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Comparison of Methods for Utilization of Geothermal Brine for Power Production

Marta R. Karlsdottir, Halldor Palsson and Olafur P. Palsson

Hjardarhaga 2-6, 107 Reykjavik, ICELAND

mrk1@hi.is, halldorp@hi.is and opp@hi.is

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ABSTRACT

The objective of the study is to compare methods that increase power generation from conventional single flash power plants by utilizing waste heat contained in brine from steam separators. Three different utilization methods are investigated by constructing thermodynamic models of different power cycles and optimizing the specific net power output for each cycle using conditions of hypothetical geothermal areas. The cycles investigated include a conventional double flash cycle, an organic Rankine bottoming cycle in parallel with a single flash cycle using isopentane as a working fluid and a modification of the double flash cycle involving an added recuperator between the geothermal brine and the steam at the high pressure turbine outlet. Also, a model of a single flash power plant is constructed for comparison. The specific net power outputs of the different cycles are compared along with the overall efficiency of the cycles. Finally, an economical analysis is performed to further compare the feasibility of the different cycles using conventional economical analysis to estimate the cost of the final product.

The results of the study can be used as a measure of comparison between the different conventional methods of utilizing geothermal energy for electrical power production with respect to the energy content, or the enthalpy, of the geothermal fluid produced from production wells. Also, a new method of utilizing geothermal brine by modifying the double flash cycle is introduced and compared to the conventional cycles. The new method could provide useful results for increased power production compared to the other cycles and also, as a future study, provide a method of better controlling the double flash cycle in case of changes in the fluid characteristics from production wells, which is expected in future operation time of geothermal power plants.

1. INTRODUCTION

One of the most common types of power plant worldwide is the single flash power plant. Single flash power plants utilize the steam portion of the geothermal fluid flowing from the wells to produce electricity without further utilizing the heat left in the geothermal liquid that travels with the steam from the well. Various technical developments have been introduced to better utilize the energy potential in the geothermal fluid than is done in the single flash cycle. The main developments are the double flash cycle and the binary bottoming cycle. These cycles have the potential to improve the power production from geothermal areas considerably.

Single flash cycles produce about 43% (in May 2005) of all the electricity generated from geothermal energy worldwide (DiPippo, 2005). If the temperature of the brine from the steam separator in the single flash unit is high enough, the brine can be utilized further to produce more electricity. The double flash cycle uses the geothermal brine by producing excess steam in a second flashing stage. The double flash cycle has been shown to be able to produce up to 20-25% more power than the single flash cycle (Dagdas, 2007).

Studies have shown that adding a binary unit as a bottoming cycle to the single flash unit in areas with low- and medium enthalpies can be preferable to a flashing unit when the composition of the geothermal fluid is likely to cause scaling in the power plant equipment after flashing and cooling of the fluid. Studies have also shown that the lowest cost per kilowatt hour would also be obtained using an organic Rankine unit instead of a second flashing unit, although the efficiency would be smaller (Moya & DiPippo, 2007). The bottoming binary cycle coupled to the single flash cycle has shown an increased power production of 13-28% compared to the conventional single flash cycle (Paloso Jr. & Mohantly, 1993). The Kalina technology has shown increased efficiency from the conventional organic Rankine cycles (Heppenstall, 1998), (Wall, Chuang, & Ishida, 1989). An organic Rankine cycle is often a more natural choice than the Kalina cycle since the technology of the ORC cycle is well known (Paloso Jr. & Mohantly, 1993).

The aim of the study is to make a general comparison of methods that increase the power generation from the conventional single flash cycle by utilizing the heat in the brine from the steam separator. The three different power cycles that were examined and compared to a conventional single flash cycle are; a conventional double flash power cycle, a bottoming organic Rankine cycle coupled in parallel to the single flash cycle using isopentane as a working fluid and lastly, a modification of the double flash cycle with an added recuperator used to superheat the steam at the outlet of the high pressure turbine. The comparison of the cycles is made with a given enthalpy range of 1000 kJ/kg to 2500 kJ/kg and can be used as an indicator for what type of power plant would be suitable for a certain geothermal area with respect to the enthalpy of the production wells and the corresponding net specific power output. A cost estimation of the production cost of electricity was also compared for the different cycles.

1.1 Prerequisites and Limitations of Study

The modeling of the different power cycles in this study is not associated with a specific geothermal area that has known characteristics of the geothermal fluid and corresponding limitations to the possibilities of utilization. Geothermal areas can have different characteristics depending on their geological conditions. The chemical content of the fluid can vary greatly; both regarding dissolved minerals from the rock formation and the amount of non condensable gases that travel with the fluid to the surface (Pálmason, 2005). The chemical content of the fluid results in some limitation of utilization possibilities, as the minerals can precipitate and cause damage to the power plant equipment due to scaling. Also, the amount of non condensable gasses directly affects the net power output of the power plants as they have to be removed from the energy conversion process with mechanical equipment such as a compressor or an ejector (Dickson & Fanelli, 2005). If the amount of non condensable gasses is too high, it can become economically unfeasible to produce power from the geothermal fluid.

2. THERMODYNAMIC MODELLING AND ECONOMICAL ANALYSIS

2.1 Modeling of a Single Flash Power Plant

A simplified schematic of a single flash power plant is shown in Figure 1. The figure shows the most important equipment that affects the thermodynamics of the energy conversion process. The two phase mixture flows from the production well, W, and is led through a steam separator, S where steam is separated from the fluid and led through towards the power house which contains the turbine, T, and the electrical generator, G.

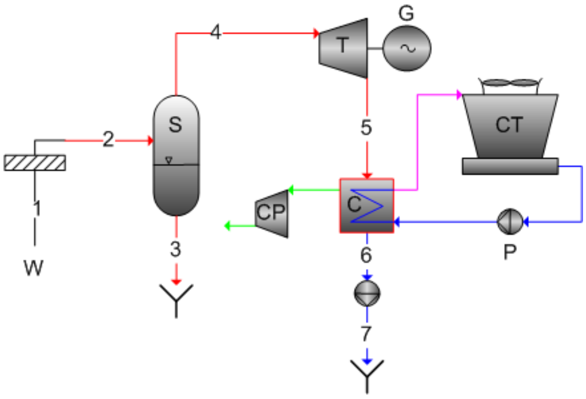

Figure 1: A schematic of a simple single flash power plant

The isentropic efficiency for a geothermal turbine is typically 81 - 85% and the mechanical efficiency of the turbine generator is approximately 96.3% (Dickson & Fanelli, 2005). Due to pressure drops in the steam across the steam turbine, the steam quality also decreases and small droplets can form that can damage the turbine blades. Thus, the pressure drop across the turbine is limited to produce no less than 85% quality of steam at the steam outlet. This criterion affects the allowable pressure at the high pressure end of the turbine as the low pressure end is usually restricted by the condensing unit, C. The heat exchangers in the condensing units in this study were assumed to be conventional counter flow heat exchangers and thus modeled without correction factors needed for modeling shell- and tube heat exchangers. Cooling water for the condensation is circulated through a cooling tower, CT where partial evaporation in the presence of moving airstream cools the cooling water to near the wet-bulb air temperature (DiPippo, 2005).

An important part of the condensing process is the extraction of non-condensable gases (NCG) that are mixed within the geothermal fluid and travel with the steam through the energy conversion process. The non-condensable gases are mostly carbon dioxide (CO_2, often about 95% (Thorbjörnsson, 1995), hydrogen sulfide H_2S) and hydrogen gas (H_2) and the composition varies depending on the different geothermal fields. The amount of non-condensable gases can range from a low gas content of about 1.5% of the total mass flow of steam from the wells up to over 12% (Dickson & Fanelli, 2005). These gases accumulate in the condenser and must be pumped out of the condensing unit using some gas extraction equipment such as a gas compressor, shown in Figure 1 marked with the symbol CP. If the gasses are not pumped out of the condenser, the pressure in the condenser will accumulate and thus the power output of the power plant will decrease (DiPippo, 2005).

The analysis of the different power cycles are based on thermodynamic equations that describe the energy and mass conservation in the main power plant components. The mass balance equations take into account that the mass flow, $\dot{m}$, into a component must be equal to the mass flow out of the component in a system at steady state conditions. The energy balance equations state that the flow of energy into a component must equal the energy flow out of the component. The energy transfer in and out of the component can occur by means of:

- Energy by fluid flow, expressed as $\dot{m} \cdot h$, accompanying the fluid as it enters or exits the component
- Work, $\dot{W}$, performed or consumed
- Heat, $\dot{Q}$, flowing in or out of a component

For the thermodynamic modeling of each component in an energy conversion system, the control volume method is applied where the principles of mass and energy conservation are used for all entering and exiting streams to and from the control volume boundary (Moran & Shapiro, 2002).

A temperature - entropy diagram for the single flash cycle can be seen in Figure 2. The numbering on the diagram corresponds to the numbering in Figure 1.

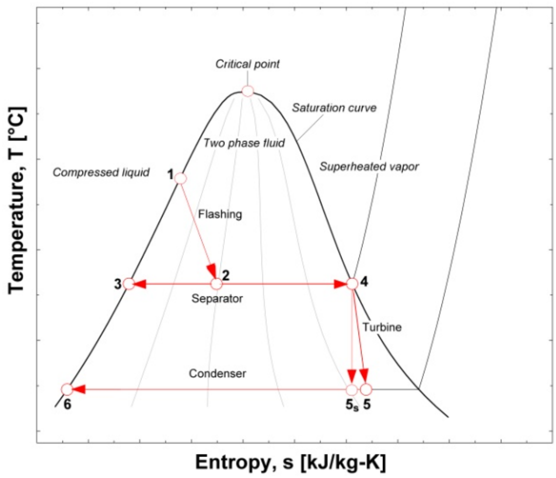

Figure 2: A temperature - entropy diagram for a single flash power plant

2.2 Modeling of a Double Flash Power Plant

The double flash cycle is a thermodynamic improvement of the single flash cycle, where the waste heat in the geothermal brine from the separator is flashed in a throttling process that decreases the pressure of the brine allowing it to boil to produce steam that can then be used to drive a low pressure turbine. A schematic of a typical double flash cycle is shown in Figure 3.

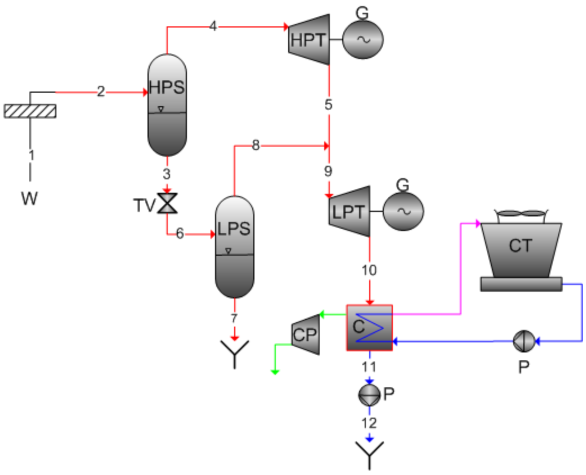

Figure 3: A schematic of a double flash power plant

The process is similar to the single flash cycle discussed in Section 2.1. After the geothermal fluid has been separated in the high pressure steam separator, HPS, the brine is flashed by using a throttle valve, TV, that decreases the pressure of the brine and a two phase fluid is produced. The two phase fluid is then led through the low pressure separator, LPS, to separate the steam from the brine. The brine is then disposed off to reinjection wells or out to the natural surroundings. The low pressure steam from the separator is then combined with the steam from the high pressure turbine, HPT, which has been set to operate at the same low pressure conditions as the low pressure separator. The combined mass flow of steam is then led through a moisture remover (not shown on the figure for simplification) before entering the low pressure turbine, LPT, producing a pressure drop down to the condenser pressure at 0.1 bars. The condensing process, non-condensable gas extraction and cooling circuit processes follow the same procedure as the single flash cycle.

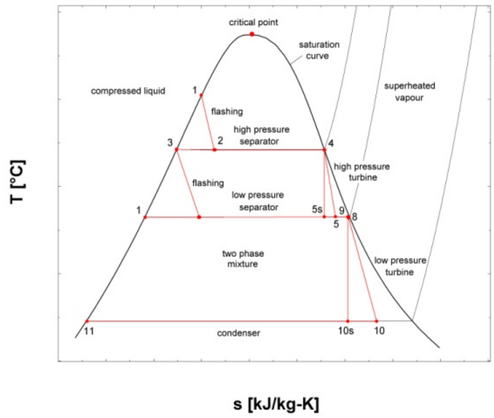

Figure 4: A temperature - entropy diagram for a double flash power plant

The temperature-entropy diagram for the double flash cycle can be seen in Figure 4. The thermodynamic analysis for the double flash cycle is similar to the analysis used in the single flash cycle.

2.3 Modeling of an Organic Rankine Bottoming Unit

Adding a binary bottoming cycle is an alternative utilization method to the double flash cycle to utilize the waste heat in the brine from a single flash cycle. This alternative could in some cases be preferable to the double flash cycle if mineral concentration in the brine is relatively high which could cause scaling if the brine would be flashed as it would in the double flash cycle (Moya & DiPippo, 2007).

An organic Rankine cycle is a binary cycle using an organic working fluid such as isopentane or isobutene to produce power. The organic fluids have an advantage over water as a working fluid due to the shape of the saturation curve as seen for isopentane in Figure 6. The shape of the curve leads to ensuring the dryness of the steam at the turbine outlet at low condenser pressures since the fluid becomes superheated at the outlet of the turbine. The organic working fluids typically have lower boiling temperatures than water, making them well suitable for utilizing lower temperature geothermal brine for power production.

For modeling a bottoming binary cycle, an organic Rankine cycle was coupled in parallel to the single flash cycle as shown on Figure 5. The brine from the steam separator is led through a heat exchanger, or a boiler B, that transfers heat to the working fluid, causing it to boil. The saturated vapor of the working fluid is then led through a turbine, BT, and the superheated vapor from the turbine outlet is pre-cooled in a recuperator, R, that preheats the compressed working fluid at state 13. Studies have shown that having an internal heat exchanger (recuperator) between the superheated stream at the turbine outlet and the compressed working fluid after condensation can increase the efficiency of the cycle (Drescher & Bruggemann, 2007). After the recuperator, the superheated vapor is condensed in the condenser, BC and finally pumped to the appropriate working pressure of the power cycle.

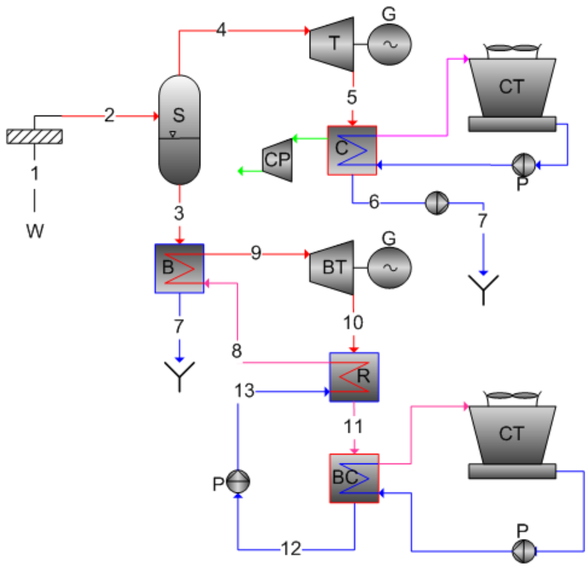

Figure 5: A schematic of a single flash power plant with an ORC bottoming unit

The heat transfer between the geothermal brine and the working fluid takes place in the boiler, B. The heat transfer has to be modeled in two stages as the working fluid both undergoes a heating process and a boiling process, causing the pinch in the heat exchanger to be located at the end of the heating process and beginning of the boiling process, as seen in Figure 7.

2.4 A Modification of the Double Flash Power Plant

A modification of the double flash cycle can be seen in Figure 8. The modification involves adding a recuperator, R, which uses a fraction of the waste brine from the high pressure steam separator, HPS, to reheat the steam from the outlet of the high pressure turbine, HPT. The rest of the brine from the high pressure separator is then flashed and used for the low pressure turbine as done in the conventional double flash cycle.

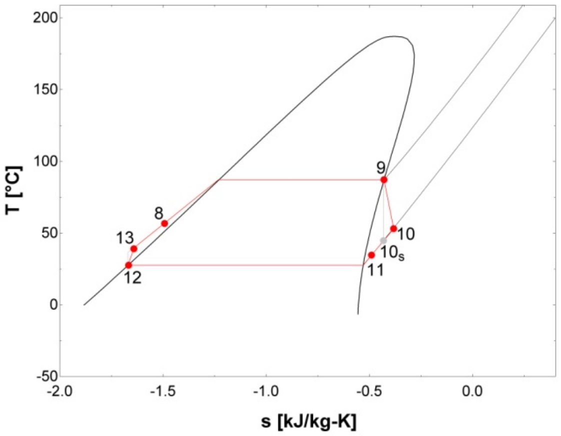

Figure 6: A temperature - entropy diagram of the Organic Rankine bottoming cycle using isopentane as a working fluid

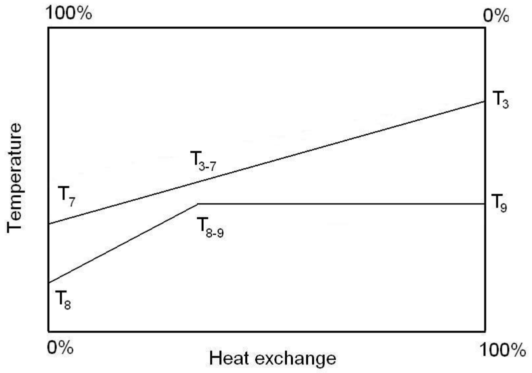

Figure 7: A temperature - quality diagram of the heat exchange between the geothermal brine and the binary working fluid

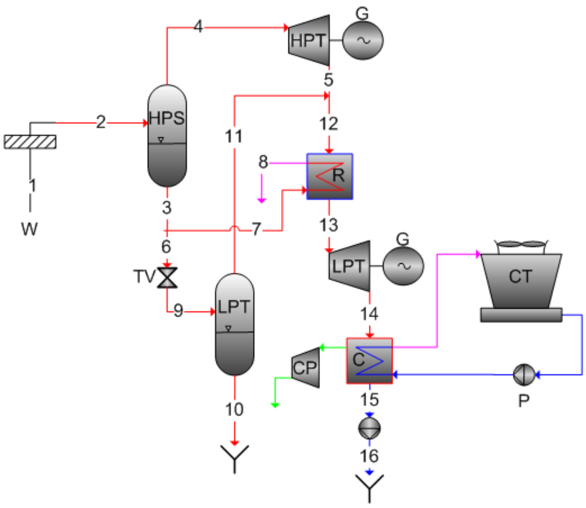

Figure 8: A schematic of a modified double flash power plant with added recuperator

The recuperator R is a heat exchanger that transfers thermal energy from the separator brine to the steam from the high pressure turbine. The temperature of the separator brine in the recuperator, T_7, is higher than the temperature of the steam from the turbine, T_5, so the steam can be heated up to approximately the same temperature as the brine in the heat exchanger. The minimum temperature difference or the pinch in the recuperator can be located either at the steam inlet (cold end) or the steam outlet (warm end) and is defined as 5°C in this study. The possible improvement compared to the conventional double flash cycle is due to superheating of the steam from the high pressure turbine which has a possibility to improve the power output of the low pressure turbine.

The idea of the modified double flash cycle is to increase the overall efficiency of the double flash cycle by superheating the steam from the high pressure turbine to enhance the power output of the low pressure turbine. The idea is similar to the idea behind a reheat Rankine cycle. Since lowering of the condenser pressure or increasing the boiler pressure is restricted by the moisture content of the steam at the turbine outlet in Rankine cycles, reheating the steam at an intermediate pressure between the high pressure at the turbine inlet and the condensing pressure could allow either lower condenser pressures or higher turbine inlet pressures without facing problems due to water droplet formation in the steam.

In a double flash power plant, where there is access to waste heat in the geothermal brine from the high pressure separator, the possibility for superheating is at hand. After the steam has been exhausted from the high pressure turbine, it is at a lower pressure and temperature than before entering the turbine as can be seen at state 5 in Figure 9. At the same time, the waste heat in the separator brine at point 3 is at the same temperature as the steam was before entering the turbine. This gives the possibility to transfer heat from the separator brine to the low pressure steam in a recuperator as explained before. By reheating the steam at a constant pressure up to almost the same temperature as the separator brine, the steam is superheated to state 13 and the thermodynamic gain is represented by the area under the superheated curve in Figure 9. The downside to this reheating process is that the brine discharge from the recuperator is at a slightly higher temperature than the discharge from the second flash steam separator, causing the average temperature at which heat is rejected from the working fluid to rise. Then the question is if the increase in power output due to the reheating process is larger than the decrease in power production due to the increase of the average discharge temperature from the cycle.

To investigate if the reheating process gives increased power output compared to the conventional double flash cycle, the possibility to use a fraction of the brine for the reheat process and the rest for the second flashing state is introduced by optimizing the amount of brine mass flow going through the recuperator and the second flashing state.

The setup of the modified double flash cycle is almost identical to the conventional double flash cycle. Only the possibility to extract some of the separator brine to a recuperator has been added.

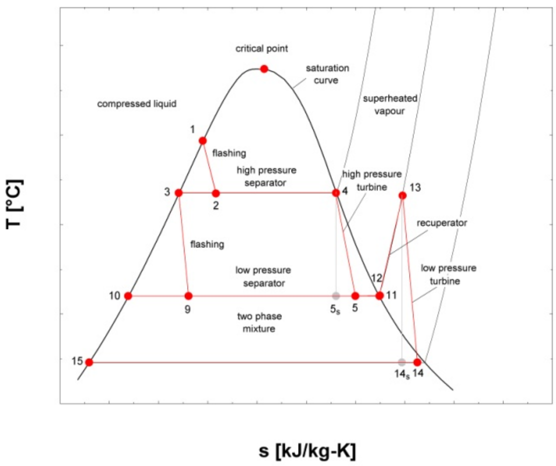

Figure 9: A temperature - entropy diagram for the modified double flash cycle

2.5 Economical Analysis

The capital an operating and maintenance (O&M) costs for each power plant type was estimated with conventional methods of economical analysis for geothermal power plants. The production cost of the final product, the electricity, was then evaluated for each power plant. In the following sections, these methods will be described within the scope of the study.

The capital cost is the initial investment cost of the power plant that is needed to purchase land, build all the necessary facilities and purchase and install the required equipment. The difference in capital investment of the different geothermal power plants lies mainly in the purchased equipment cost. For this study, the purchased equipment cost was estimated for all the different power plants in order to make a cost comparison of the different energy conversion systems. Also, the cost of the geothermal well was taken into account to calculate the total production cost of the electricity produced in the geothermal plant.

The total purchased equipment cost was estimated from classified actual data and levelized before it was used for the cost comparison. To estimate the cost of the machinery, the price and the size of the component have to be known or estimated to be able to give price estimation to the same component of another size. The effect of size on equipment cost can be found by plotting all available cost data versus the equipment size on a log-log plot and it has been shown that the data correlation normally results in a straight line within a given capacity range (Bejan, Tsatsaronis, & Moran, 1996). The slope of this line, α , represent an important cost estimating parameter such that the cost of a component of any size can be estimated by knowing the cost for the same component for a given size, given by the relation

$$C_{equipment} = C_{base}\left(\frac{size_{equipment}}{size_{base}}\right)^{\alpha} \quad (1)$$

where $C_{equipment}$ and $size_{equipment}$ is the cost and size of the equipment to be estimated and C_{base} and $size_{base}$ is the known cost and size for the same component. The scaling exponent, α , for the main components in the models in this study are given in Table 1 (Bejan, Tsatsaronis, & Moran, 1996).

Table 1: Typical values for the scaling component α

Component	Sizing	Exponent α
Compressor	Power	0.95
Cooling tower	Cooling water rate	0.93
Heat Exchanger, shell and tube	Surface area	0.66
Pump, centrifugal	Power	0.37
Separator, centrifugal	Capacity	0.49
Steam turbine, condensing	Power	0.9

The cost of drilling the geothermal well is estimated to be about 250 million ISK for a 2 km deep geothermal well. In order to adapt the cost of drilling to the unit mass flow analysis of the power plants, the specific cost of geothermal drilling was calculated by dividing the cost for a single well with the average mass flow from actual wells connected to the Svartsengi geothermal power plant located in the southern peninsula in Iceland. The specific cost of the geothermal well was then estimated to be 115.000 US$ per unit mass flow.

For the operating and maintenance (O&M) cost for the geothermal power plants, a rule of thumb was used to estimate the annual O&M expenses. The rule of thumb states that the O&M cost for a geothermal power plant can be estimated as roughly 2% of the total purchased equipment cost.

The purpose of the cost estimation in this study is to compare the difference in final production cost of the electricity and not to give a realistic view of the total cost associating the building and operating of a geothermal power plant. The capital cost of land, civil, structural and architectural work, piping, installation of equipment, instrumentation and controls and electrical equipment and materials are roughly estimated as 2/3 of the total capital cost and the purchased equipment cost accounts for 1/3 of the total capital cost.

The capital investment is the part of the capital cost that investors put into the project. The capital investment was assumed to account for 30% of the total capital cost of the different power plants, and a 70% loan was assumed to cover the rest of the required capital cost.

To calculate the annual cost of the capital investment and the annual cost of loan, the initial investment cost and the loan must be divided into equal-amount money transactions, A_{equal} , which can be calculated as

$$A_{equal} = P \cdot CRF \quad (2)$$

where P is the present worth of the capital cost and CRF is the capital recovery factor used to determine the equal amounts A of a series of n money transactions that have the present value equal to P . The CRF is defined as

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1} \quad (3)$$

Here, i is either the required rate of return for the investment capital, chosen to be 15% in this study, or the loan interest rate, chosen as 6% for the loan for the capital cost. Inflation and escalation also affect the value of the annual equal amount over the project lifetime. The effect of inflation and escalation were neglected in this study for reasons of simplification as they do not greatly affect the cost comparison between the power cycles.

Similar calculations would have to be done for the O&M costs for the entire power plant. Due to cost escalation, the estimated O&M cost increases from year to year causing non-uniform annual payments. By neglecting the effects of cost escalation, the O&M costs can be assumed to be fixed over the lifetime of the project as was done in this study.

The annual revenue needed to cover the investors requirements of return, costs associated with operation and maintenance of the power plant and costs associated with the down payments of loan can then be calculated as:

$$A_{revenue} = A_{return} + A_{loan} + A_{O\&M} \quad (4)$$

To evaluate the required cost of the product, the annual required revenue, $A_{revenue}$, is divided by the net annual power production to get the cost per kWh for the electricity. The amount of kWh produced where calculated as

$$W_{kWh} = \dot{W}_{net} \cdot t_{op} \quad (5)$$

where t_{op} is the total annual operating time of the power plant in seconds. In this project, the operating time was estimated as $3600 \cdot 8040$ seconds by assuming 30 days of downtime due to preventive maintenance of the plant.

3. OPTIMIZATION OF NET POWER OUTPUT

The optimization of the maximum net power output for each cycle was done by interaction between the thermodynamic calculations in the software Engineering Equation Solver (EES) and an optimization routine in Matlab by using the function fmincon. This was done due to problems of restricting the optimization problem in the optimization routine provided in EES. The Matlab function fmincon uses constrained nonlinear optimization and is an effective tool for this kind of optimization.

The interaction between EES and Matlab was in the form of a dynamic data exchange (DDE). Dynamic Data Exchange is a technology for communication between multiple applications under Microsoft Windows software operating system and its primary function is to allow Windows applications to share data. The DDE interaction between Matlab and EES allows the possibility to use EES as a database for thermodynamic values and solve the balancing equations used to model each power plant and send the solutions to Matlab where the optimizations routine can process the data and find the optimized values for each cycle.

3.1 Optimization Variables and Constraints

3.1.1 Single Flash Power Plant

Optimization of the power output of the single flash cycle is based on choosing the optimum wellhead (or separator) pressure that gives the maximum power output for the cycle. The optimization routine is relatively simple since there is only one optimization variable and it can be determined from varying the value of the wellhead pressure to locate the power output maximum.

The steam quality at the output of the turbine is a constraint in the optimization problem, as the quality may not go below 0.85 steam quality and that limits the maximum wellhead pressure allowed as can be seen on a temperature-entropy diagram for the single flash process, e.g. in Figure 2.

3.1.2 Double Flash Power Plant

For optimizing the power output of the double flash cycle, two optimum pressure states, P_2 and P_6, need to be found. Thus, an extra degree of freedom has been added to then optimization routine compared to optimization of the single flash cycle that makes the procedure more complicated. For each value of the operating pressure of the high pressure separator HPS, an optimum pressure value can be found for the low pressure separator LPS. The problem is then to find the two corresponding pressures at which the double flash cycle gives the highest net electrical power output $\dot{W}_{net}$.

The constraint in the optimization process is, as for the single flash cycle, the steam quality at the outlet of each turbine. This constraint affects the allowable pressure at the high pressure state of each turbine. Thus, there are two steam quality constraints for the double flash cycle; constraints for the steam quality at state 5, x_5 and at state 10, x_{10}.

3.1.3 Hybrid Single Flash Power Plant with Organic Rankine Bottoming Cycle

There are two different optimization variables for the hybrid single flash plant with the organic Rankine bottoming cycle. First, the wellhead pressure must be optimized as for the other cycles and second, the pressure in the organic Rankine bottoming cycle needs to be optimized.

For this cycle, only the steam quality at the outlet of the steam turbine becomes a constraint due to the fact that the isopentane vapor at the outlet of the binary turbine is superheated and thus, no moisture is present.

3.1.4 Modified Double Flash Cycle

Four optimization variables where used to optimize the net power output of the modified double flash cycle. First, the separator pressures, P_2 and P_9 have to be optimized as well as the constant describing the fraction of mass flow taken from the separator brine and used for reheating, f_{reheat}. The temperature of the waste brine at the cold end of the recuperator, T_8, was also optimized to monitor the location of the pinch point in the recuperator.

3.1.5 Overview of the Optimization Problems

An overview of the optimization variables and constraints for each power cycle can be seen in 3.2 Wellhead Pressure Limitations

The wellhead pressure directly affects the mass flow from the well. A typical geothermal well productivity curve for water fed well and a well producing two phase flow is shown in Figure 10. As the pressure increases, the mass flow produced by the well will eventually decrease to a point that the well is completely closed and no mass flow is produced. That is why production curves for the wells connected to the geothermal power plant must be available before optimization of the wellhead pressure is determined. At a specific pressure range, the mass flow from the well with the two phase flow is relatively stable with a low decrease in the production. This pressure range is different from well to well and depends on the geothermal reservoir. In Iceland, some high-enthalpy wells at the high temperature field at Námafjall in northern Iceland can hold a steady production up until 40-50 bars before the mass flow begins to decrease.

Table 2.

3.2 Wellhead Pressure Limitations

The wellhead pressure directly affects the mass flow from the well. A typical geothermal well productivity curve for water fed well and a well producing two phase flow is shown in Figure 10. As the pressure increases, the mass flow produced by the well will eventually decrease to a point that the well is completely closed and no mass flow is produced. That is why production curves for the wells connected to the geothermal power plant must be available before optimization of the wellhead pressure is determined. At a specific pressure range, the mass flow from the well with the two phase flow is relatively stable with a low decrease in the production. This pressure range is different from well to well and depends on the geothermal reservoir. In Iceland, some high-enthalpy wells at the high temperature field at Námafjall in northern Iceland can hold a steady production up until 40-50 bars before the mass flow begins to decrease.

Table 2: Optimization variables and constraints for each power cycle

Power cycle	Optimization variables	Constraints
Single flash	P_2	$x_5 \geq 0.85$
Double flash	P_2, P_6	$x_5 \geq 0.85$, $x_{10} \geq 0.85$
Hybrid single flash and ORC	P_2, P_{13}	$x_5 \geq 0.85$
Modified double flash	P_2, P_9, f_{reheat}, T_8	$x_5 \geq 0.85$, $x_{14} \geq 0.85$

In this study, the optimization of the wellhead pressure is not dependant on production curves and the power output is calculated as specific power production (Power produced per unit mass flow) in kW/ $\dot{m}$ where $\dot{m}$ is in kg/s. These calculations will determine the specific power output for the cycle whilst varying the energy output of the production wells. The wells are modeled as a single well with a given enthalpy ranging from h_0 = 1000 kJ/kg to h_0 = 2500 kJ/kg. The upper range of the well enthalpy is relatively high but such high enthalpies can occur in high-enthalpy high-temperature areas with steam dominated wells and even in deep drilling projects.

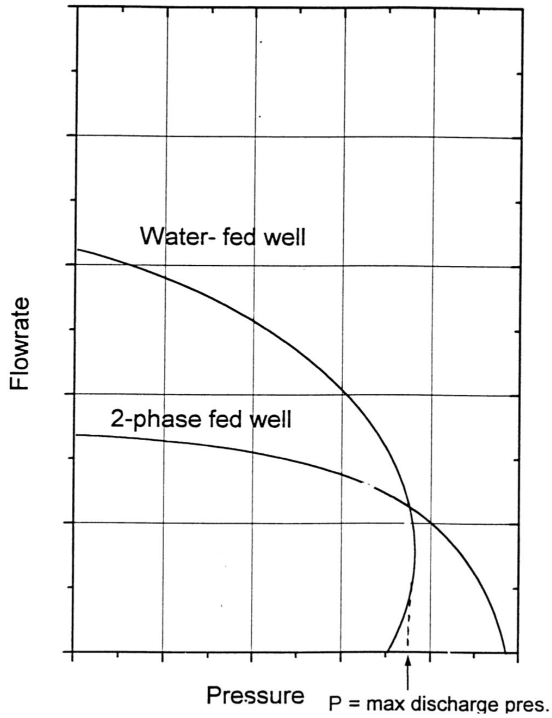

Figure 10: Productivity curves for geothermal wells producing two phase flow and liquid flow (Iceland GeoSurvey)

3.3 Other Limitations and Assumptions

For the optimization of the different cycles, some assumptions had to be made regarding the behavior of the geothermal reservoir and the limitations and restrictions in the power plant equipment. These assumptions are listed in the sections below.

<u>3.3.1 Geothermal Reservoir</u>

The following general assumptions regarding the behavior of the geothermal system were made during the thermodynamic modeling of the different power cycles:

- The maximum wellhead pressure of the production wells was restricted to 35 bars.
- The amount of non-condensable gases in the geothermal fluid was assumed to be 1% of the total mass flow from the wells.
- The possibility of scaling due to high concentrations of minerals in the geothermal fluid was neglected.
- Enthalpy of the production wells varied from 1000 - 2500 kJ/kg.
- Production wells where modeled to produce 1 kg/s to estimate the specific power output of the different cycles.
- The conditions at dead state where exergy of the working fluid is said to be zero were taken as T_0=5°C and P_0=1 bar.

<u>3.3.2 Power Plant Equipment</u>

The power plants consist of various components of complicated design and restrictions to their working conditions. The following restrictions were estimated for the different power plant components:

The turbines, pumps and compressors do not operate at 100% efficiency. The efficiencies for these components are given in The overall heat transfer coefficients used to calculate the total heat exchanger area for each heat exchanger in the modeled power plants are given in Table 4.

Pinch assumptions restrict the maximum allowable effectiveness of the heat exchangers and ensure that the heat exchanger surface does not become excessively large. The minimum pinch assumptions for the heat exchangers in the power cycles are given in Table 5.

Table 3.

The overall heat transfer coefficients used to calculate the total heat exchanger area for each heat exchanger in the modeled power plants are given in Table 4.

Pinch assumptions restrict the maximum allowable effectiveness of the heat exchangers and ensure that the heat exchanger surface does not become excessively large. The minimum pinch assumptions for the heat exchangers in the power cycles are given in Table 5.

Table 3: Isentropic efficiency of different power plant equipment

Equipment	Isentropic efficiency
Turbines	$\eta_t = 85\%$
Compressor	$\eta_{comp} = 85\%$
Pumps	$\eta_p = 50\%$

Table 4: Overall heat transfer coefficient U for various heat exchangers

Fluids	U [W/m^2·K]
Water-water	2000
Steam-water	2000
Water-isopentane	1200
Isopentane-Isopentane	1200

Table 5: Minimum pinch in various heat exchangers

Heat exchanger	Minimum pinch
Recuperator, water	5°C
Recuperator, isopentane	8°C
Boiler and preheater, water-isopentane	5°C
Condenser, water	5°C
Condenser, isopentane	5°C

The condenser pressures in the different cycles were chosen as:

- 0.1bar for the steam condenser in the flashing units.
- 1 bar for the isopentane vapor condenser in the ORC bottoming unit.

The following assumptions were made when modeling the cooling water circuit:

- The cooling water enters the condensers at 5°C.
- The cooling tower fan was estimated to consume 0.25 kW per unit mass flow of cooling water according to power requirements in the cooling tower fans in Hellisheiði geothermal power plant.
- Evaporation of the cooling water was assumed to be 10% of the total mass flow of cooling water and makeup water was extracted from the condensed steam from the condenser.

4. RESULTS

4.1 Net Power Output and Efficiencies of the Cycles

The optimized net specific power production from each of the power plants discussed above is shown in Figure 11. The single flash cycle, where the geothermal brine is disposed of after the steam separator, has the lowest power production of all the cycles. For low enthalpy areas which produce a two phase flow with relatively low temperature range, the hybrid flash-binary power plant using an organic Rankine cycle as the bottoming unit in parallel to the single flash cycle gives the best result for the maximum power production. The hybrid single flash - ORC plant is superior to the other cycles for enthalpies lower than 1300 kJ/kg, where the fluid from the production well consists of over 70% liquid and 30% steam at temperatures under 163°C for the optimum wellhead pressure for the single flash cycle. For the optimum wellhead pressure of the two double flash cycles, the mass flow of steam from the production wells is only up to 20% of the total mass flow and has temperatures under 209°C. The power output of the hybrid single flash - ORC will continue to produce more power than the single flash cycle throughout the enthalpy range but the difference between the two cycles decreases steadily as the enthalpy increases, causing them to produce almost the same amount of power for enthalpies around 2500 kJ/kg, when the steam fraction is over 80% of the produced mass flow from the wells for the given optimized wellhead pressure of 6.6 bar.

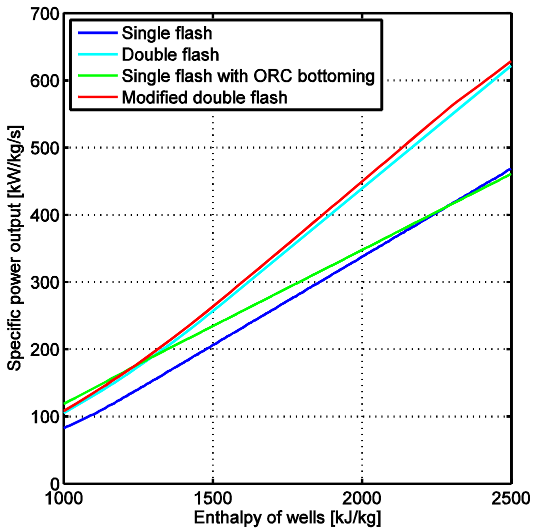

Figure 11: A comparison of specific net power output for the different cycles that where modeled

At enthalpies higher than 1300 kJ/kg, the two double flash cycles start to exceed both the single flash cycle and the hybrid cycle and the difference steadily increases with the increased enthalpy from the production wells. At higher enthalpies, the double flash cycles have a clear superiority and can produce over 35% more electricity than the other cycles. The reason for the increased power output of the double flash cycles is that the single flash cycle and the hybrid cycle immediately become restricted because the steam quality at the outlet of the turbine quickly falls to 85% which puts a restriction on the maximum allowable wellhead pressure. The optimum wellhead pressures for the different cycles can be seen on Figure 12.

The modified double flash cycle has a small advantage over the conventional double flash cycle with respect to the net power produced. The modified double flash cycle produces from 1% to 2.5% more power than the conventional double flash cycle.

The exergetic efficiency for the different cycles is compared in Figure 13. The difference in the exergetic efficiency correlates at some extent to the difference in the net specific power output for each cycle. The exergetic efficiency of the single flash cycle is the lowest one for all the different cycles, varying from 35% to 57.7%. The exergetic efficiency for the combined single flash and ORC bottoming unit varies from 47.6% to 58.5% and is superior to all the cycles for enthalpies ranging from 1000-1600 kJ/kg. The exergetic efficiencies for the two double flash cycles are similar for all enthalpies, ranging from 41.3% to 64.5% for the conventional double flash cycle and 42.5% to 65.6% for the modified double flash cycle. The modified double flash cycle is superior to all the other cycles at higher enthalpies than 1600 kJ/kg.

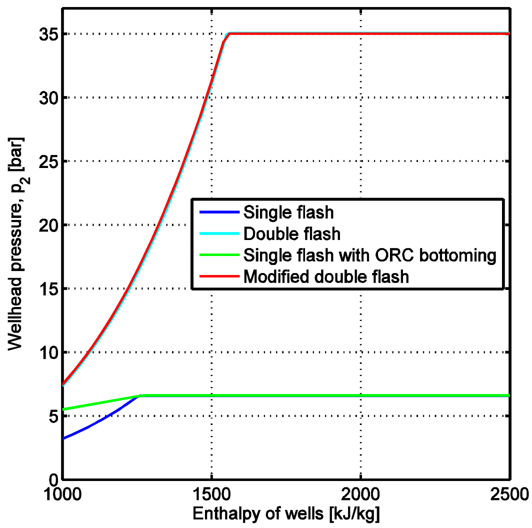

Figure 12: A comparison of the optimum wellhead pressure for the different power cycles

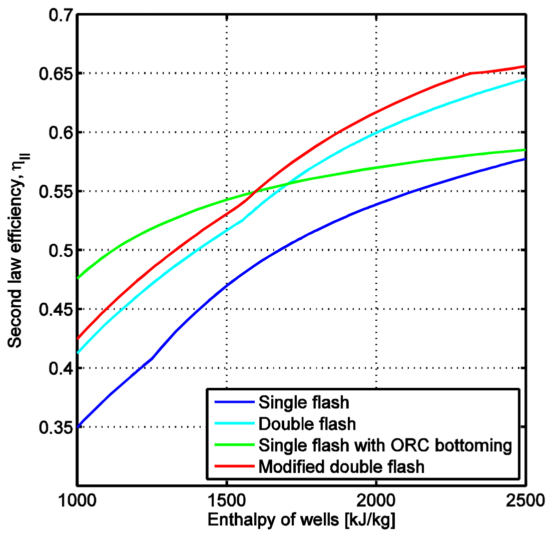

Figure 13: A comparison of the exergetic efficiency for each cycle

The discontinuous behavior of the efficiency curves are related to previously discussed restrictions and constraints in the optimization, e.g. wellhead pressure restrictions and steam quality constraints.

4.1.1 Modified Double Flash Power Plant

The specific power output of the modified double flash cycle with the added recuperator is shown in Figure 14 along with the power outputs from each turbine. The corresponding pressure optimization is given in Figure 15. The upper limit of the wellhead pressure, P_2, was set to 35 bars as previously explained for the double flash cycle. The steam quality at the turbine outlets is shown in Figure 16.

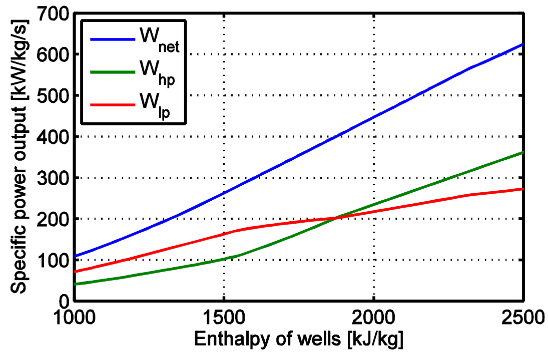

Figure 14: Optimized net power output from the modified double flash cycle and the individual power output from the high pressure turbine, W_{hp}, and the low pressure turbine, W_{lp}

The working pressure of the high pressure turbine increases rapidly as the enthalpy of the production wells increases, until it reaches the estimated pressure restriction of the geothermal reservoir of 35 bars. The working pressure of the low pressure turbine, denoted as P_9, increases at first, but as the pressure in the high pressure step becomes constant, the optimum working pressure of the low pressure turbine starts to decrease until the steam quality at the outlet of the low pressure turbine, x_{14}, becomes a constraint to the pressure decrease as it reaches the limit of 85%. After the enthalpy of the wells reaches about 1880 kJ/kg, both of the working pressures remain constant throughout rest of the enthalpy range.

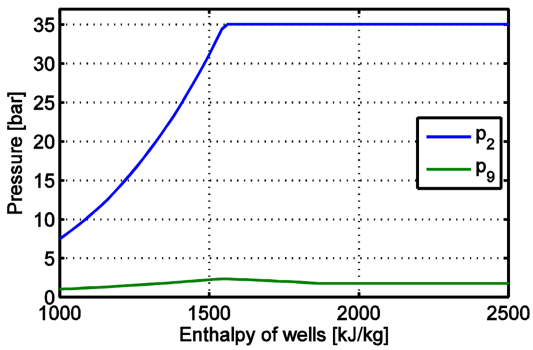

Figure 15: Optimized wellhead pressure and second flashing pressure for the modified double flash cycle

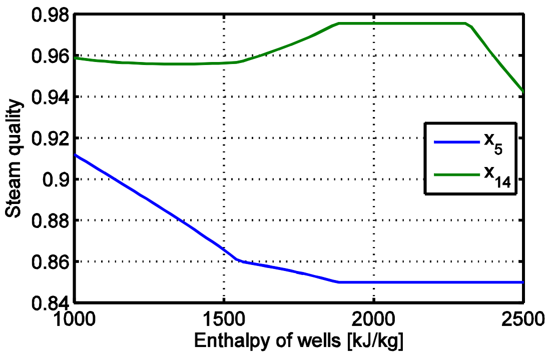

Figure 16: Steam quality at the turbine outlets for the two turbines in the modified double flash cycle

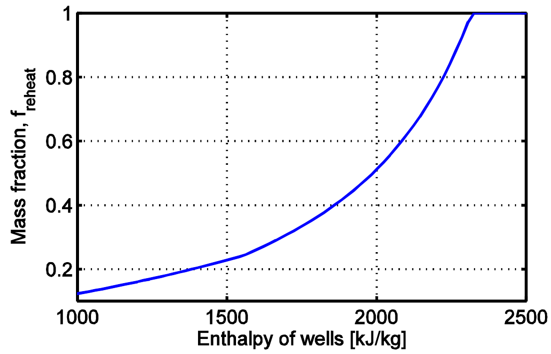

Figure 17: The mass fraction of geothermal brine that is led from the separator to the recuperator in the modified double flash cycle

The modification made on the double flash cycle is based on diverting a part of or all of the geothermal brine from the steam separator to a recuperator that transfers heat to the steam after it has undergone a pressure drop in the high pressure turbine. The mass fraction, f_{reheat}, was optimized for each case of enthalpy input from the production wells and the result can be seen in Figure 17. For low enthalpies, the mass fraction is low and starts at about 12% for the lowest enthalpy production wells that give a large amount of water for the low pressure flashing. As the enthalpy of the production wells increases, the mass flow to the recuperator increases exponentially until all of the separator water is used for the reheating process.

The temperatures in and out of the recuperator can be seen on Figure 18. As a result of the changes in working pressures throughout the simulation, the temperatures of the geothermal brine from the high pressure steam separator, T_7, and the steam from the high pressure turbine, T_{12}, change accordingly. At first, when both working pressures (P_2 and P_9) are increasing as seen in Figure 15, the temperatures of the brine and the steam also increase. When the wellhead pressure becomes restricted, the temperature of the geothermal brine from the high pressure steam separator becomes a constant at about 242.6°C, but due to the corresponding decrease in the lower pressure, P_9, the temperature of the steam also decreases. As a result, the geothermal brine is cooled further down in order to be able to fully reheat the steam into the superheated region. When the lower pressure becomes a constant due to the steam quality restriction on x_{14}, the temperature of the steam from the high pressure turbine becomes a constant of about 115.6°C.

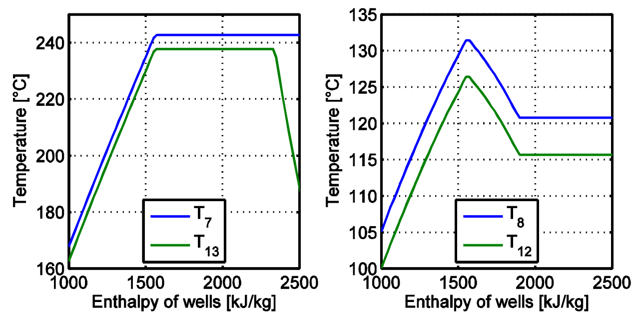

Figure 18: The temperature differences in both ends of the recuperator. T_7 and T_{13} are the temperatures at the inlet of the geothermal brine and outlet of the superheated steam, whereas T_8 and T_{12} are the temperatures of the return brine and the steam at the HP turbine outlet respectively

The temperature of the superheated steam after the reheating process in the recuperator, T_{13}, suddenly begins to decrease after being held constant at enthalpies ranging from 1880 kJ/kg to 2340 kJ/kg. At such high enthalpies and at the corresponding wellhead pressure of 35 bars, the steam quality from the production wells is high and at 2340 kJ/kg the steam quality at state 2 is about 74%. This means that the mass flow of liquid travelling with the steam and thus, the mass flow of brine from the high pressure separator, is relatively low. Due to the low mass flow of the brine from the separator, the heat needed to fully reheat the steam is not sufficient even though all of the brine is led through the recuperator. This result in the decreasing temperature of the superheated steam, but the recuperator still manages to transfer enough heat so that the steam becomes slightly superheated before entering the low pressure turbine.

4.2 Economical Comparison between Cycles - A Case of 100 MW_e Power Production

A case of 100 MW_e production was simulated for each cycle to be able to compare the production cost of electricity based on the cost estimation for the purchased equipment cost and the cost of constructions, drilling of wells and the operation and maintenance cost. The equipment cost was estimated based on actual data and levelized due to confidentiality. The base for levelization was the cost for producing 100 MW_e in the single flash cycle with an enthalpy input of 1000 kJ/kg. The results of the estimated levelized production cost for each cycle can be seen in Figure 19 where the total production cost is plotted against the enthalpy of the geothermal fluid coming from the production wells.

The single flash power plant carries the least production cost for a net power output of 100 MW_e for almost the whole enthalpy range. This is due to the fact that the single flash cycle has a simpler setup with fewer components compared to the other cycles and thus, carries the least purchased equipment cost.

The hybrid single flash and ORC unit has a lower production cost for lower enthalpies than the two double flash cycles. At approximately 1300 kJ/kg, the production from the hybrid flash-binary plant first becomes more expensive than for the conventional double flash cycle. Thus, at lower enthalpy areas, it would be more feasible to construct a hybrid flash-binary plant than a double flash cycle, but at higher enthalpies, the double flash cycles become more economically viable.

At high enthalpy input to the power plant, the modified double flash cycle gives the minimum production cost for the 100 MW_e production. This is due to the fact that the total mass flow from the steam separator is led through the recuperator instead of the second flashing state so there is no longer need for the low pressure steam separator as for the conventional double flash cycle. This leads to a considerable decrease in the purchased equipment cost for the reheating cycle and the production cost decreases as a result of that. At lower enthalpies than approximately 2300 kJ/kg, the conventional double flash cycle is less expensive than the modified cycle due to less cost for required equipment.

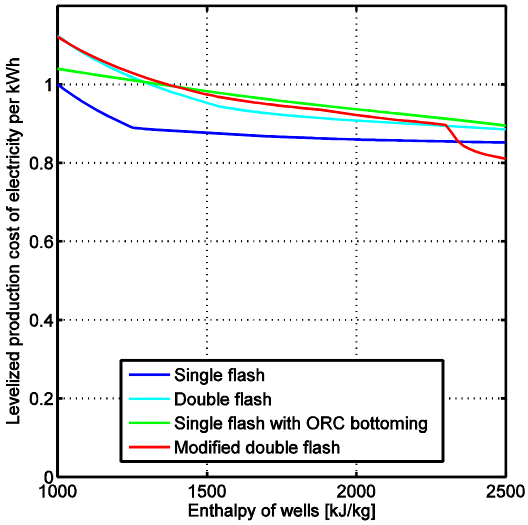

Figure 19: A comparison of the product cost for each cycle

Another interesting result from simulation of the 100 MW_e case is the difference in mass flow required from the production wells. The result for the required mass flow is shown in Figure 20. The single flash cycle always requires the greatest mass flow from the production wells which results in a need for drilling more production wells than for the other cycles, also adding to the capital cost of the power plant. The hybrid single flash and ORC power plant requires the least mass flow for lower enthalpies and the two double flash cycles require the least mass flow from the production wells for the higher enthalpies. The type of power plant chosen to be constructed at a certain geothermal area can thus be restricted to the available mass flow from the production wells. If the area does not support the mass flow required to produce these 100 MW_e from the cheapest available technology, the single flash cycle, which requires more mass flow than the more expensive cycles, then the choice will have to be to increase the production cost by using more complicated technologies with increased efficiency.

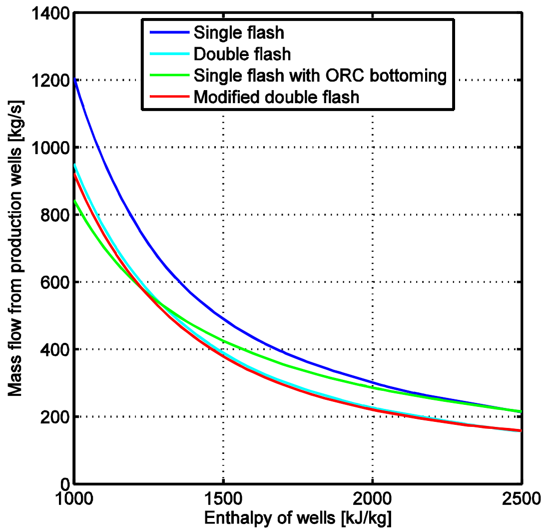

Figure 20: A comparison of the required mass flow from production wells to produce 100 MWe for each cycle

5. CONCLUSIONS

The focus of this study was to optimize the utilization of geothermal fluid from geothermal production wells by making use of the brine that travels with the steam to the surface as it enters the geothermal power plants. The brine is separated from the high pressure steam before it enters the power plant and is often discharged back into the reservoir or to the open natural surroundings without utilizing it further. Such power plants are called single flash power plants.

Three different power cycles that utilize the geothermal brine for increased power production where modeled to be able to compare the different utilization possibilities and these cycles where compared to the conventional single flash cycle. One of the cycles that where modeled in this study is a modification of a conventional double flash cycle where the possibility of superheating the geothermal steam in a recuperator after the expansion in the high pressure turbine is introduced. The results for the modified double flash cycle are promising and gave the best results for the amount of specific power output of all the different cycles. The superiority of the modified double flash cycle over the conventional double flash cycle was not measured in large numbers, as it produces about 1-2.5% more power than the conventional double flash cycle.

Adding a bottoming binary unit parallel to the single flash cycle and gave the best results for low enthalpy wells where the mass fraction of brine is relatively high and the temperatures corresponding to the wellhead pressures of the single flash cycle are low. Binary units are well known for their ability to utilize low temperature geothermal energy and this study confirmed that common knowledge.

The differences in production cost for the different cycles are associated with the difference in the total purchased equipment cost of the power plants. The two double flash cycles and the hybrid cycle require more equipment than the conventional single flash cycle which results in a higher price per produced kWh. But as these cycles also produce more power than the single flash cycle, the total revenue from selling the product increases which often justifies the increased production cost. The highest production cost for lower enthalpies was achieved in the two double flash cycles where the modified double flash cycle carried a slightly higher cost than the conventional double flash power plant. The difference between the two increased with higher enthalpies until the enthalpy reaches 2300 kJ/kg. The reheat cycle then makes it possible to discard of the low pressure steam separator as the entire mass flow of separator water is used for the reheating process. The reheat cycle then becomes the most economically viable option due to the increase in the total purchased equipment cost. The cost estimate of the hybrid flash-binary power plant showed that it is more economically viable than the double flash cycles for enthalpies under 1300 kJ/kg. The slope of the production cost for the hybrid cycle is much lower than for the flash cycles at low enthalpies as seen in Figure 19, which can lead to the conclusion that at even lower enthalpies than 1000 kJ/kg, the hybrid flash-binary power plant could carry even lower production cost than the traditional single flash power plant, making it the most economically viable options for low-enthalpy areas.

The results of this study can be used as a guide to estimate which power plant technology could provide the greatest power output and the best utilization of the geothermal fluid from the wells. Usually, studies like this one are carried out with a specific geothermal site in mind. The results of this study are restricted to the assumptions that had to be made regarding chemical content and pressure limitations of the hypothetical geothermal reservoir on which the models are based on. The thermodynamic models that were constructed can easily be adapted to specific limitations of a known geothermal reservoir and the results used as an estimate of the possible power production from that specific site.

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