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A Software to evaluate financial viability of geothermal projects

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EXECUTIVE SUMMARY

Theoretical cases are presented of electricity generation for geothermal fluid in the range of 120-170°C. The working cycles suggested are binary cycles of ORC and Kalina Cycle technology.

Two model cases were prepared, one with ORC technology and one with Kalina technology. Each model case has then the option of using wet or dry cooling and the option of being an Enhanced Geothermal System (EGS) or a conventional hydrothermal geothermal system.

The model shows that the parasitic load is higher when wet cooling is used than with dry cooling.

The power plants for EGS systems are more expensive than for conventional hydrothermal systems. This is mainly due to higher well cost.

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Electricity production descriptions

Electricity production from geothermal energy resources can be done in various ways. In this analysis there are two types of resource studied; Enhanced Geothermal System (EGS) and hydrothermal resource. There are further various ways of generating electricity from the resources. The focus here is on low temperature resources and so binary cycles are presented as the solution of choice. Two binary cycles are described namely Organic Rankine Cycle (ORC) and Kalina Cycle.

Proposed Geothermal Resources

Hydrothermal resource

In hydrothermal resources, natural permeability and water are sufficient to convey the heat to surface where it can be used to produce electricity. This can normally be found in fractured volcanic rocks where temperatures are relatively high near the surface. This can also be found in non-volcanic areas where the crustal heat flow is sufficient to produce high temperatures and the rocks are permeable to allow the production of large volumes of fluid.

Enhanced Geothermal Systems (EGS)

EGS are located in regions of elevated temperatures (caused by radiogenic heat production, elevated tectonic heat flow, or vertical heat advection through deep fault zones). EGS is typically situated in basement rock marked by relatively low natural permeability. The specific characteristics of the EGS are mainly connected to conveying the heat to surface, usually by water injection and fracturing.

EGS may be feasible anywhere in the world, depending on the economic limits of the drilling depth. Currently there are EGS systems being developed in a few countries. Six wells have been drilled in South Australia's Cooper Basin where a 25 MW EGS project is planned.

Many features associated with the technical feasibility of EGS technology have been demonstrated at more than one site in the past 30 years. However, the major shortcoming of the field testing so far is that circulation rates through the stimulated regions have been below commercially viable rates. Recent progress at Soultz-sous-Foret in France and Cooper Basin in Australia suggests that the ability to reach commercial levels is reasonably close. In 2011, 20 EGS projects were under development or under discussion in several EU countries.

Proposed Work Cycles

This project deals with electrical power generation using geothermal fluid at low temperatures areas ($\leq$ 170 °C). For this, a binary cycle power plant is presented. In binary power plants, a working fluid having lower boiling point than water, is confined in a circulating system or closed loop. Heat from the geothermal fluid is used in heat exchangers to vaporize a working fluid which impels a turbine and electricity is generated in a generator which is coupled to the turbine. Geothermal fluid of down to 100 °C or even lower temperature values can theoretically be used for electrical generation in binary cycle power plants. Whether it is feasible or not depends on other factors like for example the cooling need and method available and cost of extracting the geothermal fluid. For this project two different processes are considered i.e., Organic Rankine Cycle (ORC) and Kalina cycle.

Organic Rankine Cycle (ORC)

A schematic diagram of an ORC is shown in Figure 1. Stream 1 shows the path of the reservoir fluid which is pumped up through production wells. Generally a well pump is needed as low-temperature geothermal resources are usually not self-flowing. The binary working fluid (normally isobutane or isopentane) is heated and evaporated in the evaporator and is piped to the turbine (Stream 2). The gas impels the turbine and electricity is generated in the generator (G) coupled to the turbine. The slightly superheated binary fluid exits the turbine at lower pressure as Stream 3 and enters the condenser where it condenses back into liquid form (Stream 4). A feed pump circulates the liquid at a higher pressure (Stream 5) before entering the heat exchanger again repeating the process. The geothermal fluid is injected back into the reservoir (Stream 6) through injection wells. A recuperator can be added in an ORC cycle to increase the power cycle's efficiency. The binary fluid is cooled in the recuperator before entering the condenser and preheated before entering the heat exchanger.

The condenser requires cooling which may be provided by either water (wet cooling) or air (dry cooling). Even though air cooled condensers are more effective, wet cooling is often preferred, since the cost and foot print is smaller and the output not as dependent on ambient condition. Dry cooling may be necessary in areas of limited water resources.

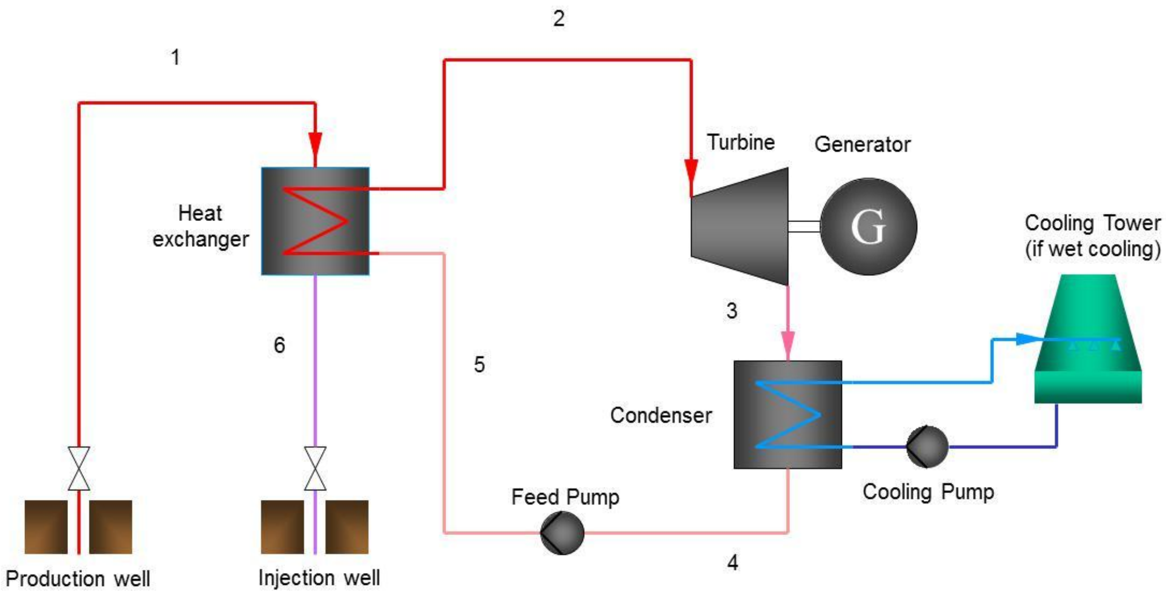

Figure 1 Process flow diagram of an ORC cycle.

The working fluid of an ORC is selected according to several criteria but of fundamental importance is the temperature of the resource. A very important design parameter of the cycle is the boiling pressure. More advanced power plants based on the ORC technology use two cycles with two pressures to increase the efficiency of the cycle. Two different working fluids have also been used in a two cycle scheme.

Sizes of binary power plants vary but the average capacity is approximately 5 MW/unit. Notice that binary plant turbines are in most cases much smaller than geothermal steam turbines. While there are examples of geothermal steam turbines larger than 100 MW, the largest binary cycle turbines are around 15 MW. 20 MW generator units have been reported where two turbines turn a single generator. 45 MW generator units have been reported in Aydin in Turkey, where two turbo expander generator trains are going to deliver these 45 MW of clean energy. Binary cycle turbines are though typically manufactured in smaller units, ranging between 1 MW and 10 MW in size.

Kalina Cycle

The working fluid in a Kalina cycle is a mixture of water and ammonia. The process is shown in Figure 2. Starting at the evaporator, the working fluid is heated and evaporated in the evaporator. It exits the evaporator as Stream 1 in the figure and enters a separator that separates the ammonia rich vapour from the ammonia lean liquid. The vapour exits the separator as Stream 2 and impels the turbine and the generator (G), which is coupled to the turbine, generates electricity. The vapour flows from the turbine as Stream 3 and is mixed with the lean fluid of Stream 5. The liquid exiting the separator as Stream 4 enters the High Temperature Recuperator (HTR). The liquid exits the HTR as Stream 5 at a lower temperature before it is mixed with Stream 3. The mixed fluid (vapour and liquid) at Stream 6 enters the Low Temperature Recuperator (LTR), which serves a similar purpose as the HTR. The liquid exits the LTR as Stream 7 before entering the condenser, which condensates the fluid to liquid form as Stream 8. A pump circulates the liquid from Stream 8 at a higher pressure as Stream 9, before entering the LTR. Stream 10 and 11 are two steps in which the liquid is heated in the recuperators, before entering the evaporator again. The heat source for the evaporator is in this case the geothermal fluid provided by the wells.

The main characteristic of the Kalina Cycle is that the working fluid, which is utilized in the closed cycle, is a mixture of water and ammonia. The evaporation temperature of the mixture changes with concentration of ammonia. Therefore, while passing through the evaporator, the temperature profile of the working fluid can be better adapted to the temperature profile of the geothermal fluid. This reduces second law losses and results in higher second law efficiency of the working cycle. Another characteristic of the cycle is that with separation and mixing, the ratio of the ammonia and water mixture can be changed and then at the same time condensation temperature and evaporation temperature as well as other properties of the fluid changes. This can be used to improve the efficiency of the cycle.

A schematic diagram of a Kalina Cycle is shown in Figure 2.

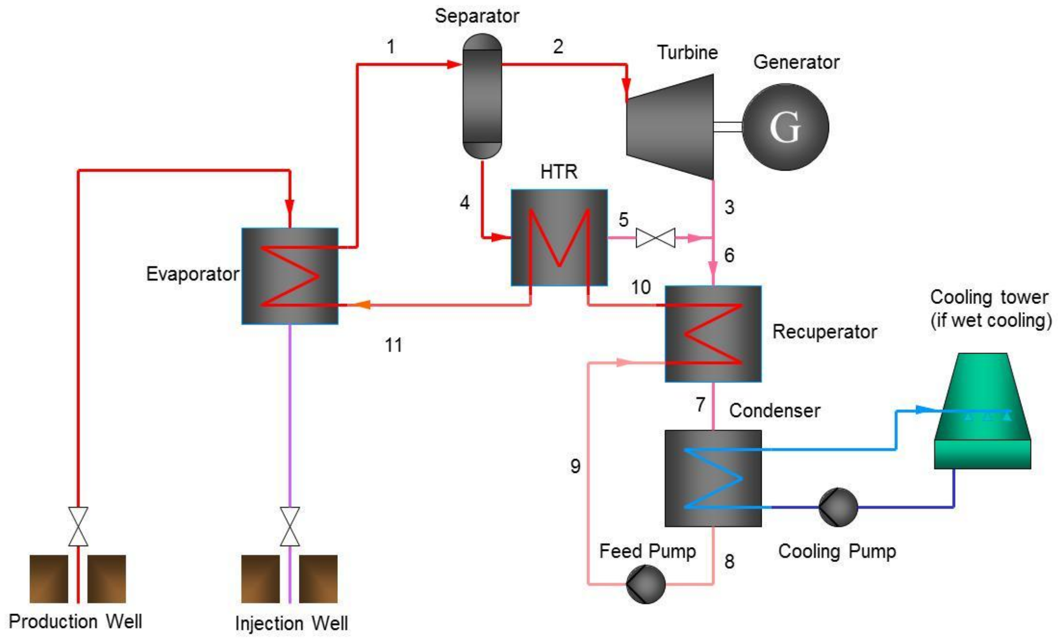

Figure 2 Process flow diagram of a Kalina cycle.

Kalina technology has a short history of commercial operation in the geothermal sector. Kalina plants can be found in Iceland, Japan and Germany, three of these plants are geothermal plants. Further Kalina plants are planned or under construction.

Electricity production calculations

The process simulations are performed with in-house calculation models prepared by Mannvit. Separate models were prepared for the ORC and the Kalina cycle for evaluation of the two processes. These calculations will allow for an evaluation and comparison of the estimated production and cost of the systems.

Input data and assumptions

Both models are based on general thermodynamics but some prerequisites are based on Mannvit‘s experience through similar work. The processes will use either wet or dry cooling for cooling the working fluid. The cold end design will be based on the assumption that the wet bulb temperature is 8,7°C, as this report focuses on utilization in Europe.

The models are adjusted in that way that the geothermal liquid is cooled down as much as possible before re-injection.

The working fluid in the ORC process is isobutane and mixture of ammonia and water in the Kalina process.

The models are used to calculate the net power and gross power for definite range of inlet temperature of the geothermal liquid (120°C-170°C). General functions for net power and gross power are then derived from these calculations where inlet temperature is the input data. The results from the functions for wet cooling are presented in Table 1 and for dry cooling in Table 2.

Table 1 General functions of gross and net power for both Kalina and ORC process with wet cooling.

T [°C]	ORC gross [kJ/kg]	ORC net [kJ/kg]	Kalina gross [kJ/kg]	Kalina net [kJ/kg]
120	18,1	22,6	21,5	25,5
125	21,0	26,2	24,0	28,2
130	24,3	30,2	26,6	31,1
135	27,9	34,7	29,3	34,0
140	31,9	39,7	32,0	37,1
145	36,2	45,1	34,9	40,2
150	40,8	50,9	37,8	43,5
155	45,8	57,3	40,9	46,8
160	51,2	64,0	44,0	50,2
165	56,9	71,2	47,2	53,7
170	62,9	78,9	50,5	57,3

Table 2 General functions of gross and net power for both Kalina and ORC process with dry cooling.

T [°C]	ORC gross [kJ/kg]	ORC net [kJ/kg]	Kalina gross [kJ/kg]	Kalina net [kJ/kg]
120	18,4	22,3	23,2	25,5
125	21,4	25,9	25,9	28,3
130	24,7	29,9	28,6	31,3
135	28,3	34,3	31,5	34,3
140	32,3	39,2	34,6	37,5
145	36,6	44,5	37,7	40,8
150	41,2	50,2	40,9	44,2
155	46,2	56,3	44,2	47,6
160	51,5	62,9	47,7	51,2
165	57,1	69,9	51,2	55,0
170	63,1	77,4	54,9	58,8

Gross power is how much electricity is generated in total. Net power accounts for the parasitic loads within each cycle. The parasitic load is the power needed to run the cycle, e.g. the production well pumps, the feed pump and pumps and fans for cooling the condenser.

The availability of the power plant is assumed to be 95%, which is in line with what can be expected from proven technology today for new binary plants. This means that the power plant will be working and delivering power of full capacity 95% of the time, but during 5% it will be stopped mostly because of maintenance but some unscheduled stops must also be expected. The plant will therefore operate for estimated 8322 hours each year.

New wells are included in the cost estimate. The mass flow from each well depends on the permeability of the reservoir, which is not possible to take into account here. It is likely that the mass flow from each well will be in the range of 20-60 kg/s and therefore it is assumed that each production well can give up to 40 kg/s of geothermal liquid in the model. For every two production wells, one injection well will be drilled, but in the case of EGS there will be one injection well for each production well.

Inputs into the model:

- Temperature of geothermal liquid.
- Total mass flow rate of geothermal liquid from all the production wells.
- Choose between wet or dry cooling for the cold end. Wet or dry cooling means that the working fluid in the condenser is cooled with either water or air.
- The vertical distance from the surface to the water level in the ground.
- EGS or not.

The model will provide the following outputs as well as the capital- and operational costs of the plant.

Outputs from the model:

- Gross power from the power plant in MW_e.
- Net power from the power plant in MW_e.
- Power production in GWh.
- Number of production wells.
- Number of injection wells.

Investment cost analysis

The cost of a geothermal project is related to the location of a resource since the geology at the site and characteristics of the geothermal fluid (temperature, pressure, chemistry, mass flow) all affect the CAPEX and OPEX of the project. The greatest cost factor is generally the drilling of the wells. If the geology of the site requires deep wells, for example more than 3 km, this has the greatest impact upon project capital cost.

The multiple factor method (Guthrie & Grace, 1969), (Helfrich & Schubert, 1973), (Perry, Green, & Maloney, 1997) is used for the capital cost estimate, based on estimated equipment costs. Equipment costs are based on experience gained from similar projects Mannvit has previously worked on. The costs are based on actual prices and/or quotations and corrected in accordance with the equation:

$$C_2 = C_1 \frac{i_2}{i_1} \cdot \left(\frac{q_2}{q_1}\right)^n$$

where the number *1* indicates a past or known value and *2* a current or wanted value. *C* stands for cost, *i* for index, *q* for quantity, capacity or size as applicable and *n* is the capacity-ratio exponent. The indexes are based on Mannvit's experience and the chemical Engineering Plant Cost Index (CEPCI) at the applicable date. The cost estimate covers only the costs as defined within the Boundary Limits.

At this level, the cost estimate is according to AACE Class 5.

CAPEX

The cost of drilling depends on several items such as location, infrastructure, type of reservoir, type of formations and well design. EGS wells are often more expensive than other wells because they have to be drilled deeper. The total cost for EGS power plants is higher than for power plants in conventional hydrothermal resources. There is also less experience in EGS and therefore the risk is higher. The price of the production well pumps also depends on the temperature of the reservoir.

The cost for the pipelines depends on the mass flow from the wells and the number of wells as well as the overall layout of the wells and power plant. Therefor some average distances are used in these cost estimations. It is assumed that there can be three wells on each well pad, production wells or injection wells. In the case of EGS there are two wells on each well pad. The distance between the wells on each well pad is 600m and the distance between well pads is 1500m.

The cost for the substation is roughly estimated as 4,6% of the total cost. This estimation is based on cost numbers from similar projects in Europe.

The cost for the power plant is based on the multiple factor method that has previously been described in this chapter. There are four different power plant cases where the power plants cost depends on if ORC or Kalina technology is used and if the cooling is wet or dry. It also depends on the temperature of the reservoir and the mass flow of the geothermal liquid.

Since there are many factors that affect the power plants cost, it's not possible to use just one equation for all the cases. The following tables show how the cost changes according to the functions for the main equipment for the ORC and Kalina plants with wet and dry cooling.

Table 3 Cost parameters for ORC wet cooling as a function of geothermal temperature.

T [°C]	Turbine [kW/kg/s]	Evaporator [m^2/kg/s]	Condenser [m^2/kg/s]	Circ. pump [kW/kg/s]	Cool. tow. [kW/kg/s]	Cool. Pump [kW/kg/s]
120	23,3	14,9	21,6	1,2	2,6	0,9
125	26,2	14,0	22,7	1,5	2,7	0,9
130	29,6	13,9	24,1	1,9	2,9	1,0
135	33,5	14,6	25,8	2,3	3,1	1,0
140	37,9	16,3	27,8	2,7	3,3	1,1
145	42,8	18,8	30,1	3,3	3,6	1,2
150	48,2	22,2	32,8	3,9	3,9	1,3
155	54,1	26,5	35,7	4,5	4,2	1,4
160	60,5	31,7	39,0	5,3	4,6	1,6
165	67,4	37,7	42,5	6,1	4,9	1,7
170	74,8	44,6	46,4	6,9	5,4	1,9

Table 4 Cost parameters for ORC dry cooling as a function of geothermal temperature.

T [°C]	Turbine [kW/kg/s]	Evaporator [m^2/kg/s]	Condenser [m^2/kg/s]	Circ. pump [kW/kg/s]
120	22,9	14,4	24,6	1,2
125	25,8	13,4	26,0	1,5
130	29,2	13,2	27,8	1,9
135	33,1	13,9	29,9	2,3
140	37,4	15,5	32,4	2,7
145	42,3	18,0	35,2	3,3
150	47,7	21,3	38,4	3,9
155	53,6	25,5	41,9	4,5
160	60,0	30,6	45,8	5,3
165	66,8	36,6	49,9	6,0
170	74,2	43,4	54,5	6,9

Table 5 Cost parameters for Kalina wet cooling as a function of geothermal temperature.

T [°C]	Turbine [kW/kg/s]	Evaporator [m^2/kg/s]	Condenser [m^2/kg/s]	Circ. pump [kW/kg/s]	Cool. tow. [kW/kg/s]	Cool. Pump [kW/kg/s]	LT recup. [m^2/kg/s]	HT recup. [m^2/kg/s]
120	24,5	16,4	25,1	0,9	1,6	0,7	3,9	0,15
125	27,6	16,3	26,9	1,0	1,7	0,7	4,3	0,13
130	30,6	16,6	28,3	1,1	1,8	0,8	4,7	0,11
135	33,7	17,2	29,2	1,2	1,9	0,8	5,0	0,10
140	36,8	18,2	29,8	1,4	2,0	0,8	5,2	0,08
145	39,9	19,6	29,9	1,5	2,1	0,9	5,3	0,07
150	43,0	21,4	29,6	1,6	2,1	0,9	5,4	0,06
155	46,1	23,5	28,8	1,7	2,2	0,9	5,4	0,06
160	49,2	26,0	27,6	1,8	2,2	0,9	5,2	0,05
165	52,4	28,9	26,0	1,9	2,3	1,0	5,0	0,04
170	55,5	32,2	24,0	2,1	2,3	1,0	4,8	0,04

Table 6 Cost parameters for Kalina dry cooling as a function of geothermal temperature.

T [°C]	Turbine [kW/kg/s]	Evaporator [m^2/kg/s]	Condenser [m^2/kg/s]	Circ. pump [kW/kg/s]	LT recup. [m^2/kg/s]	HT recup. [m^2/kg/s]
120	24,6	16,5	30,0	0,8	4,0	0,15
125	27,7	16,4	32,3	0,9	4,5	0,13
130	30,8	16,6	34,1	1,0	4,9	0,11
135	33,9	17,3	35,3	1,1	5,2	0,10
140	37,0	18,3	36,0	1,2	5,4	0,08
145	40,1	19,7	36,1	1,3	5,5	0,07
150	43,2	21,5	35,7	1,4	5,6	0,06
155	46,3	23,6	34,7	1,5	5,6	0,06
160	49,5	26,2	33,1	1,6	5,5	0,05
165	52,6	29,1	31,0	1,7	5,3	0,04
170	55,8	32,3	28,4	1,8	5,0	0,04

OPEX

Maintenance cost contains all the expenses that are related to the maintenance of the equipment of the power plant, like turbine, generator, heat exchangers, buildings, pipes and well heads. This also includes machinery overhaul, painting, road repair etc. Some of the activities can be subcontracted to specialized companies. Usually a clear distinction is made between the power plant maintenance expenses and the expenses related to the field maintenance and the make-up well drilling. The maintenance of the field can include the maintenance of the production and injection wells, well pumps, pipelines, etc.

During the first years of operation, the O&M cost is expected to be relatively low. The O&M cost will increase with time, as the power plant gets older and more maintenance or replacement is needed.

The production rate of the power plant is an average over a period of technical service lifetime of 30 years. The production will start out at a higher level and then fall below the average at some point. Mitigating measures should be taken to counteract the fall in the plant's output to some degree.

The annual O&M cost is taken as 1% of the investment cost for the wells, 5% of the investment cost for the submersible well pumps, 1% for the piping material and system and 3% of the investment cost for the power plant and its utilities, the fluid transfer, the power generation and the site infrastructure.

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