in the temperature-entropy diagram in Figure 7.12.

The triple-expansion system is a variation on the conventional double-flash system, with the addition of a “topping” dense-fluid, back-pressure turbine, shown as item SPT in Figure 7.11. The turbine is designed to handle the very high pressures postulated for the EGS geofluid, in much the same manner as a “superpressure” turbine in a fossil-fueled supercritical double-reheat power plant (El Wakil, 1984). However, in this case, we impose a limit on the steam quality leaving the SPT to avoid excessive moisture and blade erosion.

The analysis was based on the following assumptions:

- Geofluid inlet temperature, $T_1 = 400^{\circ}\text{C}$.
- Geofluid pressure, $P_1 > 22 \text{ MPa}$.
- Condenser temperature and pressure: $T_{10} = 50^{\circ}\text{C}$ and $P_{10} = 0.123 \text{ bar} = 0.0123 \text{ MPa}$.
- All turbine and pump isentropic efficiencies are 80%.
- Steam quality at SPT exit, state 2 = 0.90.
- HPT- and LPT-turbine outlet steam qualities (states 8 and 10) are unconstrained.

To determine the “optimum” performance, we selected the temperature at the outlet of the flash vessel (state-point 5) as the average between the temperature at the SPT outlet (state 2) and the condenser (state 10), in accordance with the approximate rule-of-thumb for optimizing geothermal double-flash plants (DiPippo, 2005). No claim is made, however, that this will yield the true optimum triple-expansion design, but it should not be far off.

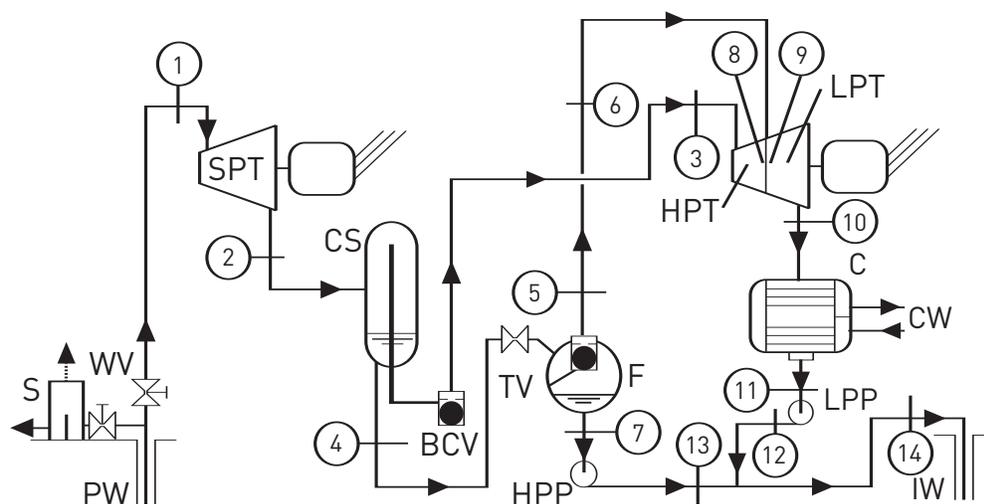


Figure 7.11 Triple-expansion power plant for supercritical EGS fluids.

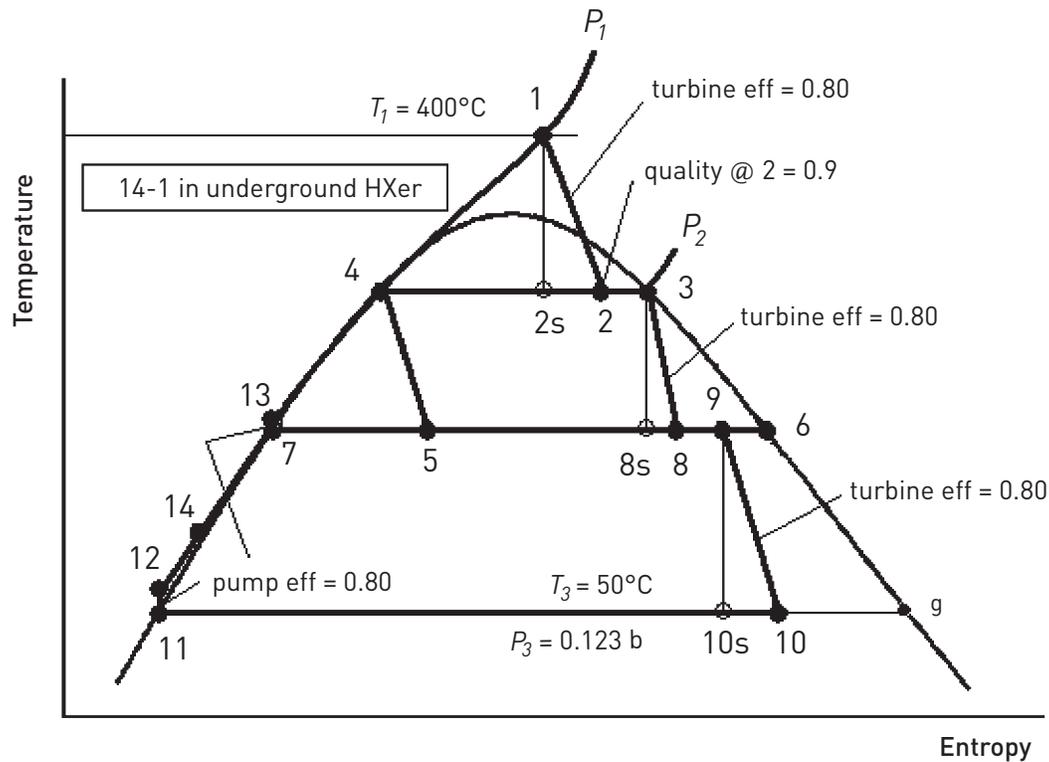


Figure 7.12 Processes for triple-expansion power plant (see Figure 7.11 for location of state points).

The results for the triple-expansion system are shown in Tables 7.6 and 7.7. It is evident that this is a very efficient means of generating electricity. The utilization efficiency is about 67%, and the thermal efficiency is about 31%. Given the high specific net power, it would take only about 15 kg/s of EGS fluid flow to produce 10 MW in either case. Such flow rates have already been demonstrated at EGS reservoirs in Europe. For inlet pressures above 27 MPa, there are no solutions that satisfy our constraints with the triple-expansion system. Even the solution at 27 MPa requires the cyclone separator to operate close to the critical point, thereby diminishing its effectiveness. The density difference between the liquid and vapor phases is not as pronounced as at separator conditions found in a typical geothermal flash plant: Here, the liquid-to-vapor density ratio is only 3.5 as compared with 172.5 in a 1 MPa separator.

Table 7.6 Results of triple-expansion analysis for an inlet temperature of 400°C.

P_1 MPa	P_2 MPa	T_2 °C	Σw_T kJ/kg	Σw_P kJ/kg	w_{net} kW/(kg/s)	q_{IN} kW/(kg/s)	η_{th} %
25	14.6	340.0	759.1	31.8	727.3	2301.3	31.6
27	19.05	361.6	699.3	34.3	665.0	2149.0	30.9

Table 7.7 Further results for triple-expansion analysis at 400°C.

P_1 MPa	η_{ll} %	Mass flow rate in kg/s needed for		
		1 MW	10 MW	50 MW
25	67.6	1.37	13.8	68.8
27	66.9	1.50	15.0	75.2

Thus, for very high inlet pressures – greater than about 28 MPa – a different form of energy conversion system must be found. A binary plant might be considered which allows the EGS fluid to be sent directly to the heat exchangers, but the extremely high pressures would necessitate very thick-walled piping and tubes in the heat exchangers. The cost of such elements would be prohibitively high, and the overall heat-transfer coefficients would be quite low. These two factors taken together would seem to rule out a simple binary plant, in spite of its inherent simplicity.

An alternative system would simply eliminate the superpressure turbine shown in Figure 7.11, and incorporate a flash-separation process that would reduce the EGS fluid pressure while generating steam for use in a conventional steam turbine. The residual liquid from the separator might then be used in a binary plant because the fluid pressure would then be manageable, or it might be flashed a second time, or most simply reinjected. The first option is what is called a flash-binary plant; the second option would be equivalent to using a double-flash plant, albeit with a very high pressure at the throttle inlet; and the last option would result in a single-flash plant or what we call a “single-expansion” plant.

We examined the last case in detail. Figures 7.13 and 7.14 show the plant in schematic form and the processes in temperature-entropy coordinates.

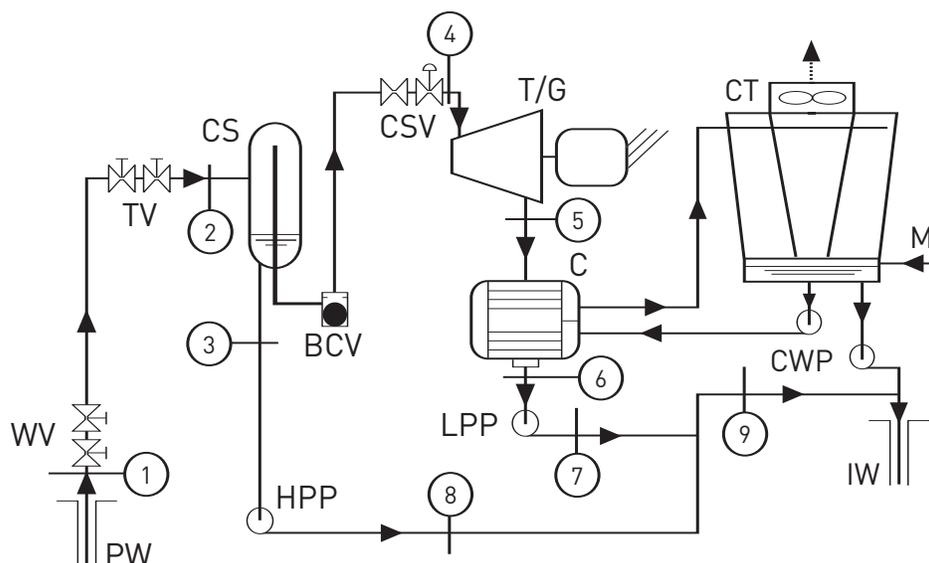


Figure 7.13 Supercritical single-expansion plant with ultra-high inlet pressures.

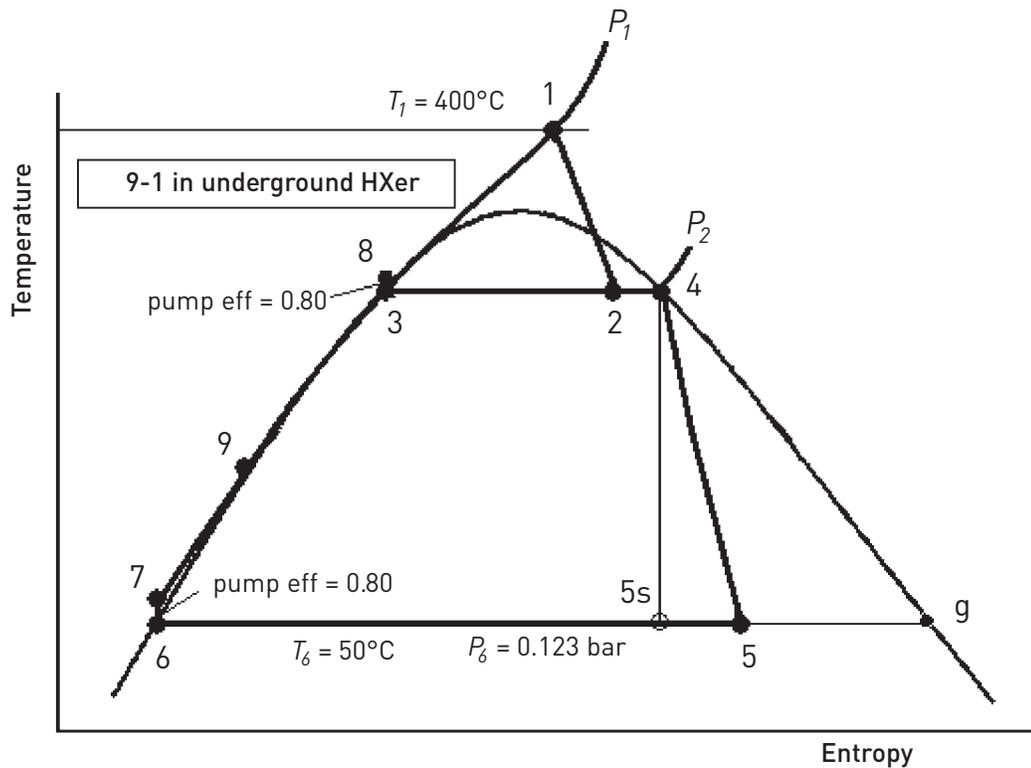


Figure 7.14 Fluid processes for supercritical single-expansion plant with ultra-high inlet pressures (see Figure 7.13 for location of state points).

The analysis was based on the following assumptions:

- Geofluid inlet temperature, $T_1 = 400^\circ\text{C}$.
- Geofluid pressure, $P_1 \geq 28 \text{ MPa}$.
- Condenser temperature and pressure: $T_{10} = 50^\circ\text{C}$ and $P_{10} = 0.123 \text{ bar} = 0.0123 \text{ MPa}$.
- Turbine efficiency found from Baumann rule with 85% dry expansion efficiency.
- All pump isentropic efficiencies are 80%.

Tables 7.8 and 7.9 show the results for optimized single-expansion plants. By comparing these results with those in Tables 7.6 and 7.7, it is clear that this system produces far less output than the triple-expansion system. This plant, however, is much simpler, and should be significantly less expensive to install and operate.

Table 7.8 Results of thermodynamically optimized single-expansion plants with supercritical EGS fluids at 400°C and various pressures greater than 27 MPa.

Inlet pressure MPa	Separator pressure MPa	Separator temperature °C	Specific turbine power kW/(kg/s)	Specific net power kW/(kg/s)	Mass flow rate in kg/s needed for		
					1 MW	10 MW	50 MW
28	8.22	297	488.89	453.8	2.20	22.0	110.2
29	5.94	275	443.82	406.7	2.46	24.6	122.9
30	4.84	262	410.35	371.5	2.69	26.9	134.6
31	4.25	254	388.02	347.6	2.88	28.8	143.9
32	3.91	249	372.93	331.0	3.02	30.2	151.1
35	3.34	240	347.46	301.2	3.32	33.2	166.0

Table 7.9 Efficiencies of optimized single-expansion plants (see Table 7.7).

P_1 MPa	Exergy, e_1 kW/(kg/s)	w_{net} kW/(kg/s)	q_{IN} kW/(kg/s)	η_{th} %	η_u %
28	941.4	453.8	1,754.3	25.9	48.2
29	886.7	406.7	1,632.7	24.9	45.9
30	842.9	371.5	1,538.0	24.2	44.1
31	812.4	347.6	1,472.8	23.6	42.8
32	791.3	331.0	1,427.1	23.2	41.8
35	755.7	301.2	1,349.4	22.3	39.9

The optimum separator temperature and the best specific power output are plotted in Figure 7.15 as a function of the inlet EGS fluid pressure. Figure 7.16 gives the thermal and utilization efficiencies. The optimization process maximized the net power (and, therefore, the utilization efficiency) so that the thermal efficiency is not necessarily at its peak value for the conditions shown.

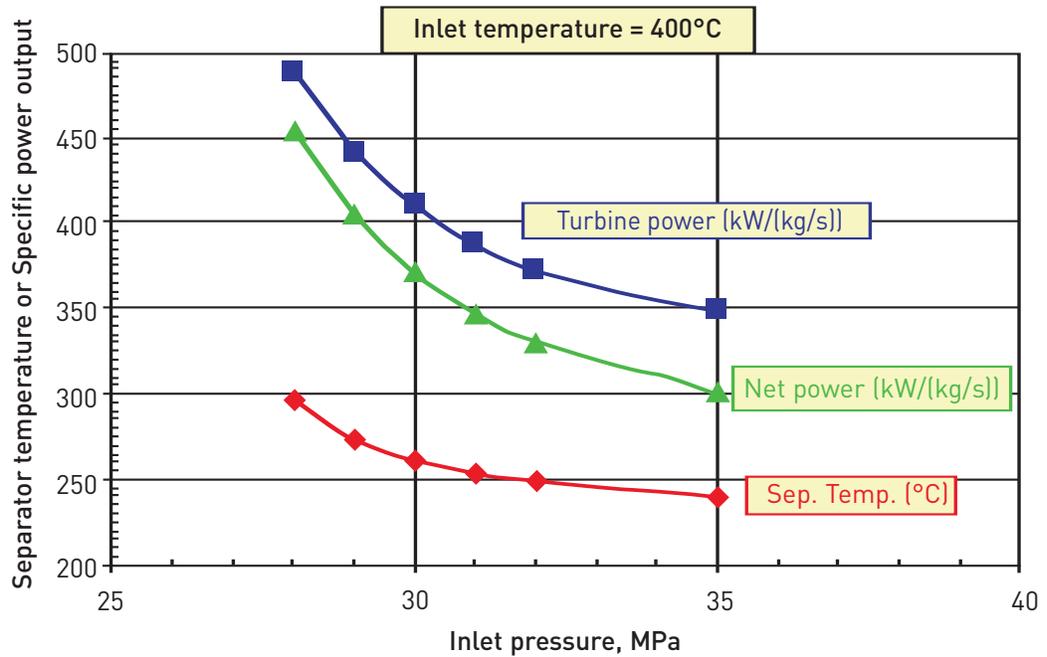


Figure 7.15 Optimum single-expansion plant performance for EGS fluid inlet temperature of 400°C and pressures greater than 27 MPa.

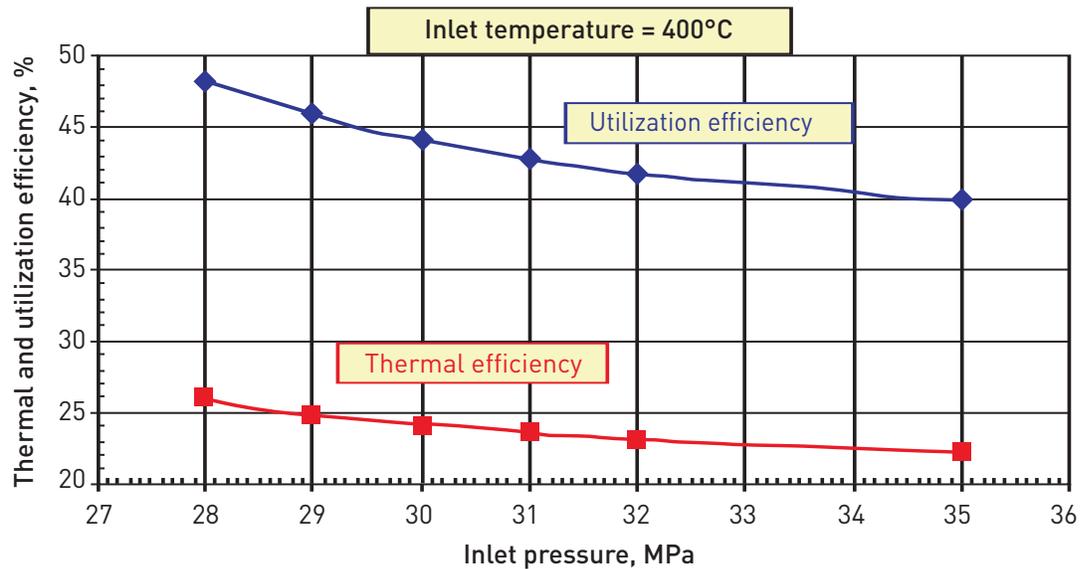


Figure 7.16 Thermal and utilization efficiencies for the supercritical single-expansion plant shown in Figure 7.13 and for the conditions shown in Figure 7.14.

It might be noted that the power needed to pump the geofluid back into the reservoir is significant, ranging from about 9%-13% of the turbine gross power. Also, the currently achievable EGS flow rates of about 20 kg/s could generate roughly 10-15 MW with this type of power plant under the fluid conditions postulated.

Thus, for supercritical geofluids from EGS reservoirs, we conclude that for those cases where the geofluid is supplied to the plant at a temperature of 400°C, and at pressures greater than 22 MPa but less than 28 MPa, the preferred energy conversion system is a relatively complex, triple-expansion system. Cycle thermal efficiencies of about 31% and utilization efficiencies of 67% can be expected.

For cases where the geofluid is supplied to the plant at a temperature of 400°C and at pressures greater than 28 MPa, the preferred energy conversion system is a single-expansion system. Cycle thermal efficiencies of about 24% and utilization efficiencies of 40%-45% can be expected.

The analysis presented here does not account for pressure losses through any piping or heat exchangers, including the manufactured one in the underground reservoir. Once the reservoir performance has been determined in the field, this can easily be taken into account by adjusting the required pump work.

We are left to speculate what geofluid pressures are reasonable for the EGS environment. For the simpler energy conversion system (i.e., the single-expansion cycle), the higher the pressure, the poorer the performance of the power cycle. The best performance occurs at pressures that may be too low to provide sufficient throughput of geofluid. For the more complex, triple-expansion system, it is not known whether the very high pressures postulated, requiring expensive thick-walled piping and vessels, may render this system uneconomic. Finally, at this stage of our understanding, we have no idea what geofluid flow rates will accompany any particular geofluid pressure because of the great uncertainty regarding the flow in the manufactured underground reservoir. More fieldwork is needed to shed light on this issue.

7.3 Cogeneration of Electricity and Thermal Energy

One of the possible uses of EGS-produced fluids is to provide both electricity and heat to residential, commercial, industrial, or institutional users. In this section, we consider the case of the MIT cogeneration system (MIT-COGEN) as a typical application.

Our tasks for the cogeneration case are:

- (a) Identify the most appropriate energy conversion system using hot geofluid from an EGS resource that will supply all the required energy flows of the current system, i.e., electricity, heating, and air conditioning.
- (b) Calculate the required flow rate of the geofluid.

MIT-COGEN employs a gas turbine with a waste heat-recovery steam generator (HRSG) to meet nearly all of the electrical and heating/cooling needs of the campus – Tables 7.10 and 7.11 give HRSG a snapshot of the energy outputs for November 18, 2005. Also, on November 18, 2005, the steam generated from the HRSG was at 1.46 MPa and 227°C, with 30°C of superheat. Figure 7.17 shows the energy flow diagram for the plant (Cooper, 2005), and Figure 7.18 is a highly simplified flow diagram for the main components of the system. It is important to note that the chiller plant is powered mainly by steam turbines that drive the compressors, the steam being raised in the HRSG of the gas turbine plant. Two of the chillers have electric motor-driven compressors.

The actual performance data for the MIT-COGEN plant were obtained from the plant engineers (Cooper, 2005). Table 7.12 shows the minimum, maximum, and average monthly demands for electricity, chiller cooling, and steam. Table 7.13 gives the annual amounts for these quantities, and Table 7.14 converts these values to instantaneous power requirements based on monthly averages.

Table 7.10 Electrical demand and supply at MIT – November 18, 2005.

Demand load, kWe	Cogen power, kWe	NSTAR power, kWe
24,087	22,100	2,060

Table 7.11 Steam demand and supply at MIT – November 18, 2005.

Demand load, lbm/h	HRSG output, lbm/h	Demand load, kg/s	HRSG output, kg/s
135,059	135,059	17.017	17.017

**MIT COGENERATION SYSTEM
ENERGY FLOW DIAGRAM**

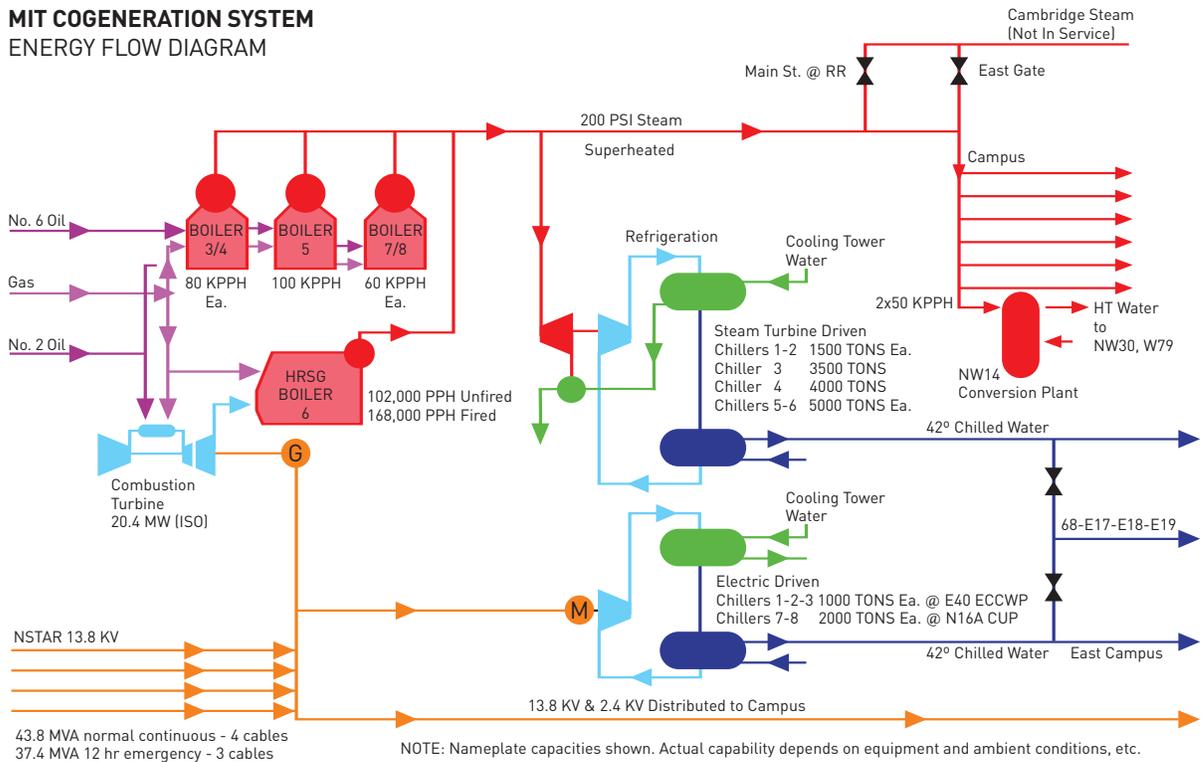


Figure 7.17 Energy-flow diagram for MIT-COGEN system.

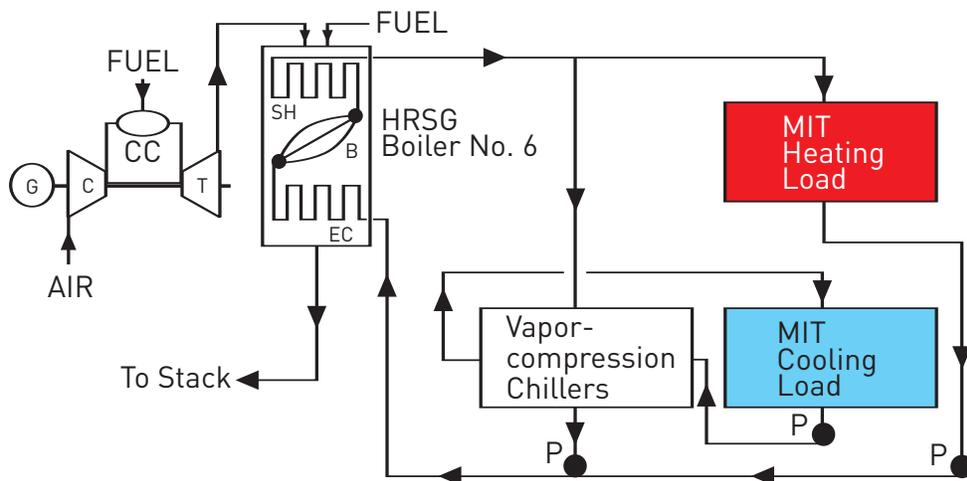


Figure 7.18 Highly simplified flow diagram for MIT-COGEN system.

Table 7.12 Monthly requirements for MIT-COGEN system, June 2004-May 2005.

Item	Minimum	Maximum	Average
Electricity demand, kWh	14,300,000 (Jan.)	19,600,000 (May)	16,500,000
Steam production, lbm	93,400,000 (Sep.)	169,400,000 (Jan.)	120,000,000
Chiller cooling, ton·h	2,000,000 (Feb.)	7,200,000 (Aug.)	3,600,000

Table 7.13 Annual requirements for MIT-COGEN system, June 2004-May 2005.

Item	Amount
Electricity demand, kWh	197,500,000
Steam production, lbm	1,440,000,000
Chiller cooling, ton·h	43,000,000

Table 7.14 Average power needs for MIT-COGEN system, June 2004-May 2005.

Item	Amount
Electricity demand, kW	22,900
Steam production, lbm/h	167,000
Steam production, kg/s	21
Chiller cooling, ton	5,000
Chiller cooling, Btu/h	60,000,000
Chiller cooling, kWth	17,500

Figure 7.19 is a flow diagram in which an EGS wellfield replaces the fossil energy input to the existing MIT-COGEN plant and supplies all of the current energy requirements.

The current gas turbine generator set is rated at 20 MW but usually puts out more than that, typically 22 MW; the remainder of the electrical load must be supplied by the local utility. The power requirements will have to be produced by a new steam turbine driven by EGS-produced steam. We have selected a single-flash system with a back-pressure steam turbine. The exhaust steam from the turbine will be condensed against part of the heating load, thereby providing a portion of the total load for the moderate- to lower-temperature applications. The separated liquid from the cyclone separators may also be used to supply some of the needs of the heating system.

If the EGS system were to replicate the existing chiller plant, a side stream of the separated steam generated in the cyclone separator would be needed to drive the steam turbine-compressor sets. However, we think it is more practical for the EGS system to provide sufficient electricity from its steam turbine-generator to supply electric motors to power the chiller compressors.

Another innovation that fits the new EGS system is to retrofit the campus to meet the heating and space cooling needs with ground-source heat pumps (GSHP). In the long-range view of this assessment, it will be beneficial to use GSHPs for space conditioning and to use electricity to drive the compressors.

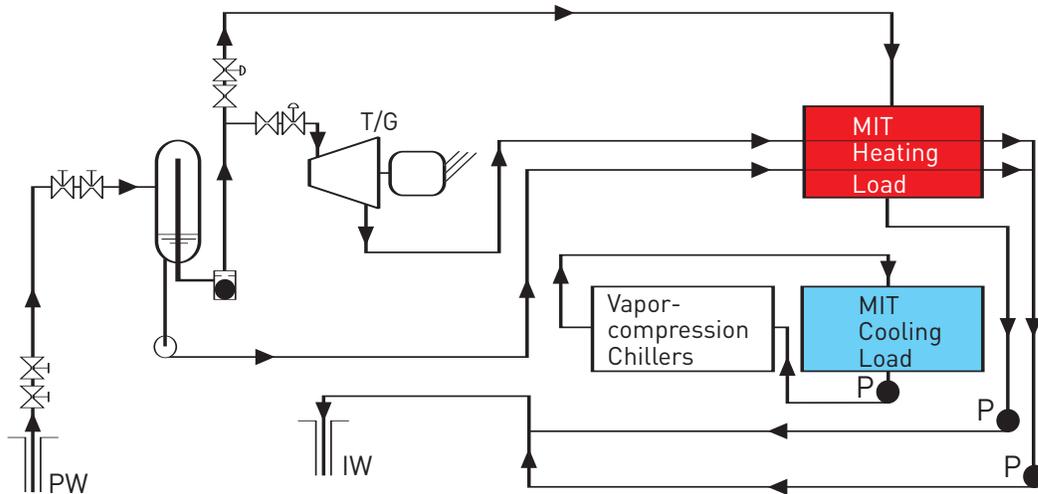


Figure 7.19 EGS system to supply MIT-COGEN energy requirements.

Switzerland, a non-hydrothermal country that is using GSHPs very extensively and effectively, is an example of what can be done with this technology. In 2004, Switzerland had 585 MWth of direct geothermal heating and cooling installed. Most of this, 91.1%, is in GSHPs, either earth- or water-coupled and geostructures, e.g., building foundation piles. The country produced 1,190 GWh of energy from their geothermal energy, enough to displace 100,000 toe (tonnes of oil equivalent) and 300,000 tonnes of carbon dioxide (Rybach and Gorhan, 2005). With more than 25,000 GSHP units installed and an annual growth of about 15% (Curtis et al., 2005), it is evident that GSHPs are an attractive and economic method of providing indoor climate control in a country not endowed with conventional high-temperature hydrothermal resources.

In the case of the MIT campus, the EGS system may be used in conjunction with ground-source heat pumps to provide all the heating and cooling needs (see Figure 7.20). The EGS system shown still allows for some direct heating using the back-pressure exhaust steam from the main turbine for those applications where steam is essential. In practice, these heating needs might be taken care of using steam bled from an appropriate stage of the turbine. Furthermore, because it is highly desirable to return the spent geofluid to the injection wells as cold as possible (to enhance the gravity-head flow effect), we still will use the liquid from the cyclone separator to meet some campus heating needs.

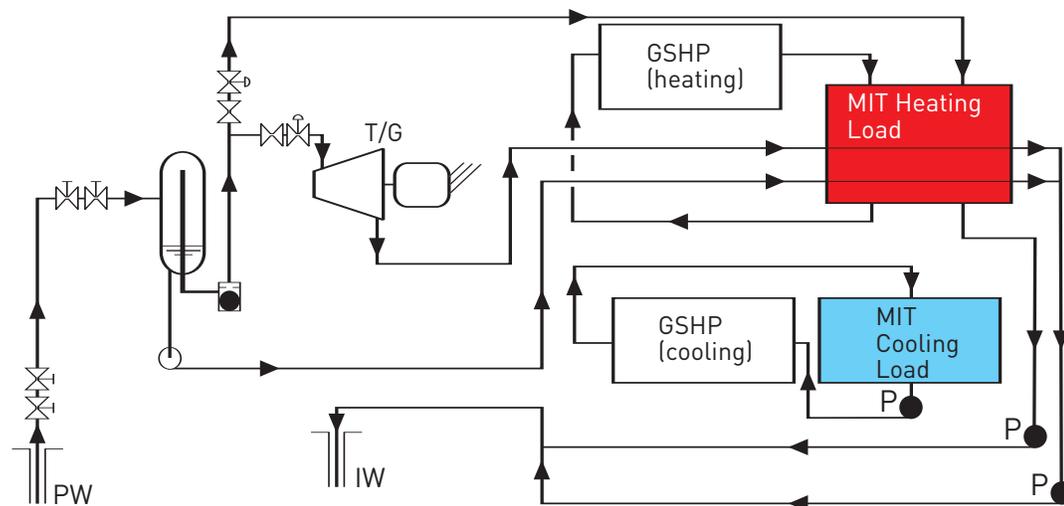


Figure 7.20 EGS system to supply MIT-COGEN energy requirements using ground-source heat pumps.

The EGS version of the COGEN plant will be as flexible as possible to accommodate varying electrical, heating, and cooling loads. However, for this analysis, it is assumed that the electrical load is a nominal 22 MW – the total heating load requires 21 kg/s of steam at 1.48 MPa and 227°C, and the cooling load is 5,000 tons of refrigeration or 17,500 kWth. The steam condensate returns saturated at about 109°C; thus, the heating load is roughly 50,700 kWth.

To find the electricity needed to drive the compressors of the GSHPs, we assumed that the COP is 5.0 in the heating mode and 7.3 in the cooling mode (U.S. DOE, 2005). Thus, on these bases, the electrical input would be 10,140 kWe to power the GSHP heating system, and 2,400 kWe to power the cooling plant. The base electric power requirement of 22 MW must be added to these, giving a total electrical output from the EGS-driven turbine-generator of 32.1 MW. This would require a mass flow rate of about 470 kg/s from an EGS reservoir having a temperature of 250°C, assuming a back-pressure turbine is used with a double-flash system. The required fluid flow rate might be somewhat lower if a condensing, extraction turbine is used, but we did not perform the engineering analysis to assess this possibility.

The type of system described here for the MIT situation can be used as a model for other similar applications. It can accommodate other direct-heat uses such as the processing of agricultural products such as foodstuffs and biomass, or in aquaculture, because only low- to moderate-temperature fluids are needed. Applications of this kind are common at existing hydrothermal plants around the world (Lund, 2005), and would make sense for power plants operating on EGS-derived fluids.

7.4 Plant Operational Parameters

Power plants operating on EGS-derived geofluids will be subject to the same kind of operating and performance metrics as those at conventional hydrothermal resources. However, because the EGS fluids are “pure” water to start with at the injection wells, and are recirculated after production, it is expected that they will be far less aggressive than typical hydrothermal fluids. This should minimize the problems often seen regarding chemical scaling, corrosion, and noncondensable gases found in some natural hydrothermal power plants where methods already exist for coping with all of these potential problems. Nevertheless, the EGS fluids may have much higher pressures than those seen at hydrothermal plants, even supercritical pressures, which already have been discussed. These conditions, when combined with very high temperatures, will need to be accounted for in the field piping and plant design.

The analysis presented here presumes that the properties of the EGS circulating fluid remain constant. Because this is unlikely to be true over the expected lifetime of a plant, it may be necessary to modify the plant components to maintain the power output, unless replacement wells are able to restore the initial fluid conditions. This problem is routinely encountered in current geothermal plants, both flash-steam and binary, and the methods used would apply to the EGS plants.

The general finding is that no insurmountable difficulties are expected on the power-generation side of an EGS operation.

7.5 Summary and Conclusions

In this section, we have shown that:

- Energy conversion systems exist for use with fluids derived from EGS reservoirs.
- Conventional geothermal power plant techniques are available to cope with changing properties of the fluids derived from EGS reservoirs.
- It is possible to generate roughly 6,000 MW of electricity from fluids that are currently being coproduced from oil and gas operations in the United States by using standard binary-cycle technology.
- Power plant capital costs for coproduced fluids range from about \$1,500-2,300/kW, depending on the temperature of the coproduced fluids.
- If a mass flow rate of 20 kg/s can be sustained from a 200°C EGS reservoir, approximately 1 MW of power can be produced; the same power can be achieved from a 250°C EGS reservoir, with only about 8.5 kg/s.
- Supercritical fluids from an EGS reservoir can be used in a triple-expansion power plant. About 15 kg/s will yield about 10 MW of power from fluids at 400°C and pressures in the range of 25-27 MPa; power plant thermal efficiencies will be about 31%.
- Supercritical fluids from an EGS reservoir at very high pressures up to 35 MPa and 400°C can be used in a single-expansion power plant to generate 10 MW of power from flow rates of 21-30 kg/s, depending on the fluid pressure.

- Fluids derived from EGS reservoirs can be used in innovative cogeneration systems to provide electricity, heating, and cooling in conjunction with ground-source heat pumps. For example, the current MIT energy needs could be met with an EGS power plant with a 32 MW rating; this could be achieved with a flow rate of 1,760 kg/s from a 200°C EGS reservoir using a single-flash system – or a 470 kg/s flow rate from a 250°C EGS reservoir using a double-flash system – and back-pressure turbines.
- The installed specific cost (\$/kW) for either a conventional 1- or 2-flash power plant at EGS reservoirs is inversely dependent on the fluid temperature and mass flow rate. Over the range from 150-340°C: For a mass flow rate of 100 kg/s, the specific cost varies from \$1,894-1,773/kW (1-flash) and from \$1,889-1,737/kW (2-flash); for a flow rate of 1,000 kg/s, the cost varies from \$1,760-1,080/kW (1-flash) and from \$1,718-981/kW (2-flash).
- The total plant cost, exclusive of wells, for a 2-flash plant receiving 1,000 kg/s from an EGS reservoir would vary from \$50 million to \$260 million, with a fluid temperature ranging from 150-340°C; the corresponding power rating would vary from about 30-265 MW. If the reservoir were able to supply only 100 kg/s, the plant cost would vary from \$5.6 million to \$45.8 million over the same temperature range; the corresponding power rating would vary from 3-26.4 MW.

It should be noted that the possibility of using supercritical-pressure carbon dioxide as the circulating fluid in the EGS reservoir, alluded to in other parts of this report, has not been analyzed in this chapter. The use of CO₂ as the heat-transfer medium raises a number of complex questions, the resolution of which lies beyond the scope of this report. The reader may consult Brown (2000) for an excellent discussion of this concept.

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Nomenclature (as used in figures)

B	Boiler
BCV	Ball check valve
C	Condenser; compressor (Fig. 7.18); Celsius (throughout)
CC	Combustion chamber
CP	Condensate pump
CS	Cyclone separator
CSV	Control and stop valves
CT	Cooling tower
CW	Cooling water
CWP	Cooling water pump
E	Evaporator
EC	Economizer
F	Flash vessel
FF	Final filter
G	Generator
HPP	High-pressure pump
HPT	High-pressure turbine
HRSG	Heat-recovery steam generator
IP	Injection pump
IW	Injection well
LPP	Low-pressure pump
LPT	Low-pressure turbine
M	Make-up water
MR	Moisture remover
P	Pump
PH	Preheater
PW	Production well
S	Silencer
SE/C	Steam ejector/condenser
SH	Superheater
SP	Steam piping
SPT	Super-pressure turbine
SR	Sand remover
T	Turbine
T/G	Turbine/generator
TV	Throttle valve
WP	Water piping
WV	Wellhead valve