7. PRODUCTION OF ELECTRICITY FROM GEOTHERMAL ENERGY

Like all conventional thermal power plants, a geothermal plant uses a heat source to expand a liquid to vapor/steam. This high pressure vapor/steam is used to mechanically turn a turbine-generator. At a geothermal plant, fuel is geothermal water heated naturally in the earth, so no burning of fuel is required.

Geothermal power is generated by using steam or a secondary hydrocarbon vapor to turn a turbine-generator set to produce electrons. A vapor dominated (dry steam) resource can be used directly, whereas a hot water resource needs to be flashed by reducing the pressure to produce steam. In absence of natural steam reservoirs, steam can be also generated in hot dry rock (HDR) or enhanced geothermal systems (EGS) engineered in the subsurface. In the case of low temperature resource, generally below 150°C, the use of a secondary low boiling point fluid (hydrocarbon) is required to generate the vapor, in a binary or organic Rankin cycle plant because initially it involved organic compounds, such as toluol (C_7H_8), pentane (C_5H_{12}), propane (C_3H_8) or halogenated hydrocarbons. More recently, the so-called Kalina Cycle technology [1984Kal; 1989Wal] improves the efficiency of this process further by evaporating a mixture of water and ammonia (NH_3) over a finite temperature range rather than a pure fluid at a definite boiling point.

The worldwide installed capacity (10717 MW in 2010) has the following distribution: 29% dry steam, 37% single flash, 25% double flash, 8% binary/ combined cycle/hybrid, and 1% backpressure (Bertani, 2005).

Wet and dry steam reservoirs are water and vapor dominated, respectively. Wet steam fields contain pressurized water at temperatures above 100 °C and a smaller amount of steam in the shallower, lower-pressure parts of the reservoir. Hot, pressurized water is the dominant phase inside the reservoir. Vapor dominated, dry steam fields produce dry saturated or slightly superheated steam at pressures above atmospheric. This steam has the highest enthalpy (energy content), generally close to 2.8 MJ kg^{-1}. Dry steam fields are less common than wet steam fields, but about half of the geothermal electric energy produced worldwide is generated in the six vapor dominated fields at Lardarello and Monte Amiata in *Italy*; The Geysers (California) in the *USA*; Matsukawa in *Japan*; and Kamojang and Darajat in *Indonesia.*

While geothermal power has been produced for a century, its development has been rather slow in the first half of this period: The first geothermal power plant was commissioned in 1913 in Larderello, Italy with an installed capacity of 250 kWel. Only about half a century later the next geothermal power plants were commissioned at Wairakei, New Zealand in 1958, an experimental plant at Pathe, Mexico in 1959, and The Geysers in the USA in 1960. Today, the Tuscan region around Lardarello is still the center of the Italian geothermal power production with an installed capacity of about 790 MWel and a production of 5340 GW he in the year 2003.

Geothermal power production has more stringent requirements with respect to temperature or physical rock properties than direct use. However, different technological and economical aspects apply to the different types of geothermal power production, depending on whether they are natural or engineered systems, involve dry or wet steam or ORC or Kalina Cycle technology. One of the advantages of geothermal power plants is that they can be built economically in much smaller units than e.g. hydropower stations. Geothermal power plant units range from less than 1 MWel up to 30 MWel. Thus, the capacity of geothermal power plants can be adjusted more easily to the growing demand for electric power in developing countries with their relatively small electricity markets than hydropower plants which come in units of 100 MWel – 200 MWel. Geothermal power plants are very reliable: Both the annual load and availability factors are commonly around 90 %. Additionally, geothermal fields are little affected by external factors, such as seasonal variations in rainfall, since meteoric water has a long residence time in geothermal reservoirs

Conversion Technology. A conversion technology represents the entire process of turning hydrothermal resources into electricity. Four options are available to developers:

- **Dry steam plants,** which have been operating for over one hundred years, make use of a direct flow of geothermal steam.
- The most common type of power plant, a **flash power plant**, uses a mixture of liquid water and steam.
- **Binary geothermal plants** function as closed loop systems that make use of resource temperatures as low as 74^{o}C. A **Rankin cycle** is the commercial binary cycle used in the United States.
- A combination of flash and binary technology, known as the **flash/binary combined cycle**, has been used effectively to take advantage of both technologies.

Cooling System. Usually a wet or dry cooling tower is used to condense the vapor after it leaves the turbine to maximize the temperature drop between the incoming and outgoing vapor and thus increase the efficiency of the operation. Most power plants, including most geothermal plants, use water-cooled systems –typically in cooling towers. In areas with scarce or expensive water resources, or where the aesthetic impact of steam plumes (produced only in water-cooled systems) are a concern, air cooling may be preferred. However, air-cooled systems are influenced by seasonal changes in air temperature.

A cooling system is essential for the operation of any modern geothermal power plant. Cooling towers prevent turbines from overheating and prolong facility life. Most power plants, including most geothermal plants, use water cooling systems. Water cooled systems generally require less land than air cooled systems, and are considered overall to be effective and efficient cooling systems. The evaporative cooling used in water cooled systems, however, requires a continuous supply of cooling water and creates vapor plumes. Usually, some of the spent steam from the turbine (for flash- and steam-type plants) can be condensed for this purpose. Air cooled systems, in contrast to the relative stability of water cooled systems, can be extremely efficient in the winter months, but are less efficient in hotter seasons when the contrast between air and water temperature is reduced, so that air does not effectively cool the organic fluid. Air cooled systems are beneficial in areas where extremely low emissions are desired, or in arid regions where water resources are limited, since no fluid needs to be evaporated for the cooling process. Air cooled systems are preferred in areas where the view shed is particularly sensitive to the effects of vapor plumes, as vapor plumes are only emitted into the air by wet cooling towers and not air cooling towers. Most geothermal air cooling is used in binary facilities.

The sources used for electricity generation if properly exploited, can have capacity for about 50 years or so. Usually the equipment after so many years of exploitation is at the end of its working life. Construction of a new plant with a geothermal source more years continuously used for electricity production, it is not economically feasible. Source has to undergo a period of time to restore. The time of recovery is different and depends on several factors. The experiments show that the time for heat pumps is about 30 years (100 ÷ 200) years for central heating installations and several hundred years for the plants to produce electricity.

Reduction in production of electricity, due to the source exhaustion, is characteristic at geysers in California, where the production of 1875 MW in 1999, decreased to 1137 MW.

7.1. Dry steam Power Plant

7.1.1. Dry steam non-condensing geothermal power plant

Dry Steam Power Plants were the first type of geothermal power plant (in Italy in 1904). The Geysers in northern California, which is the world's largest single source of geothermal power, is also home to this type of plant. They use dry saturated or superheated steam at pressures above atmospheric from vapor dominated reservoirs, an excellent resource that can be fed directly into turbines for electric power production. Permeability is generally lower in dry than in wet steam fields, and the reservoir requires a tight cap rock. Steam is the predominant continuous phase in control of reservoir pressure which is practically constant throughout the reservoir. On the surface, these fields may be indicated by boiling springs and geysers. In general, the produced steam is superheated, containing only small quantities of other gases, mainly CO_2 and H_2S. Superheating in dry steam reservoirs is caused by a transient heat transfer between the reservoir rock and the steam phase:

Fig.7.1.1 Direct-intake, non-condensing single flash geothermal power plant at Pico Vermelho (São Miguel Island, Azores) exhausting steam to the atmosphere. (source: 2004 Lund).

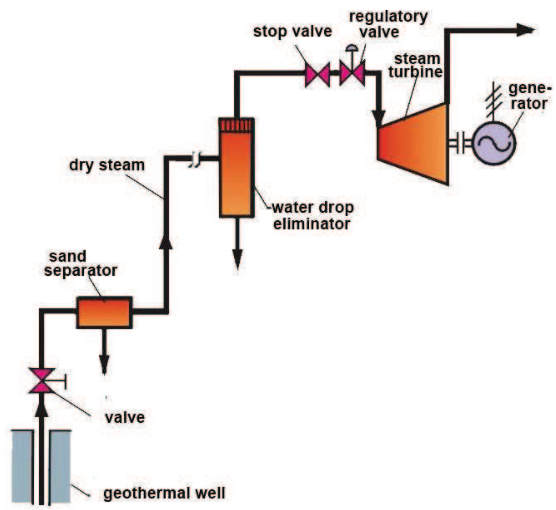

Fig.7.1.2 Dry steam non-condensing geothermal power plant

In power plants exploiting dry steam fields, steam can be fed directly from the production wells into the turbine and exhausted to the atmosphere. This *direct non-condensing cycle* is the simplest and cheapest option for generating geothermal electricity. Steam from the geothermal well is simply passed through a turbine and exhausted to the atmosphere: there are no condensers at the outlet of the turbine (Fig.7.1.1). Direct non-condensing cycle plants require about 15 kg – 25 kg of steam per kWh generated electricity [2002 Bar]. Non-condensing systems must be used if the steam contains more than 50 weight % of non-condensable gases. They are generally preferred over condensing cycles if the steam contains more than 15 weight % non-condensable gases, because their removal from the condenser consumes power and reduces plant efficiency.

7.1.2. Dry steam condensing geothermal power plant

Since almost all geothermal resources in the form of dry steam has dissolved (2 ÷ 10) % non-condensing gases, in the geothermal plant must be built system for their removal. Usually, for this purpose is uses a two stage ejector, but in many cases can be used and vacuum pumps, or turbochargers.

In a geothermal dry steam power plants with vapor condensation (fig.7.1.3), vapor at the exit of the turbine is not discharged directly into the atmosphere, but enter into a condenser in which is maintains a constant temperature, usually (35 ÷ 45)^{o}C. Due to the low temperature, the pressure in the condenser is lower than atmospheric pressure, the steam expands to a greater specific volume and this gives greater mechanical energy in the turbine blades.

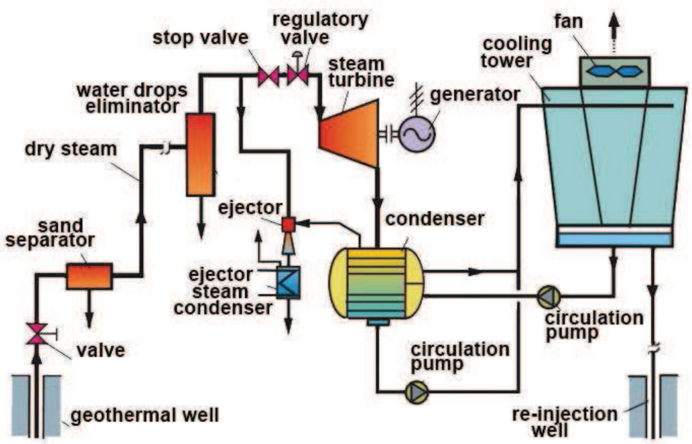

Fig.7.1.3 Dry steam condensing geothermal power plant

In the condenser, except steam condensation it is performed removal of non-condensing gases (CO_2).They from the condenser are directly discharged into the atmosphere, or if they contain toxic substances (such as H_2S), leading is away in their chemical purification plant.

The condensation of the steam can be performed with surface condenser or condenser with direct mixing. Application of one or the other mode of condensation depends on the concentration of non-condensing gases and how their processing before they can be released into the atmosphere, especially H_2S. For removing of H_2S it is need to build a chemical plant, but in geothermal power plants with a small installed capacity, it is not economical. In some geothermal plants H_2S is obtained as a byproduct.

Cooling of the condenser (Fig.7.1.3) is by water which is obtained by steam condensation from the geothermal source. Condensate obtained by condensing the steam in the condenser, which is not returned to the boiler as a conventional plant, is using as cooling water. In the cooling tower, under the influence of atmospheric air which is performing cooling, one part of this condensate is discharged into the atmosphere, while the rest returned to the underground through a reinjection well. Cooling tower can be dry, i.e. there is no direct contact between air and water cooling.

Because the geothermal water is used for condenser cooling, the total condensate of the geothermal steam is non-return underground (only 10-20%). This leads to depletion of the reservoir at a longer exploitation period. With air-cooled condensers or dry cooling towers, this problem is solved (nearly 100% is return to the underground), but they are not economically. Commonly it is use cooling towers with artificial draft, although in some plants is applied natural draft.

Advantage of the steam condensing plants in relation to plants with non-condensing is very efficient utilization of geothermal steam and eliminating the risk of environmental noise during the steam discharge. But the larger investments, more expensive maintenance, more complex performance and the need for cooling of geothermal steam, makes construction more expensive and less favorable for construction.

7.2. Flash Steam Power Plants

Flash Steam Power Plants, which are the most common, use water with temperatures greater than 182°C. This very hot water is pumped under high pressure to equipment on the surface, where the pressure is suddenly dropped, allowing some of the hot water to "flash" into steam. The steam is then used to power the turbine/generator. The remaining hot water and condensed steam are injected back into the reservoir.

A single flash condensing cycle is the most common energy conversion system for utilizing geothermal fluid due to its simple construction and to the resultant low possibility of silica precipitation. A double flash cycle can produce 15-25% more power output than a single flash condensing cycle for the same geothermal fluid conditions (DiPippo, 2007).

As the hot water moves from deeper in the earth to shallower levels, it quickly loses pressure, boils and "flashes" to steam. The steam is separated from the liquid in a surface vessel (steam separator) and is used to turn the turbine, and the turbine powers a generator. Flash power plants typically require resource temperatures in the range of 177^{o}C to 260^{o}C.

7.2.1. Single flash system

In two-phase high-temperature fields, geothermal fluid from a reservoir reaches the surface as a mixture of steam and brine due to boiling of the fluid. The steam is then separated from the brine, either by a cyclone effect in a vertical separator or by gravity in a horizontal separator. The dry steam is directed to a turbine which is connected to a generator to generate electricity while the separated brine is piped back into the reservoir through reinjection wells. According to the type of turbine (exhaust condition of the turbine), this system can be divided into two types.

7.2.1.1. Single flash condensing system

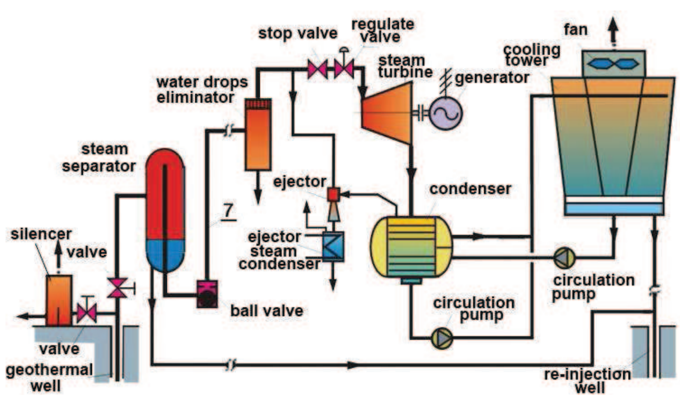

Fig.7.2.1 Simplified schematic diagram of a single flash condensing system

Figure 7.2.1 shows a simplified schematic diagram for the single flash system with a condensing turbine.

In a single flash steam plant, the two-phase flow from the well is directed to a steam separator; where, the steam is separated from the water phase and directed to the inlet to the turbine. The water phase is either used for heat input to a binary system in a direct-use application, or injected directly back into the reservoir (Figure 7.2.1).

Steam exiting the turbine is directed to a condenser operating at vacuum pressure. Low vacuum pressure in the condenser is maintained in order to increase the enthalpy difference in the turbine as well as to increase the power output of the plant. Non condensable gasses, associated with steam which is accumulated in the condenser, potentially increase the condenser pressure and must, therefore, be pumped out of the condenser. Vacuum pumps, steam jet ejectors or compressors are installed for that purpose. In this model, the gasses are assumed to be extracted from a condenser by using a compressor. In direct contact condensers, cooling water from a cooling tower is typically sprayed at the top of the condenser, condensing the steam back into liquid form. The mixture of condensate and cooling water is then pumped to the top of the cooling tower for heat rejection to the environment.

The steam is usually condensed either in a direct contact condenser, or a heat exchanger type condenser. In a direct contact condenser the cooling water from the cooling tower is sprayed onto and mixes with the steam. The condensed steam then forms part of the cooling water circuit, and a substantial portion is subsequently evaporated and is dispersed into the atmosphere through the cooling tower. Excess cooling water called blow down is often disposed of in shallow injection wells. As an alternative to direct contact condensers shell and tube type condensers are sometimes used. In this type of plant, the condensed steam does not come into contact with the cooling water, and is disposed of in injection wells.

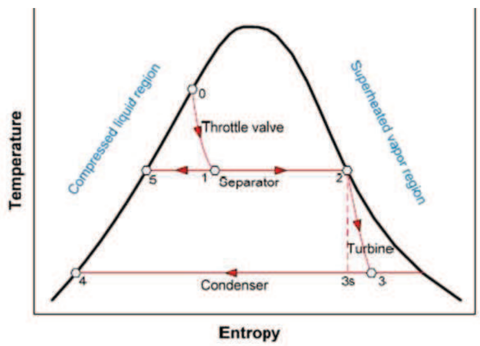

Fig.7.2.2 Temperature-entropy diagram of a single flash condensing system

Depending on the steam characteristics, gas content, pressures, and power plant design, between 6000 kg and 9000 kg of steam each hour is required to produce each MW of electrical power.

Historically, flash has been employed where resource temperatures are in excess of approximately 150°C; however, studies completed by Barber Nichols Inc. of Arvada, Colorado (Forsha, 1994) would seem to indicate that flash technology could be employed at temperatures as low as 120°C or less, and at a cost significantly lower than that of a similarly sized binary plant.

7.2.1.2. Single flash back pressure system

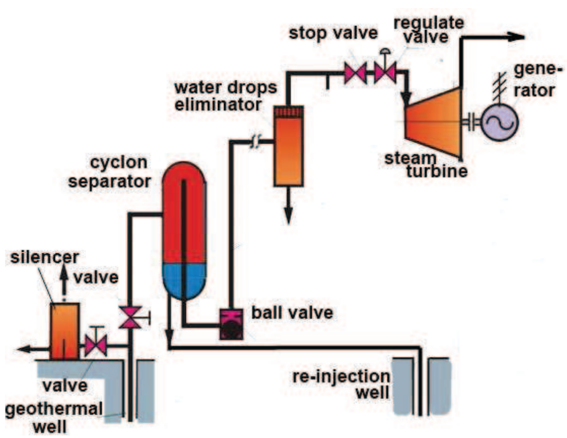

Fig.7.2.3 Simplified schematic diagram of a single flash back pressure system

Figure 7.2.3 shows a simplified schematic diagram of a single flash system with a back pressure unit. This term "back pressure" is used because the exhaust pressure of the turbine is much higher than the condensing system. The system does not use a condenser. The outlet steam from the turbine exhausts directly to the atmosphere or returns to the plant for heating purposes. In this process the exhaust pressure is controlled by a regulating valve to suit the needs of the process steam pressure. The steam consumption per power output from a back pressure turbine is almost double that from the condensing type at the same inlet pressure.

The back pressure units are very cheap and simple to install, but are inefficient (typically 10-20 tone per hour of steam for every MW of electricity) and can have higher environmental impacts.

7.2.2. Double flash system

Figure 7.2.4 shows a simplified schematic diagram of a double flash system. This configuration is very similar to a single flash system.

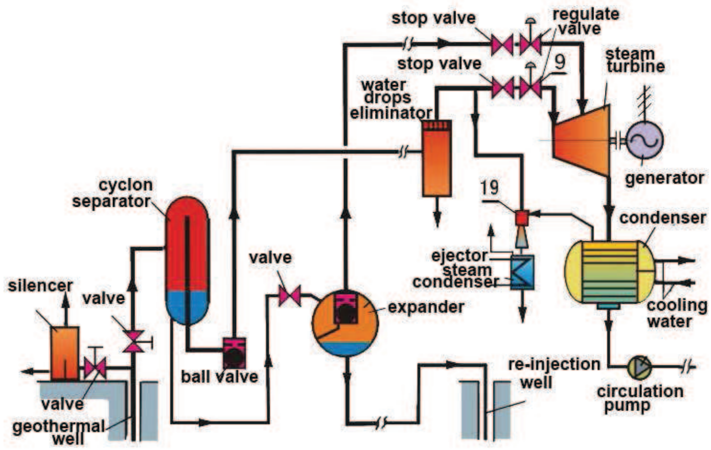

Fig.7.2.4 Simplified schematic diagram of a double flash condensing system

The double flash system uses a two stage separation of geothermal fluid instead of one, resulting in two steam admission pressures at the turbine. First, the geothermal fluid from the well is flashed at relatively high pressure. Steam and brine are separated in the separator. From the separation process, the resulting high pressure steam is directed to a high pressure turbine and the separated brine, which still contains reasonably high enthalpy, is throttled and directed to a low pressure separator for additional steam production. Steam from the high pressure turbine is mixed with the steam from the low pressure separator and then directed to the low pressure turbine to generate extra power. The brine from a low pressure separator is piped to the reinjection wells. The silica concentration of the brine injected into the reinjection wells becomes higher in the double flash system, when compared to a single flash one, and could result in scaling problems in the pipelines or the reinjection wells.

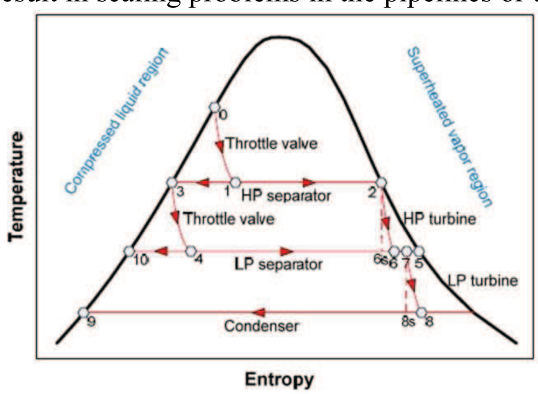

Fig.7.2.5 Temperature-entropy diagram of a double flash condensing system [13]

Figure 7.2.6 show schematic diagram of a double flash condensing system of the Bouil-lante geothermal power plant located at the coast of the island Basse Terre, south of the Bouillante in Guadeloupe.

From geothermal wells in the island, with a depth between (600÷2500) m, is getting geothermal fluid with temperature (230 ÷ 250) ^{o}C and steam in the mixture (20÷80) %. The geothermal fluid flow is 150 t/h. The steam pressure at the inlet to the high pressure turbine is 6 bar and at the low pressure turbine 1 bar.

High pressure steam from the separator go in high pressure turbine, and separated geothermal water with temperature around 160 ^{o}C, is carrying to the expander, where by expansion is getting low pressure steam. Exhaust steam from the turbine is condensing in the condenser by directly mixing with sea water used to cool the condenser. Waste geothermal water from separator and expander through silencer, with a temperature around 100 ° C, is mixing with water coming from the condenser and through the channel is discharged into the sea. In high pressure separator is receiving about 30 t / h steam, and in low pressure about 12 t / h steam.

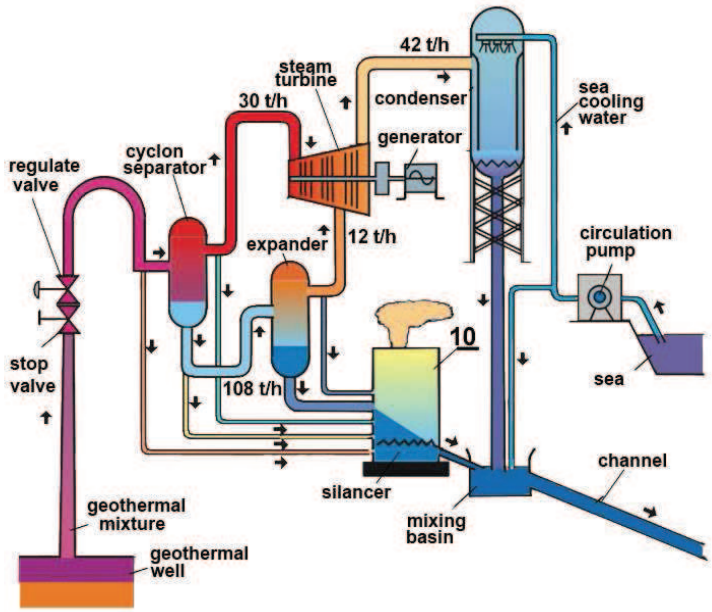

Fig.7.2.6 Schematic diagram of a double flash condensing system of the Bouillante geothermal power plant located at the coast of the island Basse Terre, south of the Bouillante in Guadeloupe

Turbine works mainly with steam from the separator and expanders, but it can work only with steam from high pressure separator. This enables replacement and maintenance of the parts of low pressure separator, without interrupting the full operation of the turbine.

Gross electric power of the plant is 5.0 MWe, net 4,2 MWe and is sufficient for the town and the western coast of the island of Basse Terre. Availability of the plant is about 98%.

Double flashing, is more expensive than a single flash, and could concentrate chemical components if they exist in the geothermal water. Even considering potential drawbacks, most geothermal developers agree that double flash is more effective than single flash because a larger portion of the resource is used.

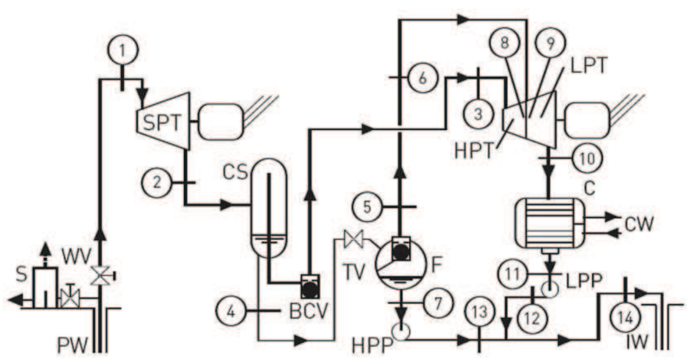

Fig.7.2.7 Triple-expansion power plant for supercritical EGS fluids.

7.2.3. Triple expansion system

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”

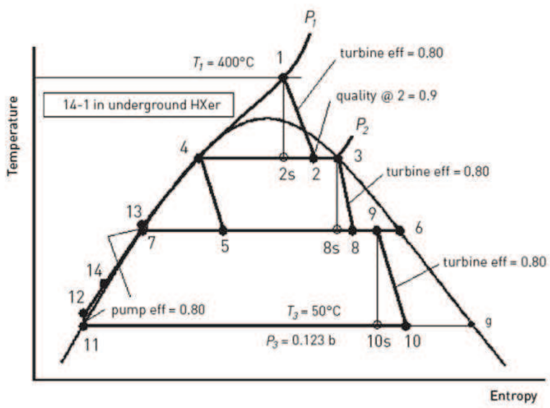

Fig.7.2.8 Processes for triple expansion power plant

system; it is shown in simplified schematic form in Figure 7.2.7, and the thermodynamic processes are shown in the temperature-entropy diagram in Figure 7.2.8.

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 7.2.8. The turbine is designed to handle the very high pressures postulated for the EGS geofluid, in much the same manner as a "super pressure" 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 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.

7.3. Binary Cycle Power Plants

Binary Cycle Power Plants operate on the lower-temperature waters, 74° to 177°C. These plants use the heat of the hot water to boil a "working fluid," usually an organic compound with a low boiling point. This working fluid is then vaporized in a heat exchanger and used to turn a turbine. The geothermal water and the working fluid are confined to separate closed loops, so there are no emissions into the air.

Because these lower-temperature waters are much more plentiful than high temperature waters, binary cycle systems will be the dominant geothermal power plants of the future.

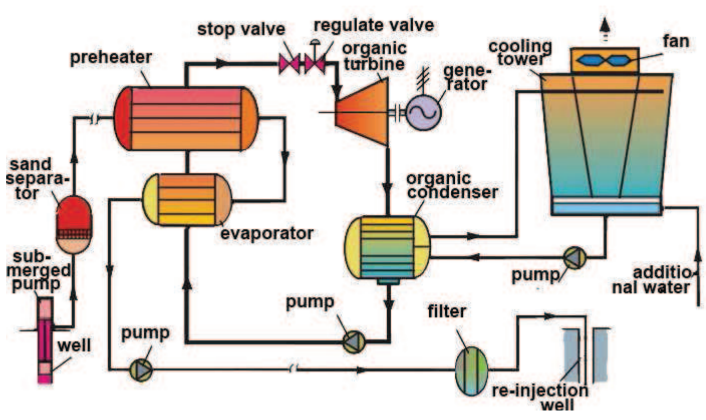

Fig.7.3.1 Simplified schematic diagram of a binary cycle power plant

Fig.7.3.2 Ormat ORC binary cycle power plant

In the binary process (figure 7.3.1), the geothermal water heats another liquid (known as the "working fluid"), such as isobutene (e.g., isopentane, propane, freon or ammonia), that boils at a lower temperature than water. The two liquids are kept completely separate through the use of a heat exchanger used to transfer the heat energy from the geothermal water to the “working-fluid" in a conventional Rankine Cycle, or alternatively Kalina Cycle (Figure 7.3.4). The secondary fluid vaporizes into gaseous vapor and (like steam) the force of the expanding vapor turns the turbines that power the generators. If the power plant uses air cooling the geothermal fluids never make contact with the atmosphere before they are pumped back into the underground geothermal reservoir, effectively making the plant emission free. The fluid in a binary plant is recycled back to the heat exchanger and forms a closed loop.

Developed in the 1980s, this technology is already in use in geothermal power plants throughout the world in areas that have lower resource temperatures. The ability to use lower temperature resources increases the number of geothermal reservoirs that can be used for power production. Approximately 15 percent of all geothermal power plants utilize binary conversion technology.

Binary cycle type plants are usually between 7 and 12 % efficient, depending on the temperature of the primary (geothermal) fluid. Binary Cycle plant typically varies in size from 500 kW to 10 MW.

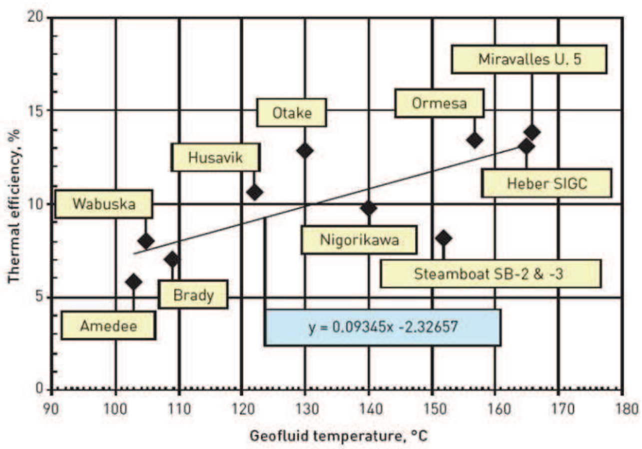

Fig.7.3.3 Correlation of binary plant cycle thermal efficiency with geo-fluid temperature in (°C)

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 plotted in Figure 7.3.3 (for several binary power plants) 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.

By selecting suitable secondary fluids, binary systems can be designed to utilize geothermal fluids in the temperature range 85-170°C. The upper limit depends on the thermal stability of the organic binary fluid, and the lower limit on technical-economic factors: below this temperature the size of the heat exchangers required would render the project uneconomical. Apart from low-to-medium temperature geothermal fluids and waste fluids, binary systems can also be utilized where flashing of the geothermal fluids should preferably be avoided (for example, to prevent well sealing). In this case, down hole pumps can be used to keep the fluids in a pressurized liquid state, and the energy can be extracted from the circulating fluid by means of binary units.

Binary plants are usually constructed in small modular units of a few hundred kW_e to a few MW_e capacity. These units can then be linked up to create power-plants of a few tens of megawatts. Their cost depends on a number of factors, but particularly on the temperature of the geothermal fluid produced, which influences the size of the turbine, heat exchangers and cooling system. The total size of the plant has little effect on the specific cost, as a series of standard modular units is joined together to obtain larger capacities.

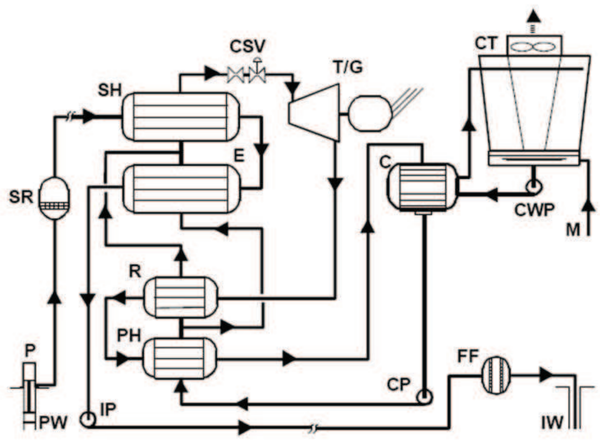

Fig.7.3.4 Simplified flow diagram for a Kalina binary geothermal power plant (DiPippo, 1999).

Binary plant technology is a very cost-effective and reliable means of converting into electricity the energy available from water-dominated geothermal fields (below 170°C).

A new binary system, the Kalina cycle, which utilizes a water-ammonia mixture as working fluid (70% ammonia and 30% water), was developed in the 1990s. The working fluid is expanded, in superheated conditions, through the high-pressure turbine and then re-heated before entering the low-pressure turbine. After the second expansion the saturated vapor moves through a recuperative boiler before being condensed in a water-cooled condenser. The Kalina cycle is more efficient than existing geothermal ORC binary power plants, but is of more complex design.

Geothermal fluids never make contact with the atmosphere before they are pumped back into the underground geothermal reservoir. Because the geothermal water never flashes in air-cooled binary plants, 100 percent can be injected back into the system through a closed loop. This serves the dual purpose of reducing already low emissions to near zero, and also maintaining reservoir pressure, thereby extending project lifetime.

7.4. Combined cycle system

In a combined single flash cycle and binary cycle, the heat from hot separated brine or exhaust steam from the back-pressure steam turbine is transferred to a secondary binary fluid. In this thesis, three configurations of combined cycles are considered.

7.4.1. Brine bottoming binary (BBB) system

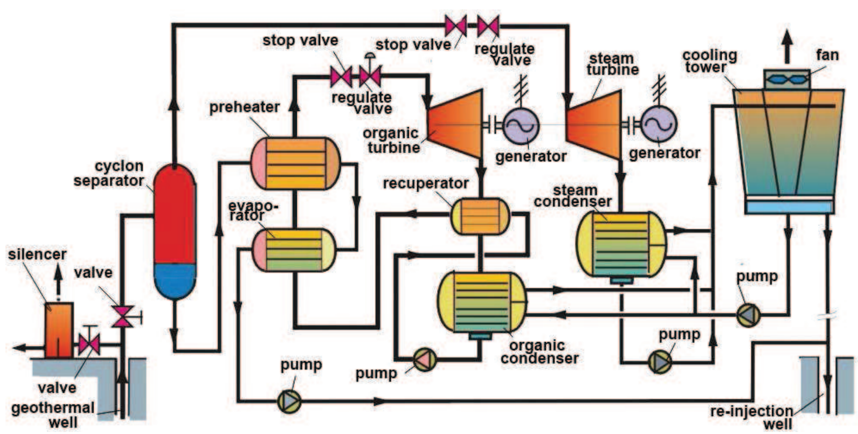

Fig.7.4.1 Simplified schematic diagram of a BBB system

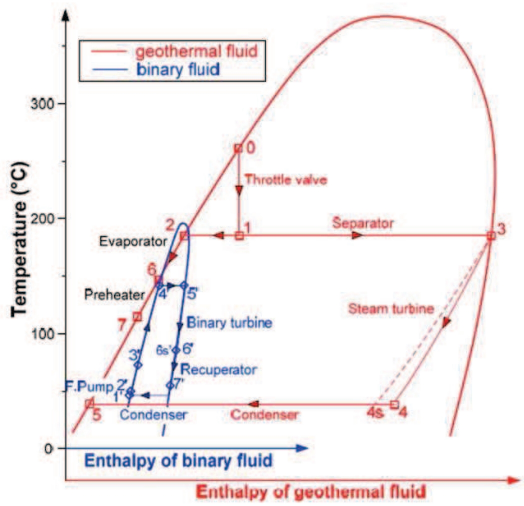

Fig.7.4.2 Temperature-enthalpy diagram of a BBB system with n-pentane as the ORC fluid

Brine bottoming binary (BBB) system is a combination of a single flash cycle using a condensing turbine and a binary cycle as a bottoming unit. The system is shown schematically in Figure 7.4.1. The dry steam from the separator is directed to a condensing steam turbine. Steam exiting the turbine is directed to a condenser operating at vacuum pressure. The hot separated brine which still contains high enthalpy is utilized to vaporize the working fluid in the binary cycle and thus produce additional power output.

The working fluid is selected by considering the critical temperature and pressure for optimizing power output of the plant. The following table shows the critical temperature (Tc) and the critical pressure (Pc) of some common working fluids for binary plants.

The working fluid absorbs heat from a heat source, in this case the hot brine, via shell and tube heat exchangers. This heat causes the working fluid to evaporate, producing the high pressure vapor that is then expanded through a turbine which is connected to a generator. The exhaust vapor from the low pressure turbine is then condensed using either air-cooled or water-cooled shell and tube heat exchangers. In this case, a water cooled system coupled with a wet cooling tower is used. From the condenser, the liquid working fluid is pumped to a high pressure and returned to the boiler to close the cycle. Due to silica scaling which limits the excess brine temperature, it is feasible to incorporate an additional heat exchanger into the cycle, known as a recuperator. In a recuperator, residual sensible heat in the low-pressure turbine exhaust stream is used for initial preheating of the cold liquid from the feed pump. A temperature-enthalpy diagram of a brine bottoming binary system is shown in Figure 7.4.2.

7.4.2. Spent steam bottoming binary (SSBB) system

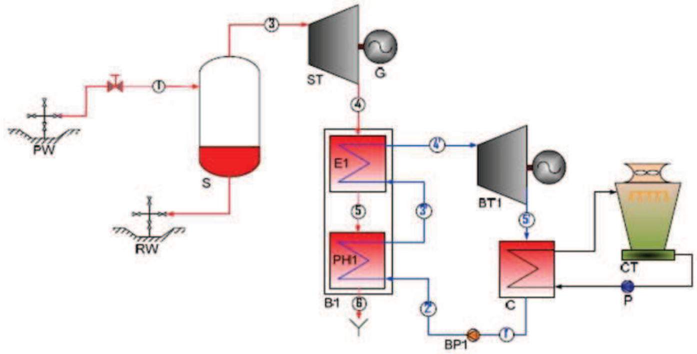

Fig.7.4.3 Simplified schematic diagram of a SSBB system [13]

A spent steam bottoming binary (SSBB) system is a combination of a single flash cycle using a back pressure turbine and a binary cycle. A SSBB system is very suitable for utilizing geothermal fluid containing high non condensable gasses which make it to use a condensing turbine. The system is shown schematically in Figure 7.4.3. The dry steam from the separator is

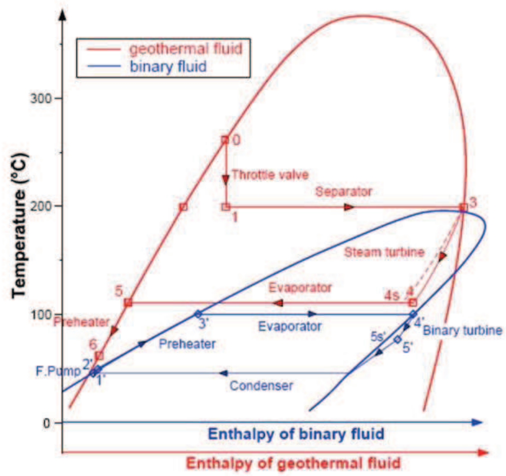

Fig.7.4.4 Temperature-enthalpy diagram of a SSBB system [13]

directed to a back-pressure steam turbine. Steam exiting the turbine is then condensed in the pre-heater and the evaporator of the binary cycle. Thus, condensation heat of the steam is used to vaporize the working fluid in the binary cycle.

A condenser for the binary cycle shown in Figure 7.4.3 is a water-cooled condenser, but an air-cooled condenser is a better choice if there are not enough water supplies at plant site. The temperature enthalpy diagram of a SSBB system is shown in Figure 7.4.4. The net power output of a SSBB system is calculated by summing up the power output of the turbines (steam turbine and binary turbine) and subtracting the auxiliary power consumption of binary fluid pumps, cooling-water pumps and cooling tower fans.

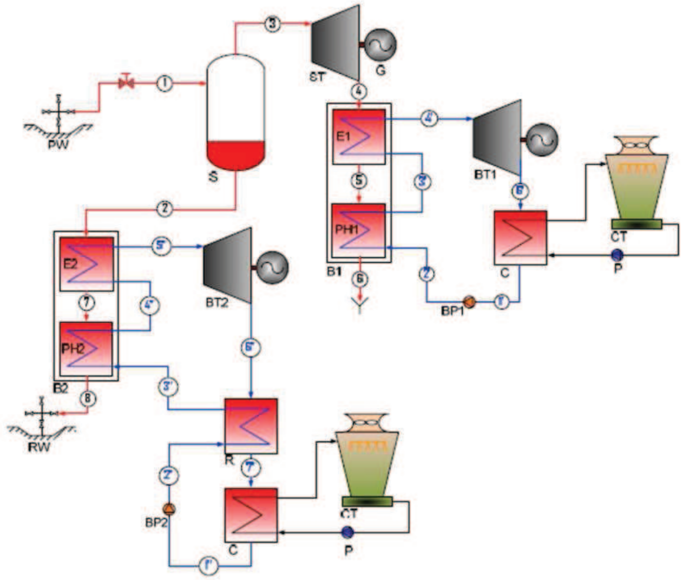

Fig.7.4.5 Simplified schematic diagram of a hybrid system

7.4.3. Hybrid system

Basically, a hybrid system is a combination of a SSBB system and a BBB system. This plant configuration consists of a single flash back pressure cycle, a binary cycle utilizing separated brine and a binary cycle utilizing the exhaust steam from the back pressure unit, as shown schematically in Figure 7.4.5. The dry steam first powers the back-pressure steam turbine and is then condensed in the boiler of the first binary cycle. The separated brine is used to preheat and evaporate the working fluid in the second binary cycle.

A temperature-enthalpy diagram of a hybrid system is shown in Figure 7.4.6. The net power output of a hybrid system is calculated by summing up the power output of the turbines (steam turbine and binary turbines) and subtracting the auxiliary power consumption for binary fluid pumps, cooling-water pumps and cooling tower fans.

This plant configuration is used for example in the 125 MW Upper Mahiao plant in the Philippines, the 100 MW Mokai I and Mokai II plants in New Zealand and the 30 MW Puna plant in Hawaii (Bronicki, 2008).

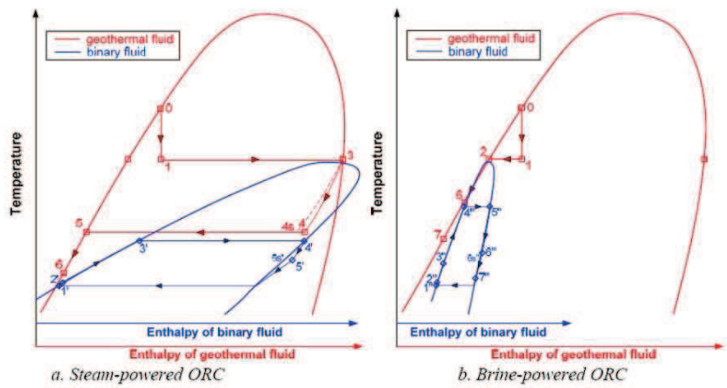

Fig.7.4.6 Temperature-enthalpy diagram of a hybrid system [13]

7.5 Cogeneration of Electricity and Thermal Energy

In Reykjanes peninsula in Iceland, in 1989, was released the first part of the 12 MWe Svarsengy geothermal cogeneration power plants. From the plant, beside electricity, is generating heat energy for central heating of 10 settlements on the peninsula west of the capital, Reykjavik. The heat capacity is 125 MWt, and the electrical power output is 16,4 MWe. The main heating plant scheme which is consists of one steam turbine, which works with dry steam from the wells and two turbines with organic working fluid, is given in figure.7.5.1.

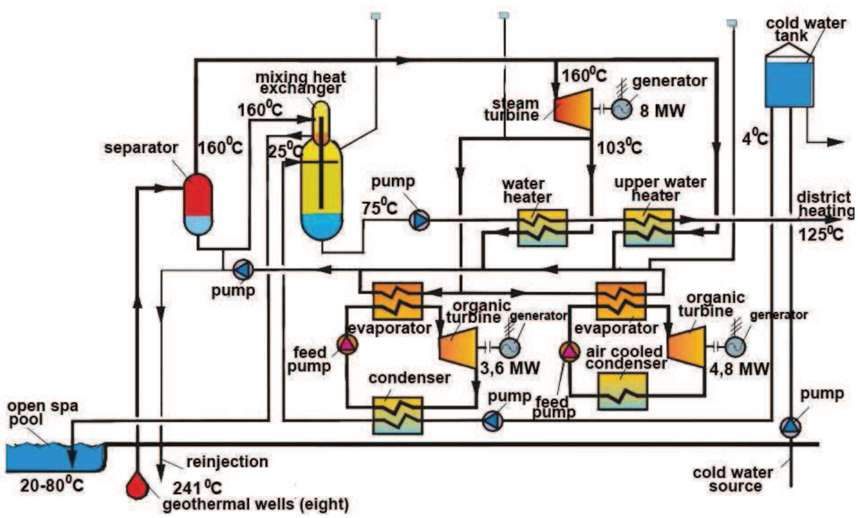

Fig.7.5.1 Simplified schematic diagram of Svarsengy geothermal cogeneration power plants In Reykjanes peninsula in Iceland

8,4 MWe electricity is produced from two turbines with organic working fluid, and 8 MWe from steam turbine which works with geothermal steam from steam separator. Waste heat from the steam turbine condenser is used for heating water intended for district heating, and waste heat from one organic working fluid condenser is discharged into a very popular outdoor swimming pool.

Hot water from eight geothermal wells (Fig.7.5.1), with a temperature of 241^{o}C, is carrying in an expander-separator, where lowering the pressure gets dry steam with a temperature of 160^{o}C. The resulting dry steam is going to the back pressure steam turbine in which expands to a temperature of 103^{o}C, and in generator is getting 8 MWel electricity. Part of the steam from the expander is carrying to the heat exchanger intended for heating water for central heating, when outside temperatures are very low. The low pressure steam from back pressure turbine is divided into two parts. One part is used for heating water for central heating in the main heater, and the second part of the working fluid is carrying in evaporators for evaporation of organic working fluid for both plants.

Condensate from geothermal steam intended for heating water for central heating and evaporation of the working fluid in the plants with organic working fluid, by one circulating pump is returning to the reinjection wells. Water from expander-separator, with a temperature of 160°C is carrying in the mixing heat exchanger which heats the water that is used for central heating. Part of the steam condensate is carried in the open swimming pool.

In one of the organic power plants, condensation of the working fluid is carried in the air-cooled condenser, and in the second one condensation is carried out with the help of cold water, which is obtained from the cold water source. Cold water from the well with a circulating pump is carrying in the cold water tank (with a temperature of 4°C), from where by a circulating pump go thought the condenser of one organic power plant, where is heated to 25°C, and entered into the mixing heat exchanger.

Figure 7.5.2 shows the basic system for upgrading a geothermal fluid for various industrial process pressures. Incorporated in this system is a flash vessel for the production of steam, a compressor driven by an isobutene turbine, an isobutane condenser, and a heat exchanger to heat and evaporate the condensed isobutene using the geothermal fluid. The compressor work requi-red should be such that the total geothermal fluid needed to produce the required flash steam is equal to the amount of hot liquid needed (at the temperature after flashing) to produce the work required by the isobutene turbine for compression. This type of design results in the minimum total fluid to produce process steam. However, with lower temperature geothermal wells (<135°C), the resulting pressure of the isobutene vapor is low.

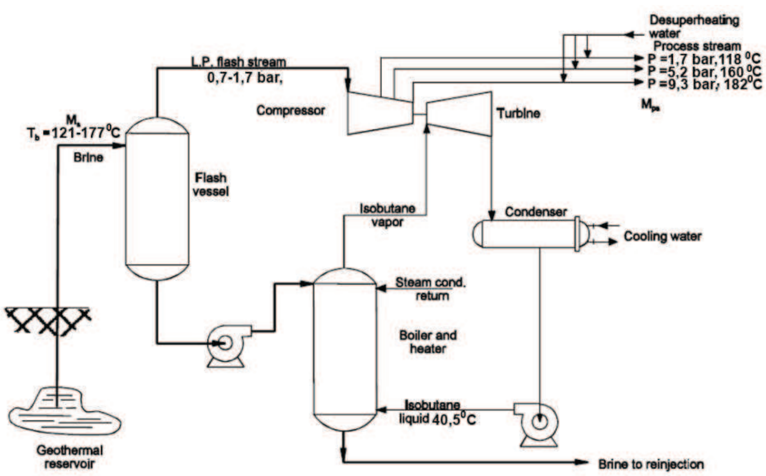

Fig.7.5.2 Basic system for upgrading geothermal fluid

One of the possible uses of EGS-produced fluids is to provide both electricity and heat to residential, commercial, industrial, or institutional users.

Figure 7.5.3 is a flow diagram in which an EGS well field replaces the fossil energy input to the existing MIT-COGEN plant and supplies all of the current energy requirements.

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.

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.

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 7.5.4). 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.

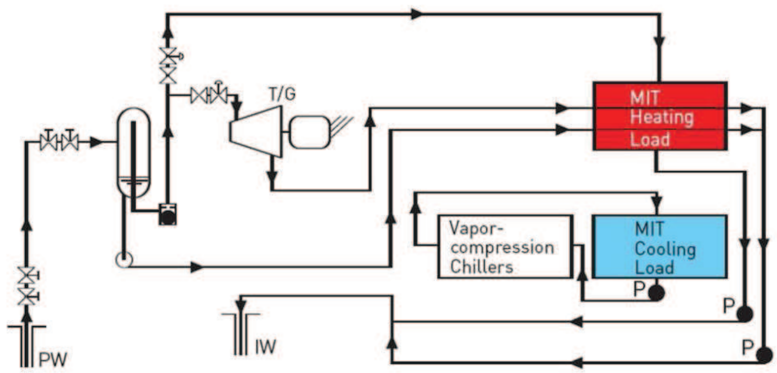

Fig.7.5.3 EGS system to supply MIT-COGEN energy requirements

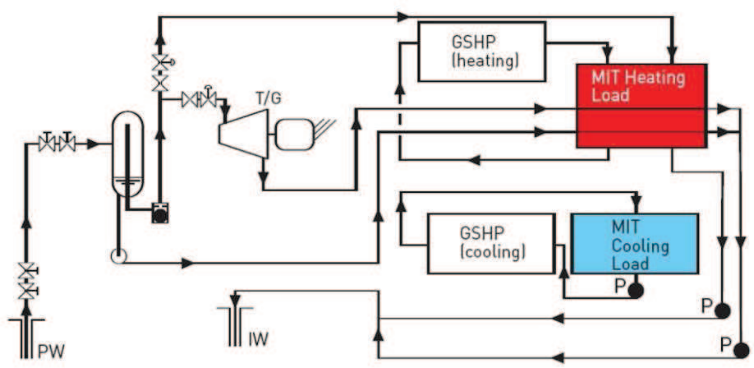

Fig.7.5.4 EGS system to supply MIT-COGEN energy requirements using ground-source heat pumps