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EME 580: Integrative Design of Energy and Mineral Engineering Systems

Feasibility and Design of an Engineered Geothermal System using Dry and Abandoned Holes as a Prospective Location

FINAL REPORT

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Amirreza Ghasemi

Dennis Arun Alexis

Pichit Vardcharagossad

Vijayragavan Krishnamoorthy

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1 INTRODUCTION

Engineered or Enhanced Geothermal Systems (EGS) extract heat energy available from the Earth's crust by forced circulation of fluid through a network of artificially created fractures. EGS can be developed in any part of the world as compared to conventional geothermal systems which rely on the presence of heated water located at extractable depths to establish natural hydrothermal circulation to produce power. Geothermal power plants are currently operating in the states of Hawaii, Utah, Nevada and California. According to the MIT report published in 2006, the geothermal resources base present in the United States available for commercial exploitation to generate electricity is estimated to be approximately 14 * 1024 J. (Tester *et al*., 2006). The favorable heat flow regime is predominantly present in the western part when compared to the eastern part of the United States (Figure 1-1). Typically hot dry rocks serve as ideal candidates for artificial stimulation for increasing the permeability to mine heat in an economical manner.

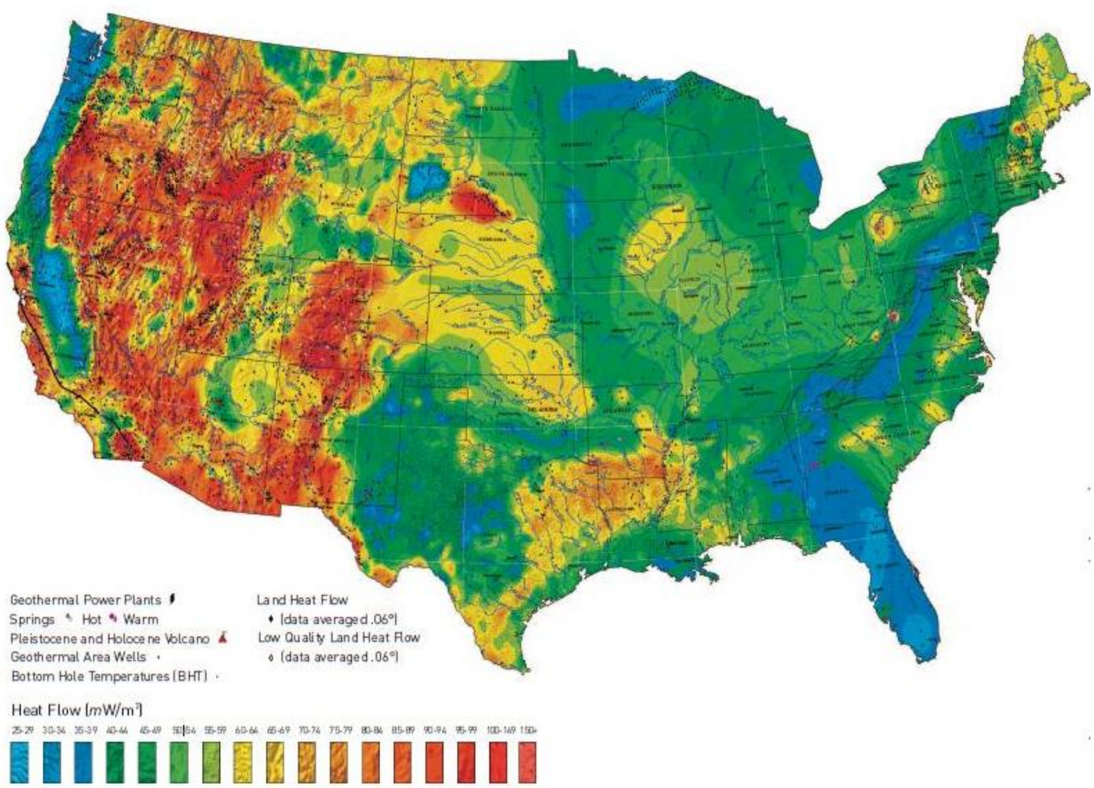

Figure 1-1- Heat flow map of the conterminous United States (Blackwell&Richards, 2004). The warmer colors indicate high heat flow regions (west)

2 PROBLEM STATEMENT AND OBJECTIVES

One of the major costs associated with the development of an EGS is attributed to drilling exploratory, injection and production wells (Petty *et al*., 1992). In the case of high grade geothermal resource the drilling and exploration costs could be 30% of the total cost and for low grade geothermal resource it could be as much as 60% (Tester *et al*, 2006).

The average depth of the dry and abandoned holes in different parts of the US (locations which had very minimal to no show of hydrocarbons) is estimated to be about 6000ft (EIA, 2008) If these locations could be used to establish geothermal production wells then there could be substantial savings in initial development costs which in turn could drive the establishment of test and operational EGS facilities on a large scale.

2.1 Objectives

To evaluate the economic, environmental and design viability in extracting thermal energy using Enhanced Geothermal Systems (EGS) from existing dry holes which are located near to existing gas fields.

To investigate different power plant designs and to select the most optimum design.

3 LOCATION SELECTION AND IDENTIFICATION

3.1 EGS Location

The factors that have to be considered for selecting an EGS development site are:(Tester *et al*., 2006)

1. Proximity to demand
2. Temperature gradient
3. Structural Information(tectonic stresses)
4. Regional Stress Regime
5. Large rock volume
6. Thick sedimentary cover
7. Water availability and storage
8. Lithology
9. Micro seismic monitoring

By looking at the factors listed above, we can see that the development of an EGS is dependent on favorable market, working fluid and subsurface characteristics.

Geothermal plants are currently operating in the states of California, Hawaii, Utah and Nevada with the first geothermal pilot plant established in Fenton Hill, New Mexico in 1974 . Presence of suitable thermal regime, hot springs and geysers in the western United States aided the growth of the geothermal power plants in the region.

In this study, for selecting a suitable location for an EGS unit the states of Texas, New Mexico, Arizona, Idaho & Colorado were considered due to the fact that these states have oil and gas drilling activity and have preferable heat flow regime. Moreover the possibility of finding dry and abandoned locations in these states is high since there are thousands of active hydrocarbon producing wells.

The state of Colorado was chosen for locating a couple of EGS wells (producer and injector) due to the reason that it has a high heat flow anomaly in various regions (Colorado Geological Survey, 2010). This could be due to the fact that Colorado has had significant volcanic activity in the last 23 million years. Due to this high heat flow anomaly, Colorado ranks 4th in the number of probable sites for geothermal power development among western states.

Moreover, Colorado has more than 60,000 oil and gas wells (Colorado Oil and Gas Conservation Commission, 2010) and there are a significant amount of dry and abandoned locations at reasonable depths

Establishing a power plant in any region has to be basically based on the availability of market or demand. Table 3-1 shows the estimated electricity power production potential from geothermal resources for Colorado to be 20 MW by the year 2015.

Table 3-1- Power generating capacity estimate for western states from Geothermal Resources (WGA, 2006)

State	Near-Market cost up to 8 cent/kWh online within 10 years (2015)	Longer-Term cost up to 20 cent/kWh online within 20 years (2025)
Alaska	20	150
Arizona	20	50
Colorado	20	50
California	2375	4703
Hawaii	70	400
Idaho	855	1670
Nevada	1488	2895
New Mexico	80	170
Oregon	380	1250
Utah	230	620
Washington	50	600
Total	5,588 MW	12,558 MW

For selecting a region and a potential location within the state of Colorado, the public GIS online map provided by the Colorado Oil and Gas Conservation Commission (COGCC) was utilized.

Two dry and abandoned locations were identified in the San Juan basin region in LA PLATA County. These two dry holes have about 8000 ft true vertical depth separated by a distance of 325 ft on the surface. Figure 3-1 shows the exact location of these two dry and abandoned locations that would be utilized in this study for developing the EGS unit.

The prospect of developing a doublet (injector and producer) is being considered based on a similar experiment conducted near Berlin, Germany (Huenges *et al*., 2007) where two deep boreholes were drilled to a depth of 4.3 km, separated by a distance of 472 m at that depth. Since we already have 8000 ft of drilled depth available we have to drill about 6000ft extra to reach a depth of 4 km where we can find favorable bottom-hole temperatures for the heat mining process.

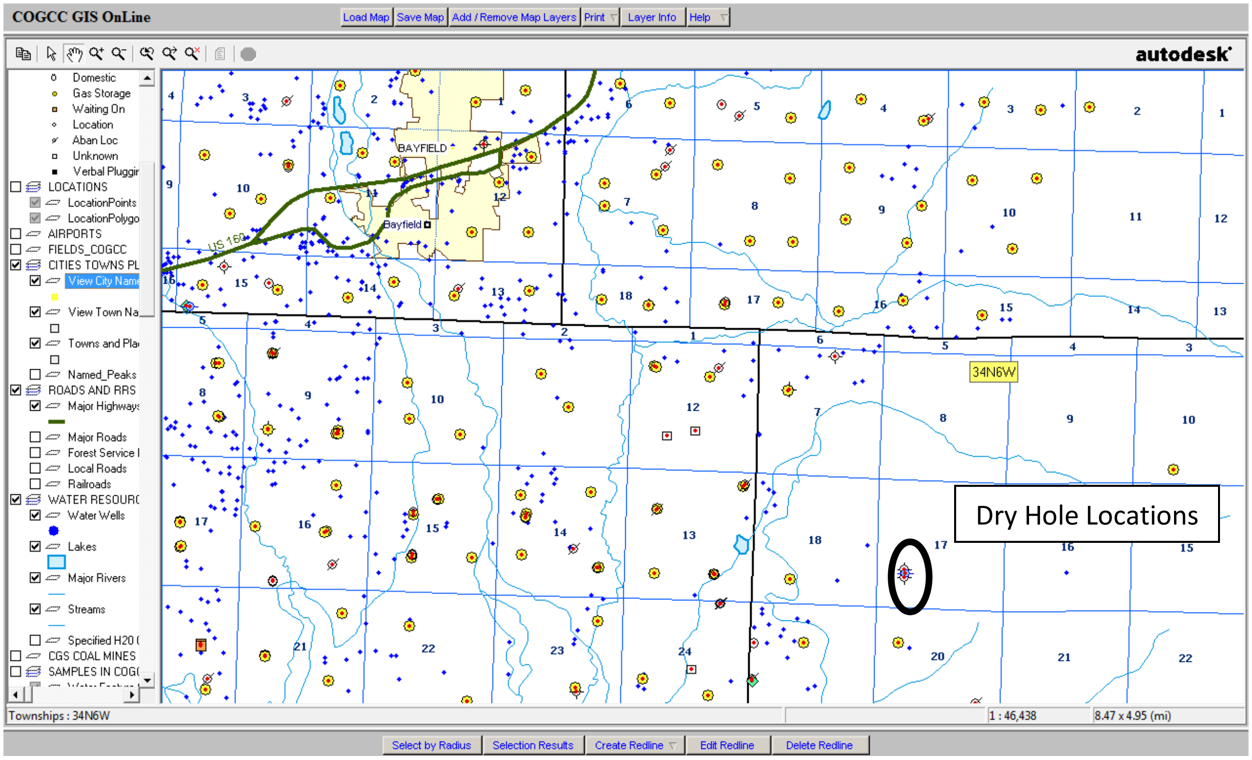

Figure 3-1- Online GIS MAP showing the location of the potential dry holes (circled in black)

4 GEOLOGY

The San Juan Basin occupies approximately 7,500 square miles in northwestern New Mexico and southwestern Colorado. As can be seen in Figure 4-1 , it is an asymmetrical syncline structure that trends east-west with a gently dipping southern flank and steeply dipping northern flank. The San Juan basin is formed in the Late Cretaceous and early Eocene. Regional extension during the Oligocene was accompanied by volcanic eruptions that formed the San Juan volcanic field and emplaced batholiths and igneous dikes north of the San Juan basin. Higher heat flux associated with the igneous event, or heat advection associated with groundwater movement, caused anomalously high thermal maturity in the northern San Juan basin.

San Juan Mountains represent the main volcanic province of Colorado State. The mountains are comprised dominantly of Tertiary volcanic rocks, with lesser amounts of Precambrian igneous and metamorphic, and upper Paleozoic and Mesozoic sedimentary rocks located on the southwest side of the volcanic field. The volcanic rocks are mainly welded ash flow tuffs that were erupted from at least 15 calderas.

The wells which were selected pas through these rock formations:

Kirtland, Fruitland, Pictured Cliffs, Lewis, Cliff house, Point lookout, Mancos, Gallup, Greenhorn, Graneros, and Dakota.

According to Figure 4-1 after over drilling, the wells will pass Morrison, Summerville, Entrado, and Chinle formations and the reservoir would be located in Precambrian basement.

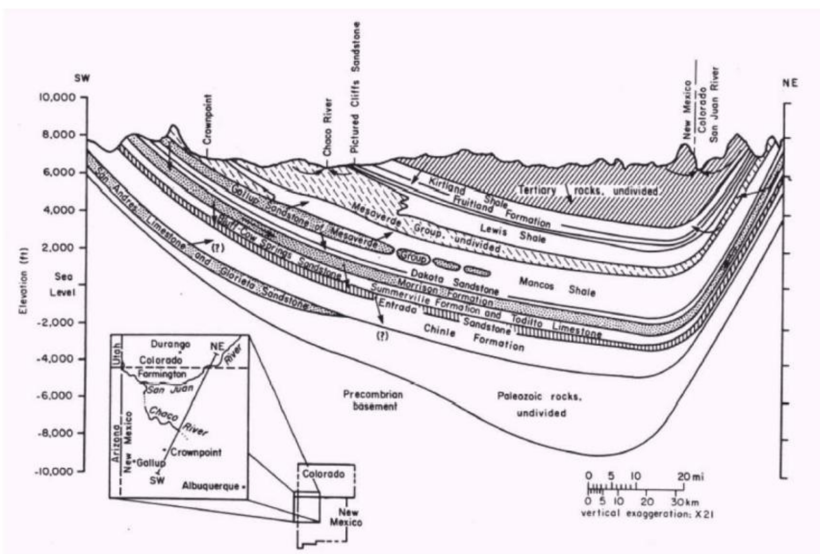

Figure 4-1- Cross section of the San-Juan Basin

5 CASE STUDIES

So far, only few EGS projects have been developed globally. As these field tests were very expensive and time consuming, it is important to study them in detail and use the lessons learned before developing any new project. Projects covered below are: Fenton Hill (USA), Rosemanowes (UK), Hijiori and Ogachi (Japan), Soultz (France), and Cooper Basin (Australia). These projects also show the evolution of EGS through time. Figure 5-1 shows the thermal output of these projects.

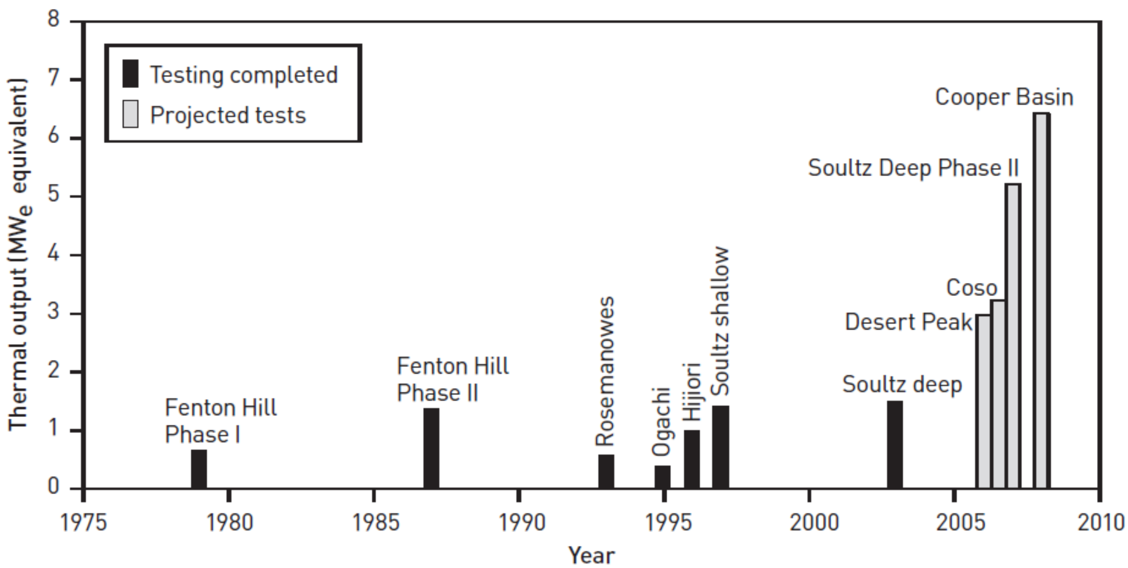

Figure 5-1- Evolution of estimated electrical power output per production well, with time from EGS projects (after Testser et. al., 2006)

5.1 Fenton Hill

Fenton Hill project is the first EGS project started in 1974. The first well drilled to the depth of 2,042 m. stimulating the reservoir was run afterwards and well deepened to the depth of 2’932 m. Bottom Hole Temperature (BHT) was about 180°C. The second well drilled down to 3,064 m with similar BTH temperature as the first well. Well stimulated using hydraulic fracturing, but the connection was not good. It was decided to directionally re-drill one of the wells into the fractured reservoir. So part of the first well was cemented and another hole directionally drilled. An acceptable connection was achieved with an average separation of 100 m between the wells. Five circulation experiments were performed, lasting for 417 days. A 60 kW binary fluid turbine generator was powered and between 3 and 5 MWt energy was produced.

In 1979, new set of wells were drilled deeper than previous wells. They were directionally drilled and separated by 380 m vertically. The deeper one reached a depth of 4,390 m and BHT of

327°C. They were hydraulically fractured at multiple depths. The progress of fractures was monitored by micro-seismic activities. The reservoir growth was not in the expected direction and connection between the wells was not enough. It was concluded that it is because of the shift in the stress field in the deeper part of the formation. Again, one of the wells re-drilled directionally to a depth of 4,018 m with BHT of 265°C. The connection considered acceptable for large scale testing. Because of a failure in casing of one of the wells, it re-drilled 800 m from the depth of 3,200 m. Flow test was conducted and did not have the high loss of fluid. At pressures below the critical pressure, the reservoir did not continue to grow. While temperature in the produced fluids changed over time, the down hole temperature did not change measurably during the testing. Long term flow test was started in 1992 and last for 112 days, until failure of the injection pumps.

Cold water was injected at 12.515 kg/s and produced at temperatures of more than 180°C. After the failure, another test was conducted for 55 days. BTH was constant, however, surface temperatures dropped, possibly because low flow rates resulted in heat loss to a shallow, cooler subsurface region.

5.2 Rosemanowes

Rosemanowes project was located in U.K. in the Carnmenellis granite. The location had high temperature gradient between 30 and 40°C per kilometer and also geology of the rocks were thoroughly understood. The main tectonic regime of the area is strike slip. Project started in 1977, with drilling some 300 m wells to test fracture initiation techniques. It was found that this depth is not representative of the deeper regions. Afterwards, two wells with the depth of 2,000 m and vertical separation of 300 m were drilled. BHT reached 79°C. Stimulation started initially with explosives, and then hydraulically at rates up to 100 kg/s and wellhead pressures of 14 MPa. It was anticipated that the reservoir will grow vertically upward; however, micro seismic monitoring showed that the reservoir is growing vertically downward. That was because the fractures were mainly due to shear not tensile fracturing.

Third well was drilled in 1983 to a Total Vertical Depth (TVD) of 2,600 m and BHT around 100°C. The well hydraulically stimulated and circulation began afterwards. A series of flow tests was then carried out. Continuous flow tests lasted for four years and led to BHT drop from 80.5°C to 70.5°C. Injection rates through the testing phase varied from 5 to 24 kg/s. In the 5 kg/s case, the return from the production well was 4 kg/s and the wellhead pressure was 40 bar. In the 24 kg/s case, the return from the production well was 15 kg/s and the wellhead pressure 10.5 MPa. In another attempt, sand was used as proppant in the joints near production well to overcome the impedance in the joints but it seemed that it worsened the short circuiting.

Also, it was tried to seal off the location of short circuit in production well but it led to very low flow rates in the well. More stimulation carried out but it did not increase the flow. It was concluded that there recent stimulated zone, is parallel and unconnected to the previously stimulated zone.

5.3 Hijiori

The Hijiori site was located in Japan. It was on the southern edge of Hijiori caldera which had a very complex stress regime. The project was started in 1989 with one injector and three producers. All wells except one of production wells (with the depth of 2,151 m), had the depth of 1,800 m. Temperature reached more than 225°C at 1,500 m. The maximum temperature in the 1,800 m deep fractures was close to 250°C. The spacing between the wells was kept to fairly small distances (between 40-50 m from injection and production wells). Natural fractures were intersected in all the wells at depths between 1,550 and 1,800 m depth making a shallow reservoir.

Two of the wells were deepened to about 2,200 m. The distance between the injection to production wells were about 80 and 130 m. Hydraulic fracturing activities were started in 1988 and 2,000 m3of water injected. Flow test started and lasted for 30 days. Total of 44,500 m3 of water was injected while 13,000 m^3 of water was produced. Another well deepened to 2,205 m and fractured. Afterwards, two other wells were also deepened to 2,302 m and a 25day circulation test was conducted. A total of 51,500 m^3 of water was injected, while 26,000 m^3 of water was produced.

A long term test of the deep and shallow reservoirs was initiated in 2000. A one year circulation test of the deep reservoir was conducted with injection of 36°C water at 15-20 kg/s. Production of steam and water was at 5 kg/s at about 163°C from one well, and at 4 kg/sec at 172°C from another well. Total thermal power production was about 8 MWt. The flow was used to run a 130 kW binary power plant. Test analysis showed that production was from both the deep and shallow reservoir. One interesting result of the test is that, while the injection flow rate remained constant at about 16 kg/s, the pressure required to inject that flow decreased during the course of the test from 84 to 70 bar. Total production from two wells was 8.7 kg/s with a loss rate of 45%.

One of the production wells, cooled dramatically from an initial temperature of 163°C to about 100°C during the long term flow test. The test was finally halted, due to the drop in temperature which was more than anticipated.

5.4 Ogachi

The Ogachi project is also located in Japan. The injection well was drilled in 1990 to a depth of about 1,000 m and temperature of 230°C. Fracture stimulations were done in bottom of the well. Also some stimulation were performed at a depth of 710 m. Production well was drilled in 1992 to a depth of 1,100 m, where a temperature of 240°C was reached. The well is less than 100 m from injection well. A circulation test in 1993 showed only 3% of injected water was produced.

Production well was stimulated again in 1994. A five month circulation test following this stimulation showed that only 10% of the injected water was produced back. The production and injection wells were again stimulated in 1995. A one month circulation test showed an improved recovery of more than 25% of the total injection.

Another well drilled in 1999 into fractures indicated from acoustic emissions mapping. Borehole tele-viewer imaging was used to observe fractures in the wellbore. Testing showed an improved response to injection.

5.5 Soultz

Soultz project is located in France in the former Pechelbron oilfield. In 1987, the first well was drilled to 2,002 m depth with BHT around 140°C. The sediment is about 1,400 m thick and it overlays a granitic basement. Three existing former oil wells were deepened to provide good coupling for seismic sounds.

An existing oil well was deepened from a depth of 930 m by continuous coring to 2,227 m, where a temperature of 150°C was encountered. First well was stimulated with high flow rates targeting the open hole section from 1,420 to 2,002 m. A fractured volume of 10,000 m^3 was created based on micro-seismic mapping. Then the well was deepened to 3,590 m, reaching a temperature of 168°C. The well was again stimulated, using large flow rates, this time targeting the newly drilled segment from 2,850 to 3,590 m.

Targeting and drilling of the second well to 3,876 m at a temperature of 168°C was done in 1995. The bottom hole location was 450 m from the first well. Analysis showed that the rock at 2,000–3,000 m depth contained large numbers of joints and natural fractures. The in situ reservoir fluid is saline with total dissolved solids (TDS) of about 100,000 mg/l (10% by weight).

During 1995, second well was stimulated in the open hole section from 3,211–3,876 m, with a maximum pressure of about 10 MP and a flow of 50 kg/s. First well showed a significant pressure response to the stimulation which showed a connection between two wells. A two week circulation test was then performed by injecting into the second well and producing from first well.

With the production well pumped, a circulation rate of more than 21 kg/s was achieved. The surface temperature of the produced water approached 136°C (injection was at 40°C), with a thermal power output of about 9 MWt. The use of a production pump helped maximize power output in this situation, with large open fractures.

In 1996, second well re-stimulated, using a maximum rate of 78 kg/s with a total volume of 58,000 m^3 injected. Following this stimulation, a four month, closed loop flow test was conducted. Injection and production stabilized at 25 kg/s, with no net fluid losses. Only 250 kWe pumping power was required to produce the thermal output of 10 MWt.

In 1998, second well was deepened to the depth of 4,950 m (TVD) where BHT was about 200°C. During the summer of 2000, the well was stimulated using heavy brines to attempt to stimulate the deeper zones preferentially. Nearly 23,400 m^3 water was injected at flow rates from 30 kg/s to 50 kg/s, with a maximum wellhead pressure of 14.5 MPa. The acoustic emissions mapping was used to monitor reservoir growth. No leak off to the upper reservoir was detected and the majority of the fluid exited the open hole at the bottom during stimulation. A number of geophysical logging runs were made to assess the natural and stimulated state of the well.

Starting in 2001, the deep production wells were drilled. All of the wells were started from the same pad. The new well was drilled to 5,093 m and then stimulated. The bottom hole separation between the wells was 600 m.

In 2003, a deviated well was drilled to a TVD of 5,105 m from the same platform as others into a target zone selected from the stimulation of the third well. The bottom of fourth well was separated from the bottom of third one by about 650 m (a total deviation of some 1,250 m). During drilling of the fourth well, the reservoir was tested by injecting into third well and producing from second well. The tests established there was an excellent connection between the two wells with productivity index of 3.5 kg/s/MPa.

Following completion, fourth well was stimulated by injecting heavy brine to encourage development of deep fractures. While an area of enhanced reservoir developed, a linear aseismic zone was apparent, separating this well from the other two deep wells. Despite a second stimulation and acidizing, no good connection yet exists. The injectivity index for this well was good, but the well was not well connected to the other two.

5.6 Cooper Basin

This project is located in a granitic basement in the Cooper Basin where oil and gas drilling indicated temperatures approaching 250°C at a depth of 4 km. The regional stress is over thrust. This area is perceived to have many radiogenic granites and other uranium rich rocks that could lead to high temperatures at relatively shallow depths in the crust. The first well was completed in 2003 to a depth of 4,421 m. Data collected from oil and gas wells along with the drilled well suggest that the granite is critically stressed for shear failure in a sub-horizontal orientation.

The bottom hole temperature was 250°C. Following completion, the first well was stimulated. Pressures up to about 70 MPa were used to pump 20,000 cubic meters of water into the well. This first stimulation created a fractured volume estimated from acoustic emissions data estimated at 0.7 km^3. The stimulation also involved attempts at depths between 4,136 m and 3,994 m; but only the zone at 4,136 m took substantial fluid and generated micro-seismic events in new areas. Following the series of stimulations, the fractured volume had expanded to cover a horizontal pancake shaped area of approximately 3 km^2. Second hit the fractures at 4,325 m. In 2005, flow test started and up to 25 kg/sec flows were measured, and a surface temperature of 210°C achieved. In 2005, first well again was stimulated with 20,000 cubic meters of water injected and, based on acoustic emissions data, the old reservoir was extended by another 50% to cover an area of 4 km^2.

5.7 Lessons learned

- Hydraulic fracturing method can create permanently open fractures in large volumes of rock (>1 km 3) to overcome the need of production for a long time period.
- Creating the connection between wells is a crucial step in developing the EGS reservoir
- Techniques using chemical tracers, active and passive acoustic emissions methods, and other geophysical logging techniques can be used to map the created fractures.
- If injection pressures were lowered to reduce water loss and reservoir growth, the flow rates were lower than desired, due to higher pressure drop through the reservoir.
- The fractures created by hydraulic stimulations, are due to shearing on preexisting joint sets.
- In the general case, a prediction of the direction of fracture growth is difficult in the absence of precise down hole data. Even with near wellbore data from image logs, the fractures may not grow exactly as predicted. As a result, it is better to create the reservoir first, and then drill into it.
- Pressure drop through the system (impedance) is a major problem. It is very important because, first, the higher the pressure drop, the greater the pumping power required and second, a high impedance requires high down hole pressures to achieve the required flow rate, and these could easily exceed the levels at which runaway fracture growth and consequent water losses are incurred.
- Placing proppants in this near wellbore area in the injector may require high pressures and flow rates that increase the likelihood of short circuits.
- Over stimulating preexisting fractures can result in a more direct connection from injector to producer than is desired.
- Pressurizing a reservoir is irreversible and not necessarily useful, e.g. pumping too long at too high a pressure will cause irreversible rock movements that could drive short circuits as well as pathways for water losses to the far field.
- The reservoir continued to grow during the circulation test.
- Well spacing needs to be as large as possible while still making a connection.
- The point at which stimulation commences in an open wellbore – and then becomes focused – depends on existing conductive fractures, the stress gradient, and fluid density.
- Identifying an extensive body of granite with relatively uniform properties can yield a huge potential heat resource.

- Over thrust stress environments are ideal for stimulation, leading to development of horizontal reservoirs

6 GEOTHERMAL RESERVOIR SIMULATION

Simulation models can provide a good insight of how a reservoir would behave with time. By simulating a reservoir under a given set of conditions, one can see the pressure and in our case the temperature changes within the reservoir which will in turn help to decide the optimum development plan. One of the most important aspect of simulation is to select the type of model that is applicable to the case we are interested in modeling.

6.1 Model Selection

We want to simulate enhanced geothermal systems which are fractured systems and have dual porosity characteristics. To simulate an EGS system, we need to first select a model which would ideally capture the mass and heat transport in a fractured system. The model selected is the MINC (Multiple Interacting Continua Model). This model was developed by (Pruess & Narasimhan, 1982b) for modeling naturally fractured geothermal systems. In this model in addition to tracking matrix – fracture transport process, the matrix is divided into sub elements so that inter- matrix transfer processes are also captured. Figure 6-1 shows the representation of the fracture matrix and inter – matrix interaction phenomena of the MINC model.

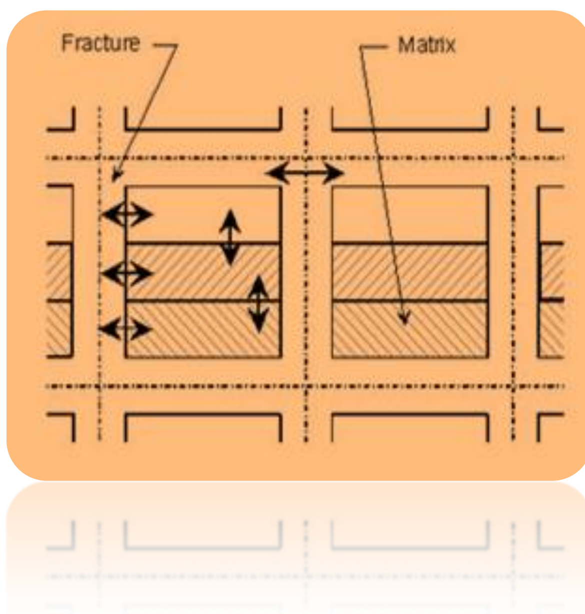

Figure 6-1- Visualization of the MINC model in a fracture and matrix blocks

6.2 Preliminary Modeling

To understand the response of the model (MINC) and to identify the behavior of the fractured reservoir, a preliminary modeling was carried out. Figure 6-2 describes the dimensions of the simulated reservoir rock volume used for the base case. As described in Section 3, the possibility of using a doublet (producer and an injector) is being explored. To discretize the system, a total of 66 blocks were used with block dimensions in the X and Y directions being 55.7 m. All the simulations are carried out using CMG-STARS, a commercial reservoir modeling package from Computer Modeling Group Ltd.

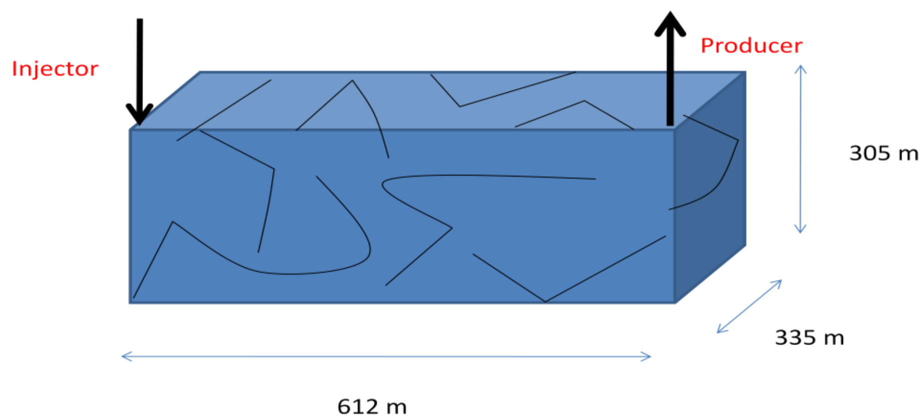

Figure 6-2- Geothermal Reservoir Setup for the base case

Table 6-1 lists the other rock and fluid parameters used for the modeling. The data especially the rock thermal properties were taken from Pruess (1983)

6.3 Preliminary Results

It is of primary interest to see the variation of temperature in the fractured reservoir rock volume with time as water at ambient temperature is continuously injected. The reservoir temperature change in time determines the production temperature at the wellhead of the production well and this temperature eventually determines the quantity of the power generated. Figure 6-3 and Figure 6-4 show the injection/production rates and variation of well bottom-hole pressures of the producer and the injector with time respectively.

In Figure 6-3, we can see that the injection and production rate of brine is steady for the entire period of operation. In Figure 6-4 we can observe that the bottom-hole pressures are increasing with time due to the fact that as the cold brine sweeps through the reservoir the fluid temperature drops leading to an increase in density. This increase in density results in a larger hydrostatic head.

Figure 6-5 to Figure 6-9 shows the snapshot (top view) of the temperature change in the reservoir with respect to time. We can see that as time progresses the temperature front is moving towards the production well from the injection well. The rate at which this temperature front moves to the producer is controlled by many factors like injection rate, well spacing, permeability of matrix and fracture, fractures, fracture spacing. In Figure 6-9 we see that the temperature front has reached the producer for the first time in about 7-8 years from the start of operation. The significance of this advancing temperature front is that it determines how long one can expect to have a steady temperature at the wellhead of the production well.

Table 6-1- Rock and Fluid Properties

Parameter	Value
Fracture Spacing	10 m
Fracture Volume Fraction	0.15
Matrix Porosity	0.1
Fracture Porosity	0.1
Matrix permeability	1×10^{-14} m^2
Fracture permeability	6×10^{-13} m^2
Injection rate(brine)	3500 m^3/day
Injection Temperature	35 C
Wellhead Pressure of the producer	10,000 kPa
Initial Reservoir Pressure	42, 000 kPa
Initial formation temperature	478 K(205 C)
Rock compressibility	4.4×10^{-7} 1/kPa
Rock heat Capacity	2.65×10^{6} J/m^3 C
Rock Thermal Conductivity	1.929×10^{5} J/ m-day-c
Heat Capacity of Overburden	2.683e6 J/(m^3*C)
Heat Capacity of Underburden	2.683e6 J/(m^3*C)
Thermal Conductivity of Underburden	1.047e6 J/(m*day*C)
Thermal Conductivity of Overburden	1.047e6 J/(m*day*C)
Initial Water Saturation	99%
Duration of Operation	20 years
Depth of Operation	4200 m

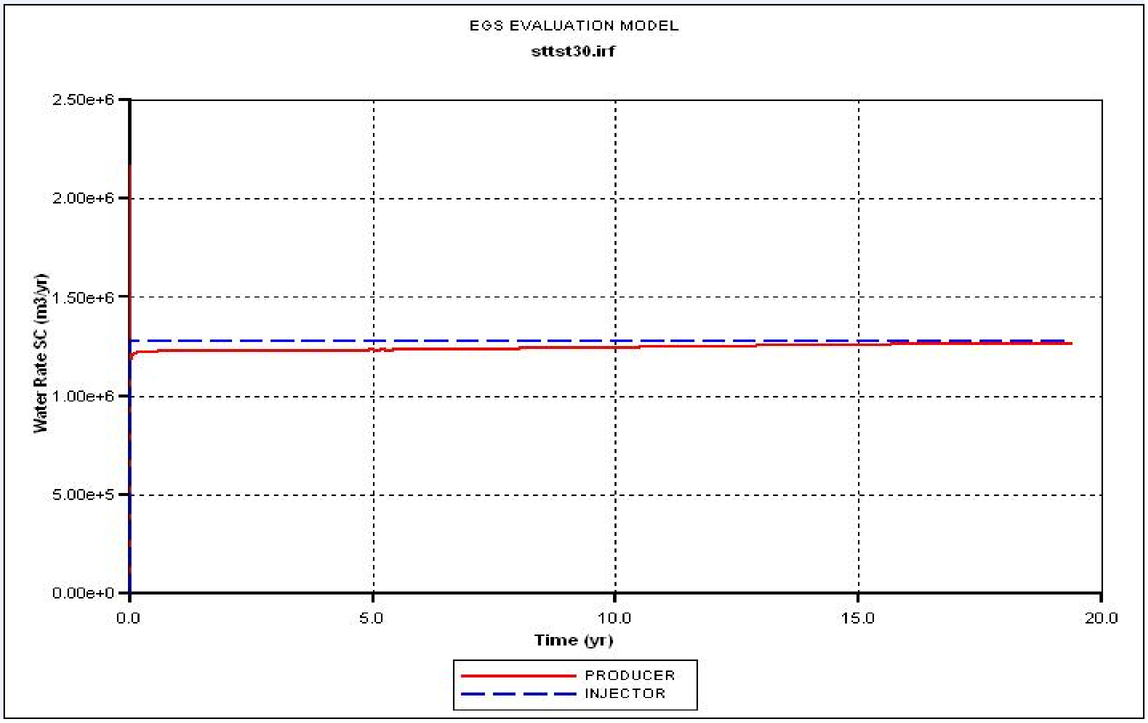

Figure 6-3- Variation of Production and Injection rates with time

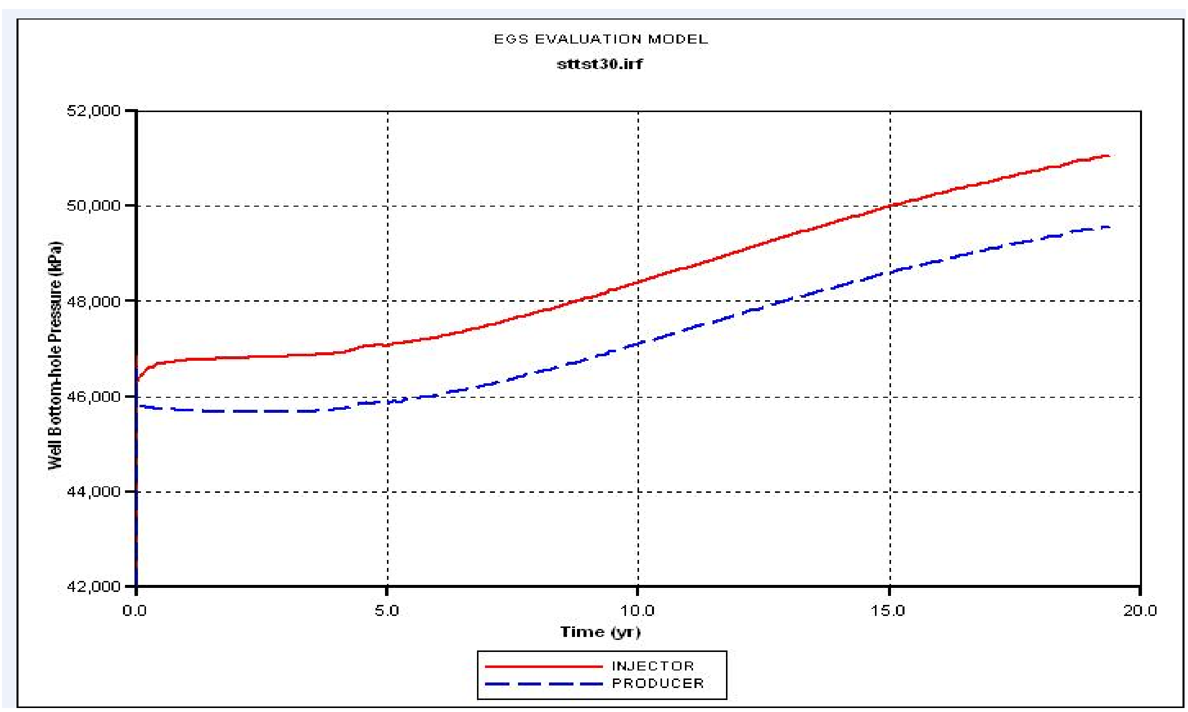

Figure 6-4- Variation of bottom-hole pressures of the producer and injector

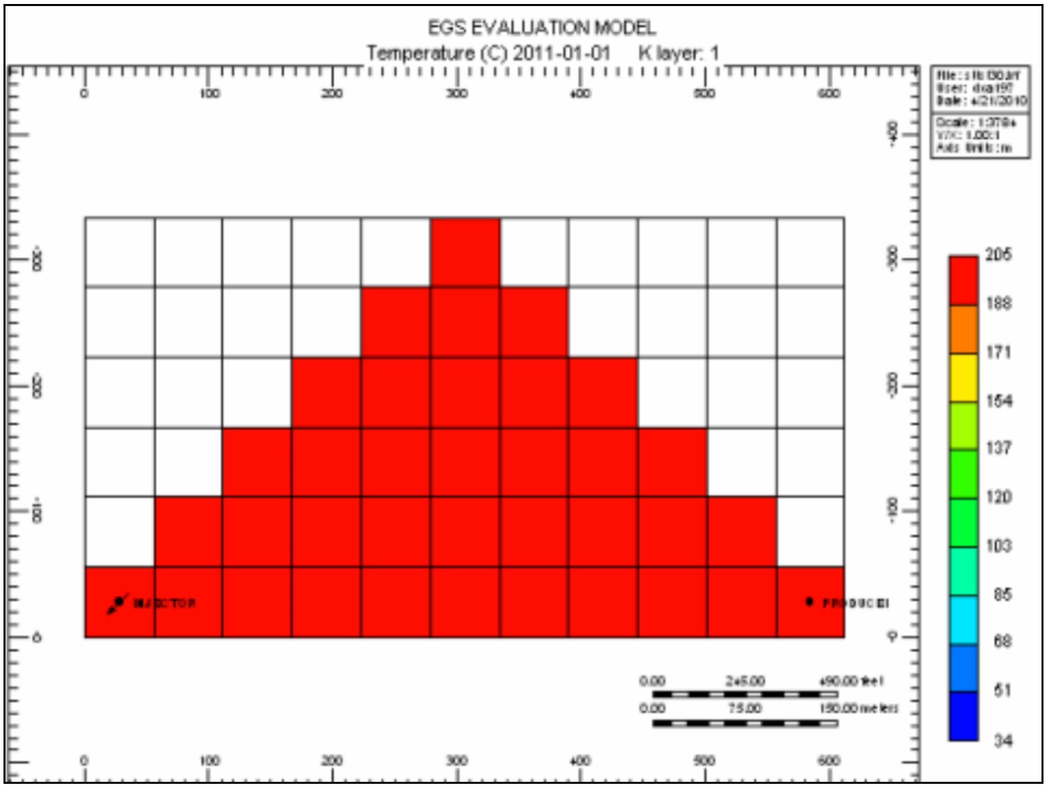

Figure 6-5- Reservoir temperature map at initial conditions

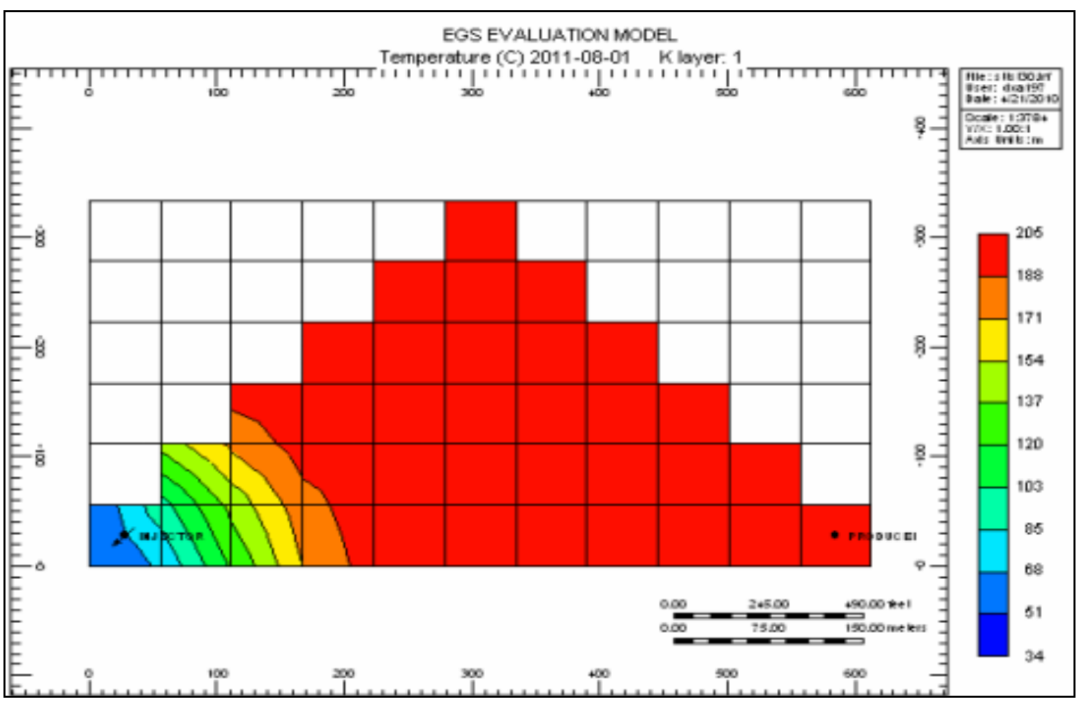

Figure 6-6- Reservoir temperature map during the 2nd year

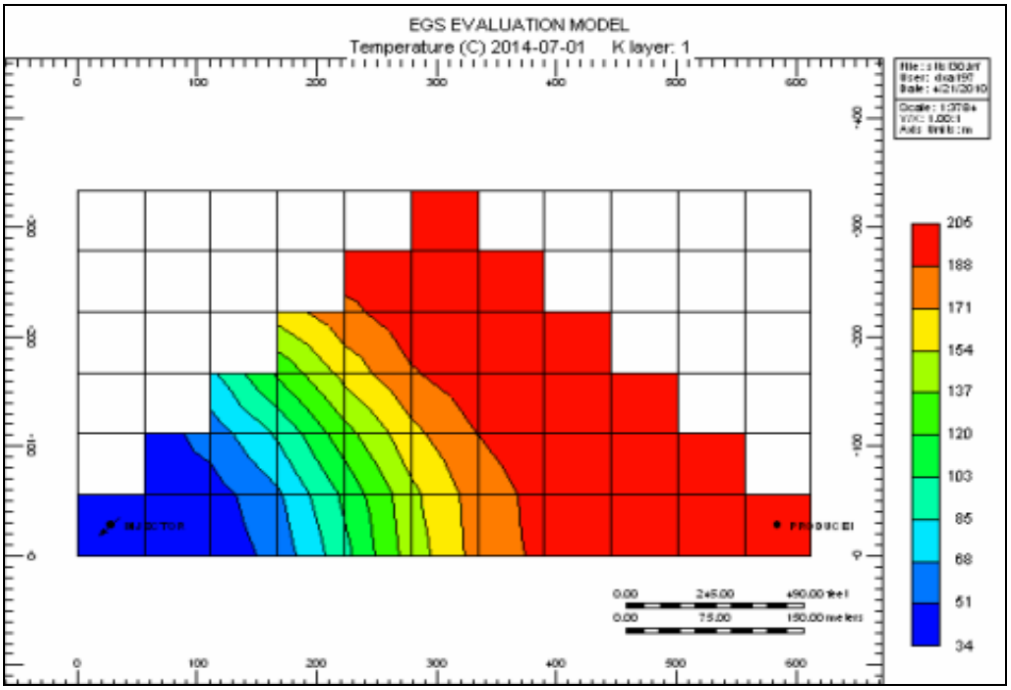

Figure 6-7- Reservoir temperature map during the 4th year

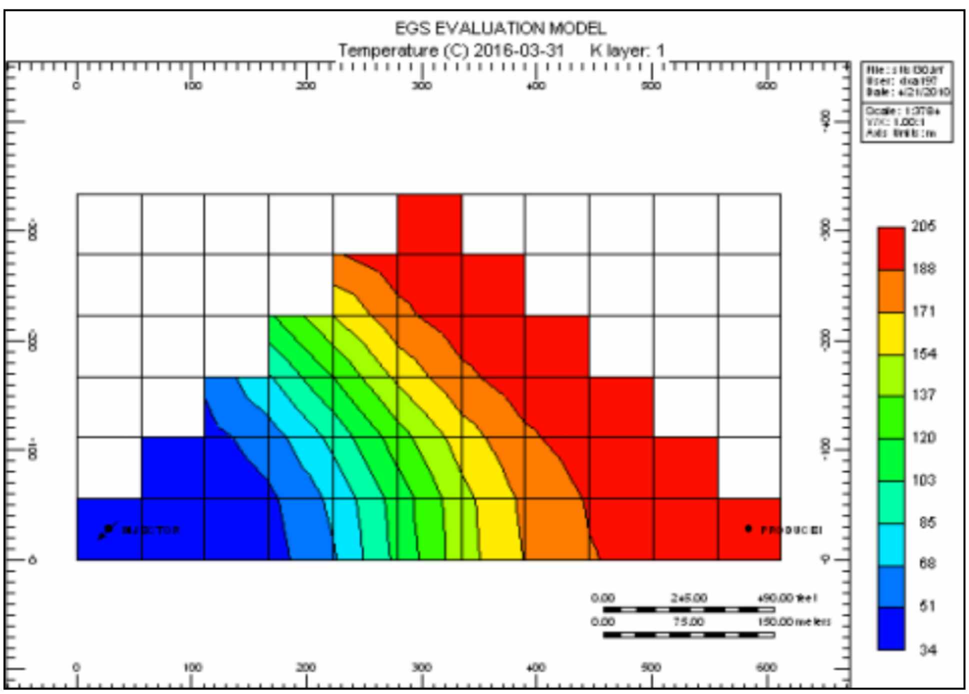

Figure 6-8- Reservoir temperature map during the 6th year

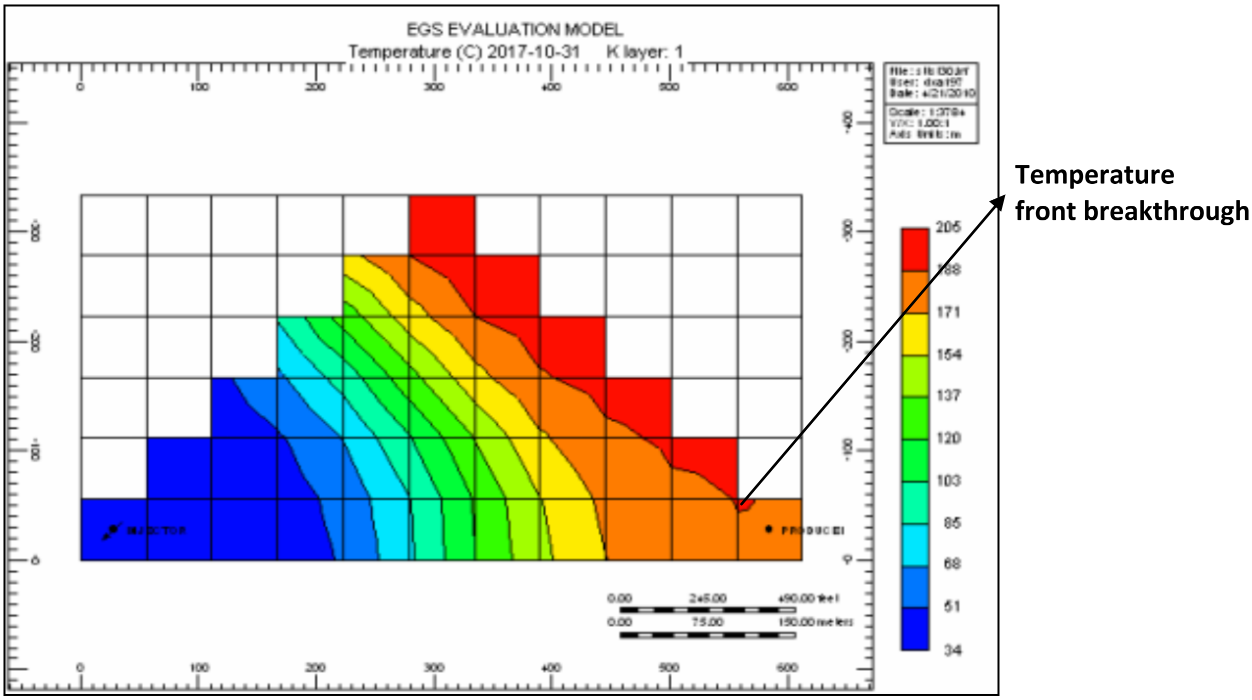

Figure 6-9- Reservoir temperature map during the 8th year

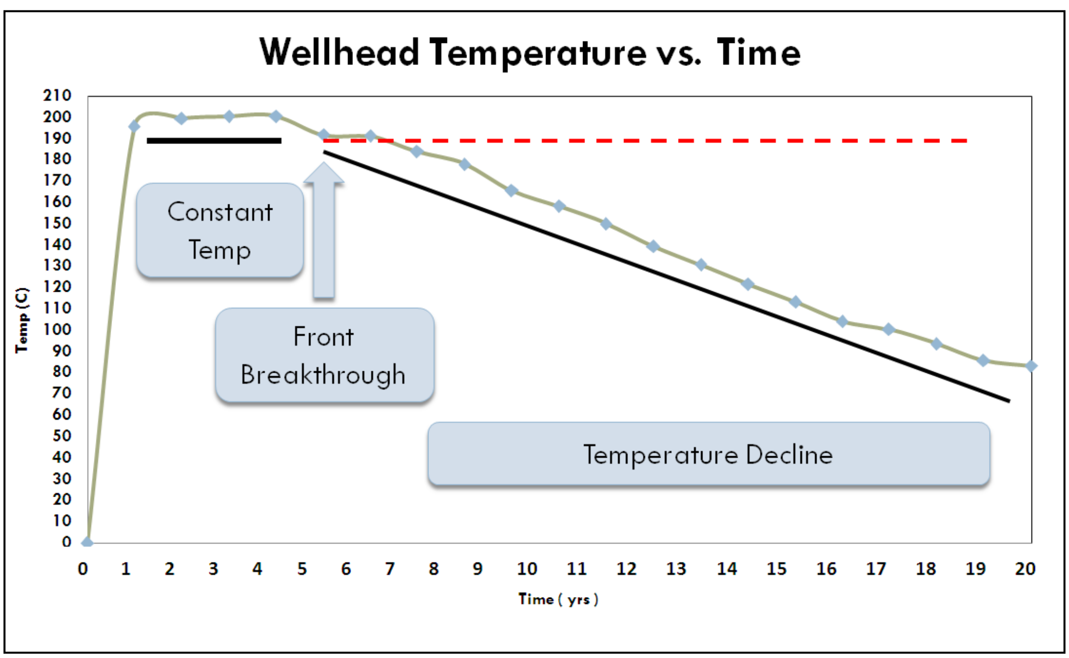

Figure 6-10- Variation of well head temperature with time

Figure 6-10 shows the change in the calculated well head temperature of the production well with time. Here we can observe that for the first six years the well head temperature is almost constant and once the front reaches the production well (Figure 6-9) the well head temperature starts to decline and keeps decreasing for the rest of the operation period.

The idea is to design an optimal production plan so that the plateau period is extended as long as possible to get a constant power production profile.

6.4 Modeling with different Scenarios

Based on the preliminary modeling and results obtained, it was decided to evaluate several cases to find which combination of parameters gave the longest period of operation (temperature decline from 200 C to 150 C at the wellhead). Table 6-2 shows the different cases considered. The period of operation for all the cases was 30 years. The 3 parameters that were varied are the rock volume, fracture spacing and water (brine) injection rates and the change in temperature profile was observed.

Table 6-2- List of different cases used in the simulation

Case #	Rock Volume		Fracture	Water Inject Rate		Res Temp	WHP
	km^3		Spacing(m)	kg/sec	m^3/d	(C)	(Mpa)
Case 1	0.062	100%	50	37	3197	205	10.0
Case 2	0.062	100%	50	61	5270	205	10.0
Case 3	0.062	100%	50	100	8640	205	10.0
Case 4	0.062	100%	50	150	12960	205	10.0
Case 5	0.062	100%	10	37	3197	205	10.0
Case 6	0.062	100%	10	61	5270	205	10.0
Case 7	0.062	100%	100	37	3197	205	10.0
Case 8	0.062	100%	100	61	5270	205	10.0
Case 9	0.094	150%	50	37	3197	205	10.0
Case 10	0.094	150%	50	61	5270	205	10.0
Case 11	0.031	50%	50	37	3197	205	10.0
Case 12	0.312	500%	50	61	5270	205	10.0
Case 13	0.187	300%	50	61	5270	205	10.0
Case 14	0.062	100%	5	61	5270	205	10.0
Case 15	0.062	100%	1	61	5270	205	10.0

6.4.1 Summary of Results

Figure 6-11 to Figure 6-13 summarize the results obtained by modeling the different scenarios listed in Table 6-2. In Figure 6-11 we can see that having a greater rock volume ensures the longevity of the project and at the same time the plateau period is also proportionally increased with the other parameters fixed

In Figure 6-12, we can observe that as the injection flow rate is increased, the outlet temperature decreases quickly thereby decreasing the plateau period.

In Figure 6-13, if the fracture spacing is short enough the heat extraction efficiency is more and also the plateau period is extended.

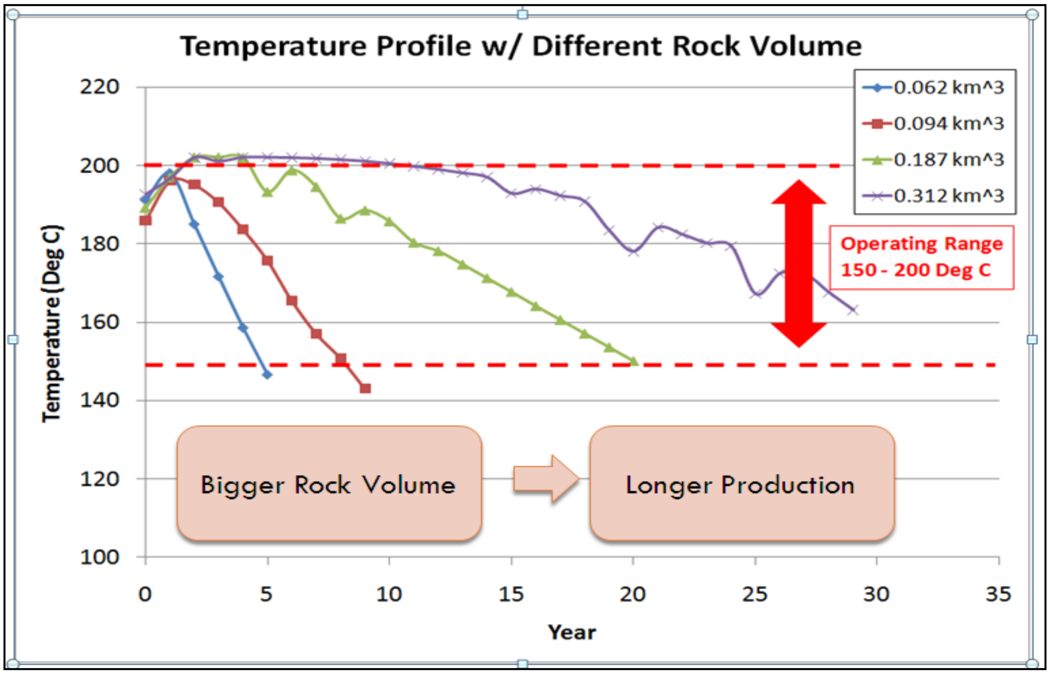

Figure 6-11- Variation of well head temperature with different reservoir volume

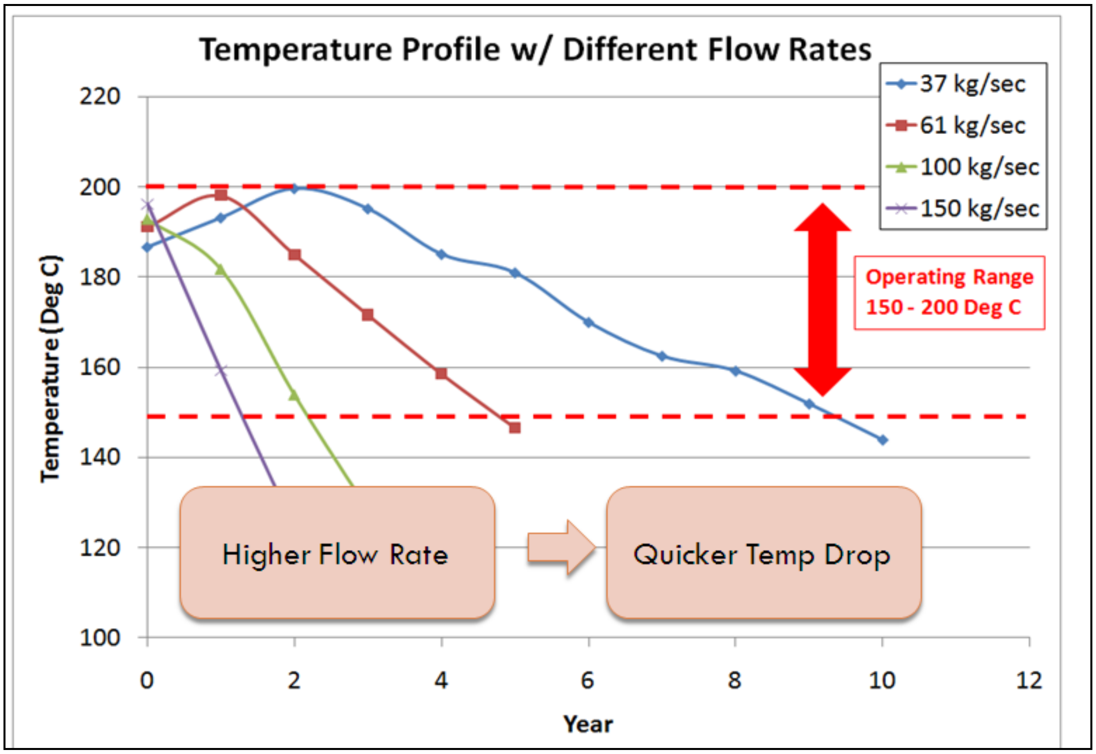

Figure 6-12- Variation of well head temperature with different brine injection rates

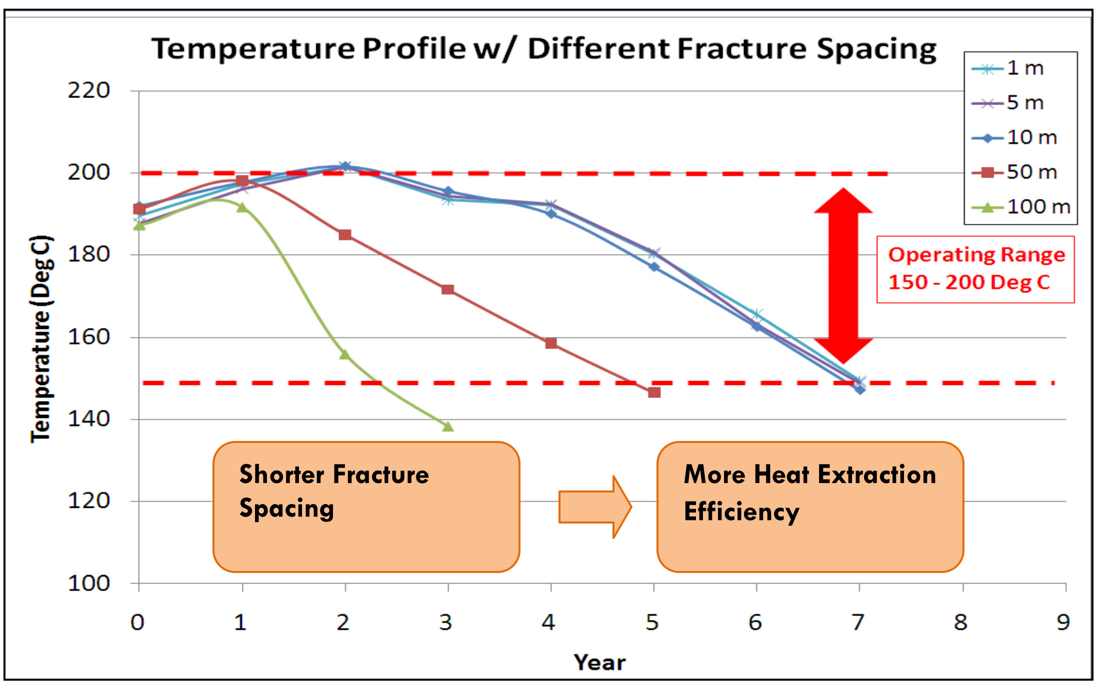

Figure 6-13- Variation of well head temperature with different fracture spacing

7 POWER PLANT

Power plant is the most important part of EGS system. Based on the reservoir simulation, the surface temperature of brine would roughly be around 473 K in the beginning and it drops down over a period of time. From the Tester report (2006), binary power plant would be more economical at a temperature of 473 K or less, while the single flash power plant makes economic sense only at temperature > 473 K. Therefore, only binary power plants alone were considered. However, the economics of the above mentioned power plants holds well only if brine is used as a geothermal fluid. Moreover, Pruess et al (2007) claimed that CO_2 as a geothermal fluid compare favorably with brine. Therefore, four power plants were considered in this study. They are:

1. Basic Binary power plant
2. Dual-Pressure Binary power plant (iso-pentane as working fluid and brine as geothermal fluid)
3. Dual-Fluid Binary power plant (iso-pentane and iso-butane as working fluid and brine as geothermal fluid)
4. Single flash power plant(CO_2 as geothermal fluid)

The design calculations are shown step by step in the following section.

7.1 Design of Basic Binary power plant

The term basic binary indicates that there are two sections- geothermal fluid section(brine) and working fluid (iso-pentane) section. Calculations were based on the Organic Rankine Cycle(ORC). The thermodynamic properties of liquids were obtained from Reynolds (1979). Assumptions and specification of the cycle were as follows:

- Brine inlet temperature, Ta = 473.15 K
- Brine specific heat= Cb =4.19 kJ/kg-K (Assuming heat capacity of water)
- Pinch-Point Temperature difference = 10 K
- Turbine isentropic efficiency(η_t)= 85 %
- Feedpump isentropic efficiency(η_p)= 75 %

State 1: Across the turbine

Saturated vapor at 2.887 MPa at T=450 K: s = 2.2229 kJ/kg-K, h_1=760.88 kJ/kg

State 2: Outlet state of the working fluid from the turbine can be found out only if we the isentropic state of working fluid.

State 2s: Isentropic state of working fluid at outlet of the turbine, i.e., entropy is same.

h_2s = 662.94 kJ/kg

State 2: Outlet turbine

$h_2 = h_1 - \eta t(h1\text{-}h2s)$

i.e., h_2 = 760.88 – (0.85 *(760.88- 662.94) = 677.63 kJ/kg

State 3: Temperature of the saturated vapor in the condenser is 320 K.

Entropy of the saturated vapor s_3 = 1.9887 kJ/kg-K; h3= 578.16 kJ/kg

State 4: Saturated liquid at T_3= 320.15 K (P_4 =0.1880 MPa) in condenser: v_4 = 0.001686 m^3/kg, h_4 = 249.50 kJ/kg

State 5s: Isentropic pump outlet (P5s=2.887 MPa); Because the liquid is very incompressible, the value of

$h_5s = h_4 + v_4(P_5s - P_4)$

h_5s= 249.50+ (0.001686*(2.887-0.1880) = 254.05 kJ/kg

State 5: In order to calculate the actual work, the efficiency term has to be included, i.e.,

$h_5 = h_4 + (h_5s - h_4)/\eta_p$

h_5= 254.05+ (254.05-249.50)/0.75= 255.57 kJ/kg

State 6: Saturated liquid iso-pentane at 2.887 MPa (450 K): h_6 = 633.77 kJ/kg

From the above enthalpy values, we get

Specific work of the turbine: wt = h_1-h_2 = 760.88-677.63 kJ/kg = 83.25 kJ/kg

Heat rejected in cooling tower: qc = h_2-h_4 = 677.63-249.50 = 428.13 kJ/kg

Specific work of the pump: wp = h_5-h_4 = 255.57- 254.05 = 6.07 kJ/kg

Total heat transferred to the working fluid : qin= h_1-h_5 = 760.88-255.57 kJ/kg =505.31 kJ/kg

Cycle thermal efficiency: η^{th} = (wt-wp)×100/qin = 15.27 %

For power plant generating 1200 kW; the mass flow rate of i-C5 is :

m'ic-5 = Power generated/(wt-wp) = 1200/(83.25-6.07)= 15.55 kg/s

Mass flow rate of brine:

m'b×cb×(Ta-Tb) = m'ic-5 ×(h_1-h_6)

$T_b = T_6 + 10$ K =460 K (where 10 K is a pinch point)

m’b = (15.55× (760.88-633.77))/(4.19×(473.15-450.15)) = 36.28 kg/s

For brine mass flow rate of 36.78 kg/s, the gross power generated is (36.78*1.2/36.28) =1.22 MW

Net power generated = Gross power generated – 0.1MW(down hole pumps) =1.22-0.10 =1.12 MW

Outlet Temperature of Brine:

Ta-Tc/(Ta-Tb) = $(h_1-h_5)/(h_1-h_6)$

Tc =Ta – $((h_1-h_5)$*(Ta-Tb)/$(h_1-h_6))$

Tc= 473.15 – ((760.88-255.57)*(473.15-460.15)/(760.88-633.77)=421 K

Utilization Efficiency:

Assuming the dead state temperature of brine to be 290.15 K, utilization efficiency can be found:

η_u = W’net/(m’b× (ha-ho –To(sa-so))

Enthalpy of brine at (Ta=473.15 K), ha , = 851.76 kJ/kg ; sa = 2.3292 kJ/ K

Enthalpy of brine at (To = 290.15 K), ho = 69.7 kJ/kg; so =0.2475 kJ/ K

η_u = (1120×100/ (36.78 × (851.76 -69.70 – (290.15×(2.3292-0.2475)) =17.10 %

Basic binary power plant

Table 7-1- Thermodynamic results for basic binary power plant

Flow rate of Brine (kg/s)	**36.78**	**61.29**	**100**	**150**
Flow rate of i-C_5 (kg/s)	15.55	25.91	42.85	64.27
Gross power Generated	1.20	2.03	3.31	4.96
Power lost in Pumping	0.10	0.17	0.27	0.41
Net Power Generated	1.10	1.86	3.04	4.55
Thermal Efficiency	**15.27 %**			
Utilization Efficiency	**17.10 %**			

From the above calculations, the resultant efficiency was to found to be affected due to limited extraction of energy from the geothermal fluid. The thermal efficiency of the power plant, compared to coal fired thermal power plant (33%) was also found to be much lower. This can be attributed to fluctuating heat flux from the working fluid and inherent inefficiency of the meta-stable turbine. The utilization efficiency, net power generated upon maximum power generated, can be improved by addition of another PH& E (pre-heater and exchanger) to extract the high outlet temperature of the brine. The thermodynamic results of all the power plants at various temperatures is shown in Appendix-A.

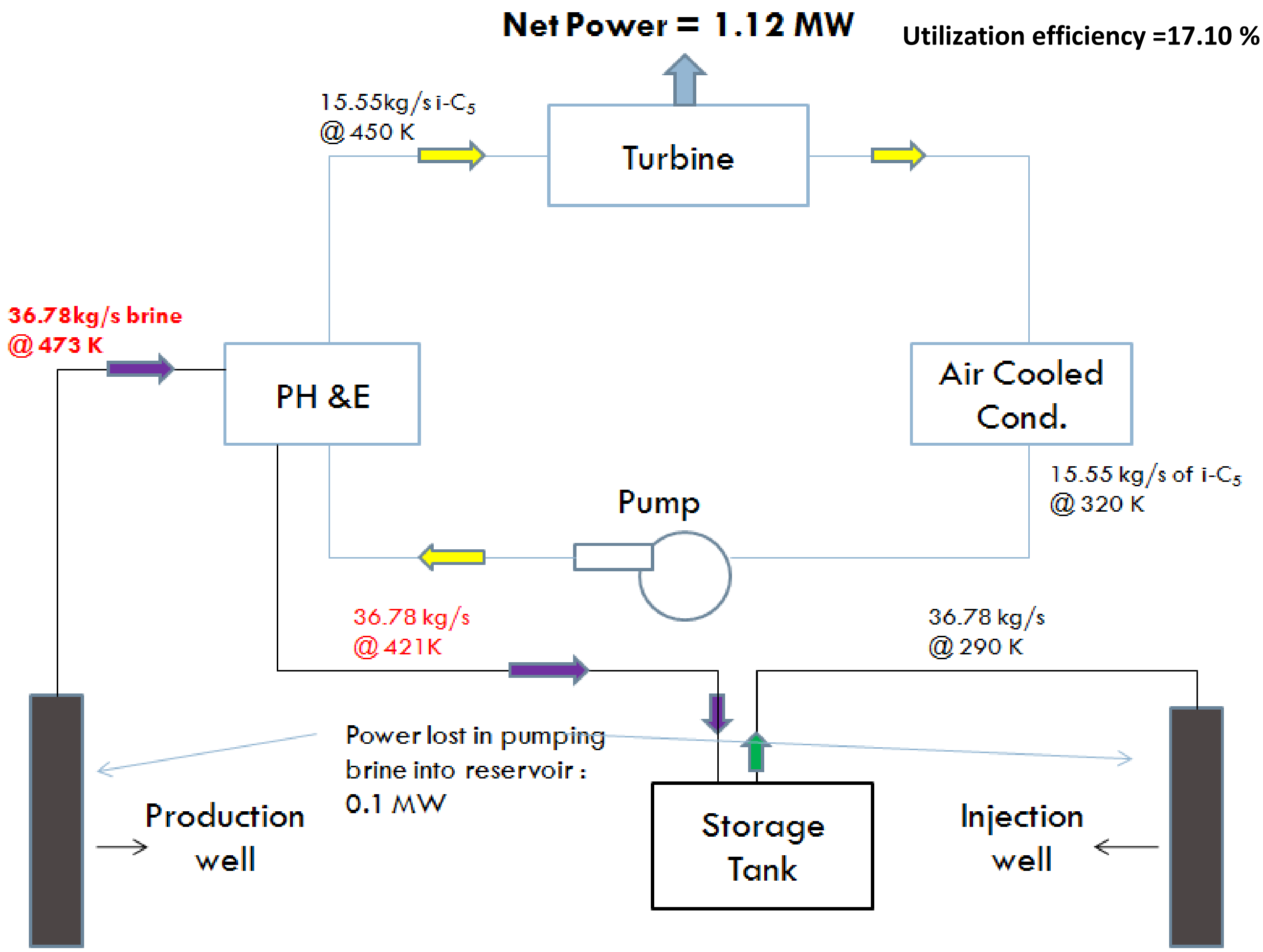

Figure 7-1- Flow diagram of basic binary power plant

Figure 7-1 show the flow diagram of the basic binary power plant. The blue line indicates the Organic Rankine Cycle (ORC), while the black line indicates the geothermal cycle.

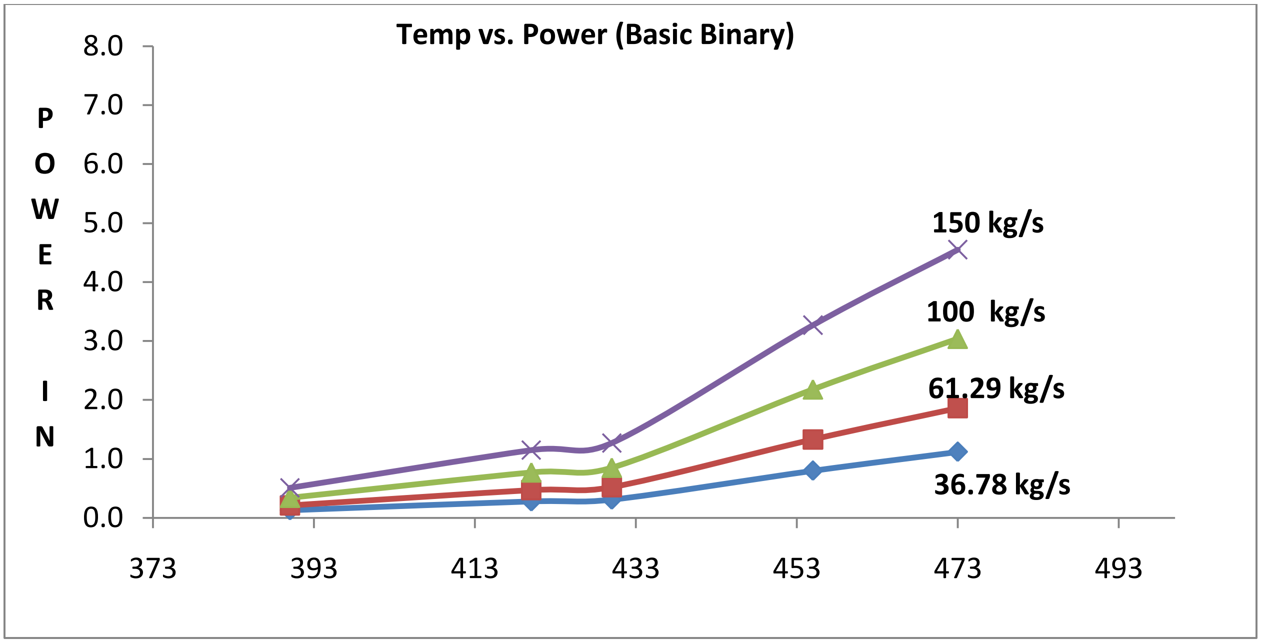

Figure 7-2- Net power generated by basic binary power plant at various temperatures and flow rates

The above figure indicates that the net power generated increases with increase in temperature, and flow rate of brine. Temperature affects the net power produced slightly more than the flow rate of the fluid. Although, flow rates above 40 kg/s has its own disadvantages, it was included to show the effect of flow rate on the overall net power generated. Because the net power generated was found to be low with basic binary, the dual-fluid and dual-pressure system were considered due to its prospect of extracting more energy from the brine.

7.2 Dual-Pressure Basic Binary

The word dual-pressure binary clearly indicates there are two pressure cycles- two Rankine cycles- of a same fluid. Figure 7-3 shows the flow diagram of the dual-pressure binary power plant cycle.

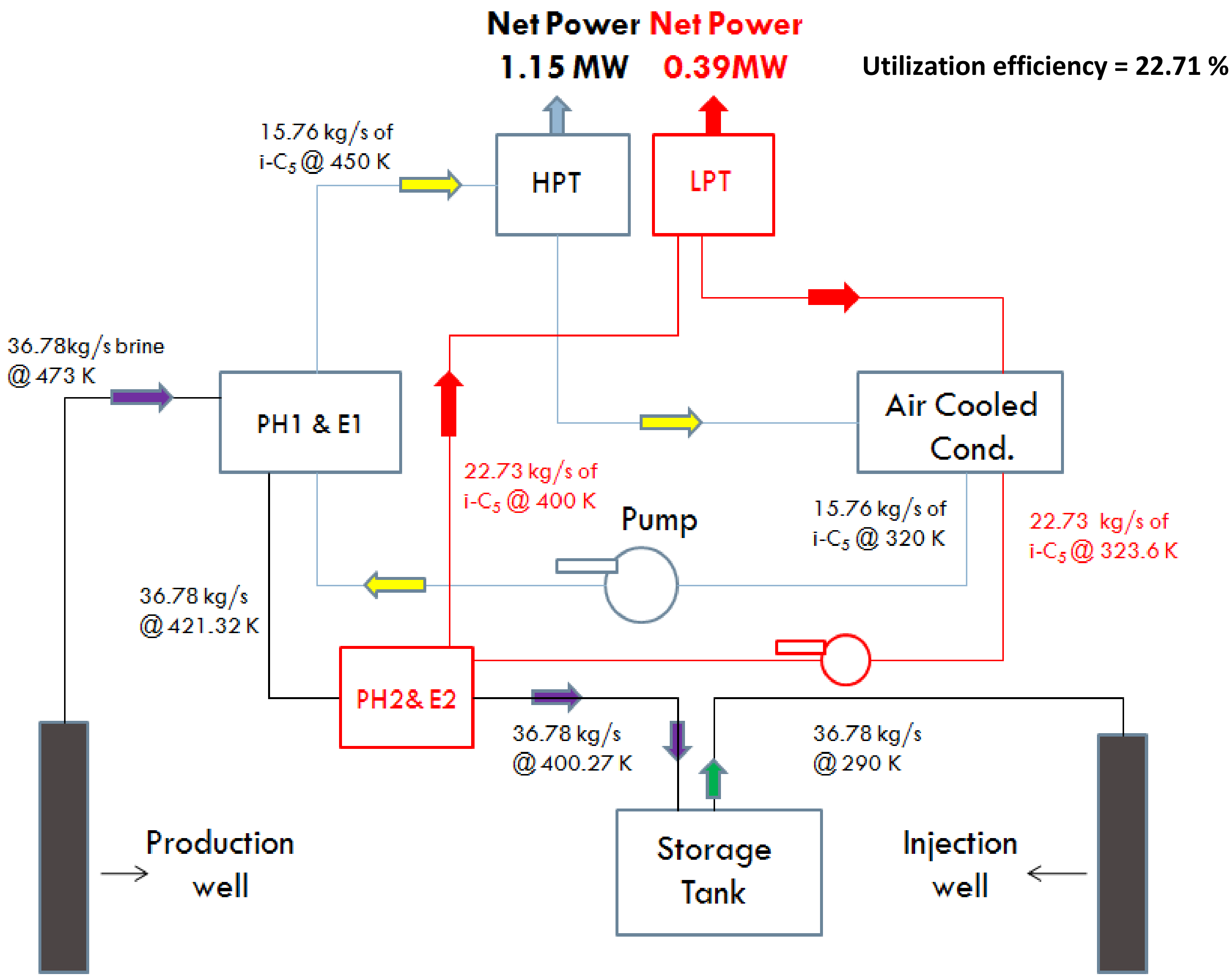

Figure 7-3- Flow diagram of dual-pressure binary power plant

From the above flow diagram, addition of another PH&E unit resulted in additional extraction of energy from the geothermal fluid resulting in increased net power generated.

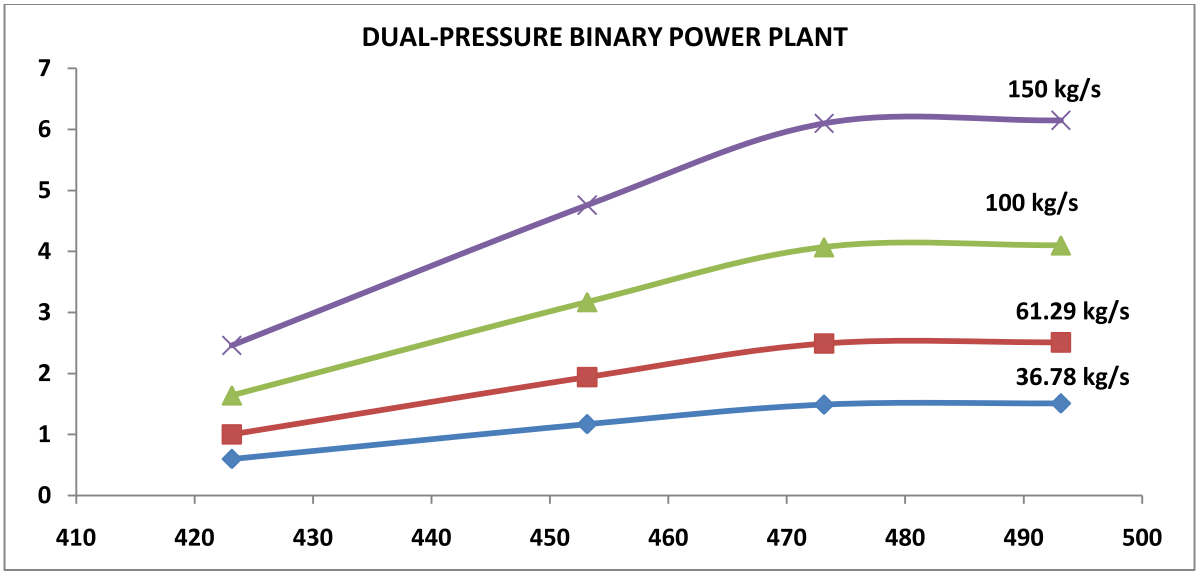

Figure 7-4- Net power generated by dual-pressure binary power plant at various temperatures and flow rates

Figure 7-4 shows the effect of temperatures and flow rates on net power generated. It is interesting to note that the net power generated flattens out after 473.15 K. This observation can be attributed to the saturation in thermal capacity of the working fluid for a given flow rate of working fluid. However, at high temperature, the low density working fluid occupies more volume for a given flow rate, resulting in increased size of the pipeline and eventually the turbine size for a given thermal flux. Moreover, increase in turbine, without increasing the net power output, decreases the efficiency. Taking all these in to consideration, it was decided to consider same flow rate of working fluid for given flow rate of geothermal fluid at various temperatures for all binary power plant.

Although the calculation showed that the outlet brine temperature for dual-pressure binary power plant was lower than the basic binary power plant, it was decided to use thermodynamically more favorable fluid for additional extraction of useful energy from the geothermal fluid. Therefore, instead of iso-pentane in dual pressure power plant, iso-butane, a thermodynamically better fluid was considered as the secondary fluid for the dual-fluid power plant.

7.3 Dual Fluid Power Plant

Dual fluid power is equally complicated compared to dual-pressure binary power plant. The differentiating factor from dual-pressure binary power plant is the thermodynamically better fluid being used as a secondary fluid in dual-fluid power plant. Figure 7-5 shows the results of the net power produced at various temperatures and flow rates. Dual-fluid binary power plant like dual-pressure power plant is more complicated, but with higher net power generated.

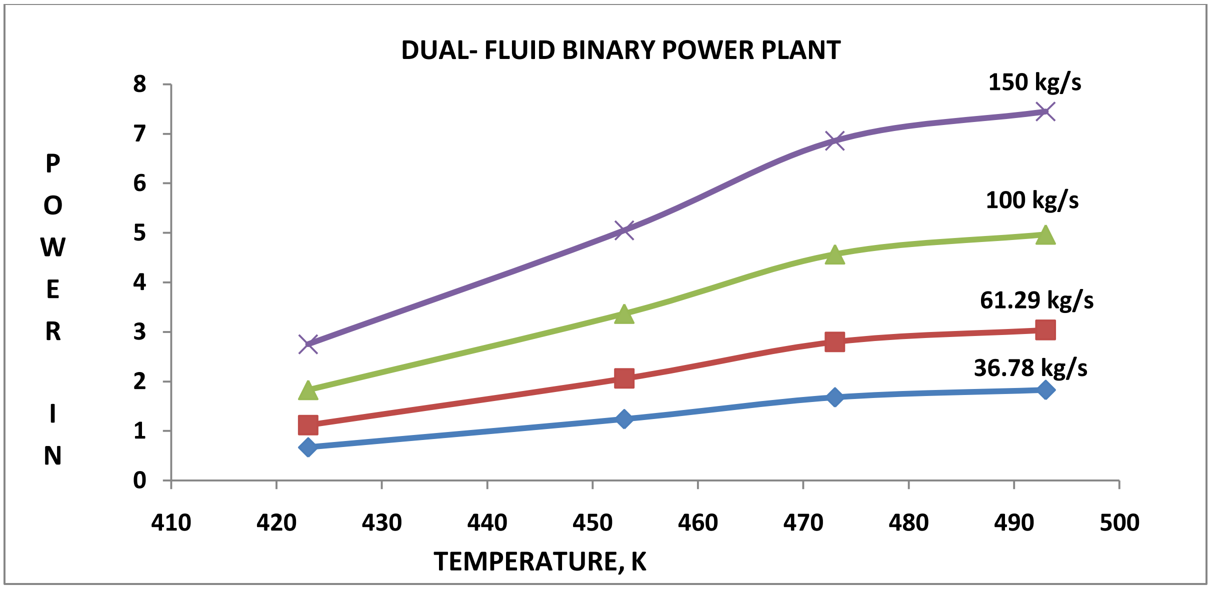

Figure 7-5- Net power generated by dual-fluid binary power plant at various temperatures and flow rates

The explanation of flattening of the trend line beyond 473 K in the above figure is same as explained for dual-pressure power plant. Because the net power generated is more than the dual-pressure power plant, the flattening is not to the extent as shown in Figure 7-4. The flow diagram of the dual-fluid power plant is shown in the Figure 7-6. From Figure 7-6, it is clear that the outlet temperature of brine (384 K) is lower than other binary power plants. Therefore, the efficiency of this power plant is higher than other binary power plants.

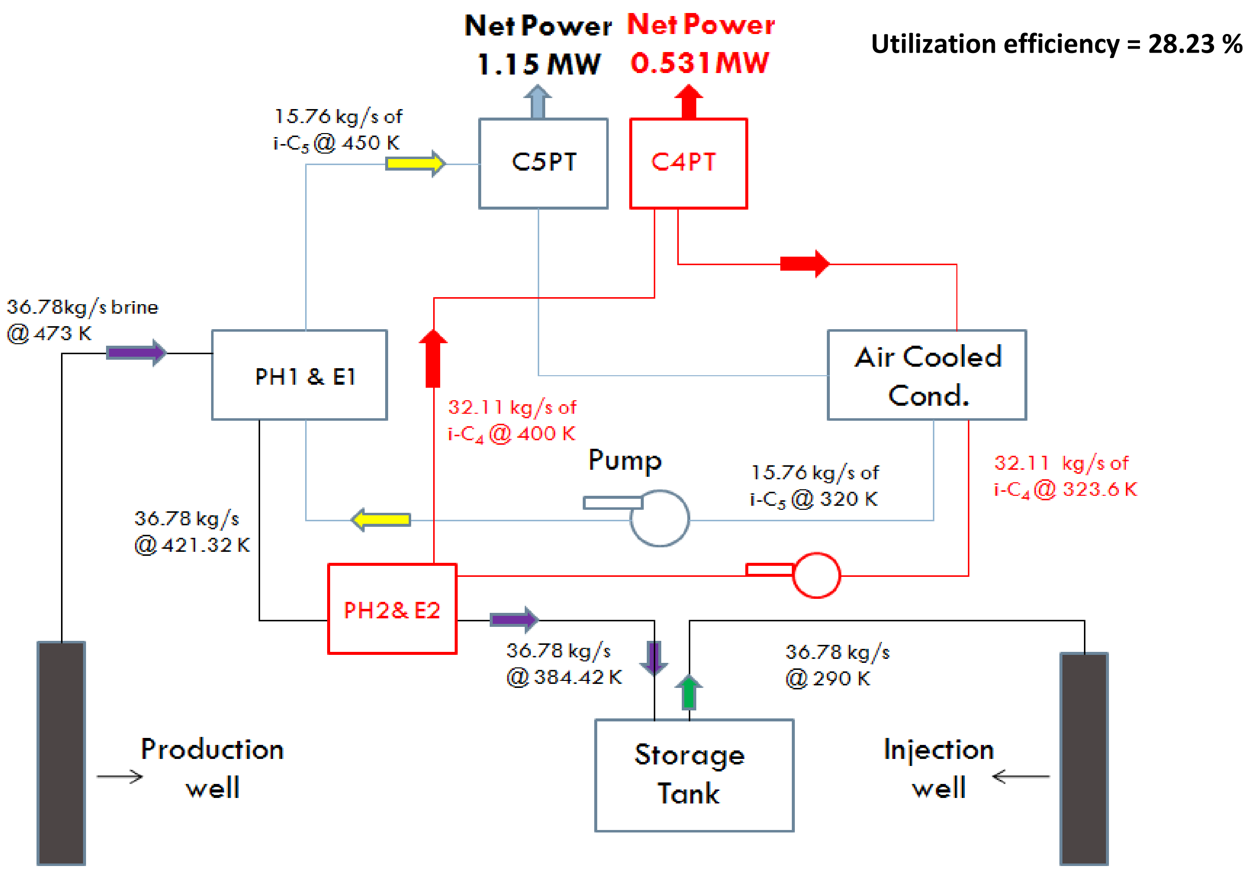

Figure 7-6- Flow diagram of dual-fluid binary power plant (0.1 MW for downhole pumps was considered in the calculation)

7.4 CO2 Flash Power plant

Pruess et al (2007) claimed that CO_2 has better characteristics than brine as geothermal fluid. Therefore, CO_2 flash power plant was considered and compared with other power plants explained in the work. Figure 7-7 shows the net power generated at various temperatures and pressures, while the Figure 7-8 shows the flow diagram of the CO_2 flash power plant.

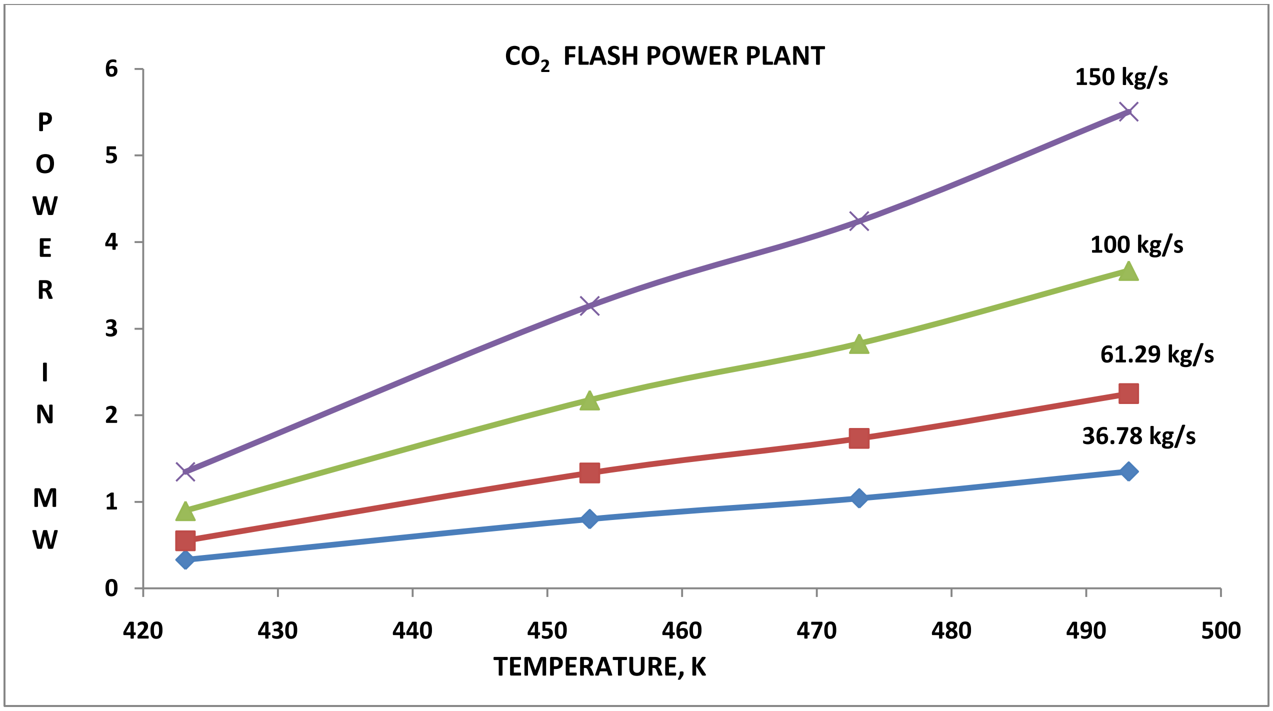

Figure 7-7- Net power generated by CO_2 flash power plant at various temperatures and flow rates

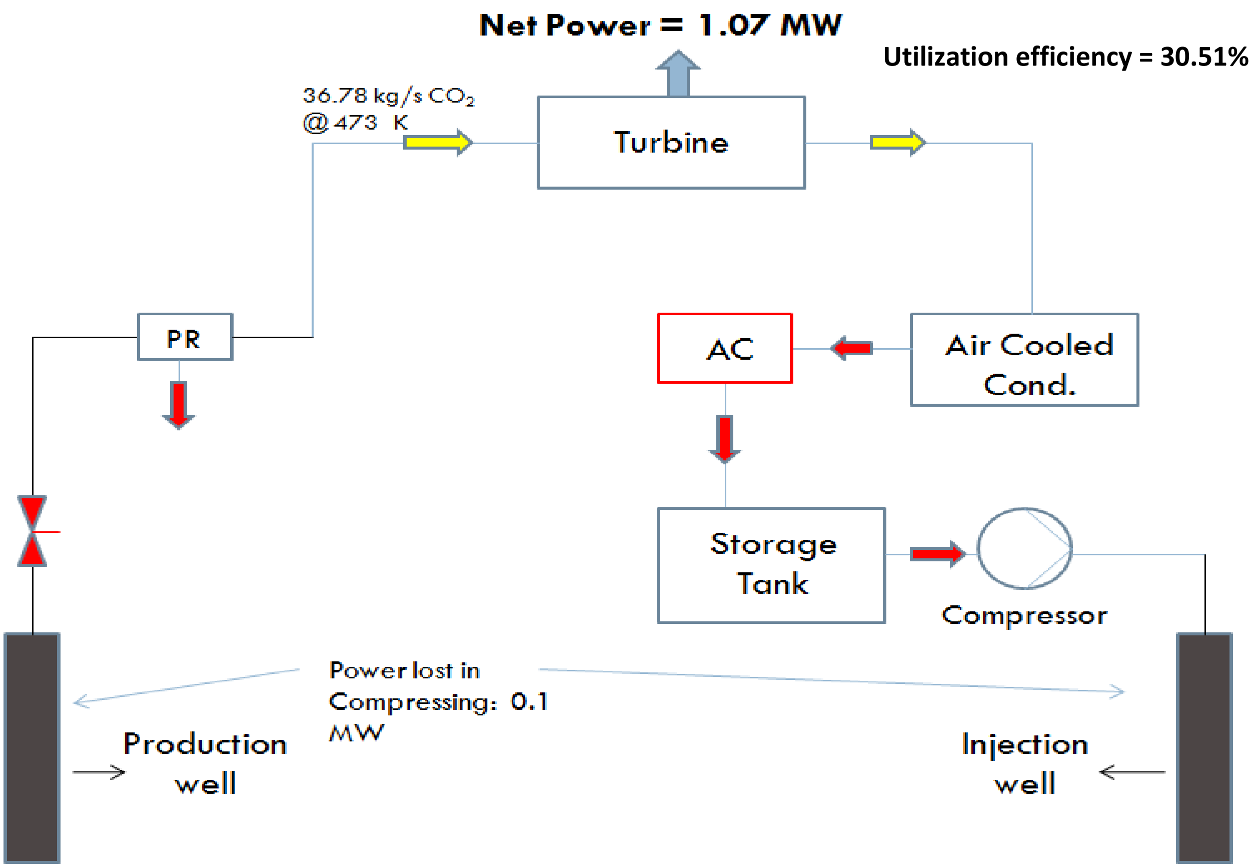

Figure 7-8- Flow diagram of CO_2 flash power plant

Although CO_2 flash power plant seems more attractive due to its simple design, there were no conclusions about this power plant due to lack of various information, such as operation and maintenance cost, simulation results and longevity of the project. Therefore, this power plant was not considered for calculating NPV.

8 ECONOMMIC ANALYSIS

All 15 cases which were used in simulation were economically evaluated. Results are mentioned in Table 8-1. It should be noted that values below were assumed to be constant in all cases:

- Saved Drilling Cost for the Production Well = 3,000,000 $
- Saved Drilling Cost for the Injection Well = 3,000,000 $
- Reservoir Temperature = 205° C
- Production Well Head Pressure = 10 MPa
- Efficiency of the whole system = 95 %
- Electricity Price in Colorado = 0.1 $/kWhr
- Electricity Price Change Rate = 1 %
- Drilling Cost of the Production Well = Drilling Cost of the Injection Well = 3,200,000 $
- Surface Cost = 400,000 $
- Stimulation Cost = 782,500 $
- Power Plant Cost = 2690 $/kWh
- Adjustment Factor for Power Plants with the capacity lower than 4 MWt = 1.25
- Discount Rate = 5 %

Table 8-1- Summary of Cash Flow Analysis of different Scenarios

Case #	Rock Volume (km^3)	Fracture Spacing (m)	Inject Rate (kg/s)	Pumping Cost ($)	Designed Power Plant (MWt)	Power Plant Cost ($)	NPV at 5% Cost of Capital ($)	Rate of Return (%)
1	0.06	50	37	408000	1.70	5,716,250	-9,033,115	-11.39
2	0.06	50	61	764775	2.70	9,078,750	-12,647,874	N/A
3	0.06	50	100	1177584	4.00	10,760,000	-14,855,844	N/A
4	0.06	50	150	1842954	6.25	16,812,500	-20,856,968	N/A
5	0.06	10	37	471192	1.75	5,884,375	-7,491,550	-5.04
6	0.06	10	61	795555	2.75	9,246,875	-10,846,690	-13.84
7	0.06	100	37	428880	1.50	5,043,750	-10,094,089	N/A
8	0.06	100	61	710055	2.50	8,406,250	-13,677,158	N/A
9	0.09	50	37	470160	1.65	5,548,125	-6,694,719	-2.86
10	0.09	50	61	747675	2.60	8,742,500	-9,818,069	-9.89
11	0.03	50	37	370572	1.25	4,203,125	-11,295,375	N/A
12	0.31	50	61	798975	2.75	9,246,875	2,191,091	6.00
13	0.19	50	61	798120	2.75	9,246,875	-3,436,274	2.63

13-A	0.19	50	61	798120	2.75	9,246,875	102,354	5.31
14	0.06	5	61	716040	2.75	9246875	-10776864.5	N/A
15	0.06	1	61	713475	2.75	9246875	-10727979	N/A

Drilling costs were assumed using the data available in Figure 8-1.

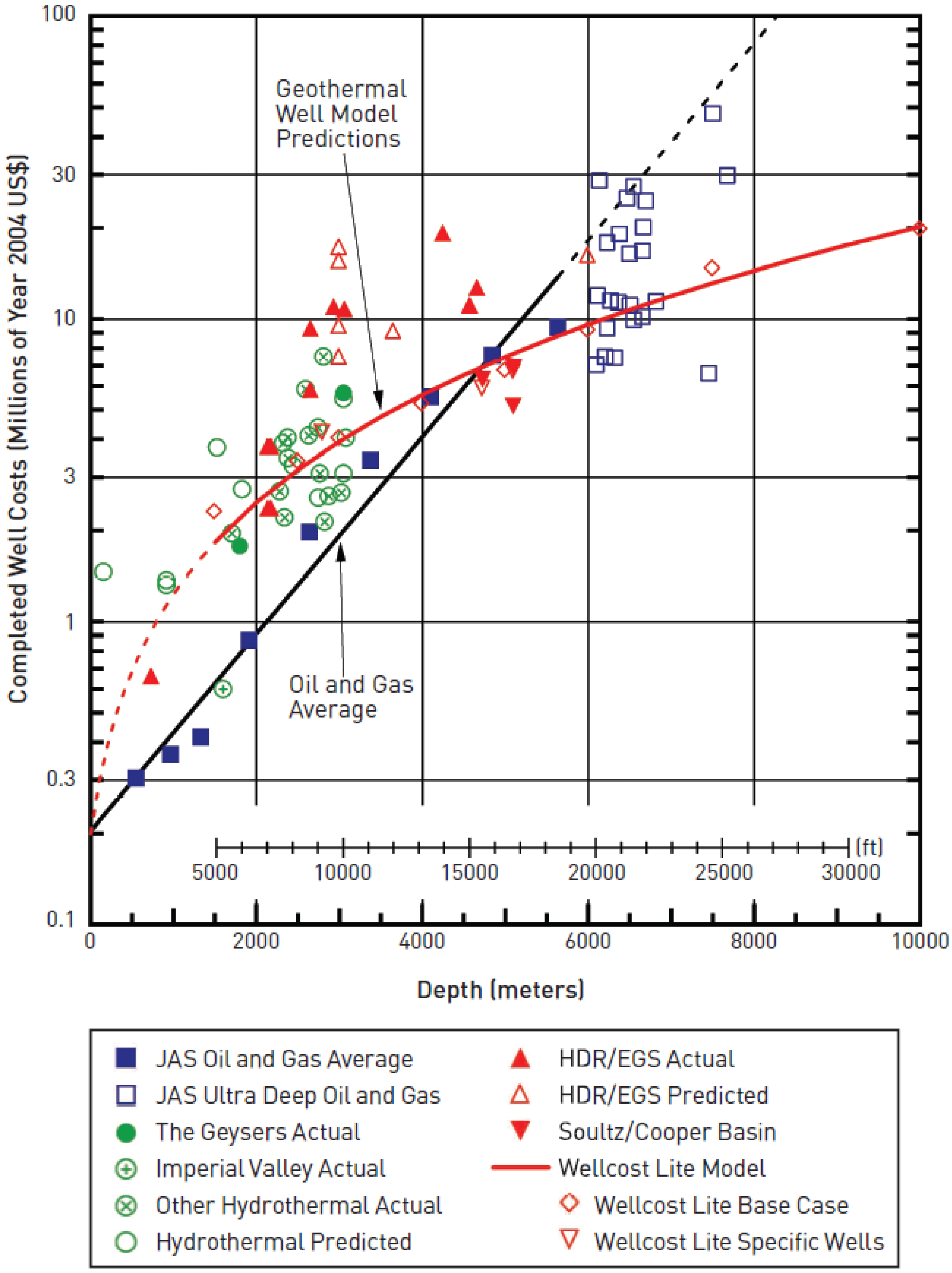

Figure 8-1- Drilling cost prediction curve (after Tester *et al*., 2006)

The parameters which are changed in the scenarios are:

- Reservoir Volume
- Fracture Spacing
- Injection Rate
- Pumping Cost
- Power Plant Cost

As can be seen, Net Present Value (NPV) for all scenarios except for the scenario 12 and 13-A are negative which shows that the project is NOT economically feasible.

In case 12, reservoir volume is assumed to be 0.31 km^3 which is 5 times more than the base case (case number 1). According to the other projects, 0.31 km^3 is not very significant as 0.7 km^3 and 0.27 km^3 were achieved in Cooper Basin and Soultz projects, respectively.

However, this number is not possible for our project as the boreholes are only 100 m apart from on surface and they are vertical up to the depth of 2,500 m (current depth). And we cannot have the big reservoir by drilling the next almost 2 km. Figure 8-2 shows the impact of reservoir volume on the economy of the project. It should be noted if we want to expand the reservoir to 0.31 km^3, it can e possible by sing one of the dry holes and drilling a new borehole in a reasonable distance from the first one. But, as we already have saved almost 3 million dollars in drilling for each well and considering the NPV of case 12 (2,191,091 $) it would be unviable again.

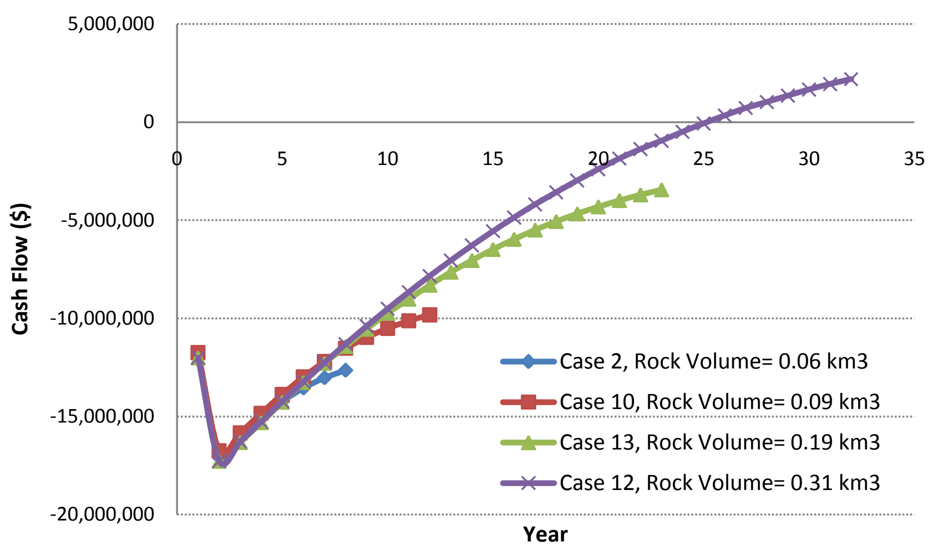

Figure 8-2- Impact of the Reservoir Volume (Inj. Flow = 61 Kg/s, Fracture Spac.=50 m, i=5%)

In case 13 and 13-A reservoir volume is assumed to be 0.19 km^3 which is 3 times bigger than the base case. All assumptions are the same in both cases and the only difference is that in case 13-A, it is assumed that the government will provide us with the low interest (1.5 %) loan for drilling the wells and constructing the power plant (15,646,875 $). All other expenses (2,763,120 $) will be covered by ourselves and we will pay back the loan within 16 years (1,000,000 $ each year and 646,875 $ in the year 16). Figure 8-3 shows these two cases.

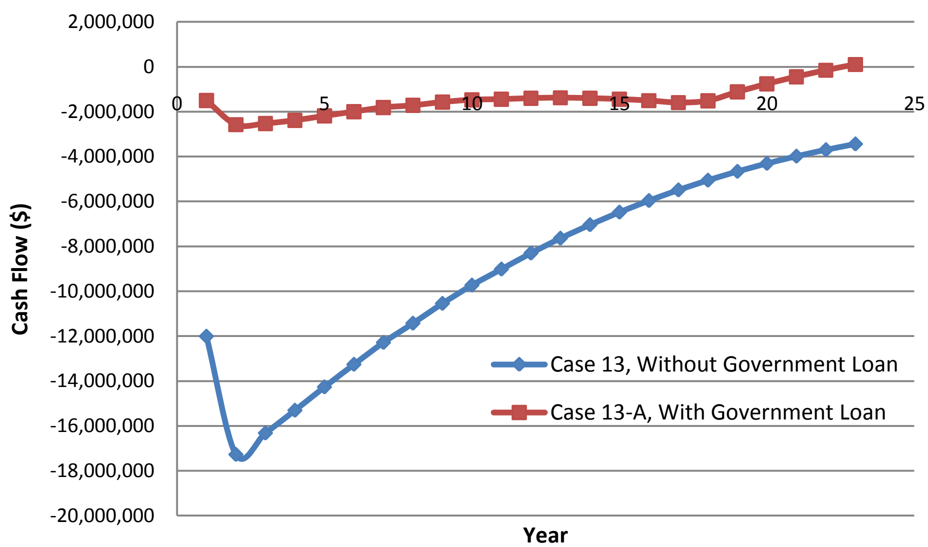

Figure 8-3- Impact of Government Loan (Inj. Flow = 61 Kg/s, Fracture Spac.=50 m, Rock Volume = 0.19 km3, i=5%)

Figure 8-4 and Figure 8-5 show the impact of Injection rate and Fracture spacing on the viability of the project.

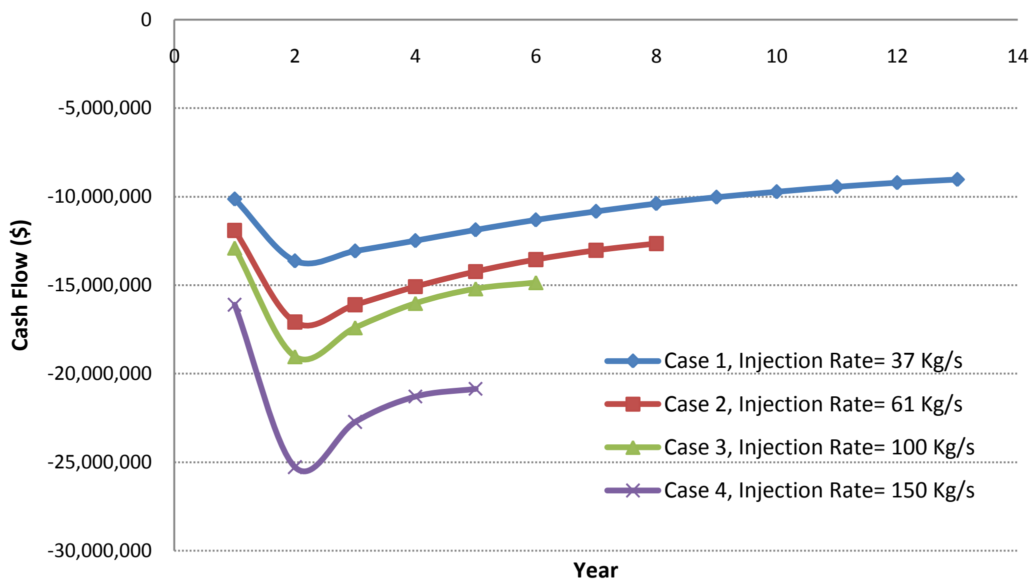

Figure 8-4- Impact of Injection Rate (Rock Volume= 0.06 km3, Fracture Spac.=50, i=5 %)

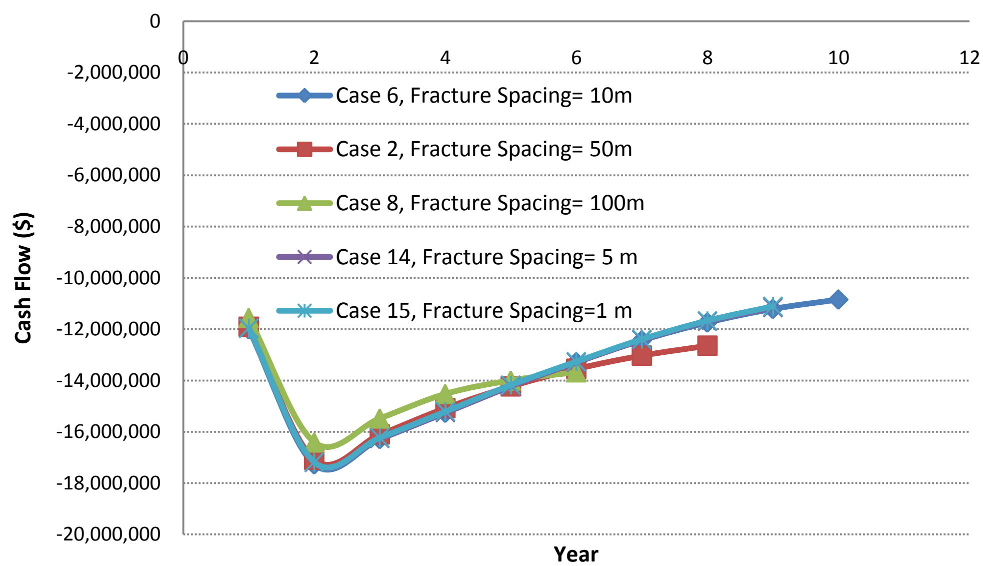

Figure 8-5- Impact of Fracture Spacing (Rock Vol.= 0.06 km3, Inje. Rate = 37 Kg/s, i=5 %)

Figure 8-6 shows the impact of increase in the rate of electricity price change. It seems that if the rate of price change was equal to 6.5%, case 9 would be feasible. The reason for choosing case 9 is that the lifetime of the project is relatively higher than other cases (19 years).

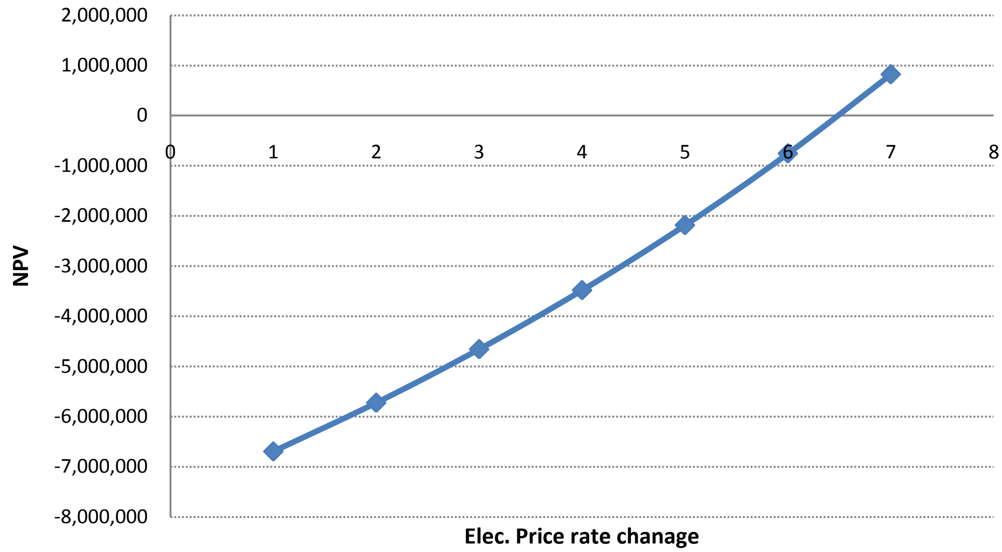

Figure 8-6-Imapct of Electricity Price Change Rate in Case 9

9 ENVIRONMENTAL, SAFETY, AND POLICIES

9.1 Gaseous Emissions

Gaseous emissions from EGS power plants are expected to be very low because they do not burn fuel like fossil fuel power plants. The gaseous emissions result from the discharge of non-condensable gases from working fluid production-reinjection loop. For stream and flash power plants, the non-condensable gases must be removed from the working fluid to avoid the buildup of pressure in the condenser and the resultant loss in power from the steam turbine. For binary power plants, there is no discharge of the non-condensable gases because the working fluid is kept in close loop system and the heat is recovered via secondary working fluid stream.

In conventional geothermal power plants, the most common non-condensable gases consist of small amount of carbon dioxide (CO_2) and only trace amounts of hydrogen sulfide (H_2S), sulfur dioxide (SO_2), nitrogen oxides (NOx), and particulate matter. A comparison of gaseous emissions from typical geothermal power plants and other types of power plants is in Figure 9-1. Because all working fluid will be re-circulated though the EGS reservoirs and most of the non-condensable gases should be removed since the first re-circulation, the EGS power plants are expected to emit less amount of those gases than the conventional geothermal power plants which have less or no working fluid re-circulation.

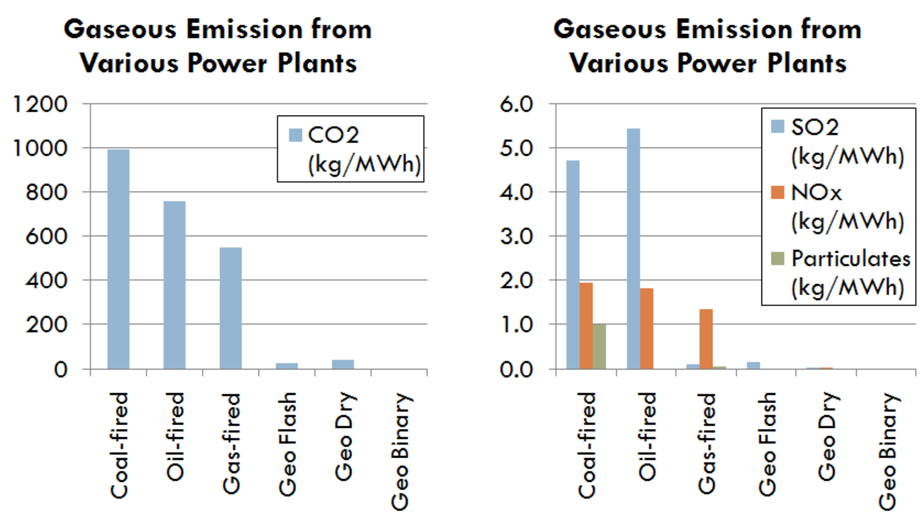

Figure 9-1- A comparison of gaseous emissions from various types of power plants (Tester et al., 2006)

Even through gaseous emissions from EGS power plants are a lot cleaner than that of other conventional power plants, the necessary treatment processes may still need to avoid adverse impacts on plant and human. There are two main regulations for controlling gaseous emissions of EGS project in Colorado, Clean Air Act (federal) and Air Quality Control Commission

Regulations (state). According to experience from other geothermal development projects, emission of H_2S is the most concerning issue among other gaseous emissions. With the proper selection of H_2S removal technology, we should be able to maintain the H2S emission under requirements of those regulations.

The Clean Air Act sets National Ambient Air Quality Standards (NAAQS) to regulate emissions of criteria pollutants on a federal level. A criteria pollutant is a principal pollutant identified as most harmful to people and the environment. The six criteria pollutants regulated by NAAQS are carbon monoxide, lead, nitrogen dioxide, particulate matter, ozone, and sulfur dioxides. The standard for six criteria pollutants is shown in Table 9-1.

Table 9-1- National Ambient Air Quality Standards

	Primary Standards		Secondary Standards	
Pollutant	Level	Averaging Time	Level	Averaging Time
Carbon Monoxide	9 ppm (10 mg/m3)	8-hour	None	
	35 ppm (40 mg/m3)	1-hour		
Lead	0.15 µg/m3	Rolling 3-Month Average	Same as Primary	
	1.5 µg/m3	Quarterly Average	Same as Primary	
Nitrogen Dioxide	53 ppb	Annual (Arithmetic Avg)	Same as Primary	
	100 ppb	1-hour	None	
Particulate Matter (PM10)	150 µg/m3	24-hour	Same as Primary	
Particulate Matter (PM2.5)	15.0 µg/m3	Annual (Arithmetic Avg)	Same as Primary	
	35 µg/m3	24-hour	Same as Primary	
Ozone	0.075 ppm (2008 std)	8-hour	Same as Primary	
	0.08 ppm (1997 std)	8-hour	Same as Primary	
	0.12 ppm	1-hour	Same as Primary	
Sulfur Dioxide	0.03 ppm	Annual (Arithmetic Avg)	0.5 ppm	3-hour
	0.14 ppm	24-hour		

Source: ***http://epa.gov/air/criteria.html***

Even through gaseous emission from EGS power plant are very small, the common gaseous associated with geothermal fluid production are as discussed follows;

Nitrogen Oxides

Nitrogen oxides (NOx) are often colorless and odorless, or reddish brown as nitrogen dioxide. Nitrogen oxides form during high temperature combustion processes from the oxidation of nitrogen in the air. Motor vehicles are the major source of these pollutants, followed by industrial fuel-burning sources such as fossil fuel-fired power plants. Fossil fuel-fired power plants are responsible for 23 percent of nitrogen oxide emissions.

Nitrogen oxides contribute to smog formation, acid rain, water quality deterioration, global warming, and visibility impairment. Health effects include lung irritation and respiratory ailments such as infections, coughing, chest pain, and breathing difficulty. Geothermal energy produced in the United States, when compared to coal, offsets approximately 32 thousand tons of nitrogen oxide emissions each year. This is substantial considering that even brief exposure to high levels of nitrogen oxides may cause human respiratory problems, and airborne levels of nitrogen oxides above the EPA established average allowable concentration of 0.053 parts per million can cause ecosystem damage. Nitrogen dioxide is a federally regulated criteria pollutant. Power plants built after September 17, 1978 must comply with federal nitrogen oxide standards; those built before may be subject to state or local standards.

Because geothermal power plants do not burn fuel, they emit very low levels of nitrogen oxides. In most cases, geothermal facilities emit no nitrogen oxides at all. The small amounts of nitrogen oxides released by some geothermal facilities result from the combustion of hydrogen sulfide. Geothermal plants are generally required by law (with some variation from state to state) to maintain hydrogen sulfide abatement systems that capture hydrogen sulfide emissions and either burn the gas or convert it to elemental sulfur. During combustion, small amounts of nitrogen oxides are sometimes formed, but these amounts are miniscule.

Hydrogen Sulfide

Hydrogen sulfide (H_2S) is a colorless gas that is harmless in small quantities, but is often regarded as an annoyance due to its distinctive rotten-egg smell. Hydrogen sulfide can be lethal in high doses. Natural sources of hydrogen sulfide include volcanic gases, petroleum deposits, natural gas, geothermal fluids, hot springs, and fumaroles. Hydrogen sulfide may also form from the decomposition of sewage and animal manure, and can be emitted from sewage treatment facilities, aquaculture facilities, pulp and paper mills, petroleum refineries, composting facilities, dairies, and animal feedlot operations. Individuals living near a gas and oil drilling operation may be exposed to higher levels of hydrogen sulfide.

Anthropogenic (manmade) sources of hydrogen sulfide account for approximately 5 percent of total hydrogen sulfide emissions. Health impacts from high concentrations include nausea, headache, and eye irritation; extremely high levels can result in death. Hydrogen sulfide remains in the atmosphere for about 18 hours. Though hydrogen sulfide is not a criteria pollutant, it is listed as a regulated air pollutant.

Hydrogen sulfide remains the pollutant generally considered to be of greatest concern for the geothermal community. However, it is now routinely abated at geothermal power plants. Current hydrogen sulfide abatement systems could convert over 99.9 percent of the hydrogen sulfide from geothermal non-condensable gases to elemental sulfur, which can then be used as a soil amendment and fertilizer feedstock.

As a result of abatement measures, geothermal steam- and flash-type power plants produce only minimal hydrogen sulfide emissions. Hydrogen sulfide emissions from California geothermal plants are reported as below the limits set by all California air pollution control districts. This is significant, considering that California's clean air standards tend to be more restrictive than federal standards. Binary and flash/binary combined cycle geothermal power plants do not emit any hydrogen sulfide at all.

Sulfur Dioxide

Sulfur dioxide belongs to the family of SOx gases that form when fuel containing sulfur (mainly coal and oil) is burned at power plants. Fossil fuel-fired power plants are responsible for 67 percent of the nation's sulfur dioxide emissions. High concentrations of sulfur dioxide can produce temporary breathing impairment for asthmatic children and adults who are active outdoors. Health impacts from short-term exposures include wheezing, chest tightness, shortness of breath, aggravation of existing cardiovascular disease, and respiratory illness. Sulfur oxide emissions injure vegetation, damage freshwater lake and stream ecosystems, decrease species variety and abundance, and create hazy conditions.

While geothermal plants do not emit sulfur dioxide directly, once hydrogen sulfide is released as a gas into the atmosphere, it spreads into the air and eventually changes into sulfur dioxide and sulfuric acid. Therefore, any sulfur dioxide emissions associated with geothermal energy derive from hydrogen sulfide emissions. When comparing geothermal energy to coal, the average geothermal generation of 15 billion kilowatt hours avoids the potential release of 78 thousand tons of sulfur oxides per year.

Particulate Matter

Particulate matter (PM) is a broad term for a range of substances that exist as discrete particles. Particulate matter includes liquid droplets or particles from smoke, dust, or fly ash. Primary particles such as soot or smoke come from a variety of sources where fuel is burned, including fossil fuel power plants and vehicles. Secondary Particles form when gases of burned fuel react with water vapor and sunlight. Secondary particulate matter can be formed by NOx, SOx, and Volatile Organic Compounds (VOCs). Large particulates in the form of soot or smoke can be detected by the naked eye, while small particulates (PM2.5) require a microscope for viewing. PM10 refers to all particulates less than or equal to 10 microns in diameter of particulate mass per volume of air.

Particulate matter is emitted through the full process of fossil fuel electricity production, particularly coal mining. Health effects from particulate matter include eye irritation, asthma, bronchitis, lung damage, cancer, heavy metal poisoning, and cardiovascular complications.

Particulate matter contributes to atmospheric deposition, visibility impairment, and aesthetic damage.

While coal and oil plants produce hundreds of short tons on an annual basis (where one short ton equals 2,000 pounds), geothermal plants emit almost no particulate matter. Water-cooled geothermal plants do emit small amounts of particulate matter from the cooling tower when steam condensate is evaporated as part of the cooling cycle. However, the amount of particulate matter given off from the cooling tower is quite small when compared to coal or oil plants which have burning processes in combination with cooling towers. In a study of California geothermal plants, PM10 is reported as zero. It is estimated that geothermal energy produced in the United States offsets 17 thousand tons of particulate matter each year when compared to coal production.

Carbon Dioxide

Carbon dioxide, a colorless, odorless gas, is released into the atmosphere as a byproduct of burning fuel. While carbon dioxide emissions are also produced by natural sources, most experts agree that increased atmospheric carbon dioxide concentrations are caused by human fossil fuel burning. Concentrations in the atmosphere have increased by approximately 20 percent since 1960. The increase in carbon dioxide is typically attributed to power plant (primarily coal) and vehicle emissions, and secondarily to deforestation and land-use change. About 37 percent of incremental carbon dioxide accumulation is caused by electric power generation, mainly from fossil fuels.

According to the Energy Information Administration (EIA), carbon dioxide accounts for 83 percent of U.S. greenhouse gas emissions. While carbon dioxide does not pose any direct human health effects, experts generally agree that global warming poses significant environmental and health impacts, including flood risks, glacial melting problems, forest fires, increases in sea level, and loss of biodiversity. Geothermal plants do emit carbon dioxide, but in quantities that are small compared to fossil fuel-fired emissions. Some geothermal reservoir fluids contain varying amounts of certain non-condensable gases, including carbon dioxide.

Geothermal steam is generally condensed after passing through the turbine. However, the carbon dioxide does not condense, and passes through the turbine to the exhaust system where it is then released into the atmosphere through the cooling towers. The amount of carbon dioxide found in geothermal fluid can vary depending on location, and the amount of carbon dioxide actually released into the atmosphere can vary depending on plant design. This makes it difficult to generalize about the amount of carbon dioxide emitted by geothermal power plant. For example, binary plants with air cooling are in a closed loop system and emit no carbon dioxide because in this system the geothermal fluids are never exposed to the atmosphere.

Despite these disparities, geothermal power plants will emit only a small fraction of the carbon dioxide emitted by traditional power plants on a per-megawatt hour basis. Non-condensable gases such as carbon dioxide make up less than 5 percent by weight of the steam phase of most geothermal systems. Of that 5 percent, carbon dioxide typically accounts for 75 percent or more of non-condensable gas by volume. Because of the low level of carbon dioxide emissions, geothermal power production currently prevents the emission of 22 million tons of carbon dioxide annually when compared to coal production.

Mercury

The majority of mercury emissions derive from natural sources. Mercury occurs naturally in soils, groundwater, and streams, but human activity can release additional mercury into the air, water, and soil. Coal-fired power plants are the largest source of additional mercury of any energy source, because the mercury naturally contained in coal is released during combustion. Currently, the coal industry contributes 32.7 percent of the nation's anthropogenic mercury emissions.

Mercury emissions from power plants pose a significant risk to human health. When mercury enters water, biological processes transform it to a highly toxic form, methyl mercury, which builds up in fish and animals that eat fish. People are exposed to mercury primarily by eating fish or by drinking contaminated water. Mercury is especially harmful to women: in February 2003, a draft report about mercury contamination noted that eight percent of women between the ages of 16 and 49 have mercury levels in the blood that could lead to reduced IQ and motor skills in their offspring. Mercury and mercury compounds are considered one of 188 Hazardous Air Pollutants (HAPs) and one of 33 urban HAPs under section 112 of the Clean Air Act. Urban HAPs are considered to present the greatest threat to public health in the largest number of urban areas. To date, EPA has established National Emission Standards for

Hazardous Air Pollutants (NESHAPs) for mercury emissions, but these standards only apply to facilities such as mercury ore processing centers with high concentrations of mercury. Individual states can mandate specific regulations for individual facilities. In addition, the EPA issued draft regulations on March 15, 2005, under The Clean Air Mercury Rule, which limits federal mercury emissions through a market-based regulatory program.

Mercury is not present in every geothermal resource. However, if mercury is present in a geothermal resource, using that resource for power production could result in mercury emissions, depending upon the technology used. Because binary plants pass geothermal fluid through a heat exchanger and then return all of it to the reservoir, binary plants do not emit any mercury. In the United States, The Geysers is the main geothermal field known to emit small quantities of mercury in the atmosphere. The Geysers, however, was also mined for mercury from about 1850-1950, so it is likely that some degree of mercury emissions would exist independently of geothermal development. Within The Geysers, the presence of mercury in the steam varies dramatically, as around 80 percent of mercury emissions derive from only two facilities. These individual high mercury facilities are scheduled to install mercury abatement equipment in 2005 that will significantly reduce the overall geothermal mercury emissions. Furthermore, mercury emissions from The Geysers are below the amount required to trigger a health risk analysis under existing California regulations.

While federal proposals related to mercury risk have focused on coal, state and local governments have also introduced measures to reduce mercury emissions from other sources. As a result, mercury abatement measures are already in place at most geothermal facilities. The abatement measures that reduce mercury also reduce the emissions of sulfur generated as a byproduct of hydrogen sulfide abatement: after hydrogen sulfide is removed from geothermal steam, the gas is run through a mercury filter that absorbs mercury from the gas. In removing mercury, the sulfur that is created from the abatement process can then is used as an agricultural product. The rate of mercury abatement within a facility, which varies according to the efficiency of the activated carbon mercury absorber, is typically near 90 percent, and is always efficient enough to ensure that the sulfur byproduct is not hazardous. The activated carbon media is changed out periodically and is disposed of as a hazardous waste. The amount of hazardous waste reduction is thousands of tons/year.

9.2 Induced Seismicity

Induced seismicity refers to typically minor earthquakes and tremors that are caused by human activity that alters the stresses and strains of subsurface structure. For EGS project, induced seismicity is expected because we have to inject fluid to stimulate our reservoirs as well as circulate fluid to extract underground heat. Local and regional geologic conditions which contribute to seismicity include orientation and magnitude of stress field, extent of faults and fractures, rock mechanical properties, hydrologic factors, and natural seismicity of the area. EGS application facilitates seismicity in several different mechanisms include pore-pressure increase, temperature decrease, volume change due to fluid withdrawal / injection, and chemical alteration of fracture surfaces. These mechanisms result in reducing stress of the rock, decreasing static friction of the fault system, and perturbing local stress condition, which could consequently lead to induced seismicity.

Signatures of the micro-seismic events also can be used to quantify the energy radiated from the shearing of fractures, the size of the fractures, the orientation of fractures, dilation and slip of fractures, etc. This is a unique method and serves as a remote sensing technique to observe changes in the reservoir properties (stress), not just during the development of the reservoir but also during the long-term energy-extraction phase.

The largest induced seismic events from EGS projects worldwide are shown in Table 9-2. Those events are classified into minor and micro earthquake classes which are non-threatening and non-damaging. However, two EGS projects have been terminated because neighboring communities are not adequately communicated and convinced to accept cost-benefit balance between green energy and inconvenience ground shaking. There are several different mechanisms that have been hypothesized to explain the occurrence of induced seismicity in geothermal settings.

Table 9-2- The Largest Seismicity Events at EGS Sites Worldwide (Bromley, C.J. & Mongillo, M.A., 2007)

Site	Maximum Magnitude (Richter Scale)
Cooper Basin, Australia	3.7
Basel, Switzerland	3.4
Rosemanowes, United Kingdom	3.1
Soultz-sous-Forets, France	2.9

Pore-pressure increase – In a process known as effective stress reduction, increased fluid pressure can decrease static friction and thereby facilitate seismic slip in the presence of a deviatoric stress field. In such cases, the seismicity is driven by the local stress field, but triggered on an existing fracture by the pore-pressure increase. In many instances, the pore pressure required to shear favorably oriented joints can be very low and vast numbers of micro-seismic events occur as the pressure migrates away from the wellbore in a preferred direction associated with the direction of maximum principal stress. In a geothermal field, one obvious mechanism is fluid injection, which can increase pore pressure locally and thus may account for high seismicity around injection wells, if there are local regions of low permeability. At higher pressures, fluid injection can exceed the rock strength, actually creating new fractures in the rock.

Temperature decrease – Cool fluids interacting with hot rocks can cause contraction of fracture surfaces, in a process known as thermo-elastic strain. As with effective stress, the slight opening of the fracture reduces static friction and triggers slip along a fracture that is already near failure in a regional stress field. Alternatively, cool fluid–hot rock interactions can create fractures and seismicity directly related to thermal contraction. In some cases, researchers have detected non-shear components, indicating tensile failure, contraction, or sapling mechanisms.

Volume change due to fluid withdrawal/injection – As fluid is produced from (or injected into) an underground resource, the reservoir rock may compact or be stressed. These volume changes cause a perturbation in local stress conditions, which are already close to the failure state (geothermal systems are typically located within faulted regions under high states of stress). This situation can lead to seismic slip within or around the reservoir. A similar phenomenon occurs where solid material is removed underground, such as in mines, leading to “rock bursts,” as the surrounding rock adjusts to the newly created void space.

Chemical alteration of fracture surfaces – Injecting non-native fluids into the formation (or allowing “outside fluids” to flow into the reservoir in response to pressure drawdown) may cause geochemical alteration of fracture surfaces, thus changing the coefficient of friction on those surfaces. In the case of reduced friction, MEQs (smaller events) would be more likely to occur. Pennington *et al*. (1986) hypothesized that if seismic barriers evolve and asperities form (resulting in increased friction), events larger than MEQs may become more common.

Based on lesson learned from other EGS projects, we will manage the concern regarding induced seismicity in our EGS development using four components. First, we will conduct studies in order to understand underlying mechanisms causing the events. Second, we will evaluate the cost-benefit balance of EGS implementation, thoroughly. Next, we will set up the real-time monitoring system and reasonable threshold in order to ensure that we could handle unexpected or emergency situations properly. Last, we will develop corporate social responsibility plan to build good relationship between corporate and communities as well as cultivate better understanding of induced seismicity to local population.

9.3 Water Use and Water Pollution

EGS project use water in many activities throughout project development include well drilling, reservoir stimulation, power plant construction, working fluid circulation, and cooling system (if chosen). Utilized water may be taken from a nearby high-flow stream or river (if available), collected in a temporary surface reservoir during the rainy season, taken from nearby underground water wells, or received from nearby communities as treated waste water.

Well drilling, reservoir stimulation, and circulation – Water is required during well drilling to provide bit cooling and rock chip removal. This water (actually a mixture of water and chemicals) is re-circulated after being cooled and strained. Makeup water is required to compensate for evaporation losses during cooling. It is expected that in most advanced EGS applications, surface water will be needed to both stimulate and operate the reservoir (i.e., the underground heat exchanger) and produce the circulation patterns needed. The quantity of hydrothermal fluids naturally contained in the formation is likely to be very limited, particularly in formations with low natural permeability and porosity. In the western part of the United States, where water resources are in high demand, water use for geothermal applications will require careful management and conservation practice. The water may be taken from a nearby high-flow stream or river, if available, or collected in a temporary surface reservoir during the rainy season. Sometimes, local streams may be dammed and diverted. In some EGS resource areas, water treatment will be needed to ensure sufficient quality for reinjection and reuse or to remove potentially hazardous contaminants that might be dissolved or suspended in the circulating geo-fluid or cooling water. It is necessary to coordinate water use during field development with other local water demands for agricultural or other purposes.

Fluids produced from the reservoir – Production of geo-fluids from a hydrothermal reservoir for use in power or thermal energy generation can lower the water table, adversely affect nearby geothermal natural features (e.g., geysers, springs, and spas), create hydrothermal (phreatic) eruptions, increase the steam zone, allow saline intrusions, or cause subsidence. EGS systems are designed to avoid these impacts by balancing fluid production with recharge. In principle, EGS systems may be approximated as “closed-loop” systems whereby energy is extracted from the hot fluid produced by production wells (namely, a heat exchanger for binary plants) and cooled fluid is re-injected through injection wells. However, the circulation system is not exactly closed because water is lost to the formation; this lost water must be made up from surface water supplies.

Cooling water for heat rejection – Cooling water is generally used for condensation of the plant working fluid. The waste heat can be dissipated to the atmosphere through cooling towers if makeup water is available. Water from a nearby river or other water supply can also serve as a heat sink. There are opportunities for recovering heat from these waste fluids (and possibly from the brine stream) in associated activities such as fish farms or greenhouses. An alternative to water-cooling is the technique of air-cooling using electric motor-driven fans and heat exchangers. This approach is particularly useful where the supply of fresh water is limited, and is currently used mainly for binary power plants. While air-cooled condensers eliminate the need for fresh makeup water that would be required for wet cooling towers, they occupy large tracts of land owing to the poor heat transfer properties of air vs. water. This greatly increases the land area needed for heat rejection compared to a plant of the same power rating that uses a wet cooling tower. The environmental impacts of waste heat rejection into the atmosphere or water bodies can be minimized through intelligent design and the use of well-developed technologies; but the amount of heat that must be dissipated is controlled by the laws of thermodynamics.

Wastewater Injection – Geothermal plants have the potential to improve local water quality. So-called waste water injection projects serve the dual purpose of eliminating wastewater, which would otherwise be dumped into local waterways, and rejuvenating geothermal reservoirs with new water sources. A wastewater injection project was initiated at The Geysers geothermal reservoir in December of 2003. Treated wastewater from the nearby community of Santa Rosa had been previously discharged directly into the Russian River, prompting state water quality regulators to take action against the community. Now, 11 million gallons of treated wastewater from Santa Rosa are being pumped daily to The Geysers for injection into the geothermal reservoir. Any residual biological contamination in the wastewater is instantly sterilized upon contact with the reservoir rock (usually above 400°F). The project has also been of great help in maintaining the sustainability of the geothermal reservoir. The additional water being pumped into the geothermal reservoir has helped recharge the resource to make full use of the heat still trapped in the Earth’s rock and has slowed the decline of the resource. The $250 million project has so far proven to be a great success in reducing surface water pollution for the community of Santa Rosa, and has also helped to improve the sustainability of the geothermal reservoir.

In general, utilization of water is not a significant concern because high demand of water is temporary while continuous demand of water is not dramatically decrease the amount of surface and underground water. Despite that fact, we evaluate availability of water for our selected well location. We found that there are nearby stream and underground water well within 3 km distance and neighboring city and town, which are the possible source of treated waste water, within 10 km distance (See Figure 9-2).

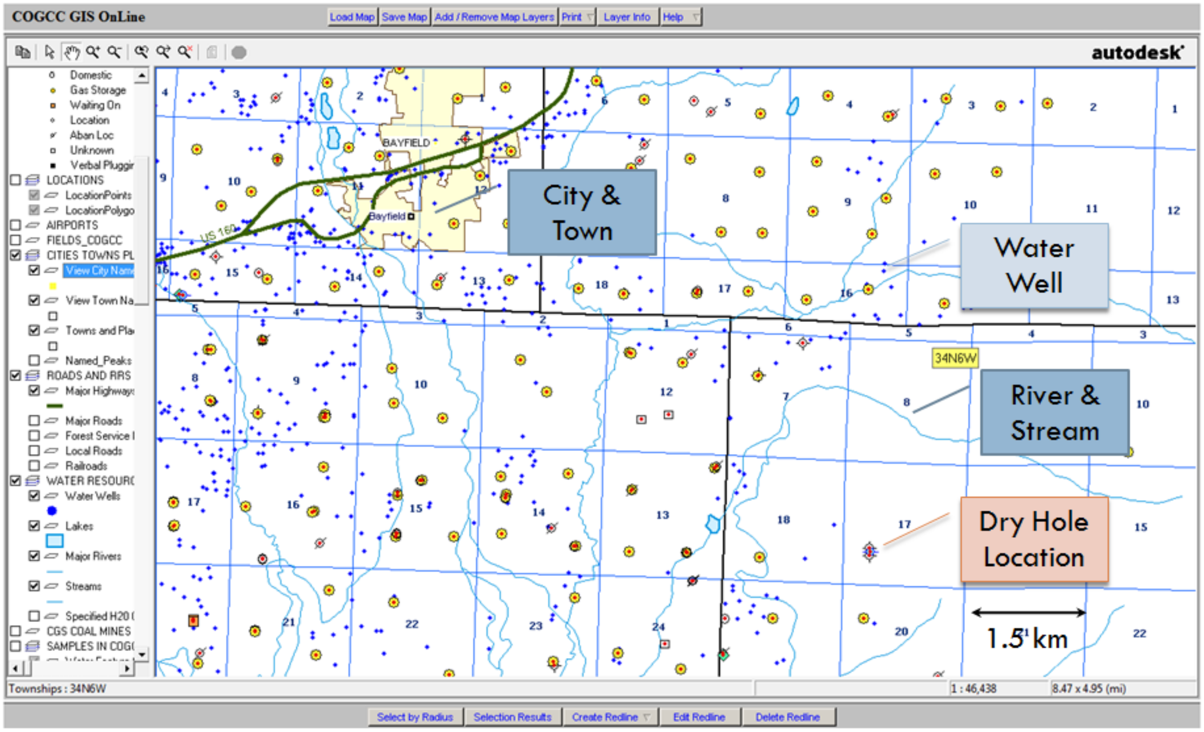

Figure 9-2- Map of Nearby Water Resources (GIS online map, http://oil-gas.state.co.us/infosys/maps/loadmap.cfm)

There will be no contamination of ground and surface water which results from our normal activities in EGS development. Liquid streams from well drilling, stimulation, and production may contain a variety of dissolved minerals, especially for high-temperature reservoirs (>230°C). The amount of dissolved solids increases significantly with temperature. Some of these dissolved minerals (e.g., boron and arsenic) could poison surface or ground waters and also harm local vegetation. The liquid wastes from well drilling and reservoir stimulation have to be stored in lined sumps before being properly disposed of in accordance with the state regulations. Working fluid will be re-circulated into our EGS reservoirs via water injector wells with thick casing to prevent cross-contamination with groundwater systems. A well casing is composed of thick specialized pipe surrounded by cement in order to prevent any contamination as working fluid is re-injected.

9.4 Other Environmental and Safety Issues

Several potential environmental impacts from EGS project have been evaluated. All of them present much lower overall environmental impact than the development of conventional fossil-fuel and other renewable resources. The issues are summarized as follows;

Solid Emissions

There is practically no chance for contamination of surface facilities or the surrounding area by the discharge of solids by itself from the geo-fluid. The only conceivable situation would be an accident associated with a fluid treatment or minerals recovery system that somehow failed in a catastrophic manner and spewed removed solids onto the area. There are no functioning mineral recovery facilities of this type at any geothermal plant – although one was piloted for a short time near the Salton Sea in southern California – and it is not envisioned that any such facility would be associated with an EGS plant. Precautions, however, need to be in place should the EGS circulating fluid require chemical treatment to remove dissolved solids, which could be toxic and subject to regulated disposal and could plug pathways in the reservoir.

Noise Pollution

Noise from geothermal operations is typical of many industrial activities (DiPippo, 1991a). The highest noise levels are usually produced during the well drilling, stimulation, and testing phases when noise levels ranging from about 80 to 115 decibels A-weighted (dBA) may occur at the plant fence boundary. During normal operations of a geothermal power plant, noise levels are in the 71 to 83 decibel range at a distance of 900 m (DiPippo, 2005). Noise levels drop rapidly with distance from the source, so that if a plant is sited within a large geothermal reservoir area, boundary noise should not be objectionable. If necessary, noise levels could be reduced further by the addition of mufflers or other soundproofing means but at added cost. For comparison, congested urban areas typically have noise levels of about 70 to 85 decibels, and noise levels next to a major freeway are around 90 decibels. A jet plane just after takeoff produces noise levels of about 120 to 130 decibels.

During normal operations, there are three main sources of noise: the transformer, the power house, and the cooling tower. Because the latter is a relatively tall structure and the noise emanates from the fans that are located at the top, these can be the primary source of noise during routine operation. Air-cooled condensers employ numerous cells, each fitted with a fan, and are worse from a noise perspective than water cooling towers, which are smaller and use far fewer cells for a given plant rating. Because EGS plants will likely be located in regions where water may be in short supply, they may require air-cooling, and proper attention may be needed to muffle the sound from their air-cooled condensers.

Land Use

Land footprints for hydrothermal power plants vary considerably by site because the properties of the geothermal reservoir fluid and the best options for waste stream discharge (usually reinjection) are highly site-specific. Typically, the power plant is built at or near the geothermal reservoir because long transmission lines degrade the pressure and temperature of the geo-fluid. Although well fields can cover a considerable area, typically 5 to 10 km^2 or more, the well pads themselves will only cover about 2% of the area. With directional-drilling techniques, multiple wells can be drilled from a single pad to minimize the total wellhead area.

Gathering pipelines are usually mounted on stanchions, so that most of the area could be used for farming, pasture, or other compatible use. The footprint of the power plant, cooling towers, and auxiliary buildings and substation is relatively modest. Holding ponds for temporary discharges (during drilling or well stimulation) can be sizeable but represent only a small fraction of the total well field.

A comparison of land uses for typical geothermal flash and binary plants with those of coal and solar photovoltaic plants is presented in Table 9-3 using data from DiPippo (1991).

Table 9-3- Comparison of Land Requirement for Typical Power Generation Options

Technology	Land Use m^2/MW	Land Use m^2/GWh
110 MW geothermal flash plant (excluding wells)	1,260	160
20 MW geothermal binary plant (excluding wells)	1,415	170
49 MW geothermal FC-RC plant (excluding wells)	2,290	290
56 MW geothermal flash plant (including wells, pipes, etc.)	7,460	900
2,258 MW coal plant (including strip mining)	40,000	5,700
2,258 MW coal plant (including strip mining)	10,000	1,200
47 MW (Avg) solar thermal plant (Mojave Desert, CA)	28,000	3,200
10 MW (Avg) solar PV plant (Southwestern US)	66,000	7,500

These data incorporate realistic capacity factors for each technology. Note that average power outputs, not rated values, were used for the solar plants. A solar-thermal plant requires about 20 times more area than a geothermal flash or binary plant; and a solar photovoltaic plant (in the best insolation area in the United States) requires about 50 times more area than a flash or binary plant per MW. The ratios are similar on a per GWh basis. The coal plant, including 30 years of strip mining, requires between 30-35 times the surface area for a flash or binary plant, on either a per MW or GWh basis. The nuclear plant occupies about seven times the area of a flash or binary plant. The land use for geothermal plants having hyper-saline brines is about 75% greater than either simple flash or binary because of the large vessels needed to process the brine. EGS plants are expected to conform more closely to the conventional geothermal flash and binary plants because of the relatively benign chemical nature of the circulating fluids.

Land Subsidence

If geothermal fluid production rates are much greater than recharge rates, the formation may experience consolidation, which will manifest itself as a lowering of the surface elevation, i.e., this may lead to surface subsidence. This was observed early in the history of geothermal power at the Wairakei field in New Zealand where reinjection was not used. Subsidence rates in one part of the field were as high as 0.45 m per year (Allis, 1990). Wairakei used shallow wells in a sedimentary basin. Subsidence in this case is very similar to mining activities at shallow depths where raw minerals are extracted; leaving a void that can manifest itself as subsidence on the surface. After this experience, other geothermal developments adopted actively planned reservoir management to avoid this risk.

Most of EGS geothermal developments are likely to be in granitic-type rock formations at great depth, which may contain some water-filled fractures within the local stress regime at this depth. After a geothermal well is drilled, the reservoir is stimulated by pumping high-pressure water down the well to open up existing fractures (joints) and keep them open by relying on the rough surface of the fractures. Because the reservoir is kept under pressure continuously, and the amount of fluid in the formation is maintained essentially constant during the operation of the plant, the usual mechanism causing subsidence in hydrothermal systems is absent and, therefore, subsidence impacts are not expected for EGS systems.

Induced Landslide

There have been instances of landslides at geothermal fields. The cause of the landslides is often unclear. Many geothermal fields are in rugged terrain that is prone to natural landslides, and some fields actually have been developed atop ancient landslides. Some landslides can be triggered by large earthquakes, but it is highly unlikely that geothermal production and injection could lead to such a massive event. Badly sited wells, particularly shallow injection wells, may interact with faults and cause slippage similar to what has been described in the preceding section.

Under these circumstances, it is possible for a section of a slope to give way initiating a landslide. However, such events at hydrothermal fields are rare, and proper geological characterization of the field should eliminate the possibility of such a catastrophe. EGS reservoir development should avoid areas of high landslide risk even though the chance of a catastrophic event is extremely low.

Disturbance of Natural Hydrothermal Manifestations

Although numerous cases can be cited of the compromising or total destruction of natural hydrothermal manifestations such as geysers, hot springs, mud pots, etc. by geothermal developments (Jones, 2006; Keam *et al*., 2005), EGS projects will generally be sited in non-hydrothermal areas and will not have the opportunity to interfere with such manifestations. For

EGS facilities sited at the margins of existing hydrothermal plants where manifestations might be present, reservoir simulations should be performed to gauge the possible effects on those surface thermal features of drilling new wells and operating the EGS plant. However, because there is no "drawdown" in the traditional sense of an existing water table for an EGS system, it is unlikely that normal operations will have a significant effect on them.

Disturbance of Wildlife Habitat, Vegetation, and Scenic Vistas

Problems related to loss of habitat or disturbance of vegetation are relatively minor or nonexistent at hydrothermal projects in the United States. Given the relatively small area taken out of the environment for geothermal operations, these potential impacts can be minimized with proper planning and engineering. It is difficult to imagine an EGS development causing more of an impact on wildlife and vegetation than a hydrothermal project. Furthermore, an Environmental Impact Statement must be filed before any permits can be granted for a geothermal project, and any potential impact in this area would have to be addressed.

It is undeniable that any power generation facility constructed where none previously existed will alter the view of the landscape. Urban plants, while objectionable to many for other reasons, do not stand out as abruptly as a plant in a flat agricultural region or one on the flank of a volcano. Many geothermal plants are in these types of areas, but with care and creativity can be designed to blend into the surroundings. Avoiding locations of particular natural beauty is also important, whether or not the land is nationally or locally protected. EGS developments will be no different than conventional hydrothermal plant developments, in that the design of the facility must comply with all local sitting requirements.

The development of a geothermal field can involve the removal of trees and brush to facilitate the installation of the power house, substation, well pads, piping, emergency holding ponds, etc. However, once a geothermal plant is built, reforestation and plantings can restore the area to a semblance of its original natural appearance, and can serve to mask the presence of buildings and other structures.

Catastrophic Events

Accidents can occur during various phases of geothermal activity including well blowouts, ruptured steam pipes, turbine failures, fires, etc. This is no different from any other power generation facility where industrial accidents unfortunately can and do happen. The ones that are unique to geothermal power plants involve well drilling and testing. In the early days of geothermal energy exploitation, well blowouts were a fairly common occurrence; but, nowadays, the use of sophisticated and fast-acting blowout preventers have practically eliminated this potentially life threatening problem. Furthermore, geothermal prospects are now more carefully studied using modern geo-scientific methods before well drilling commences.

In the case of EGS projects, it will be critical to study and characterize the nature of any potential site before any development begins. This will minimize the chances for a catastrophic event related to the drilling phase. Proper engineering and adherence to standard design codes should also minimize, if not completely eliminate, any chance of a mechanical or electrical failure that could cause serious injury to plant personnel or local inhabitants.

Thermal Pollution

Although thermal pollution is currently not a specifically regulated quantity, it does represent an environmental impact for all power plants that rely on a heat source for their motive force. Heat rejection from geothermal plants is higher per unit of electricity production than for fossil fuel plants or nuclear power plants; because the temperature of the geothermal stream that supplies the input thermal energy is much lower for geothermal power plants. Considering only thermal discharges at the plant site, a geothermal plant is two to three times worse than a nuclear power plant with respect to thermal pollution, and the size of the waste heat rejection system for a 100 MW geothermal plant will be about the same as for a 500 MW gas turbine combined cycle (DiPippo, 1991a). Therefore, cooling towers or air-cooled condensers are much larger than those in conventional power plants of the same electric power rating. The power conversion systems for EGS plants will be subject to the same laws of thermodynamics as other geothermal plants, but if higher temperature fluids can be generated, this waste heat problem will be proportionally mitigated.

9.5 Laws and Regulations

There are many laws and regulations that EGS project must follow. These regulations dictate how permits can be issued, what sorts of environmental reviews must take place, what level of gaseous emissions will be allowed, what land types may be approved for development, etc. All of the following laws and regulations play a role before EGS project can be brought to fruition.

Federal Laws

- Clean Air Act
- National Environmental Policy Act
- National Pollutant Discharge Elimination System Permitting Program
- Safe Drinking Water Act
- Resource Conservation and Recovery Act
- Toxic Substance Control Act
- Noise Control Act
- Endangered Species Act
- Archaeological Resources Protection Act
- Hazardous Waste and Materials Regulations
- Occupational Health and Safety Act
- Indian Religious Freedom Act.

State Laws

- Colorado Statutes Article 90.5, "Colorado Geothermal Resources Act"
- Code of Colorado Regulations (CCR) Subtitles 402-10, "Rules and Regulations for Permitting the Development and the Appropriation of Geothermal Resources through the Use of Wells"

Thus, it is highly unlikely that any geothermal power plant will be a threat to the environment anywhere in the United States, given the comprehensive spectrum of regulations that must be satisfied. There are several interesting aspects that I would like to highlight as follows;

Clean Air Act

Several pollutants discussed in the above section of this report are regulated under the Clean Air Act (CAA) as criteria pollutants. A criteria pollutant is a principal pollutant identified as most harmful to people and the environment. The Clean Air Act sets National Ambient Air Quality Standards (NAAQS) to regulate emissions of criteria pollutants on a federal level. The six criteria pollutants regulated by NAAQS are carbon monoxide, lead, nitrogen dioxide, particulate matter, ozone, and sulfur dioxides.35 States containing nonattainment areas, geographic areas that do not meet NAAQS standards, are required to develop a State Implementation Plan (SIP), a strategy to meet NAAQ standards at the local and state level. States and tribes are responsible for meeting NAAQS standards under U.S. Environmental Protection Agency (EPA) oversight. State and local governments issue most of the air permits required by Title V of the Clean Air Act. These air permits include enforceable air emissions limitations and standards as established by the state or local government. Title V permits are issued to certain air pollution sources after they have begun to operate. In certain circumstances, for example on tribal lands, EPA may issue Title V permits as needed. EPA permits do not supersede state permits but rather serve areas not under traditional state and local government jurisdictions.

All emitting facilities must comply with federal emission standards under sections 111 and 112 of the Clean Air Act. Under section 111, sources built after September 18, 1978 are subject to particulate matter, sulfur dioxide, and nitrogen oxides standards established by the new source performance standards (NSPS), while those built before 1978 are not subject to federal regulation unless significant renovations occur at the facility. The uncertainty of what constitutes a significant renovation or modification to a power plant has been the subject of recent controversy. Under section 112, "major" industrial facilities that emit one or more of 188 listed hazardous air pollutants, or air toxics, must be EPA regulated. EPA defines "air toxics" as those pollutants that are known or suspected of causing cancer or other serious health effects, such as developmental effects or birth defects. Because geothermal power plants emit pollutants at lower levels than those regulated by the Clean Air Act, they do not face the same constraints as new fossil fuel facilities seeking air and operating permits from state governments.

National Environmental Policy Act

Under the National Environmental Policy Act (NEPA), any geothermal project selling power to a federal entity, moving power over a federal transmission line, or using federal funding or federal land must undergo an environmental analysis in order to determine potential environment impact. Power plants constructed on private or state lands are usually subject to similar state requirements. Depending upon the conclusions reached by the environmental review, additional studies, public hearings and documentation may be required before construction can begin. Any significant environmental impacts identified in an Environmental Assessment (EA) or Environmental Impact Statement (EIS) must be accompanied by a plan for monitored mitigation measures.

Colorado Geothermal Resources Act

- "Geothermal resource" means the natural heat of the earth and includes:
  - The energy that may be extracted from that natural heat
  - The material medium used to extract the energy from a geothermal resource, and
  - Geothermal by-products.
- "Hot dry rock" means a geothermal resource which lacks sufficient geothermal fluid to transport commercial amounts of energy to the surface and which is not in association with an economically useful groundwater resource.
- The property right to a hot dry rock resource is an incident of the ownership of the overlying surface, unless severed, reserved, or transferred with the subsurface estate expressly.
- The property right to a hot dry rock resource has been severed, reserved, or transferred with the subsurface estate, its owner may enter upon the overlying surface parcel at reasonable times and in a reasonable manner to prospect for and produce the energy from such resource, if adequate compensation is paid to the owner of the surface parcel for damages and disturbance. This right of entry shall not include the right to construct surface utilization facilities, and such facilities may be constructed only upon agreement with the surface owner.
- Most of permits required for EGS project have to be obtained from “State Engineer”. The state engineer shall adopt such rules as are necessary to protect the public health, safety, and welfare and the environment and to prevent the waste of any geothermal resource. The state engineer shall also adopt rules for the assessment of reasonable fees for the processing and granting of a permit under this section.

9.6 Colorado State Policies

There are four key recommendations which are deemed to have the most measurable potential for creating a political and economic climate conducive to expanded geothermal development.

Grants and Loan

In a 2004 paper entitled "Geothermal Policy Options for States," the National Geothermal Collaborative (www.geocollaborative.org) wrote:

"…Twenty states have grant programs to support renewable energy in the commercial, industrial and government sectors and for schools and utilities. Some programs focus on research and development, but most aim to encourage the purchase and installation of renewable energy equipment. Programs vary in the amount offered—from a few hundred dollars up to $1 million— and some states set no limit. States also offer low- or no-interest loans to help citizens buy renewable energy equipment…"

Colorado should follow the lead of these states by creating a low-interest loan program through the Colorado Governor's Energy Office. Providing and guaranteeing loans to both residential customers and commercial businesses would facilitate the state's geothermal development.

Resource Assessment

Roy Mink, DOE Program Manager of Geothermal Technologies (April 6 2006) testimony before the U.S. House Committee on Resources, Subcommittee on Energy and Mineral Resources wrote:

"…Resource assessment is an important activity, as the current success rate for discovering new geothermal (hydrothermal) fields is about 20 percent. Most new fields are "blind" in that there are no surface manifestations of the existence of hot water at depth. Much of the risk is up front, requiring investment in exploration, exploratory drilling, and resource assessment…"

Efforts to share information between state and federal agencies that have successfully developed geothermal direct-use projects – including businesses, companies, consultants, and contractors – should continue and expand. Entities should be encouraged to report on geothermal direct-use projects in industry trade magazines, such as greenhouse and aquaculture industry publications that provide visibility about geothermal technology to a broader audience.

Drilling Incentives

While existing federal incentives (PTCs, accelerated depreciation and depletion allowances) are usually sufficient to spur development in the post-feasibility study stage, they are no help during the pre-feasibility study phase. To remedy this situation, state drilling incentives should be created to advance geothermal activity and enhancing capital availability.

State Renewable Purchases

As contrasted from state Renewable Portfolio Standards (RPS), state renewable energy purchase requirements can differ greatly, but most states with such requirements apply them to stateowned facilities. Several states with state renewable energy purchase requirements do not have RPS laws.

Lead by example measures include:

- Establishing clean and / or renewable energy purchasing or generation goals for their own facilities.
- Requirements to obtain a certain percentage of electricity usage from clean renewable generation sources.
- A minimum clean energy purchase volume (in megawatt-hours) by a given date.

Lead by example measures may also take the form of goals for self-generation of clean or efficient energy, such as clean distributed generation or combined heat and power. These goals can be met through a variety of methods including onsite generation, purchasing clean renewable energy power products, or by purchasing renewable energy certificates. Colorado should continue to lead by example, by setting strict renewable usage standards for state buildings and facilities.

10 CONCLUSIONS & RECOMMENDATIONS

In regard to decrease the capital cost needed for an EGS project, it was decided to implement and EGS project using two dry wells(holes). Regions with large thermal gradient with significant oil and gas activity were investigated, thoroughly. Two dry wells, each with about 2,500 m depth were selected in South West Colorado, in San Juan basin. The wells were 100 m apart. Using available curves for drilling costs it is anticipated that approximately 6 million dollars is saved using the dry holes.

13 different scenarios were evaluated to study the viability and feasibility of the project. With the assumptions made, it seems that EGS is NOT economically feasible, even after utilizing dry holes. The most significant factors that could make this project feasible are

- Large resources (large rock volume)
- Environmental friendly policies i.e. low interest rate loan or Cap & Trade
- Highly escalated electricity price
- Reasonable injection rate which still able to maintain the wellhead temperature for long period of time (>20 yrs.)

Recommendations for future study could be categorized as below:

- Find better locations of dry holes at reasonable distance apart with good depth
- Better cost assumptions
    - i.e. power plant, drilling, and stimulation
- More geological information
    - i.e. stress regime, pre-existing fractures, underground water
- Study various types of fracture modeling
- Study potential production problem
    - i.e. scale build-up
- Evaluate CO_2 as geothermal working fluid
- Evaluate possibility of hybrid power plants

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Appendix A

SCENARIO-I: BASIC-BINARY POWER PLANT

Basic binary power plant

Brine Temperature	Temperature of the i-C_5 at Evap. & PH	Condensor Temp. (WF)	Evap. P (Bar)	Condenser P	Turbine efficiency & Pump Eff.	Brine from PH and E
473 K	**450 K**	**320 K**	**28.87**	**1.880**	**0.85 & 0.75**	**421.32 K**

Flow rate of Brine	**36.78**	**61.29**	**100**	**150**
Flow rate of i-C_5 (kg/s)	15.55	25.91	42.85	64.27
Gross power Generated	1.22	2.03	3.31	4.96
Power lost in Pumping	0.10	0.17	0.27	0.41
Net Power Generated	1.12	1.86	3.04	4.55
Thermal Efficiency	**15.27 %**			
Utilization Efficiency	**17.10 %**			

Scenario-I

Brine Temperature	Temperature of the i-C_5 at Evap. & PH	Condensor Temp. (WF)	Evap. P (Bar)	Condenser P	Turbine efficiency & Pump Eff.	Brine from PH & E
455 K	**430 K**	**320 K**	**20.98**	**1.880**	**0.85 & 0.75**	**416.08 K**

Flow rate of Brine	**36.78**	**61.29**	**100**	**150**

Flow rate of i-C_5 (kg/s)	16.24	27.07	44.17	66.26
Gross power Generated	0.90	1.50	2.45	3.68
Power lost in Pumping	0.10	0.17	0.27	0.41
Net Power Generated	0.80	1.33	2.18	3.27
Thermal Efficiency	**16.37 %**			
Utilization Efficiency	**16.42%**			

Brine Temperature	**Temperature of the i-C_5 at Evap. & PH**	**Condensor Temp. (WF)**	**Evap. P (Bar)**	**Condenser P**	**Turbine efficiency & Pump Eff.**	**Brine from PH & E**
430 K	**410 K**	**320 K**	**14.87**	**1.880**	**0.85 & 0.75**	**409.53 K**

Flow rate of Brine	**36.78**	**61.29**	**100**	**150**
Flow rate of i-C_5 (kg/s)	19.77	32.94	53.75	80.62
Gross power Generated	0.41	0.69	1.12	1.68
Power lost in Pumping	0.1	0.17	0.27	0.41
Net Power Generated	0.31	0.52	0.85	1.27
Thermal Efficiency	**13.04 %**			

Utilization Efficiency	**8.75 %**

Scenario -IV

Brine Temperature	**Temperature of the i-C_5 at Evap. & PH**	**Condensor Temp. (WF)**	**Evap. P (Bar)**	**Condenser P**	**Turbine efficiency & Pump Eff.**	**Brine from PH & E**
420 K	**400 K**	**320 K**	**12.38**	**1.880**	**0.85 & 0.75**	**401.40 K**

Flow rate of Brine	**36.78**	**61.29**	**100**	**150**
Flow rate of i-C_5 (kg/s)	19.89	33.15	54.07	81.11
Gross power Generated	0.38	0.64	1.04	1.56
Power lost in Pumping	0.1	0.17	0.27	0.41
Net Power Generated	0.28	0.47	0.77	1.15
Thermal Efficiency	**12.36 %**			
Utilization Efficiency	**9.14 %**			

Scenario-V

Brine Temperature	**Temperature of the i-C_5 at Evap. & PH**	**Condensor Temp. (WF)**	**Evap. P (Bar)**	**Condenser P**	**Turbine efficiency & Pump Eff.**	**Brine from PH & E**
390 K	**370 K**	**320 K**	**6.736**	**1.880**	**0.85 & 0.75**	**375.52 K**

Flow rate of Brine	**36.78**	**61.29**	**100**	**150**

Flow rate of i-C_5 (kg/s)	29.16	48.59	79.28	118.92
Gross power Generated	0.23	0.38	0.61	0.92
Power lost in Pumping	0.1	0.17	0.27	0.41
Net Power Generated	0.13	0.21	0.34	0.51
Thermal Efficiency	**10.13 %**			
Utilization Efficiency	**5.91 %**			

DUAL-FLUID BINARY POWER PLANT

Dual Fluid Binary Power plant- Scenario -I

Brine Temperature	**Temperature of the i-C_5 at Evap. & PH**	**Condensor Temp. (WF)**	**Evap. P (Bar)**	**Condenser P**	**Turbine efficiency & Pump Eff.**	**Brine from PH & E -I**
493 K	**473 K**	**320 K**	**40**	**1.886**	**0.85 & 0.75**	**437.96 K**
	Temperature of the i-C_4 at Evap. & PH	**Condensor Temp. (WF)**	**Evap. P (Bar)**	**Condenser P**	**Turbine efficiency & Pump Eff.**	**Brine from PH & E-II**
	423 K	**323.6 K**	**40**	**7**	**0.85 & 0.75**	**388.72**

Flow rate of Brine (kg/s)	**36.78**	**61.29**	**100**	**150**
Flow rate of i-C_5 (kg/s)	14.12	23.54	38.41	57.61
Flow rate of i-C_4 (kg/s)	31.12	51.86	84.61	126.92

Gross power Generated	1.93	3.21	5.24	7.86
Power lost in Pumping	0.1	0.17	0.27	0.41
Net Power Generated	1.83	3.04	4.97	7.45
Thermal Efficiency	**12.28%**			
Utilization Efficiency	**23.06 %**			

Dual Fluid Binary Power plant- Scenario -I

Brine Temperature	**Temperature of the i-C_5 at Evap. & PH**	**Condensor Temp. (WF)**	**Evap. P (Bar)**	**Condenser P**	**Turbine efficiency & Pump Eff.**	**Brine from PH & E -I**
473 K	**450 K**	**320 K**	**28.87**	**1.886**	**0.85 & 0.75**	**421.25 K**
	Temperature of the i-C_4 at Evap. & PH	**Condensor Temp. (WF)**	**Evap. P (Bar)**	**Condenser P**	**Turbine efficiency & Pump Eff.**	**Brine from PH & E-II**
	400 K	**323.6 K**	**32.04**	**7**	**0.85 & 0.75**	**384.42**

Flow rate of Brine (kg/s)	**36.78**	**61.29**	**100**	**150**
Flow rate of i-C_5 (kg/s)	15.76	26.27	42.86	64.29
Flow rate of i-C_4 (kg/s)	32.11	53.52	87.32	130.98
Gross power Generated	1.78	2.97	4.85	7.27
Power lost in Pumping	0.1	0.17	0.27	0.41
Net Power	1.68	2.80	4.57	6.86

Generated				
Thermal Efficiency	**13.04 %**			
Utilization Efficiency	**28.23%**			

Scenario-II

Brine Temperature	**Temperature of the i-C_5 at Evap. & PH**	**Condensor Temp. (WF)**	**Evap. P (Bar)**	**Condenser P**	**Turbine efficiency & Pump Eff.**	**Brine from PH & E -I**
453 K	**430 K**	**320 K**	**28.87**	**1.880**	**0.85 & 0.75**	**419.24 K**
	Temperature of the i-C_4 at Evap. & PH	**Condensor Temp. (WF)**	**Evap. P (Bar)**	**Condenser P**	**Turbine efficiency & Pump Eff.**	**Brine from PH & E-II**
	395 K	**323.6 K**	**29.61**	**7**	**0.85 & 0.75**	**380.79**

Flow rate of Brine (kg/s)	**36.78**	**61.29**	**100**	**150**
Flow rate of i-C_5 (kg/s)	15.76	26.27	42.86	64.29
Flow rate of i-C_4 (kg/s)	34.24	57.06	93.10	139.65
Gross power Generated	1.34	2.23	3.64	5.46
Power lost in Pumping	0.1	0.17	0.27	0.41
Net Power Generated	1.24	2.06	3.37	5.05
Thermal Efficiency	**12.76 %**			
Utilization Efficiency	**23.84 %**			

Scenario-III

Brine Temperature	Temperature of the i-C_5 at Evap. & PH	Condensor Temp. (WF)	Evap. P (Bar)	Condenser P	Turbine efficiency & Pump Eff.	Brine from PH & E -I
423 K	**400 K**	**320 K**	**12.38**	**1.866**	**0.85 & 0.75**	**398.80 K**
	Temperature of the i-C_4 at Evap. & PH	**Condensor Temp. (WF)**	**Evap. P (Bar)**	**Condenser P**	**Turbine efficiency & Pump Eff.**	**Brine from PH & E-II**
	370 K	**323.6 K**	**19.01**	**7**	**0.85 & 0.75**	**368.72**

Flow rate of Brine (kg/s)	**36.78**	**61.29**	**100**	**150**
Flow rate of i-C_5 (kg/s)	21.39	35.66	58.18	87.27
Flow rate of i-C_4 (kg/s)	40.01	66.68	108.79	163.19
Gross power Generated	0.77	1.29	2.10	3.16
Power lost in Pumping	0.1	0.17	0.27	0.41
Net Power Generated	0.67	1.12	1.83	2.75
Thermal Efficiency	**10.68 %**			
Utilization Efficiency	**20.84 %**			

CO2 FLASH POWER PLANT

Scenario-I

CO2 Temperature	Evap. P (Bar)	Turbine efficiency & Pump Eff.	Injection Temperature, K & P(bar)	Pinch Point T

493.15	**300**	**0.85 & 0.75**	**300 & 67.15**	**10**
Power Generated	1.1	1.83	4.56	9.15
Flow rate of CO2 (kg/s)	29.86	49.76	124.40	248.81
Thermal efficiency	**14.83 %**			
Utilization Efficiency	**35.15%**			

Scenario-II:

CO2 Temperature	**Evap. P (Bar)**	**Turbine efficiency & Pump Eff.**	**Injection Temperature, K & P(bar)**	**Pinch Point T**
473.15	**300**	**0.85 & 0.75**	**300 & 67.15**	**10**
Power Generated	1.07	1.78	4.46	8.92
Flow rate of CO2 (kg/s)	37.70	62.84	157.10	314.19
Thermal efficiency	**13.10 %**			
Utilization Efficiency	**30.51 %**			

Scenario-III:

CO2 Temperature(K)	**Evap. P (Bar)**	**Turbine efficiency & Pump Eff.**	**Injection Temperature, K & P(bar)**	**Pinch Point T**
453.15	**300**	**0.85 & 0.75**	**300 & 67.15**	**10**
Power Generated	1.04	1.74	4.33	8.66
Flow rate of CO_2 (kg/s)	47.98	79.97	199.91	399.83

Thermal efficiency	**11.89 %**
Utilization Efficiency	**26.36 %**

Scenario-IV:

CO2 Temperature	**Evap. P (Bar)**	**Turbine efficiency & Pump Eff.**	**Injection Temperature, K & P(bar)**	**Pinch Point T**
423.15	**300**	**0.85 & 0.75**	**300 & 67.15**	**10**
Net Power Generated	0.87	1.46	3.64	7.28
Flow rate of CO2 (kg/s)	97.33	162.22	405.56	811.12
Thermal efficiency	**7.66 %**			
Utilization Efficiency	**13.54 %**			

DUAL-PRESSURE FLUID BINARY POWER PLANT

Working fluid : Isopentane

Brine Temperature	**Temperature of the i-C_5 at Evap. & PH**	**Condensor Temp. (WF)**	**Evap. P (Bar)**	**Condenser P**	**Turbine efficiency & Pump Eff.**	**Brine from PH & E -I**
493 K	**473 K**	**320 K**	**28.87**	**1.886**	**0.85 & 0.75**	**437.96 K**
	Temperature of the i-C_4 at Evap. & PH	**Condensor Temp. (WF)**	**Evap. P (Bar)**	**Condenser P**	**Turbine efficiency & Pump Eff.**	**Brine from PH & E-II**
	420 K	**320 K**	**17.73**	**1.886**	**0.85 & 0.75**	**419.80**

Flow rate of Brine	**36.78**	**61.29**	**100**	**150**

(kg/s)				
Flow rate of i-C_5 (kg/s)	14.12	23.54	38.41	57.61
Flow rate of i-C_5 (kg/s)	19.55	32.59	53.17	79.76
Gross power Generated	1.61	2.68	4.37	6.56
Power lost in Pumping	0.1	0.17	0.27	0.41
Net Power Generated	1.51	2.51	4.10	6.15
Thermal Efficiency	**14.34%**			
Utilization Efficiency	**19.03%**			

Scenario -I

Brine Temperature	**Temperature of the i-C_5 at Evap. & PH**	**Condensor Temp. (WF)**	**Evap. P (Bar)**	**Condenser P**	**Turbine efficiency & Pump Eff.**	**Brine from PH & E -I**
473 K	**450 K**	**320 K**	**28.87**	**1.886**	**0.85 & 0.75**	**421.25 K**
	Temperature of the i-C_4 at Evap. & PH	**Condensor Temp. (WF)**	**Evap. P (Bar)**	**Condenser P**	**Turbine efficiency & Pump Eff.**	**Brine from PH & E-II**
	400 K	**320.15 K**	**12.38**	**1.886**	**0.85 & 0.75**	**400.27**

Flow rate of Brine (kg/s)	**36.78**	**61.29**	**100**	**150**
Flow rate of i-C_5 (kg/s)	15.76	26.27	42.86	64.29
Flow rate of i-C_5 (kg/s)	22.73	37.89	61.82	92.73

Gross power Generated	1.59	2.66	4.34	6.51
Power lost in Pumping	0.1	0.17	0.27	0.41
Net Power Generated	1.49	2.49	4.07	6.10
Thermal Efficiency	**13.59%**			
Utilization Efficiency	**22.71%**			

Dual Pressure Binary Power plant- Scenario -II

Brine Temperature	**Temperature of the i-C_5 at Evap. & PH**	**Condensor Temp. (WF)**	**Evap. P (Bar)**	**Condenser P**	**Turbine efficiency & Pump Eff.**	**Brine from PH & E -I**
453 K	**430 K**	**320 K**	**20.98**	**1.866**	**0.85 & 0.75**	**419.27 K**
	Temperature of the i-C_4 at Evap. & PH	**Condensor Temp. (WF)**	**Evap. P (Bar)**	**Condenser P**	**Turbine efficiency & Pump Eff.**	**Brine from PH & E-II**
	400 K	**320.15 K**	**12.38**	**1.866**	**0.75 & 0.7**	**402.03**

Flow rate of Brine (kg/s)	**36.78**	**61.29**	**100**	**150**
Flow rate of i-C_5 (kg/s)	16.24	27.07	44.17	66.25
Flow rate of i-C_5 (kg/s)	22.73	37.89	61.82	92.73
Gross power Generated	1.27	2.11	3.44	5.16
Power lost in Pumping	0.1	0.17	0.27	0.41
Net Power	1.17	1.94	3.17	4.76

Generated				
Thermal Efficiency	**13.45%**			
Utilization Efficiency	**21.97%**			

Brine Temperature	**Temperature of the i-C_5 at Evap. & PH**	**Condensor Temp. (WF)**	**Evap. P (Bar)**	**Condenser P**	**Turbine efficiency & Pump Eff.**	**Brine from PH & E -I**
423 K	**400 K**	**320 K**	**12.38**	**1.866**	**0.85 & 0.75**	**398.82 K**
	Temperature of the i-C_4 at Evap. & PH	**Condensor Temp. (WF)**	**Evap. P (Bar)**	**Condenser P**	**Turbine efficiency & Pump Eff.**	**Brine from PH & E-II**
	380 K	**320 K**	**8.34**	**1.866**	**0.75 & 0.7**	**385.00 K**

Flow rate of Brine (kg/s)	**36.78**	**61.29**	**100**	**150**
Flow rate of i-C_5 (kg/s)	19.89	33.15	54.09	81.13
Flow rate of i-C_5 (kg/s)	30.29	50.48	82.36	123.54
Gross power Generated	0.70	1.17	1.91	2.86
Power lost in Pumping	0.1	0.17	0.27	0.41
Net Power Generated	0.60	1.00	1.64	2.46
Thermal Efficiency	**11.45%**			
Utilization Efficiency	**16.30%**			