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THERMODYNAMIC AND ECONOMIC ASSESSMENT OF POWER PLANT EXPANSION FROM 140 TO 200 MWe IN KAMOJANG - INDONESIA

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ABSTRACT

Kamojang power plant is the first geothermal plant in Indonesia. The two-phase steam-dominated reservoirs produce steam to service three turbo-generator units with a total capacity of 140 MWe. Unit one, 30 MWe, began commercial operation in 1982, followed by two units in 1987, 2×55 MWe. Further evaluation of the resources indicates that it is possible to add a 60 MW turbo-generator for 25 years to fill the high electricity demand in the Java-Bali interconnection grid system. The proposed 60 MW turbo-generator plant is a condensing turbine with turbine inlet pressure in the range of 6-8 bar, and mass flow rate in the range of 500-540 tons/h. Increasing the well head pressure will increase utilization efficiency to a range of 58-62%. Steam is supplied mainly from the southeast part of the 14 km^2 proven reservoir. A new power house should be located in the same area as the existing one to minimize environmental impact and reduce landscape costs, while giving an increase in length of the steam transportation piping system. The total transportation pipe length is about 2.5 km, and it has a pressure drop in the range of 1.5-2.0 bar.

Economic feasibility is assessed with the investment-cost-base method and net-back-value approach. The investment cost is mainly generated from steam field and power plant costs. In the net-back-value approach, the electricity price of the plant is compared with a coal power plant and a combined-cycle gas turbine plant. Economic simulation shows that geothermal cost, based on the investment-cost-base, gives a negative value of NPV, if the electricity price is less than 0.05 USD/kWh, IRR of 16.4%. The government project gives an electricity price of 0.04 USD/kWh which corresponds with IRR of 16.1%. With net-back-value, geothermal electricity competes with coal fuelled steam plant (or natural gas combined-cycle) if the price is less than 0.043 USD/kWh. Hence, the 60 MW geothermal project will be competitive if the government of Indonesia owns this geothermal project. Coal and natural gas are high level energy grades. Geothermal heat is, on the other hand, low level energy grade. If tax rates of private geothermal projects are decreased to 10%, the geothermal project becomes economically more feasible than a coal fuelled steam plant and a combined-cycle gas turbine power plant.

1. INTRODUCTION

1.1 Location and geography

The Kamojang geothermal field is located about 42 km southeast of Bandung, the capital city of West Java. The mountainous area comprises several mountains such as Gandapura, Rakutak, Masigit and Guntur. On average the geothermal area has an elevation of 1500 m above sea level. The centre of the field indicates an apparent rim structure with a diameter of about 4 km, which possibly used to be a volcanic caldera. The ambient temperature is, on average, in the range of 12-20˚C, with a relatively high intensity of rainfall. A small lake, called Danau Pangkalan, is in the centre of the field and another lake called Danau Ciharus, with a diameter of about 1 km is about 3 km southwest of the area. The field is located in the area of a government reservation forestry. A promising nearby geothermal source is the Darajat geothermal field, which is located about 5 km south of Kamojang.

1.2 The project history

The exploration history of Kamojang began in 1918 when the Holland Colonial government discovered geothermal activities in the area. In 1926-1928, five exploration wells were drilled by Netherlands East Indies Volcano. One of these wells is still in production with a pressure of 3.5-4 bar, and temperature of 140˚C, at a depth of 66 m. In 1971, further exploration research was conducted by the joint cooperation of the government of Indonesia and the government of New Zealand. In 1972, the first exploration well was drilled, and then in 1979, ten more production wells were drilled to supply the first power plant. On October 22, 1982, the first 30 MWe geothermal power plant was connected to the grid. Given that unit one was successful, it was decided to expand the power plant further. On February 7, 1982, one 55 MWe unit was connected to the grid and on September 13, 1982 another 55 MWe unit was added, resulting in a total production of 140 MWe.

1.3 Geology, geochemistry, and geophysics

The geological structure of the field is mainly controlled by the faults, fractures and calderas rim. There are four main groups of faults in the system.

a. Faults trending N60˚E are the oldest. Investigation indicates that these have a low permeability. No wells were drilled along them.
b. Faults trending N140˚E are productive. The intersection between these faults and the rim has proven to be a productive location and one of the main supplying areas to the power plant.
c. Faults striking N110˚E are apparent in the northeast part of the field. This area probably will be a target for further development.
d. Faults with a direction of N15˚E are the youngest in the field, located in the east part of the field; drilling has proven that this is a good production area.

The calderas rim and the intersection of the faults and fissures have become the main production area of the fields. The central rim area is the main steam supplier for the 140 MWe power plant, while the southeast part of the rim is proposed to become the main part of the expanded 60 MWe turbine. The alteration minerals found during drilling, such as epidote and wairakite, show that reservoir temperature is around 240˚C. Figure 1 shows the geology map of the field.

The geothermal surface manifestations are steaming ground, mud pools, hot pools, ground collapse, solfataras, and a small spring. The water is acidic, with low pH, low chloride, and low carbonate. The explanation for the acid water is that the reservoir is boiling, steam rises and condenses, diluted with surface water. The sulphur in the steam oxidizes to form sulphate water. This water leaches the surrounding ground to form mud pools and collapsed craters.

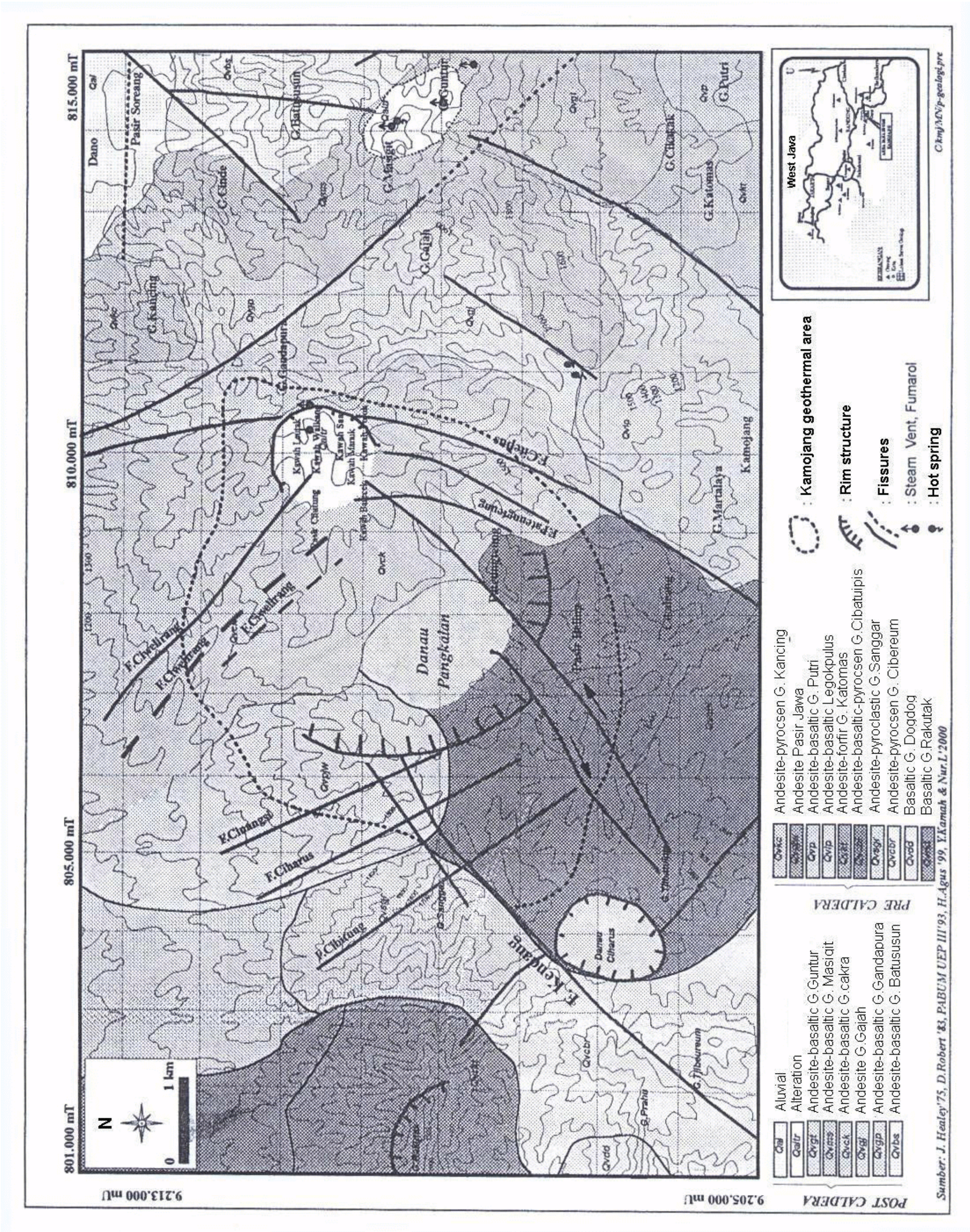

FIGURE 1: Geological map of the Kamojang geothermal field (Pertamina, 2000)

The isotope data from wells indicates there is no significant oxygen shift. The water is from meteoric water. The tritium data shows that the water in the wells is modern water. Possibly the fluid of the reservoir is from a modern recharge with low residence time (Pertamina, 2000).

The initial geophysical survey illustrates a low apparent resistivity in an area of about 14 km^2. Further exploration supported the possibility of increasing the production area from 14 km^2 to 17 km^2 and even up to 21 km^2. An exploration well will prove whether increasing the production area is economic or not.

The reservoir is a two-phase steam-dominated system. At the well head pressure, steam is produced with enthalpy of about 2800 kJ/kg, operating steam pressure is in the range of 8-15 bar, and temperature is in the range of 165-207°C. The average depth of the wells is in the range of 1000-1500 m, both for directional wells or deviated wells. Steam capacity from the wells is, on average, 20-110 tons/h.

2. PROPOSAL TO ADD 60 MWe TURBO-GENERATOR

2.1 Power potential of the field

After geophysical exploration, the initial reservoir model of the field was proposed by Manfred P. Hochstein. Resistivity measurements indicated that the apparent resistivity below 10 ohm-m covers about 14 km^2 (Hochstein, 1975). In Figure 2 the double dashed line shows the low-resistivity area. Additional information from the resistivity sounding, combined with the surface manifestations, created a model of the geothermal reservoir of this field. The model consists of natural heat discharge, a condensate layer, which has a depth of 0.5 km, a reservoir with a mixture of vapour and hot water, which has a depth in the range of 0.5-1.5 km below the surface, and hot rock in the deeper reservoir. By assuming that the porosity is 15%, the heat storage in the reservoir can be calculated. Based on the surface manifestations, the estimation of natural discharge is 10^8 J/s and the heat stored in the condensate layer is 0.6×10^{18} J; the heat stored in the mixture of vapour and hot water depends on the ratio of the two. Assuming that the reservoir is 50% vapour and 50% hot water, the heat stored is 1.2×10^{18} J. Heat stored in the hot rock is 6×10^{18} J, which is possible to mine if there is a recharge flow from the deep reservoir. Figure 3 shows the initial model of the reservoir.

From the reservoir modelling, the power potential can be estimated. Assuming that the heat will be tapped through the vapour at a pressure of 3 bar and temperature of 150°C, and 50 years plant life, the plant efficiency will be 25%. The power potential from the renewable resources will be 25 MW, from the lower part of the condensate layer it will be 50 MW, and from the reservoir mixture it will be 200 MW. The power potential from the deeper heat has not been calculated yet, since there is no data to estimate the recharge from the deeper reservoir which will transport the heat to the surface. Hence, the total power potential is 275 MW (Hochstein, 1975). The recent reservoir model is slightly different from the initial model. The following parameters are used in the reservoir models (Pertamina, 2000):

Reservoir area	= 14.4 km^2;
Reservoir thickness	= 1000 m;
Rock density	= 2640 kg/m^3;
Porosity	= 10%;
Recovery factor	= 70%;
Rock specific heat	= 1000 J/kg°C;
Average reservoir temperature	= 242.5°C;
Water saturation	= 30%;
Plant efficiency	= 16.4%;
Plant life	= 25 years;
Load factor	= 0.85;
Abandonment temperature	= 200°C.

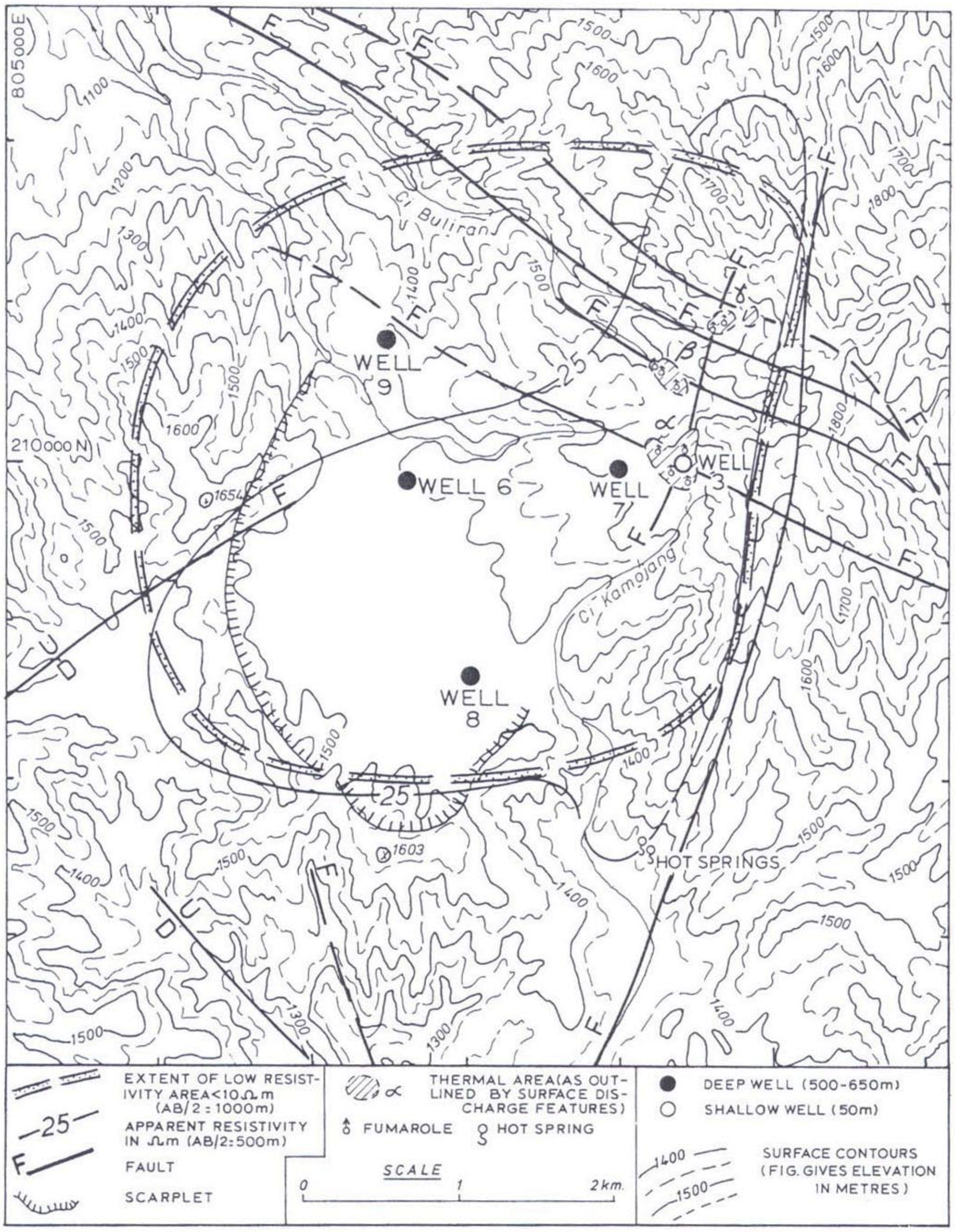

FIGURE 2: Resistivity map of the Kamojang geothermal field (Hochstein, 1975)

Figure 4 shows the recent reservoir model for Kamojang field. The simulation gives a potential capacity of 195 MWe.

Another parameter which is used to measure the power potential is the power density of the field. The existing power plant installation capacity is 140 MW. Geothermal steam is tapped from about 30 wells, which have a production area of about 8.5 km^2. Then, the power density of the field is 140 MW divided by 8.5 km^2, or 16.5 MW/km^2. However, the minimum production area is 14 km^2, which gives a minimum power potential of about 231 MW.

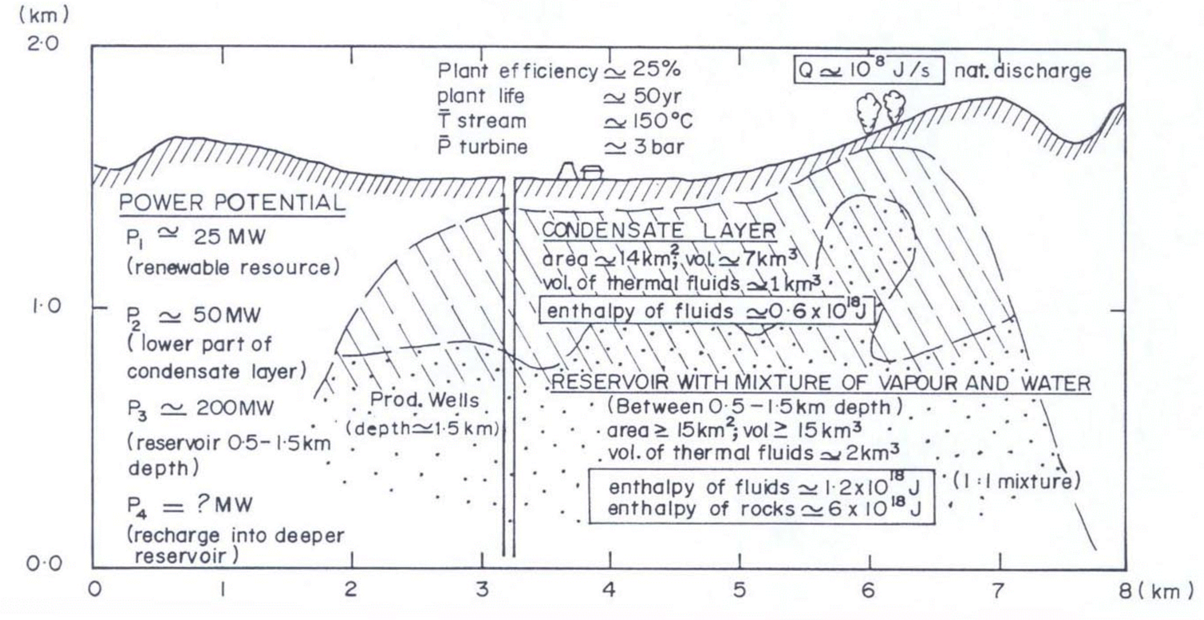

FIGURE 3: The initial reservoir model of the Kamojang geothermal field (Hochstein, 1975)

Further drilling activities prove that the expansion of the power plant from 140 MWe to 200 MWe can be done and it operated in several years. Nine wells will supply the steam with a total mass flow of 507 tons/h at 12.5 bar well head pressure (WHP), or 449 tons/h for a well head pressure of 15 bar. Based on steam consumption in the existing turbines, that is 8.4 tons/h per MWe output at 6 bar turbine inlet pressure, the available steam supply produces a total of 60.4 MWe or 54.4 MWe, depending on the operating well pressure. Table 1 shows the steam production from these wells.

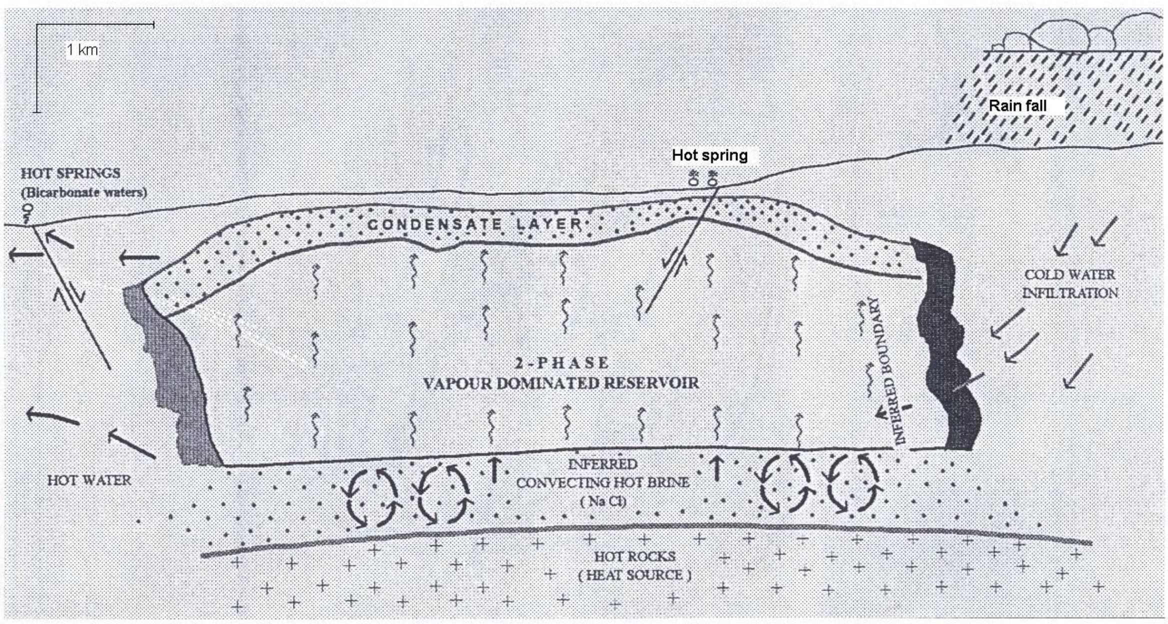

FIGURE 4: Recent reservoir model of the Kamojang geothermal field (Pertamina, 2000)

TABLE 1: The wells capacity for 60 MW expanding turbo-generator (Pertamina, 2000)

Wells	WHP 12.5 bar		WHP 15 bar	
	(Tons/h)	**(MWe)**	**(Tons/h)**	**(MWe)**
KMJ – 48	66	8.25	60	7.5
KMJ – 49	48	6	45	5.63
KMJ – 53	60	7.5	50	6.25
KMJ – 57	32	4	30	3.75
KMJ – 58	40	5	35	4.38
KMJ – 59	52	6.5	39	4.88
KMJ – 61	97	12.13	90	11.25
KMJ – 69	71	8.88	61	7.63
KMJ – 71	41	5.13	39	4.88
Total	**507**	**60.4**	**449**	**54.4**

2.2 Forecast for productivity decline

Reservoir decline is one of the important common parameters during geothermal utilization, since the mass extracted is sometimes more than the natural discharge in natural conditions. Reservoir decline also means that the power potential declines due to the decline in mass flow rate and enthalpy or boiling, dependent on the mass flow of the recharge water, and on the changing properties of the reservoir. During operation, some measurements indicate that the harmonic decline rate is 4.2% (Sanyal et al., 2000). This is a normal decline rate for a geothermal field. As seen in Figure 5, the total steam extraction jumped from around 250 to 1150 tons/h. As the power plant production increased from 30 to 140 MWe, the average well productivity declined from about 65 tons/h to about 45 tons/h. Increasing the power plant from 140 to 200 MWe will also increase the amount of steam extraction, which may possibly give a faster significant reservoir decline.

Nine wells are theoretically already available for an additional 60 MWe unit. However, in practice, more wells should be drilled as make-up wells. The number of make-up wells depends on the decline rate of the reservoir. At maximum load operation, the well decline would be about 6.4% (Sanyal et al., 2000). That means 32.2 tons/h or 3.84 MWe of additional steam is needed. If the average well capacity is 55 tons/h, 2-3 wells have to be drilled per year as make-up wells.

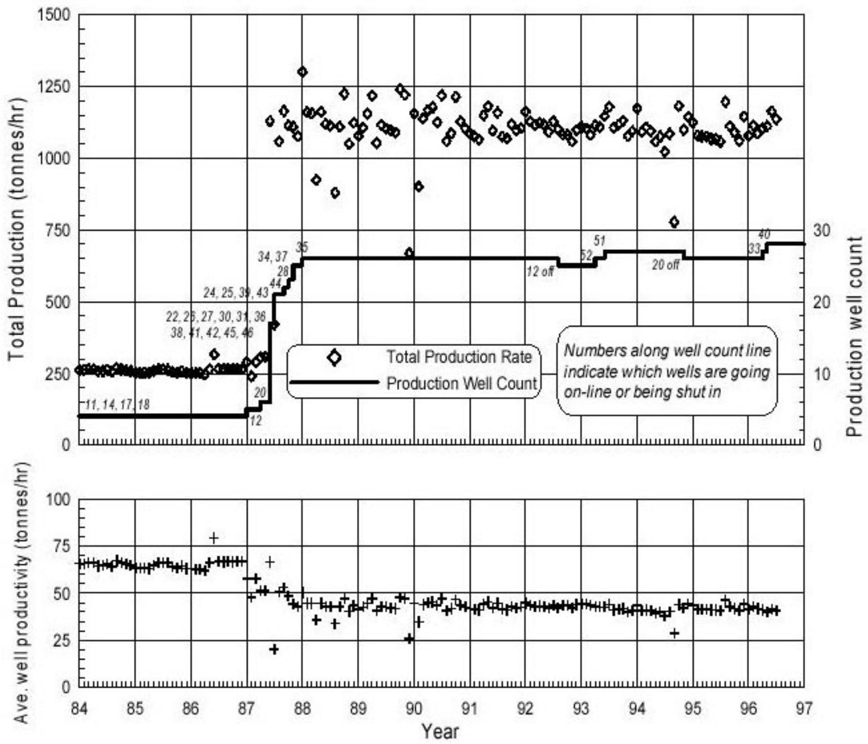

FIGURE 5: The total mass extraction and well decline of the Kamojang geothermal field during operations since 1984-1987 (Sanyal et al., 2000)

Assuming that 40 wells supply steam to units 1-3 and 9 wells supply steam to unit 4, the total number of wells is 49. In 30 years, the total number of make-up wells will be 75, so the total number of wells will be 115. Since the total production area is 14.4 km^2, then the average area per well will be 0.16 km^2, or the well spacing will be about 390 m. In fact, the rule of thumb is that the minimum well spacing should be about 350 m to satisfy a geothermal project. For comparison, the average well spacing in some geothermal fields are Wairakei (New Zealand) with 50-70 m, The Geysers (USA) with 90 m and Otake (Japan) with 80 m.

2.3 Electricity demand

The electric power from a power plant is transferred through the interconnection grid system in the switch gear or switch yard. This grid is a 150 kV transmission grid which has two direct connections, the 500 kV Java-Bali main grid system and the 220 volt or higher voltage distribution system, depending on the type of consumers. In recent conditions, expanding the Kamojang power plant will theoretically have a good effect on the voltage quality of the transmission system. This is due to the power plant being located in the south part of Java, where the voltage of the grids is already down, because the power plants are mainly located near the coast along the northern part of Java island. The electric transmission investment is mainly for a step-up transformer and a switch board system. Figure 6 is a map of the Java-Bali transmission line.

The electrical consumption growth in the Java-Bali system from 1994 to 2000 was normally in the range of 7-15%. The optimistic consumption growth from 2000 to 2003, is in the range of 10-12 %. In 2000, the 10% electrical growth will be equivalent to about 118 MW. Table 2 shows the Java-Bali electricity consumption from 1994 to 2000. In 1998, there was a decline in electricity consumption during the enormous economic and political crisis that started in March, 1998. Although complete recovery from the crisis is not achieved to date, electricity consumption is growing again. The total installed capacity of power plants attached to the grid is about 19,000 MW with about 12% from hydropower plants.

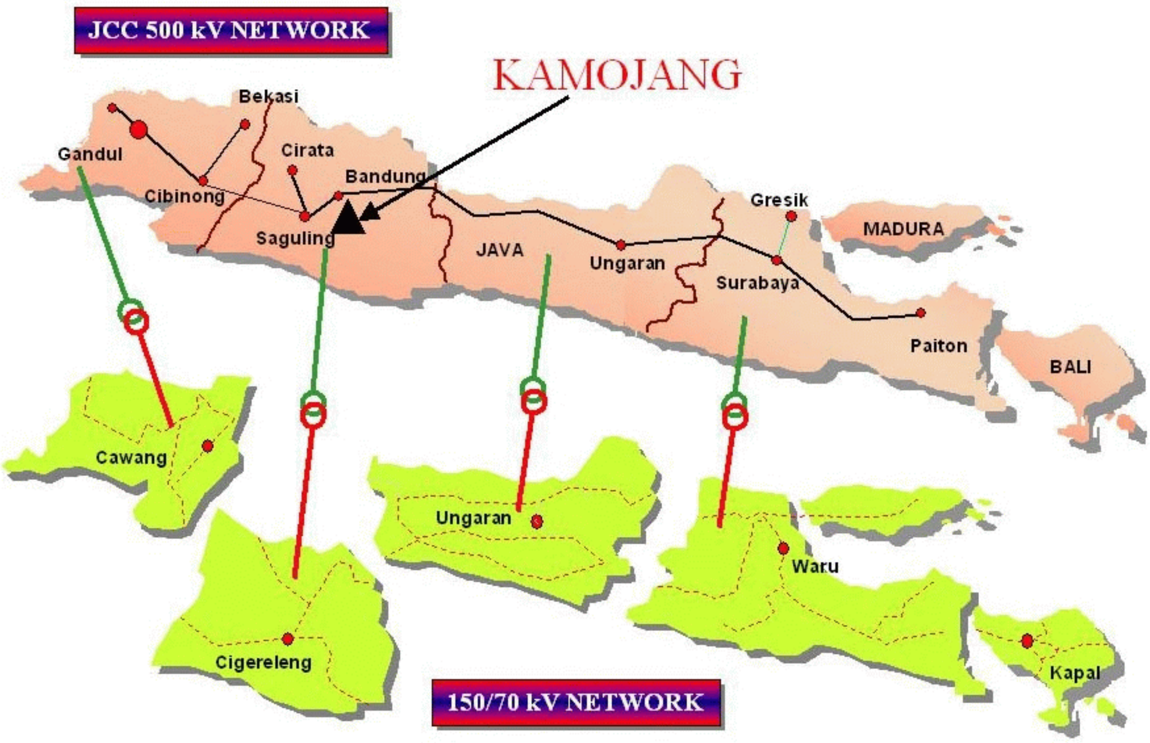

FIGURE 6: The Java-Bali 500 kV and 150 kV electrical interconnection transmission system

Hydropower has a very low capacity factor of about 42%, and the power plants are mostly affected by the amount of rainfall. The electricity forecast indicates that if there is no development of new power plants, starting in 2003 there will be an alarming lack in the electricity supplying system in Java-Bali, as the peak load plus a 30% reserve is less than the availability of the power plants. The development of a 60 MW Kamojang power plant is really too far from the capacity of the new power plants that need to be built in the next few years. But today, international financial market assistance is no longer available for the development of new power plants. The development of Kamojang 60 MW will be timely as the infrastructure and reservoir are already there. The total cost is less than the development of a new geothermal field.

TABLE 2: The Java-Bali electricity market from 1994 to 2000

	1994	1995	1996	1997	1998	1999	2000
Electricity consumption (GWh)	42,057	48,751	54,970	62,179	62,025	67,710	72,670
Equivalent power plant load (MW), 70% capacity factor	6,859	7,950	8,965	10,140	10,115	11,042	11,851
Growth (%)		15.9	12.8	13.1	-0.25	9.2	7.3

3. THERMODYNAMIC ANALYSES OF THE SYSTEM

3.1 Thermodynamic process

A typical power plant flow diagram is shown in Figure 7. Saturated geothermal steam from several wells is piped to a single pipe transmission line for every power plant unit. Because the reservoir is two-phase and steam-dominated, the fraction of steam coming from the well head will be 100%. The operating well head pressure varies from 12 to 15 bar (new drilled wells). But for simplicity, it is assumed that all wells

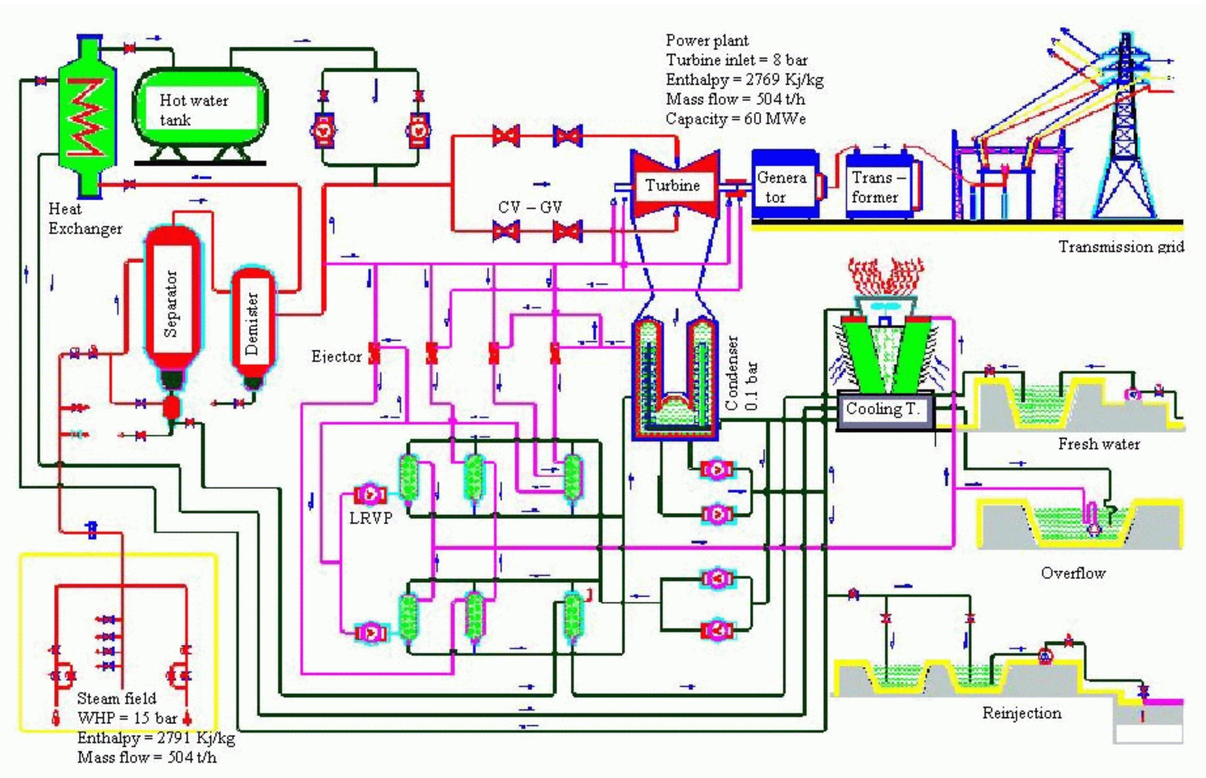

FIGURE 7: A typical flow diagram for a 60 MWe geothermal power plant

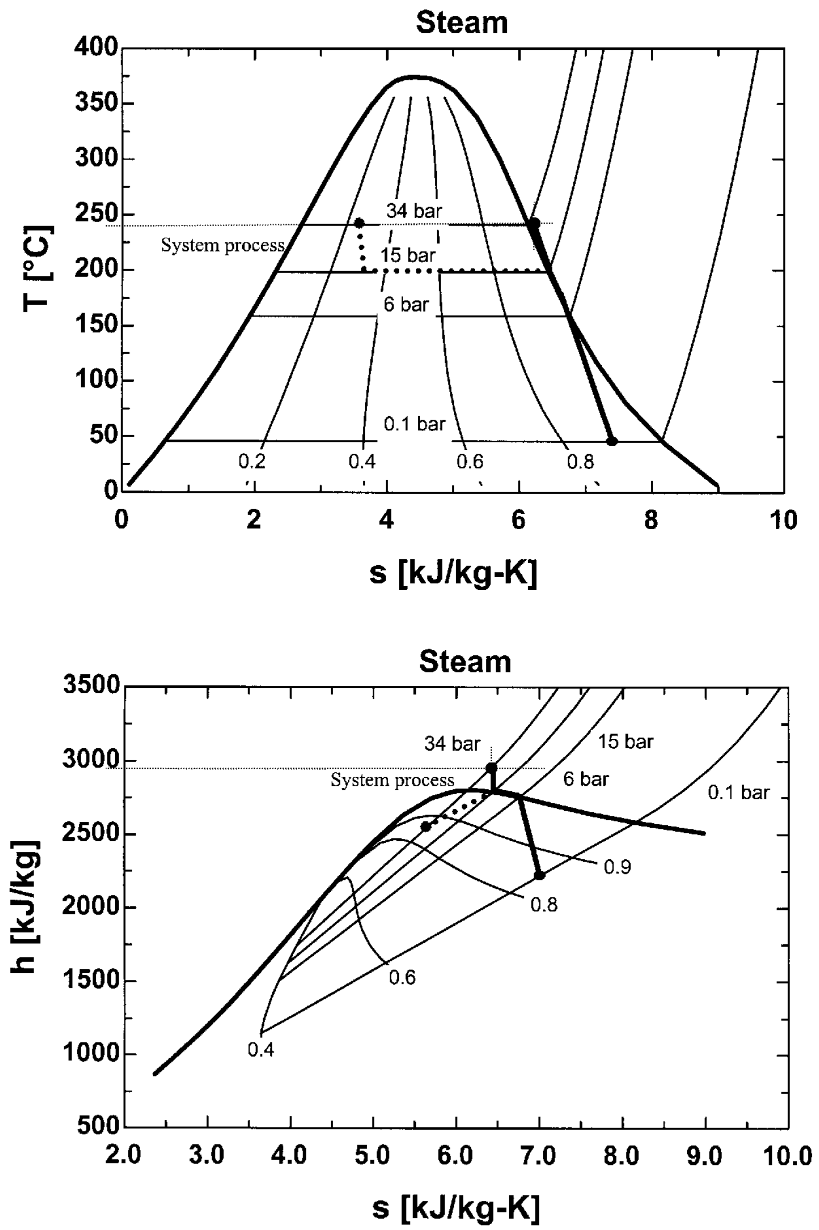

FIGURE 8: Mollier diagram showing schematically the thermodynamic process for the system

supplying the 60 MWe power plant have an average well head pressure of 15 bar. Based on the reservoir modelling data, the reservoir temperature is 242.5°C, which is associated with a pressure of about 34 bar. These conditions give a maximum fluid heat content of about 2803 kJ/kg. When the fluid flows up the wells, the enthalpy is constant at 2791 kJ/kg at a pressure of 15 bar. The next step is gathering and transmitting steam to the power plants. The turbine operating pressure is 6-8 bar, in order to accommodate the draw-down pressure of the reservoir, while increasing operation pressure up to 8 bar is available for the same turbine. The fluid enthalpy at the turbine inlet pressure is 2769 kJ/kg. After steam expansion in the turbine, steam is condensed in the condenser. Given that the condenser pressure is 0.1 bar, turbine efficiency is 85%, the mixture enthalpy is 2209 kJ/kg and gives water enthalpy of 192 kJ/kg. It is clearly seen that the biggest part of the energy is lost in the condenser during the condensation process, rather than supplying usable energy in the turbine expansion. The schematic of the thermodynamic process is shown in the Mollier diagram in Figure 8. The continuous line represents the vapour extraction, while the dashed line is a boiling process in the reservoir.

Appendix I gives general formulae that are used for the technical calculations and their nomenclature. Calculations were carried out with the Engineering Equation Solver (EES) software (Klein and Alvardo, 2001). Appendix II lists the EES programs that were used.

3.2 Energy and exergy calculation approach

The pressure change from the well bore to the turbine represents the energy content in the steam, whereas the energy in the exhaust steam is represented by pressure and steam fraction. It is common to assume that during steam transmission from the well bore to the power plant, steam is always in a saturated state.

The heat transfer is only from the steam to the surroundings due to friction and temperature differences; the cooling effect will produce steam condensate. Steam and condensate are always in thermal equilibrium. It is clearly seen that energy loss is directly related to the decreasing pressure in the steam pipe line. In the condenser, the transfer energy during the process of condensation has the same amount as the energy content of the fluid in the turbine exhaust and in the hot wells. Table 3 represents the energy calculation of the fluids in each state.

The concept of exergy is being developed in the geothermal cycle to give a yardstick of system efficiency. The second law of thermodynamics states that in the adiabatic irreversible process, work done to the surroundings will increase entropy from state one to state two, but the total entropy will remain constant. The exergy concept is used to determine the available work in state one that can be utilized at the surrounding temperature as a dead state of the closed system.

For the power plant process, let us say that the initial condition is the condition in the well bore that is assumed to have the same properties as the reservoir. The final stage is the condition in the condenser with a pressure of 0.1 bar. Surrounding is an ambient temperature of 15˚C and 1 bar atmospheric pressure. Table 3 also represents the exergy calculation of the fluids in each state.

TABLE 3: The energy and exergy calculations and the efficiency

	Well bore T=242.5˚C	**WHP P=15 bar**	**Inlet turbine P=8 bar**	**Exhaust turbine P=0.01 bar**	**Condenser P=0.01 bar**
Enthalpy (kJ/kg)	2803	2791	2769	2225	192
Enthalpy losses (kJ/kg)		12	22	532	2033
Ratio of enthalpy losses to the well bore (%)		0.4	0.8	19	72.5
Entropy (kJ/kgK)	6.13	6.44	6.76	7.02	0.64
Exergy (kJ/kg)	1040	937	852	204	3
Exergy losses, (kJ/kg)		103	85	607	201
Ratio of exergy losses to the well bore (%)		9.9	8.2	58.4	19.3
Efficiency					
Thermal efficiency (%)	19				
Utilization efficiency (%)	58				
Mass flow rate (tons/h)	504				

3.3 Thermal efficiency and utilization efficiency

Energy losses from the well bore to the condenser are mainly due to condensation of exhaust steam to condensate water in the condenser. As seen in Table 3, this loss is about 73 %, while useful energy is only 19%. Energy loss due to friction and heat transfer to the surroundings is only about 1.2%. The thermal efficiency of the system is about 19%. This is very low. One of the reasons is because the heat content in the steam is mainly latent heat in the range of 62-84% of the total enthalpy with pressure in the range 1-37 bar. In conventional steam turbines there is, up to now, no turbine technology to utilize the energy released from the condensation process by converting it to useful electrical energy. The heat transfer equipment such as the condenser is the only one which can be further utilized to obtain more energy. A cascade system, utilizing heat from the condenser to heat up cold water will increase thermal efficiency with significant values.

The exergetic analyses will give a more realistic guide to measuring the availability of heat to perform work on a definite surrounding. This means, that for the same heat quantity, the availability to perform a job depends on the temperature of the surroundings. Again, Table 3 gives exergy losses from the well bore to the condenser. The exergetic losses in the well bore are about 10% and in the steam transmission line about 8.2%, while exergetic losses during condensation are about 19.3%. The pressure decrease along the steam line, due to heat transfer or flow restriction in the valve, will significantly influence the decrease of available energy. Designs of steam transmissions and valves are important in a geothermal system. While not readily apparent when analysing energy production, they are significant in exergetic analyses.

Simulation with different pressures of both the well head and the inlet turbine, shows a change in mass flow rate and efficiency. Increasing turbine inlet pressure from 6 to 8 bar will decrease the mass flow from 539 to 504 tons/h. The thermal efficiency rises from 19 to 19.4%, while the utilization efficiency increases from 58 to 62%. Meanwhile, decreasing well head pressure from 15 to 12 bar does not change steam consumption, but enthalpy loss is about 0.3% and exergy loss is about 2.1%. Table 4 shows this simulation.

TABLE 4: Comparison of operating parameters with different operating well head pressure and turbine inlet pressure

	Well head pressure	**Inlet turbine pressure**
Decreasing parameters (bar)	**15 → 12**	**8 → 6**
Enthalpy loss (kJ/kg)	7	8
Ratio of enthalpy loss to the well bore (%)	0.3	0.4
Exergy losses (kJ/kg)	30	41
Ratio of exergy losses to the well bore (%)	2.1	3.9
Efficiency		
Thermal efficiency (%)		0.4
Utilization efficiency (%)		3.9
Mass flow rate (tons/h)		35

3.4 The main system design parameters

3.4.1 The steam field, production wells, and re-injection wells

There is a strong correlation between steam flow and well head pressure. In a dry well steam, the maximum well head pressure is when the well is being closed. When a well is opened, the lower the pressure the more steam is produced, and the more electricity is produced, but the well will decline faster, and the reservoir will decline faster and cool faster. The ideal exploitation for natural field sustainability is for the mass flow of natural recharge to be the same as mass flow of the steam production with no cooling effect on the reservoir. The exergy analysis indicates that a minimum loss of available work (maximum utilization efficiency) from the well bore to the power plant will be reduced if the pressure change is small. Based on this, well head pressure should be chosen at some pressure where there is a balance between electricity production and reservoir sustainability. Assuming that the production wells will be operated at a pressure in the range of 12-15 bar (depending on the well location and well topography), and the turbine will be operated at a pressure of 6-8 bar during the lifetime of the plants.

There may be a problem of scale build-up in the steam transmission line and the turbine blades, a common problem encountered in a high-temperature field. In the existing plants, scale build up in the piping system between the well head and the main stream transmission line has been observed. Scale build-up was found in piping wherever a sudden change of flow direction occurred and down stream of the intersection of the main steam transmission line. The scale build-up in the turbine mainly occurred on the first stationary turbine blades. The scale components are dominated by silica oxide, aluminium oxide (impurities from the reservoir), iron oxide (a corrosion product), and magnesium oxide and calcium oxide (groundwater inferred). Table 5 shows the main composition of the scale. For comparison, Table 6 shows scale build-up in the Svartsengi and Námafjall power plants, Iceland.

TABLE 5: Scale composition in steam piping and turbine blades (based on Kamojang data and Sulaiman et al., 1995)

No.	Scale	Steam transmission line from wells				Turbine
		KMJ-11	KMJ-18	KMJ-27	KMJ-41	
1	SiO_2	89.38	89.19	88.47	88.57	38.32
2	Al_2O_3	2.05	5.00	3.63	4.47	3.56
3	FeO	0.46	0.23	0.46	0.93	n/a
4	Fe_2O_3	2.00	0.81	2.00	1.33	n/a
5	CaO	0.36	0.36	0.55	0.36	2.19
6	MgO	0.22	0.25	0.22	0.43	n/a
7	Na_2O	0.84	1.41	1.38	1.08	22.86
8	K_2O	0.03	0.17	0.06	0.07	1.18
9	TiO_2	0.01	0.02	0.02	0.01	n/a
10	MnO	0.02	0.01	0.01	0.02	n/a
11	P_2O_5	0.02	0.08	0.02	0.04	n/a
12	SO_3	n/a	n/a	n/a	n/a	18.74
13	Cl	n/a	n/a	n/a	n/a	4.37

TABLE 6: Scale composition in Iceland (Ármannsson, 2001)

	Svartsengi	Námafjall
SiO_2 (%)	45.1	55.8
Al_2O_3 (%)	2.2	1.9
FeO (total Fe) (%)	1.6	0.7
MgO (%)	32.2	24.2
CaO (%)	0.2	4.3

Removing scale from the steam piping and turbine blades is difficult, as scale is hard and well bonded on the parent metal. Chemical injection in the steam pipe to remove scale was not successful. Both mechanical cleaning and chemical injection are often used to remove scale. On the turbine side, scale is periodically removed during annual inspection, but recently it was proposed to install a turbine washing system which can remove scale while the turbine is on line.

The study of a re-injection system to help to sustain a reservoir, has become a part of reservoir management instead of just dumping the effluent fluid to the well bore. Reduced steam production from cold water in the re-injection wells can be mitigated by placing the re-injection wells on the outside boundary of the reservoir, or choosing unproductive wells inside the reservoir for re-injection. The three existing re-injection wells in the Kamojang field are KMJ-15, KMJ-21, KMJ-32. Only KMJ-15 affects the quality of steam produced from KMJ-18, which is a bit wet, while the others do not seem to influence the steam quality. In general, a re-injection system has a good effect on the reservoir if operated correctly.

3.4.2 Steam transmission system

Steam from several wells flows directly to the steam gathering system pipeline, and is then transmitted to the power plant through the power plant separator and demister. There is no well separator needed; the condensate produced during steam transmission is drawn out by means of drain traps. The mass flow is about 504 tons/h, pipe line diameter is 914 mm, and the total pipe length is about 2500 m. The pressure drop along the pipe is in the range of 1-2 bar. The transmission pipe is rock wool insulated with aluminum cladding on the outer part to protect the rock wool from deteriorating by weathering. For stability, the steam pipe has supports every 15 m. The distance between anchors is about 150 m with an expansion loop every several hundred metres.

3.4.3 Power plant

A typical conventional power plant with a capacity of 60 MWe with a steam turbine washing system is proposed. The main equipment of the power plant are the turbine washing system, separator and demister, turbine-generator, condenser, switch gear-transformer, and control system. Figure 8 is a typical flow diagram for a 60 MWe power plant.

The turbine washing system removes scaling on the turbine blades, while the turbine is in operation. The cleaning process is done by means of injecting high-pressure water into the steam line to scrape scale in the turbine. The injected water should be free of oxygen and solid particles,.

Separator and demister. A final separator is used to separate the steam and impurities such as water and well bore materials before steam goes into the turbine. It is a cyclone separator which has no moving parts, so it is simple. The steam flows tangentially in the cyclone separator. There are three forces which control particle motion in a cyclone; centrifugal force, gravity and archimedes forces. In principle, the separation of a dispersed solid from liquid is governed by four factors which are; the established centrifugal field, the radial velocity pattern, the residence time of the particle to be separated, and the turbulence which has developed. The term cyclone efficiency is usually associated with collection efficiency, which is defined as the fraction of particles of any given size that are retained by the cyclone. Some modern cyclones have a confirmed efficiency of 99.9%.

A demister is usually used to make sure that the steam is really clean before going into the turbine. Steam flows through the mist filter, which traps mist in the steam. Separating even a few percentages of mist from the steam is important because the mist usually contains dissolved solid such as chlorite, silica oxide, ferrous oxide and ferrous sulphites. Mist and steam separation is due to the differential inertia of water and steam and also adhesion to the wet surface of the filter.

Turbine. The proposed turbine is a double flow 60 MWe geothermal turbine. The turbine material is carefully selected for resistance to corrosion due to the presence of hydrogen sulphide and salt (chloride), and scale components such as silica oxide, aluminium oxide, and sulphur oxide. The blade material is also resistive to erosion due to the presence of condensate or brine and solid particles such as corrosion products. However, the best way to avoid the appearance of corrosion and erosion is to keep steam impurities out of the turbine (Mitsubishi, 1993).

When steam expands on the turbine blades, the fall in pressure starts to produce water particles in the mixture zone of the T-S diagram. The impurities of the steam dilute into the water particles to form a scale on the blades. For the next blades, a faster condensation takes place with lower energy content from the steam and increased expansion area on the blades. Experience shows that scale build-up is limited on the first stationary and moving blades. Small scaling was found on the following blades. Possibly, the impurities' saturation index was diluted in the dry and wet zones. In the wet zone, the condensate is much more likely to reduce the concentration of impurities. To reduce the erosion effect on the last blades, it is more convenient to add stellite strip material on the tips of the end of the turbine blades where the maximum water velocity exists.

It is assumed that turbine efficiency is 85%. Since dry expansion is more efficient than wet expansion, it is proposed to maintain high efficiency by installing the inter-stage drain catcher. Reducing the wetness of the steam also decreases the effect of water erosion.

Condenser. As there is no further utilization of turbine exhaust and no significant effect on the environment of non condensable gases, the practical condenser is a direct contact condenser. The steam from the exhaust turbine is contacted directly with cooling water from a cooling tower by means of water spraying inside the condenser. The heat transfer process is governed by different temperatures and a mass transfer process of exhaust steam and cooling water. The condensation process occurs when the latent heat of the steam is absorbed as sensible heat by the cold water. In order to have maximum useful energy in the turbine, the condenser pressure stays in vacuum conditions. Theoretically, the more vacuum created, the more useful energy is gained. The condenser vacuum attainable in practice is, however, restricted by the thermodynamic properties of steam, the type of condenser and evacuation process selected, and the amount of non-condensable gas present in the steam. The typical condensate temperature attained in practice is 45-50°C, corresponding to a condenser pressure of 0.0959-0.1234 bar-a. Condenser evacuation equipment not only evacuates the non-condensable gases but also some of the associated water vapour. This reduces the condenser evacuation efficiency, and further limits the attainable vacuum.

In general, the direct contact condenser is preferred rather than a non-contact condenser for several reasons:

The heat transfer performance deteriorates less during operation;
The heat transfer process is more efficient, which reduces the size of the condenser;
Size is compact, it is less expensive;
Minimal pressure drop of cooling water side;
Minimum maintenance of scaling and sedimentation of mud or microorganism.

Gas removal system. It is well known that gases in geothermal steam influence the design of the main part of the power plant equipment such as the turbine, condenser, cooling tower, and gas extraction system. This is caused not only by corrosion problems but also by the high volume of gases occupied in the turbine and condenser. As a rule of thumb, if the amount of gases is more than 10%, it is more economic to expand the steam in the back pressure turbine, otherwise an expensive gas extraction system has to be installed. Several gas extraction systems that have been used worldwide in geothermal power plants use steam ejectors, blowers and compressors. However, for more reliability and economy, a combination of this equipment is often used.

A steam ejector is mainly used, the simpler the lower the investment cost. But it is not always effective because of its low efficiency with low driving pressure of the motive steam for high amount of gases. However, it is often combined with a radial blower or a compressor, where a double steam ejector is used as a backup equipment. The amount of gases in the Kamojang field is about 0.5%. By using the steam ejector, the amount of motive steam is about 19 tons/h or about 3.7% of the electrical output produced. In comparison, a typical motor driven liquid ring vacuum pump uses less than 200 kW in electric consumption. For this reason, the combination of a steam ejector and liquid ring vacuum pump is proposed as a gas exhaust system.

Cooling system. In general, geothermal resources are located in remote areas, and often in mountainous area. Cold ground water is not always found in enough volume in an economic way. This is why geothermal power plants are usually equipped with cooling towers, either a wet or dry one. In a wet cooling tower, the cooling process can be described by contact of the warm water with the surrounding ambient air both through natural draft and mechanical draft. In a dry cooling tower, the cooling process can be illustrated by means of a heat exchanger where ambient air is the cooling media and warm water is the media being cooled.

It is proposed that the cooling system be a wet cooling tower with a mechanical draft air system. The cooling duty of the system is to reduce the water temperature from 45 to 27°C, with a capacity of 650-700 tons/h of warm water. The ambient temperature is in the range of 12-20°C. The performance of a cooling tower means decreasing the temperature from the inlet to outlet of the tower and the temperature difference between the warm water inlet and ambient temperature. An efficient cooling tower will give a high temperature difference between the inlet water and the outlet water with a low temperature difference between the inlet water and ambient temperature.

The auxiliary equipment such as electrical equipment and a control system sometimes presents a unique problem. Technological development of electrical and control systems is much faster than development of mechanical systems. This is not always convenient for older power plants since the technology in use may no longer be available on the market. When equipment breaks, it will sometimes be hard to find replacement able to integrate with the old system. Changing the whole system by upgrading with new technology may not be economical. Thus, the system is less reliable due to lack in monitoring and system control.

The appropriate selection of a monitoring and control system should be done carefully, taking into account both technological development and price. Recent technology is promising but also costly. In this case, it is proposed to use monitoring and control system which is simple, but viable for part by part upgrading of equipment.

4. ECONOMIC ASSESSMENT OF THE PROJECT

4.1 Simulation of the cost project analyses

The economic assessment is used to quantify the total project cost in accordance with various economic parameters, such as interest rates, interest rate of returns, economic life span, electricity sales price, and benefit investment ratio. Since the cost of the geothermal project is specific to the geothermal area, this cost simulation is carried out by chosen cost parameters. The cash flow models will be helpful in determining the net present value and interest rate of return. Cost parameters that are used in this simulation include capital cost, fixed and variable costs, money costs and taxes. The project finance is assumed to be a debt of about 75% and equity of 25%. The assumption of money costs is linked with the opportunity to gain benefits in the current time investment, whereas the inflation rate is neglected. Several technical parameters such as well draw down (make-up wells), plant capacity, parasitic load, capacity factor, and specific steam consumption are significant parameters in the calculation. The geothermal taxes and electrical tariff structure will sometimes be key factors which determine the feasibility of the project. Financial sources of both international finance grants or commercial finance are other aspects not considered in terms of cost. The risk factors such as country risk (local risk), project risk, and market risk are also not included in the terms of cost.

The total project activities illustrate the amount of money going to be spent, but it should be noted that the capital cost of a geothermal project is dominated by well costs and construction costs. If the average steam capacity from wells is lower than expected, then the cost of the geothermal project will be increased, because more wells must be drilled either for the initial project or for make-up wells during the life of the power plant.

The following parameters define the assessment of the feasibility of the project. Interest rates reflect the time value of or opportunity cost of money, interest rate of return (IRR) defines the net present value as zero. Tax is taxable income times the tax rate; taxable income consists of revenue, operating costs, and depreciation. In this simulation, the following parameters are assumed:

Wells

Enthalpy	= 2790 kJ/kg
Production well depth	= 1500-2000 m
Production well diameter	= 8 5/8”
Average production wells	= 50 tons/h
Number of production wells	= 10 wells (initial)
Production well declining	= 6.4 %
Make-up wells	= 10 wells for 20 years
Injection well depth	= 1500 m
Injection well diameter	= 8 5/8”
Number of injection wells	= 2
Non-productive wells	= 2
Exploration wells	= 1
Land for pipelines	No charge

Power plant

Capacity	= 1 x 60 MW
Cooling water	= Wet cooling tower
Steam cleaning equipment	= Separator + demister
Prevention of scaling	= Turbine washing system
Parasitic load	= 5%
Land for power house	No charge

Economics and costs

Capital structure	= 75% debt, 25% equity
Economic life span	= 20 years
Interest rate	= 15%
Tax	= 34% all included
WAT (worth added tax)	= 10%
Pre-drilling	= 1,000,000 USD
Drilling wells with valves	= 30,000,000 USD
Steam pipe transmission line	= 10,000,000 USD
Power plant	= 41,700,000 USD
Civil work for power house	= 2,200,000 USD
Fixed maintenance cost	= 20,000,000 USD
Variable cost	= 16,977 USD per year
Cost/kW installed	= 1,498 USD/kW

There are two different government tax rules which depend on whether a geothermal project is financed and owned by a private company, such as direct foreign investment, or it is financed and owned by the government. Several schemes for foreign direct investment have been applied to develop geothermal projects in Indonesia, such as BOT (build operation and transfer) and BOO (build operation and own). On both schemes, the private companies have to pay the government taxes of 34% tax rate, all included. A tax rate of 34%, all included, means that the private companies are free WAT or other taxes in buying all the equipment for the geothermal project. On the other hand, if the Government of Indonesia is responsible for the project through a governmental company, then the tax is government WAT.

The results of the simulation (Table 7) show that the private projects give 18.1% and 16.4% interest rate of return, associated with the net present value of USD 10,990,840 and USD 919,132. Interest of 15% and a price of electricity as 0.055 USD/kWh or 0.050 USD/kWh, gives a profit-own equity ratio of 49% or 4%, respectively. The government project gives an interest rate of return of 16.1%, associated with the net present value of USD 292,304, with interest of 15% and the price of electricity at 0.040 USD/kWh, with a profit own equity ratio of 1.2%, as shown in Table 7.

TABLE 7: The simulation results of the economic assessment of a geothermal project cost assuming 15% interest (refer also to Appendix III)

	Private project		**Government project**
	0.055 USD/kWh	**0.050 USD/kWh**	**0.040 USD/kWh**
Total cost (USD)	110,967,030	110,967,030	119,911,204
Total investment (USD)	89,900,000	89,900,000	98,890,000
Operating cost (USD/yr)	152,754	152,754	152,754
Depreciation (USD/yr)	4,495,000	4,495,000	4,944,500
Revenue (USD/yr)	23,343,210	21,221,100	16,976,880
10% WAT	0	0	8,990,000
Tax with rate at 34% (USD/yr)	6,400,455	5,679,659	0
Net revenue (USD/yr)	16,919,412	15,520,220	16,824,126
IRR (%)	18.1%	16.4%	16.1%
NPV (USD)	10,990,840	919,132	292,304
Profit /own equity (%)	49	4	1.2

For Table 7, some terminology is necessary and is given here below:

Private project is a geothermal project which a private company runs. The private company should pay a government tax of 34% tax rate, all included.
Government project is a geothermal project which is run by the government. The government company should pay WAT of 10% during the equipment acquisition.
The total cost is all costs in the cash flow models. This cost includes all costs spent for the project including the pre-feasibility study, project construction, the costs during operation of the power plant, make-up wells, operation and maintenance cost.
Total investment cost includes that spent to develop the project to produce electricity in the geothermal power plant. Disbursement is counted as if all money is spent in year nil. Total investment cost is total cost minus operation and maintenance costs, and make-up well costs.
Operating cost is cost for the operation and maintenance of the plant. This cost consists of fixed operation and maintenance costs and variable costs. It is assumed that the drilling of make-up wells is the biggest part of the fixed maintenance cost. The cost for drilling make-up wells is assumed to be the same as for production drilling at year nil. Total variable operation and maintenance costs are assumed to be one percent of gross revenue.
Depreciation is chosen as flat depreciation of 20 years economic life of the project.
Tax is Indonesian governmental tax, which has a 34% rate. Taxable income consists of generated electricity sales, depreciation, and operation costs. It is assumed that no investment credit is given to the project.
Net revenue will be the same as gross revenue minus operation costs and government tax. IRR and NPV are the economic terms assumed before.

4.2 Government taxes

In order to speed up the development of geothermal resources in Indonesia, the government gives a special tax incentive which is very different from tax that is taken from oil and gas. The total tax is about 34%, all included, for direct investment to develop geothermal resources in Indonesia by private company. There is no import tax, WAT, property tax or other. The government tax is paid if the power plant starts to produce electricity in a commercial operation. In some cases, the government is willing to give a reduction cost as investment credit where this credit is paid by increasing capital costs for several years in the beginning of expenditure. In this simulation, investment credit is not included.

4.3 Electricity prices and benefit-investment ratio

A cash flow model simulates the relationship between the price of electricity and the benefit-investment ratio on positive NPV at a given total investment cost of USD 89,000,000. Appendix III shows a cash flow model for a 20-year project life. Simulation shows that electricity priced at 0.05 USD/kWh, an interest rate of 15%, will give IRR of 16.4% at NPV equal to USD 919,132. An electricity price increase to 0.060 USD/kWh will give NPV of 19,500,000 USD, with an IRR of 19,5% and a benefit investment ratio of 23% as shown in Figure 9. That would be a very attractive project.

4.4 Sensitivity of the economic analyses

4.4.1 IRR and number of production wells (well capacity)

In a geothermal project, costs will be sensitive to the price of electricity, the economic life span and the number of wells or, in other words, average well capacity. The electricity price will be associated with project revenue, while the number of wells is associated with the investment cost and fixed maintenance

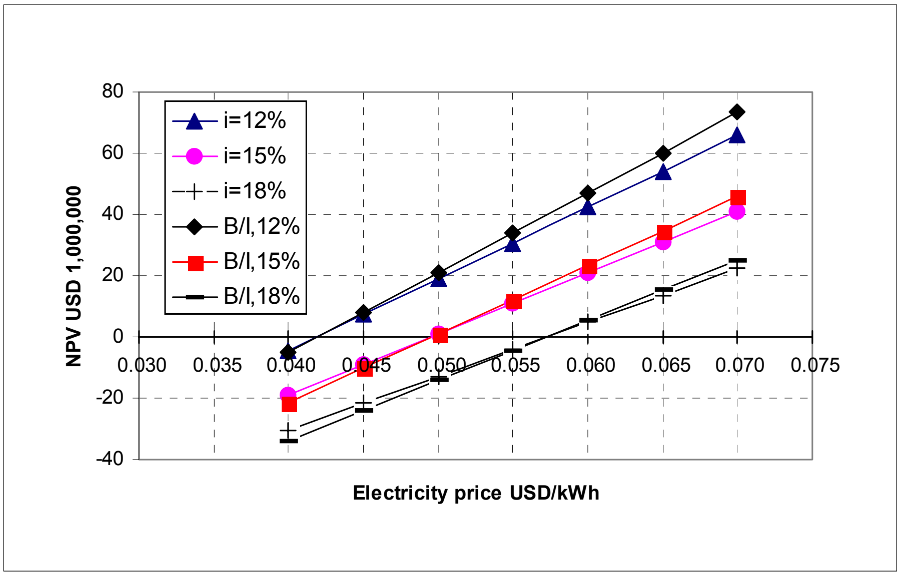

FIGURE 9: The NPV, benefit-investment ratio for different electricity prices

cost. If the average well capacity is low, both initial well cost and the cost for make-up wells will increase significantly because of increased drilling activity. In this simulation we assume that the production wells are 10 and that the make-up wells are 10 during the economic life of the project; the number of injection wells is 2 and the number of non-productive wells is 2.

4.4.2 Interest rate (i), NPV and benefit-investment ratio

In terms of economic analysis, money is expensive. The opportunity for money to develop a benefit or the cost of money is represented by the interest rate. In Figure 10, it is clear that NPV around zero will be equal to electricity priced at 0.05 USD/kWh, with an interest rate of 15%, and IRR of 16.4%. If the interest rate is lowered to 12%, then the NPV will be around 20,000,000 USD, which gives benefit-investment ratio of around 20%. On the other hand, increasing the price of electricity from 0.050 USD/kWh to 0.055 USD/kWh will increase the NPV to USD 10,990,840 which corresponds with a benefit-investment ratio of 10% and an IRR of 18.1%. It is important to decide on a reasonable interest rate. A higher interest rate will cause the project to be less competitive, while a lower interest rate will restrict the project from producing the money needed to pay back the bank.

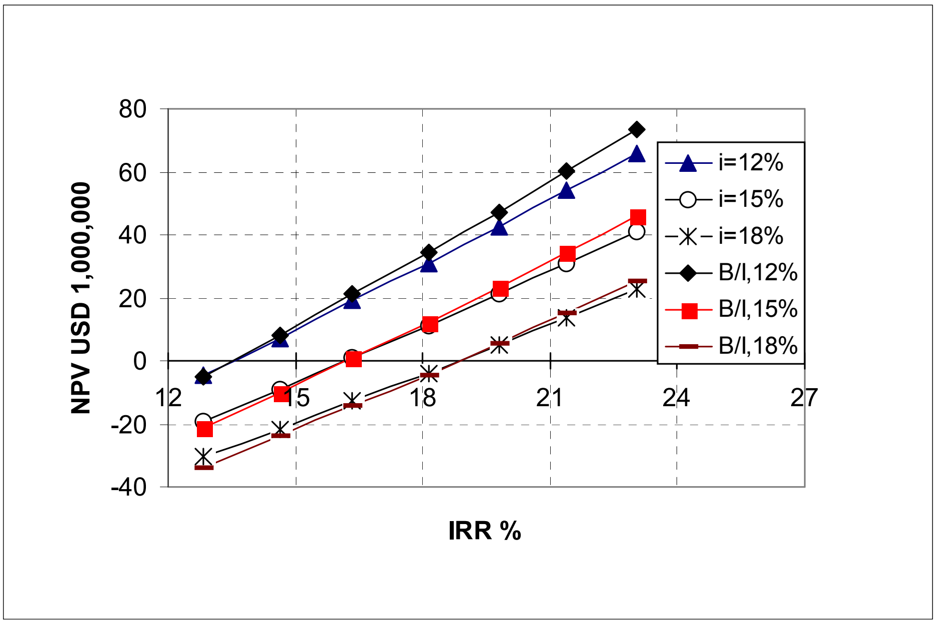

FIGURE 10: The electricity price and IRR for different interest rates

4.4.3 Electricity price, NPV and economic life span

Project revenue will be proportional to the price of electricity generated, while total revenue depends on the economic life span of the project. NPV and benefit-investment ratio will be a check counter to

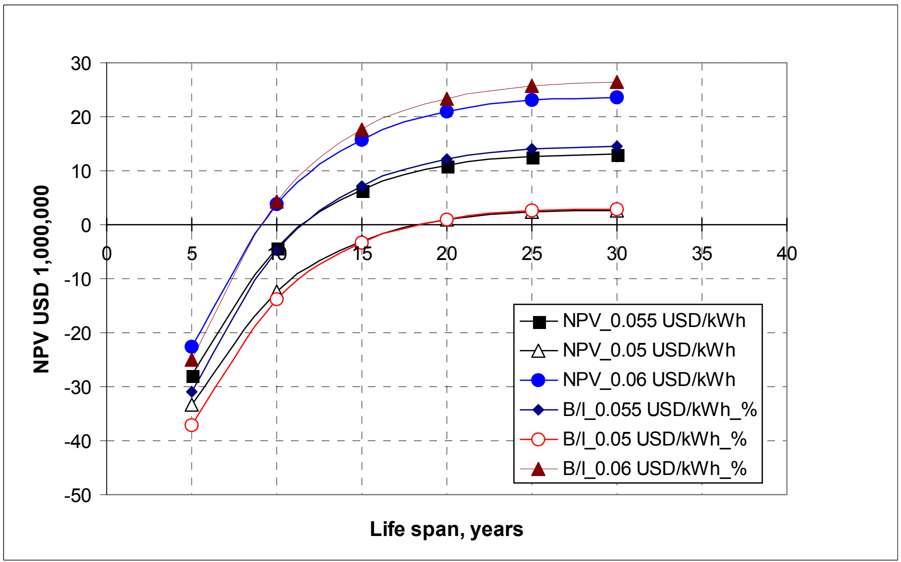

FIGURE 11: NPV, benefit-investment ratio and economic life span

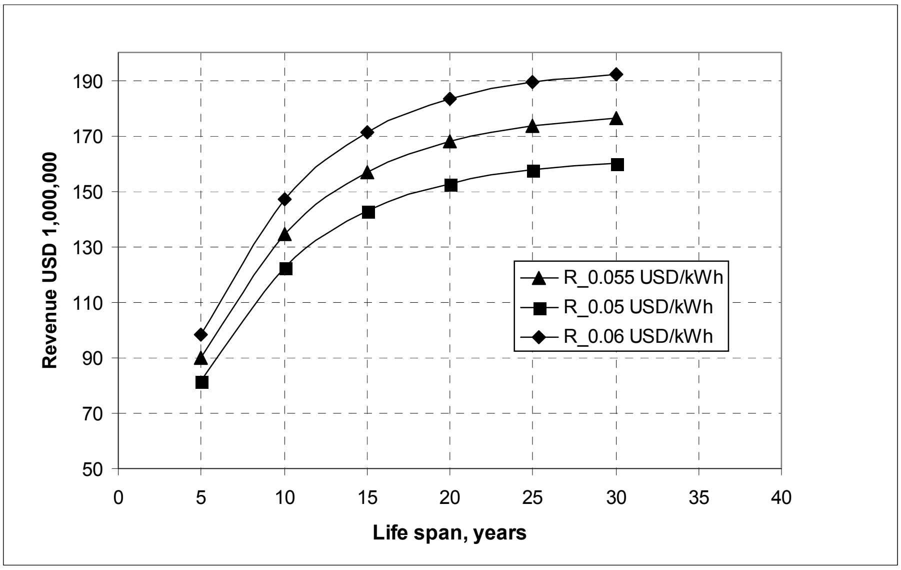

FIGURE 12: Revenue and economic life span

evaluate whether the project is economical or not. Figures 11 and 12 show graphs of the economic life span and NPV, which are unique. A life span below ten years gives a very high slope, while for an economic life span of over 20 years it is nearly flat. This demonstrates that the project is very sensitive to an economic life span less than ten years. In the range 10-15 years, the project is still fairly sensitive, but not when it is over 20 years. An electricity price of 0.055 USD/kWh (Figure 11) gives NPV of USD 10,990,840 which corresponds to an IRR of 18.1% for an economic life of 20 years. Extending the economic life up to 25 years increases NPV to USD 12,703,836 and IRR increases to 18.5%. However, curtailing the economic life to 15 years will decrease NPV to USD 6,400,846 and IRR to 17.5%. Another example in Figure 11 shows that if the life span is 10 years and the electricity price is 0.055 USD/kWh, the NPV is negative by USD 4,326,486 which corresponds with an IRR of 13.4%. Hence, this project is feasible for a 15 year life span with electricity price of 0.055 USD/kWh, but is not feasible for a life span of 10 years or less.

4.4.4 Reducing geothermal taxes

One could increase the competitive ability of geothermal power plants by reducing government tax (Figure 13). Decreasing government tax to 10% will give the geothermal project economic feasibility with a minimum IRR of 15%, and electricity price of 0.04 USD/kWh. Reducing government tax to 25%, will give the geothermal project economic feasibility with a minimum IRR of 15%, and an electricity price of 0.050 USD/kWh. It is obvious that reducing government income by curtailing the tax rate, will be balanced by increasing government income through the preservation of fossil fuel, as geothermal power plants become a substitute for fuel power plants.

4.5 Cost comparison of thermal power plants

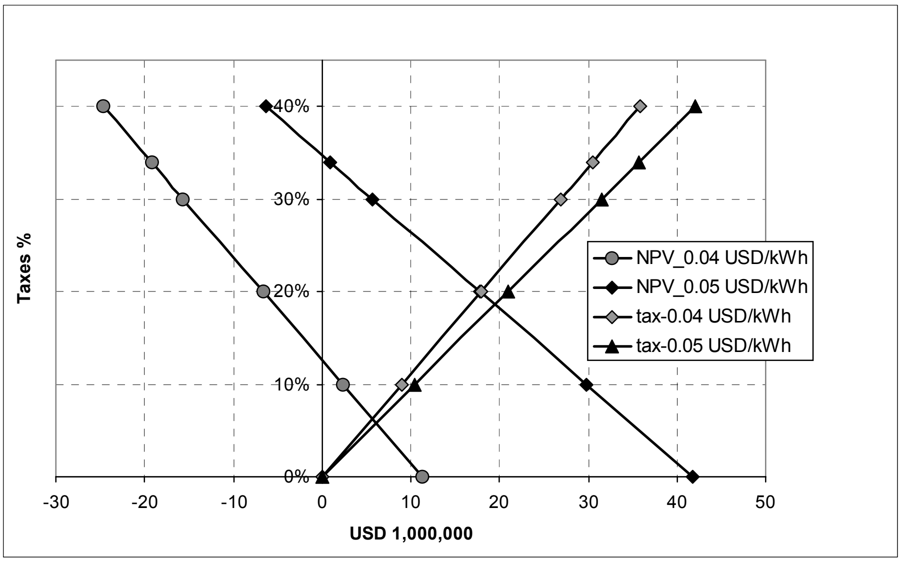

FIGURE 13: Taxes and NPV for different electricity prices

For comparison, the typical costs of thermal power plants is listed in Table 8. It should be noted that the government of Indonesia still gives a subsidy for oil fuel to communities, and for fuel for power plants. This table shows that the most attractive power plant is a conventional steam power plant fuelled by coal. In this power plant, there is no equipment to abate the gas pollutants such as NO_x, and SO_x. Technology applied to clean gas/coal power plants such as flue gas desulphurisation, a low NO_x cell burner, and fluidized bed combustion will raise the total cost significantly. The combined-cycle gas power plant is a developing technology giving the second best competitive total cost, assuming the gas fuel cost to be 2.45 USD/MMBTU.

TABLE 8: Geothermal energy compared to other fuel production alternatives (Akmal et al., 2000)

Plant type	Fuel type	Life (years)	CF (%)	Capital cost (cent/kWh)	O&M cost (cent/kWh)	Fuel cost (cent/kWh)	Total cost (cent/kWh)
Steam power	Coal	25	70	3.027	0.213	0.955	4.195
Steam power	MFO	25	70	2.27	0.226	1.248	3.745
Comb.-cycle gas turbine	Gas	20	70	2.084	0.278	1.939	4.303
Comb.-cycle gas turbine	HSD	20	70	2.084	0.283	1.522	3.891
Open-cycle gas turbine	Gas	15	30	3.253	0.94	3.04	7.234
Open-cycle gas turbine	HSD	15	30	3.253	1.032	2.387	6.673
Geothermal steam	Steam	25	70	2.522	0.65	4.6	7.392
Diesel oil	HSD	15	50	2.342	1.074	2.019	5.436
Diesel oil	MFO	15	50	2.732	1.181	1.323	5.238

4.6 Net-back-values

The other parameter for determining the price of electricity is comparison of the geothermal tariff with other thermal power plant prices in unit cost, cent/kWh. In this method, two power plants to be compared have the same total cost in unit cost, the reference power plant price is known. Then other power plant prices can be determined. This is the net-back-value approach. Several parameters included in this calculation include plant capacity, plant life span, capacity factor, interest rate, and power plant cost. Table 9 gives the competitiveness of geothermal cost, which is calculated based on the net-back-value.

TABLE 9: The results of simulations of the cost of a 60 MWe geothermal power plant using the net-back approach

IRR = 15%

Type of power plants	SPP		CCGT		OCGT		Diesel	
	Coal	MFO	Gas	HSD	Gas	HSD	HSD	MFO
Capacity, MW	400	400	500	500	100	100	20	20
Capacity factor, %	70	70	70	70	30	30	50	50
Project life, yrs	25	25	20	20	15	15	15	15
Electricity generation, TWh	61.32	61.32	61.32	61.32	3.942	3.942	1.314	1.314
Capital cost, cent/kWh	3.027	2.27	2.084	2.084	3.253	3.253	2.342	2.732
Fuel cost, cent/kWh	0.955	1.248	1.939	1.522	3.04	2.837	2.019	1.323
O & M cost, cent/kWh	0.213	0.226	0.278	0.283	0.94	1.032	1.074	1.181
Total cost, cent/kWh	4.195	3.744	4.301	3.889	7.233	7.122	5.435	5.236
Yearly cost, USD	102,894,960	91,832,832	131,868,660	119,236,740	19,008,324	18,716,616	4,761,060	4,586,736
Present value, IRR = 15	665,128,362	593,621,117	825,409,654	746,342,280	111,148,705	109,442,981	27,839,680	26,820,343
Power plant cost, USD/kW	1,663	1,484	1,651	1,493	1,111	1,094	1,392	1,341
Geothermal cost calculated from the net back value								
Capacity, MW	60	60	60	60	60	60	60	60
Capacity factor, %	70	70	70	70	70	70	70	70
Project life, yrs	25	25	25	25	25	25	25	25
Electricity generation, tWh	9.198	9.198	9.198	9.198	9.198	9.198	9.198	9.198
Capital cost, cent/kWh	2.522	2.522	2.522	2.522	2.522	2.522	2.522	2.522
Fuel cost, cent/kWh	**1.023**	**0.572**	**1.129**	**0.717**	**4.061**	**3.95**	**2.263**	**2.064**
O & M cost, cent/kWh	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
Total cost, cent/kWh	4.195	3.744	4.301	3.889	7.233	7.122	5.435	5.236
Yearly cost, USD	15,434,244	13,774,925	15,824,239	14,308,409	26,611,654	26,203,262	19,996,452	19,264,291
Present value, IRR = 15%	111,099,257	99,155,093	113,906,532	102,995,235	191,556,835	188,617,141	143,939,085	138,668,822
Power plant cost, USD/kW	1,852	1,653	1,898	1,717	3,193	3,144	2,399	2,311
O & M Cost yearly cost, USD	2,391,480	2,391,480	2,391,480	2,391,480	2,391,480	2,391,480	2,391,480	2,391,480
Present value, IRR = 15%	17,214,426	17,214,426	17,214,426	17,214,426	17,214,426	17,214,426	17,214,426	17,214,426
Total Investment cost, USD	93,884,831	81,940,667	96,692,106	85,780,809	174,342,409	171,402,715	126,724,659	121,454,396
Total Investment cost, USD/kW	1,565	1,366	1,612	1,430	2,906	2,857	2,112	2,024

IRR = 20%

Type of power plants	SPP		CCGT		OCGT		Diesel	
	Coal	MFO	Gas	HSD	Gas	HSD	HSD	MFO
Capacity, MW	400	400	500	500	100	100	20	20
Capacity factor, %	70	70	70	70	30	30	50	50
Project life, yrs	25	25	20	20	15	15	15	15
Electricity generation, TWh	61.320	61.320	61.320	61.320	3.942	3.942	1.314	1.314
Capital cost, cent/kWh	3.027	2.27	2.084	2.084	3.253	3.253	2.342	2.732
Fuel cost, cent/kWh	0.955	1.248	1.939	1.522	3.04	2.837	2.019	1.323
O & M cost, cent/kWh	0.213	0.226	0.278	0.283	0.94	1.032	1.074	1.181
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Present value, IRR = 15	665,128,362	593,621,117	825,409,654	746,342,280	111,148,705	109,442,981	27,839,680	26,820,343
Power plant cost, USD/kW	1,663	1,484	1,651	1,493	1,111	1,094	1,392	1,341
Geothermal cost calculated from the net back value								
Capacity, MW	60	60	60	60	60	60	60	60
Capacity factor, %	70	70	70	70	70	70	70	70
Project life, yrs	25	25	25	25	25	25	25	25
Electricity generation, tWh	9.198	9.198	9.198	9.198	9.198	9.198	9.198	9.198
Capital cost, cent/kWh	2.522	2.522	2.522	2.522	2.522	2.522	2.522	2.522
Fuel cost, cent/kWh	**1.023**	**0.572**	**1.129**	**0.717**	**4.061**	**3.95**	**2.263**	**2.064**
O & M cost, cent/kWh	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
Total cost, cent/kWh	4.195	3.744	4.301	3.889	7.233	7.122	5.435	5.236
Yearly cost, USD	15,434,244	13,774,925	15,824,239	14,308,409	26,611,654	26,203,262	19,996,452	19,264,291
Present value, IRR = 20%	90,189,938	80,493,714	92,468,873	83,611,125	155,505,083	153,118,651	116,849,181	112,570,802
Power plant cost, USD/kW	1,503	1,342	1,541	1,394	2,592	2,552	1,947	1,876
O & M Cost yearly cost, USD	2,391,480	2,391,480	2,391,480	2,391,480	2,391,480	2,391,480	2,391,480	2,391,480
Present value, IRR = 20%	13,974,603	13,974,603	13,974,603	13,974,603	13,974,603	13,974,603	13,974,603	13,974,603
Total Investment cost, USD	76,215,335	66,519,111	78,494,270	69,636,522	141,530,480	139,144,048	102,874,578	98,596,199
Total Investment cost, USD/kW	1,270	1,109	1,308	1,161	2,359	2,319	1,715	1,643

For a geothermal plant to compete with a coal steam power plant or a combined-cycle gas turbine power plant, the electricity price must be less than 0.043 USD/kWh, and the present value of geothermal total cost should be in the range of USD 90,189,938 - 92,468,873, correlating with an IRR of 20%. If an IRR of 15% is chosen, then the geothermal total cost would be in the range of USD 111,099,257 - 113,906,532. Other thermal power plants such as an open-cycle gas turbine, diesel, or steam power plants with oil fuel are not taken into consideration, since they are either more expensive or use fuel subsidised by the government.

The summary of the calculations of the total project costs based on the net-back-value approach is given in Table 10 and Figure 14, with an electricity price for coal steam power plants of 0.0419 USD/kWh and for natural gas combined-cycle power plants of 0.043 USD/kWh.

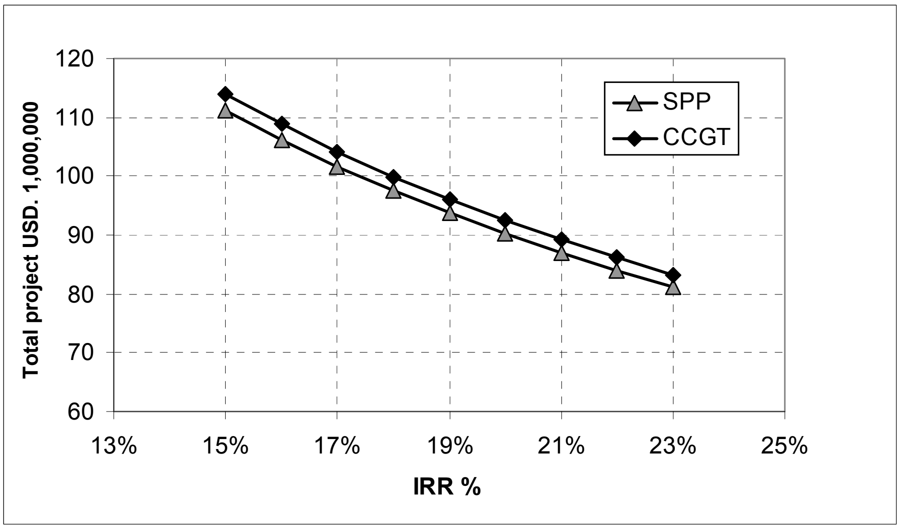

FIGURE 15: IRR and total project cost based on the net-back-value

TABLE 10: IRR and total cost of geothermal power plant based on the net-back-value approach

IRR	Coal steam PP (0.0419 USD/kWh)	Natural gas combined-cycle PP (0.043 USD/kWh)
15%	111,099,257	113,906,532
16%	106,148,325	108,830,500
17%	101,626,591	104,194,510
18%	97,486,403	99,949,706
19%	93,686,261	96,053,542
20%	90,189,938	92,468,873
21%	86,965,728	89,163,193
22%	83,985,819	86,107,988
23%	81,225,758	83,278,185

In comparison, for a private project, the simulation of geothermal cost based on the investment cost (Figure 9), gives a negative value of NPV if the electricity price is less than 0.05 USD/kWh, while a government project with an electricity price of 0.04 USD/kWh corresponds to an IRR of 16.1%. Hence, tax regulation decides whether the geothermal project can compete with a steam coal (or natural gas combined-cycle) power plant. This 60 MW geothermal project will be able to compete with steam coal power plant (or natural gas combined-cycle plant) if the government of Indonesia owns it.

4.7 Preservation of high-level energy grade

Fossil fuels contain high-grade energy levels. This energy is easily used for a variety of manufacturing, not only for electricity generation plants. High-level energy grades are a commodity which can be exported for money. While heat, particularly geothermal heat, is low-level energy grade. Geothermal energy can only be utilized in local areas near the source. Table 11 describes the money that can be earned if a geothermal power plant of 60 MW is built instead of steam coal power plants or combined-cycle gas turbine power plants. The coal and natural gas that can be preserved total USD 140,933,123 and USD 336,963,119 respectively for the twenty years economic life of geothermal plant.

TABLE 11: Preservation of coal and natural gas from a 60 MW geothermal power plant

	Coal steam PP	**Natural gas comb.-cycle PP**
Capacity in MW	60	60
Capacity factor in %	0.85	0.85
Energy generated in kWh	446,760,000	446,760,000
Heat rate in kcal/kWh	2,500	2,200
Calorific value in kcal/kg (kcal/MMSCF)	5,100	252,000
Energy from 1 kg in kWh (1 MMSCF)	2.040	114.5
Fuel required, kg (MMSCF)	219,000,000	3,900,286
Fuel energy required in MMBTU	4,431,859	3,900,036
Fuel price in US cents/MMBTU)	159*	432**
Conversion factor kCal - BTU	3.968	3.968
Total fuel price in US cents	704,665,613	1,684,815,593
Total fuel price in USD	7,046,656	16,848,156
Total fuel price in 20 years in USD	140,933,123	336,963,119

* Coal price of New England, period of January-March 2001 (EIA, 2001a);
** Average annual natural gas price 2000 (EIA 2001b).

4.8 Tariff structure

Although the regulation of the end user electricity price still is under the authority of the government of Indonesia, the restructuring tariff toward the market mechanism is a part of the restructuring programme of the energy sector. The electricity business is transforming from a monopoly of the national state electricity company, to single-buyer, multi-seller, even more toward multi-seller, multi- buyer in the Java – Bali market system. In the singe-buyer, multi-seller system, there will be at least two players in the system, the generation power company and the transmission company, whereas the generation company will be split into a system unit business which has its own price from the power plants. The transmission company will buy the electric power based on the merit order price. While in the multi buyer, multi seller system, there will be alot of companies taking part in the system. Consequently, competitive electricity prices will be created naturally by a free market system.

4.9 Benefits of the project and competitiveness with other thermal power plants

There are several benefits in utilizing geothermal resources in Indonesia

- Geothermal energy can only be utilized in local areas; it is not exportable energy;
- It reduces domestic oil and gas uses or other fossil fuel uses;
- Geothermal energy is relatively environmentally friendly, with lower amounts of NO_x and SO_x.

However, a geothermal power plant has a very high investment cost per kW installed, compared with other thermal plants, since in the geothermal system the fuel cost (geothermal steam) is paid at the start of the life span of the plants, while in other thermal power plants the fuel cost will be paid over the long life of the plants. In order to make geothermal plants more competitive, the following discussion is proposed to enhance the development of the geothermal fields:

- Government commitments to utilize geothermal resources by paying the costs of reconnaissance surveys, drilling exploration, and appraisal drilling to reduce geothermal development risk;
- Increase human resource capabilities particularly in geothermal aspects; it will reduce the use of geothermal experts from overseas;
- Strict environmental enforcements, especially in the development of new power plants;
- Reducing investment cost by taking low cost sources of money such as international grants for low emission power plants;
- Reducing the domestic fuel subsidy, where the prime energy should be paid in competitive market prices.

5. CONCLUSIONS

The results of the simulation of increasing the capacity of the Kamojang geothermal power plant from 140 to 200 MWe are both thermodynamically and economically feasible. The 60 MWe turbo generator plant includes a condensing turbine with a turbine inlet pressure in the range of 6-8 bar, mass flow rate in the range 500-540 tons/h. Increasing well head pressure will increase utilization efficiency in the range 58-62%. The nine production wells provide steam mainly from the southeast part of the 14 km^2 existing reservoir. One new well has to be drilled every 2-3 years as a make-up well. A new power house located near the 140 MW power house will likely minimize environmental impact and reduce landscape preparation costs, but increase the length of the steam transport piping system. The total length of the transport pipe is 2-2.5 km, with a pressure drop in the range of 1.5-2.0 bar.

Two different methods of economic assessment have been used to determine total project cost, the investment-cost-base and net-back-value approach. Investment costs are mainly generated from well drilling, the steam pipe distribution line, and the power plant construction, while the sensitivity of the electricity delivery price is most affected by average well capacity.

The simulation of geothermal cost based on the investment-cost-base gives a negative value of NPV if the electricity price is less than 0.050 USD/kWh with IRR of 16.4%. While a government project with electricity priced at 0.040 USD/kWh corresponds to an IRR of 16.1%. Based on the net-back-value, the geothermal electricity can compete with steam coal (or natural gas combined-cycle) if the electricity price is less than 0.043 USD/kWh. Hence, the 60 MWe geothermal project will be competitive with coal fuelled steam plant (or natural gas combine-cycle) if the government of Indonesia owns it.

Coal and natural gas have high-level energy grades, which are good commodities. However, geothermal heat has a low-level energy grade. If the tax rate of private geothermal projects is decreased to 10%, the geothermal project is economically more feasible than a coal fuelled steam plant and a combined-cycle gas turbine power plant.

The expansion of the geothermal power plant from 140 to 200 MWe provides several benefits to the government of Indonesia such as increasing the utilization of environmentally friendly local sources of energy, taking advantage of non-exportable energy, reducing domestic consumption of oil and gas, and further minimizing depletion of fossil fuel.

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APPENDIX I: General formulae for technical calculations

Nomenclature, see next page.

1. *Exergy equations* (Kestin et al., 1980)

$$w^o = \left\{ h_1 - \sum_i^n \varphi_i h_{2i} \right\} - T_o \left\{ s_1 - \sum_i^n \varphi_i s_{2i} \right\}$$

2. *Dalton gas law* (Dunstall, 1998)

$$P_t = P_{ncg} + P_{wp}$$

$$V_t = V_{ncg} + V_{wp} = V$$

$$V = \left(\frac{(M\ R\ T)_{ncg}}{P_{ncg} + P_{wp}} \right)_{ncg}$$

3. *Pressure drop in steam flow in the pipe*

$$\Delta P = f \,.\, \frac{\rho \,.\, V^2}{2} \,.\, \frac{L}{d}$$

$$f = f\left(\mathrm{Re}\,, \frac{\varepsilon}{d} \right)$$

4. *Pipe design*

$$t_{\min} = \frac{P_d}{2\,.\left(SE + P_y \right)} + A$$

$$L_{\min} = \sqrt{\left(k\,.\,S_n - \frac{P_d\,.\,d}{4\,.\,t_{\min}} - \frac{F_x}{A} \right) . \left(\frac{8\ .\ z}{0.75\ \ .\,i\,.\left(\sqrt{q_{ya}^2 + q_{za}^2} + \sqrt{q_{yb}^2 + q_{zb}^2} \right)} \right)}$$

$$z = \frac{\pi}{32} \,.\, \frac{\left(D^4 - d^4 \right)}{D}$$

5. *Interest discounted factor*

$$PV = A \left[\frac{\left(1 + i \right)^n - 1}{i \left(1 + i \right)^n} \right]$$

$$FV = PV \left(1 + i \right)^n$$

Nomenclature

w^o	=	Available work [kJ/kg]
h_1	=	Enthalpy at initial stage [kJ/kg]
h_{2i}	=	Enthalpy at stage i [kJ/kg]
φ_1	=	Specific mass flow
s_1	=	Entropy at initial stage [kJ/kg K]
s_{2i}	=	Entropy at stage i [kJ/kg K]
T_o	=	Environment temperature [K]
i	=	Number of processes
n	=	Total number of internal processes
P_t	=	Total pressure [N/m^2]
P_{ncg}	=	Partial pressure due to non condensable gases [N/m^2]
P_{wp}	=	Partial pressure due to water vapour [N/m^2]
V	=	Total volume [m^3]
V_t	=	Total volume due to volume of NCG and water vapour [m^3]
V_{ncg}	=	Partial volume due to non condensable gases [m^3]
V_{wp}	=	Partial volume due to water vapour gases [m^3]
M	=	Gas mass flow rate [kg/s]
R	=	Gas constant 8,314.3 / molecular weight [J/kg K]
ΔP	=	Pressure drop [N/m^2]
f	=	Friction factor in pipe
ρ	=	Density [kg/m^3]
V	=	Fluid velocity [m/s]
L	=	Pipe length [m]
d	=	Inside diameter [m]
Re	=	Reynold number
ε	=	Roughness divide by inner pipe diameter
$t_{\min}$	=	Minimum temperature [^{o}C]
P_d	=	Design pressure [N/m^2]
SE	=	Toughness of material [N/m^2]
P_y	=	Pressure component in y direction [N/m^2]
A	=	Cross-section area of pipe [m^2]
$L_{\min}$	=	Minimum length [m]
k	=	Safety factor, 1.2
S_n	=	Stress component in normal direction [N/m^2]
F_x	=	Force component in x direction [N]
z	=	Diameter factor [m^2]
i	=	Bend factor
q_{ya}	=	Weigh effect in y direction [N]
q_{za}	=	Weigh effect in z direction [N]
q_{yb}	=	Weigh effect in y direction [N]
q_{zb}	=	Weigh effect in z direction [N]
D	=	Outer diameter [m]
PV	=	Present value
A	=	Annual payment
i	=	Interest rate
n	=	Economic life span
FV	=	Future value

APPENDIX II: Lists of EES programs for technical calculations
(EES, see Klein and Alvardo, 2001)

1. Thermodynamic process

```
{Calculation of enthalpy and exergy of the process}

{well bore - stage 1}
{Nomenclature:
tr = reservoir temperature
pr = reservoir pressure
hrs = enthalpy of steam in the reservoir
hr = enthalpy of the reservoir at pressure equal to pr
sro = entropy of steam phase in the reservoir
sr =  entropy of the reservoir at temperature equal te, and pressure equal pr
h_? = enthalpy of fluid at certain (?) condition
s_? = entropy of fluid at certain (?) condition
to = ambient temperature
s_iso = entropy of isoentropy process}

tr = 242.5 {deg C, asumption from the reservoir model}
pr = PRESSURE(Steam,T=tr,x=0) {water phase}
hrs = ENTHALPY(Steam,T=tr,x=1)
hr = ENTHALPY(Steam,T=tr,p=pr)
sro = ENTROPY(Steam,T=tr,x=0) {steam phase}
sr = ENTROPY(Steam,T=tr,P=pr)

{well head pressure at 15 bar}
h_12 = ENTHALPY(Steam,x=1,P=12)
s_12 = ENTROPY(Steam,x=1,P=12)

{inlet turbine}
h_8 = ENTHALPY(Steam,x=1,P=8)
s_8 = ENTROPY(Steam,x=1,P=8)

{hot well}
h_0.1 = ENTHALPY(Steam,x=0,t=45)
s_0.1 = ENTROPY(Steam,x=0,P=0.1)

{Mixture}
h_0.1m = ENTHALPY(Steam,x=0.85,P=0.1)
s_0.1m = ENTROPY(Steam,x=0.85,P=0.1)
t_0.1m = TEMPERATURE(steam,x=0.85,P=0.1)

{ambient}
to = 15
so = ENTROPY(Steam,x=0,t=15)
ho = ENTHALPY(Steam,x=0,t=15)

{exergy}
e_r = (hr - ho) - (to +273) * (sr-so)
e_12 = (h_12 - ho) - (to +273) * (s_12 - so)
e_8 = (h_8 - ho) - (to +273) * (s_8-so)
e_0.1m = (h_0.1m - ho) - (to +273) * (s_0.1m - so)
e_0.1 = (h_0.1 - ho) - (to +273) * (s_0.1 - so)

{isoentropic expansion in the turbine}
s_iso = s_8
h_iso = ENTHALPY(Steam,s=s_iso,P=0.1)
```

```
0.85 = (h_8 - h_0.1t)/(h_8 - h_iso )

{mass flow calculation}
Mass_flow = 60000 / (h_8 - h_0.1t) / 0.85 / 0.9 {kg/s}
Mass_flow_th = Mass_flow * 3600 / 1000 {tons/h}
steam_consumption = Mass_flow_th / 60 {t/MW}
```

2. Ejector calculation

```
{ Ejector calculation}
{Data Requirement}
Ps = 8 *100000 {N/m2, steam line pressure}
ncg = 0.5 / 100 { % of Non condensable gas}
M_ncg1 = 0.5/100 * 519 * 1000 /3600 {kg/s in the condenser}
P_t1 = 0.09 * 100000 {N/m2, condenser pressure - suction pressure in the 1 ejector}
P_t2 = 0.305 * 100000 {N/m2, intercondenser pressure - suction pressure in the 2
    ejector}
P_t3 = 1.05 * 100000 {N/m2, intercondenser pressure - discharge pressure in the 2
    ejector}
T = 25 + 273.1 {kelvin, non consdensable gas temperature}
P_wv = PRESSURE(Steam,T=25,x=1) * 100000 {N/m2, generate from software}
Mncg2 = M_ncg1 + M_ncg1 * 10/100 {kg/s with 10 % additional gas from ejector first
   stage}
W_ncg = 43.1 {assumption for typical NCG from geothermal high temperature field,
   mainly CO2}
Ro = 8314.3 {gas constant value}
R_ncg = Ro/W_ncg  {J/kg.K}

{Dalton law - for gas}
(P_t1 - P_wv ) * V_ncg1 = M_ncg1 * R_ncg * T
(P_t2 - P_wv ) * V_ncg2 = M_ncg2 * R_ncg * T
V_wv = VOLUME(Steam,T=25,x=1) {m3/kg, generate from software}
M_wv1 = V_ncg1 / V_wv  {kg/s, mass flow rate of water vapour in the first  ejector -
   assuming that : Volume = volume NCG + Water vapour = volume NCG }
M_wv2 = V_ncg2 / V_wv  {kg/s, mass flow rate of water vapour in the second ejector -
   assuming that : Volume = volume NCG + Water vapour = volume NCG }

{entrainment ratio - graphical sources}
ER_ncg= 1.17 {from graphical, which show the relationship between the entrainment
   ratio with molecular weight, w-ncg = 43.1}
ER_wv= 0.81  {entrainment ratio is a ratio between the weight of gas  to the equivalent
   weight of air}

{Total air equivalent}
M_a1 = M_ncg1 / ER_ncg  +  M_wv1 / ER_wv  {first stage ejector}
M_a2 = M_ncg2 / ER_ncg  +  M_wv2 / ER_wv  {second stage ejector}

{Compression ratio}
Cr1 = P_t2 / P_t1 {first stage ejector}
Cr2 = P_t3 / P_t2 {second stage ejector}

{Expansion ratio : the ratio between the pressure of steam pipe line to condenser
   pressure.
The expansion ratio is given by the graphical experiments}
Er1 = Ps / P_t1 {first stage ejector}
Er2 = Ps / P_t2 {second stage ejector}
{Air to steam ratio, is given by the graphical experiments which is a function between
   compression ratio and expansion ratio}
```

```
Ar1 = 0.43 {first stage ejector}
Ar2 = 0.21 {second stage ejector}

{Steam flow rate }
Ms1 = M_a1 / Ar1 {first stage ejector}
Ms2 = M_a2 / Ar2 {second stage ejector}
Total_steam_flow = Ms1 + Ms2  {kg/second}
Total_steam_flow_th = Total_steam_flow * 3.6 {tons/h}
Total_steam_flow_% = Total_steam_flow * 3.6 /519 {% of motive steam to total steam}
```

3. Pressure drop in the pipe

```
{Simulation model of the pipe design - single flow}
{Pressure drop calculation}
{Steam gathering  and transmission system}

m= 519 * 1000 / 3600 {mass flow - kg/s}
P1=15 {operating pressure}
x1=1  {steam fraction}
vel=30 {steam velocity m/s}
h= enthalpy(STEAM,P=P1,x=x1) {steam enthalpy}
t=temperature(STEAM,P=P1,x=x1) {steam temperature}
v=volume(STEAM,P=P1,x=x1){steam volume}

m=1/v*vel*3.14/4*dpipe^2  {calculate the required pipe diameter}
DN900=dpipe*1000 {pipe diameter standard}
design_diameter=914 {DIN 2458 standard in mm}
Design_pressure=14 * 100000 {newton/m2 - DIN Standard ND 16 C 22 N}

{Actual velocity - vel_a}
vel_a=m/(1/v * 3.14 / 4 * (design_diameter/1000)^2)

{Pressure drop / meter}
myu_s =viscosity(Steam,x=x1,P=P1) {steam viscosity}
delta_p = f_s_old_pipe *vel_a^2 *(1/v) /  (2 *design_diameter/1000) * 2500 {pressure
  drop in the straight pipe}
delta_p_equivalent_length = delta_p * 15/100 {pressure drop in the straight pipe -
  assumption 15%}

Total_delta_p = delta_p + delta_p_equivalent_length {total pressure drop in the  pipe,
  N/m2}
Total_delta_p_bar = Total_delta_p / 100000 {total pressure drop in the  pipe, bar}

{Moody diagram}
f_s=0.02 {friction factor which is generated by EES inherent programme}
f_s_old_pipe= 1.5 *  f_s
```

4. Pipe design

```
{Simulation model of the pipe design - single flow}
"Steam gathering system "
m= 519 * 1000 / 3600  {mass flow - kg/s}
P1=12 {Operating pressure}
x1=1
to=10 {ambient temperature}
vel=30 {steam velocity m/s}
h= enthalpy(STEAM,P=P1,x=x1) {steam enthalpy}
```

```
t=temperature(STEAM,P=P1,x=x1)
v=volume(STEAM,P=P1,x=x1)

m=1/v*vel*3.14/4*dpipe^2  {finding pipe diameter}
DN900=dpipe*1000 {pipe diameter standard}
design_diameter=914 {DIN 2458 standard in mm}
Design_pressure=14 * 100000 {newton/m2 - DIN Standard ND 16 C 22 N}

{Basic allowable stress, S = min tho_bc/3, tho_bh/3, 2/3 tho_fc, 2/3 tho_fh, 2/3
  tho_c10000
pipe material, steel st 37.2 (s235 JER), fe 360}

tho_fc = 235 * 10^6 {newton/m2}
tho_fh = 185 * 10^6 {newton/m2}
tho_bc = 360 * 10^6 {newton/m2}

a=tho_fc/3
b=tho_fh*2/3
c=tho_bc/3

S_min = c

{wall thickness, twall_m}
twall_m=
Design_pressure*design_diameter/(2*(S_min+(Design_pressure*0.4)))+add_thickness
{mm}
add_thickness=1.5
twall_design = 7.1 {mm}


{Applied loading}

{1. Wind loading}
vel_wind = 10 {m/s - wind velocity}
q_wind=0.78 * P_wind*design_diameter  {newton/m2}
P_wind=vel_wind^2/1.6

{2. Weight effect}
wall_rho= 7850 {kg/m3}
rho_fluid = 1/v {density of steam}
rho_ins = 150 {kg/m3}
t_ins=0.075 {insulation thickness 7.5 mm}
A_outside=3.14 /4*(design_diameter/1000)^2
A_inside=3.14 /4*(design_diameter/1000 - 2/1000*twall_design)^2
A_wall_perimetric=A_outside - A_inside {total area of wall thickness in cross-section
  area}
A_ins=3.14 /4*(design_diameter/1000 + 2*t_ins)^2

{mass}
m_pipe = wall_rho*A_wall_perimetric
m_fluid = rho_fluid * A_inside
m_ins = rho_ins * A_ins
m_total = m_pipe + m_fluid + m_ins

{weight}
q_pipe = m_pipe * 9.81 {newton}
q_fluid = m_fluid * 9.81 {newton}
q_ins = m_ins * 9.81 {newton}
q_weight = q_pipe + q_fluid + q_ins {newton}
```

```
{3. Seismic loading}
h_acc = 1.1 * 9.81 {horizontal acceleration}
v_acc = 0.55 * 9.81 {vertical acceleration}
q_h_seism = m_total * h_acc
q_v_seism = m_total * v_acc

{4. Combination loading}
q_ya = q_weight
q_za = 0
{q_yb = max (q_snow, q_v_seismic)}
{q_zb = max (q_wind, q_h_seismic)}
q_yb = q_h_seismic
q_zb = q_v_seismic

{Distance between support}
Fx=0
z = 3.14/32 *(((design_diameter/1000))^4 - ((design_diameter - 2*
   twall_design)/1000)^4) / (design_diameter/1000)
S_min = Design_pressure*( design_diameter/1000)/(4 *twall_design/1000)  +
   Fx/A_outside + 1/z * length_between_support^2/8 *  ((q_ya ^2 + q_za ^2)^0.5 +
   (q_yb ^2 + q_zb ^2)^0.5 )

{Expansion loop}
u_el = 150 {distance between anchor}
u_el^2=length_1^2 + length_2^2
alpha = 0.000012
t_diff = 230 {temperature difference between hot and cold}
dlength_1 = alpha * length_1 * t_diff
dlength_2 = alpha * length_2 * t_diff
y_el^2 =  dlength_1^2 + dlength_2^2
L_dl = length_1 + length_2 {development length}

{Requirement
design_diameter * y_el / (L_dl - u_el)^2 less than 208.3 }
check= design_diameter * y_el / (L_dl - u_el)^2
length_1 = 145
```

5. Economic calculation formula

The definition of economic discounted factor as:

```
i  = i_p  {interest rate}
n =20    {year of payment}
fv = pv * (1+ i)^n  {correlation between future value and present value with a certain i
   and n}
pv=a * (((1+ i)^n-1)) /  (i*(1+ i)^n)  {correlation between present value and annual value}
```

APPENDIX III: Cash flow model for 20-year project life

COSTING - REVENUE (assumptions)

Unit size - MW		60
Sfc kq/mw		2.4
Capacity factor - %		0.85
Parasitic load - %		5
Net plant output - MW		57
Economical lifetime		20
Capital structure		
debt	75%	67,425,000
equity	100%	89,900,000

Descriptions	Unit cost USD	Quantity	Total Investment cost USD	Unit cost / revenue USD/kW	Cash flow Year 0	Cash flow Year 1..............20	Tot. cost year 0
Fixed capital cost			89,900,000	1,498.3	89,900,000		89,900,000
Geological and geoscientific	1,000,000		1,000,000				
geological survey							
geochemical							
geophysics							
Wells drilling & maintenance	-		30,000,000				
well exploration							
number of wells	2,000,000	1	2,000,000	333.3			
well logging							
well testing and reservoir asseswsment							
production wells	2,000,000	10	20,000,000				
number of wells							
well capacity (kq/s)							
well logging							
well testing and reservoir assessment							
monitoring wells							
reinjection wells	2,000,000	2	4,000,000	666.7			
non producing wells	2,000,000	2	4,000,000				
number of wells							
Steam gathering system and fluid transmission	10,000,000		10,000,000				
well steam piping							
pipe diameter		0.66					
pipe length		300					
pipe supports							
expansion loops							
valves							
insulation							
cross country piping system							
pipe diameter		0.86					
pipe length		2500					
pipe supports							
expansion loops							
valves							
insulation							
Power plant development	41,700,000		41,700,000				
steam supply system	1,000,000						
separator							
demister							
piping system							
auxiliaries							
Turbine washing system	1,000,000						
heat exchanger							
cooling pump							
heat conversion system	28,000,000						
turbine							
generator							
auxiliaries							
cooling system	8,000,000						
cooling towers							
condenser							
cooling water pump							
secondary cooling water pump							
auxiliaries							
gas disposal system	600,000						
intercondenser							
aftercondenser							
liquid ring vacuum pump							
ejector							
auxiliaries							
electrical system	1,600,000						
switchboard							
main transformer							
second transformer							
grid connection							
auxiliaries							
control system	1,500,000						
DCS system							
Civil work	2,200,000		2,200,000				
site preparation							
building and foundation							
Total labour and transportation costs	5,000,000		5,000,000				
labour cost							
transportation cost							

Descriptions		Unit cost USD	Quantity	Total investment cost USD	Unit cost / revenue USD/kW	Year 0	Year 1..............20	Tot. cost year 0
Variable operating and maintenance cost		**23,343**		**23,343**	**0.389**		23,343	168,030
Annual maintenance cost	0.0005	11,672		11,672	0.195			
spare part changeover								
consumable material								
labor cost								
auxiliaries								
Operating cost	0.0005	11,672		11,672	0.195			
variable operating cost								
labour cost								
auxiliaries								
Fixed maintenance cost		**20,000,000**		**20,000,000**				
Steam field maintenance								
make up wells 5 % drawd(	10	2,000,000		20,000,000				
Cost of money		899,000		899,000	15			
interest payment								
insurance								
legal fees								
upfront fees	0.50%	449,500		449,500	7.49167			
administration costs								
agent / bank fees	0.50%	449,500		449,500	7.49167			
others fees								
Tax								
vat	0							
Non investment cost and cost of money				20,899,000		20,899,000		20,899,000
Total project cost				**110,822,343**		110,799,000	23,343	**110,967,030**
REVENUE								
Energy sales, 0.55 US $/kWh	**0.055**	**23,343,210**		**23,343,210**	**389.05**		23,343,210	168,029,822
kwh /yrs		424,422,000					424,422,000	
	0.075	31,831,650					31,831,650	229,131,576
	0.070	29,709,540					29,709,540	213,856,138
	0.065	27,587,430					27,587,430	198,580,699
	0.060	25,465,320					25,465,320	183,305,261
Price / kWh	0.055	23,343,210					23,343,210	168,029,822
	0.050	21,221,100					21,221,100	152,754,384
	0.045	19,098,990					19,098,990	137,478,946
	0.040	16,976,880					16,976,880	122,203,507
	0.035	14,854,770					14,854,770	106,928,069
	0.030	12,732,660					12,732,660	91,652,630
Depreciation (flat 20 years)		4,495,000					4,495,000	32,356,049
Tax rate	34%							
Tax		6,400,455		**6,400,455**	**107**		6,400,455	46,071,953
NET CASH FLOW						- 110,799,000	16,919,412	10,990,840

Economic assesment	
interst rate (i)	15%
DER	
debt	83,225,272
equity	110,967,030
own equity	27,741,757
IRR	
NPV for elec. price 0.055	10,990,840
ROI	10
ROE (self equity)	40
pay back period	20