Guidelines for Optimum Gas Extraction System Selection

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Faculty of Industrial Engineering, Mechanical Engineering and Computer Science
University of Iceland
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30 ECTS thesis submitted in partial fulfillment of a
Magister Scientiarum degree in Mechanical Engineering

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Abstract

The utilization of the geothermal resource for power generation is always related to the presence of non condensable gases, as natural components of the steam. For this reason, it is necessary to remove these elements in order to improve the thermodynamic efficiency of geothermal power plants.

In practical applications there are three main equipments for this task, which are: steam ejectors, liquid ring vacuum pumps and compressors, each of them with advantages and disadvantages that should be considered to achieve the best economical benefits from each project.

Finding the balance between this variables can become a difficult task and depends on several operational and economical factors. This study is intended to establish the most important parameters and design conditions to determine the optimum equipment for every condition.

To achieve this, a model using MatLab and Refprop was created to simulate the thermodynamic relation between the systems involved in the energy conversion process. The main analysis factors in this thesis were: The non condensable gases amount in the steam, condenser and separator pressure, and from economical factors, the steam and electricity price and interest rate.

The results showed that the amount of non condensable gases in the steam is the most important factor to determine the optimal gas extraction system. Under this analysis conditions it is recommended from 0[%] to 1,8[%] the use of steam ejectors, from 1,8[%] to 7,3[%] hybrid system and from 7,3[%] to 20[%] LRVP systems. Compressors system do not give optimal result for this analysis range and conditions.

Separator pressure also influences the gas extraction system selection. For high separator pressures ejectors are more efficient in gas removal, but when this parameter is reduced LRVP is recommended to achieve better results.

Regarding the condenser pressure was possible to determine that for higher vacuum levels ejectors are the best option. However, when this increases hybrid system is the best option for this analysis case.

From the economical analysis was possible to conclude that steam price is the most important factor to determine the best gas extraction system, for low steam prices ejectors are the best option and as the price increases hybrid system and LRVP system become a better option. Electricity price impact is reduced in the GES selection; an increase in electricity price will benefit the utilization of ejectors systems. Interest rate showed to have impact in the economical results of the project, but do not influence the behavior between gas extraction systems.

Finally Krafla power plant conditions were simulated to determine the best gas extraction system. The results showed that steam ejectors are the best option for this case.

Preface

This M.Sc. project was carried out at the Faculty of Industrial Engineering, Mechanical Engineering and Computer Science at the University of Iceland.

I will like to thank my supervisor, Professor Halldór Pálsson at the University of Iceland, for all his time, guidance, and support through this study. I would also like to thank my advisor Þorleikur Jóhannesson at Verkis consulting engineers, for his help during the writing and development of this thesis.

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Nomenclature

C_n: Cash flow of the period n [USD]

$Cost_{EQ1}$: Cost of equipment of capacity S_1[USD]

$Cost_{EQ2}$: Cost of equipment of capacity S_2[USD]

c_p: Specific heat of the mixture [J/kg°K]

DER_{CO2} : Temperature entrainment ratio [-]

DER_{H2O} : Temperature entrainment ratio [-]

h_{cw}: Enthalpy of cooling water into the condenser [kJ/kg]

h_{in}: Enthalpy of steam entering the condenser [kJ/kg]

h_{sat}: Saturation enthalpy of water at condenser conditions [kJ/kg]

$\dot{m}_a$: Mass flow of gases into the condenser [kg/s]

$\dot{m}_{CO2}$: Mass flow of CO2 [kg/s]

$\dot{m}_{H2O}$: Mass flow of steam [kg/s]

$\dot{m}_{mix}$: Mass flow of gases [kg/s]

$\dot{m}_{stin}$: Mass of steam into the condenser [kg/s]

$\dot{m}_{stout}$: Mass of steam out of the condenser [kg/s]

$\dot{m}_v$: Mass flow of steam in the gas [kg/s]

$\dot{m}_a$: Mass of gas extracted from condenser [kg/s]

$\dot{m}_v$: Mass of steam extracted from condenser [kg/s]

M_a : Molecular mass of gases [g/mol]

M_{mix}: Molar mass of the mix [g/mol]

M_v : Molecular mass of steam [g/mol]

p_c : Condenser pressure [bar-a]

p_s : Saturation pressure of steam at gas outlet temperature [bar-a]

R_{mix}: Mixture gas constant [J/mol K]

T_{mix}: Temperature of the mix [°C]

T_s: Temperature of the mixture [°K]

W_c: Compressor work [kW]

W_{cc} : Work required for the two stage compressor system [kW]

W_{ctfan}: Work of the cooling tower fan [kW]

WER_{CO2} : Weight entrainment ratio [-]

WER_{H2O} : Weight entrainment ratio [-]

W_{lrvp} : Work required for the two stage liquid ring vacuum pump [kW]

W_{pump}: Work of pumps [kW]

W_{tur} : Work output in the turbine [kW]

η_c: Compressor efficiency [-]

η_{lrvp}: Efficiency of the LRVP [-]

I_0: Investment cost [USD]

P_{dis} : Discharge pressure [bar-a]

P_{int} : Intercondenser pressure [bar-a]

P_{loss}: Pressure loss in the intercondenser [bar-a]

P_{ms}: Motive steam pressure [bar-a]

P_{suc} : Suction pressure [bar-a]

Δh: Change in enthalpy due compression [kJ/kg]

n: Scaling exponent [-]

NPV: Net Present Value [USD]

γ: Gamma: Cpgas/Cvgas [-]

N: Total number of periods [-]

i: Interest rate for the project [%]

1 Introduction

Geothermal resources are unique in their composition; this makes every geothermal power plant also unique since they must be adapted to the specific characteristics of each resource. This creates a challenge for geothermal power plant developers in choosing the right equipment to obtain the optimum economical results fulfilling all the technical requirements for the specific resource.

The utilization of geothermal fluid for power generation is always related with non condensable gases (NCGs) like CO_2, H_2S, NH_3, which are natural components of geothermal brine (DiPippo, 2008). After the separation process the steam can contain from 0,1[%] to even more than 20[%] of NCGs by weight of steam.

The presence of non condensable gases has no major negative impact until the fluid reaches the condenser, in which the steam is cooled and condensed to be pumped out of the system.

Nevertheless as NCGs do not condense, if are not extracted the heat transfer efficiency of the condenser is reduced and a build up in the pressure is created, which reduces the turbine efficiency, decreasing the total power output of the power plant.

Also due the high water solubility of gases as carbon dioxide and hydrogen sulfide, corrosion in piping and equipment can be produced if the gases are not removed from the condenser, for these reasons the gas extraction system becomes a critical power plant equipment.

As the typical condenser pressure is close to 0,1 [bar-a] or even less, is required to create a higher vacuum to extract the NCGs from the condenser, this increases the power plant cost due the requirement of a gas extraction system and also the operational cost due the auxiliary power and maintenance associated with these equipments.

In practical applications there are three major equipments available for gas extraction: Steam ejectors, liquid ring vacuum pumps, and centrifugal compressors. Normally these are combined in hybrid systems or in several stages with intercooling to obtain better results. (Hall, 1996)

Steam ejectors have no moving parts and due to their simple construction, this is a relatively low-cost component, easy to operate and requires low maintenance but the steam consumption used to operate the system is quite high. (Perry, 2008), On the other hand, liquid ring vacuum pumps do not consume steam in the process but the cost of maintenance and operation can be more. Finally centrifugal compressors are the most complex but robust gas extraction system. Nevertheless installation cost can be very high.

The decision about what gas extraction system to use depends on many factors, as the amount of non condensable gases in the steam, condenser and separator pressure, and also economic factors like steam price, electricity price, maintenance and investment cost.

In this project it is intended to model the relation between the main components of gas extraction systems in geothermal power plants and analyze the operational results for the most common configurations used, in order to create guidelines and recommendations to help in the decision making process to determine the optimum technical and economical gas extraction system.

The optimum configuration will be the one which will give the best economical results fulfilling all the technical requirements for every specific operational condition.

1.1 Objectives

Main objective

-Create guidelines to determine the optimum gas extraction system for a geothermal power plant depending on economical end technical factors.

Specific objectives

-Determine the main operational characteristics of different gas extraction systems to be analyzed.

-Model a typical geothermal power plant.

-Model the relation between the simulated power plant and the relevant gas extraction systems.

-Determine the main economical results from every model depending on different parameters such as, NCG amount in the steam, separator pressure, condenser pressure, steam price, electricity price and interest rate.

-Compare the results and determine the best gas extraction system for different conditions establishing limits and recommendations.

2 Technical modeling

2.1 Power plant modeling

The single flash configuration is the most common design used in geothermal energy production. As of May 2007, there were 159 units of this kind in operation in 18 countries around the world. Single-flash plants account for about 32[%] of all geothermal plants. They constitute over 42 [%] of the total installed geothermal power capacity in the world. (DiPippo,2008)

The term *single flash power plant* refers to an energy conversion process, in which a pressurized geothermal fluid is flashed to produce a mixture of steam and liquid. After that, the phases are isolated using a steam separator and the steam is send to a turbine to drive an electricity generator and produce energy.

A simplified representation of the single flash system is shown in the Figure 1:

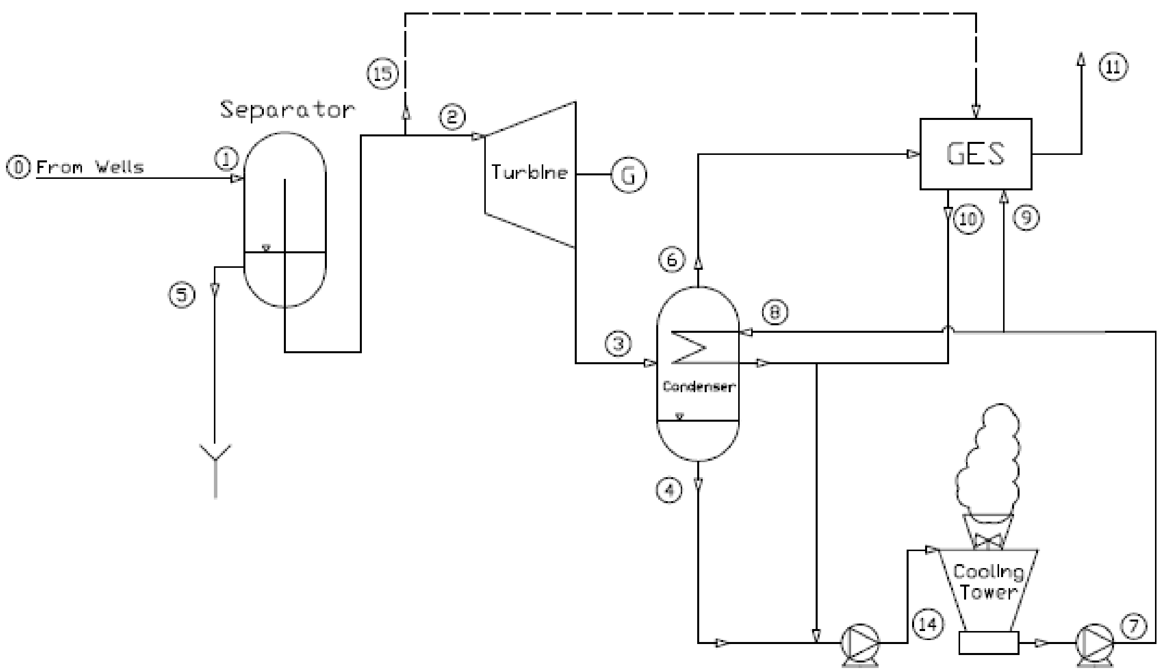

Figure 1.- Single flash power plant layout

For a better understanding of the energy conversion process a temperature entropy diagram is shown in Figure 2.

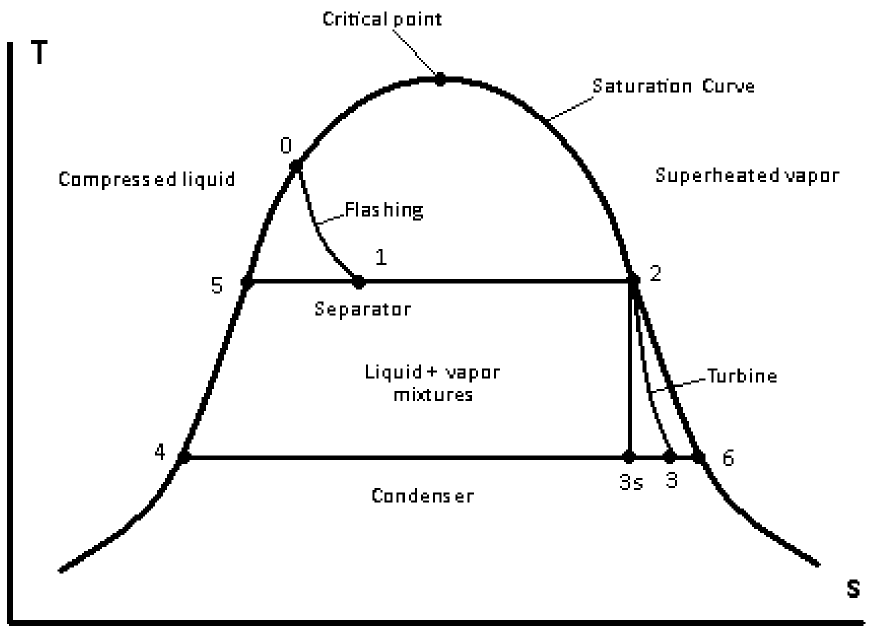

Figure 2.- Single flash power plant T-s diagram

The geothermal fluid is extracted under pressure from the bottom of the well at condition 0, to the steam separator in 1, this process is assumed to be an isenthalpic process with no work involved.

$$h_0 = h_1 \qquad (1)$$

The quality of the steam X is defined as the amount of steam in the mixture. From Figure 2 is possible to observe that the resulting quality in the separator can be defines as:

$$X_1 = \frac{h_1 - h_5}{h_2 - h_5} \qquad (2)$$

The steam from the separator is now send to the turbine for the expansion process, the amount of steam entering the turbine can be defined as:

$$\dot{m}_2 = \dot{m}_1 * X_1 \qquad (3)$$

For the expansion process is possible to notice from the T-s diagram that as the steam is at saturated state in point 2, and after the expansion process at point 3 the quality of the steam is lower than one, which means that part of the steam is condensate, which decreases the turbine efficiency. To calculate this reduction the Baumann rule can be applied, which mainly states that the turbine efficiency is reduced in one percent for every one percent drop in steam quality. (DiPippo, 2008)

Thus is possible to calculate the resulting turbine efficiency using:

$$\eta_{wet} = \eta_{dry}\left[\frac{x_2+x_3}{2}\right] \quad (4)$$

The quality of the turbine outlet in 3 is related with the turbine efficiency, is first required to calculate the isentropic enthalpy which can be defined as:

$$h_{3s} = h_4 + [h_6 + h_4] * \left[\frac{s_2-s_4}{s_6-s_4}\right] \quad (5)$$

Then is possible to calculate the turbine outlet enthalpy using:

$$h_3 = \frac{A*\left[1-\frac{h_4}{h_6-h_4}\right]}{1+\frac{A}{h_6-h_4}} \quad (6)$$

Where the constant A is defined as:

$$A = \frac{\eta_{dry}}{2}(h_2 - h_{3s}) \quad (7)$$

Finally the power output of the turbine can be calculated as:

$$W_{tur} = \eta_{wet} * \dot{m}_2(h_2 - h_3) \quad (8)$$

2.2 Gas extraction systems assumptions

The presence of non condensable gases has no major impact on the conversion process until the condenser is reached. There the steam is cooled and condensed to be pumped out of the system. Nevertheless as NCGs do not condense pressure will build up, decreasing the total power output of the power plant.

The gas extraction system is assumed to be able to extract all the non condensable gases from the condenser in two compression stages and released to an exhaust at atmospheric pressure.

When the non condensable gases are extracted from the condenser, some steam is also extracted along with the NCGs, because the gases are mixed inside the condenser. It can be assumed that the gases are saturated with steam when they are sucked out of the condenser (Pálsson, 2010). The mass of steam extracted along with the NCGs, can be defined as:

$$\dot{m}_v = \frac{M_v p_s}{M_a(p_c-p_s)} * \dot{m}_a \quad (9)$$

Where p_s is the saturation pressure of the steam at the outlet of the condenser conditions.

The amount of non condensable gases extracted by the system is defined as a fraction of the steam entering the turbine. The composition of the NCGs is assumed to be 100[%]

CO_2. This is because the normal composition of geothermal gas is equivalent to more than 95[%] of the total NCG content, thus other gases have no influence in the energy consumption of the gas extraction systems. Also, it is important to consider that in intercondenser and aftercondenser when steam ejectors are used, the amount of non condensable gases in the motive steam must be added.

The intercondenser pressure will be selected to have equal compression ratio between stages. Then to define the pressure level in the intercondenser is possible to use the next equation:

$$\frac{P_{con-0,01}}{P_{int}} = \frac{P_{int}-P_{loss}}{P_{atm}*1,1} \qquad (10)$$

The suction pressure will be 0.01 [bar-a] lower than the condenser pressure assuming constant pressure loss between condenser and the gas extraction system. Discharge pressure will be 10 [%] higher than the atmospheric pressure.

In every cycle using steam fluid is required to condense after the expansion process in the turbine. This is needed In order to be able to pump the fluid back into the system for cooling, reutilization or reinjection. In the case of a single flash power plant using a two stage gas extraction system, three condensers are used, the main condenser after the turbine, an intercondenser between gas extraction stages and an aftercondenser before the exhaust.

By condensing the steam between gas extraction stages the load of the next stage is decreased. This reduces the requirements in the next stage and in the case of steam ejector reduces also the motive steam consumption. Also normally, an aftercondenser is used in order to reduce the amount of steam released to the environment, although this equipment does not affect the gas extraction system performance.

In every condensing stage is assumed that all the steam is condensed with exception of the steam saturated with NCGs and also it is assumed that the water leaving the condensers is at saturated state.

From energy balance in every condenser is possible to find the amount of water required to condensate the steam and can be expressed as:

$$\dot{m}_{cool} = \frac{(\dot{m}_{stin}-\dot{m}_{stout})(h_{in}-h_{sat})}{(h_{sat}-h_{cw})} \qquad (11)$$

2.3 Auxiliary power

For the cooling and condensing processes is required to use pumps and cooling tower, which consume different amount of power depending on the operating conditions of the power plant.

The cooling tower auxiliary power demand will be related with the temperature of water leaving the three condensers.

The power used in the cooling tower is related with the fan motor consumption, the amount of energy required to run the fan is defined with the amount of dry air needed to cool down the water to the temperature requirement.

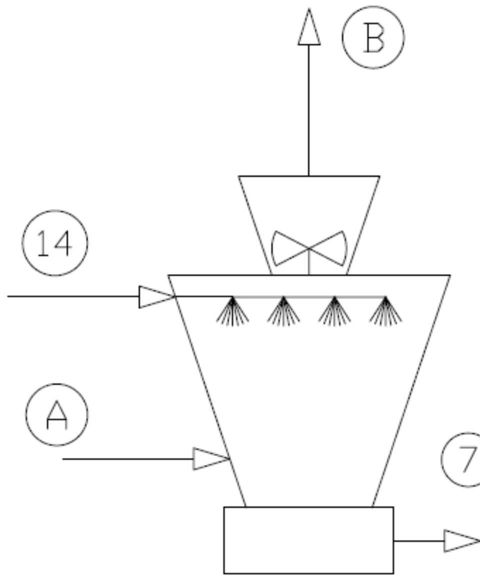

Figure 3.- Cooling tower layout

The general assumptions for the calculations are:

The temperature of the water entering the cooling tower in point 14 is assumed to be constant at 30[°C] and the temperature of water leaving the cooling tower in point 7 is variable depending on the condensing conditions.

The ambient air conditions are assumed to be 15[°C] (dry bulb) and a 60[%] relative humidity and leave the cooling tower at 30[°C] in saturated state. These values were selected assuming typical operational conditions in Iceland.

An energy balance for the cooling tower shown in Figure 3 is made:

$$\sum_{in} \dot{m}\, h = \sum_{out} \dot{m}\, h \rightarrow \dot{m}_{14} h_{14} + \dot{m}_A h_A = \dot{m}_7 h_7 + \dot{m}_B h_B \quad (12)$$

The mass flows and enthalpies in 14 and 7 are known, the mass flow of air in A must be defined and the enthalpies of air in A and B are also known.

A mass balance is required for the dry air and water; the dry air remains unchanged during the process, and the water flow from 14 to 7 is decreased due the evaporation process in the cooling tower. These mass balances are:

$$\dot{m}_A = \dot{m}_B = \dot{m}_{dry} \qquad (13)$$

and

$$\dot{m}_{14} + \dot{m}_A\omega_A = \dot{m}_7 + \dot{m}_B\omega_B \qquad (14)$$

Now replacing:

$$\dot{m}_{14} - \dot{m}_7 = \dot{m}_{dry}(\omega_A - \omega_B) \qquad (15)$$

Finally solving for the mass of dry air:

$$\dot{m}_{dry} = \frac{\dot{m}_{14}(h_{14} - h_7)}{h_B - h_a - h_7(\omega_B - \omega_A)} \qquad (16)$$

Then the volume of mass air is:

$$\dot{V}_{dry} = \frac{\dot{m}_{dry}}{\rho_{air}} \qquad (17)$$

With the mass flow of air defined is possible to determine the power of the fan as:

$$W_{fan} = \frac{\dot{V}_{dry}\Delta P_{fan}}{\eta_{fan}} \qquad (18)$$

Finally the power used by the motor of the fan is:

$$W_{motorfan} = \frac{W_{fan}}{\eta_{motorfan}} \qquad (19)$$

The system configuration considers two pumps, one for pumping the liquid leaving the three condensers, and one for pumping the cooling water from the cooling tower to the condensers. In general, pumping energy requirements depend mainly in the volume of water being pumped and the pressure drop, which depends on many factors. For this modeling a constant pressure drop will be assumed, thus the energy requirements for pumping can be defined as:

$$W_{pump} = \frac{\dot{V}_{water}\Delta P}{\eta_{pump}\eta_{motorpump}} \qquad (20)$$

2.4 Steam ejectors

Steam jet ejectors are the simplest device for non condensable gas extraction from condensers and for any vacuum operating equipment , It consists essentially of a nozzle which discharges a high-velocity jet across a suction chamber that is connected to the equipment to be evacuated. (Perry, 2008)

The main advantages of using steam jet ejectors are that this equipment is easy to operate and maintain, the cost of installation are low compared with other systems and due its simplicity it has a long life and low maintenance cost. The main disadvantage of the steam ejectors is that this equipment requires steam to operate, this steam is extracted from the high pressure steam line, and thus when the amount of non condensable gases increases the steam consumption also does, reducing considerably the power output from the power plant.

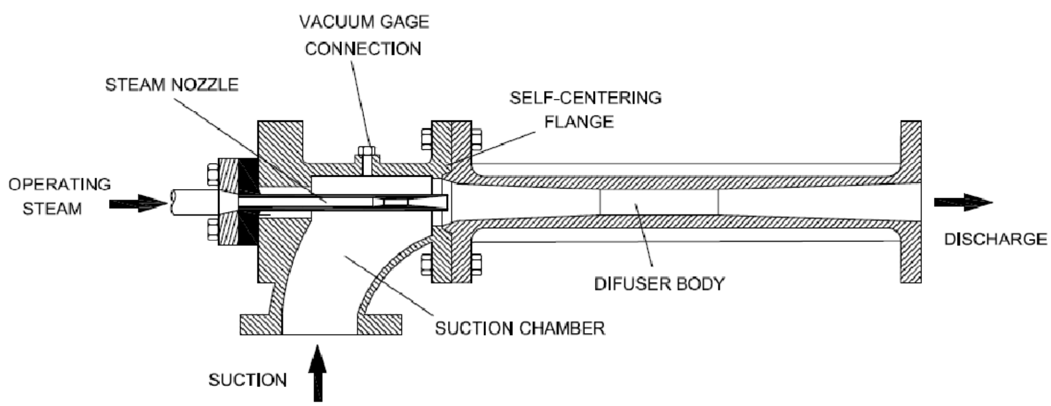

Figure 4.- Typical steam ejector configuration

2.4.1 Operating principle

The operating principle of a steam jet ejector stage is that the pressure energy in the motive steam is converted into kinetic energy in the nozzle and this higher velocity of the steam entrains the gas being pumped. The resulting mixture at the resulting velocity enters a diffuser where this velocity energy is converted to pressure energy so that the pressure of the mixture at the ejector discharge is substantially higher than the pressure in the suction chamber but lower than the pressure of the motive steam. Figure 5 shows the pressure and velocity profiles in a typical steam jet ejector.

A simple stage of a steam ejector has limitations on the compression possible to achieve and it performance is only good under certain compression ratio (discharge pressure divided by the suction pressure).

If greater compression ratios are needed then is possible to arrange two or more ejectors in series, thus decreasing the compression ratio in every stage

On the other hand the amount of gas that the ejector is able to handle is fixed for every device and depends on the physical proportions of the diffuser, then to handle different volumes is require to use more than one device in parallel, these can be single o multiple stages configurations (HEI Standards, 2000)

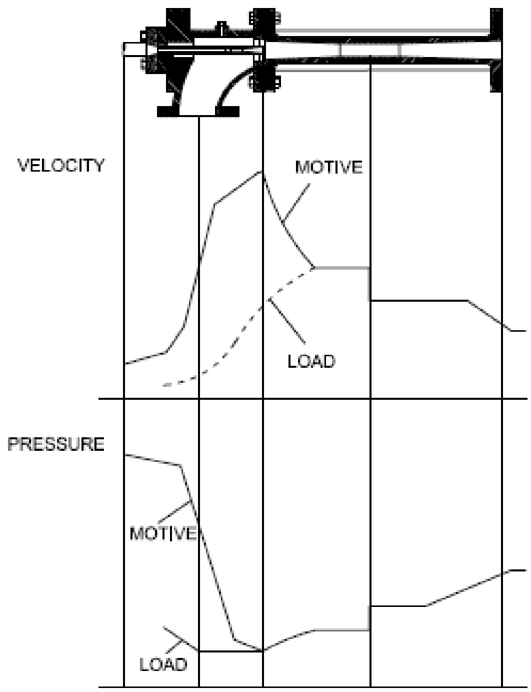

Figure 5.- Velocity and pressure profile in steam jet ejector.

2.4.2 Steam consumption calculations

The range of gases an ejector can handle is very extent; often the gases are flammable, toxic, highly corrosive, or very expensive. There is a problem to determine the capacity of an ejector because it will be related with the gas it is been handled. The Heat Exchange Institute HEI, sponsored tests to predict the gas handling capacity of stages from their air handling capacity at the specified suction and discharge pressure. Results from those tests were published in 1951 and incorporated into the HEI Standards for Steam Jet Ejectors as entrainment ratio curves.

The HEI procedure for using the curves does simplify and standardize load calculations for steam jet ejectors. This procedure can have some weaknesses such as the absence of gas specific heat and specific heat ratio from the correlations, but this weakness is compensated by the simplicity of the method. Also for modeling different conditions and variable loads and pressures, the most flexible procedure to determine the amount of steam required to operate the ejectors.

These curves can convert any gas at any temperature in its Dry Air Equivalent DAE which is the main parameter to define the steam consumption of a steam ejector stage.

When the gas to be extracted by the ejector system is steam and other gases this must be treated individually and then added in order to get the DAE value, then the first step is to calculate the steam air equivalent value, the NCGs air equivalent value and finally the DAE is the sum of both values.

The first step is to convert the steam extracted from the condenser into a 70[°F] equivalent. This is done using correction factor for the temperature and entrainment molecular weight ratio.

For the temperature correction is required to calculate the entrainment temperature ratio in order to find the flow of air equivalent. This can be done using Figure 6, entering the chart with the steam temperature in [°F] and intersecting the steam line to get the correction factor value from the y axis.

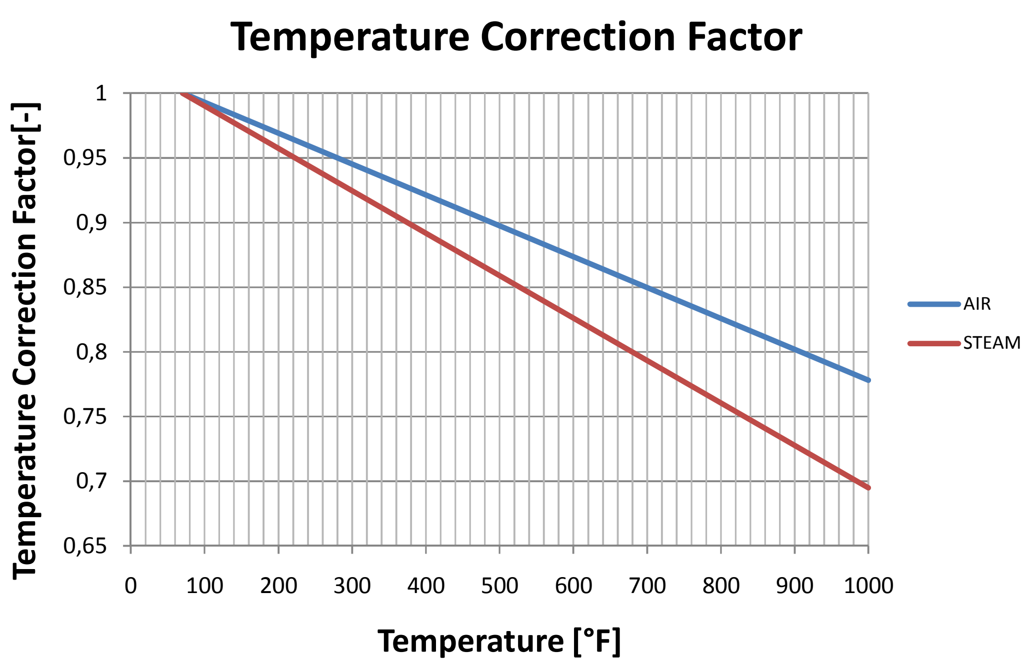

Figure 6.- Temperature correction factor

After correcting the temperature value is required to calculate the weight entrainment ratio value from Figure 7, using the molecular weight of water (steam) 18.02, and entering the chart from the x axis until intersecting the curve, it is possible to read the entrainment weight value from the y axis.

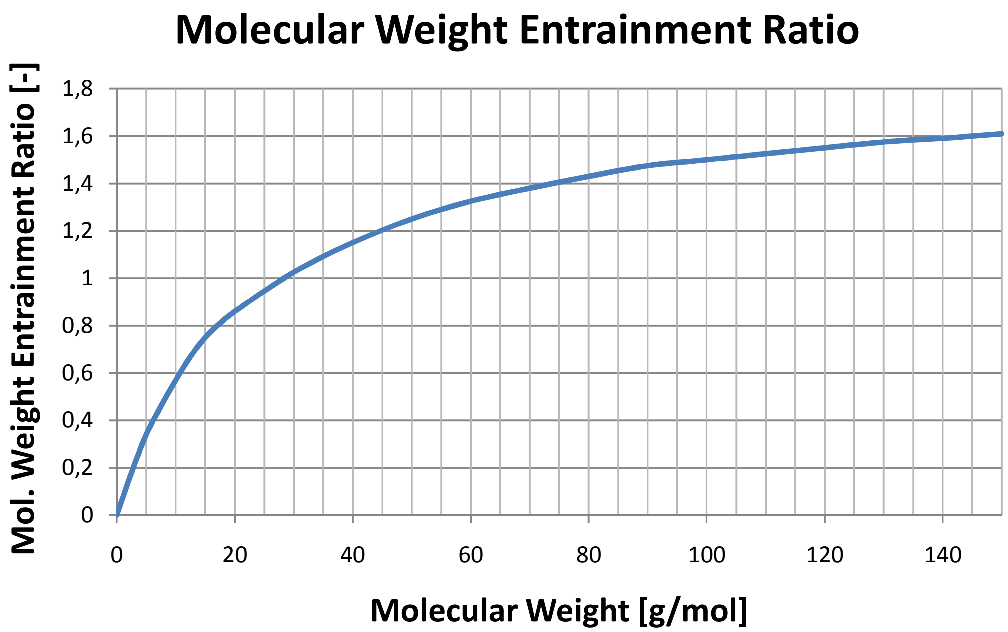

Figure 7.- Molecular weight entrainment ratio

Then the steam to air equivalent is calculated by:

$$DAE_{H2O} = \frac{\dot{m}_{H2O}}{TCF_{H2O} * WER_{H2O}} \qquad (21)$$

Non condensable gases are assumed to be composed of 100[%] of CO_2. Then for the air equivalent calculations the procedure according to HEI is similar to the steam air equivalent calculations, only for this case is needed first to correct the weight of CO_2 into air equivalent using Figure 7 and then correcting the temperature of the gas to 70 [° F] equivalents using the temperature correction factor from Figure 6. Then the CO_2 air equivalent is calculated by:

$$DAE_{CO2} = \frac{\dot{m}_{co2}}{TCF_{CO2} * WER_{CO2}} \qquad (22)$$

Finally the total air equivalent is the addition of both steam and CO_2 air equivalent values

$$DAE = DAE_{CO2} + DAE_{H2O} \qquad (23)$$

Once defined the DAE, is required to calculate the amount of steam that will be needed to remove the flow of gases from the condenser, this is done using the air to steam ratio, which defines the amount of steam required to remove certain amount of air equivalent under certain pressure conditions. These pressure conditions are related to the motive steam pressure, suction pressure and the discharge pressure.

The air to steam ratio is obtained from the graph shown in Figure 8, the input data are the compression ratio (CR), and the expansion ratio (ER) which are defined as:

$$CR = \frac{P_{dis}}{P_{suc}} \qquad (24)$$

$$ER = \frac{P_{ms}}{P_{suc}} \qquad (25)$$

For this case is important to notice that like every stage has the same compression ratio, CR is constant in both stages, which is not the same case for the expansion ratio.

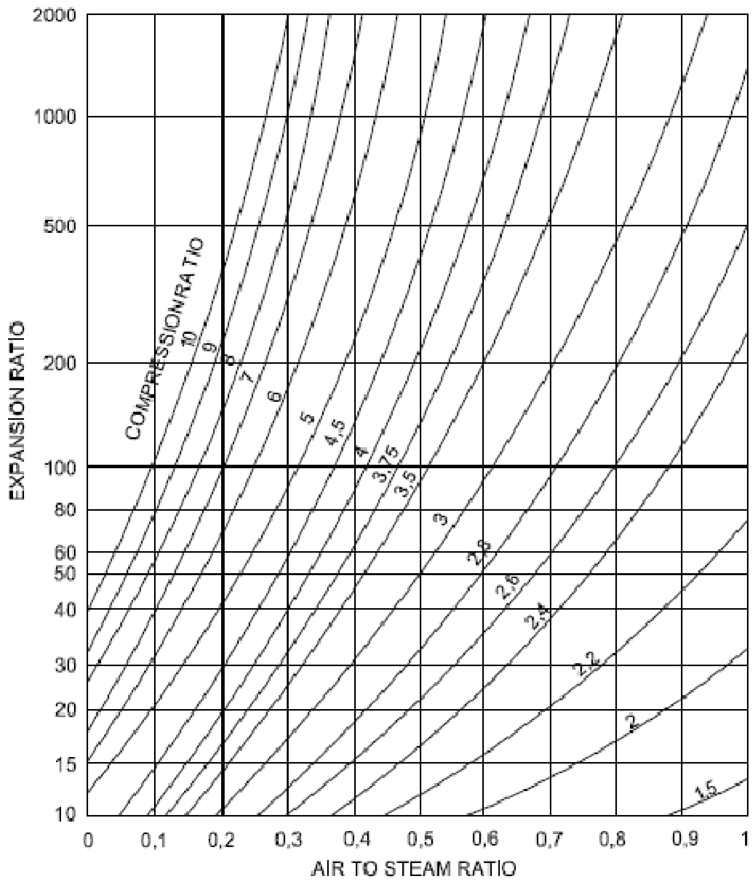

Figure 8.- Air to steam ratio

Finally the steam consumption (SC) for every stage ejector is defined as

$$SC = \frac{DAE}{AS} \qquad (26)$$

The pressure in the separator (motive steam) and in the condenser will influence the compression and expansion ratio, thus modifying the air to steam ratio and the steam consumption. This parameters influence the amount of steam consumed in every stage of the steam ejector system.

2.5 Centrifugal compressors

Centrifugal compressors are the most robust and efficient systems for gas extraction systems when high amount of non condensable gases are present in the steam. It mainly consists in a rotating element attached with several decreasing height blades having airfoil cross sections. Between every rotating blade row there is a stationary blade row.

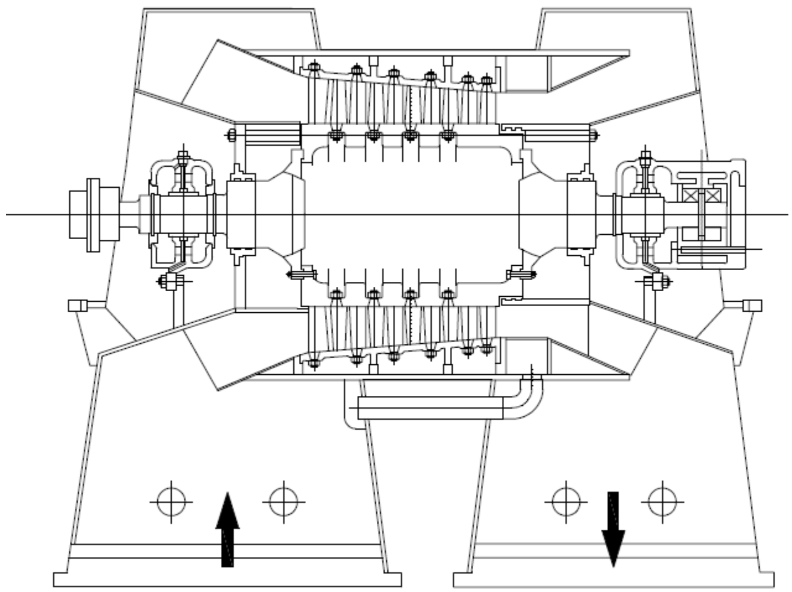

Figure 9.- Centrifugal compressor

In a typical centrifugal compressor, the fluid is forced through an impeller by rapidly rotating impeller blades. The velocity of the fluid is converted to pressure, partially in the impeller and partially in the stationary diffusers. It is normal practice to design the compressor so that half the pressure rise takes place in the impeller and the other half in the diffuser. The diffuser consists of a stator blade, a vane that is tangential to the impeller, or a combination of both. These vane or diffusers reduce velocity and increase static pressure.

For calculating the power required for the GES using gas compressors is required to calculate the enthalpy change between the suction and the discharge during the compression. It is possible to define the isentropic enthalpy of the mixture after the compression as:

$$h_{outs} = \frac{m_{st} * h_{st\,s} + m_{co2} * h_{co2\,is}}{m_{st} + m_{co2}} \qquad (27)$$

Then assuming isentropic compression efficiency is possible to determine the real outlet enthalpy as:

$$h_{out} = h_{in} + \frac{h_{out\,s} - h_{in}}{\eta_{is}} \qquad (28)$$

Finally the compressor work is defined as:

$$W_c = m_{tot} * (h_{out} - h_{in}) \qquad (29)$$

For the compressor system no electrical motor are considered, is assumed that the equipment is connected directly to the turbine shaft.

2.6 Liquid ring vacuum pump

The liquid ring vacuum pump (LRVP) is the most common system used in gas extraction systems along with steam ejectors. Normally the LRVP is used in combination with steam ejectors in the so called hybrid systems, in which the first stage is compressed using a steam ejector and the second stage using a LRVP.

The corrosive nature of the gas to be handled and the requirement for a reasonable operational life means stainless steel construction is essential. The cost of stainless steel pumps and their relatively low capacity are probably the main reasons why two stage systems are not common. However LRVP could be used in conjunction with steam ejectors in hybrid systems (Hall, 1996). A typical liquid ring vacuum pump is shown schematically in Figure 10.

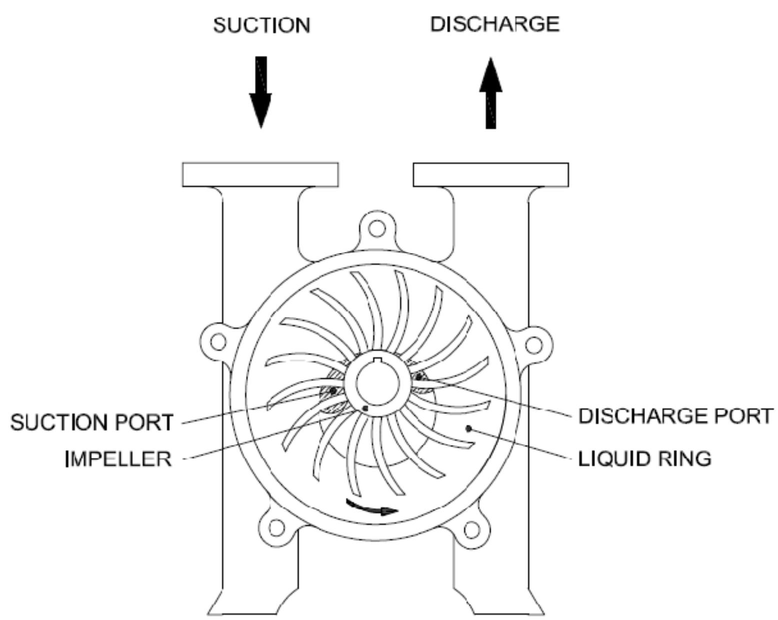

Figure 10.- Liquid ring vacuum pump

The compression action is performed by a rotating ring of liquid, usually water. As the impeller rotates in eccentric position relative to the pump casing, the sealing liquid flows against the casing by the centrifugal force. As the impeller is in an eccentric position a decrescent cavity is produced inside the pump. This cavity becomes smaller since the inside face of sealing liquid circulating flow gradually approaches the discharge port, as it rotates, and thus compresses the gas on the inside.

For calculating the energy requirement of the liquid ring vacuum pump the following formula is used (Siregar,2004):

$$W_{lrvp} = \left[\frac{\gamma}{\gamma-1}\right] * \frac{\dot{m}_{mix} * R * T_{mix}}{\eta_{lrvp} * M_{mix}} * \left[\left(\frac{P_{dis}}{P_{suc}}\right)^{\left(1-\frac{1}{\gamma}\right)} - 1\right] \quad (30)$$

2.7 Gas extraction system configuration

In this section, four different setups of gas extraction systems are considered.

2.7.1 Multistage Steam Ejectors

A multi stage steam ejector system configuration is shown in Figure 11. The motive steam to operate the steam ejectors is extracted from the separator conditions in (15).

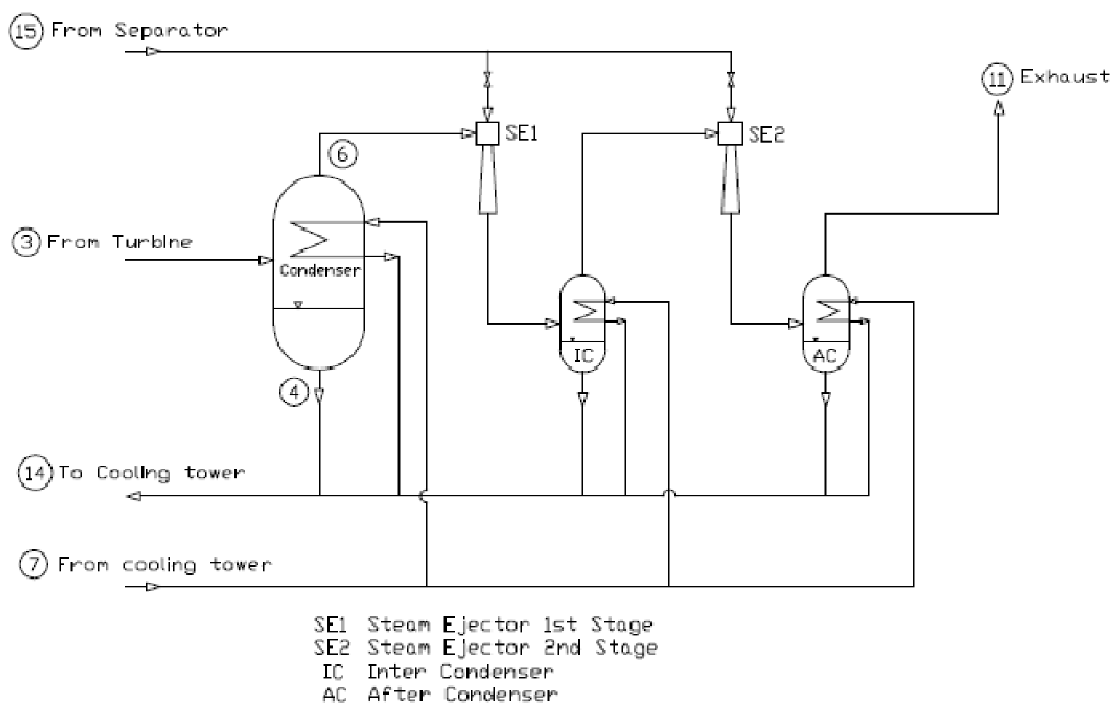

Figure 11.- Double stage steam ejector configuration.

Like the steam ejectors use steam as the operating energy, there are no motors involved and the electricity power consumption is reduced. Nevertheless the amount of steam used is increased to supply the ejectors. The total power output is calculated as:

$$W_{\text{out se}} = W_{\text{tur}} - W_{\text{ctfan}} - W_{\text{pump}} \quad (31)$$

It is important to notice that the cooling tower fan will increase its work if the amount of non condensable gases is increased. This is because the motive steam is transferred to higher pressure levels, and needs to be condensed at higher temperature.

2.7.2 Multistage centrifugal compressors

Multi stage centrifugal compressors are the most efficient system to extract non condensable gases from the condenser and vacuum systems. The amount of energy required is not highly affected by the amount of non condensable gases in the steam. The multistage compressor system layout is shown Figure 12.

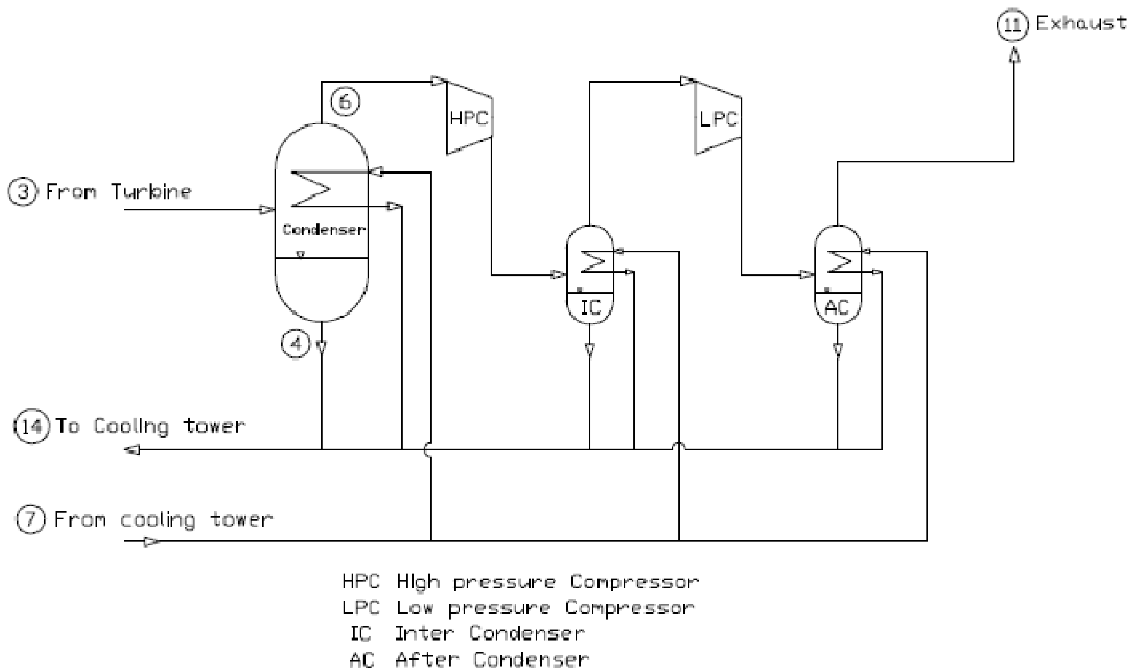

Figure 12.- Double stage compressor configuration.

The amount of energy required by this configuration can be defined as:

$$W_{out\ cc} = W_{tur} - W_{cc} - W_{ctfan} - W_{pump} \quad (32)$$

2.7.3 Multistage liquid ring vacuum pump

The utilization of a double stage liquid ring vacuum pump is not a very common configuration in geothermal power plants. This may be related with its relatively low capacity and the high cost of constructive materials. (Hall, 1996)

The multistage LRVP system configuration is shown in Figure 13

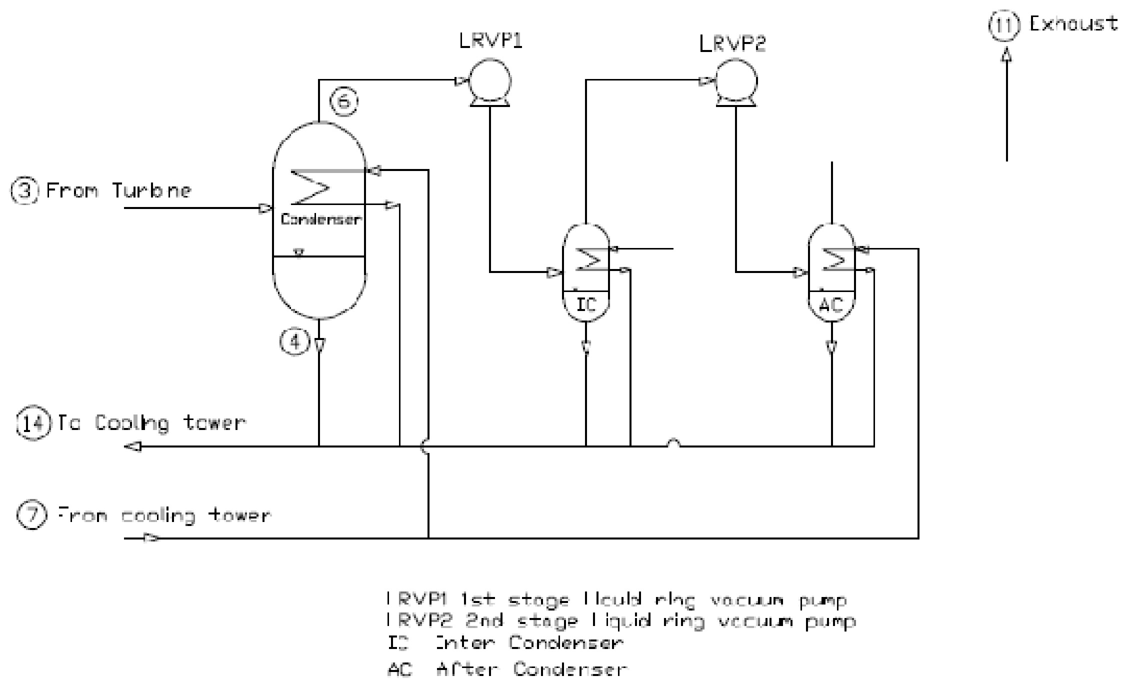

Figure 13.- Multistage liquid ring vacuum pump configuration

The energy requirements for the multistage LRVP system can be defined as:

$$W_{outlrvp} = W_{tur} - W_{lrvp} - W_{ctfan} - W_{pump} \quad (33)$$

2.7.4 Hybrid system, steam ejector + liquid ring vacuum pump

When a combination of two different extraction systems is used, it is called an hybrid system. In this case a steam ejector in the first stage and a liquid ring vacuum pump for the second stage are used. In Figure 14 the system layout for this configuration is shown.

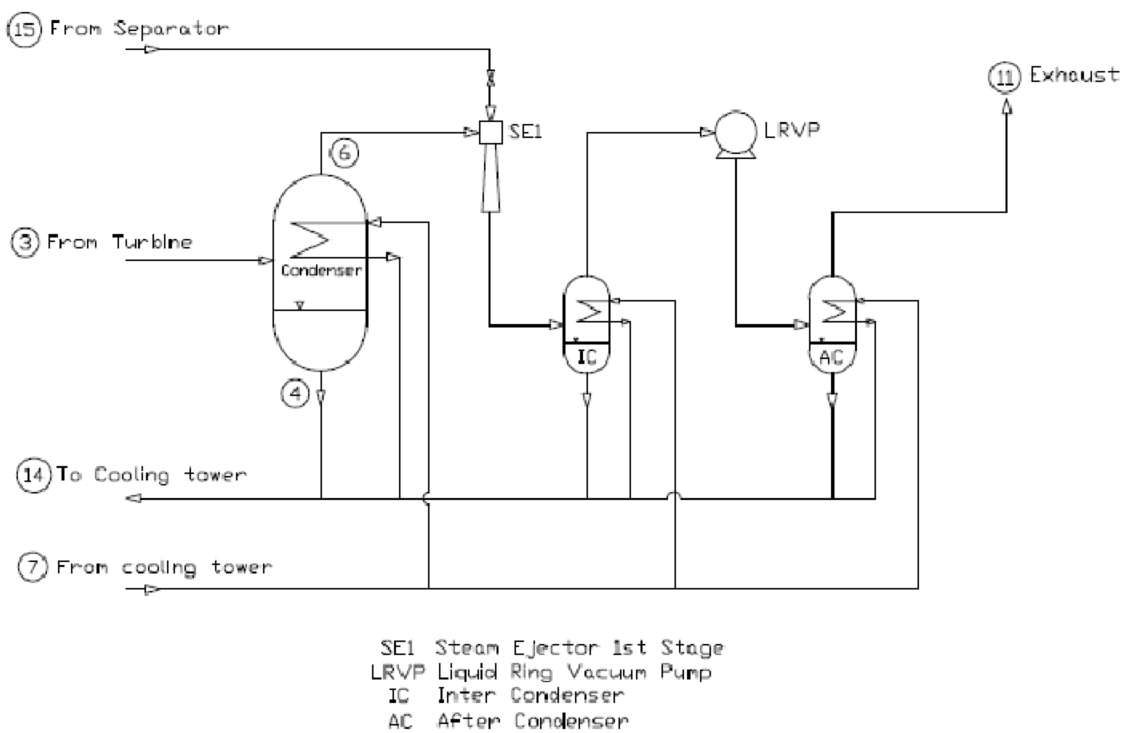

Figure 14.- Hybrid system, steam ejector and liquid ring vacuum pump configuration

The energy requirements for the hybrid system can be defined as:

$$W_{out\ hy} = W_{tur} - W_{lrvp} - W_{ctfan} - W_{pump} \quad (34)$$

3 Economical modeling

The main objective of this thesis is to determine the optimum gas extraction system for a single flash power plant. The optimum system will be the one which give the best economical results for determined operational and economical conditions.

The economical modeling is based on a fixed net power output of 50 [MW], the main input for this analysis will be the steam price, investment cost and operational costs, and as main output variable the electricity price.

3.1 Investment Costs

In order to model the power plant economical behavior it is important to consider the change in the size of the equipment as the operational conditions are modified to obtain a 50 [MW] power output. For example, when the amount of non condensable gases is increased, every gas extraction system modifies its operation conditions. The steam consumption of the ejectors increase, and compressors and liquid ring vacuum pump also increase the auxiliary energy consumption. As a fixed 50 [MW] power output is required, for the energy consumption of the auxiliary system, the size of the turbine will also be modified to keep this output. When steam ejectors are used, the size of the turbine is not so drastically affected, because the energy required to operate the ejectors comes from the steam, not from the generator itself. This is not the case of compressors or LRVP which take the power from the power plant production. It is also important to notice that the price of steam is different from the price of electricity.

To analyze the influence of this variation in size and to model the change in the investment cost, scaling will be used for the different components in the power plant using the formula (Perry, 2008, 1999):

$$\mathrm{Cost}_{EQ2} = \mathrm{Cost}_{EQ1}\left(\frac{S_2}{S_1}\right)^n \qquad (35)$$

This method for scaling the equipment investment cost is normally called the six-tenths method, because the average exponential for all equipments is 0,6[-] (Perry, 2008,1999)

The values for the different equipments are shown in the next table:

Table 1.- Exponential n factors per equipment

Equipment	Unit of scaling	n factor [-]
Turbine vacuum discharge	[W]	0,81**
Steam Ejectors double stage	[kg/s]	0,43*
Steam Ejector single stage	[kg/s]	0,5*
Centrifugal Compressor without driver	[W]	0,62**
Liquid ring vacuum pump (centrifugal)	[W]	0,67*

** From Perry´s "Chemical engineering handbook" 1999*
*** From Walas´s "Chemical process equipment"2010*

Other costs are related with the investment in a geothermal power plant project, these are for example, plant engineering and specification, insurance, taxes, general administration, contingency, etc. This will be considered as a 25[%] of the total equipment investment cost.

3.2 Operational costs

To calculate the maintenance cost of the equipments a percentage of the total investment costs will be assumed, this is different for every equipment; in the next table the assumed values are shown:

Table 2.- Maintenance costs per equipment

Equipment	**Maintenance cost [% of investment cost]**
Turbine	5
Steam Ejectors	2
Compressor	5
Liquid ring vacuum pump	5
General power plant equipment	5

These values are based on oral information from Þorleikur Jóhannesson´s experience in maintenance of different power plants.

As main economical factors, the steam price is mainly related with the direct operational cost of the power plant and the electricity price with the profit from the power plant. Thus these factors must be evaluated for different ranges to see it influence in the total behavior of the economical system.

It is assumed that steam is available for the power plant at a defined price. The gathering system, exploration, drilling, and all related investment involved are considered in this price.

3.3 Economical evaluation methods

To determine the best option for the gas extraction system from the economical point of view different methods can be used.

The first method is the Simple Payback Time (SPT). Is the simplest economical analysis, and considers the resulting annual cash flow and the initial investment cost. The payback time then is the amount of time needed to recover the initial investment and can be expressed as:

$$\mathrm{PBT} = \frac{\text{Total Investment}}{\text{Annual Cash Flow}} \qquad (36)$$

The simple payback time analysis do not use all the economical factors involved in the project such as interest rate and taxes which are simple ignored in the calculation. For this reason this method is just a first indicator of the viability of the investment but not a conclusive sign of the profitability of the project.

The second method is the Net Present Value (NPV), which is used to measure the profit or losses in a certain period of time taking the value of money to the present, using a defined interest rate and a certain period, for this thesis the reference interest rate will be 5[%] and the period of evaluation is 25 years. The NPV can be expressed as:

$$\mathrm{NPV} = \sum_{n=0}^{N} \frac{C_n}{(1+i)^n} - I_0 \qquad (37)$$

The NPV is the value that the project will create in a defined period considering the initial investment cost and the yearly cash flows. This means that a project with higher NPV under same conditions is the most desirable to develop. Nevertheless in real cases the interest rate is not constant in the period of time and it changes depending on market conditions, thus it is an indicator of the results under static market conditions.

The last method is the Internal Rate of Return (IRR), also called return of discount cash flow or profitability index. This is defined as the interest rate at which the net present value is equal to zero; this means that the net present value of the costs is equal to the net present value of the benefits. The internal rate of return express the real return of an investment, giving as indicator an interest rate of the expected profit. Is possible then to compare the IRR with the market opportunity interest rates, if the project IRR is lower than the market interest rate the project may not be desirable. The IRR is calculated making the NPV equal to zero using the following formula:

$$\mathrm{NPV} = \sum_{n=0}^{N} \frac{C_n}{(1+\mathrm{IRR})^n} = 0 \qquad (38)$$

Under similar conditions the system with higher IRR should be consider as the best option to be developed.

4 Analysis and Results

To better understand of the modeling procedure for the different operational parameters, a diagram flow of the process is shown in Figure 15.

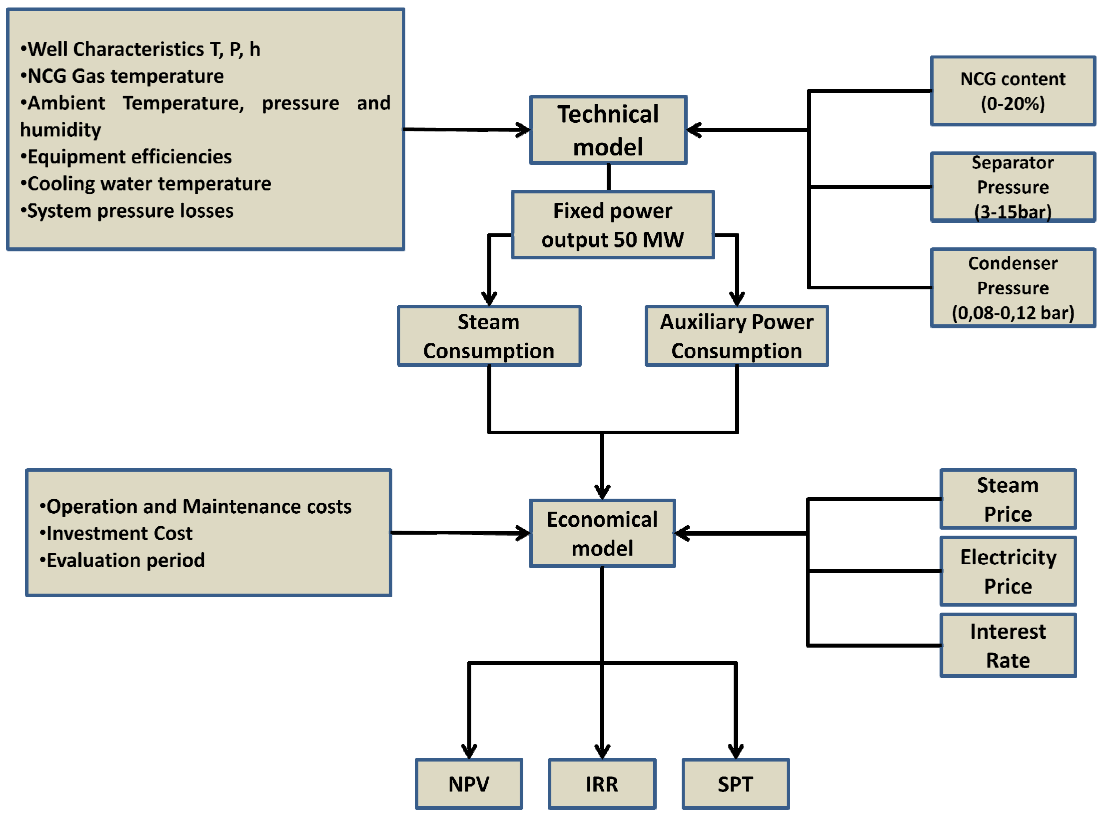

Figure 15.- Flow diagram of modeling process

Three main parameters will be adjusted in the technical modeling, which are: NCG content in geothermal steam, from 0[%] to 20[%], separator pressure, from 3 [bar-a] to 15[bar-a] and condenser pressure from 0,08 [bar-a] to 0,12 [bar-a], with a reference values of 1[%], 7 [bar-a] and 0,1 [bar-a] respectively.

From the economical modeling three parameters will be analyzed. Steam price, electricity selling price, and interest rate, with reference values of 0,002 [USD/ton] 0,05 [USD/kWh] and 5[%] respectively.

For every analysis three economic indicators will be given as results; net present value, internal return rate and simple payback time. With these results will be possible to define the best system configuration for every case.

4.1 General modeling assumptions

For modeling every thermodynamic process MatLab and Refprop were used considering the following technical and economical reference values and general assumptions:

Technical assumptions

- Well bottom temperature = 250[°C]
- Well head pressure = 3 - 15[bar-a] (reference value of 7 [bar-a])
- Atmospheric pressure = 1,1[bar-a]
- Condenser pressure = 0,08 – 0,12 [bar-a] (reference value of 0,1 [bar-a])
- NCG (CO_2) fraction on steam = 0 - 20 [%] (reference value of 1 [%])
- Temperature entering cooling tower = 30[°C]
- Ambient temperature = 15[°C] (dry bulb)
- Air humidity = 60[%]
- Compression ratios will be equal between stages
- No air leakages are included with the NCG
- No NGC dissolution in water is considered
- Bauman rule applies to turbine efficiency
- Geothermal fluid is at saturated state
- Pinch point temperature in condensers = 7[°C]
- Condenser type is shell and tube

Economical assumptions

- Period of evaluation 25 [year]
- Interest rate 5 [%]
- Electricity price 0,05 [USD/kWh]
- Steam Price 0,002 [USD/kg]
- Investment cost relation for reference value SE/LRVP/CC = 1/4/8
- Maintenance costs (percentage of investment cost):
  Steam ejectors = 2 [%]
  LRVP= 5 [%]
  Centrifugal compressors = 5 [%]
  Other power plant equipment = 5 [%]

All the presented values are based on referential power plant operational values according to Þorleikur Jóhannesson from Verkis consulting engineers.

4.2 NCG content analysis

The model was used to simulate a varying amount of non condensable gases entering the system. From 0 [%] to 20 [%], with 7 [bar-a] separator pressure and 0,1 [bar-a] condenser pressure. These values were selected as typical operative conditions In Icelandic power plants.

The results for the auxiliary power consumption are shown in Figure 16.

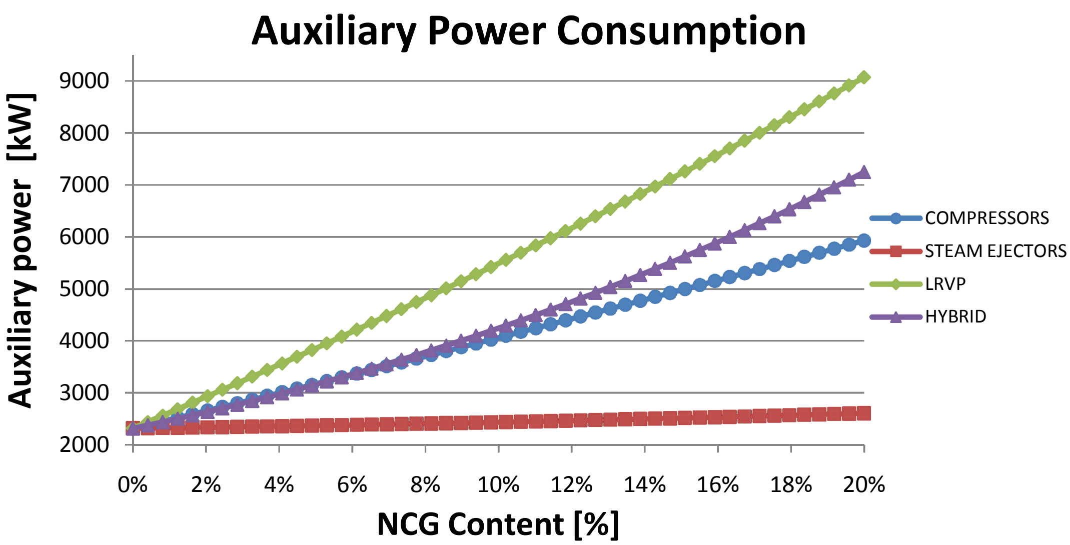

Figure 16.- NCG variation aux. power consumption

The figure indicates that, auxiliary power increases with increasing NCG fraction. The system that consumes most auxiliary power is the LRVP, followed by hybrid system and compressors. Steam ejectors are almost unaffected to the variation, and only a small increment related to cooling water pumping can be observed.

The total steam consumption is shown in Figure 17. Steam ejector system increases the steam consumption of the system considerably, nevertheless LRVP and compressors are less affected. As expected, the hybrid system is between LRVP and steam ejectors, due the steam consumption of the first stage ejector.

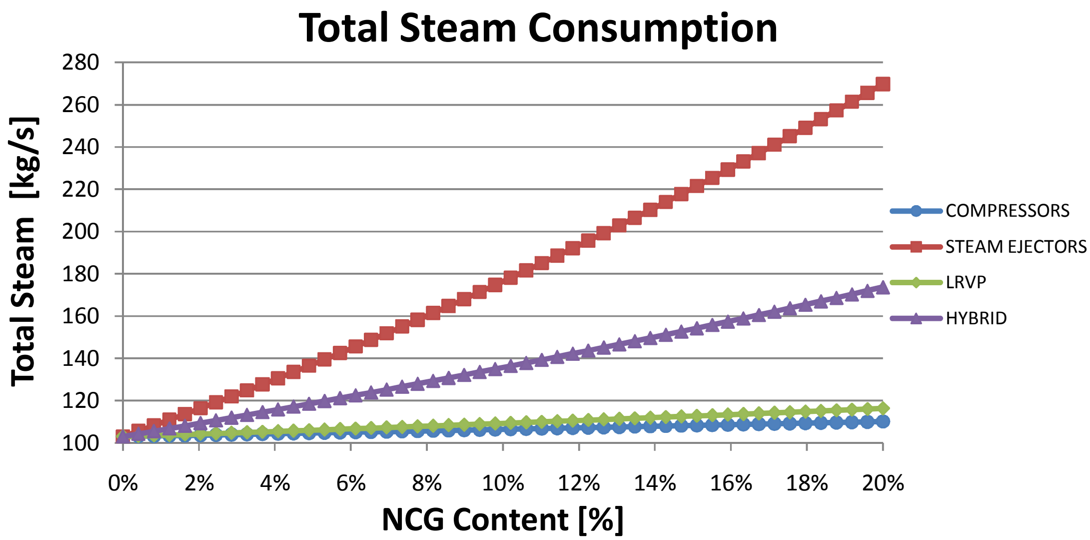

Figure 17.- NCG variation total steam consumption

The economical analysis will give the best extraction system for every percentage of NCG present in the geothermal steam.

In Figure 18 is possible to observe the results for the simple payback time method.

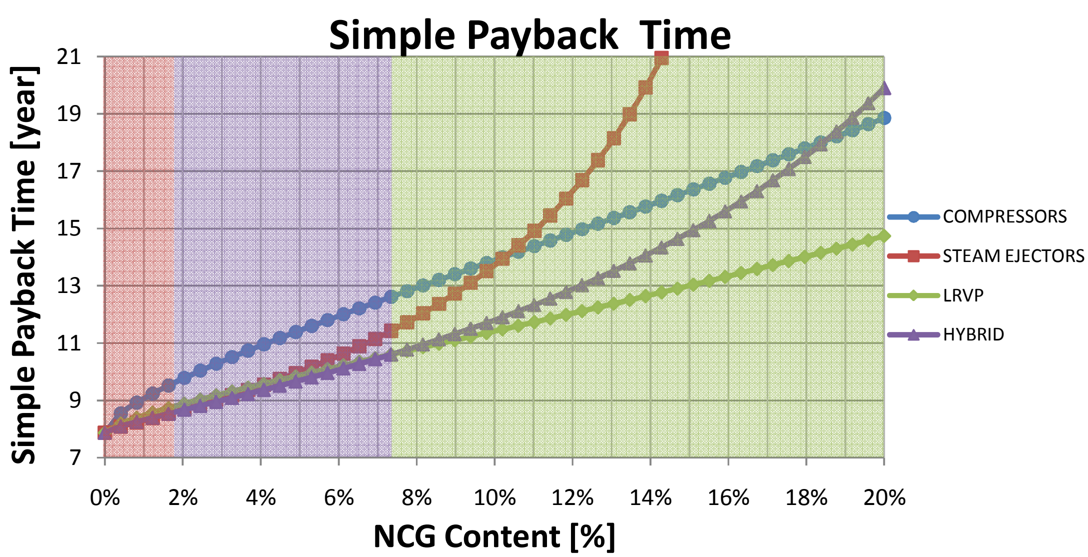

Figure 18.- NCG variation SPT results

Three different zones for the SPT method can be observed. From 0[%] to 1,8 [%] of NCG content steam ejector system gives the lowest SPT, from 1,8 [%] to 7,3[%] hybrid system, and finally from 7,3[%] to 20[%] the LRVP system.

Centrifugal compressors do not give good results for this analysis, because this system involves the highest investment which is not recovered in the evaluation period of the project. The simulation for the internal return rate gives similar results ranges as the SPT method, and is possible to observe these on Figure 19. After 13,5 [%] the IRR becomes negative, and these values are not considered in this evaluation because they do not represent a feasible market option.

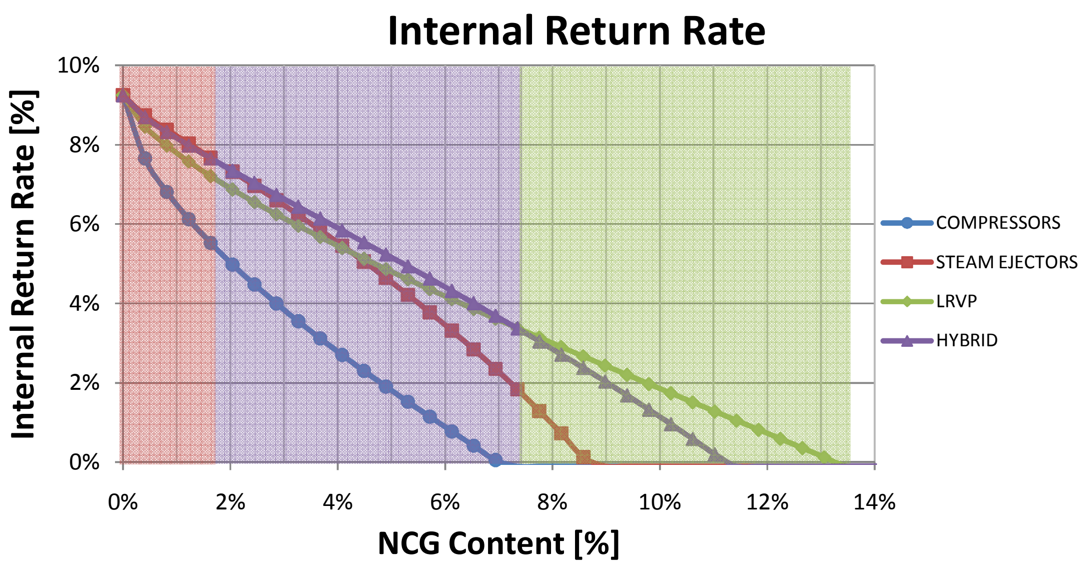

Figure 19.- NCG variation IRR results

Finally, the analysis for the NPV method is shown in Figure 20. A similar behavior is observed than for SPT and IRR, nevertheless the amount of NCG varies in this case, steam ejectors are better from 0[%] to 1,3[%], then hybrid system from 1,3[%] to 8,45[%] and from 8,45[%] to 20[%] LRVP are the best option. Once again compressor system does not give good result for this analysis.

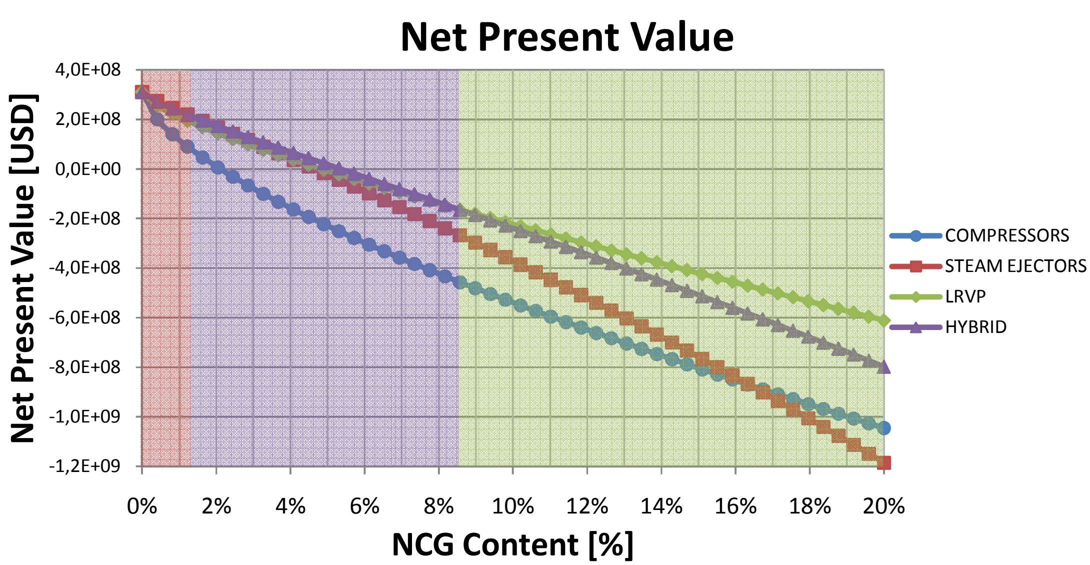

Figure 20.- NCG variation NPV results

The difference between ranges in the different methods is explained because the SPT and IRR methods do not consider the interest rate in its calculations, but NPV is influenced by this factor. The presence of NCG in the geothermal steam has a negative impact in the total economical results of the power plant.

4.3 Separator Pressure analysis

Another factor of importance is the separation pressure. The current analysis range is from 3[bar-a] to 15[bar-a], assuming 1[%] of NCG in the geothermal steam and 0,1[bar-a] condenser pressure. The results for the auxiliary power consumption are shown in Figure 21.

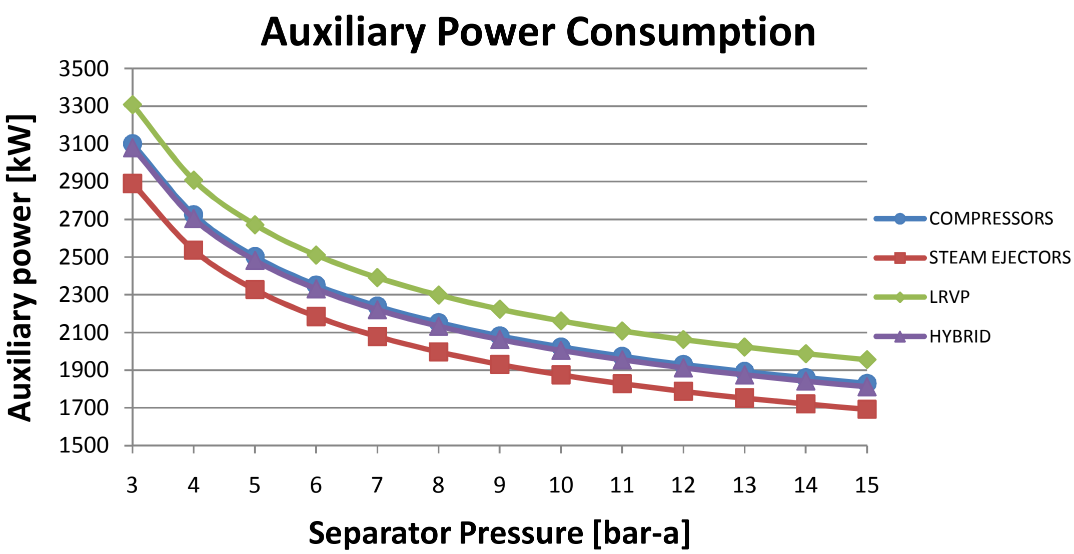

Figure 21.- Separator pressure variation Aux. power consumption

Is observed that when the separator pressure increases from 3 [bar-a] to 15 [bar-a] the auxiliary power is reduced. This can be explained because less steam is required to achieve the 50[MW] power output, thus, the amount of NCG in the steam is reduced along with the auxiliary power to remove the gas. The total steam consumption is shown in Figure 22.

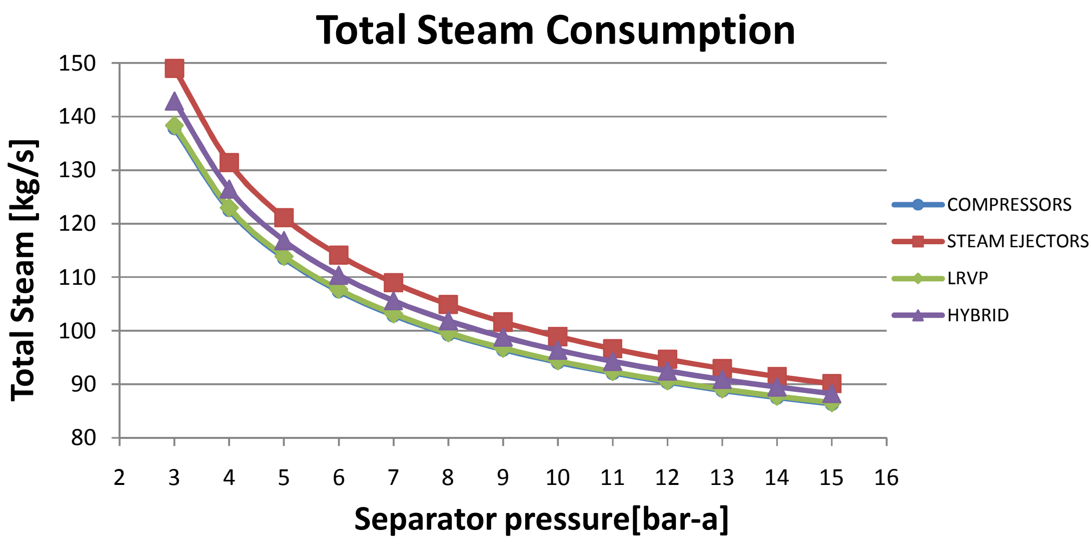

Figure 22.- Separator pressure variation Total Steam Consumption

The economical results for the SPT and IRR method for the separator pressure variation are presented in Figure 23 and 24. In this economical analysis the steam price is considered constant for all the pressure levels.

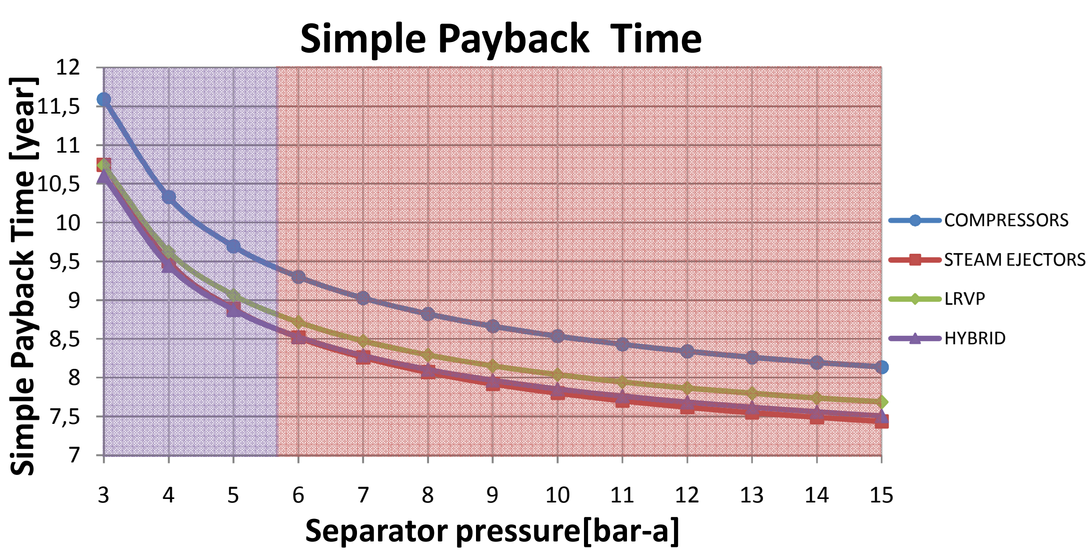

Figure 23.- Separator pressure SPT results

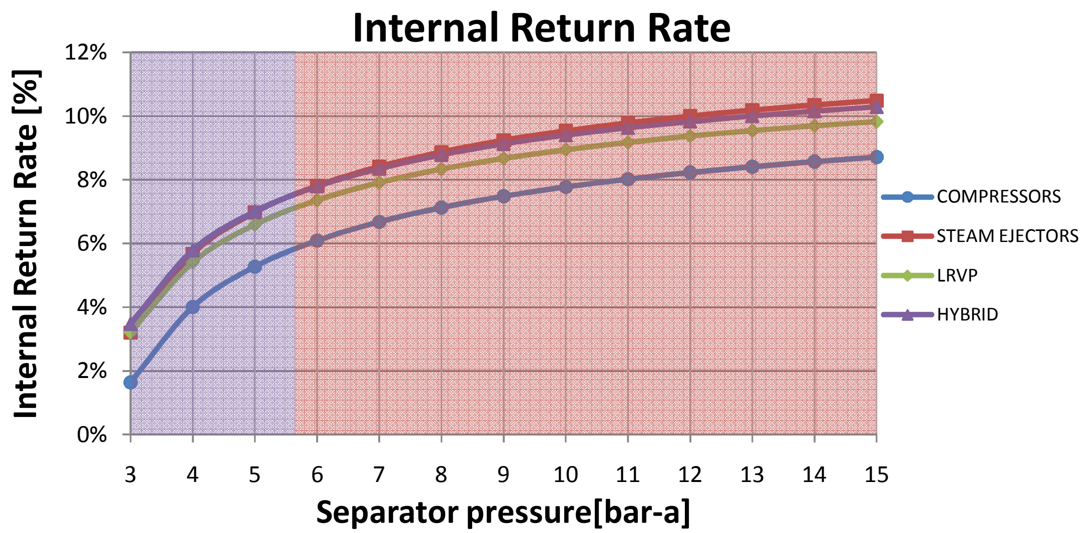

Figure 24.- Separator pressure IRR results

Two zones can be observed in Figure 23 and 24. From 3 [bar-a] to 5,7[bar-a] hybrid systems give the best result, and from 5,7[bar-a] to 15[bar-a] steam ejectors. The difference between hybrid system and ejectors system tend to increase with increasing separator pressure. This can be explained because an increase in the motive steam pressure will reduce the steam consumption of the ejectors, thus, increasing its efficiency in gas removal.

In Figure 25 is possible to observe the NPV results.

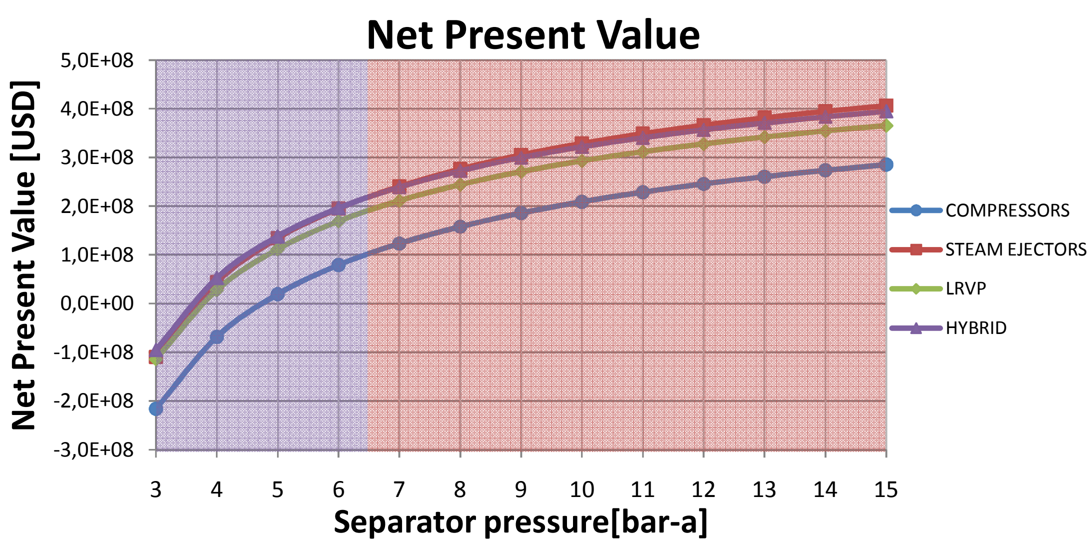

Figure 25.- Separator pressure NPV results

Also in this case two zones are identified, but the range varies, from 3 [bar-a] to 6,4 [bar-a] hybrid system are the best option, and from 6,4 [bar-a] to 15[bar-a] steam ejectors give best results.

The increase in the separator pressure have beneficial effects in the economical results of the power plant, because it reduces the auxiliary power and steam consumption needed, thus, decreasing the operational costs of the power plant.

4.4 Condenser Pressure analysis

The final operational factor of analysis is the condenser pressure, the analysis range is from 0,08[bar-a] to 0,12[bar-a], assuming 1[%] of NCG in the geothermal steam and 7[bar-a] separator pressure. The results for the auxiliary power and steam consumption are shown in Figure 26 and Figure 27.

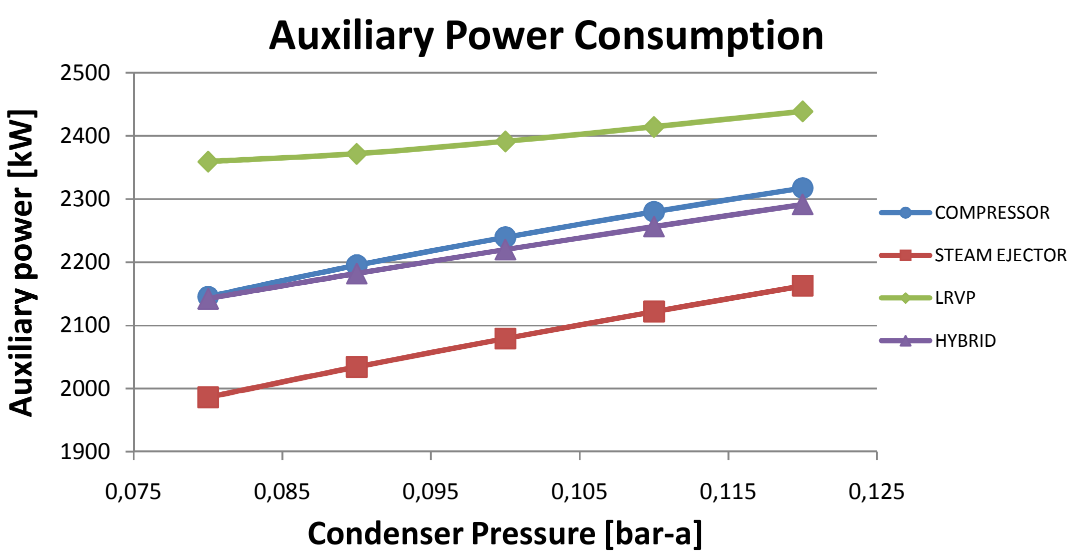

Figure 26.- Condenser pressure aux. power consumption

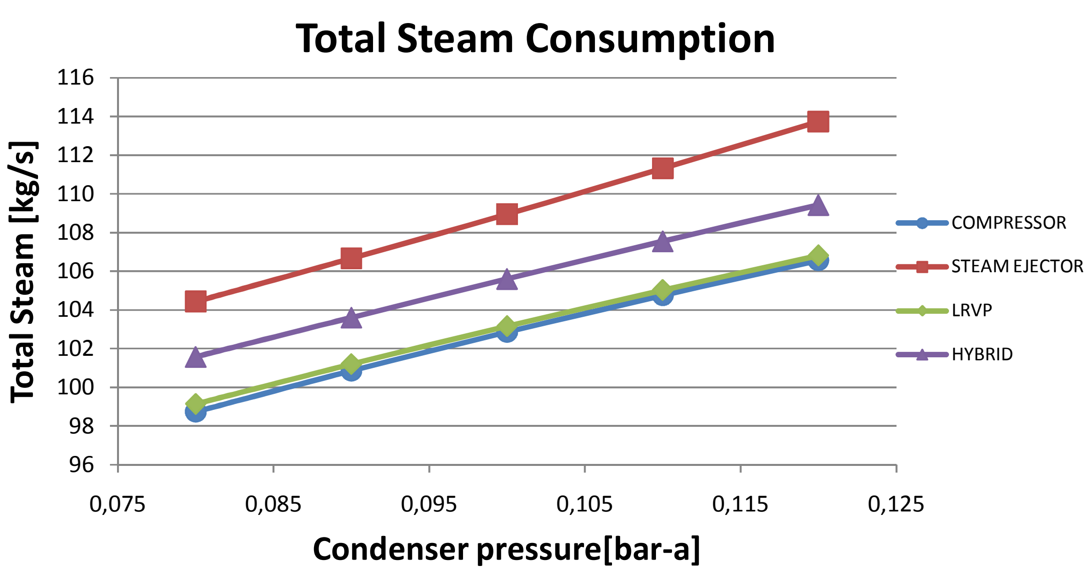

Figure 27.- Condenser pressure total steam consumption

It is observed that the increment in the condenser pressure also increments the auxiliary power and steam consumption. In the same manner that the separator pressure, when the condenser pressure is increased, more steam is needed to achieve the 50 [MW] energy output. This increases the amount of NCG in the system and the amount of auxiliary power required for gas removal.

Finally the economical results for the condenser pressure variation are shown in Figure 28, 29 and 30.

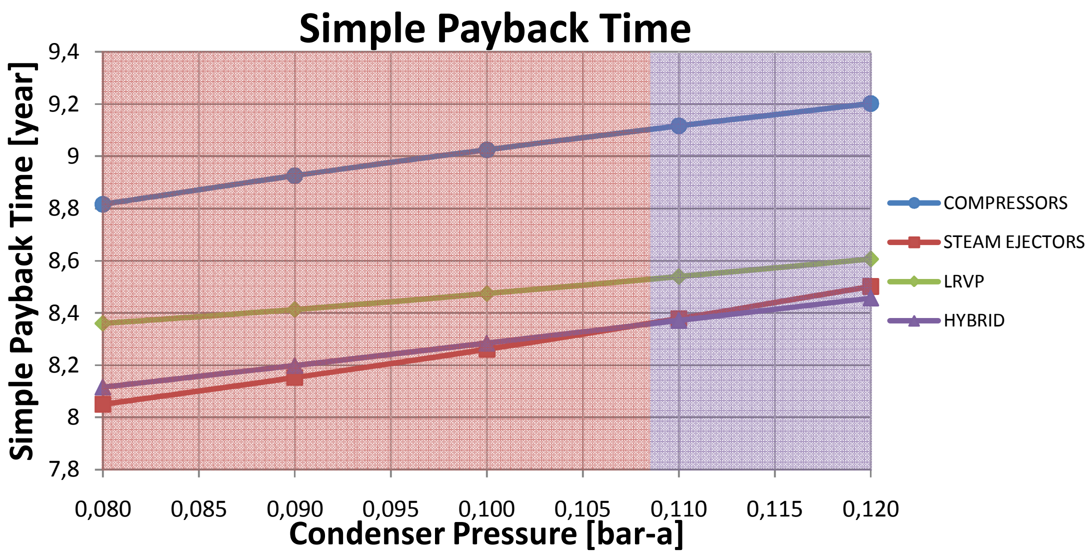

Figure 28.- Condenser pressure SPT results

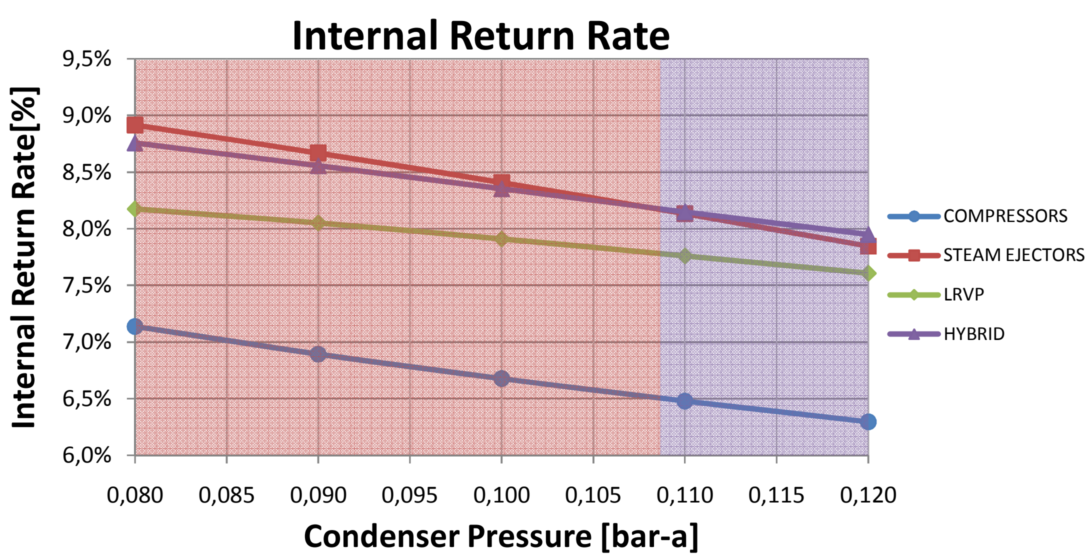

Figure 29.- Condenser pressure IRR results

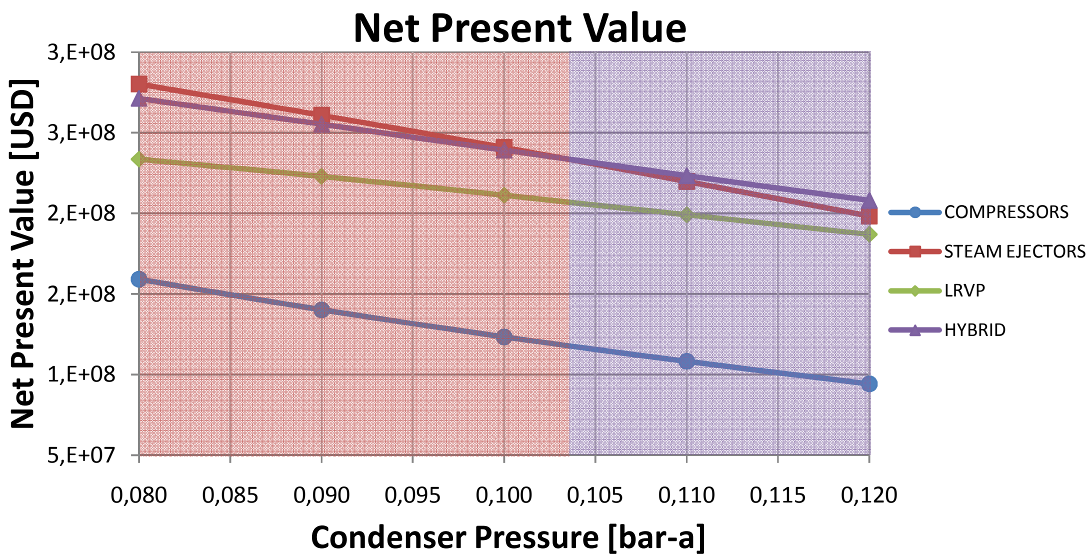

Figure 30.- Condenser pressure NPV results

From the economical results is possible to observe two zones for the condenser pressure variation. For the IRR and SPT method from 0,08[bar-a] to 0,108[bar-a] steam ejectors give the best results and from 0,108[bar-a] to 0,12[bar-a] hybrid systems. The behavior is the same for the NPV method, but the range varies, from 0,08[bar-a] to 0,104[bar-a] steam ejectors give best results and from 0,104[bar-a] to 0,12[bar-a] hybrid systems. In this model the efficiency of LRVP system is less affected to the increase in condenser pressure variation, reducing the difference between steam ejectors and hybrid system.

4.5 Economical Sensitivity analysis

To analyze the influence of the economical variables in the system behavior a sensitivity analysis has been done for a reference case.

A power plant is simulated with 1[%] NCG content in the geothermal steam, 7[bar-a] separator pressure, and 0,1[bar-a] condenser pressure. The results for steam and auxiliary power consumption are shown in table 3

Table 3.- Steam and Auxiliary power consumption reference case.

Gas extraction system	Total Steam Consumption [kg/s]	Auxiliary Power [kW]
Compressors	102,86	2.239,51
Steam Ejectors	108,95	2.079,21
Liquid ring vacuum pumps	103,12	2.369,42
Hybrid system	105,61	2.220,17

4.5.1 Electricity price analysis

Electricity price is an important economical parameter which will affect the income of the power plant. Economical results are shown in Figures 31, 32 and 33.

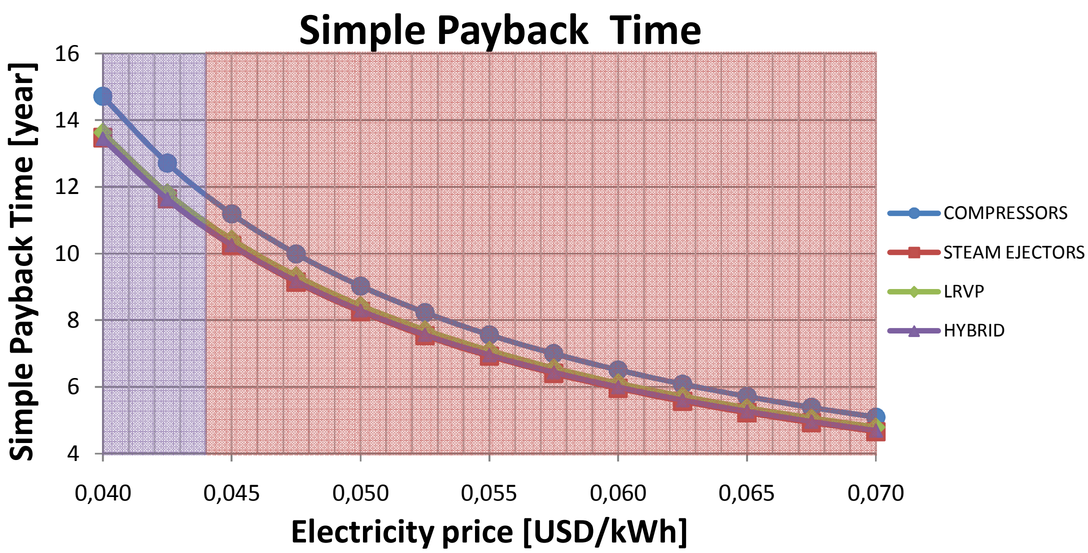

Figure 31.- Electricity price SPT sensitivity results

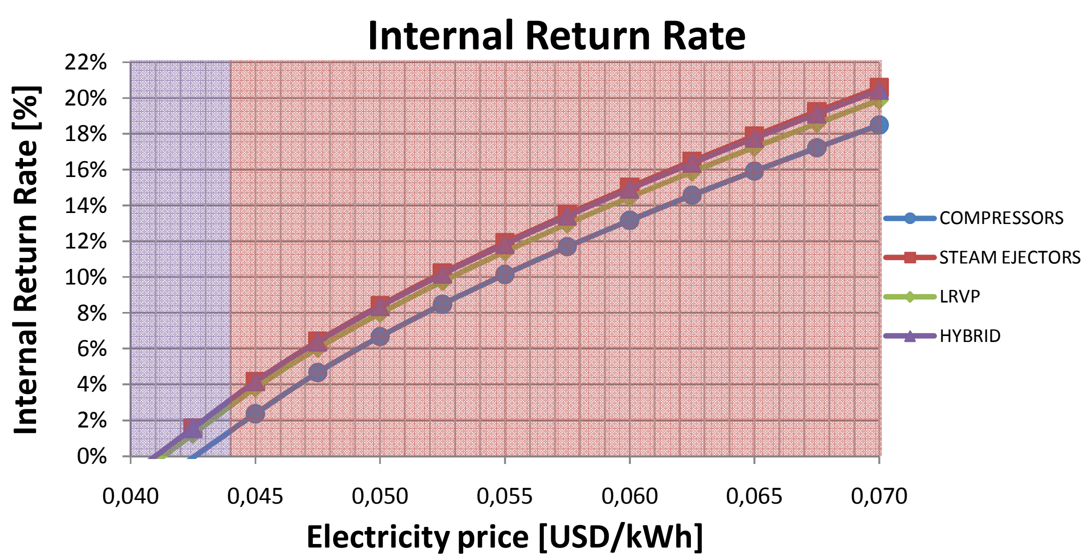

Figure 32.- Electricity price IRR sensitivity results

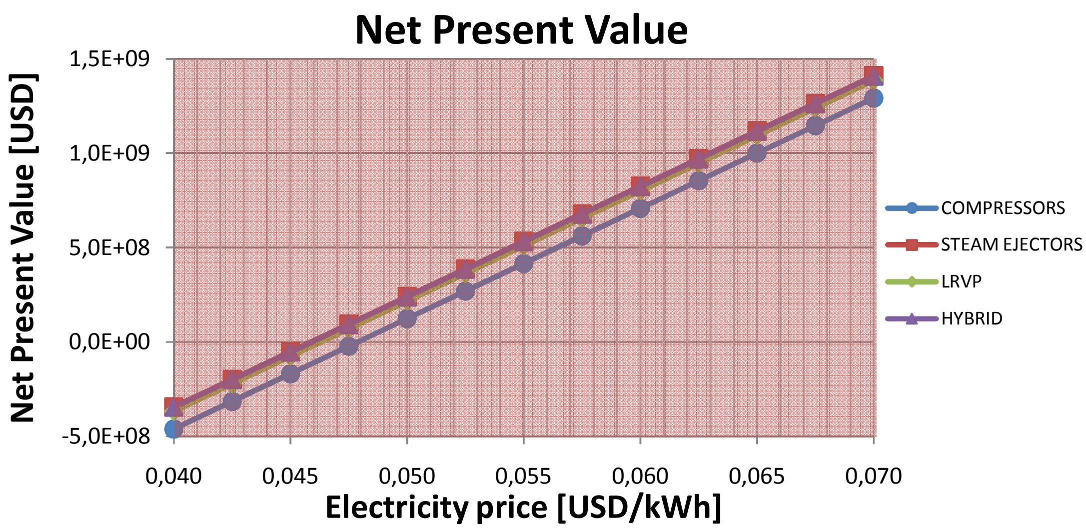

Figure 33.- Electricity price NPV sensitivity results

For the IRR and SPT method two zones are identified, from 0,04 [USD/kWh] to 0,044 [USD/kWh] hybrid system give best results, and from 0,044[USD/kWh] to 0,07[USD/kWh] steam ejectors. In the NPV method ejectors give the best results in all the analysis range. It is possible to observe that the price of electricity has a great influence in the total economical results of the power plant. However, from the NCG extraction system point of view, it has reduced influence in the behavior of the system. The reduction of the electricity price affects negatively the economical results of ejectors making hybrid system a better option.

4.5.2 Steam price

Steam price is another factor of importance in the economical results of the power plant and it is related with the power plant operational costs. The economical results are shown in Figure 34, 35 and 36.

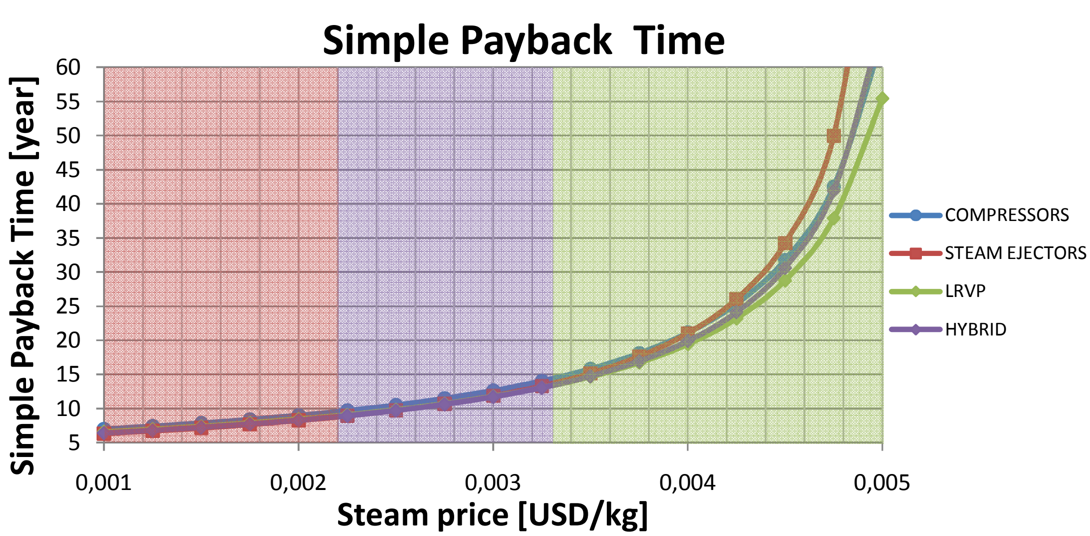

Figure 34.- Steam price SPT sensitivity results

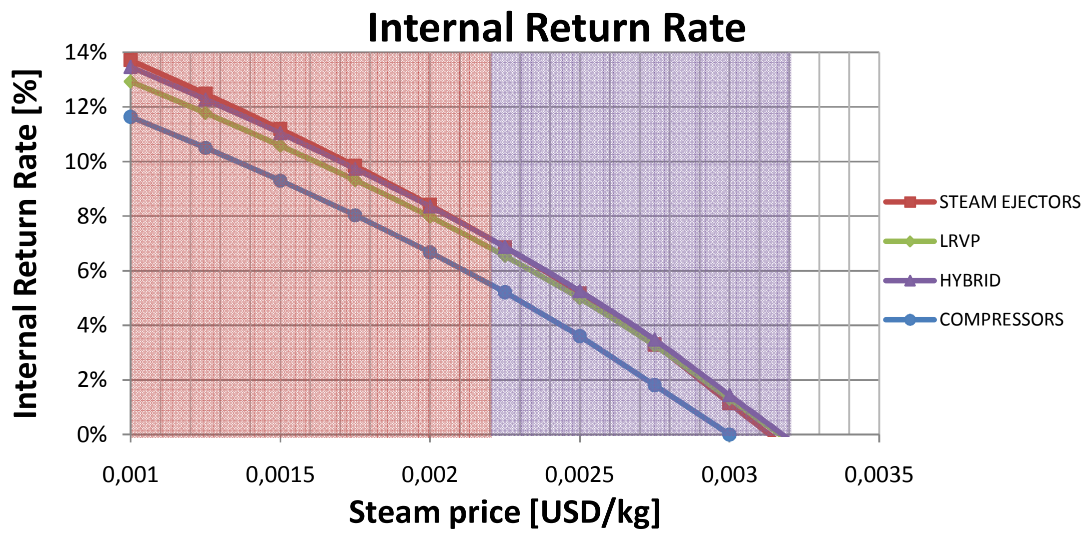

Figure 35.- Steam price IRR sensitivity results

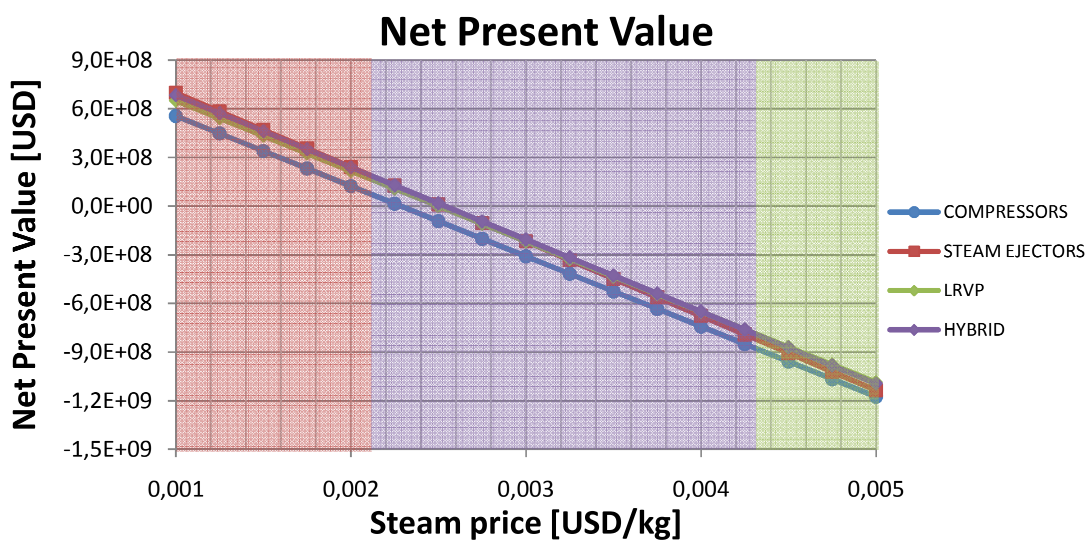

Figure 36.- Steam price NPV sensitivity results

From figure 35, three zones for the SPT method can be identified. From 0,001 [USD/kg] to 0,0022 [USD/kg], steam ejectors are the best option, from 0,0022 [USD/kg] to 0,0033 [USD/kg] hybrid system, and from 0,0033 [USD/kg] to 0,005 [USD/kg] LRVP system. The behavior for the IRR method is the same, but after 0,0032[USD/kg] it becomes negative, then, further values are not considered. Finally for the NPV method also three zones are identified, in this case the ranges are: From 0,001 [USD/kg] to 0,0021[USD/kg] steam ejectors are the best option, from 0,0021[USD/kg] to 0,0043[USD/kg] hybrid system, and from 0,0043[USD/kg] to 0,005[USD/kg] LRVP system.

The increase in steam cost has a negative impact on the steam-consuming configurations, it has a greater impact on steam ejectors and hybrid system, and this is reduced in LRVP and compressors. As the price of steam increases the economical results of ejectors and hybrid configurations is reduced faster than LRVP and compressors.

4.5.3 Interest rate analysis

The final economical factor of analysis is the interest rate which affects the investment cost and the net yearly cash flows. It is important to notice that the interest rate does not affect the IRR and SPT methods. The results for these calculations are shown in Table 4

Table 4.- SPT and IRR for interest rate variation.

Gas extraction system	Simple payback time [year]	Internal return rate [%]
Compressors	9,02	6,68
Steam Ejectors	8,26	8,41
Liquid ring vacuum pumps	8,44	7,98
Hybrid system	8,28	8,35

The results for the net present value are shown in

Figure 37

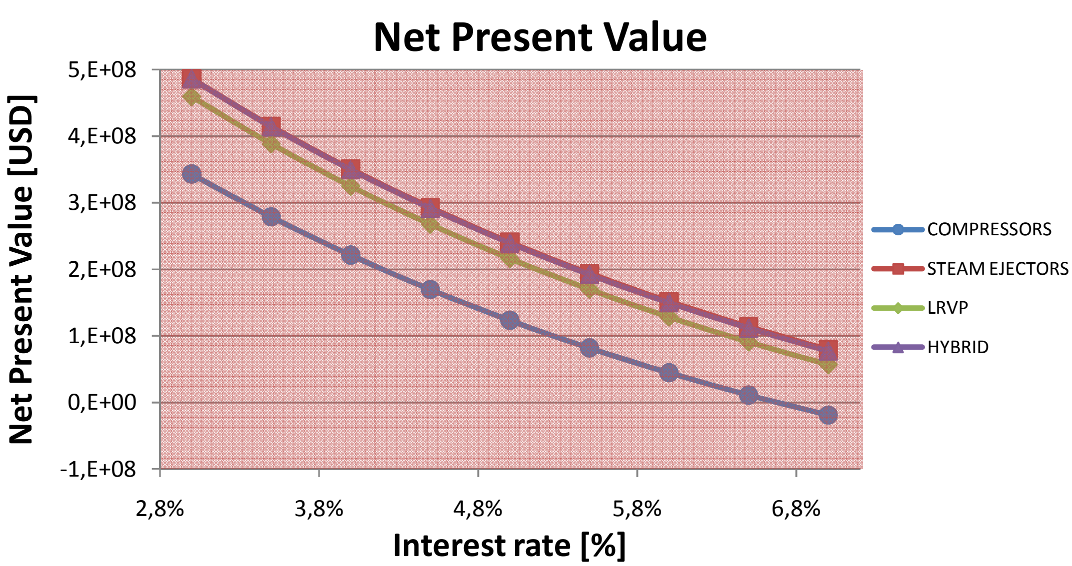

Figure 37.- Interest rate NPV sensitivity results

Steam ejectors give the best economical result for the reference case. The results also show that the difference between systems is the same for all the evaluation range; thus, there is no influence of this factor in the behavior of the gas extraction systems.

4.6 Krafla power plant

Krafla power plant is located in northern Iceland, it consist in two 30[MW] units using a double flash system. It is possible to use the model to simulate the actual conditions for Krafla power plant. Nevertheless, to be consistent with this model, the power output was fixed to 50[MW] in order to keep the power plant and GES system investment in the reference values. It is expected that from the GES system point of view this has no influence in the results, because the main parameter that influence the selection of the GES are condenser pressure, motive steam pressure and NCG content. The design parameters values for Krafla power plant are:

Table 5.- Krafla Power plant design parameters.

Parameter	Value	Units
NCG content	0,83	%
Gas temperature	25	°C
Motive steam pressure	7,06	bar-a
Turbine inlet steam pressure	7,55	bar-a
Suction pressure from condenser	0,113	bar-a
Intercondenser pressure	0,44	bar-a
Discharge pressure	1,1	bar-a

These values correspond to the data in the operative manual of Krafla power plant. With these values is possible to simulate the system steam and auxiliary power requirements and economical results. These are shown in table 6 and 7:

Table 6.- Auxiliary power and steam consumption.

Gas extraction system	Auxiliary Power [kW]	Steam Consumption [kg/s]
Compressors	2.253,73	101,55
Steam Ejectors	2.039,96	104,95
Liquid ring vacuum pumps	2.227,9	101,5
Hybrid system	2.115,51	103,55

Table 7.- Krafla power plant economical results.

Gas extraction system	NPV [USD]	SPT [year]	IRR [%]
Compressors	103.838.942	9,15	6,40
Steam Ejectors	279.197.952	8,05	8,91
Liquid ring vacuum pumps	254.433.359	8,22	8,50
Hybrid system	272.426.054	8,10	8,80

The economical results show that the best gas extraction system for these conditions is steam ejector system. However it is possible to observe from table 7 that the results for IRR and SPT are very similar between systems. LRVP and hybrid system have a difference in the IRR of 0,11 [%] and 0,41[%] with steam ejectors and 0,05[year] and 0,17[year] in the SPT method. This makes any of these three systems a feasible solution. Centrifugal compressors were shown to be the worst option for the analyzed parameters.

5 Conclusions

The amount of non condensable gases has been shown to be the most important factor to determine the optimum gas extraction system for a single flash power plant. In this analysis three different zones of use are identified. From 0 [%] to 1,8 [%] of NCG content the steam ejector system gives the lowest SPT and the best IRR, then, from 1,8 [%] to 7,3 [%] hybrid system, and finally form 7,3 [%] to 20 [%]LRVP system.

Regarding the NPV method the behavior is the same, but the range varies. Steam ejectors are better from 0 [%] to 6,8 [%], then hybrid system from 6,8 [%] to 17,4 [%] and from 17,4 [%] to 20 [%] LRVP are the best option. Compressor system involves a big investment that is not recovered during the evaluation period of the project, and does not give optimal results for the analysis range and conditions.

The separator pressure analysis of the reference case showed two zones for the IRR and SPT methods. From 3 [bar-a] to 5,7[bar-a] hybrid systems give the best result, and from 5,7[bar-a] to 15[bar-a] steam ejectors. The behavior of the system for the NPV method is the same, but the range varies, from 3 [bar-a] to 6,4 [bar-a] hybrid system are the best option, and from 6,4 [bar-a] to 15[bar-a] steam ejectors give best results.

Steam ejector system become less efficient at lower separator pressure levels. This is explained because the motive steam pressure reduction affects the expansion ratio and air to steam ratio, which finally increase the total steam consumption of this system. This result in an increment of the operative costs of the power plant, then, steam ejectors are recommended for higher separator pressure levels.

The condenser pressure increase will demand a higher steam and auxiliary power consumption. From the GES perspective the economical results showed two zones for the IRR and SPT methods: From 0,08[bar-a] to 0,108[bar-a] steam ejectors give the best results and from 0,108[bar-a] to 0,12[bar-a] hybrid systems. The behavior is the same for the NPV method, but the range varies, from 0,08[bar-a] to 0,104[bar-a] steam ejectors give best results and from 0,104[bar-a] to 0,12[bar-a] hybrid systems. For this model the performance of LRVP system is less affected to this variation, reducing the difference of steam ejectors and hybrid system with increasing condenser pressure, making this last one a better option for lower vacuum levels in the condenser.

From the economical analysis of the steam price variation three zones were identified for the SPT method. From 0,001 [USD/kg] to 0,0022 [USD/kg], steam ejectors are the best option, from 0,0022 [USD/kg] to 0,0033 [USD/kg] hybrid system and from 0,0033 [USD/kg] to 0,005 [USD/kg] LRVP system. The behavior for the IRR method is the same than SPT method, but after 0,0032[USD/kg] the result become negative, then, further values are not considered. Finally for the NPV method also three zones are identified, in this case the ranges are: From 0,001 [USD/kg] to 0,0021[USD/kg] steam ejectors are the best option, from 0,0021[USD/kg] to 0,0043[USD/kg] hybrid system, and from 0,0043[USD/kg] to 0,005[USD/kg] LRVP system. The steam price affects in higher manner the steam-consuming configurations. Then for high steam prices LRVP system is a better option.

Electricity price is another factor of importance to determine the best GES. Nevertheless its influence in the economical results of the project is bigger than in the GES selection. For the reference case analysis, two zones were identified regarding the IRR and SPT methods. From 0,04 [USD/kWh] to 0,044 [USD/kWh] hybrid system give best results, and from 0,044[USD/kWh] to 0,07[USD/kWh] steam ejectors. In the NPV method ejectors give the best results in all the analysis range. The increase in the electricity price makes ejectors system a more suitable option.

Interest rate variation affects all the systems in similar manner and has no impact in the gas extraction system selection. An increment in the interest rate will have a negative effect on the economical results of the project.

Finally for the Krafla design values was possible to determine that the best extraction system is steam ejector configuration, however, the difference between LRVP and hybrid systems is reduced, making any of these systems a feasible solution.

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