Economic Comparison between a Well-head Geothermal Power Plant and a Traditional Geothermal Power Plant

by

Carlos Atli Córdova Geirdal

Thesis
Master of Science in Sustainable Energy

January 2013

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Thesis submitted to the School of Science and Engineering
at Reykjavík University in partial fulfillment
of the requirements for the degree of
Master of Science in Sustainable Energy

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Abstract

One of the reasons why geothermal energy is still not used in a larger scale for electricity generation worldwide is that it takes a long time from the time the resource is discovered until the time the power plant is operational. This puts financial pressure on the project, sometimes making it financially not feasible.

The objective of this thesis was to develop a method for geothermal projects where the time until energy production begins, and cash flow starts, is reduced to make more geothermal projects feasible by incorporating the use of smaller wellhead power plants. The focus is on the plant construction stage of the project development.

In this study I defined a hypothetical steamfield, created different scenarios for the steamfield utilization where the advantages of wellhead power plants could be shown, and compared them using the Net Present Value method based on calculations of net power output.

A sensitivity analysis was made where a relevant factor was the time difference (TD) from the moment a wellhead power plant could start to produce energy and the moment a traditional power plant could start to produce energy in a given steamfield.

The main results show that the use of wellhead power plants can have important benefits for a geothermal project, if the time difference (TD) is greater than 12 months the use of wellhead power plants in the early stages of development can increase the NPV of the project, and if the time difference (TD) is greater than 18 months the wellhead power plant can become attractive even as a permanent option.

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Acknowledgements

I want to thank:

My Supervisor: María Sigríður Guðjónsdóttir for her guidance and the time she dedicated to helping me through the work on this thesis.

My co-supervisor: Páll Jensson for his valuable recommendations.

Páll Valdimarsson for his help in the initial stages of this work.

Einar Gunnlaugsson from Orkuveita Reykjavikur for his help with the creation of the hypothetical steamfield.

Kristinn Ingason from Mannvit for his help with information about costs and time calculations.

Sverrir Thorhallsson from ISOR for his help with information about drilling and testing of wells.

Gestur Bárðarson from Green Energy Group for the information and time dedicated to explain regarding the wellhead power plants.

Everyone in the University of Reykjavik and the people in REYST for their help.

All the Teachers in this program .

The other students in this program with whom I worked with in several projects and learned a lot from:

Baldur Karasson
Darren Atkins
Maria Carmela Marino
Vignir Bjarnason

My mother and Benni for their help.

And especially to my wife and children that have been with me through this adventure.

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1. Introduction

Geothermal Energy is the thermal energy stored in the earth´s crust. It has been used for centuries for cooking and bathing but it was not until the 19th century that geothermal energy started to be used for industrial purposes and has been used for electricity production since the early twentieth century.

For the production of electricity with the technology available today, a geothermal resource usually needs to have a temperature above 90^{o}C (see Figure 11) at a depth in a range of 1-5 km and a good supply of underground water; this is what is called a hydrothermal resource(Tester et al., 2005).

Geothermal energy for the production of electricity has many advantages over other sources of energy, some of them are:

- A high capacity factor (above 90%), higher than most of other renewable energy options and comparable to base load fossil fueled power plants, i.e. coal (capacity factor is defined as the actual electricity produced in a period of time divided by electricity the power plant would have produced at full nameplate capacity for the same period of time), this allows a geothermal power plant to provide stable and reliable base load power output, usually for several decades (Gehringer, 2012).
- Low cost of energy produced (LCOE, see Figure 1), between 4-10 US cents per kWh with current prices, mainly because there is no direct cost of fuel and a high capacity factor, offering an economically attractive power operation.
- Low land use per unit of energy produced (see Figure 2).
- Low CO_2 emissions and relatively low overall environmental impact compared to other energy sources.
- Development of a domestic energy source that reduces the risks related to the price of imported fuels.

Yet with all this advantages electricity produced from geothermal sources is only around 0.03% of global electricity production (Gelman, 2010)

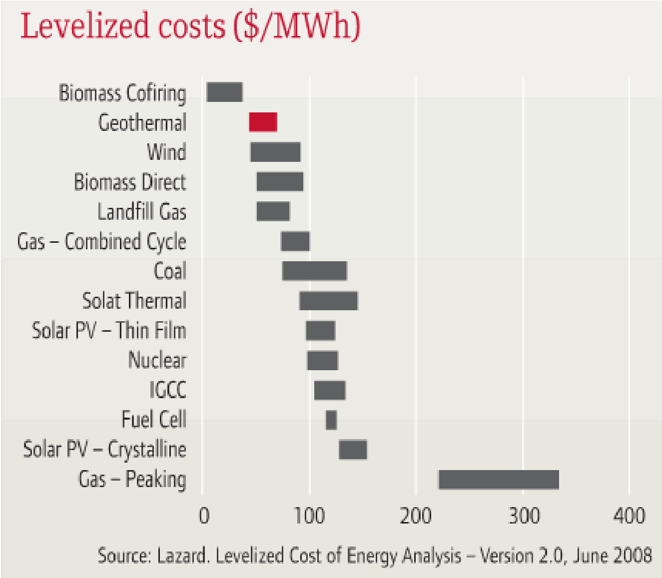

Figure 1: Levelized cost of some renewable energy sources(Islandsbanki, 2011)

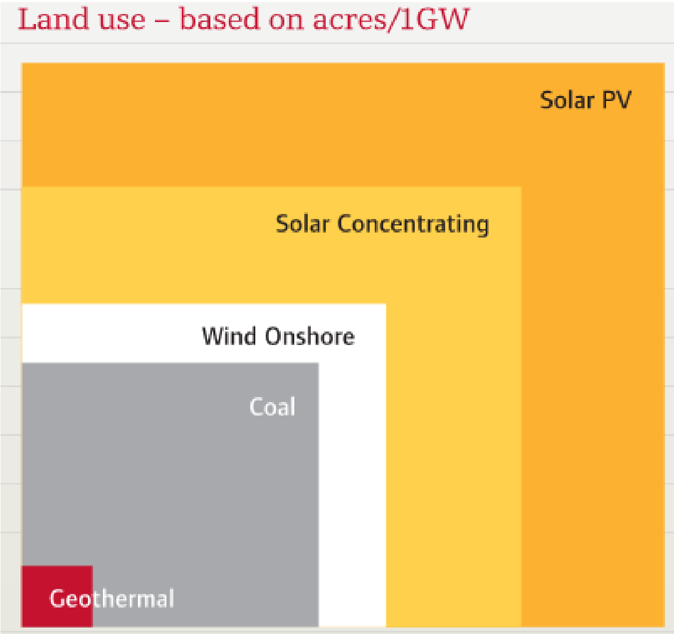

Figure 2: Land use comparison(Islandsbanki, 2011)

The exploitable geothermal energy potential in several parts of the world is much higher than the current utilization, which in 2010 was about 11 GW of installed capacity (Bertani, 2012). Geothermal energy plays an important role in the energy systems of many countries, it is estimated that about 40 countries have the potential, from a technical perspective, of satisfying their entire electricity demand from geothermal sources (Gehringer, 2012). Geothermal resources have been identified in nearly 90 countries and currently electricity from geothermal energy is produced in 24 countries, so it is a proven technology.

It´s also important to mention that with current technology the economic potential, that is: the part of the technical resource that can be exploited economically in a competitive market at some specified time, in this case for the year 2050, is about 70 GW without considering the possibility of successful Enhanced geothermal systems technology (EGS) (Bertani, 2012). This would be in addition to the approximately 11 GW of actual installed capacity in 2010, this shows that the small share of geothermal energy is not due to the lack of resources.

The main obstacles for having more energy from geothermal sources are:

- The availability of geothermal resources, it is estimated that geothermal resources are only available for utilization on one quarter to one third of the planet´s surface, and
- The difficulty to raise capital for such projects. This difficulty is basically for 3 reasons:
  - The large up front capital cost of geothermal power plants
  - High risk in the early stages of development of geothermal projects, mainly in the drilling stage (see Figure 3).
  - Long time for geothermal projects to start producing energy and revenue, as you have to drill and test the wells to design the power plant, plus the lead time it takes to get energy production going.

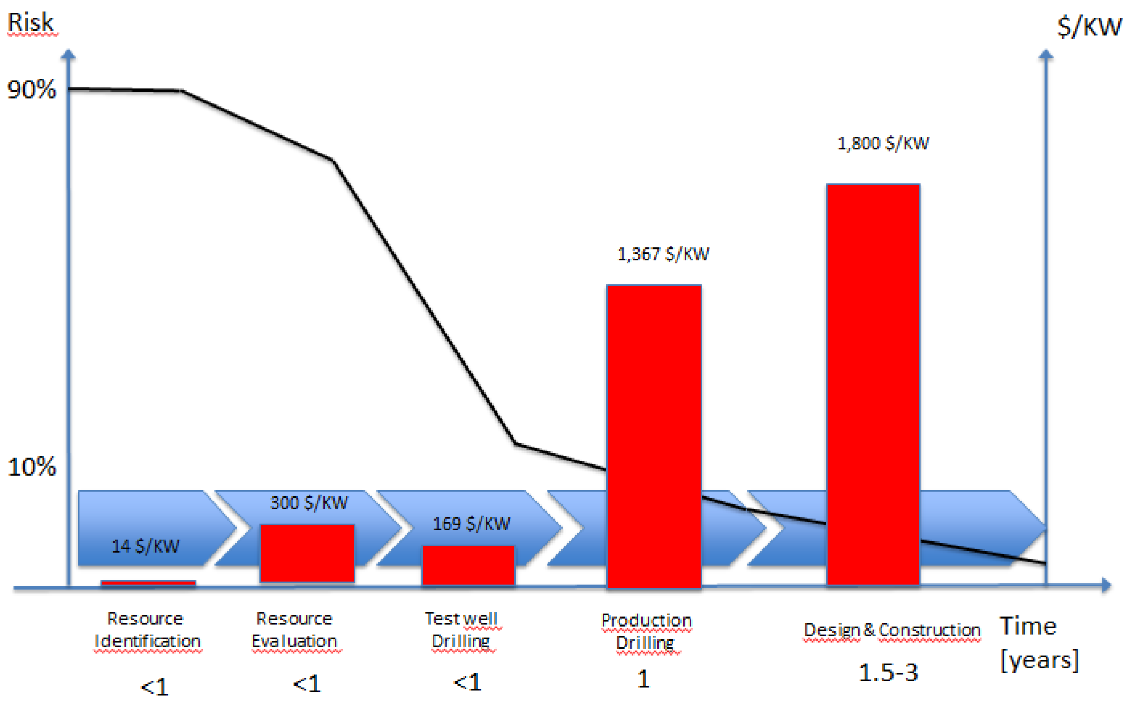

Figure 3: Geothermal project risk vs. investment cost.

This thesis addresses the second obstacle and focuses on starting to get revenue earlier in the project by incorporating the use of smaller wellhead power plants. This smaller power plants can be built and put online as soon as each well is drilled and tested instead of having to wait for all the wells in the steam field to be drilled and tested, which is typically three years for a traditional power plant (Cross and Freeman, 2009). Another use of the small wellhead power plants could be to use them as a complementary power plant to exploit the wells in a steam field that are either in the high pressure (HP) end or the low pressure end (LP). This could be a good idea because after drilling the wells in a steam field you have to balance the pressure and the mass flow from the wells to get the optimum operation for the entire steamfield, which might not be the optimum for some wells, in this thesis this type of use is called complementary. The main objective of this thesis was to develop a method for geothermal projects where the time until energy production begins, and cash flow starts, is reduced to make more geothermal projects feasible. The focus is on the plant construction stage of the project development.

This thesis is structured starting with a method section that is divided in two parts, the first part where important concepts to better understand this study are mentioned: geothermal steamfields, conventional techniques for geothermal exploitation, an overview of the thermodynamics of the energy conversion processes in a geothermal power plant and a comparison between a central power plant and a wellhead power plant, the second part describes the methods used to obtain the objectives of this work: the definition of the scenarios to be used, the cost and revenue estimation methods, as well as the estimation of time and net present value calculation criteria.

In section 3 the results will be presented for the power output, the costs, the net present value and a sensitivity analysis for the different scenarios.

Finally, a discussion of the results comparing the different scenarios is presented and a brief conclusion, followed by references and appendixes.

2. Method

As mentioned in the previous section: “The main objective of this thesis was to develop a method for geothermal projects where the time until energy production begins, and cash flow starts, is reduced. The focus is on the plant construction stage of the project development.”

The way to achieve this objective in this thesis was to create a hypothetical steamfield and to create different scenarios with different types of power plant arrangements on each one. The reason why a hypothetical steamfield was created was to have an equal base from which to make the comparison.

This section is divided in two, in the first part a background covering important concepts to better understand the content of this thesis, in the second part the scenarios were defined, also the cost and revenue estimation method; and time estimates for the start of energy production.

The power output was calculated for each scenario using the equations in section 2.1.3 with the help of the EES (Engineering Equation Solver) software. The next step was to calculate a cash flow and a Net Present Value (NPV) for each of the scenarios.

Finally the method of sensitivity analysis was done with regards to time between the start of power production from wellhead power plants and a central power plant, the rate at which the wellhead power plants are installed and the order in which the wells are drilled.

2.1. Background

This section covers some concepts for a better understanding of this study: about geothermal steamfields, conventional techniques of utilization of geothermal energy, a comparison between a traditional geothermal power plant and a wellhead power plant, and a theoretical background of thermodynamics of the energy conversion processes.

2.1.1. Average power of a steamfield for a feasible geothermal project

Utilizing geothermal energy for power production began in Lardarello, Italy in 1904, and the electricity generation has risen into installed capacity in the world of 10,898 MW in 2010 and 24 countries generate electricity from geothermal resources (Bertani, 2012). Most of the installed capacity has been installed after 1980 (see Figure 4).

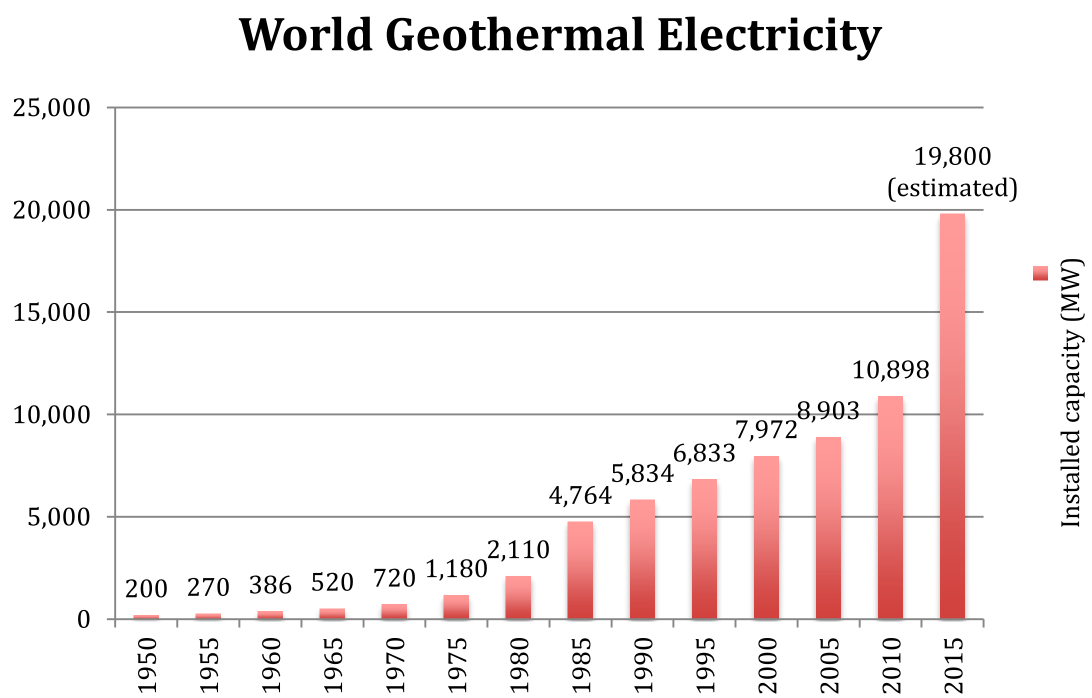

Figure 4: Installed capacity from 1950 to 2015 (MW)(Bertani, 2012)

Geothermal energy can be found anywhere in the world. But the high enthalpy energy that is needed to drive electric generation is found in relatively few places and to be feasible to produce electricity from it, it has to be located near the place where it will be used. This is one of the reasons why geothermal energy is not used more widely.

Most geothermal energy resources presently used result from the intrusion of magma from great depths (greater than 30 km) into the earth´s crust; these intrusions usually reach depths between 0 and 10 km (Tester et al., 2005).

The relationship between temperature (T) and depth (z) is called the geothermal gradient (∇T):

$$\nabla T \equiv \frac{\partial T}{\partial z} \qquad (1)$$

Where T is temperature and z is depth.

Some concepts about geothermal resources that are used throughout this thesis are defined as follows:

A *geothermal steamfield* is a geographical definition, usually indicating an area of geothermal activity at the Earth´s surface. In cases where there is no surface activity, this term may be used to indicate the area at the surface corresponding to the geothermal reservoir below.(Gehringer, 2012)

A *Geothermal system* refers to “all parts of the hydrological system involved, including the recharge zone, all subsurface parts, and the outflow of the system”(Axelsson, 2008).

A *geothermal reservoir* “indicates the hot and permeable part of a geothermal system that may be directly exploited. For a geothermal reservoir to be exploitable, it needs to have sufficient natural heat that transforms to pressure and brings the steam to the surface”(Axelsson, 2008).

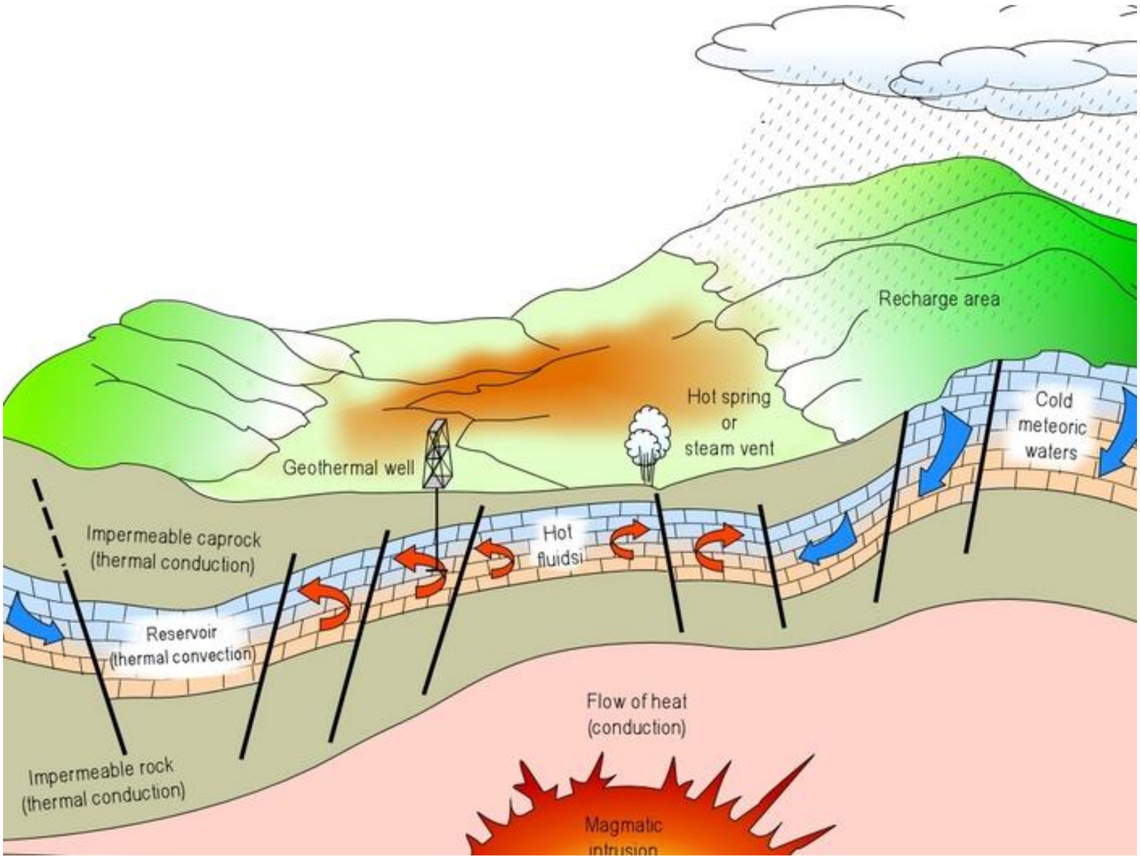

Figure 5: Schematic view of a geothermal system(Dickinson and Fanelli, 2004)

Low temperature geothermal resources, have been used for heating and bathing for many years but only the high temperature (> 90^{o}C) geothermal resources are considered to be feasible for the production of electricity.

Geothermal resources are commonly divided into four categories (Tester et al., 2005).

- Hydrothermal resource: where hot fluids are produced spontaneously. This type of geothermal resource requires the combination of: a heat source (usually a magmatic intrusion), a permeable formation to allow the fluid to move and a sufficient source of fluid. This type of resource can be *vapour dominated*, which is the easiest to exploit for the production of electricity but occur rarely; or *liquid dominated*, this happens because the resource is pressurized above the saturation pressure and the fluid is hot water or a mixture of hot water and steam. The liquid dominated type of resource is more common than vapour dominated and in most geothermal projects this type of resource is being utilized.
- Geopressured resource: this type of resource is contained in large sediment-filled reservoirs under confining pressures much greater than hydrostatic pressure, usually they contain methane and their utilization is restricted.
- Hot dry rock: this type of resources is that where the reservoir is hot enough but there is not enough fluid, also called enhanced geothermal systems (EGS).
- Magma: this resources consists of molten rock at accessible depths

High-grade resources are those that have hot fluids contained in high permeability and high porosity rock and at relatively shallow depths (less than 3 km).

The geochemistry of the fluids is also very important, as fluids with low salinity and low concentration of non-condensable gases (NCG) are easier to exploit than fluids with high salinity or high concentration of NCG and/or dissolved minerals.

There are five features that make a hydrothermal geothermal resource commercially viable (DiPippo, 2008):

- Large heat source
- Permeable reservoir
- Supply of water
- Overlying layer of impervious rock
- Reliable recharge mechanism

The goal of a geothermal exploration project is to locate such a system.

In this thesis the focus will be on the use of geothermal energy to produce electricity, so the hypothetical steamfield will be a hydrothermal resource.

According to information from 69 steamfields (Bertani, 2005), excluding vapor-dominated steamfields, and considering only the steamfields with two phase geothermal fluid, the average installed power of a steamfield is 98 MWe,

Most of the data about steamfields in geothermal projects where electricity is produced, and the wells in those steamfields, is calculated dividing the power plant installed capacity between the number of wells, this available data is in MW/well, this is called “well productivity”(Bertani, 2005).

But for this thesis the data needed is about the properties of the wells: enthalpy and productivity curves, and that is data that is more difficult to find. For this reason a hypothetical steamfield was created using data from the steamfield in Hellisheidi, Iceland (Sigfusson et al., 2012). To try to have a balanced steamfield, 10 wells from that steamfield were chosen, 3 wells with high enthalpy, 3 wells with low enthalpy and 4 wells with medium enthalpy.

The productivity curve is the relation between the pressure at the wellhead and the mass flow of the geothermal fluid from the well, which is usually presented as:

$$\dot{m}_{well} = f(P) \tag{2}$$

Where $\dot{m}_{well}$ is the mass flow of geothermal fluid coming from each well and P is the wellhead pressure (see Figure 6).

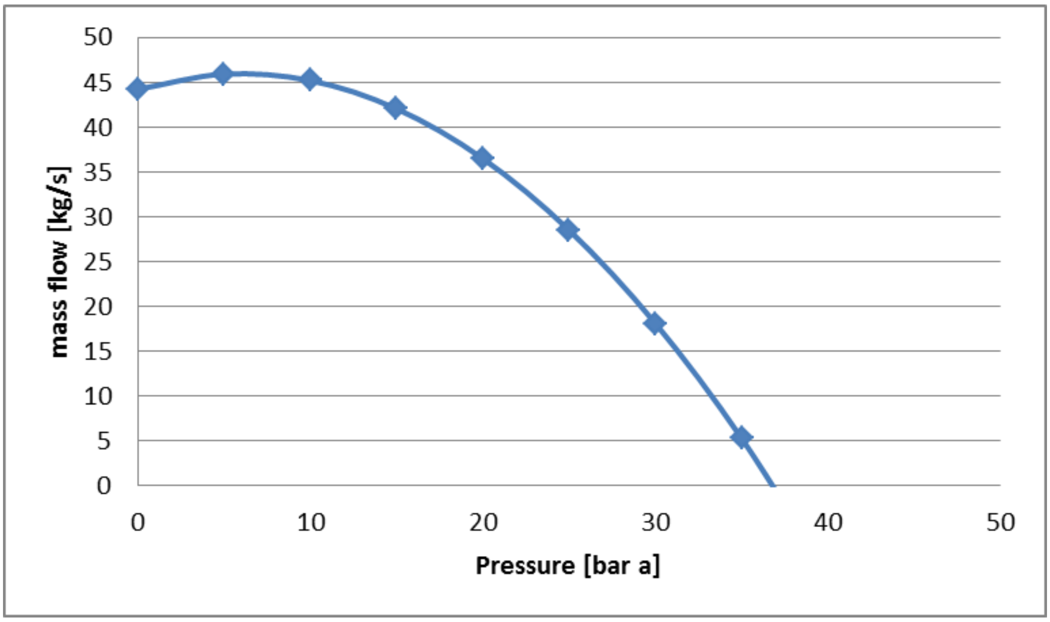

Figure 6: Average productivity curve of the hypothetical steamfield.

This productivity curve is different for each individual well and it is created during a testing period, that usually takes between 3 to 6 months (Thorhallsson, 2012). The well properties of the hypothetical steamfield created for this thesis, productivity curves and enthalpies (Sigfusson et al., 2012), are:

Table 1: Hypothetical steamfield well properties

well	Productivity curve ($\dot{m}_{well} = f(P)$)	Enthalpy (h)[kJ/kg]
1	$\dot{m}_{well\ 1} = -0.003(P^2) + 0.032(P) + 10.03$	2660
2	$\dot{m}_{well\ 2} = -0.008(P^2) + 0.262(P) + 37.5$	2500
3	$\dot{m}_{well\ 3} = -0.0052(P^2) + 0.101(P) + 50.76$	1990
4	$\dot{m}_{well\ 4} = -0.038(P^2) + 0.942(P) + 61.23$	1800
5	$\dot{m}_{well\ 5} = -0.047(P^2) + 1.131(P) + 19.35$	1750
6	$\dot{m}_{well\ 6} = -0.034(P^2) + 0.739(P) + 78.03$	1740
7	$\dot{m}_{well\ 7} = -0.009(P^2) + 1.56(P) + 82.95$	1500
8	$\dot{m}_{well\ 8} = -0.179(P^2) + 3.265(P) + 15.27$	1220
9	$\dot{m}_{well\ 9} = -0.038(P^2) + 0.578(P) + 22.78$	1170
10	$\dot{m}_{well\ 10} = -0.059(P^2) + 1.261(P) + 43.33$	1110

2.1.2. Conventional techniques for geothermal utilization

Geothermal power plants work similarly to traditional thermal power plants in that they convert thermal energy to electricity using a turbine and a generator in an energy process. The difference is the source of heat: in geothermal power plants geothermal fluids provide the heat from the hydrothermal system.

2.1.2.1. Types of power plants

Geothermal power plants are basically divided in two groups: steam cycles and binary cycles.

In the steam cycle the geothermal fluid is allowed to boil or "flash" above boiling point by lowering the pressure (state 0-1 in Figure 7), then becoming a two-phase fluid, and then the steam is separated from the brine and expanded in a turbine (state 3-4 in Figure 7). The process of lowering the pressure to boil the fluid (state 0-1 in Figure 7) is called "flash process". From this group the single flash power plant (see Figure 8), the double flash power plant and the backpressure power plant will be used in this thesis as described later.

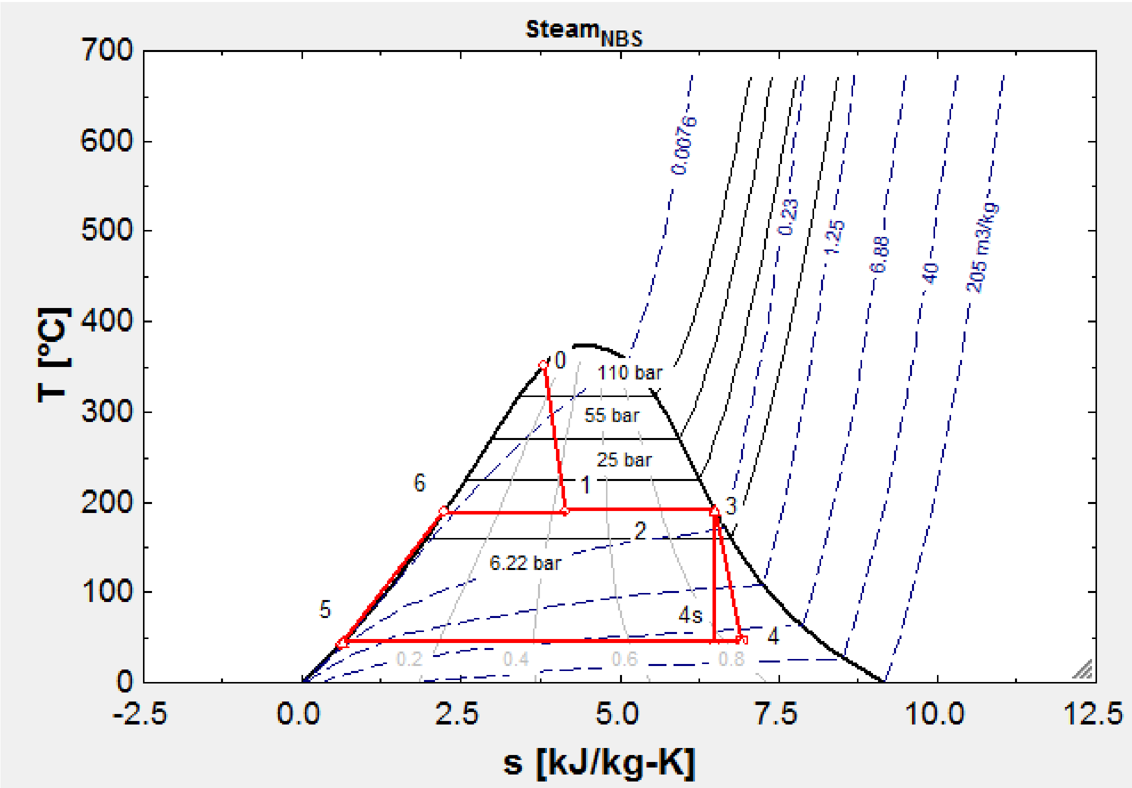

Figure 7: T-s diagram of a steam cycle power plant.

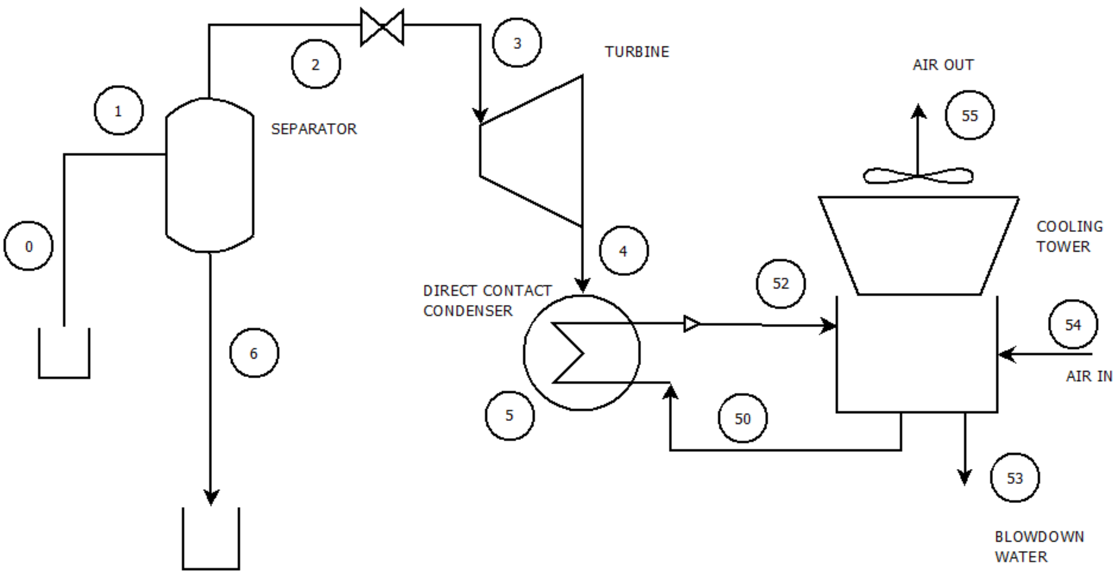

Figure 8: Process flow diagram of a steam cycle geothermal power plant (single flash).

The binary cycles use a secondary working fluid in a closed cycle. A heat exchanger is used to transfer heat from the geothermal fluid to the working fluid, the working fluid is vaporized and expanded in a turbine, and the cooled geothermal fluid is reinjected to the reservoir (see Figure 9).

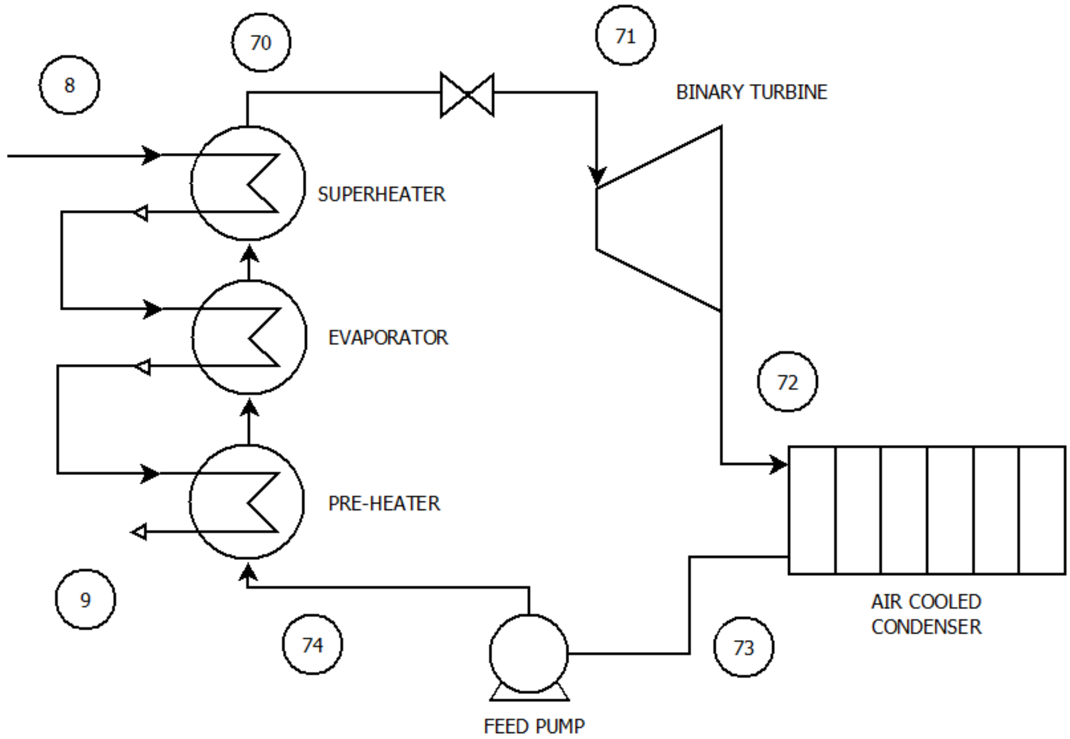

Figure 9: Process flow diagram of a binary power plant.

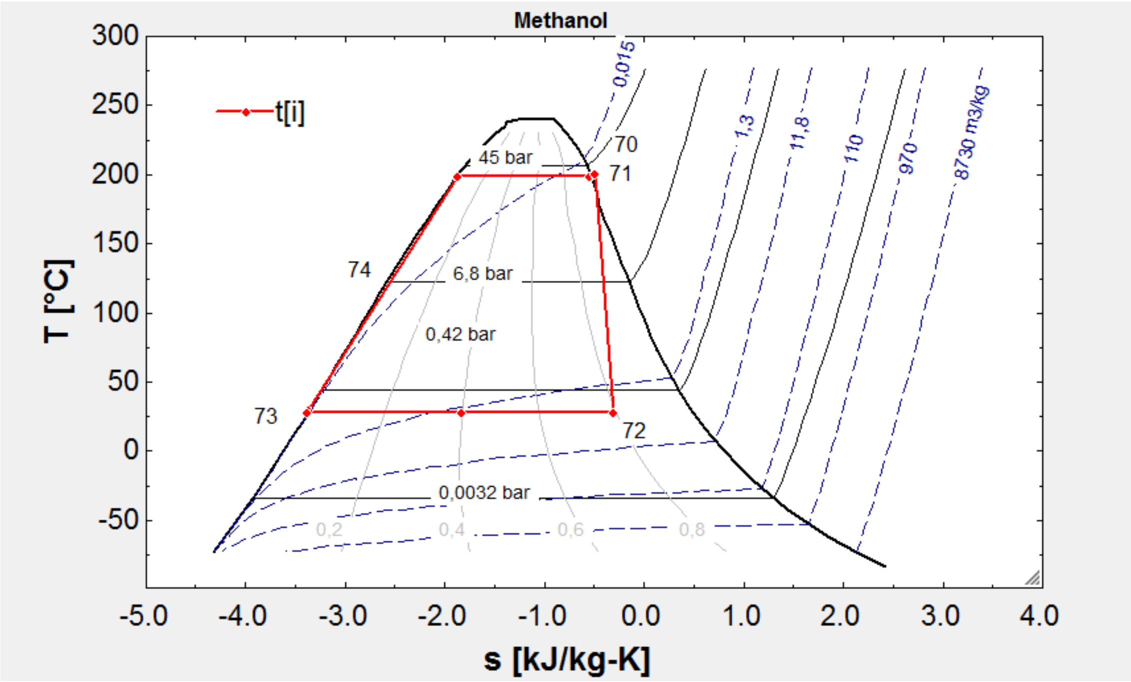

Figure 10: Temperature-entropy diagram of a geothermal binary power plant with methanol as the working fluid.

Usually steam cycles are used in steamfields with high enthalpy wells and the binary cycles for steamfields with low enthalpy wells (see Figure 11).

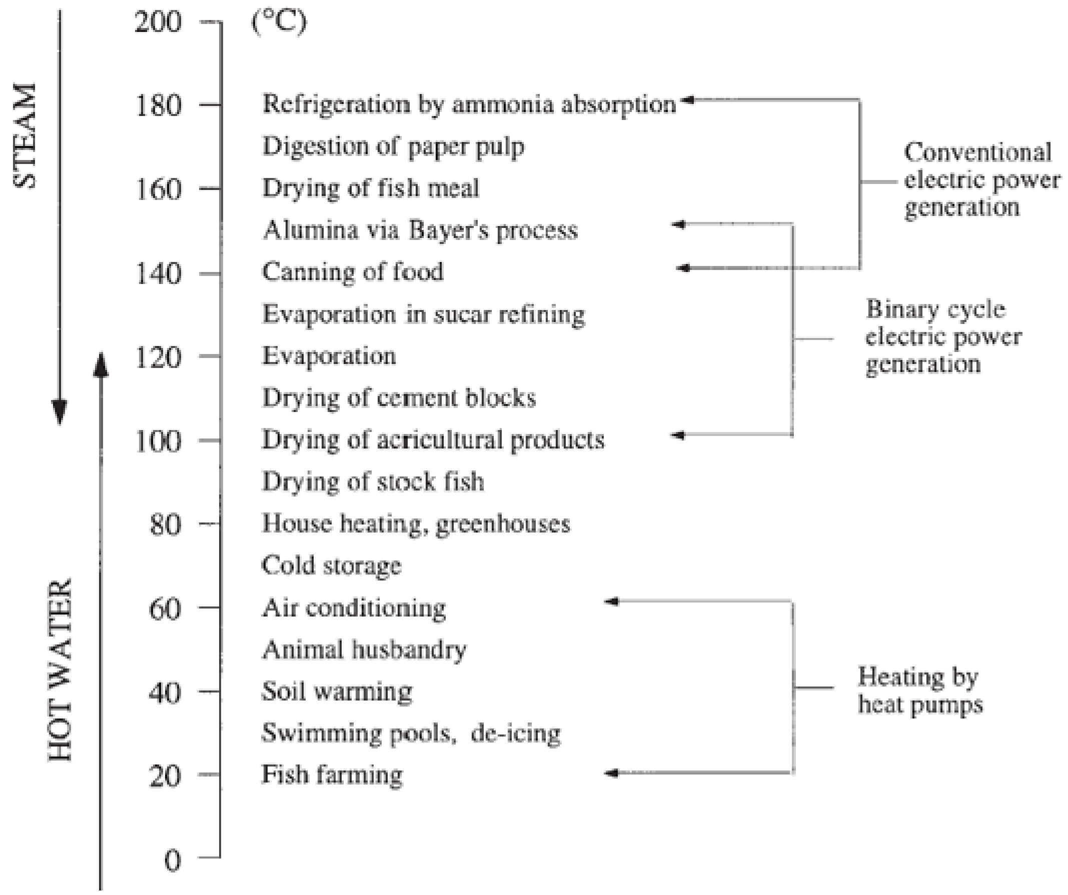

Figure 11: Lindal diagram showing the use of geothermal fluid with regards to its temperature (Lund, 2000)

The main types of geothermal power plants are:

- Flash steam power plants: single flash and double flash
- Dry steam power plants
- Backpressure power plants
- Binary cycle power plants

Although over 25% of installed capacity of geothermal power plants is from dry steam power plants (see Table 2) this can basically only be found in two steamfields: Lardarello, Italy and The Geysers, USA and the rareness of such power plants is the reason why this type of power plant is not going to be included in this thesis.

Table 2: Power plant types (MW installed capacity) (Bertani, 2012)

Power plant type	(MW)	%
Dry steam	2,822	25.89
Single flash	4,552	41.77

Power plant type	(MW)	%
Double flash	2,183	20.03
Binary	1,193	10.95
Backpressure	147	1.35
Hybrid	2	0.02
TOTAL	10,899	100

2.1.2.1.1. Flash Steam Power plants

The most common type of geothermal reservoir is liquid-dominated (DiPippo, 1999). For artesian flowing wells, the produced fluid is a two-phase mixture of liquid and vapor. An Artesian flowing well refers to a well from an aquifer that is under positive pressure that allows the level of water to rise without the need of a pump (see Figure 12).

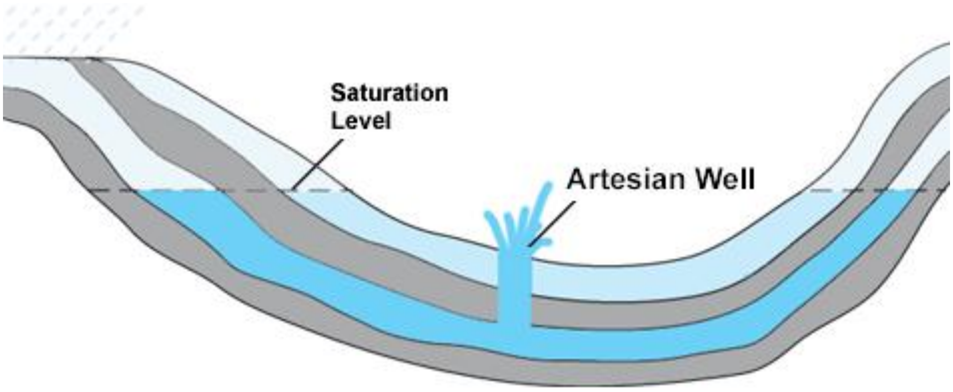

Figure 12: Artesian flowing well

In the case of the two phase mixture, the amount of vapor (quality) at atmospheric conditions depends on the conditions of the reservoir, the well dimensions, and the wellhead pressure which is controlled by a wellhead valve or orifice plate. The quality of the two phase mixture (x_{atm}) is a function of the reservoir fluid enthalpy (which depends on the fluid pressure and temperature) and the fluid saturation enthalpies at atmospheric conditions:

$$x_{atm} = \frac{h_0(p_{res}) - h_f(p_{atm})}{h_{fg}(p_{atm})} \qquad (3)$$

Where $h_0(p_{res})$ is the enthalpy of the saturated liquid at the temperature of the reservoir, $h_f(p_{atm})$ is the enthalpy of the saturated liquid at atmospheric temperature and $h_{fg}(p_{atm})$ is the enthalpy of the vapor minus the enthalpy of the liquid at atmospheric temperature, e.g. the latent heat of vaporization.

Typical wellhead qualities may range from 10 to over 50 % (DiPippo, 1999). The turbines in the geothermal power plants only use the vapor part of the two phase flow, so the two-phase mixture has to be separated, since the wellhead pressure is fairly low, typically 5-10 bar abs, the brine (liquid) and vapor phases differ significantly in density, this allows effective separation by centrifugal action. Highly efficient cyclone separators yield steam qualities ranging as high as 99.99%(DiPippo, 1999). This steam is then expanded in a turbine (state 3-4 in Figure 7 and Figure 8).

The brine from the separator (state 6 in Figure 7 and Figure 8) is usually reinjected to the reservoir or flashed to a lower pressure with the possibility to produce additional steam for the use in a lower pressure turbine (double flash power plant).

Power plants where only the steam from the first separation process is used are called single flash power plants; plants that use the steam from the lower pressure separator as well are called double flash power plants (see section 2.1.2.1.2.)

2.1.2.1.2. Double flash power plants

Double flash power plants work with the same principle as a single flash power plant, the difference is that the separated water coming from the high pressure separator is flashed again to get more steam from it, this steam from the lower pressure separator, also called secondary steam, is used either in a separate turbine or in the appropriate stage of the main turbine (dual pressure turbine). With a double flash technology a power plant can produce between 20% to 25% more power from the same geothermal fluid (DiPippo, 1999), although with high enthalpy steamfield the increase in power is less. However, the cost of a double flash power plant is higher due to the extra equipment and the relatively low pressures and therefore low density steam leading to larger dimensions of pipes and components.

2.1.2.1.3. Backpressure power plants

Backpressure power plants also use the steam produced from a flashing process, the difference is that their turbines discharge the steam to the atmosphere, they produce less energy than condensing turbines but they are the most simple of all, they don´t have condensers, gas extraction systems and cooling towers, thus making them more portable. They are also of the lowest cost.(Hiriart, 2003)

2.1.2.1.4. Binary cycle power plants

In a binary power plant the thermal energy of the geothermal fluid is transferred through a heat exchanger to a working fluid to be used in a closed Rankine cycle, after this the geothermal fluid is returned to the injection wells, so it is never in contact with the moving parts of the power plant, thus eliminating the adverse effects of erosion and scaling from dissolved materials that can be found in the geothermal fluid. Binary power plants are advantageous under certain conditions, especially for geothermal fluid temperatures under 150^{o}C (see Figure 11), or when the geothermal fluid has high concentration of non-condensable gases or high corrosion or scaling potential, these problems increase when the geothermal fluid flashes to vapor as it occurs in artesian flowing wells as the geothermal fluid is under high pressures in the reservoirs. Most binary power plants use downwell pumps located below the flash level to raise the pressure and prevent the flashing process so that the geothermal fluid remains in the liquid phase throughout the power plant: from production wells, through the heat exchangers and to the injection wells (DiPippo, 1999).

2.1.3. Thermodynamics of the energy conversion processes

It is important to describe the thermodynamic principles governing energy conversion processes of geothermal power plants. This is better understood by showing the different states of the processes in a T-s diagram (Temperature-Entropy) and a process flow diagram for each of the different types of power plants used in this thesis. This way the reader will be able to understand this thesis better.

2.1.3.1. Single-flash power plants:

This type of power plant is the mainstay of the geothermal power industry (DiPippo, 2008).

The term single-flash means that the geothermal fluid has undergone a single flash process, which is a transition from a pressurized liquid to a two phase mixture of liquid and vapor, as a result of lowering the pressure below the saturation point corresponding to the original fluid temperature. Due to the high enthalpy of the fluid, a part of the liquid vaporizes as the pressure is lowered and the fluid undergoes phase change into the two phase zone of water and steam. This mixture or two-phase fluid is then separated into steam and liquid phases in a cylindrical pressure vessel, due to their difference in densities.

The equations and variables in this process refer to the process flow diagram in Figure 13, the T-s diagram in Figure 14 and the P-h diagram in Figure 15.

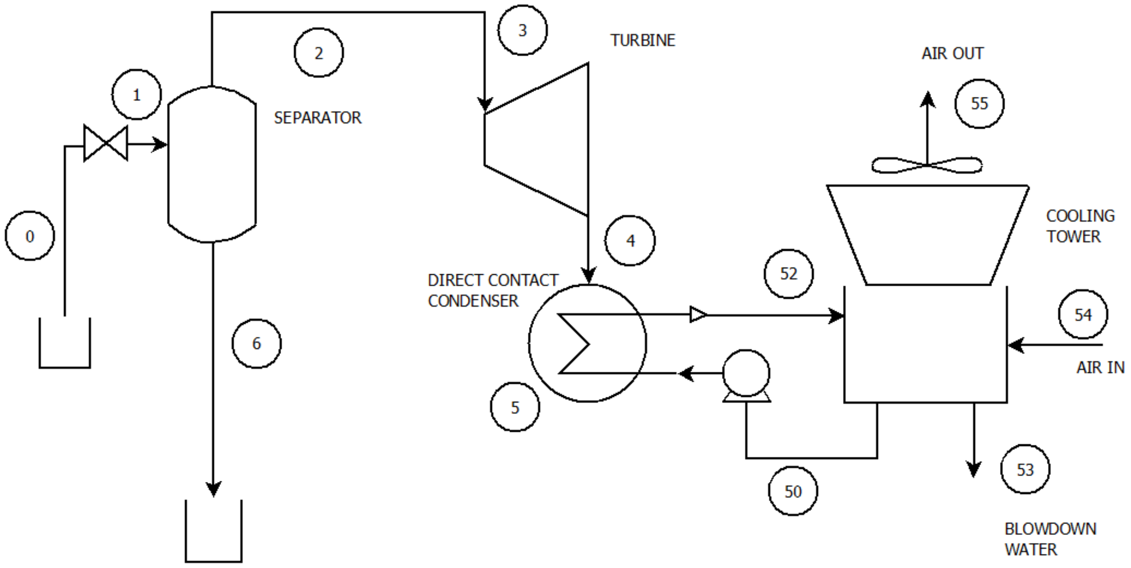

Figure 13: Simplified process flow diagram of a single flash power plant

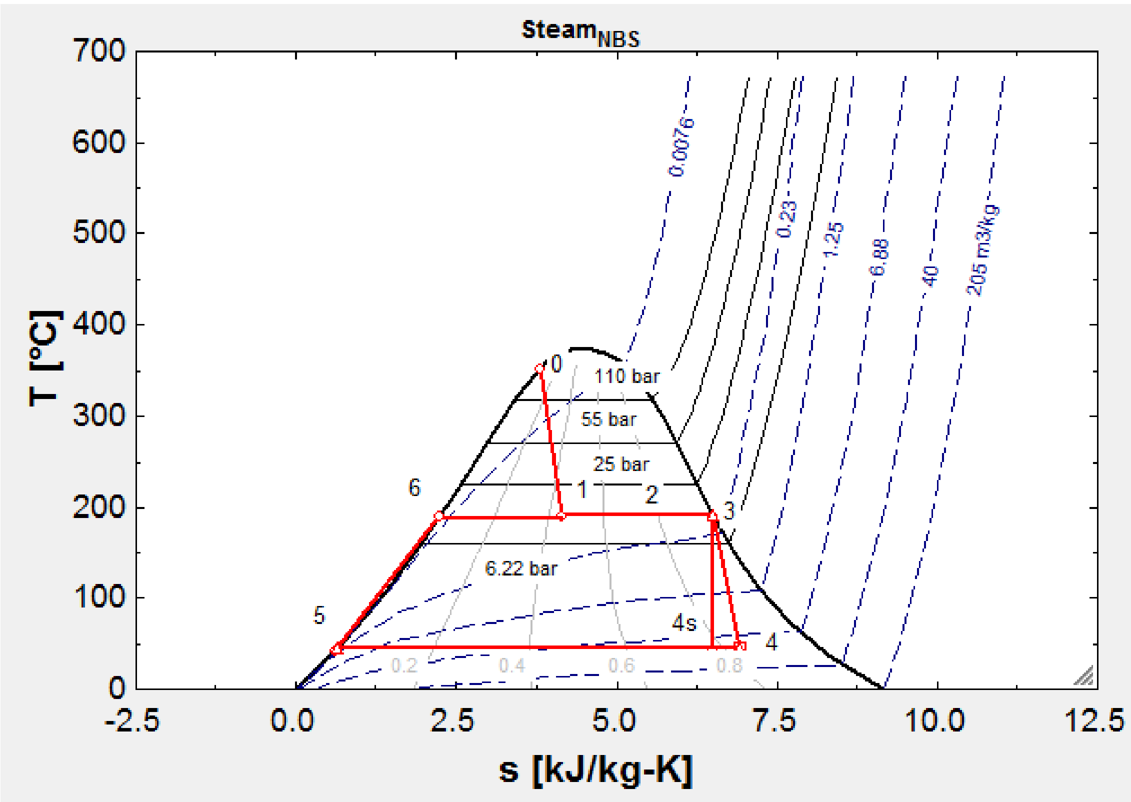

Figure 14: Temperature-entropy (T-s) diagram showing states in a single flash power plant.

2.1.3.1.1. Flashing process

The process begins with the geothermal fluid under pressure at state 0, close to the saturation curve and due to the pressure drop the fluid starts to boil as it moves from state 0 to state 1 shown in Figure 14. This process is assumed to be isenthalpic (constant enthalpy), because it involves no heat transfer (adiabatic process) see Figure 15.

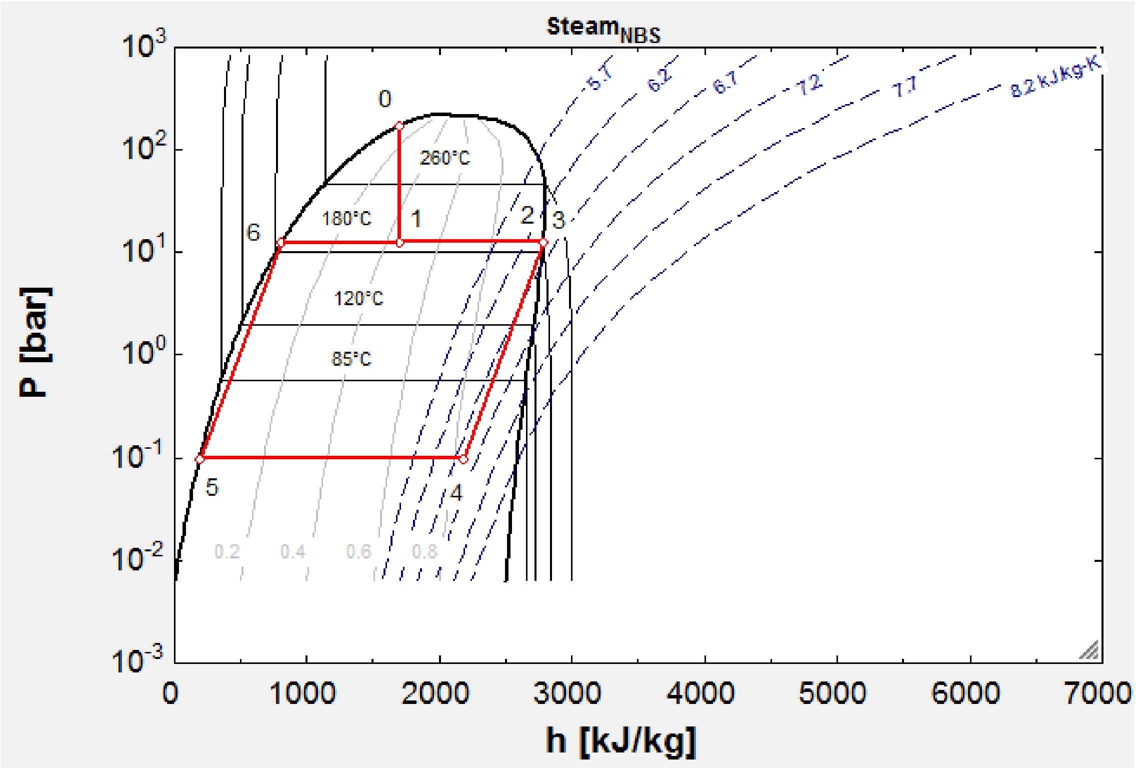

Figure 15: Pressure-enthalpy diagram (P-h) of a single flash power plant.

The energy and mass balance through the process from 0-1 become:

$$h_0 = h_1 \tag{4}$$

$$\dot{m}_0 = \dot{m}_1 \tag{5}$$

Where h_0 is enthalpy at state 0, h_1 is enthalpy at state 1, $\dot{m}_0$ is mass flow at state 0 and $\dot{m}_1$ is mass flow at state 1.

2.1.3.1.2. Separation process

This is an isobaric process (constant pressure) and the quality (the steam portion, $x = \frac{\dot{m}_{steam}}{(\dot{m}_{steam}+\dot{m}_{water})}$) of the two-phase flow is:

$$x_1 = \frac{h_1 - h_6}{h_2 - h_6} \qquad (6)$$

Where h_6 is the enthalpy of the separated water and h_2 is the enthalpy of the steam from the separator.

This gives us the amount of steam that goes into the turbine (state 3, in this thesis it´s going to be assumed that state 3 is equal to state 2) and from here we also get the brine out of the separator (state 6)

$$\dot{m}_3 = \dot{m}_2 = \dot{m}_1 x_1 \qquad (7)$$

$$\dot{m}_6 = \dot{m}_1(1 - x_1) \qquad (8)$$

The separator contains a mixture of steam and water in equilibrium, so all temperatures in the separator are equal, assuming there are no significant pressure losses in the separator:

$$T_1 = T_2 = T_6 = T_{sat}(P_1) \qquad (9)$$

Where T_1 is the temperature in state 1, T_2 is the temperature of the steam in state 2, T_6 is the temperature of the separated water in state 6 and $T_{sat}(P_1)$ is the saturation temperature of the water at the pressure in state 1.

And the enthalpy of the steam out of the separator is:

$$h_2 = h_{steam}(P_1) \qquad (10)$$

Where h_{steam} is the saturated steam enthalpy in state 2 at the pressure in state 1.

The mass flow of steam ($\dot{m}_2$) and the mass flow of brine ($\dot{m}_6$) equals the mass flow of the two phase flow coming into the separator ($\dot{m}_1$):

$$\dot{m}_1 = \dot{m}_2 + \dot{m}_6 \qquad (11)$$

A very important aspect of the design of a geothermal power plant is the selection of the separator pressure that will yield the best overall plant performance in terms of power generation. This selection of this pressure is done by performing a maximization process of the power output of the power plant.

2.1.3.1.3. Turbine expansion process

The saturated steam that comes from the separator is expanded in the turbine, where part of the energy of the steam is transformed to mechanical work to a shaft and then electricity is produced in the generator. The work is calculated by the following equation:

$$\dot{W}_t = \dot{m}_3(h_3 - h_4) \tag{12}$$

Where $\dot{W}_t$ is the work of the turbine, $\dot{m}_3$ is the mass flow in state 3, h_3 is the enthalpy in state 3 and h_4 is the enthalpy in state 4, after the turbine.

In an ideal turbine the process is assumed to be at constant entropy (isentropic process), so the ideal enthalpy after the turbine expansion would be h_{4s} calculated considering the entropies equal in state 3 and 4 (s_3=s_4).

Enthalpy in state 4 (h_4) is determined using the turbine isentropic dry efficiency (η_{td}), provided by the manufacturer of the turbine, and the fluid properties at state 4s, the ideal turbine outlet state. The isentropic efficiency is the ratio of the actual work to the isentropic work.

$$\eta_t = \frac{h_3 - h_4}{h_3 - h_{4s}} \tag{13}$$

The isentropic efficiency of a turbine is affected by the amount of moisture that is present during the expansion process, the higher the moisture, the lower the efficiency. And since turbines used in geothermal power plants generally operate in the wet region (since the inlet condition is at saturation) it is very important to calculate the isentropic efficiency of a turbine operating with wet steam, to do this the Baumann rule (equation 13) is used:

$$\eta_{tw} = \eta_{td} * \left[\frac{x_3 + x_4}{2}\right] \tag{14}$$

Where η_{tw} is the wet isentropic efficiency of the turbine, η_{td} is the dry isentropic efficiency of the turbine, x_3 and x_4 are the steam qualities in and out of the turbine respectively.

In this thesis the dry turbine efficiency is assumed to be η_{td}=82% throughout.

2.1.3.1.4. Condensing process

After the turbine expansion the geothermal fluid is a mixture of saturated steam and saturated liquid at a known condenser pressure(P_1). The steam is then condensed in the condenser rejecting heat and the fluid leaves the condenser as saturated liquid. The two main types of condensers for this type of power plants are:

- Surface contact condensers: in this type of condenser the condensate and the cooling water do not mix.
- Direct contact condensers: in this type of condenser there is a simple mixture of the condensate and the cooling water.

In this thesis the condensers used for the steam cycle power plants (except for the backpressure turbine) are direct contact condensers, the reason for using the direct contact condensers is to use the same type of components to make the comparison on an equal base, and the wellhead power plants used in this thesis are designed with this type of condenser.

The mass and energy balance for the condenser gives:

Mass balance:

$$\dot{m}_4 + \dot{m}_{50} = \dot{m}_{52} \tag{15}$$

Energy balance:

$$\dot{m}_4 h_4 + \dot{m}_{50} h_{50} = \dot{m}_{52} h_{52} \tag{16}$$

Equations (14) and (15) refer to Figure 13.

Together with the cooling tower calculations below we can calculate the flow rate of cooling water required to achieve enough cooling and thereby the desired condensing pressure, this flow rate is important to calculate the power of the pump needed for the circulation of the cooling water which is an important parasitic load that decreases the net power output of the power plant. Another important parasitic load is the gas extraction system for the non-condensable gases (NCG).

The condenser pressure in this thesis is assumed to be 0.1 bar abs where applicable.

2.1.3.1.5. Cooling tower process

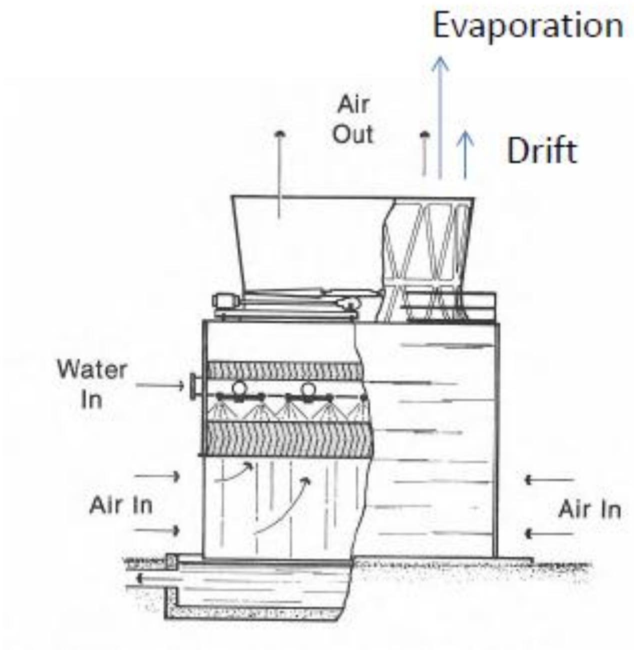

Figure 16: Induced draft counterflow cooling tower(Hensley, 1967)

The purpose of the cooling towers is to reject the heat of the condensing steam and maintain the cooling water circulation. The basic way a cooling tower works is the following: The steam condensate is pumped, in the case of a direct condenser is used, from the condenser hotwell and sprayed into the cooling tower ("water in" in Figure 16), this hot water is then cooled by evaporation from contact with the air that is coming up, and the air is drawn by a fan at the top of the cooling tower. The cooling water is collected at the bottom and then pumped back to the condenser. The process involves exchange of both heat and mass between water and air, so the mass balance has to be done for both water and air.

Mass balance of air:

$$\dot{m}_{54} = \dot{m}_{55} \tag{17}$$

Where $\dot{m}_{54}$ is the air coming into the cooling tower that comes in contact with the water flowing down, and has a content of water $\dot{m}_{water,54}$ depending on the outside ambient conditions; and $\dot{m}_{55}$ is the air coming out of the cooling tower, it also has a content of water $\dot{m}_{water,55}$.Mass balance of water:

$$\dot{m}_{52} + \dot{m}_{water,54} = \dot{m}_{50} + \dot{m}_{water,55} + \dot{m}_{53} \tag{18}$$

Variables in equations (16) and (17) refer to Figure 13.

Where $\dot{m}_{53}$ is a water discharge to control concentrations of salts and other impurities in the circulating water called *blowdown* (Hensley, 1967).

To calculate the water content $\dot{m}_{water,54}$ and $\dot{m}_{water,55}$is done calculating the humidity ratio (ω) of an air-water gas mixture, this can be calculated given the wet bulb temperature, the relative humidity and the pressure of the mixture, all of which can be measured.

$$\dot{m}_{water,54} = \omega_{54}\dot{m}_{54} \qquad (19)$$

$$\dot{m}_{water,55} = \omega_{55}\dot{m}_{55} \qquad (20)$$

And the energy balance:

$$\dot{m}_{52}h_{52} + \dot{m}_{54}h_{54} = \dot{m}_{50}h_{50} + \dot{m}_{55}h_{55} + \dot{m}_{53}h_{53} \qquad (21)$$

Variables in equations (18), (19) and (20) refer to Figure 13.

Combining these equations with the equations from the condenser it is possible to calculate the mass flow of air and water needed to obtain the target condenser pressure, and with that it is also possible to calculate the size (power) of the pumps and fans needed, also the vacuum pumps, that are considered parasitic load of the power plant resulting in less net energy produced by the power plant.

There are two important parameters of cooling towers: the range and the approach. The range is the difference in temperature between the water coming into the cooling tower and the water leaving the cooling tower ($T_{52} - T_{50}$); the approach is the difference between the wet bulb temperature and the water coming out of the cooling tower. The wet-bulb temperature is the temperature of the air after it saturates to 100% relative humidity, which is the ratio of the amount of moisture the air holds relative to the maximum of moisture the air can hold at the same temperature, it is also called adiabatic saturation temperature.(Cengel and Boles, 2006)

An ideal cooling tower would have an approach=0, and as a rule of thumb a cooling tower´s size increases (as well as the cost) as the approach decreases.

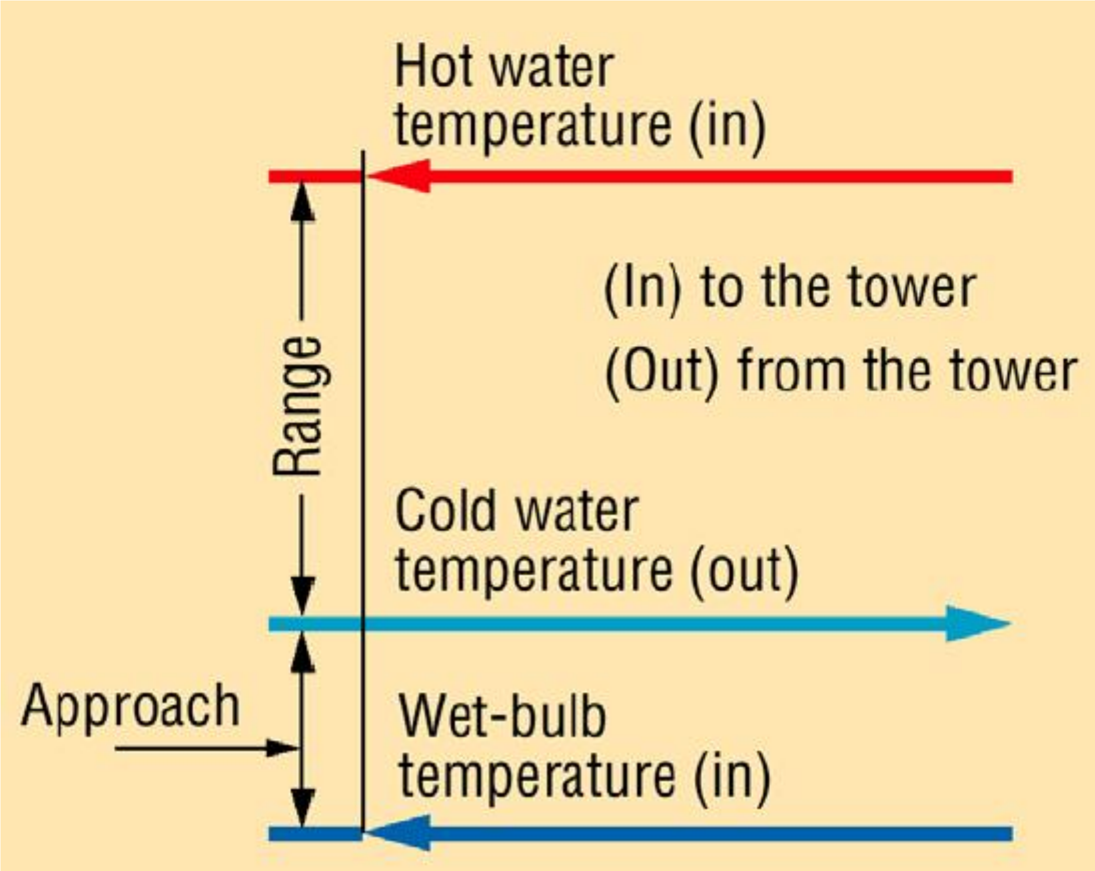

Figure 17: Approach and range of cooling tower(Hensley, 1967)

In this thesis the design parameters for the cooling tower used are:

Wet bulb temperature= 11^{o}C

Approach of 7^{o}C.

Relative humidity 50%

An important thing to calculate for the cooling tower is the power of the fan needed to move the calculated mass flow of air through the cooling tower as this is also an important parasitic load of the power plant.

$$\dot{W}_{fan} = \dot{m}_{55} * \frac{1}{\rho} * \Delta P * \eta_{fan} * \eta_{motor} \tag{22}$$

Where ρ is the density of air and ΔP is the pressure drop across the tower, η_{fan} is the efficiency of the fan, η_{motor} is the efficiency of the fan´s motor and $\dot{m}_{55}$ is the air coming out of the cooling tower. In this thesis: ΔP will be 0.002 bar g, η_{fan}=70% and η_{motor}=95%

2.1.3.2. Double flash Power Plant

A double flash power plant is basically a single flash power plant where the separated water coming from the separator flows through another separator (secondary separator) at a lower pressure to get more steam out of the fluid (second flash process). This steam is then expanded in another turbine or in the same turbine (at a lower pressure stage) where the steam from the first flash process if a dual pressure turbine is used.

With this type of power plant usually between 20-25% more power can be obtained compared to that from a single flash power plant (DiPippo, 1999), with the disadvantage of the additional component costs.

The equations and variables describing the processes of the double flash power plant refer to Figure 18, Figure 19 and Figure 20.

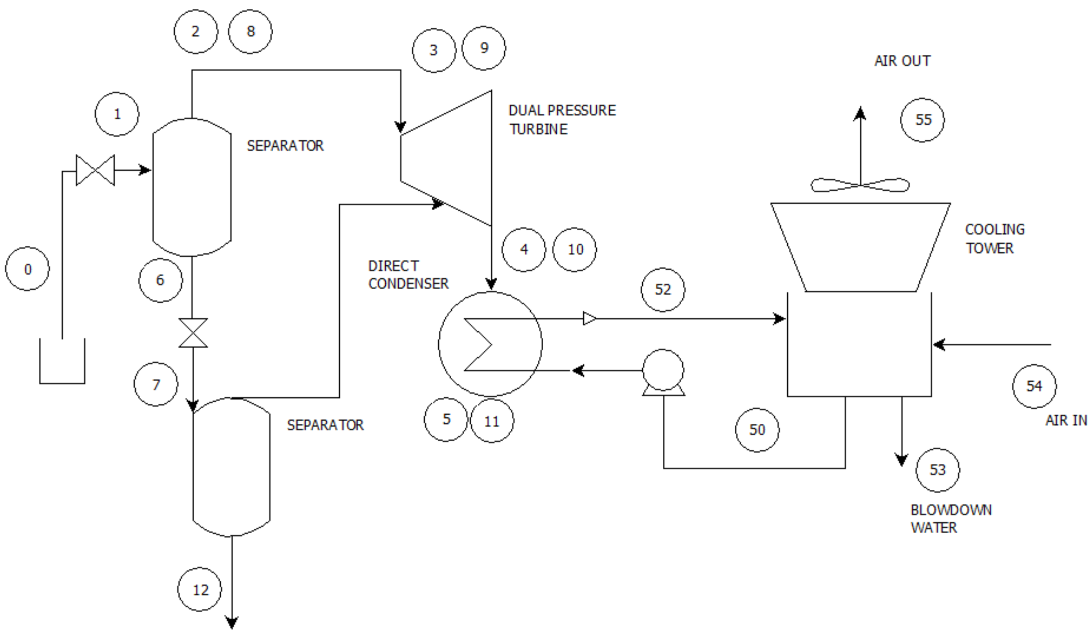

Figure 18: Simplified process flow diagram of a double flash power plant.

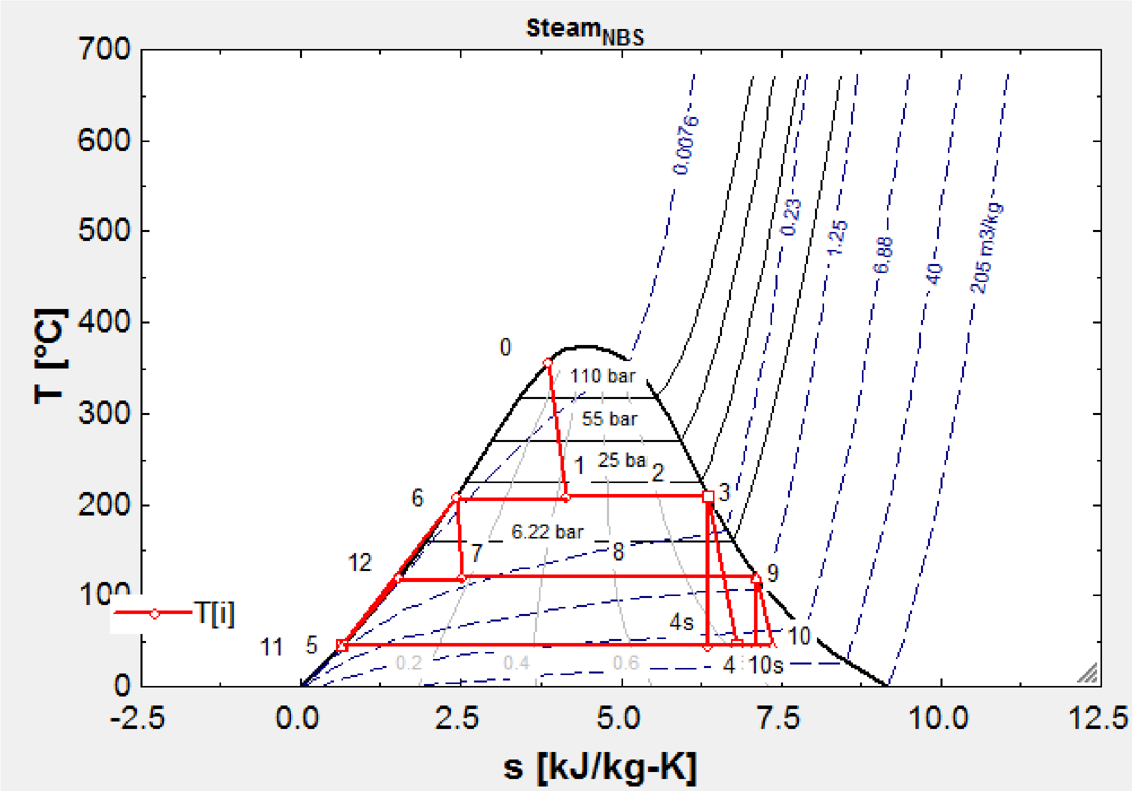

Figure 19: Temperature-entropy (T-s) diagram showing the stages of a double flash power plant.

2.1.3.2.1. Flashing processes

In the double flash power plants there are, of course, two flashing processes 0-1 and 6-7, and these processes, as in the single flash power plant in the previous section are isenthalpic processes (see Figure 20).

2.1.3.2.2. Separation processes

In the double flash power plants there are two separators and the separation processes take place at states 1 and 7 and just as in the single flash power plants it is an isobaric process (see Figure 19) and the quality of steam is given by:

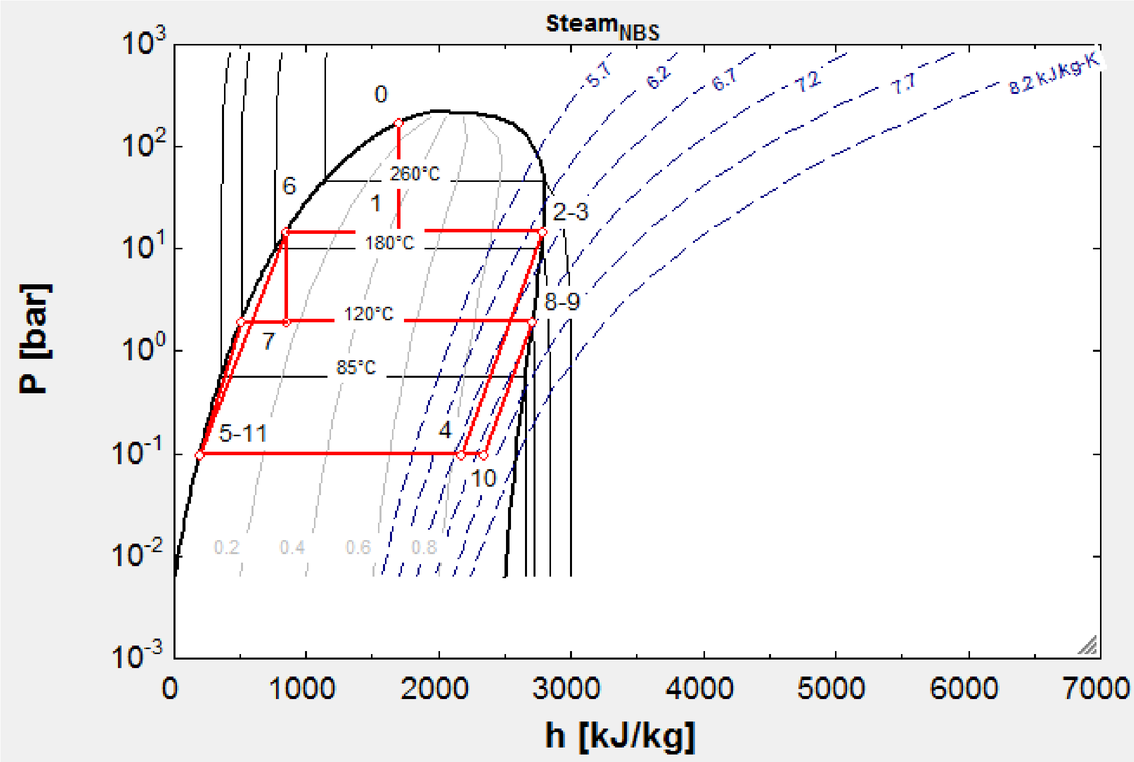

Figure 20: Pressure-enthalpy (P-h) diagram of a double flash power plant.

$$x_1 = \frac{h_1 - h_6}{h_2 - h_6} \tag{23}$$

And

$$x_7 = \frac{h_7 - h_{12}}{h_9 - h_{12}} \tag{24}$$

2.1.3.2.3. Turbine expansion process

In this thesis the use of one dual pressure turbine for the double flash power plant is considered. The work is calculated in the same way as with the single flash power plant, the only difference is that you have to add the work from both the steam from the first flash process and that from the second flash process.

$$\dot{W}_{thp} = \dot{m}_3(h_3 - h_4) \tag{25}$$

And

$$\dot{W}_{tlp} = \dot{m}_9(h_9 - h_{10}) \tag{26}$$

Where $\dot{W}_{thp}$ is the work done by the high pressure turbine (steam from the first flash process) and $\dot{W}_{tlp}$ is the work done by the low pressure turbine (steam from the second flash process).

2.1.3.2.4. Condensing process

In this report, the condensing process is considered the same as for the single flash power plant. In the case of using one dual pressure turbine there is only one condenser as well, only it can be larger than that of the single flash power plant.

2.1.3.2.5. Cooling tower process

The cooling tower process is the same as that of the single flash power plant only there has to be a larger cooling tower to reject more heat as there is more steam.

2.1.3.3. Power plant with backpressure turbine

This type of power plant is also a steam cycle and also very similar to the single flash power plant. The difference is that the turbines exhaust is to the atmosphere not to a condenser. This means the exhaust pressure and temperature is higher and the power output is much lower, about a third less than it would be for a condensing unit, but on the other hand this type of power plants are more simple and with lower cost than the condensing units because they don´t have condensers and cooling towers. The energy conversion process is the same as that of a single flash power plant only it ends at the turbines outlet; there is no condensing process and no cooling tower process.

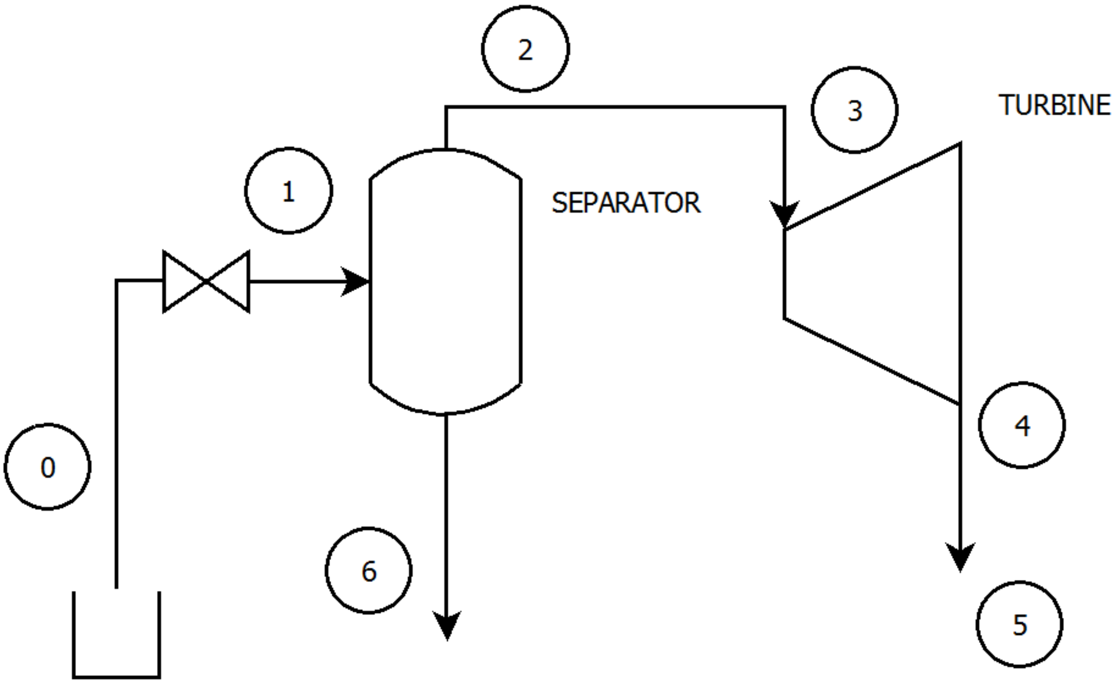

Figure 21: Simplified process flow diagram of a backpressure power plant.

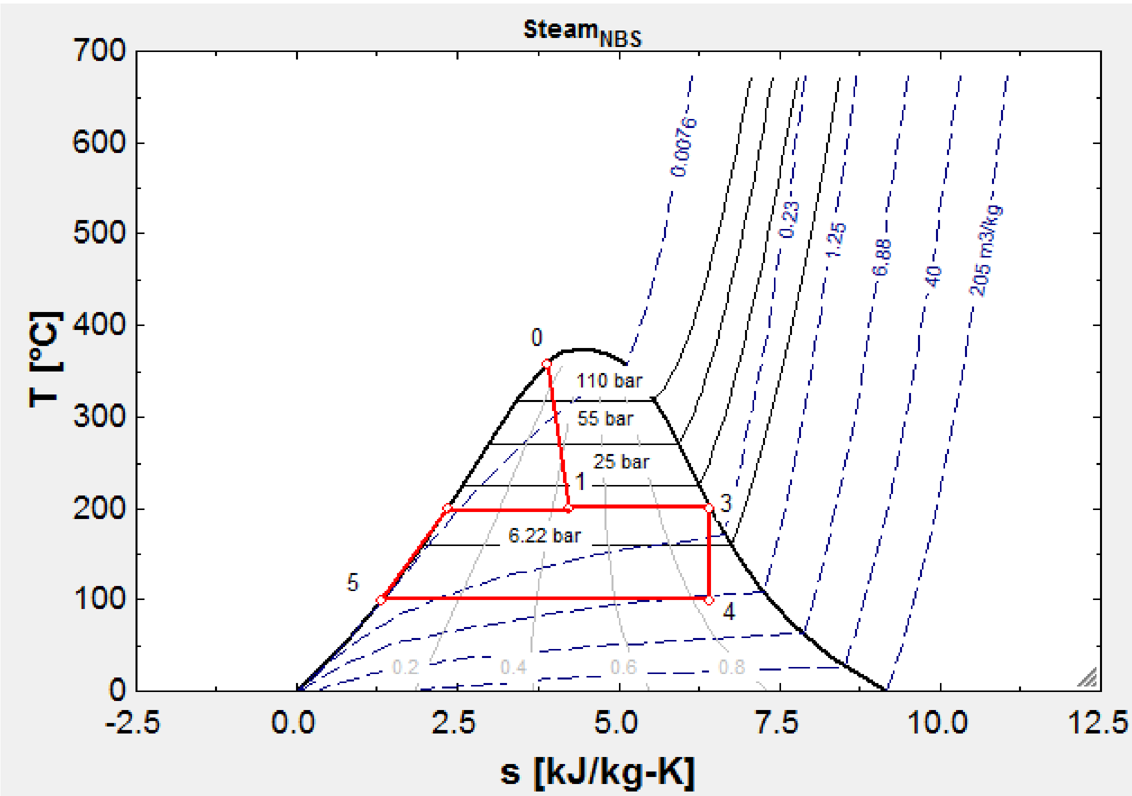

Figure 22: Temperature-entropy (T-s) diagram showing stages of a backpressure power plant.

2.1.3.3.1. Flashing process

The same as the single flash power plant

2.1.3.3.2. Separation process

The same as the single flash power plant

2.1.3.3.3. Turbine expansion process

The same as the single flash power plant, the only difference is the outlet pressure of the turbine is atmospheric pressure.

2.1.3.4. Binary Power Plant

The main difference between a binary power plant and a steam cycle plant is that the geothermal fluid does not come in contact with the turbine, that is done by using a working fluid that is heated by the geothermal fluid through a heat exchanger, then the working fluid is condensed and returned to the heat exchanger in a closed cycle by means of a feed pump, the geothermal fluid is returned after the heat exchanger.

The equations and variables describing the processes of the binary power plant refer to Figure 23 and Figure 24.

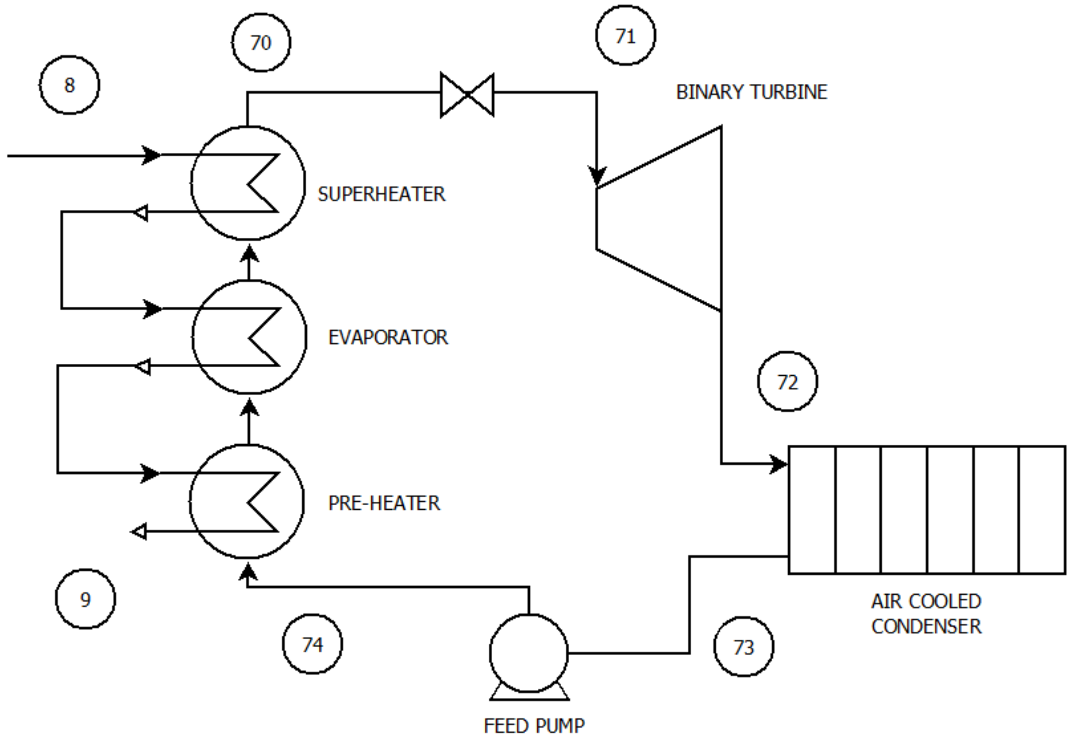

Figure 23: Process flow diagram of a binary power plant

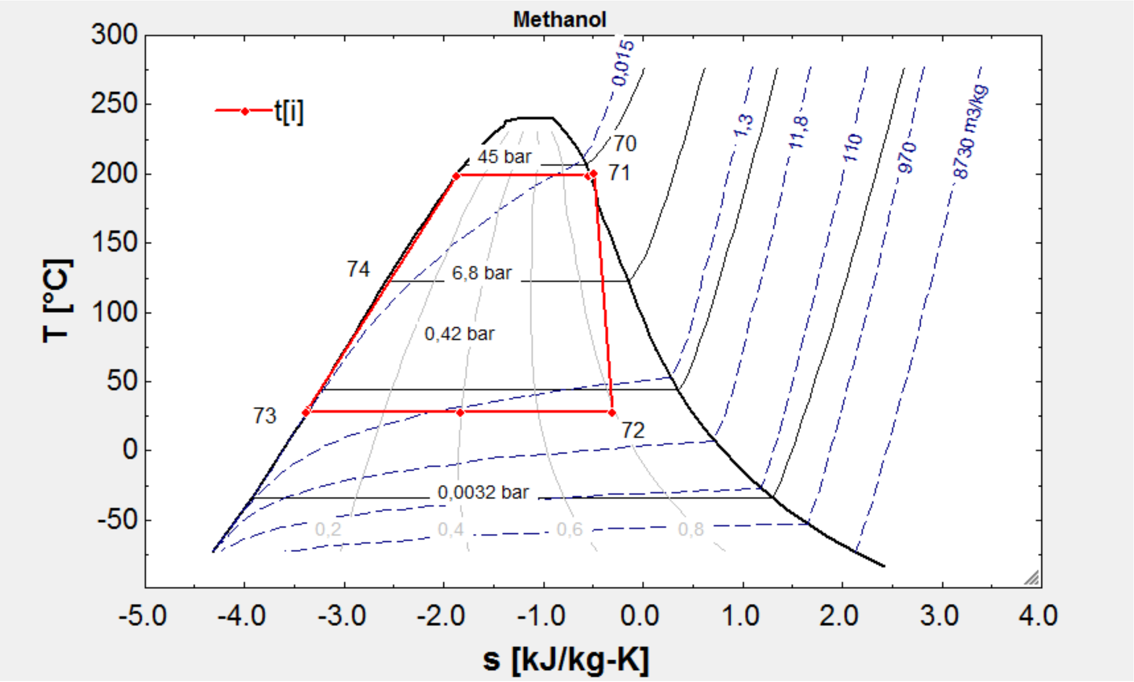

Figure 24: Temperature-entropy diagram of a geothermal binary power plant with methanol as the working fluid.

2.1.3.4.1. Heat exchanger process: preheater and evaporator

This process is where the geothermal fluid transfers some of its heat to the working fluid through a heat exchanger. We assume this process to be adiabatic, so the analysis can be simple using the basic principles of thermodynamics and mass conservation.

Energy balance:

$$\dot{m}_8 h_8 + \dot{m}_{74} h_{74} = \dot{m}_9 h_9 + \dot{m}_{70} h_{70} \qquad (27)$$

State numbers on the variables in equations (27) refer to Figure 23.

In this thesis the mass flow of geothermal fluid can be determined from the productivity curves of the wells in Table 1.

To better understand the process in the heat exchangers it is required to use a Temperature-heat transfer diagram (T-Q diagram) (see Figure 25). A preheater is used to raise the working fluid temperature to the boiling point (state 2), then the working fluid starts to evaporate from state 2 through state 3, from state 3 to state 4 the working fluid enters a superheater to raise the temperature before entering the turbine. It is important that the temperature of the geothermal fluid is always greater than the temperature of the working fluid. The point where the difference in temperature between the geothermal fluid and the working fluid is the minimum is called the pinch point. This pinch point is usually provided by the manufacturer and the temperature at state 2 of the working fluid is also a known value, so it is possible to calculate the mass flow of the working fluid which is then necessary for the calculation of the power of the turbine, this mass flow is also needed to calculate the size of the condenser and of the pump.

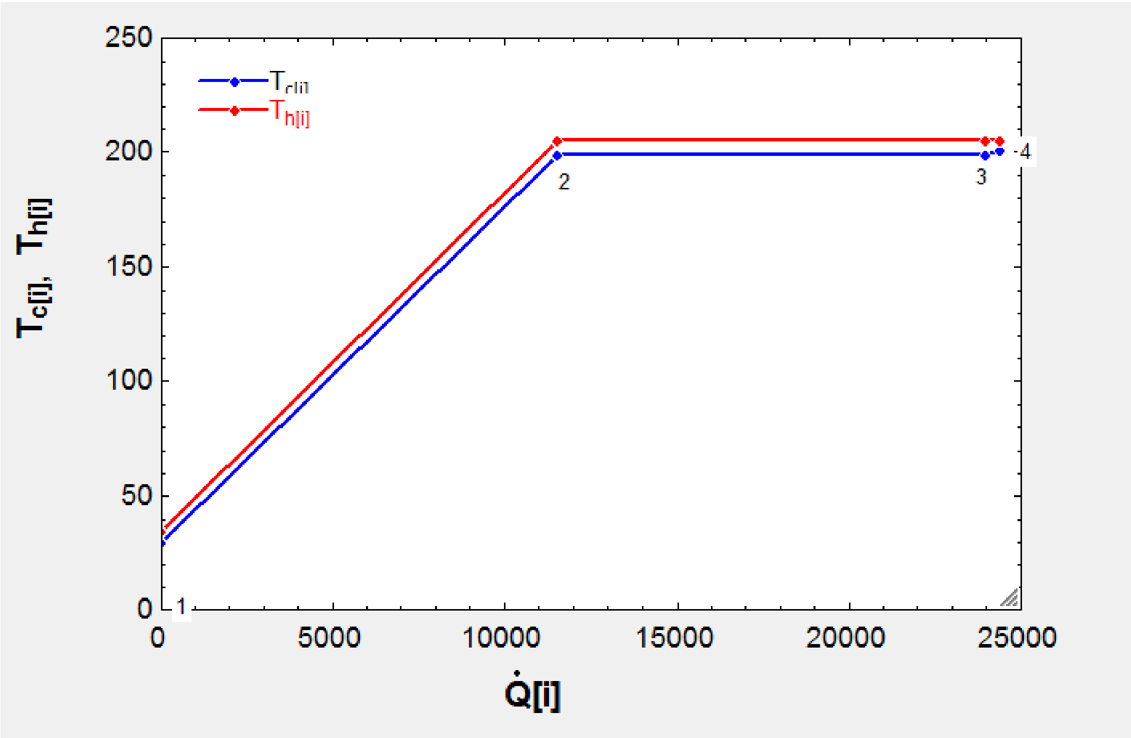

Figure 25: T-Q diagram heat exchanger binary plant with methanol

2.1.3.4.2. Turbine expansion process

The analysis of the binary turbine is the same as for a steam turbine and the work can be calculated in the same way:

$$\dot{W}_{t\ binary} = \dot{m}_{71}(h_{71} - h_{72}) * \eta_t \tag{28}$$

2.1.3.4.3. Condensing process

The analysis of this process is also the same as with steam cycles, the heat of the steam from the turbine must be rejected from the working fluid to a cooling medium, this cooling medium can be water or air. In this thesis the cooling medium used for the binary power plant is air. Here it is also important to look at a T-q diagram (see Figure 26), the working fluid comes out of the turbine at state 5, the air temperature is known and in this thesis is 15^{o}C. The analysis of the condensing process can be done with an energy balance and a mass balance of the condenser.

Energy balance:

$$\dot{m}_5 h_5 + \dot{m}_{air\ in} h_{air\ in} = \dot{m}_7 h_7 + \dot{m}_{air\ out} h_{out} \qquad (29)$$

Mass balance working fluid:

$$\dot{m}_8 = \dot{m}_9 \qquad (30)$$

Mass balance air:

$$\dot{m}_{air\ in} = \dot{m}_{air\ out} \qquad (31)$$

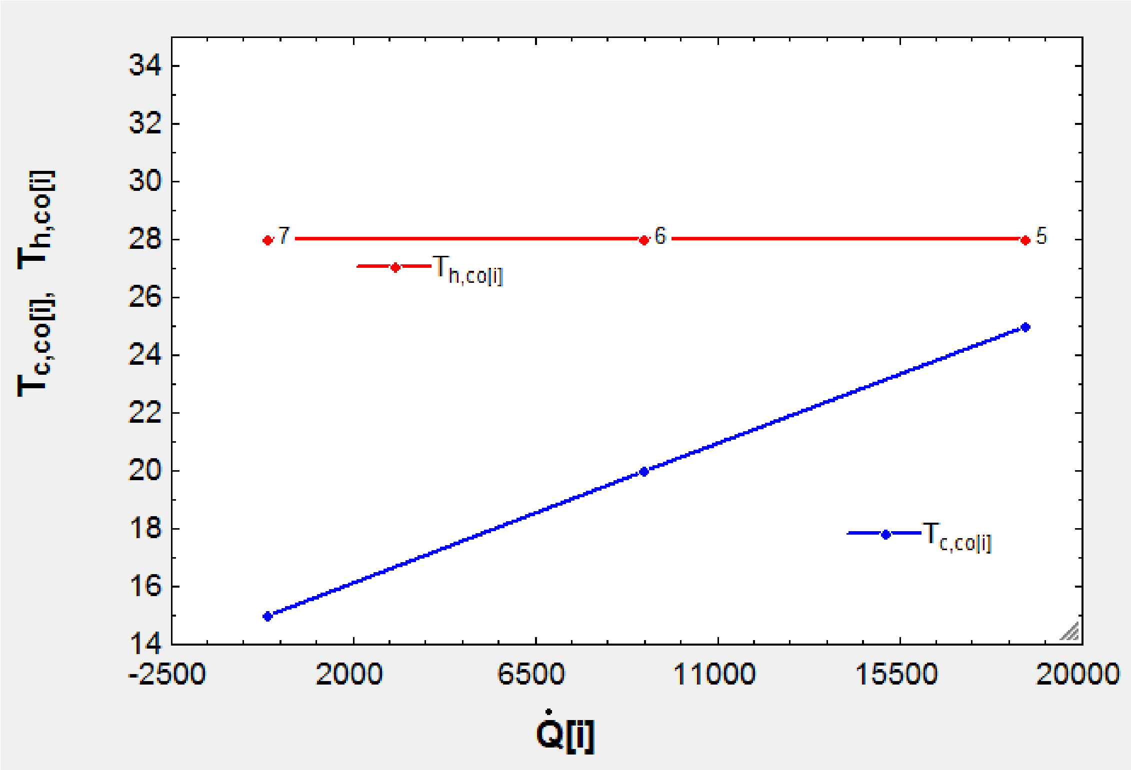

Figure 26: TQ diagram of condenser in the binary power plant (methanol)

2.1.3.4.4. Feedpump analysis

As the binary cycle is a closed cycle there is the need of a pump to get the working fluid, after it is condensed, to the desired pressure in the preheater, this pump is called the feedpump. It is important to calculate the power of the feedpump as this is an important parasitic load of the power plant to be able to calculate the net power of the power plant.

It is a very important decision in the design of a binary power plant to choose the appropriate working fluid. There are many choices available for working fluids and many constraints regarding thermodynamic properties as well as for safety, health and environmental reasons. In this thesis the working fluid chosen for the binary power plant is methanol and the reason for this choice is because the temperature of the geothermal fluid used to heat the working fluid is coming at a temperature close to 200^{o}C and it is important to use a working fluid that has a critical point above the temperature of the geothermal fluid, the critical point of methanol is: 240^{o}C at 78.5 bar abs.

2.1.4. Comparison of central power plants and wellhead power plants

Geothermal steamfields can have wells within large areas, this makes some wells to be located very far from each other, a question arises, install a power plant next to each well or transport the geothermal fluid from several wells to a larger central power plant. The answer to which one is a better option is not always a simple one, there are many factors that affect which decision to make: topography, conditions of the geothermal fluid, and many others, but a very important one is costs and which option would be a more profitable investment. That is part of the objective of this thesis, to find options of making geothermal projects feasible by incorporating the use of wellhead power plants. It is important to define these two options:

The exploitation of a geothermal steamfield for the production of electricity can be done in two ways (Hiriart Le Bert, 1986):

- Collecting the geothermal fluid from several wells into a single power plant, in what is called a "steam gathering system". This option is called "central power plant" (see Figure 27).

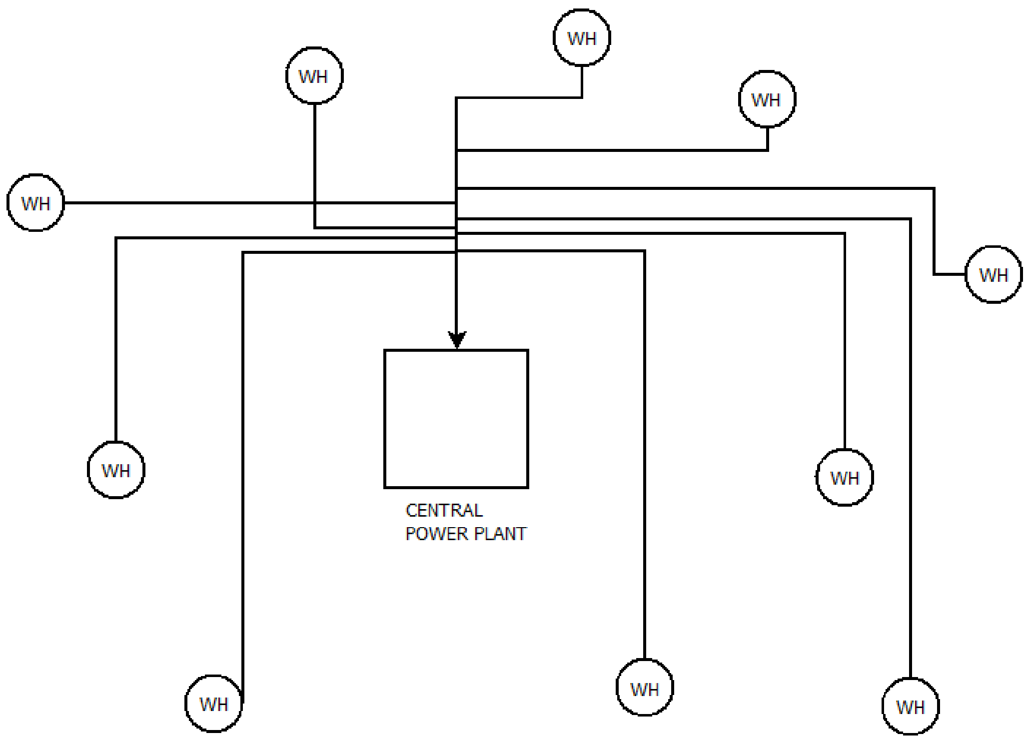

Figure 27: Schematic layout of a central power plant

Where WH in Figure 27 represents each wellhead.

- Installing next to each wellhead a small power plant, this option is called a "wellhead power plant" (see Figure 28)

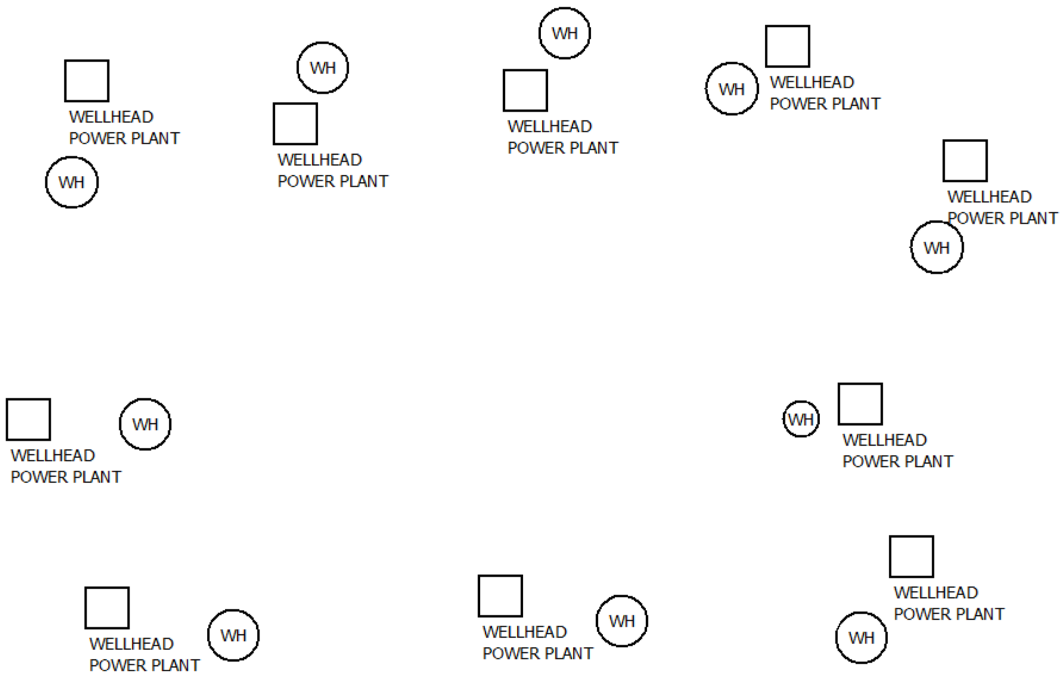

Figure 28: Schematic layout of wellhead power plants.

Where WH in Figure 28 represents each wellhead.

2.1.4.1. Central Power plants with combined flow from several wells (Conventional method)

The central power plant power plants have several advantages, some of which are:

- economies of scale
- Components are designed to the optimum for the steam conditions of the entire steamfield.

Disadvantages:

- Long time to get power output, mainly because the design of the components begins until most of the wells are drilled and tested.
- As the steam for the power plant is from a steam field with several wells, the gathering system has to balance the steam from all the wells and the design

pressure going into the power plant is that of the well with the lowest pressure, this way it might be less efficient for the high pressure wells.

2.1.4.2. Wellhead power plants

The advantages of wellhead power plants are:

- As they use steam from only one well you don't have to wait for all the wells from the steamfield to be drilled and tested, this allows for the power plant to start producing energy at an earlier timescale than a traditional power plant.
- There is no need for a large steam gathering system, this reduces the pressure drops in the piping system and also lead to important savings in the project.
- Wellhead power plants can be used to produce energy from remote wells in a steamfield, as it is not practical to transport high temperature two phase mixtures or steam over long distances.
- Because wellhead power plants use steam from one well, this could allow them to produce optimum power from each well regardless of their differing outputs and conditions.
- In the case of a technical problem with any of the components in the power plant, only the energy from few wells would be suspended and not of the entire steamfield.
- Wellhead power plants could be used also to produce energy from those wells that are either in the high or the low end of the pressure and enthalpy in a given steamfield, so that the energy from the best wells in the steamfield is not lost. Or in the case of the low pressure wells, sometimes this wells are discarded in a central power plant because they would lower the pressure at which the rest of the wells would be utilized, so by using a wellhead power plant this low pressure wells could produce some energy without sacrificing the rest of the steamfield.
- Wellhead power plants are more easily transportable, making them a better option for cases in which they are going to be used temporarily.

Some disadvantages of wellhead power plants are:

- Lower turbine efficiencies.
- Longer transmission lines from each wellhead power plant as they are scattered throughout the steamfield.
- Higher cost per kW installed, because of smaller sizes.
- More cost in transformers and related equipment.
- A separation station for each power plant instead of having only one in the central power plants.

In this thesis the turbine efficiency of the wellhead power plants is considered to be 20% less than the turbine efficiency of the central power plants.

2.2. Definition of the scenarios

The scenarios considered in this thesis were 3 main scenarios. One in which a type of power plant was installed from the beginning and stayed through the entire planning horizon, this scenario is called the permanent scenario; another scenario where a combination of power plants was used in sequential form: wellhead power plants in the early stage of the project and a central power plant after that. And a final scenario where the two types of power plants are used simultaneously, this is called a complementary scenario. Each one of these 3 scenarios has combinations of different types of power plants (see Table 3), in all 10 scenarios were created.

All the scenarios utilize the geothermal fluid from the hypothetical steamfield created in section 2.1.1.

Main assumptions of all scenarios

- Pressure drops in the power plants pipelines are not considered
- Same type of components where applicable: i.e. vertical separators, axial centrifugal pump, direct contact condenser, induced counter flow cooling towers.
- Same dry bulb temperature and wet bulb temperature
- Same steamfield.
- Installation times are considered equal for all scenarios, the time difference (TD) considered in this thesis is determined by the time taken to drill the necessary wells to start production for each type of power plant: wellhead or central.

- Non-condensable gases extraction systems not considered.
- No thermal losses considered
- No changes in potential or kinetic energy considered.

Assumptions for the Central power plants (scenarios using the geothermal fluid from several wells)

- The separator pressure was calculated using the geothermal fluid from all the wells in the hypothetical steamfield.

Assumptions for the Wellhead power plants:

- The separator pressure is calculated for each power plant depending on the properties (productivity curve and enthalpy) of each well. This is done to show the theoretical potential of those power plants, although wellhead power plants are not custom built now.
- The order in which the wells are drilled is considered to begin with well number 1 and end with well number 10. This is relevant in the case where the wellhead power plants are considered because each well has different power outputs. In a sensitivity analysis the results are calculated in the reverse order to show the "worst case".
- The time to install each wellhead power plant after the first one is installed was considered to be 3 months.

Double flash scenarios:

- One dual pressure turbine.

Table 3: Scenarios

	Scenario number	**SCENARIOS**
Permanent	1	Single flash Traditional power plant with condensing turbine
	2	Double flash Traditional power plant with condensing turbine
	3	Wellhead power plant as a permanent option with condensing turbine
Wellhead power plant in early stages of project	4	Wellhead power plant w/condensing turbine and traditional power plant after all wells are drilled and tested
	5	Wellhead binary power plant and traditional power plant after all wells are drilled and tested
	6	Wellhead power plant w/backpressure turbine and traditional power plant after all wells are drilled and tested

	Scenario number	SCENARIOS
Complementary	7	Wellhead power plant for high pressure wells w backpressure equal to inlet pressure of traditional PP/traditional PP for rest of wells.
	8	Wellhead PP w/condensing turbine for low pressure wells. Traditional PP for rest of wells
	9	Wellhead binary PP for low pressure wells. Traditional for rest of wells
	10	Wellhead PP with backpressure turbine for low pressure wells and traditional PP for rest of wells

2.2.1. Permanent scenario

In this scenario there are 3 options; in this scenario the power plants are going to be installed in a permanent basis. The first two options: the single flash central power plant and the double flash power plant are the traditional arrangements; these were considered as a reference to compare the other scenarios.

In this scenario the backpressure turbines and the binary power plants are not considered. The backpressure option was not considered because the lower power output over the long run would not make it an attractive option, this option is more suited for temporary use. The binary option is not considered because of its high capital and O&M costs; and also because it is usually considered an option for low temperature and low pressure steamfields (see Figure 11). The options which were calculated are:

2.2.1.1. Scenario (1) single flash traditional power plant with condensing turbines

This is the base scenario against which the other scenarios were compared.

In this scenario the geothermal fluid from all the wells were used in a central power plant arrangement as mentioned in section 2.1.4.1.

The power plant is considered to be installed once all the wells in the steamfield are operational.

2.2.1.2. Scenario (2) double flash traditional power plant with condensing turbines

As with the previous scenario, this would start production once all the wells in the steamfield are operational.

2.2.1.3. Scenario (3) wellhead power plant with condensing turbine

The energy conversion cycle of this power plant is the same as for the single flash power plant; the only difference is that this power plant is a wellhead power plant (see 2.1.4.2). In this scenario one such power plant was considered for each of the wells in the hypothetical steamfield. The power production in this scenario is considered to start after each well is drilled and tested, this being the main difference between this scenario and the previous scenarios.

The advantage of this scenario compared to the central power plant is that the wellhead power plants can start production of energy and revenue as each well is drilled and tested instead of having to wait for most of the wells in the steamfield to be drilled and tested.

2.2.2. Wellhead power plant in early stages of project

In this scenario wellhead power plants were installed after each well is drilled and tested, once the complete steamfield is drilled and tested the conventional power plant was installed.

The time interval between the start and the end of the drilling stage can take several months and in some cases even years. When the conventional power plant is ready to be operated the wellhead power plants would be decommissioned, this means the wellhead power plants will be temporary and that should be kept in mind. Because of the temporary nature of the use of the wellhead power plants in this scenario it is important that these are portable in order for them to be reused for other wells. In this scenario a wellhead single flash power plant with condensing turbine is used, a backpressure turbine, which although does not produce as much electricity as the condensing type, are easier to move once the conventional power plant is ready to be installed. Also a binary power plant is considered in this scenario.

As mentioned in section 2.1.4.2, one important advantage of wellhead power plants is that they can produce optimum power from each well; in these scenarios the separator pressure was calculated to optimize power output for each well.

An important factor in this scenario is to consider a salvage value or scrap value of the wellhead power plants for the calculations of the net present value; this will be further discussed in the cost estimation section 2.3.1.

2.2.2.1. Scenario (4) single flash wellhead power plant with condensing turbine

In this scenario single flash wellhead power plants would be installed after each well is drilled and tested.

2.2.2.2. Scenario (5) binary wellhead power plant

In this scenario the wellhead power plants installed were binary power plants using methanol as working fluid.

2.2.2.3. Scenario (6) single flash wellhead power plant with backpressure turbine

Backpressure turbines are the simplest type of power plants and the cheapest, although they produce less energy than a power plant with condensing turbines.

2.2.3. Complementary scenario

The complementary scenario is divided in four scenarios, in the first scenario (section 2.2.3.1) the wellhead power plants were installed to utilize the geothermal fluid from the high enthalpy wells and in the latter three scenarios (sections 2.2.3.2, 2.2.3.4 and 2.2.3.3) the wellhead power plants utilize the geothermal fluid from the low enthalpy wells.
The high enthalpy wells in the hypothetical steamfield are wells 1, 2 and 3 and the low enthalpy wells are wells 8, 9 and 10 (see Table 1). The rest of the wells are utilized in a single flash central power plant.

2.2.3.1. Scenario (7) wellhead power plant with backpressure turbine for high pressure (HP) wells and traditional power plant with condensing turbine for the rest of the wells

In this scenario the wellhead power plant was used to produce electricity from the wells with the higher pressure and higher enthalpy and then the geothermal fluid from these wells was used in another cycle together with the geothermal fluid from the rest of the wells (medium pressure power plant) from the steam field (see Figure 29). This can help the overall power production of the steamfield because in this way the complementary wellhead power plant would be producing the optimum amount of energy from the high pressure wells.

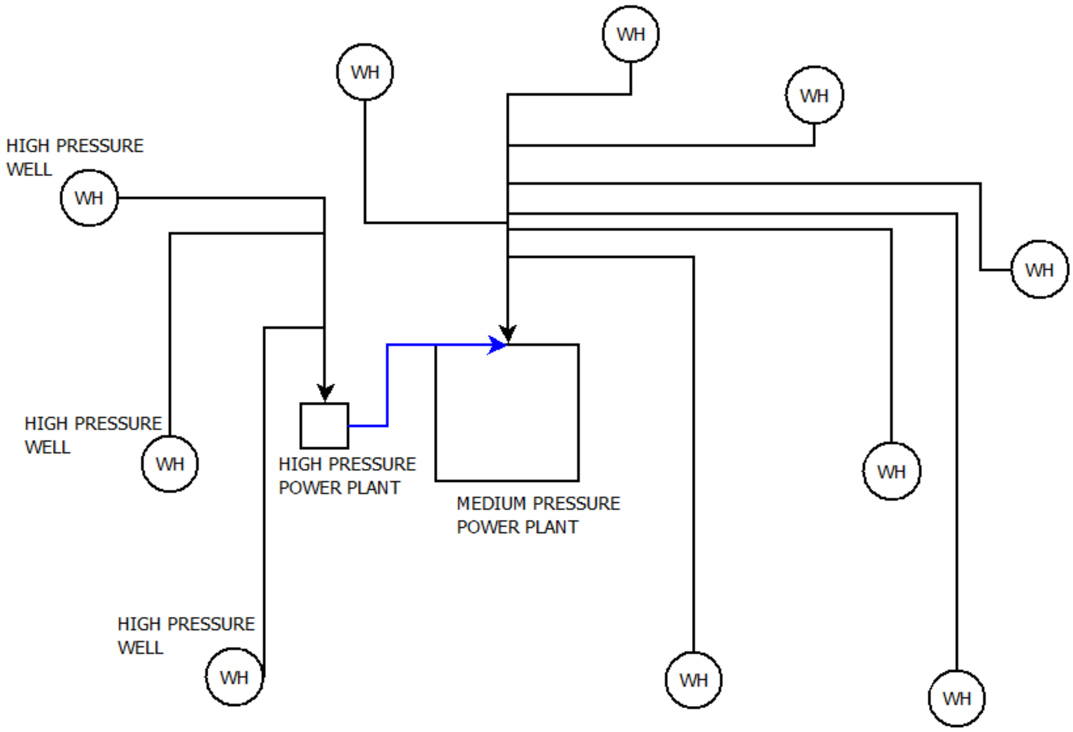

Figure 29: Schematic layout of complementary scenario 7

Where WH in Figure 29 is each wellhead in the hypothetical steamfield.

Also, as the wellhead power plant was installed as a complementary power plant with another power plant that uses the rest of the wells, the outlet pressure for this complementary power plant has to be the separator inlet pressure for the "medium pressure separator", so in the arrangement for this scenario the wellhead power plant would not be condensing at a low pressure (see state 4 in Figure 30).

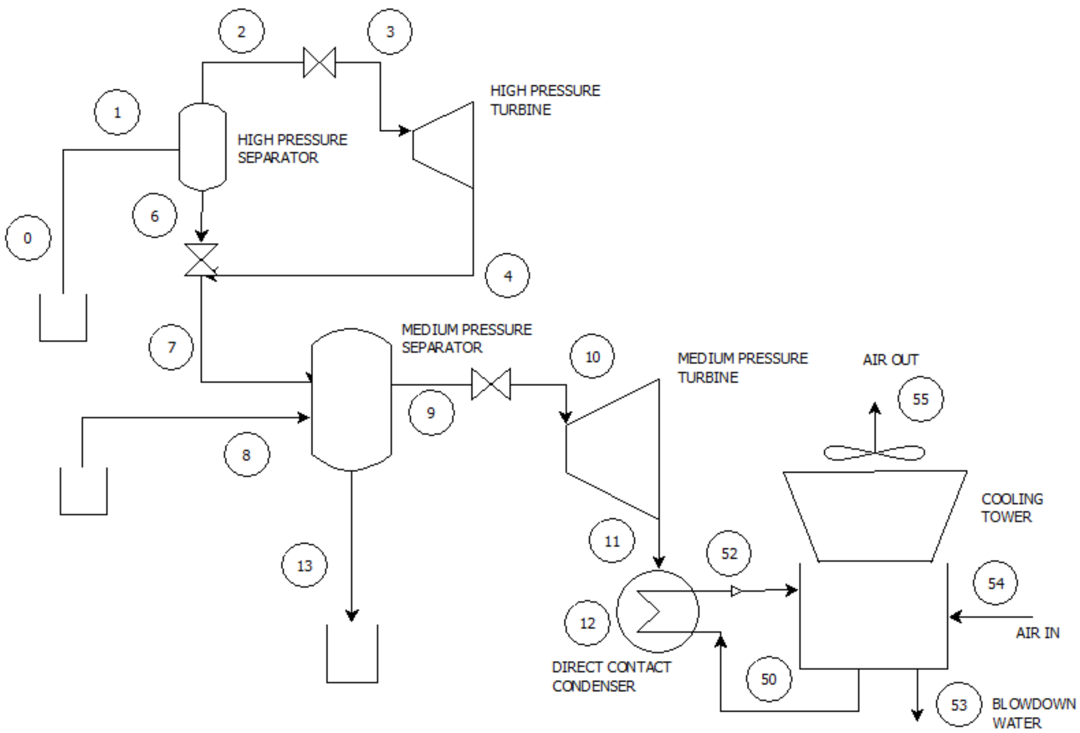

Figure 30: Simplified process flow diagram of a complementary power plant for high enthalpy and high pressure wells.

In this scenario, as the wellhead power plant is using the geothermal fluid from the high pressure and high enthalpy wells and the binary power plants are better suited for low temperature and low enthalpy wells this option will not be considered.

2.2.3.2. Scenario (8) single flash wellhead power plant with condensing turbine for low pressure wells and traditional power plant for rest of wells.

In this scenario the wellhead power plant was installed separately of the power plant where the geothermal fluid of the rest of the wells would be utilized. The reason is because in the power plant were the rest of the wells would be utilized it would be best to use condensing turbines so the outlet pressure from this power plant would be too low to be utilized again, making it impossible to use in the wellhead power plants installed for the low pressure wells (see Figure 31). The expected benefit for the arrangement in this scenario would be that the power plant that uses the geothermal fluid from the higher pressure (rest of wells) wells can be designed for a higher pressure and therefore produce more power overall.

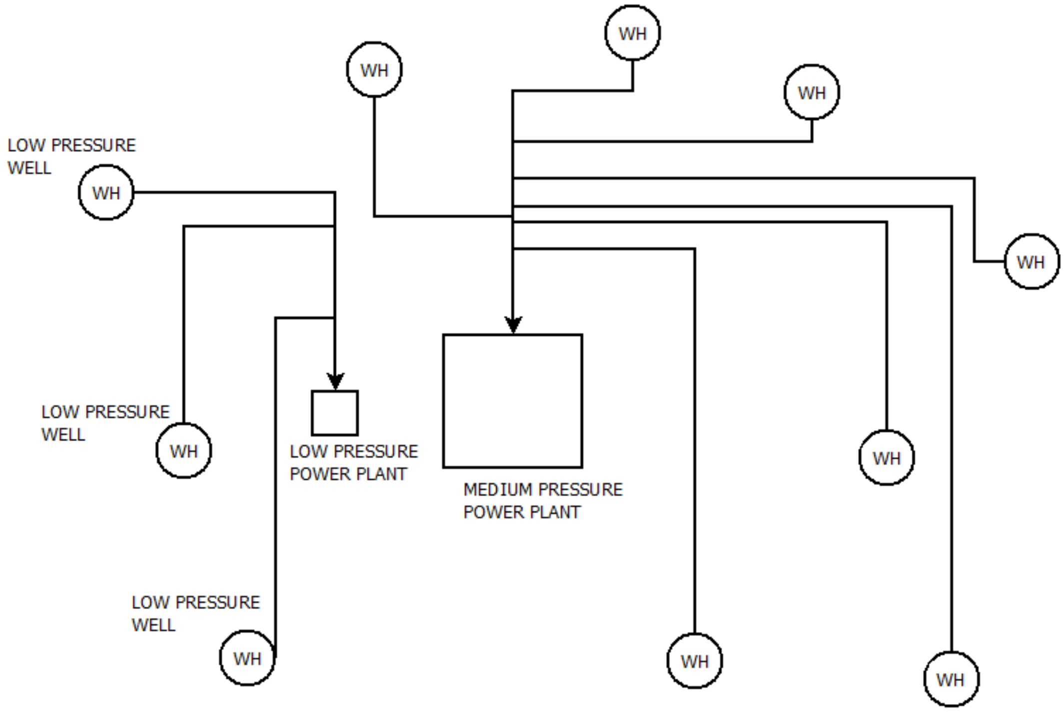

Figure 31: Schematic layout of complementary scenarios 8, 9 and 10.

Typically what happens now in steamfields is that the low pressure wells are discarded as “dead” so as not to lower the pressure of the rest of the wells in the steamfield, but if this low pressure wells could be exploited in independent wellhead power plants some energy could be extracted from them without any adjustments to the central power plant.

In this scenarios, the wellhead power plants with condensing turbine, a wellhead binary power plant and a wellhead with backpressure turbine are considered.

2.2.3.3. Scenario (9) binary wellhead power plant

The same arrangement as the previous scenario but with wellhead binary power plants for the low pressure wells.

2.2.3.4. Scenario (10) single flash wellhead power plant with backpressure turbine

The same arrangement as the previous scenario but with wellhead power plants with backpressure turbines for the low pressure wells.

2.3. Cost and Revenue Estimation Method

A cost estimate is an approximation of the cost of a project. Cost estimates are classified depending on the level of accuracy needed and the amount of information available. One of the most used classifications of cost estimates is shown in the following table:

Table 4: Cost Estimate classification(U.S. D.O.E., 2011)

Cost Estimate Classification	Level of definition (% of complete definition)	Cost estimating description (techniques)
Class 55, Order of magnitude	0% to 2%	Stochastic, most parametric, judgment (parametric, specific analogy, expert opinion, trend analysis)
Class 4, Intermediate	1% to 15%	Various, more parametric (parametric, specific analogy, expert opinion, trend analysis)
Class 3, Preliminary	10% to 40%	Various, including combinations (detailed, unit-cost, or activity-based; parametric; specific analogy; expert opinion; trend analysis)
Class 2, Intermediate	30% to 70%	Various, more definitive (detailed, unit-cost, or activity-based; expert opinion; learning curve)
Class 1, Definitive	50% to 100%	Deterministic, most definitive (detailed, unit-cost, or activity-based; expert opinion; learning curve)

For this thesis an "order of magnitude" cost estimate was used, this means that the cost is used only for feasibility purposes, at this level there is not a lot of information available and cost has to be estimated by using various techniques such as factoring, where you take the cost of a similar facility and factor the cost for size; you also rely on opinions from experienced people; historic data, rules of thumb and some simple mathematical calculations.

There is an important concept to take into account when estimating costs: economy of scale.

Economy of scale refers to the idea that "bigger is cheaper" per unit output. In quantitative terms:

$$\left(\frac{C_i}{K_i}\right) = \left(\frac{C_0}{K_0}\right)\left(\frac{K_i}{K_0}\right)^{n-1} \qquad (32)$$

Where:

C_i is the cost of the unit of size i

C_0 is the cost of the reference unit

K_i is the size or rating of unit i

K_0 is the size or rating of the reference unit

n is the scale exponent

Costs of geothermal projects are divided in two: capital cost and operations and maintenance costs (O&M). Capital cost is the amortization of the initial investment and includes all the costs of the different stages of development of a geothermal project: Exploration, resource confirmation, drilling and reservoir development, plant construction and finally power production (Cross and Freeman, 2009). O&M costs are only incurred in the power production stage.

Since this thesis focused on the comparison of different types of power plants on an already defined hypothetical steamfield the initial stages of development of a geothermal project were not considered, that includes: exploration, resource confirmation and drilling and reservoir development. The main interest of this study was the plant construction and power production stages. For this reason the costs considered for the power plant options discussed this thesis were:

- Cost of power plant
- Cost of operation and maintenance of a geothermal power plant (O&M)
- Cost of transmission lines, this were used for the wellhead power plants
- Cost of steam gathering system, this was used for the central power plants

As the focus of this thesis were the differences between central power plants and wellhead power plants and although transmission lines and steam gathering systems are a part of both wellhead and central power plants, for this thesis the transmission lines are only considered for the wellhead power plants and the steam gathering system is considered only for the central power plants. The costs of transmission lines and the cost of the steam gathering system are not considered to be affected by economies of scale for this thesis.

Capital costs of geothermal projects are very site and resource specific and there are many factors that affect projects, the characteristics of the resource, the topography of the steamfield, the weather conditions and land ownership, this explains why the costs of geothermal projects vary from site to site, as well as the cost of financing.

The costs considered in this thesis were “overnight costs”, this is as if the power plants were completed overnight.

All costs are per kW, except cost of operation and maintenance which are per kWh. The currency used is US dollars (USD).

2.3.1. Cost of power plant

From confidential communication with industry participants it was found that the cost of a geothermal single flash power plant of 5 MW with condensing turbine was 1,700 USD/kW, in the case of the binary power plant the capital cost is considered 34.85% higher (Hance, 2005) than the flash steam power plant and the back pressure power plant is considered to be 1,500 USD/kW for the 5 MW power plant (Long and Harvey, 2012). These costs include: steam separators, well conection, civil works, electric and mechanical installations, switches and controls, generator and everything needed to have the power plants running. To account for economies of scale, the following equation was used (Sanyal, 2005):

$$CC = CPP * e^{-0.0025(P-5)} \qquad (33)$$

Where CC is capital cost in USD/kW, CCP is the cost per kW of the power plant, depending on the type of power plant (flash, binary or backpressure) and P is the gross power output of the power plant.

It is important to consider in scenarios 4, 5 and 6, where the wellhead power plants are installed in the early stages of development while the central power plant is being built, that a resale value is to be included. The only information found on some resale value for wellhead power plants was in a case where the wellhead power plant is assumed to be sold after 10 years for 40% of its initial value(Long and Harvey, 2012) and another where it is mentioned that wellhead power plants claim to have a scrap value of 70% (Elíasson and Smith, 2011). Because the resale value was calculated for a much shorter time than the cases mentioned (between 6- 24 months), for this thesis the resale value considered is 90%. The resale value was considered at the same time that the central power plant is installed and in the calculations it was considered as a negative investment.

2.3.2. Cost of operation and maintenance

This is the cost once electricity production starts, and it is also affected by economies of scale. For this thesis the following equation was considered (Sanyal, 2005):

$$C_{o\&m} = 2 * e^{-0.0025(P-5)} \qquad (34)$$

Where $C_{o\&m}$ is the cost of operation and maintenance (O&M) in US cents/kWh and P is the gross power output of the power plant.

This assumes a O&M cost of 2 US cents per kWh for a 5 MW single flash power plant in 2005, but after analyzing more recent data it was found that O&M costs have declined over the last decade (Entingh and McVeigh, 2003) and even in some cases the cost considered in recent papers is lower: 1.6 US cents per kWh (Long and Harvey, 2012) , it was decided to use 2 US cents per kWh and only in the case of the binary power plant consider an additional 35% in the O&M costs according to personal communication with people in the industry.

2.3.3. Cost of transmission lines

The transmission lines considered in this thesis are the ones that travel from each wellhead power plant to the central transformer station, in this we do not consider the transmission lines to the grid.

The cost of transmission lines considered for this thesis is: 100 USD/kW (Hance, 2005)

2.3.4. Cost of steam gathering system

This is the cost of the steam gathering system that transports the steam or two-phase geothermal fluid from the wells in the steamfield to the central power plants, the steam gathering system inside the power plants is not considered in this thesis. This cost can vary a lot between steamfields since it depends mostly on the length of the pipelines. From research done on the cost of geothermal projects it is considered that the cost of the steam gathering system is: 250 USD/kW (Hance, 2005)

2.3.5. Revenue estimation

Together with the cost estimation results it is important to calculate an estimate of the revenues from each of the power plants according to the net power output calculations, in order to do that the power output results are converted to energy produced during one year using a capacity factor:

$$\frac{Revenue}{year} = net\ power\ output * 365 * 24 * c.f. * price \qquad (35)$$

Where c.f.= capacity factor

Net power output= gross power output – parasitic loads

Price=the price of electricity, in this thesis the price considered is 0.1 USD/kWh

For this study the capacity factor considered for all the power plants was 90% which is well in the range of geothermal power plants (see Figure 32).

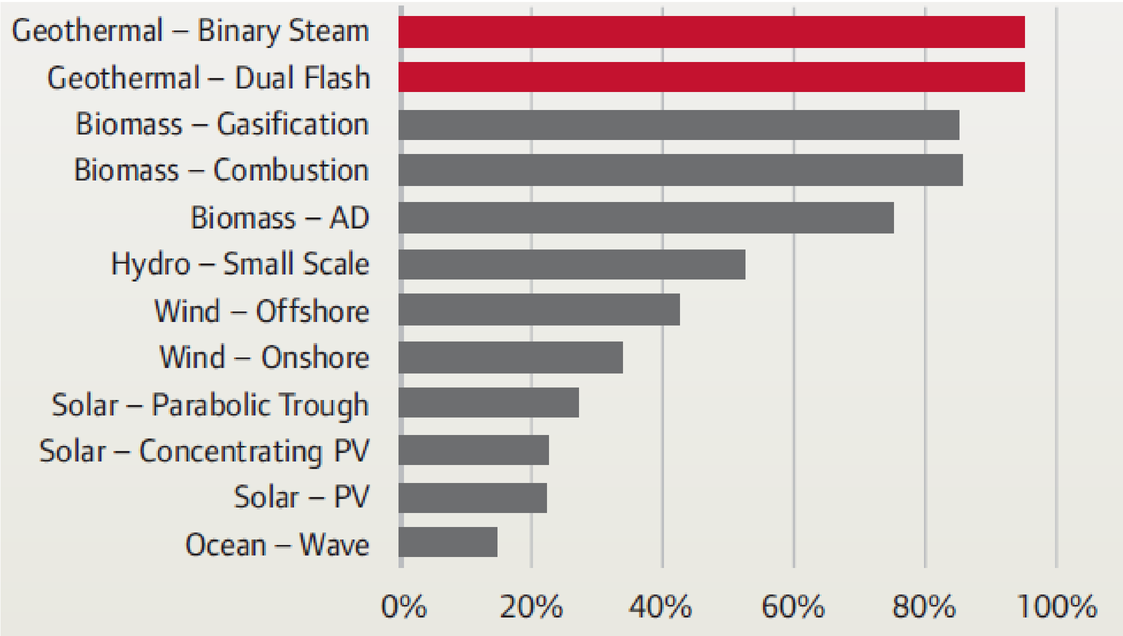

Figure 32: Capacity factors of selected renewable energy sources (Islandsbanki, 2011).

2.4. Calculation of time before energy production starts

Geothermal projects are known to take a long time to start production, approximately 5 years (Islandsbanki, 2011). The stages of a geothermal project development are (Cross and Freeman, 2009):

- Exploration
- Resource confirmation
- Drilling and reservoir development
- Plant construction
- Power production

As shown in Figure 3, the first three stages have greater risks so it is very difficult to have accurate time estimations of their completion.

This thesis focuses on the power plant construction stage of a geothermal project, the time it takes to complete the first stages of development of a geothermal project: Exploration, resource confirmation, drilling and reservoir development are not considered.

There is no significant difference in lead time between the wellhead and central power plants considered (Long and Harvey, 2012). The lead time considered in this study will

be the time it takes between the moment you order a power plant and the time it is installed.
The objective of this section is to calculate the time difference (TD) a wellhead power plant can start production before a central power plant starts production. This was achieved by focusing on the time it takes to drill each well and the fact that the installation of a wellhead power plant can be done once each well is drilled and tested and a central power plant has to have all of the wells drilled and tested to be installed.

The time it takes to drill one well is considered to be:
43.5 ± 5.5 days (Thorhallsson and Sveinbjornsson, 2012)
This time is assumed to follow a normal distribution.
Time to test the wells: 3 months ≈ 90 days (Thorhallsson, 2012)

The time was calculated in the following way:

WHT= Time to drill 1 well with a (95% certainty) + time to test the wells
CT== Time to drill 10 wells with a (95% certainty) + time to test the wells

And then
TD = CT- WHT

Where WHT is the time for a wellhead power plant to start production and CT is the time for a central power plant to start production.
In the 10 scenarios the TD is the same.

2.5. Net Present Value calculation method

The analysis in this thesis is focused on the differences of each of the scenarios created in section 2.2, it was considered that a Net Present Value calculation was the best option to compare all the scenarios and determine which was better with regards to a financial aspect.
The Net Present Value (NPV) is a method that brings future cash flows to present values using a given discount rate, the formula to do that is:

$$NPV = \sum_{i=0}^{n} \frac{CF_i}{(1+dr)^i} \qquad (36)$$

Where i is the time of the cash flow which is divided in periods, CF_i is the cash flow of the period, dr is the discount rate for the period.

The discount rate is a key variable of this process and is a measure of the difference in value an investor puts on money in the present vs. the future.

The net present value was calculated creating cash flows of the different scenarios. Negative cash flows are investment costs and O&M costs; and positive cash flows are revenues. The planning horizon considered is 20 years fixed from the start of production of the wellhead power plants. The start of production of the central power plants start after the TD calculated. The cash flows were divided into quarterly cash flows; this is that cash flows are calculated for periods of 3 months each, this means there are 80 periods in this NPV analysis. The discount rate used for these calculations was 16% per year. In this thesis inflation was not considered.

Cash flows for the wellhead power plants start in the first period and the central power plants start after the time difference (TD) calculated in section 2.4.

2.6. Sensitivity analysis.

The calculations of the net present value were done considering the following factors as the most relevant:

1. Time between the start of production from wellhead power plants and central power plants: TD.
2. Order in which the wells were drilled: The first well to start production was well 1, then well 2, and ending with well 10, this is: starting from the high enthalpy wells.
3. Rate at which the wellhead power plants were installed: Installing one wellhead power plant every three months.

The sensitivity analysis in this thesis was done by considering additional values for the previous factors, creating new scenarios. With these values the Net Present Value was calculated.

1. Time to start production: TD

2. Order in which the wells were drilled: Starting with well 10 instead of from well 1, this means the production would start from the low enthalpy wells.
3. Rate at which the wellhead power plants were installed: Installing one wellhead power plant every month.

3. Results

In this section the results of the different scenarios will be presented, the power output, the cost estimates, the time calculation, the net present values and the sensitivity analysis.

The power output calculations were done using the EES software (Engineering Equations Solver) with the equations governing the power cycles described in section 2.1.3.

The time calculation is the time difference (TD) between the start of energy production of a wellhead power plant and the start of production of the central power plant, the result of this time calculation is an important input for the Net Present Value calculation.

As the time difference (TD) was used in all scenarios and is the same it will be shown at the beginning of this results section.

3.1. Time calculation results

The result of the calculation of the time difference (TD) of the start of production of a wellhead power plant and the start of production of a central power plant is shown in Table 5.

Table 5: Results of time calculation (Time to have wells ready for power plant to be installed with one drilling rig)

Number of wells		Mean	std. dev	Prob.	days	test	total	months
		[days]	[days]	%		[days]	[days]	
1	WELL	43.50	5.5	95%	53	90	143	5
10	WELLS	435.00	17.39	95%	464	135	554	18
			Time difference (TD)				**411**	**13**

For simplification purposes, 12 months was considered the TD in this thesis.

3.2. Results of the scenario (1) with a single flash traditional power plant with condensing turbines

In this scenario the power plant uses the geothermal fluid of the 10 wells of the hypothetical steamfield and the separator pressure was calculated to optimize the power output of the power plant using the combined geothermal fluid of the 10 wells.

3.2.1. Power output result of scenario 1

The power output of the single flash central power plant with condensing turbine is shown in Table 6.

Table 6: Power output results of scenario 1

Separator pressure	Condenser Pressure	Gross Power	NET POWER
[bar abs]	[bar abs]	[KW]	[KW]
13	0.10	117,755	**115,047**

3.2.2. Cost and revenue estimation results for scenario 1

In this scenario the transmission costs are omitted and only the steam gathering system from the wells to the central power plant is calculated.

Table 7: Revenue and cost results for scenario 1.

REVENUE	**COST**				
REVENUE	cost per KW	power plant cost	O&M		Steam Gathering
[$/year]	[$/KW]	[$]	[cent/KWh]	[$/year]	[$]
90,703,054	1,212	**142,732,099**	1.51	**14,006,634**	**29,438,750**

3.2.3. Net Present Value results for scenario 1

The net present value of this scenario is shown in Figure 33 together with the cash flows for the first 3 years of the project; the cash flows remain constant for the rest of the planning horizon.

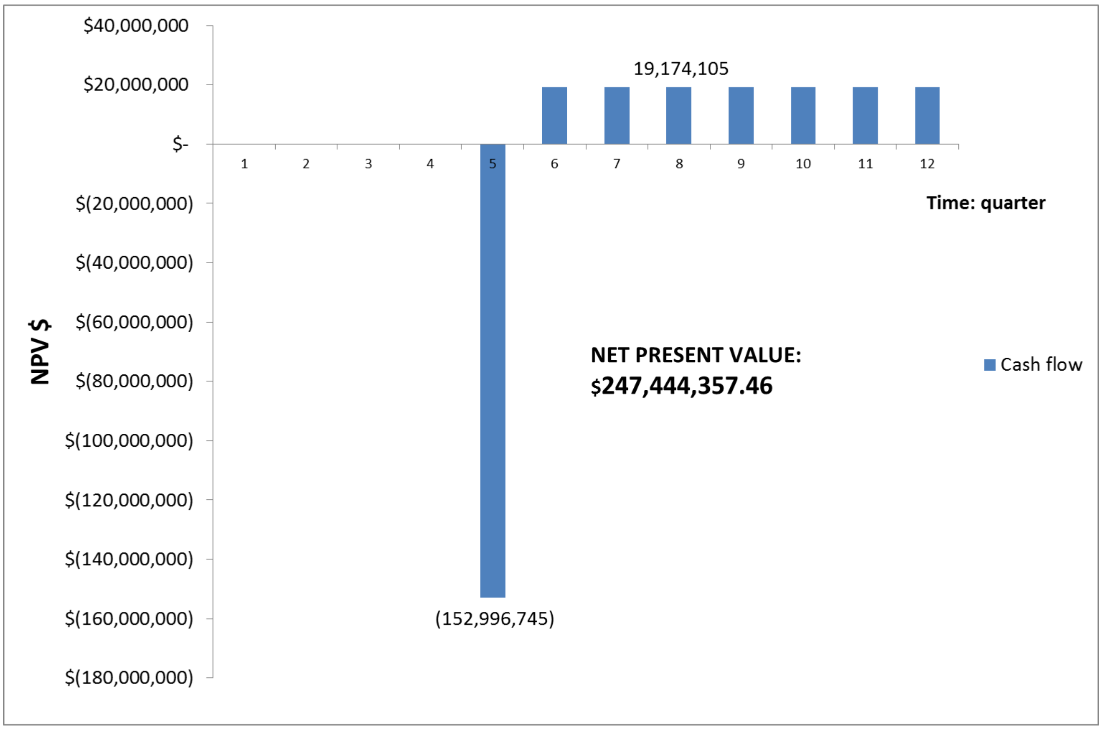

Figure 33: Cash flow and Net Present Value of scenario 1

3.2.4. Sensitivity analysis for scenario 1

The sensitivity analysis was done starting the production of this power plant in 6, 12, 18 and 24 months see Figure 34. The other factors considered relevant for the sensitivity analysis do not apply for this scenario: order in which the wells are drilled and the rate at which wellhead power plants can be installed.

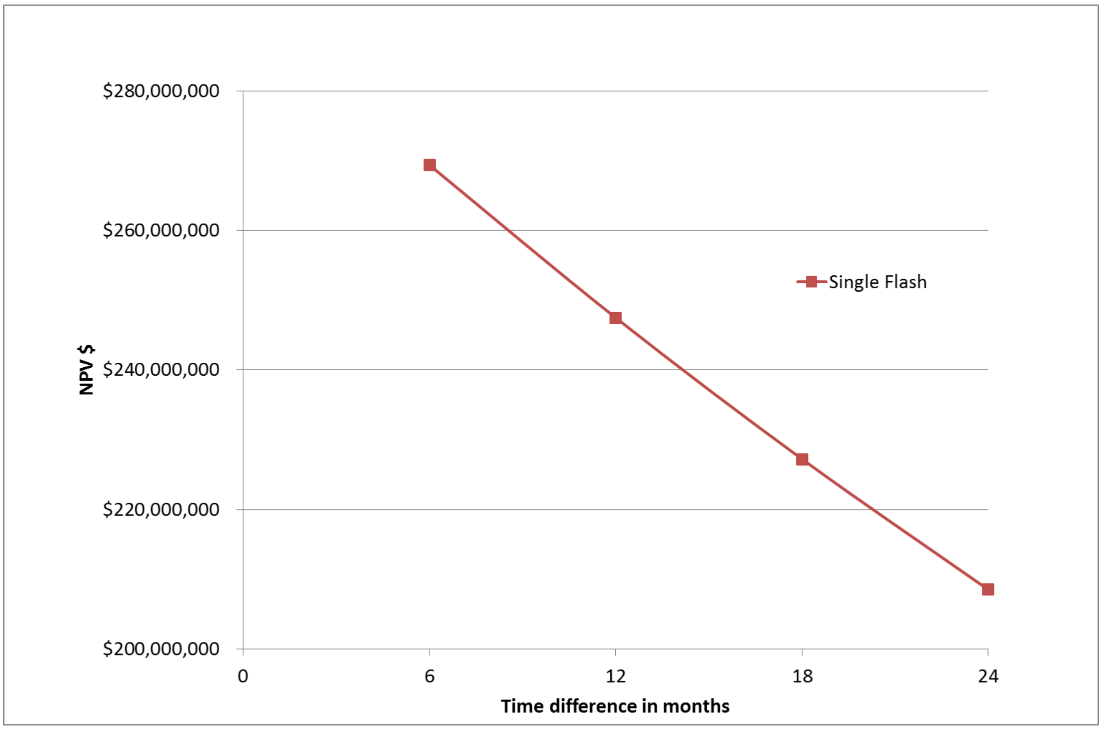

Figure 34: Net Present Values calculated in the Sensitivity analysis for scenario 1

3.3. Results of the scenario (2) with a double flash central power plant with condensing turbine

In this scenario the power plant uses the geothermal fluid from the 10 wells of the hypothetical steamfield and the separator pressure of the two separators was calculated to optimize the power output of the power plant using the combined geothermal fluid from the 10 wells.

3.3.1. Power output result of scenario 2

The power output of the double flash central power plant with condensing turbine is shown in Table 8.

Table 8: Power output results of scenario 2

Separator pressure of high pressure separator	Separator pressure of medium pressure separator	Condenser pressure	Gross Power HP	Gross Power MP	Total Gross Power	NET POWER
[bar abs]	[bar abs]	[bar abs]	[KW]	[KW]	[KW]	[KW]
15	2	0.10	116,831	13,537	130,368	**127,227**

3.3.2. Cost and revenue estimation results for scenario 2.

In this scenario the transmission costs are omitted and only the steam gathering system from the wells to the central power plant is calculated.

Table 9: Revenue and cost results for scenario 2.

REVENUE	**COST**				
REVENUE	cost per KW	power plant cost	O&M		Steam Gathering
[$/year]	[$/KW]	[$]	[cent/KWh]	[$/year]	[$]
100,305,766	1,167	**152,152,829**	1.46	**15,025,572**	**32,592,000**

3.3.3. Net Present Value results for scenario 2.

The net present value of this scenario is shown in Figure 35 together with the cash flows for the first 3 years of the project; the cash flows remain constant for the rest of the planning horizon.

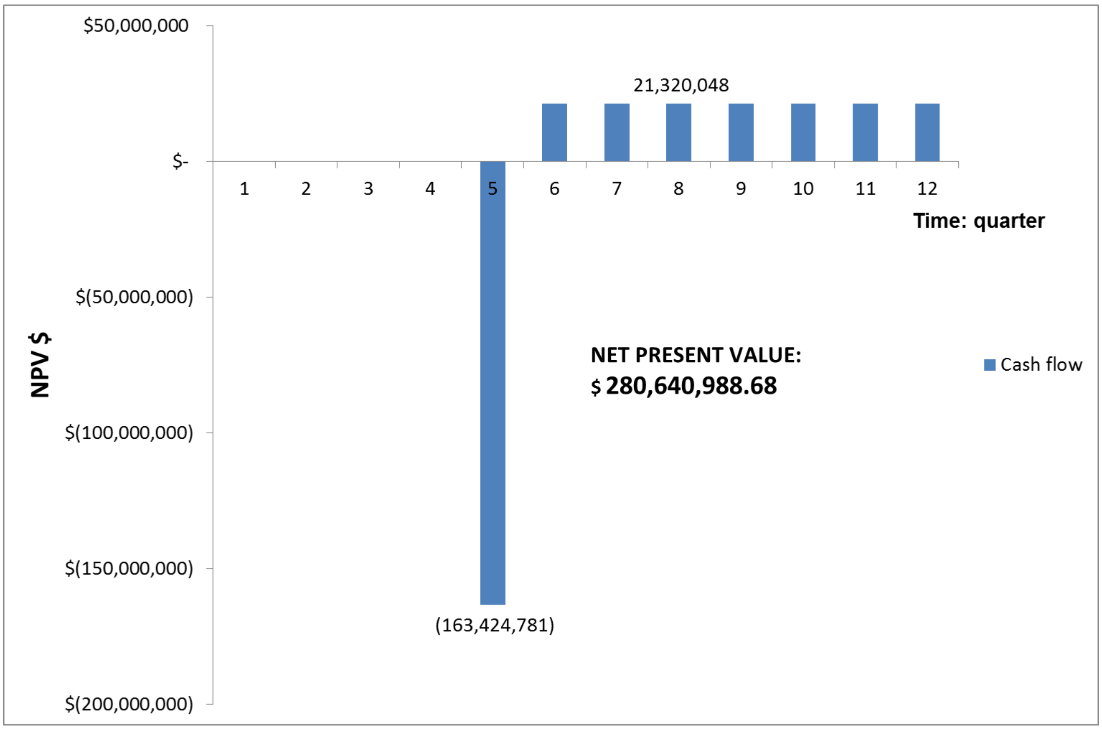

Figure 35: Cash flow and Net Present Value of scenario 2.

3.3.4. Sensitivity analysis for scenario 2.

The sensitivity analysis was done starting the production of this power plant in 6, 12, 18 and 24 months see Figure 36. The other factors considered relevant for the sensitivity analysis do not apply for this scenario: order in which the wells are drilled and the rate at which wellhead power plants can be installed.

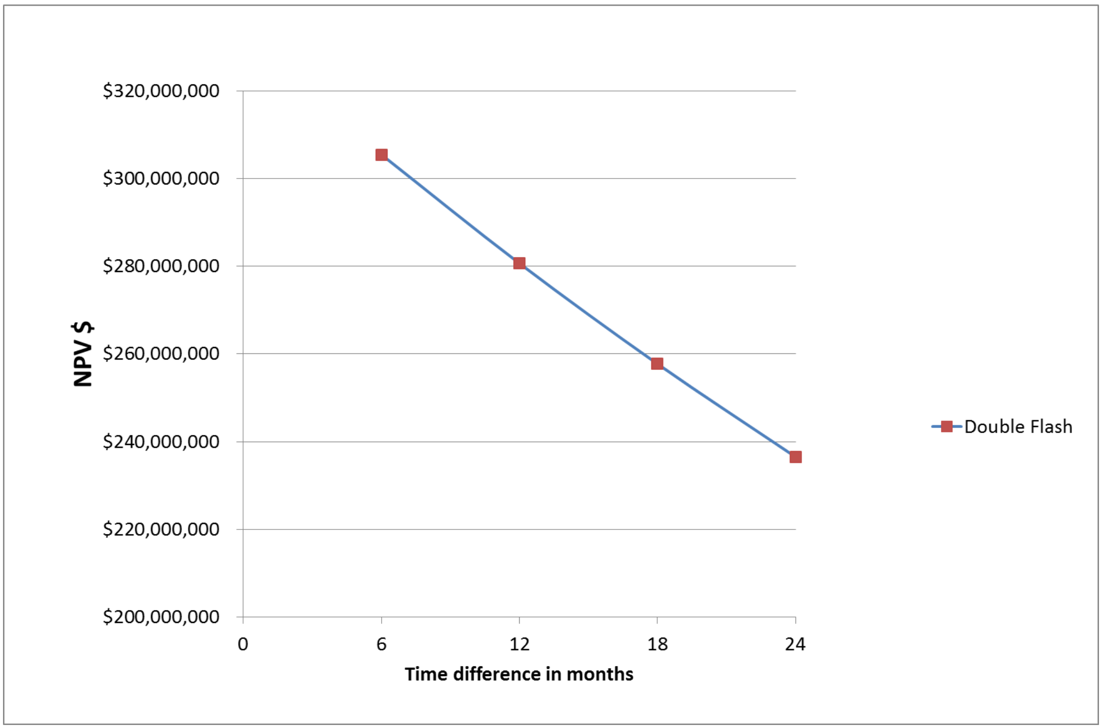

Figure 36: Net Present Values calculated in the Sensitivity analysis for scenario 2.

3.4. Results of the scenario (3) with wellhead power plants with condensing turbine

In this scenario a wellhead power plant with condensing turbine is installed permanently for each of the 10 wells of the hypothetical steamfield, for this reason the separator pressure is different for each of the power plants depending on the productivity curve of each well (see Table 1).

3.4.1. Power output result of scenario 3.

The power output results of these wellhead power plants are shown in Table 10.

Table 10: Power output results of scenario 3.

Well	Optimum Flash P	Gross Power	NET POWER
	[bar abs]	[KW]	[KW]
1	19	5,704	5,583
2	27	22,039	21,608
3	22	18,868	18,483
4	16	20,202	19,760
5	13	7,418	7,248
6	15	23,082	22,568
7	5	14,732	14,295
8	8	3,940	3,838
9	6	3,007	2,922
10	6	5,186	5,040
Totals		**124,178**	**121,345**

3.4.2. Cost and revenue estimation results for scenario 3.

In this scenario the cost of the steam gathering system is omitted and the cost of transmission lines from each wellhead power plant to a central transformer station is calculated.

Table 11: Revenue and cost results for scenario 3.

	REVENUE	**COST**				
Well	REVENUE	cost per KW	power plant cost	O&M		Transmission
	[$/year]	[$/KW]	[$]	[cent/KWh]	[$/year]	[$]
1	4,401,637	1,696	9,676,342	2.00	897,825	570,400
2	17,035,747	1,615	35,599,260	1.92	3,330,187	2,203,900
3	14,571,997	1,631	30,768,505	1.93	2,873,727	1,886,800
4	15,578,784	1,624	32,812,314	1.93	3,066,660	2,020,200
5	5,714,323	1,688	12,519,454	1.99	1,162,621	741,800
6	17,792,611	1,610	37,167,523	1.91	3,478,706	2,308,200
7	11,270,178	1,651	24,323,775	1.95	2,267,107	1,473,200
8	3,025,879	1,705	6,719,334	2.01	622,908	394,000

	REVENUE	COST				
Well	REVENUE	cost per KW	power plant cost	O&M		Transmission
9	2,303,705	1,710	5,142,556	2.01	476,512	300,700
10	3,973,536	1,699	8,811,282	2.00	817,348	518,600
Totals	**95,668,398**		**203,540,344**		**18,993,601**	**12,417,800**

3.4.3. Net Present Value results for scenario 3.

The net present value of this scenario is shown in Figure 37 together with the cash flows for the first 3 years of the project; the cash flows remain constant for the rest of the planning horizon.

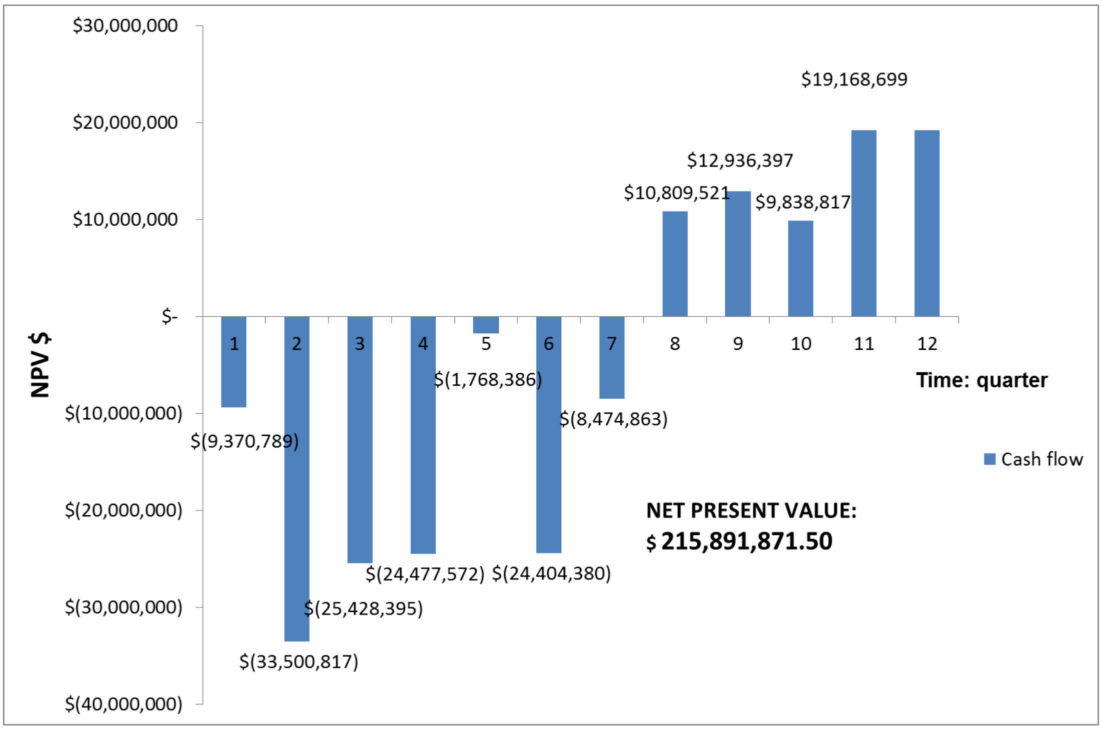

Figure 37: Cash flow and Net Present Value of scenario 3.

3.4.4. Sensitivity analysis for scenario 3.

In this scenario all the factors considered for the sensitivity analysis are relevant; in Figure 38 the different Net Present Values for each of the possible options can be seen:

- The line 3 H means: one wellhead power plant installed every 3 months and the drilling started with the high enthalpy wells.

- 3 L means: one wellhead power plant installed every 3 months and the drilling started with the low enthalpy wells.
- 1 H means: one wellhead power plant installed every 1 month and the drilling started with the high enthalpy wells.
- 1 L means: one wellhead power plant installed every 1 month and the drilling started with the low enthalpy wells.

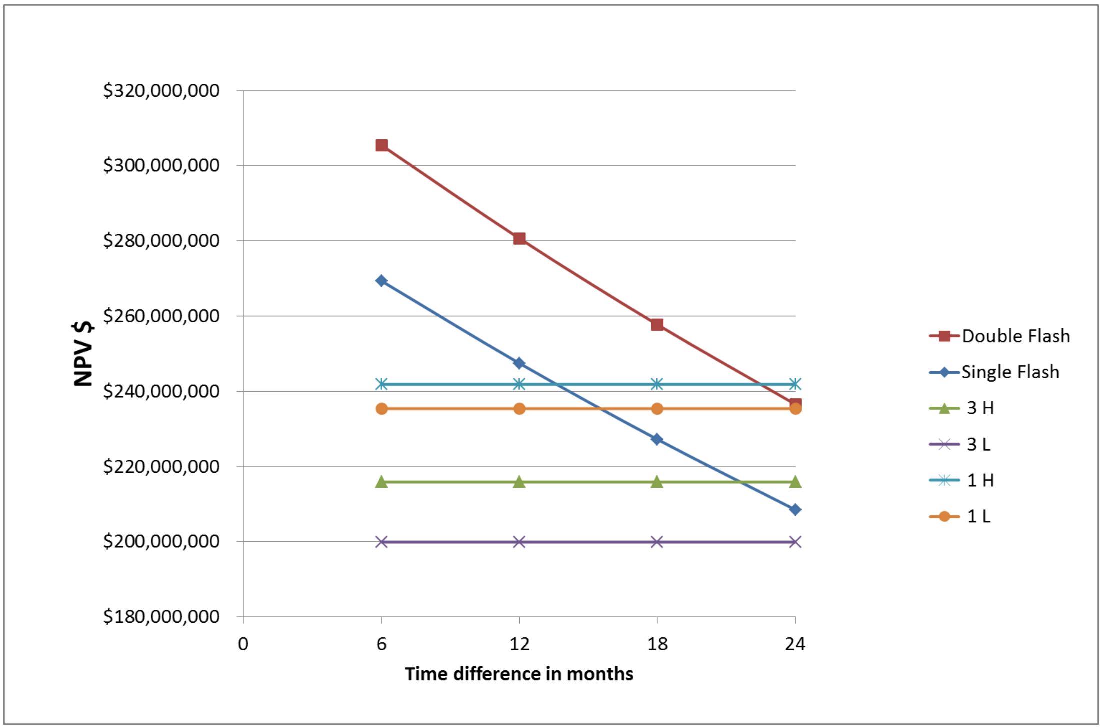

Figure 38: Net Present Values calculated in the Sensitivity analysis for scenario 3.

3.5. Results of the scenario (4) with a wellhead power plant with condensing turbine in the early stages and single flash traditional power plant after all wells are drilled and tested

This scenario is divided in two parts, in the first part wellhead power plants with condensing turbine where installed after each well was drilled and tested, and in the second part, once all the wells were drilled and tested a single flash central power plant was installed. The results for the first part: the wellhead power plants with condensing turbines are the same as the previous section(3.4) and the results of the second part are the same as the for the single flash central power plant (section 3.2).

3.5.1. Power output result of scenario 4

In the first part of this scenario the power output is the same as in Table 10 and after all the wells are drilled and tested the power output is the same as in Table 6.

3.5.2. Cost and revenue estimation results for scenario 4

The cost and revenue results of the first part of this scenario is the same as in Table 11 and after all the wells are drilled and tested and the single flash central power plant is installed the cost and revenue results are the same as in Table 7.

3.5.3. Net Present Value results for scenario 4

The net present value of this scenario is shown in Figure 39 together with the cash flows for the first 3 years of the project; the cash flows remain constant for the rest of the planning horizon. In this scenario in the fifth quarter the investment of the central power plant is done, at the same time the resale value of the wellhead power plants that were installed in the first four quarters is considered. The resale value does not consider the cost of the transmission lines from the first 4 quarters.

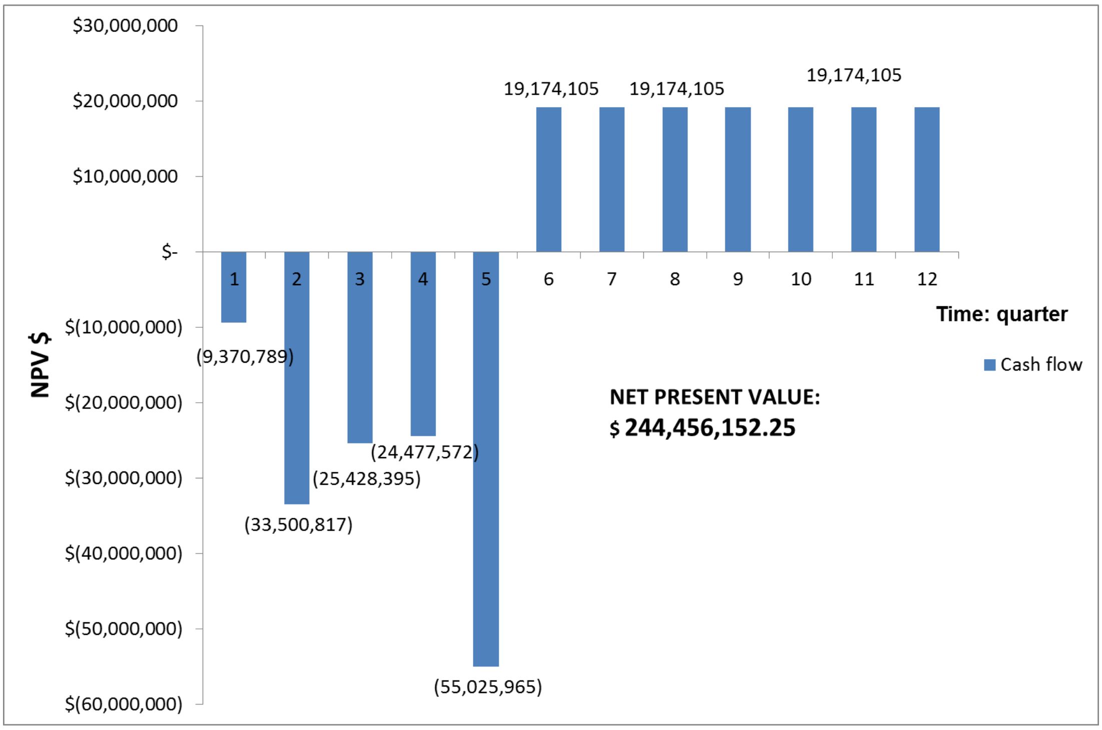

Figure 39: Cash flow and Net Present Value of scenario 4

3.5.4. Sensitivity analysis for scenario 4

In this scenario all the factors considered for the sensitivity analysis are relevant; in Figure 40 the different Net Present Values for each of the possible options can be seen:

- The line 3 H means: one wellhead power plant installed every 3 months and the drilling started with the high enthalpy wells.
- 3 L means: one wellhead power plant installed every 3 months and the drilling started with the low enthalpy wells.
- 1 H means: one wellhead power plant installed every 1 month and the drilling started with the high enthalpy wells.
- 1 L means: one wellhead power plant installed every 1 month and the drilling started with the low enthalpy wells.

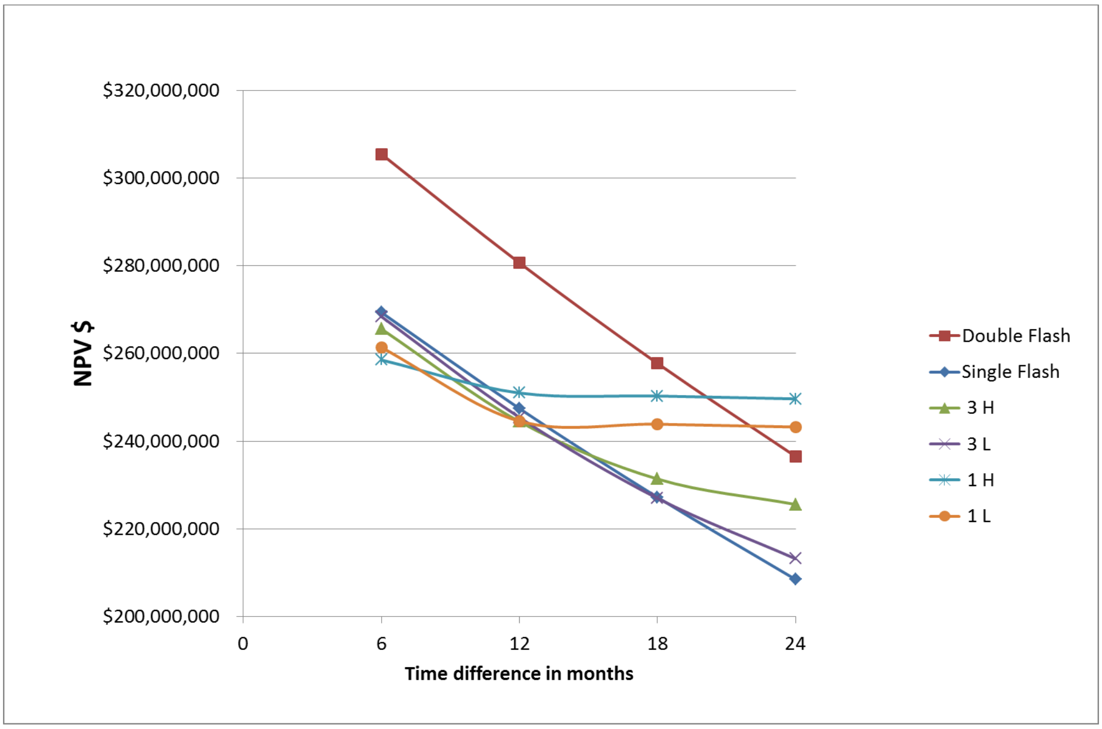

Figure 40: Net Present Values calculated in the Sensitivity analysis for scenario 4.

3.6. Results of the scenario (5) with a wellhead binary power plant

In this scenario wellhead binary power plants were installed after each well was drilled and tested and after all the wells were drilled and tested a single flash central power plant was installed. The working fluid used in the wellhead binary power plants is methanol.

3.6.1. Power output result of scenario 5.

The power output of the binary wellhead power plants are shown in Table 12. The power output of the single flash central power plant is the same as shown in section 3.2.1.

Table 12: Power output results of wellhead binary power plants.

Well	Optimum separator Pressure	well ṁ	Gross Power	NET POWER
	[bar abs]	[kg/s]	[KW]	[KW]
1	17.2	9.693	6,287	5,364
2	24.92	39.06	24,715	20,948
3	25.46	49.96	24,803	21,009
4	18.31	65.74	28,283	24,113
5	14.54	25.86	10,478	8,948
6	18.49	80.07	33,240	28,335
7	6.39	72.60	19,258	16,379
8	9.05	30.16	5,292	4,517
9	8.31	24.96	3,916	3,340
10	6.97	49.26	6,776	5,770
Totals		**447**	**163,048**	**138,723**

3.6.2. Cost and revenue estimation results for scenario 5.

The cost and revenue results for this scenario are divided in two: the first part are the cost of the wellhead binary power plants in Table 13, and then the cost and revenue results from Table 7. As with scenario 4 the first part of this scenario includes the transmission costs and the second part (central power plant) include the steam gathering system.

Table 13: Revenue and cost results for the wellhead binary power plants.

	REVENUE	**COST**				
Well	REVENUE	cost per KW	power plant cost	O&M		Transmission
	[$/year]	[$/KW]	[$]	[cent/KWh]	[$/year]	[$]
1	4,228,978	2,283.62	14,357,093	1.99	988,150	628,700
2	16,515,403	2,160.79	53,404,043	1.90	3,709,641	2,471,500
3	16,563,496	2,160.22	53,580,046	1.90	3,722,031	2,480,300
4	19,010,689	2,137.79	60,463,086	1.89	4,207,488	2,828,300
5	7,054,603	2,255.08	23,628,768	1.97	1,629,699	1,047,800
6	22,339,314	2,106.23	70,011,190	1.86	4,884,009	3,324,000
7	12,913,204	2,196.46	42,299,433	1.93	2,930,268	1,925,800
8	3,561,203	2,290.44	12,121,023	2.00	833,834	529,200
9	2,633,256	2,299.92	9,006,476	2.01	619,151	391,600
10	4,549,068	2,280.27	15,451,098	1.99	1,063,706	677,600
Totals	**109,369,213**		**354,322,256**		**24,587,976**	**16,304,800**

3.6.3. Net Present Value results for scenario 5.

The net present value of this scenario is shown in Figure 41 together with the cash flows for the first 3 years of the project; the cash flows remain constant for the rest of the planning horizon. In this scenario in the fifth quarter the investment of the central power plant is done, at the same time the resale value of the wellhead power plants that were installed in the first four quarters is considered. The resale value does not consider the cost of the transmission lines.

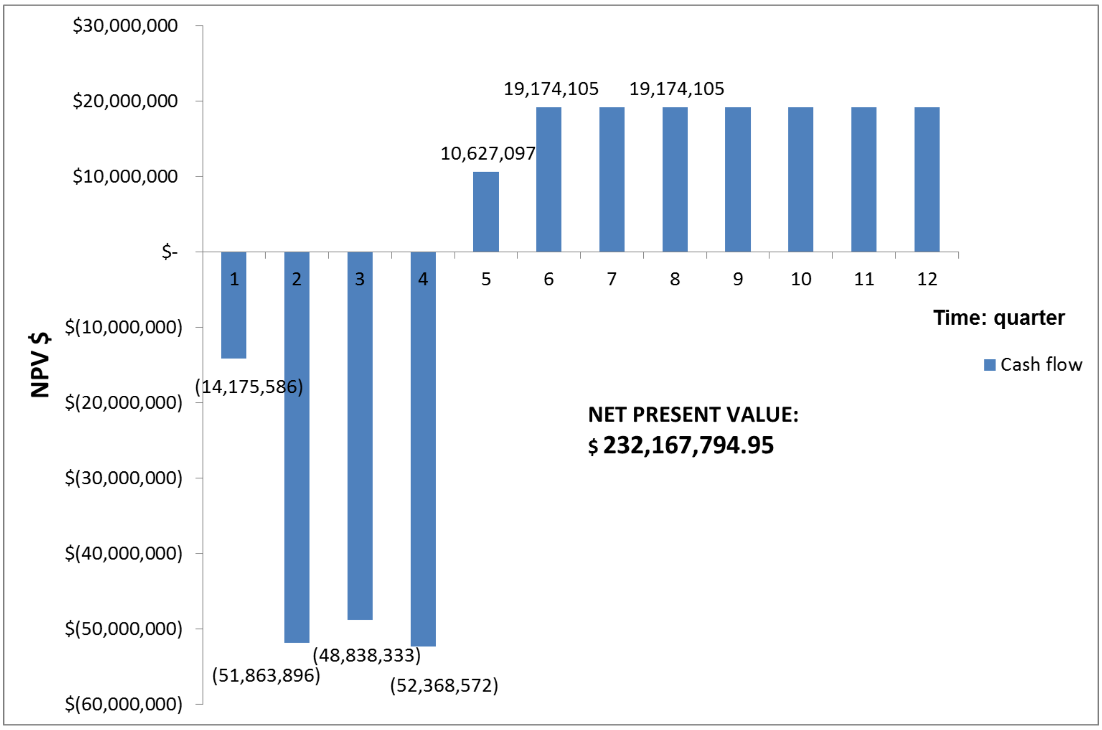

Figure 41: Cash flow and Net Present Value of scenario 5

3.6.4. Sensitivity analysis for scenario 5.

In this scenario all the factors considered for the sensitivity analysis are relevant; in Figure 42 the different Net Present Values for each of the possible options can be seen:

- The line 3 H means: one wellhead power plant installed every 3 months and the drilling started with the high enthalpy wells.
- 3 L means: one wellhead power plant installed every 3 months and the drilling started with the low enthalpy wells.
- 1 H means: one wellhead power plant installed every 1 month and the drilling started with the high enthalpy wells.
- 1 L means: one wellhead power plant installed every 1 month and the drilling started with the low enthalpy wells.

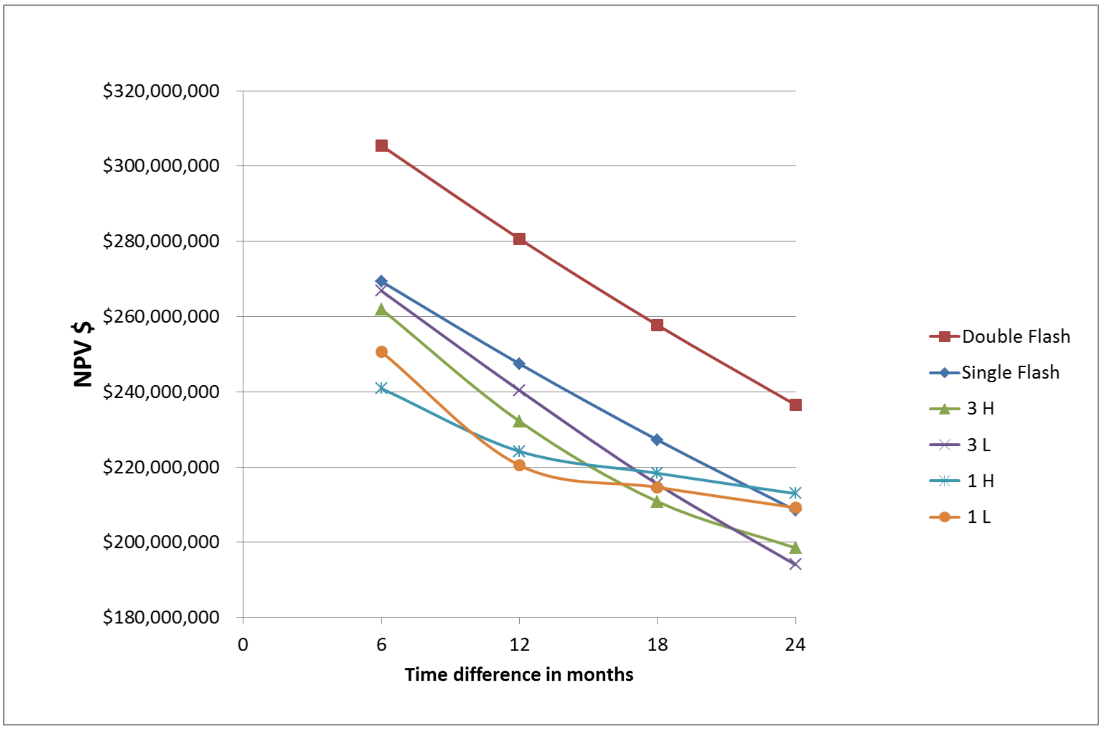

Figure 42: Net Present Values calculated in the Sensitivity analysis for scenario 5.

3.7. Results of the scenario (6) with a single flash wellhead power plant with backpressure turbine

In this scenario wellhead power plants with backpressure turbines were installed after each well was drilled and tested and after all the wells in the steamfield were drilled and tested a single flash central power plant was installed.

3.7.1. Power output result of scenario 6.

The power output for each of the wellhead power plants with backpressure turbines can be seen in Table 14 and the power output of the single flash central power plant is the same as in section 3.2.1.

Table 14: Power output of the wellhead power plants with backpressure turbines

Well	Optimum Flash P [bar abs]	Gross Power [KW]
1	23	3,642
2	32	14,695
3	31	12,418
4	20	12,586

Well	Optimum Flash P	Gross Power
	[bar abs]	[KW]
5	16	4,475
6	20	14,334
7	10	7,751
8	10	2,171
9	10	1,595
10	10	2,749
Totals		**76,416**

3.7.2. Cost and revenue estimation results for scenario 6.

The cost and revenue results for this scenario are divided in two: the first parts are the cost of the wellhead binary power plants in Table 15, and then the cost and revenue results from Table 7. As with scenario 4 and 5, the first part of this scenario includes the transmission costs and the second part (central power plant) include the steam gathering system.

Table 15: Revenue and cost results for the wellhead power plants with backpressure turbine.

Well	**REVENUE**	**COST**				
	REVENUE	cost per KW	power plant cost	O&M		Transmission
	[$/year]	[$/KW]	[$]	[cent/KWh]	[$/year]	[$]
1	2,871,353	1,506.12	5,485,302	2.01	576,224	364,200
2	11,585,538	1,457.00	21,410,627	1.95	2,261,622	1,469,500
3	9,790,351	1,466.99	18,217,053	1.96	1,922,092	1,241,800
4	9,922,802	1,466.25	18,454,204	1.96	1,947,278	1,258,600
5	3,528,090	1,502.36	6,723,081	2.00	706,545	447,500
6	11,300,926	1,458.58	20,907,280	1.95	2,208,054	1,433,400
7	6,110,888	1,487.67	11,530,941	1.99	1,213,801	775,100
8	1,711,616	1,512.78	3,284,256	2.01	344,753	217,100
9	1,257,498	1,515.40	2,417,065	2.02	253,650	159,500
10	2,167,312	1,510.16	4,151,440	2.01	435,909	274,900
Totals	**60,246,374**		**112,581,249**		**11,869,927**	**7,641,600**

3.7.3. Net Present Value results for scenario 6.

The net present value of this scenario is shown in Figure 43 together with the cash flows for the first 3 years of the project; the cash flows remain constant for the rest of the planning horizon. In this scenario in the fifth quarter the investment of the central power plant is done, at the same time the resale value of the wellhead power plants that were installed in the first four quarters is considered. The resale value does not consider the cost of the transmission lines.

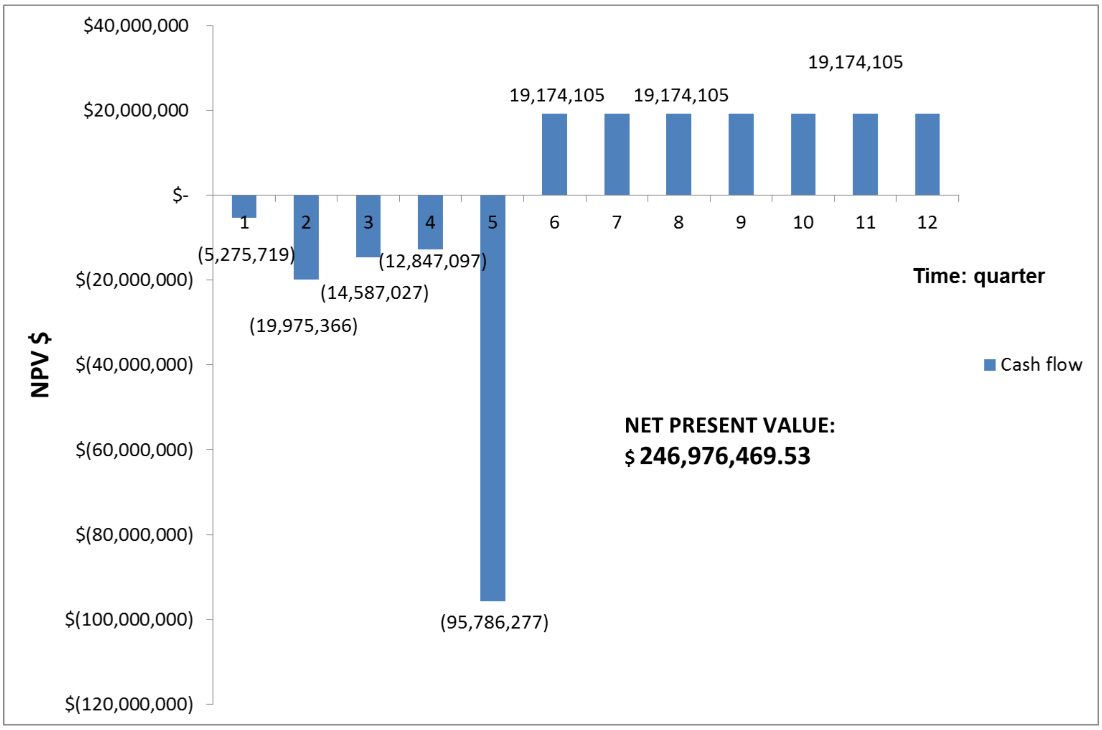

Figure 43: Cash flow and Net Present Value of scenario 6

3.7.4. Sensitivity analysis for scenario 6.

In this scenario all the factors considered for the sensitivity analysis are relevant.

In Figure 44 the different Net Present Values for each of the possible options can be seen:

- The line 3 H means: one wellhead power plant installed every 3 months and the drilling started with the high enthalpy wells.
- 3 L means: one wellhead power plant installed every 3 months and the drilling started with the low enthalpy wells.
- 1 H means: one wellhead power plant installed every 1 month and the drilling started with the high enthalpy wells.

- 1 L means: one wellhead power plant installed every 1 month and the drilling started with the low enthalpy wells.

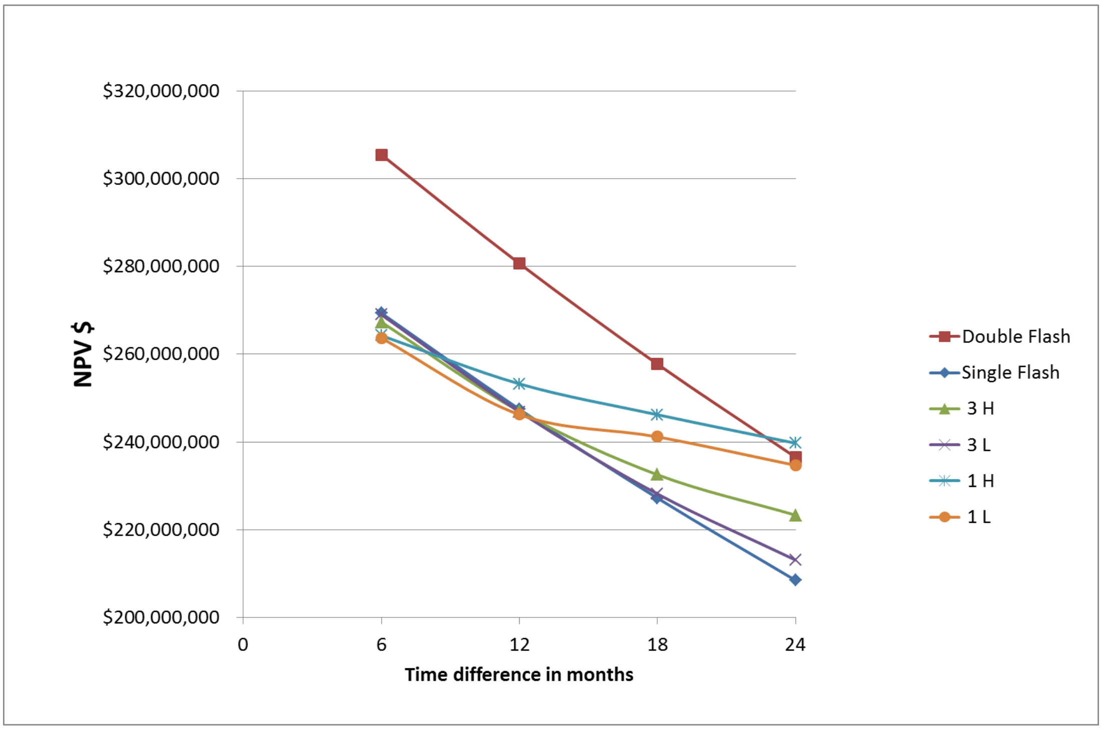

Figure 44: Net Present Values calculated in the Sensitivity analysis for scenario 6.

3.8. Results for scenario (7) with a wellhead power plant with backpressure turbine for high pressure (HP) wells and traditional power plant with condensing turbine for the medium pressure (MP) wells

In this scenario the wellhead power plant was used for the geothermal fluid from the 3 wells with the highest enthalpy, and higher pressure, in a high pressure power plant. The geothermal fluid from the rest of the wells was used in a central medium pressure power plant together with the geothermal fluid from the high pressure power plant. In order to be able to utilize the geothermal fluid of the high pressure power plant in the medium pressure power plant the backpressure at which the high pressure turbine exhausts has to be slightly higher than the inlet pressure of the separator of the medium pressure power plant.

3.8.1. Power output result of scenario 7.

The power output results of this scenario are shown in Table 16.

Table 16: Power output results of scenario 7.

Well		Separator Pressure	Gross Power	NET POWER
		[bar abs]	[KW]	[KW]
HP wells	1	**27**	10,459	
	2			
	3			
	4	**10**	112,583	
	5			
	6			
	7			
	8			
	9			
	10			
Totals				**120,280**

3.8.2. Cost and revenue estimation results for scenario 7.

In the complementary scenarios the wellhead power plants have the cost of the transmission lines and the power plant with the rest of the wells has the cost of the steam gathering system.

Table 17: Revenue and cost results for scenario 7.

REVENUE	**COST**					
REVENUE	cost per KW	power plant cost	O&M		Transmission	Steam Gathering
[$/year]	[$/KW]	[$]	[cent/KWh]	[$/year]	[$]	[$]
8,245,876	1,672	17,491,483	1.97	1,626,821	1,045,900	
88,760,437	1,231	138,596,936	1.53	13,565,714		28,145,750
97,006,313		**156,088,419**		**15,192,535**	**12,304,200**	**30,760,500**

3.8.3. Net Present Value results for scenario 7.

The net present value of this scenario is shown in Figure 45 together with the cash flows for the first 3 years of the project; the cash flows remain constant for the rest of the planning horizon.

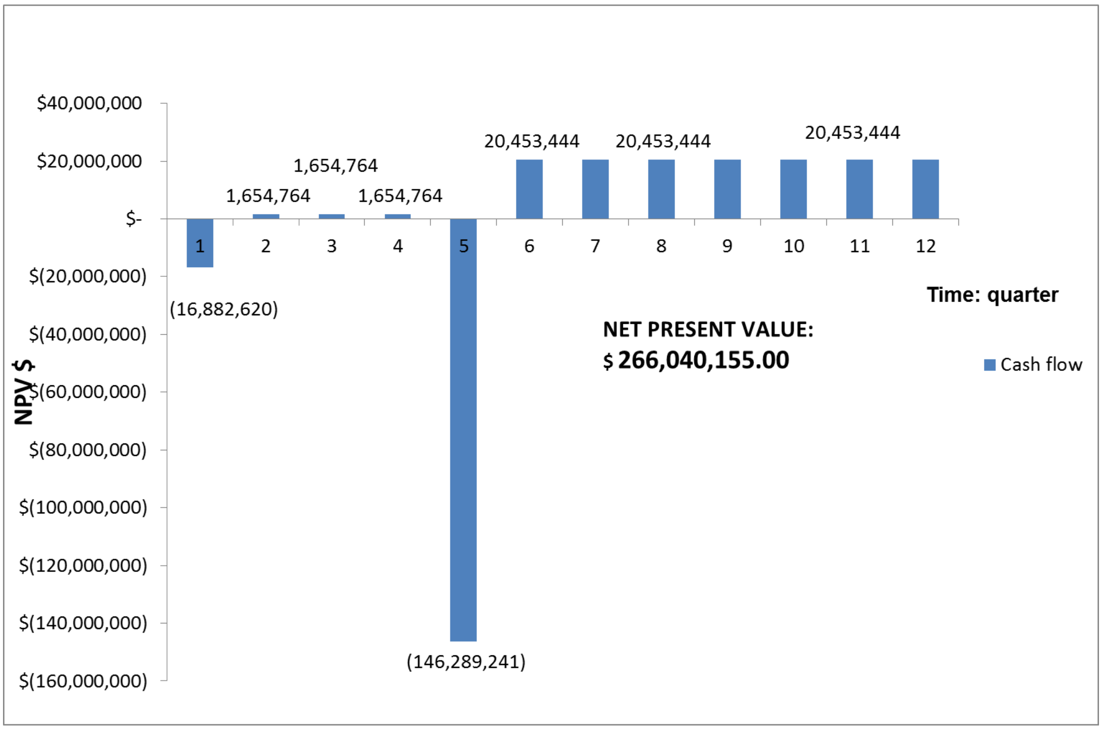

Figure 45: Cash flow and Net Present Value of scenario 7

3.8.4. Sensitivity analysis for scenario 7.

In this scenario the only relevant factor that applies for the sensitivity analysis is the time difference (TD), the other factors do not apply (the order in which the well are drilled and the rate at which the wellhead power plants can be installed). The sensitivity analysis was done starting the production of this power plant in 6, 12, 18 and 24 months see Figure 46. All the results of the NPV in the sensitivity analysis are very similar and can´t be distinguished from one another in the graph.

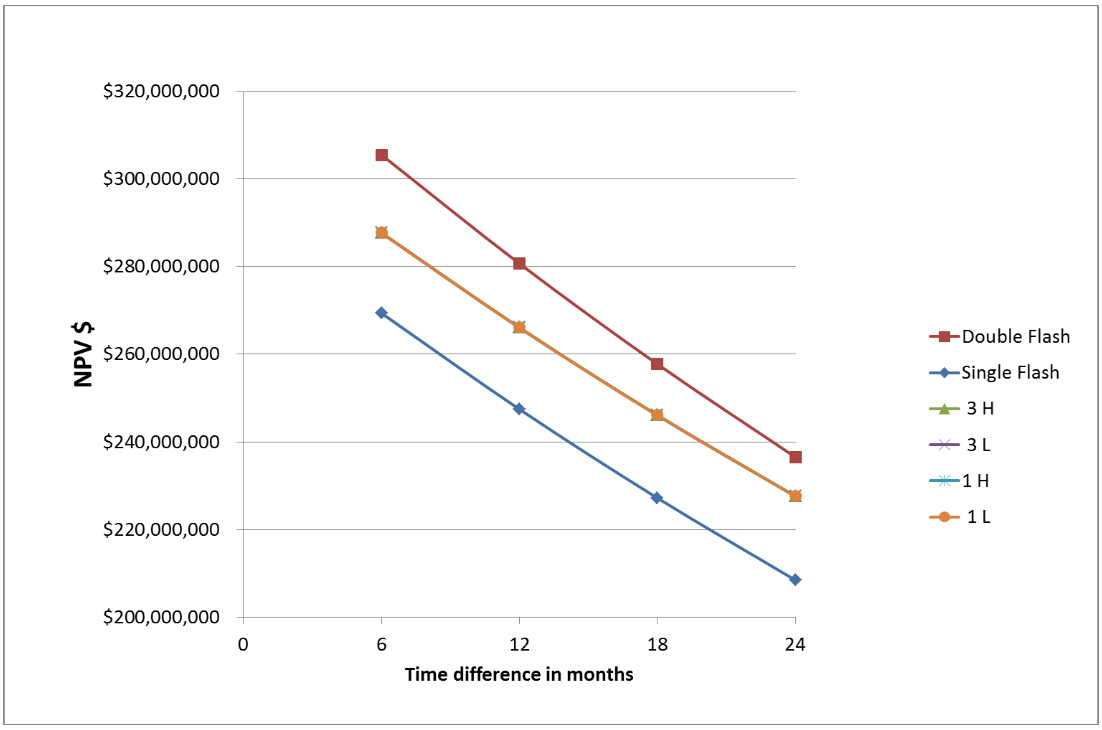

Figure 46: Net Present Values calculated in the Sensitivity analysis for scenario 7.

3.9. Results for scenario (8) with wellhead power plants with condensing turbines for the low pressure wells and a single flash traditional power plant for the rest of the wells.

In this scenario wellhead power plants with condensing turbines were installed for the 3 wells with the lowest enthalpy and pressure of the steamfield. The rest of the wells were utilized in a single flash central power plant. The wellhead power plants and the central power plants are all independent of each other.

3.9.1. Power output result of scenario 8.

The results for power output of this scenario are shown in Table 18.

Table 18: Power output results of scenario 8.

Well	Separator Pressure [bar abs]	well ṁ [kg/s]	Gross Power [KW]	NET POWER [KW]
1	14	334.6	107,522	105,093
2				
3				

Well	Separator Pressure	well ṁ	Gross Power	NET POWER
	[bar abs]	[kg/s]	[KW]	[KW]
4				
5				
6				
7				
8	8	29.93	3,940	3,838
9	6	24.88	3,007	2,922
10	6	49	5,186	5,040
Totals		**438**	**119,655**	**116,893**

3.9.2. Cost and revenue estimation results for scenario 8.

In the complementary scenarios the wellhead power plants have the cost of the transmission lines and the power plant with the rest of the wells has the cost of the steam gathering system.

Table 19: Revenue and cost results for scenario 8.

REVENUE	**COST**					
REVENUE	cost per KW	power plant cost	O&M		Transmission	Steam Gathering
[$/year]	[$/KW]	[$]	[cent/KWh]	[$/year]	[$]	[$]
82,855,321	1,249	134,391,573	1.55	13,120,854		26,880,500
3,025,879	1,705	6,719,334	2.01	622,908	394,000	
2,303,705	1,710	5,142,556	2.01	476,512	300,700	
3,973,536	1,699	8,811,282	2.00	817,348	518,600	
92,158,441		**155,064,745**		**15,037,622**	**1,213,300**	**26,880,500**

3.9.3. Net Present Value results for scenario 8.

The net present value of this scenario is shown in Figure 47 together with the cash flows for the first 3 years of the project; the cash flows remain constant for the rest of the planning horizon.

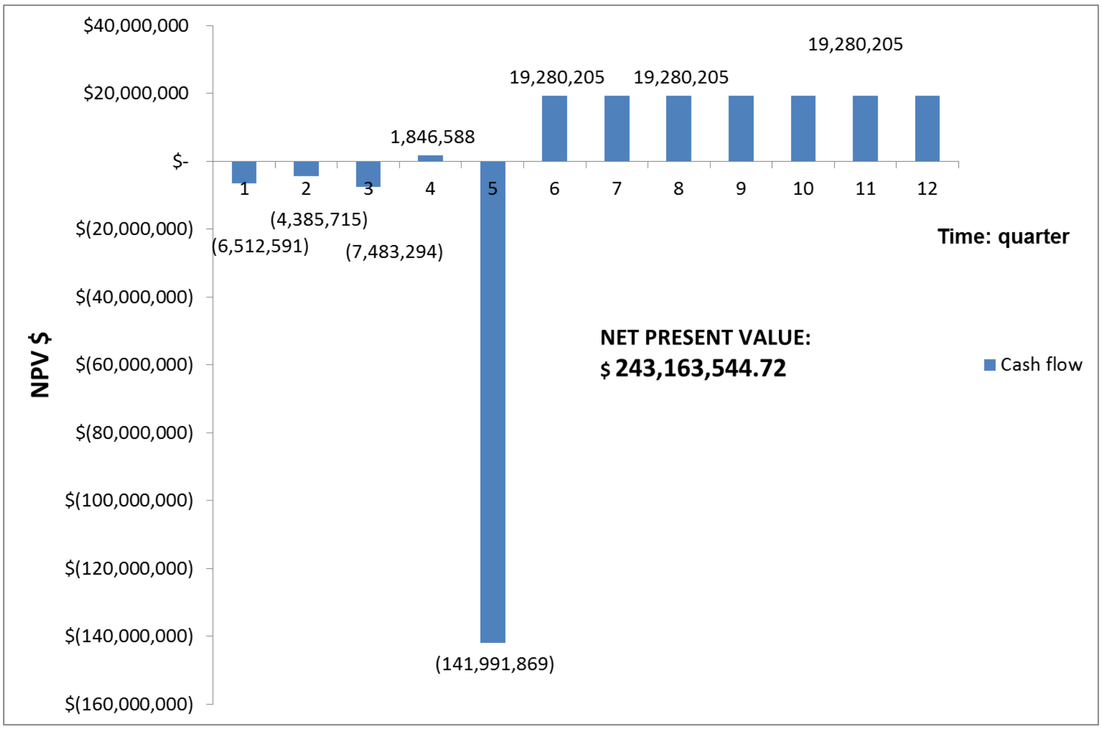

Figure 47: Cash flow and Net Present Value of scenario 8

3.9.4. Sensitivity analysis for scenario 8.

In the 3 complementary scenarios where the wellhead power plants are used for the low enthalpy wells the only significant factor is the time difference (TD), the differences in NPV with changes in any of the other two factors are practically nonexistent, as can be confirmed by looking at Figure 48. All the results of the NPV in the sensitivity analysis are very similar and can´t be distinguished from one another in the graph.

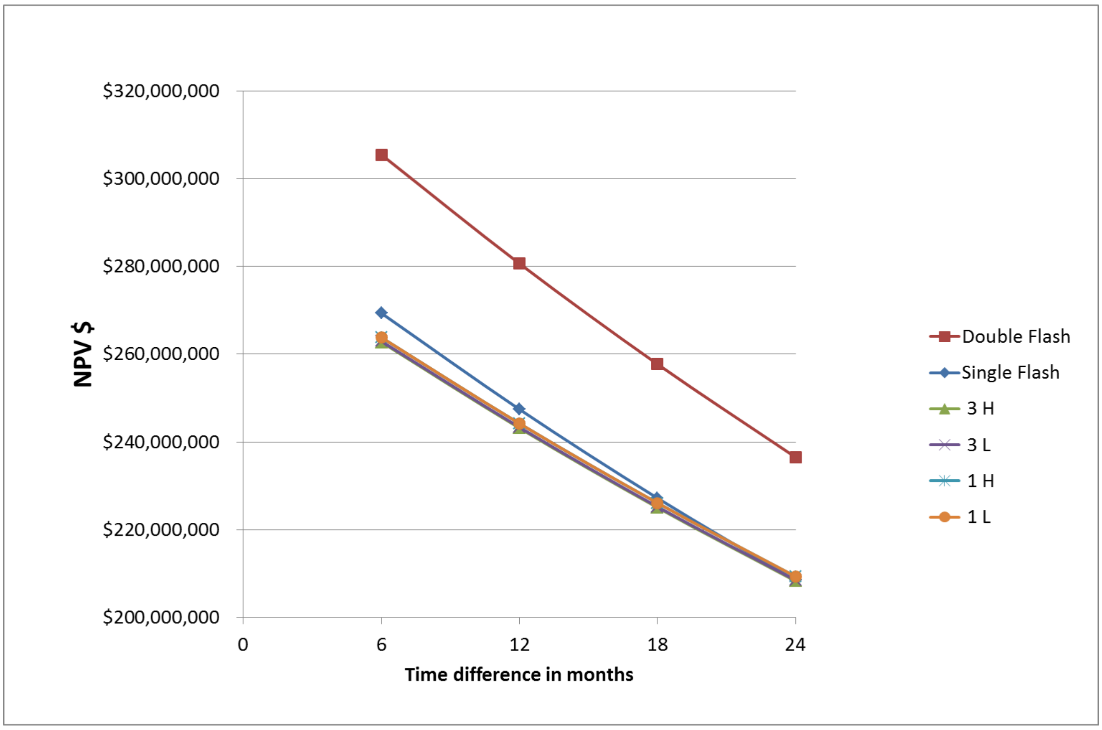

Figure 48: Net Present Values calculated in the Sensitivity analysis for scenario 8.

3.10. Results for scenario (9) with wellhead binary power plants for the low pressure wells and a single flash traditional power plants for the rest of the wells.

In this scenario the wellhead power plants are used for the low pressure wells in the steamfield, in this case the wellhead power plants used are binary power plants with methanol as the working fluid. The rest of the wells are utilized in a single flash central power plant.

3.10.1. Power output result of scenario 9.

The results of the power output are shown in Table 20.

Table 20: Power output results of scenario 9.

	Well	Separator pressure	well mass flow	Gross Power	NET POWER
		[bar abs]	[kg/s]	[KW]	[KW]
Traditional single flash	1	14	334.6	107,522	105,093
	2				
	3				

	Well	Separator pressure	well mass flow	Gross Power	NET POWER
		[bar abs]	[kg/s]	[KW]	[KW]
power plant	4				
	5				
	6				
	7				
Binary Power plant	8	9.05	30.16	5,292	4,517
	9	8.31	24.96	3,916	3,340
	10	6.97	49.26	6,776	5,770
Totals			**439**		**118,720**

3.10.2. Cost and revenue estimation results for scenario 9.

In the complementary scenarios the wellhead power plants have the cost of the transmission lines and the power plant with the rest of the wells has the cost of the steam gathering system.

Table 21: Revenue and cost results for scenario 9.

REVENUE	**COST**					
REVENUE	cost per KW	power plant cost	O&M		Transmission	Steam Gathering
[$/year]	[$/KW]	[$]	[cent/ KWh]	[$/year]	[$]	[$]
82,855,321	1,249.90	134,391,573	1.55	13,120,854		26,880,500
3,561,203	2,290.44	12,121,023	2.00	833,834	529,200	
2,633,256	2,299.92	9,006,476	2.01	619,151	391,600	
4,549,068	2,280.27	15,451,098	1.99	1,063,706	677,600	
93,598,848		**170,970,170**		**15,637,544**	**1,598,400**	**26,880,500**

3.10.3. Net Present Value results for scenario 9.

The net present value of this scenario is shown in Figure 49 together with the cash flows for the first 3 years of the project; the cash flows remain constant for the rest of the planning horizon.

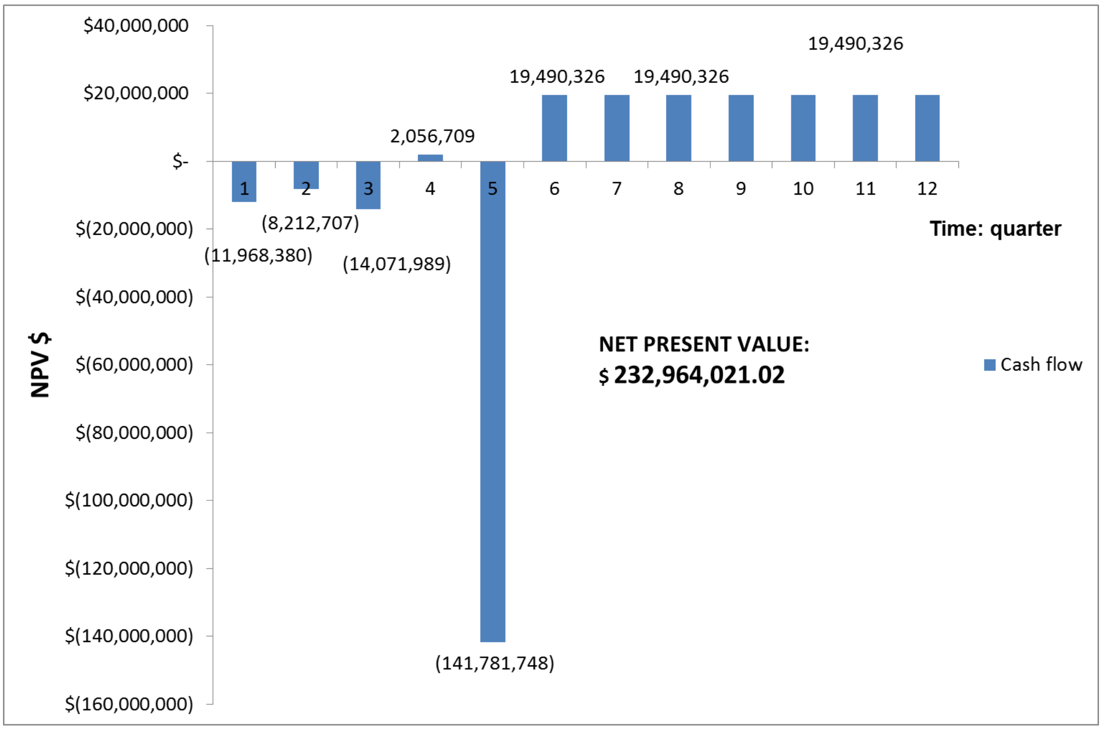

Figure 49: Cash flow and Net Present Value of scenario 9

3.10.4. Sensitivity analysis for scenario 9.

In the 3 complementary scenarios where the wellhead power plants are used for the low enthalpy wells the only significant factor is the time difference (TD), the differences in NPV with changes in any of the other two factors are practically nonexistent, as can be confirmed by looking at Figure 50.

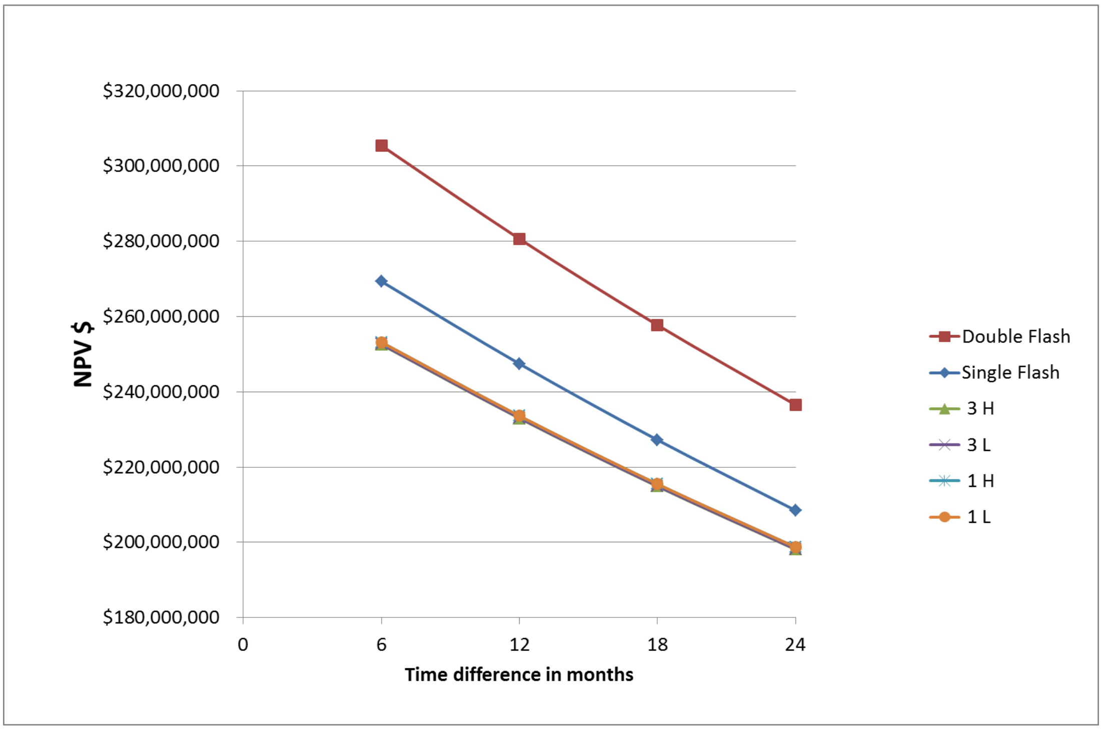

Figure 50: Net Present Values calculated in the Sensitivity analysis for scenario 9.

3.11. Results for scenario (10) with wellhead power plants with backpressure turbines for the low pressure wells and a single flash traditional power plant for the rest of the wells.

In this scenario the geothermal fluid from the wells with the lowest enthalpy and lowest pressure was utilized in wellhead power plants with backpressure turbines, the geothermal fluid from the rest of the wells was utilized in a separate single flash central power plant.

3.11.1. Power output result of scenario 10.

The power output results are shown in Table 22.

Table 22: Power output results of scenario 10.

Well	Separator Pressure	well ṁ	Gross Power	NET POWER
	[bar abs]	[kg/s]	[KW]	[KW]
1	14	334.6	107,522	105,093

Well	Separator Pressure	well $\dot{m}$	Gross Power	NET POWER
	[bar abs]	[kg/s]	[KW]	[KW]
2				
3				
4				
5				
6				
7				
8	10	30.02	2,171	2,171
9	10	24.76	1,595	1,595
10	10	50	2,749	2,749
Totals		**439**	**114,037**	**111,608**

3.11.2. Cost and revenue estimation results for scenario 10.

In the complementary scenarios the wellhead power plants have the cost of the transmission lines and the power plant with the rest of the wells has the cost of the steam gathering system.

Table 23: Revenue and cost results for scenario 10.

REVENUE	**COST**					
REVENUE	cost per KW	power plant cost	O&M		Transmission	Steam Gathering
[$/year]	[$/KW]	[$]	[cent/KWh]	[$/year]	[$]	[$]
82,855,321	1,249	134,391,573	1.55	13,120,854		26,880,500
1,711,616	1,512	3,284,256	2.01	344,753	217,100	
1,257,498	1,515	2,417,065	2.02	253,650	159,500	

REVENUE	COST					
REVENUE	cost per KW	power plant cost	O&M		Transmission	Steam Gathering
[$/year]	[$/KW]	[$]	[cent/KWh]	[$/year]	[$]	[$]
2,167,312	1,510	4,151,440	2.01	435,909	274,900	
87,991,747		**144,244,334**		**14,155,165**	**651,500**	**26,880,500**

3.11.3. Net Present Value results for scenario 10.

The net present value of this scenario is shown in Figure 51 together with the cash flows for the first 3 years of the project; the cash flows remain constant for the rest of the planning horizon.

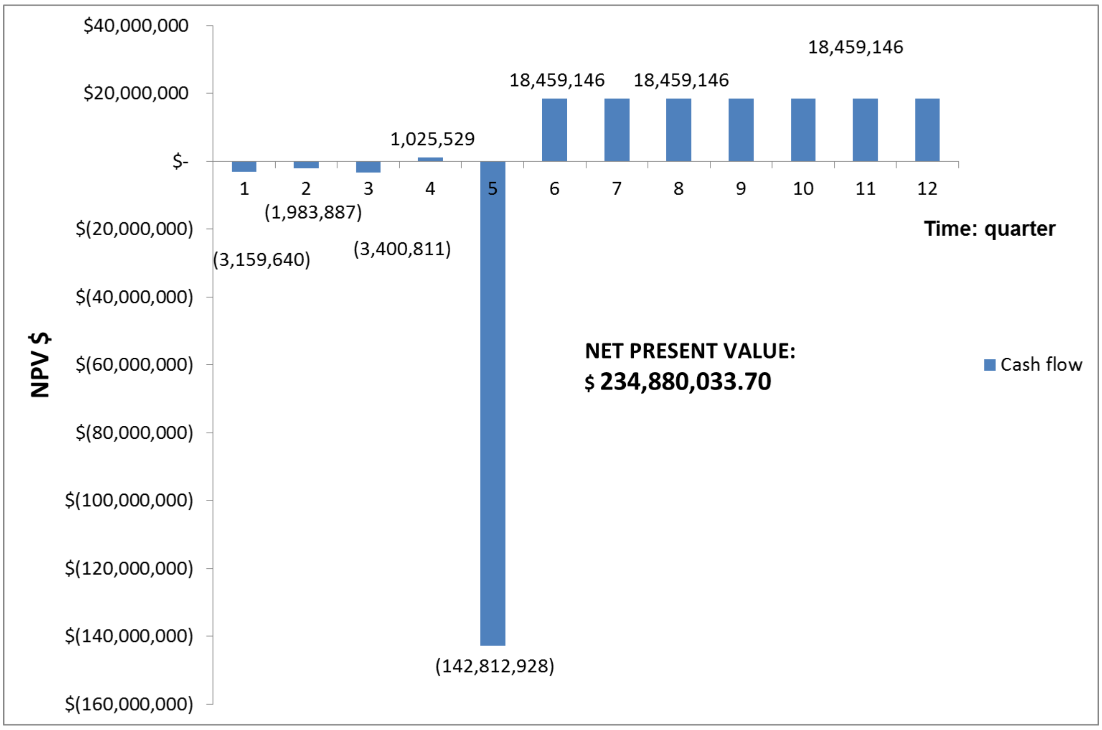

Figure 51: Cash flow and Net Present Value of scenario 10

3.11.4. Sensitivity analysis for scenario 10.

In the 3 complementary scenarios where the wellhead power plants are used for the low enthalpy wells the only significant factor is the time difference (TD), the differences in NPV with changes in any of the other two factors are practically nonexistent, as can be confirmed by looking at Figure 52.

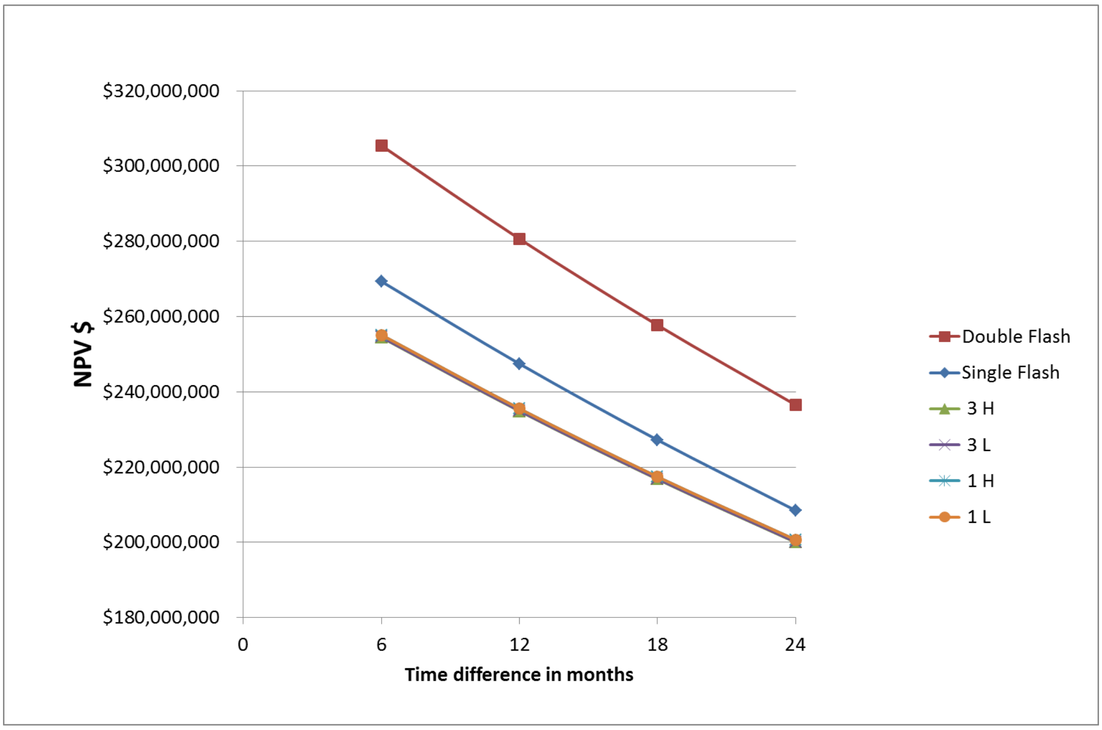

Figure 52: Net Present Values calculated in the Sensitivity analysis for scenario 10.

4. Discussion

To summarize the results, we should look them by type of scenario and refer to the sensitivity analysis graphs that were shown with the results of each scenario in the previous section.

It is important to note that in the power output results of the wellhead power plants where the geothermal fluid of the high enthalpy wells is utilized the separator pressure to optimize the power output is sometimes higher than what is currently available in the market, it was decided to make the calculations with these results to show the potential of those wells.

4.1. Permanent scenario

In this scenario the only scenario where wellhead power plants were considered was scenario 3, wellhead power plants with condensing turbines were used. It is interesting to see that after 12 months' time difference (TD) from start of production, the wellhead option becomes better than the single flash central power plant when the rate at which the wellhead power plants are installed is one per month.

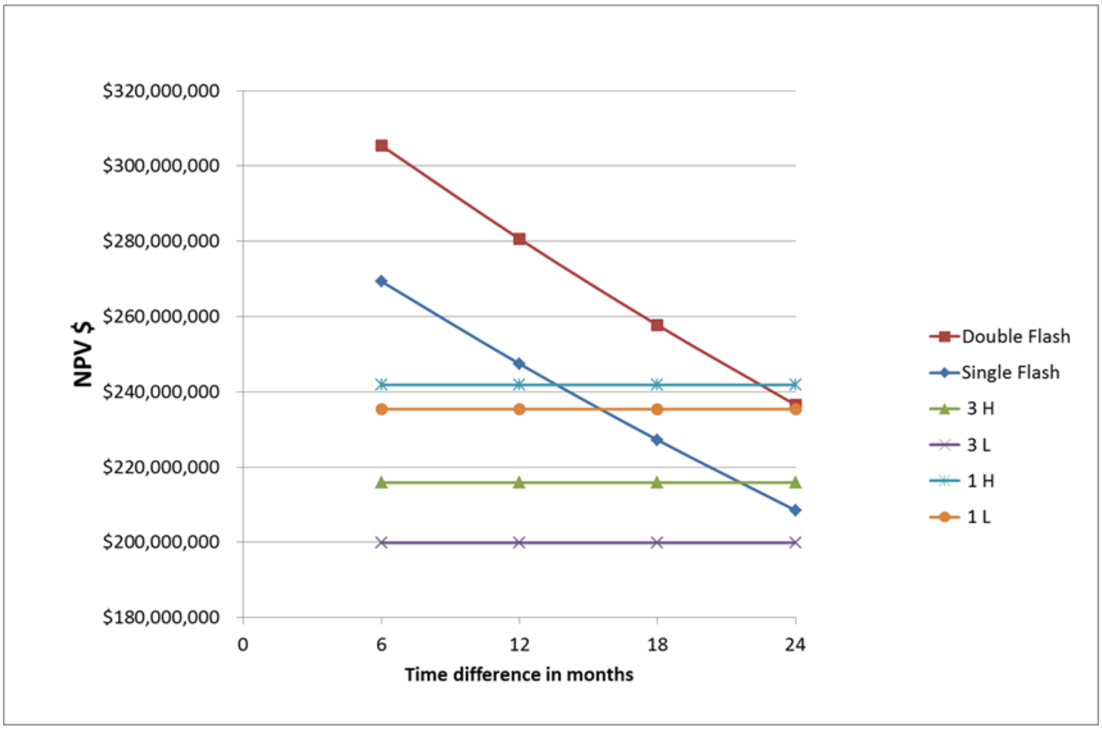

Figure 53: Net Present Values calculated in the Sensitivity analysis for scenario 3.

4.2. Wellhead power plants in the early stages of development

- In the early stages, if the time difference (TD) becomes bigger than 18 months the wellhead power plants with condensing turbines become a very good option when the rate of installation of wellhead power plants is one per month; and it can be observed that the NPV "flattens" (see Figure 54).

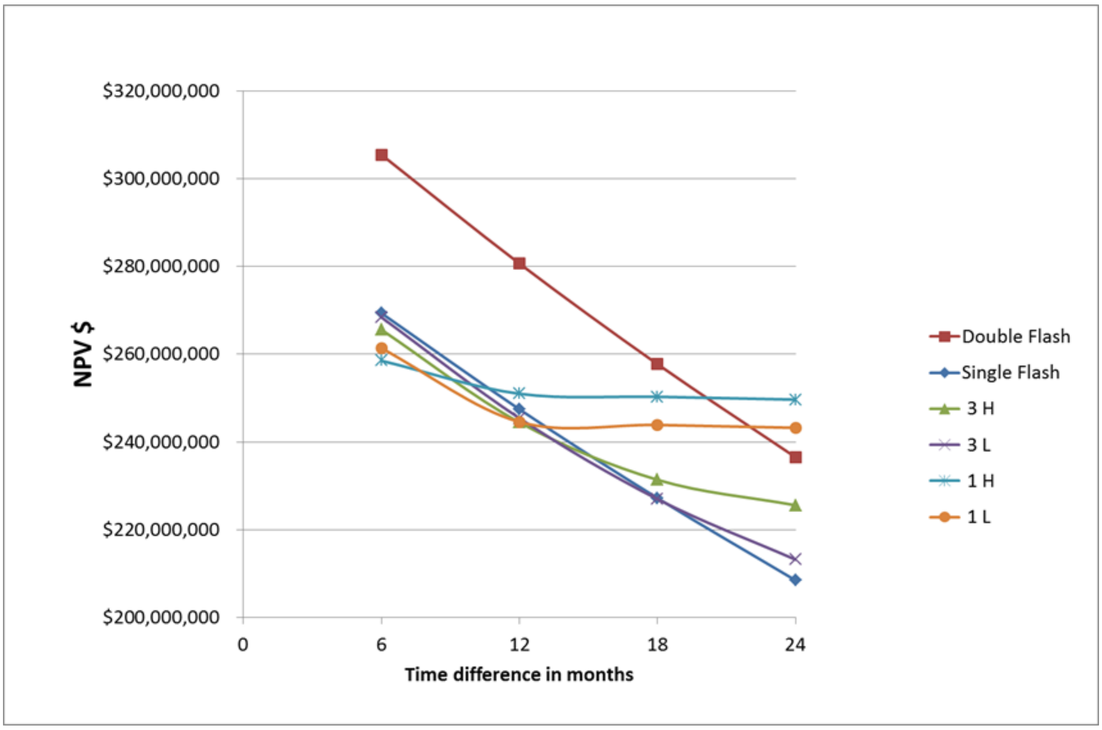

Figure 54: Net Present Values calculated in the Sensitivity analysis for scenario 4.

- Of the three scenarios where the wellhead power plants were installed in the early stages, the binary was the less attractive although it had the highest power output, mainly because of its high capital cost and high O&M costs (see Figure 55). Another factor that could affect this scenario is the assumption made in this thesis of not considering the non-condensable gas extraction system. If it had been considered this would reduce the power output of the steam cycle power plants as the NCG system does not apply to binary power plants.

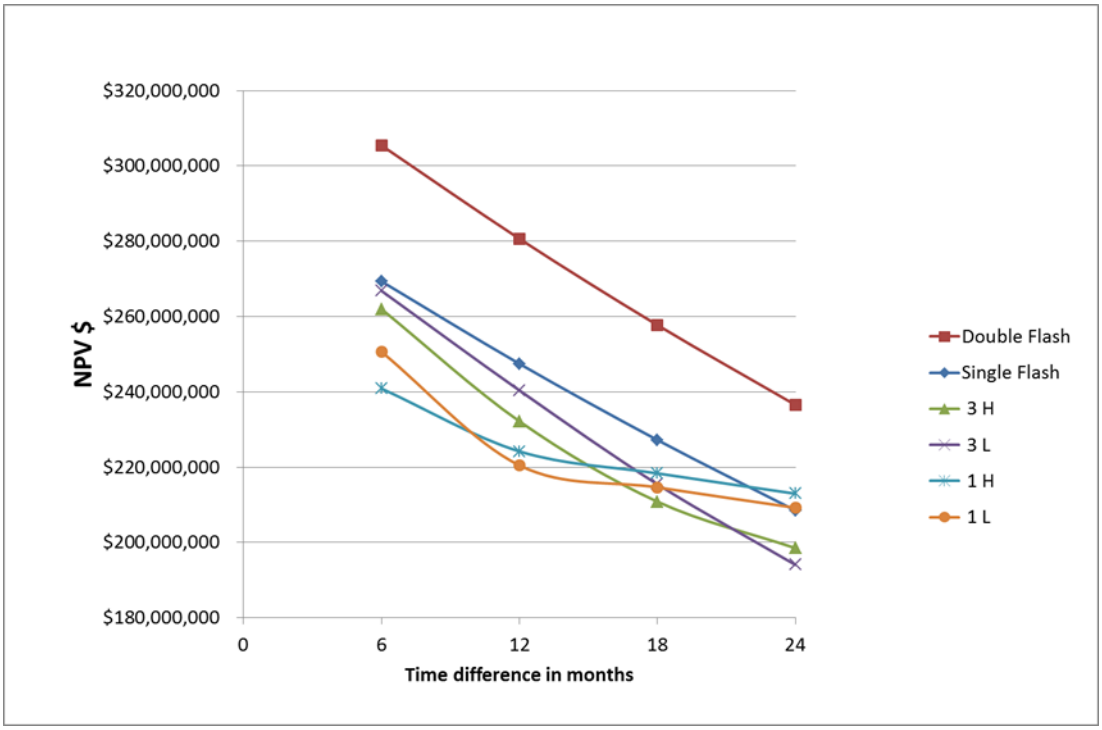

Figure 55: Net Present Values calculated in the Sensitivity analysis for scenario 5.

- If the time difference (TD) is 12 months or less the better option is the wellhead power plants with backpressure turbines (see Figure 56).

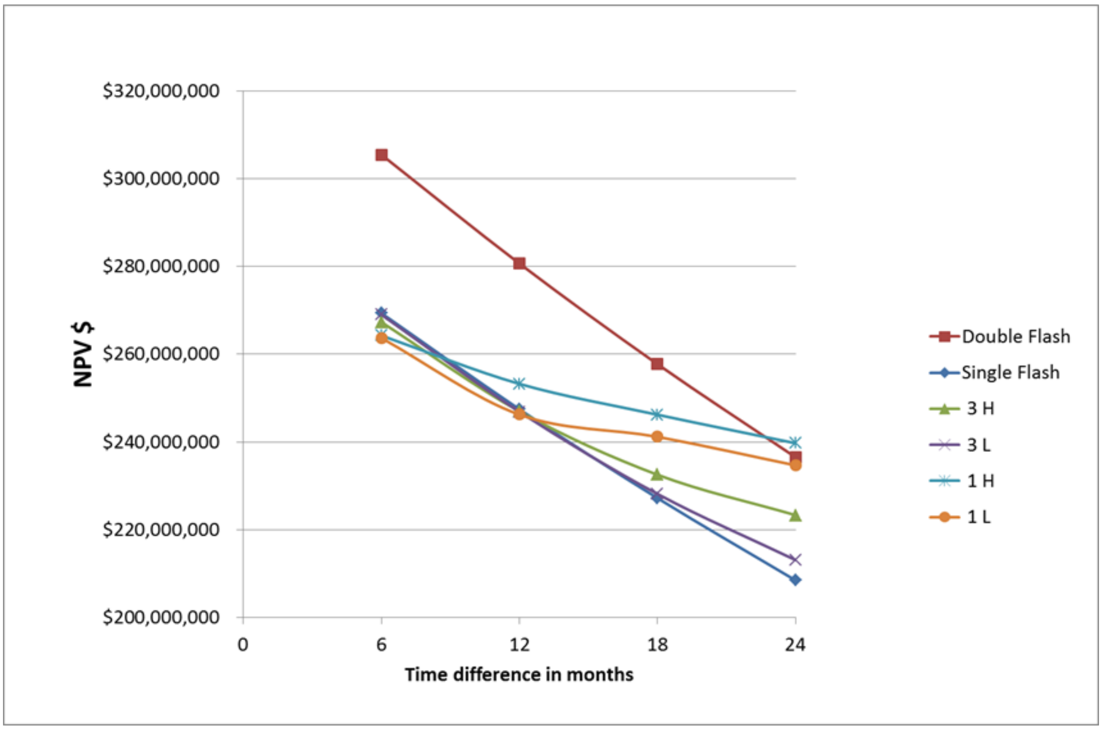

Figure 56: Net Present Values calculated in the Sensitivity analysis for scenario 6.

4.3. Complementary scenarios:

Of the complementary scenarios it can be seen that the only scenario where the use of wellhead power plants brings some benefit is scenario 7 (see Figure 57), where the wellhead power plants are used for the high enthalpy wells. The other three scenarios (see Figure 58, Figure 59 and Figure 60), where the wellhead power plants use the low enthalpy wells the results are worse than if those wells had been used in the single flash central power plant, perhaps the results would be different in a steamfield with wells with lower enthalpies or lower mass flows than those from the hypothetical steamfield. In these scenarios there is no benefit from a time difference (TD) between the wellhead and the central power plants, because both type of power plants are used simultaneously, so the NPV follows the same trend as the NPV of the central power plants (scenario 1 and 2)

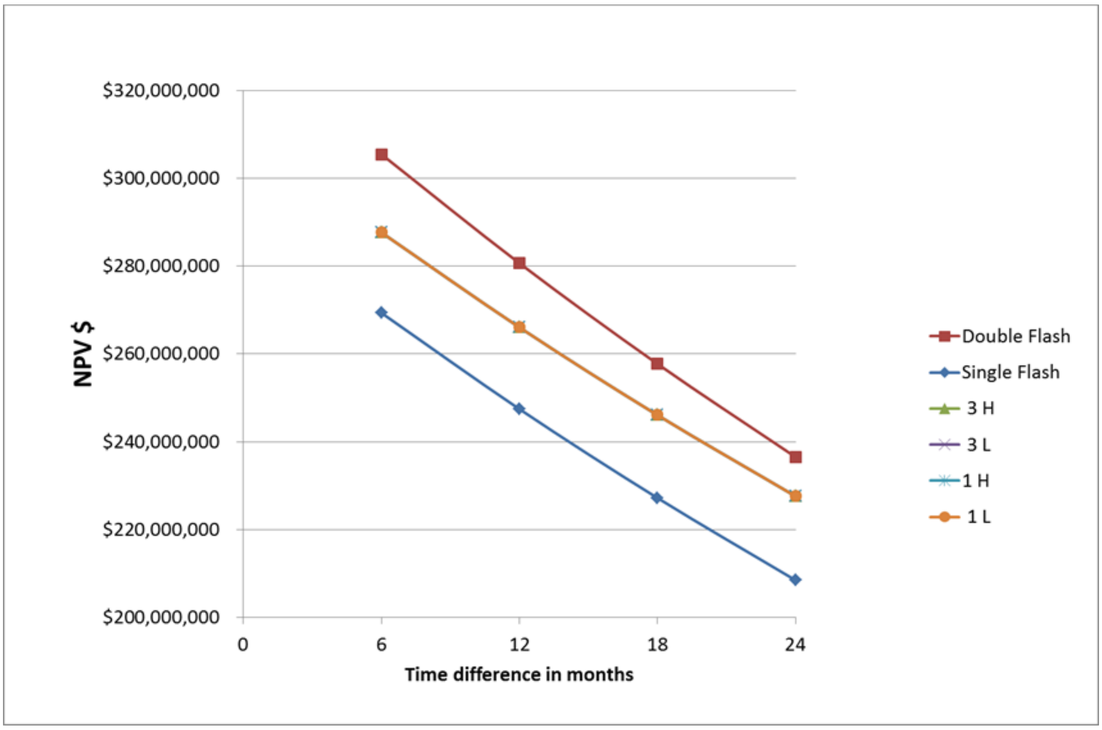

Figure 57: Net Present Values calculated in the Sensitivity analysis for scenario 7.

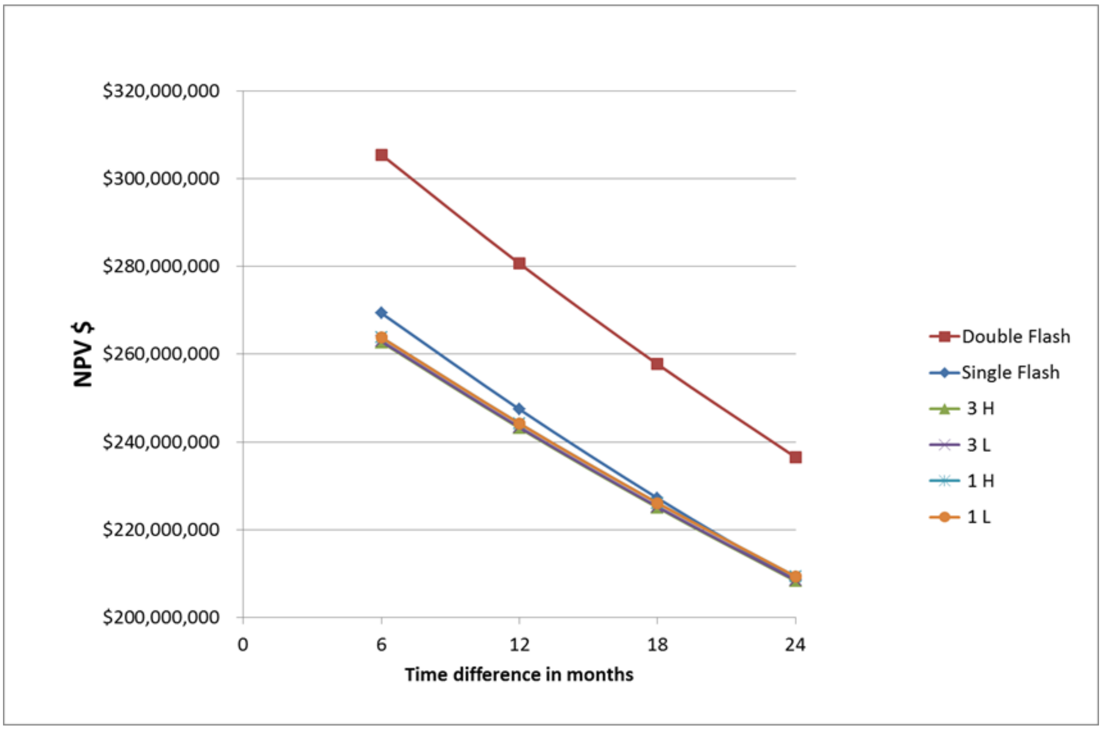

Figure 58: Net Present Values calculated in the Sensitivity analysis for scenario 8.

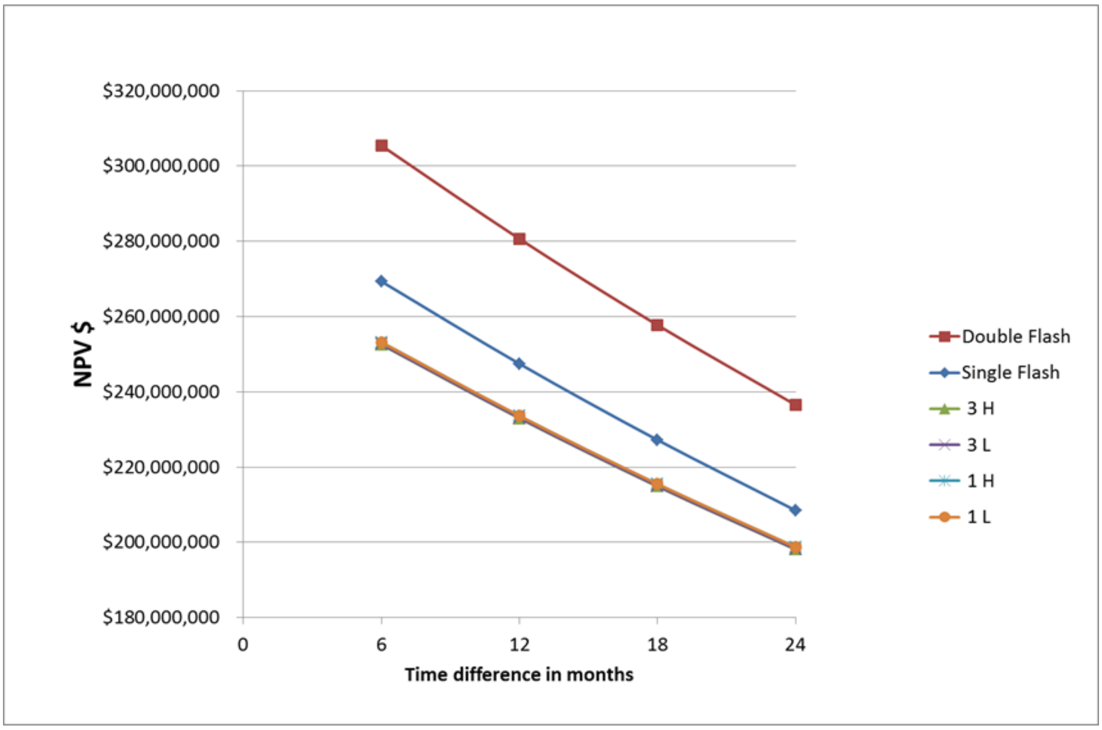

Figure 59: Net Present Values calculated in the Sensitivity analysis for scenario 9.

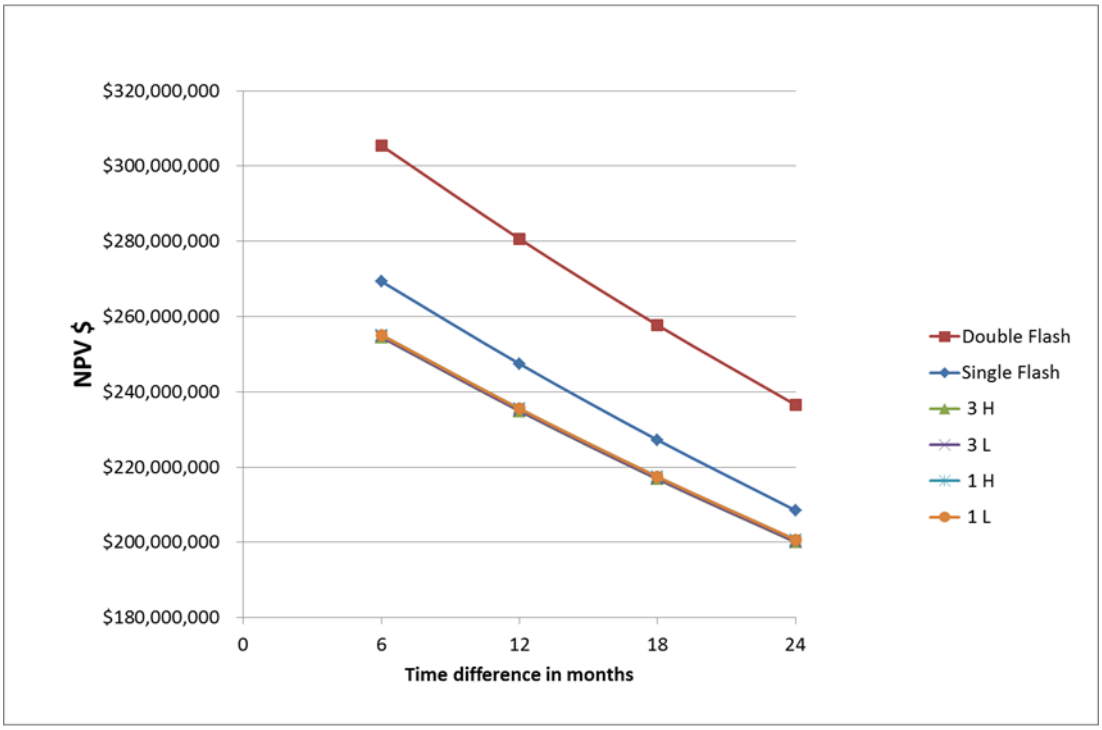

Figure 60: Net Present Values calculated in the Sensitivity analysis for scenario 10.

5. Conclusions

Interesting to see that in the three scenarios, important benefits can be obtained from the use of wellhead power plants depending on some factors:

- Time difference (TD) between the start of production with a wellhead power plant and a central power plant. The longer the time difference (TD) between the start of production of a wellhead power plant and a central power plant the more attractive the wellhead option becomes. Of course if this time difference (TD) is reduced the benefit of the wellhead power plants decreases.
- Another important factor is the rate at which the wellhead power plants can be installed, if the installation can be at the rate of one wellhead power plant every month then the scenarios where the wellhead power plants are installed in the early stages of development (scenarios 4, 5 and 6) are attractive with time difference (TD) as small as 12 months. Also in the permanent scenario (scenario 3) the benefit is greater in the cases where the wellhead power plants are installed once a month.
- Of the three factors analyzed in the sensitivity analysis the less relevant was the order of drilling, this factor was incorporated to try to have the two extremes, on the high end: starting with the high enthalpy wells; and on the low end: starting with the low enthalpy wells. The difference in NPV with this factor is less than with the other two factors: time difference (TD) and rate to install wellhead power plants.
- In the complementary scenarios the only benefit was observed in the scenario where the wellheads were used for the high enthalpy wells.

6. Future work

This thesis was done considering one hypothetical stamfield with ten scenarios with different types of power plants. Some assumptions were made in order to make the comparisons on an even basis and to establish the methodology. In my opinion it would be important to make a more detailed analysis of some of these assumptions:

- The resale value in the early stages scenarios as it is a very important factor in those scenarios and there is not a big market for used wellhead power plants that provides reliable information about the resale values
- It would be very important to include in the sensitivity analysis:
    - the resale value
    - costs
    - economies of scale
- Include the non-condensable gas extraction system to consider the parasitic load from it
- Consider a more detailed analysis on the equipment needed in each type of power plant. In central power plants there need to be some redundant equipment, such as pumps, etc… that in a wellhead arrangement might not be necessary
- Make a more detailed model to calculate the power output
- Make a deeper analysis of the costs
- It would be very interesting to see results using this method with more steamfields, especially with steamfields with low enthalpy wells that are not used since the hypothetical steamfield might not be appropriate to test some scenarios, especially the ones where the low enthalpy wells were utilized with the wellhead power plants separately from the rest of the wells. With data from more steamfields it would also be interesting to calculate power output results of the binary power plants with other working fluids

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