

## 1 General Introduction

In the core of planet Earth, radioactive decay constantly generates heat that slowly moves to outer layers, including the mantle and the surface. This process is available everywhere and reflected in an average global temperature gradient of 30°C/km. Therefore, in most areas of the planet, one could find temperatures of 90°C at 3 km depth, to give an example. In areas with volcanic activity, however, temperature gradients of over 100°C/km can be found.

This heat energy is called “Geothermal Energy”. Since the radioactive processes in the core of the Earth are continuous, it can be classified as a renewable energy source.

The general process of tapping into geothermal energy can be described as follows: A water tight cap rock above the hot spot enables an accumulation of pressurized hot water stored in porous and fragmented rock formation. Drilling through the cap rock will enable the pressurized hot water to vent off in form of a mixture of water and steam. At the surface, water (also called brine because it is rich in minerals) and steam are separated. The steam is piped to the power station where it is expanded through a steam turbine. At the exhaust of the turbine, low pressure steam is condensed (cold water, evaporation - cooling tower - or air) and water is returned to underground by reinjection wells.

Geothermal fields are classified according to their temperature in the reservoir. In Africa, governments and investors are mainly targeting high-enthalpy (temperature) fields, i.e. with temperatures over 200°C. The classification of high, medium and low enthalpy resources is explained in Table 1 on the next page.

It is worth mentioning that this handbook module does not discuss the so called Engineered Geothermal Systems, EGS, previously also called Hot Dry Rock. Furthermore, this handbook module does not discuss shallow geothermal energy where heat pumps are deployed to heat and cool buildings.

Theoretically, geothermal energy could provide mankind with all its energy needs many times over, but in practice it has been shown to be difficult to develop geothermal energy projects due to two main reasons:

- Resource risk: Knowledge on the thermal characteristics of the subsurface is quite limited, though geophysics and geology have made progress over recent decades. Even after a completed state-of-the-art exploration program, the actual existence of a geothermal reservoir and its potential can only be confirmed by test drillings, followed by months of well testing. There are three types of wells: (i) Temperature gradient (TG) wells, (ii) Statigraphic or “slim” wells and (iii) commercial grade wells. One commercial grade well requires an investment in the range of about US\$ 10 to 25 million, depending on the site in question, and this investment is at risk if the resource cannot be confirmed or the potential turns out to be insufficient for the intended purpose. The cost of TG well or Slim well is a fraction of the cost a commercial grade well (in the range of 3-10% for a TG well and 30-50% for a slim well).
- Project finance and profit margins: Investors in geothermal projects need to have access to “patient” capital. The project cycle is on average seven to nine years until utility scale power

generation (>25 MWe) can start and revenues can be generated. For the first phases including test drilling, three years should be estimated. These facts and the fact of the resource risk mentioned above, make it very difficult, if not impossible, for private sector companies to develop a geothermal power project from the beginning. Furthermore, it is common that geothermal power generation cannot offer the high returns that investors are targeting. Especially in countries where power tariffs are low, profit margins will be too low to generate interest from the private sector.

### Geothermal Potential in Sub-Saharan Countries

It is good to know that all figures about geothermal potential, whether in Africa or elsewhere, are based on pure estimates and usually have a limited scientific base. In fact, the reservoir potential can only be fully confirmed after test drilling and the full potential of a field only after years of operation. It is not enough to count volcanoes, take samples from hot springs or transfer the lessons learned from one reservoir to another, even though they are in close proximity. Therefore all talk about 15,000 MWe potential for East-Africa (Source M. Gehring) should be taken as a very rough estimate and could change much by the time the potential is scientifically proven.

A few countries, for example Ethiopia, are firm on having geothermal power projects developed by their public sector, while other countries might be more willing to invite foreign and domestic private sector companies (IPPs) to develop and operate power projects and sell power to their public utility / off-taker. Few of these country governments have, however, the capacity and/or finance to invest in the early stage geothermal exploration to address the resource risk and make projects accessible to IPPs on reasonable terms.

The following table gives an insight into the status quo and a rough estimate of the geothermal potential in several sub-Saharan countries.

**Table 1: Geothermal development and future potential in Africa (Source: M. Gehring)**

Country	2014 inst. capacity MWe	Resource temperatures (estimated)	Number of fields known	Estimated country potential for power generation (Installed capacity, MWe)
Kenya	520	High	About 20	4000 to 7000
Ethiopia	7	High	About 20	3000 to 5000
Djibouti	0	High	2 to 3	30 to 200
Sudan	0	unknown	n/a	n/a
Tanzania	0	Medium / high	5 to 10	200 to 2000
Zambia	0*	Medium	5 to 10	50 to 500
Rwanda	0	Medium / low	Around 10	50 to 300
Uganda	0	Medium / low	>20	50 to 300
Burundi	0	Low	2 to 3	10 to 50
DR Congo	0*	Medium / low	5 to 10	50 to 500
Malawi	0	Low	5 to 10	10 to 50
Mozambique	0	Low	n/a	n/a
Cameroon	0	Medium / high	3 to 5	n/a
Chad	0	Medium / low	n/a	n/a
Madagascar	0	Medium / high	n/a	n/a
Comoros	0	High	2 to 3	n/a

**Explanations to the table:**

- “\*” means that these two countries had previously installed geothermal power plants that have been decommissioned
- MWe = megawatt electric (not including options for waste heat or direct use)
- Resource temperatures: High >200°C, medium 120 to 200°C (still usable for power generation) and low <120°C (only direct use commercially viable).

**Worldwide Geothermal Success Stories**

The total installed capacity from worldwide geothermal power plant amounts to 12635 MW (2015) and should increase to 21443 MW by 2020. America, Asia and Europe are leading. Africa is lagging with 601 MW. The worldwide lead turbine manufacturers are Japanese companies (Toshiba, Mitsubishi, Fuji), while geothermal construction in Japan is at a halt.

**Table 2: Installed geothermal electric capacity outside Africa**

Country	2015 inst. Capacity (MWe)	Forecast for 2020 (MWe)
USA	3450	5600
Philippines	1870	2500
Indonesia	1340	3500
Mexico	1017	1400
New Zealand	1005	1350
Italy	916	1000
Iceland	665	1300
Japan	519	570
Turkey	397	600
Costa Rica	207	260
El Salvador	204	300
Nicaragua	159	200
Russia	82	190
Papoua N. G.	50	70
Guatemala	52	140
Portugal	29	60
China	27	100
Germany	27	60
France	16	40

Source: Ruggero Bertani, Enel Green

Power, <https://pangea.stanford.edu/ERE/db/WGC/papers/WGC/2015/01001.pdf>

**Geothermal Success Story in Sub-Saharan Africa**

Kenya is leading the way with the Olkaria geothermal field developed by KenGen, the public power company. In February 2015, KenGen had successfully developed 520 MWe and is aiming at 1000 MWe in just a few years. To secure financing, KenGen might need Joint-Venture (JV) partners and/or tender out entire projects, both of which may require lending products from donors and Multilateral

Development Banks (MDBs). Currently in 2014/15, KenGen is clearly the World's fastest and most successful geothermal developer, although all progress is concentrated on the Olkaria geothermal field. The Kenyan GDC (Geothermal Development Company) has done excellent work in exploration and drilling since the public agency was established in early 2009. Currently the GDC is promoting its Menengai field and preparing exploration to start at two other fields, Bogoria-Silali and Suswa.

### Development Issues and Barriers

- **Kenya:** Use of waste heat from Kenyan power plants is limited to greenhouses. So far, some heat and gas (CO<sub>2</sub>) are used for greenhouses. The national company, Geothermal Development Company (GDC) is likely to need further advice, e.g. on how to adapt its geothermal strategy to the performance of the Menengai field and how to sell steam to IPPs with a separate steam sales agreement. Furthermore, the GDC has applied for grant support to the Geothermal Risk Mitigation Facility (GRMF) operated by the African Union Commission (AUC) and KfW but may require additional support from Multilateral Development Banks (MDB) and donors to develop other sites. The installed capacity should reach 1500 MW by 2020.
- **Ethiopia and Tanzania** are not yet ready for IPPs but working on the issue. This might be one more good reason for MDBs and donors to monitor these two countries since they have a large geothermal potential.
- **Zambia, Uganda, Rwanda** are more receptive to private sector companies as power producers. Especially the Zambian mining sector with its strong financial background might be leading the country into private power generation. Kalahari Geoenergy is making some initial efforts in this regard with test drillings to happen soon in several locations. Rwanda has drilled a commercial grade test well at the Karisimbi volcano but results do not look encouraging. New studies show lower temperatures at depth than previously expected and a limited resource base in terms of flow. If true, this would still promote smaller 5 to 10 MWe binary power projects along with waste heat use for industries and agriculture. For Uganda, no firm data on geothermal potential is available due to the lack of test wells. One could, however, expect a potential quite similar to that of Rwanda, since the geothermal reservoirs of these two countries are actually in the same Graben (fault / reservoir system).
- **Djibouti** has a limited demand for power of max. 50 MWe and geothermal will have to compete with hydro power from Ethiopia, provided through the EU funded 300 MWe interconnector. However, the country needs own power generation for base load demand, since the interconnector cannot provide firm capacity. If the four test drillings planned for 2015 (financed by World Bank and AfDB) show positive results, lending products from MDBs and advice (TA) might be in high demand by IPPs competing for the 50 MWe power project.
- **Other Sub-Saharan African countries:** There are several little explored geothermal areas in Africa: The Western African geothermal area from Sao Tome to Cameroun and up to Chad has only seen limited exploration. Furthermore, very little is known about the eastern islands like Reunion, Madagascar, Comoros etc., but they are all likely to have high enthalpy steam for power generation. These countries use mainly diesel and HFO for their power generation.

## 2 Tasks and Timeslines of Project Development

The following table provides an overview over the most important phases of geothermal project development along with the required estimated time for each phase or task.

**Table 3: Geothermal project development (Stepwise approach, for first approx. 50 MW unit)**



Source: M. Gehringer

### Mitigation of the Resource Risk

A comprehensive strategy for minimizing resource risk exposure should consider the following approaches:

- **Portfolio exploration**, in which the country to some extent explores and evaluates multiple geothermal fields simultaneously, thereby increasing the probability of finding at least one viable site and reducing the chance of overlooking significant development opportunities;
- **Parallel development** of the fields selected from the portfolio to multiply the pace of development, reduce time and costs;
- **Stepwise expansion**, reducing the risk of reservoir depletion and pressure drops by developing a geothermal power project in cautiously sized increments/steps, determined by reservoir data. As a rule of thumb, a pilot power plant (e.g. well head generator with 2 to 10 MWe capacity) should be installed to gain solid geophysical data about the reservoir over a period of 2 years. Thereafter and based on this information, a utility scale power plant can be built in incremental steps of e.g. 25 or 50MWe, depending on field potential and pressure-drop measured;

- **The country's minimum system demand<sup>1</sup> for electricity** will determine the maximum amount of geothermal capacity that can be installed, since geothermal is base load and steam is only controllable by vent-off at the entrance of the power plant (and not at the well), so that geothermal power plants usually do not follow load.

Unlike the oil and gas industry that serves the global market, demand for geothermal power is localized and limited by a specific country's / region's minimum system demand (base load). This means that the entire demand for geothermal power may be met by a relatively small number of productive geothermal fields.

### 3 Technologies for Geothermal Power Generation

In Africa, usually only two kinds of power conversion systems are implemented:

- Binary plants for fluid temperatures of 120 to 200°C
- Flash or double flash systems for fluid / steam temperatures over 200°C

Other technologies like Dry Steam cannot be used, because all reservoirs found so far have produced fluids containing steam (gas) and brine (fluid) which have to be separated before they can enter the turbine. Due to environmental and efficiency concerns, Back Pressure turbines with vent of the exhaust steam (i.e. without condenser) are not used.

#### Flash Power Plants

Flash plants, also called Condensing Units or Conventional Steam Cycles, usually come in sizes from 25 to 60 MWe per turbine and as one pressure stage application (single flash) or with two pressure stages (double flash<sup>2</sup>). The double flash option is significantly more efficient but also more costly. The decision as to whether or not a double flash is worth the extra cost and complexity can only be made after a thorough economic evaluation of the project.

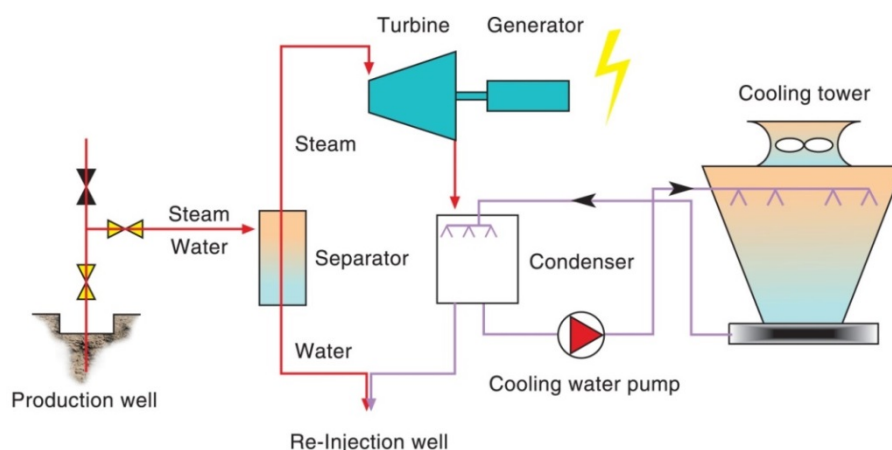


Figure 1: Concept of Flash power plant (Gehring & Loksha, 2012)

<sup>1</sup> or regional system demand in case of a regional interconnected system

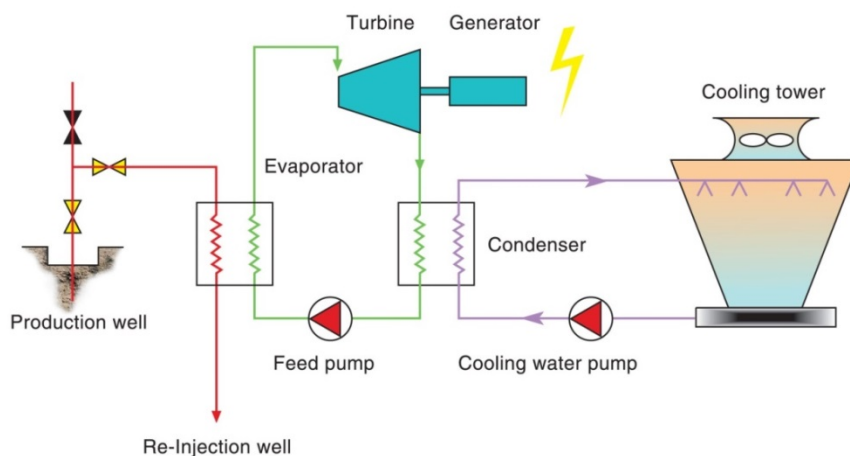
<sup>2</sup> In the double flash cycle, the water separated from the first flash drum is flashed again in a second drum at a lower pressure providing additional steam to be injected along the steam turbine or between a high pressure body and a low pressure body

In the diagram above, the two-phased fluids (liquid-vapour mixture) enter through a separator. While the separated steam continues to the turbine to be used for power generation, the fluids (brine) either get re-injected right away, or could be used for secondary uses. The steam is expanded through a turbine (injection pressure around 6 bar sat. 170°C in Kenya - Olkaria) and then cooled in the condenser (often cooling towers enabling to reach 40-50°C at the condenser) so it can be re-injected into the reservoir. Secondary uses include bottoming cycles, i.e. additional power generation with usually a binary unit, or other “waste heat” uses as discussed below.

## Binary Cycles

Binary cycles, also called Organic Rankine Cycles or ORC, are being built to generate power from fluid temperatures below 100°C. For reasons of project economics, 120°C is seen as the absolute minimum fluid temperature to deploy a binary cycle. Binary cycles operate quite efficiently on fluid temperatures over 140°C.

As shown in the diagram (Gehringer & Loksha, 2012) below, a binary cycle has two loops: An open loop for the geothermal fluids coming up from the reservoir, heat being extracted by heat exchangers (evaporator or boiler) and the cooled geothermal fluids being re-injected in the reservoir. A second, closed loop is filled with an organic working fluid (alcohol, usually iso-pentane) that has a very low boiling point (30°C under one atmosphere) and creates steam to drive the turbine. This enables the binary cycle to utilize such low fluid temperatures. After exhaustion of the steam in the turbine, the working fluid has to be cooled down (re-liquefied) in a condenser, so that it can be pumped back into the storage tank and finally been used again.



**Figure 2: Concept of a typical binary cycle power plant, ORC<sup>3</sup> or Kalina<sup>4</sup>**

Binary cycles are being produced by many suppliers, with different working fluids and come in sizes from 100 kWe to 20 MWe. They are often used as “bottoming units”, i.e. the binary plant uses the

<sup>3</sup> The **Organic Rankine cycle (ORC)** is named for its use of an organic, high molecular mass fluid with a liquid-vapor phase change, or boiling point, occurring at a lower temperature than the water-steam phase change. The fluid allows Rankine cycle heat recovery from lower temperature sources that is converted into electricity.

<sup>4</sup> The **Kalina cycle** uses a solution of 2 fluids (usually water and ammonia) with different boiling points for its working fluid instead of two separate fluids as in ORC. Since the solution boils over a range of temperatures as in distillation, more of the heat can be extracted from the source than with a pure working fluid.



(waste) brine from the separator of a flash plant and the residual fluids (also called waste heat) coming from the turbine. Combined, the two energy sources can provide 10 to 20% of additional power to any power project and therefore bottoming units should always be part of the initial project / power plant design. This is an important way to make best possible use of the energy from the reservoir. Binary cycles are often more capital-intensive per MWe installed but are usually easy to maintain and operate.

### Efficiency and Power Generation Costs of the Technologies

Flash power plants are used to generate power from high enthalpy resources. The efficiency for the overall conversion process of heat energy into electricity may be around 15-20% and power generation costs for utility scale power projects of over 25MWe are usually between US\$ 0.04 and 0.11 per kWh. For binary cycles, efficiency is less mainly due the heat exchange for the second, closed loop. With an overall efficiency of 10 to 14%, the power generation costs of binary units are significantly higher than from flash power plants. Since binary units are usually also smaller in size than flash plants, an estimate for production costs from binary would be between US\$ 0.08 and 0.2 per kWh, depending mainly on resource temperature and plant size.

## 4 Important Issues for Planning Geothermal Power Projects

### Cooling of Power Plants

In warm climates of Africa, the cooling of geothermal fluids or steam would require enormous amounts of cooling water. Water from large rivers, lakes and also the sea can be used. However, many geothermal areas do not have access to sufficient amounts of cooling water and therefore use cooling towers. Cooling towers operate on a closed loop of refrigeration water that needs chemical treatment and make-up since about 8 to 15% of the water evaporates. In areas where no cooling water or sea water is available, air cooling has to be used (cooling towers if the ambient air is dry, fin tubes if the ambient air is saturated). Due to its low efficiency and high power consumption (for cooling fans), air cooling can reduce the actual power output from the power plant significantly while at the same time increasing investment costs.

### Well Head Units

Well head units can be deployed in most geothermal power projects after completion of test wells. A set of 4 to 5 test wells is on average capable to provide steam from 2 to 3 successful wells with a generation capacity of 5 to 10 MWe. This would enable the developer, whether private IPP or public agency, to deploy one or two 5 MWe wells head units. These off-the-shelf and turn-key units are likely to reduce capital expenses and project risk and allow for quicker payback on investment. At a later stage, they can be replaced by a full size utility scale power plant with one or more 25 to 55 MWe turbines.



Figure 3: Cooling Towers at Olkaria II power plant (Kenya)



### Use of Waste Heat / Residual Heat, Cascaded Use, Combined Heat and Power (CHP)

Several African countries are serious about significantly scaling up their geothermal power generation. In countries with high reservoir temperatures (see table 1), the power plants will be “flash” plants and convert steam of around 250°C into electricity. Brine can be flashed to generate low pressure steam at 130 to 150°C that has little interest for power generation. Over time, large amounts of energy (waste heat) will become available for e.g. bottoming cycles, cold storages, canning factories and fruit / food drying facilities, to name a few examples. Benefits of CHP include value creation for the entire country through taxes, job creation, export, new agricultural opportunities and increased value of food products as well as significant regional development.

It will, however, take time to identify industries willing to move to the sites where the waste heat is available, and the power plant operator has in fact little security when this will happen and how secure the payments from these industries will be.

Therefore, the use of waste heat should be treated as a development target and integral part of the country’s geothermal regulatory development framework. From the beginning, tariffs for waste heat use should therefore be integrated into standard PPAs, environmental standards and legal frameworks to ensure the best possible use of energy and project outcome.

### Direct Use of Geothermal Energy

In low enthalpy<sup>5</sup> geothermal fields with fluid temperature of 60 to 120°C, direct use may be a feasible option. This includes the same uses as mentioned above for waste heat use, but, due to low fluid temperatures, does not include power generation. Such fields might be available in Uganda, Rwanda, Burundi, Zambia, Malawi and Mozambique. This could also be an ideal use of geothermal for the capital areas outside the known geothermal areas, e.g. cities like Addis Ababa or Nairobi, and other locations in similar distance from the high enthalpy fields located in the Rift Valley.

### Co-production by Extraction of Precious Minerals from Geothermal Fluids

The ability to remove silica from geothermal brines can add to energy extraction, reduces operation and maintenance costs. Recovery of silicon opens the way for the recovery of other metals like zinc, lithium, manganese, cesium, rubidium and even precious metals like gold, silver that could increase the probability of the operation. For example:



Figure 4: 2.4 MW Well-head power plant at Eburru (Kenya)

<sup>5</sup> Enthalpy is defined as a thermodynamic potential, designated by the letter "H", that consists of the internal energy of the system (U) plus the product of pressure (p) and volume (V) of the system. The unit of measurement for enthalpy in the International System of Units (SI) is the joule. The enthalpy is the preferred expression of system energy changes in many chemical, biological, and physical measurements at constant pressure, because it simplifies the description of energy transfer. For liquid water, enthalpy is strictly proportional to temperature.

- The use of geothermal fluid in heap leaching for **Silver** and **Gold** extraction in Round Mountain Gold and the Florida Canyon Mine. (Trexler., et al 1990)
- Extraction of **silica** from geothermal power plant in Mammoth Lake, California. (Parker A., 2005).
- Mining **lithium**, from geothermal fluid, in Salton Sea hypersaline geothermal reservoir in Imperial Valley, CA

## 5 Economics of geothermal power generation

Table 4 (Gehring, 2011) provides a range of “Investment Cost Estimates” according to the different development activities of a typical 50 MW geothermal plant being between US\$2,800 to 5,500 per installed kW.

**Table 4: Indicative Costs for Geothermal Development (50 MW Power Project) in Million US\$**

Phase / activity	Low estimate	Medium estimate	High estimate
1: Preliminary survey, permits, market analysis <sup>6</sup>	1	2	5
2: Exploration <sup>7</sup>	2	3	4
3: Test drillings, well testing and reservoir evaluation <sup>8</sup>	11	18	30
4: Feasibility study, project planning, funding, contracts, insurances, etc. <sup>9</sup>	5	7	10
5: Drillings (20 boreholes) <sup>10</sup>	45	70	100
6: Construction (power plant, cooling, infrastructure, etc.) <sup>11</sup> Steam gathering system and substation, connection to grid (transmission) <sup>12</sup>	65 10	75 16	95 22
7: Start-up & commissioning <sup>13</sup>	3	5	8
TOTAL:	142	196	274
In million US\$ per MW installed	2.8	3.9	5.5

Source: M. Gehring

<sup>6</sup> Costs for survey depend heavily on size and accessibility of area. Costs for EIA depend on country regulations..

<sup>7</sup> Depending on methods used and accessibility and size of area

<sup>8</sup> For 3 to 5 drillings with variable depths and diameter, from slim hole to full size production wells

<sup>9</sup> Studies and contracts provided by external suppliers or own company. Conditions and regulations of relevant country

<sup>10</sup> Depending on depth, diameter, and fluid chemistry, casings and wellhead requirements in terms of pressure and steel material / coating. Also influenced by underground and fractures (drilling difficulty and time)

<sup>11</sup> Power plant prices vary by system used and supplier, but most impact comes from infrastructure (roads etc.) and cooling options (water or air)

<sup>12</sup> Depending on distance from plant to transmission grid access point, and on distance between boreholes and power plant.

<sup>13</sup> Standard industrial process. Power plant may need fine tuning for some time and minor adaptations. For high estimate, major changes, repairs and improvements are needed to supply power according to PPA

## 6 Financing Geothermal Power Projects

Figure 5 below gives a generic overview on project risks and investment required, as well as project development phases and financing options. The high risk factor and financial requirements of the test drilling for geothermal resources makes public sector support for geothermal projects nearly inevitable. Typically, for the fear of the project not being financially viable, the private sector will be extremely hesitant to finance a geothermal project until the geothermal resource is proven. Especially the test drilling phase has been a bottleneck to development; there are very few options for developers to finance their projects through this stage. In Africa, the Geothermal Risk Mitigation Facility (GRMF - <http://www.grmf-eastafrica.org/>) operated by the African Union Commission (AUC) and KfW, is currently offering grants to push geothermal projects over this hurdle.

The impact of financing options and related costs can be shown quantitatively by a financial model based on cash-flow analysis (Gehring&Loksha, 2012). The model rendered a levelized cost of energy (LCOE) of US\$ 0.05 to 0.07 per kWh for an example 50 MWe flash power plant, and, most importantly, shows the enormous impact of public support in early project stages for the overall financial viability of the project. In short, financing costs encountered by private sector companies financing their project with venture capital can easily double the LCOE / required power tariff, thereby rendering the project uneconomical.

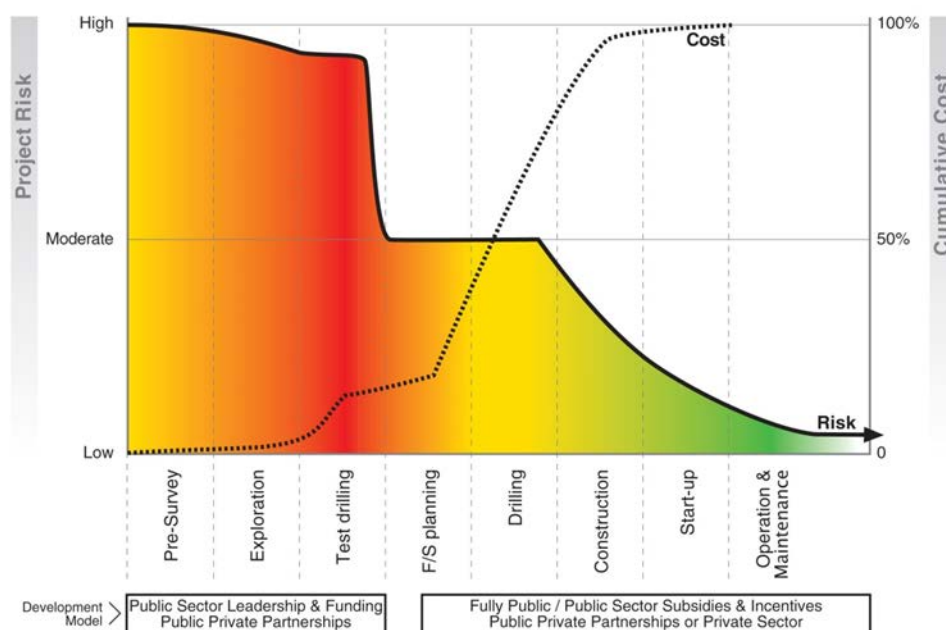


Figure 5: Financing a Typical Medium Size Geothermal Power Project (50MW)

### Environmental and Social Issues

Geothermal energy has several characteristics that make it appealing for power generation. Geothermal power plants provide base load power with a high capacity factor; modern geothermal power plants can have a capacity factor of 92 percent or higher. They are also an ideal complement to conventional hydroelectric power whose load-following capability allows a power system to serve peak loads. Once a geothermal power plant is up and running, there is less need for fossil fuels, which contributes to lower operation and maintenance costs. The multiple uses of geothermal resources, including for power generation, industrial heat, tourism, and agricultural production, can enhance the economics of geothermal projects.

Some of the drawbacks of geothermal energy are associated with characteristics of the resource itself. Field depletion is a risk which can be mitigated by designing the geothermal development carefully with the stepwise approach. Depending on characteristics of the field, additional wells (make-up wells) may have to be drilled every few years (at a significant cost) to sustain the production rate. Additionally, there may be temperature drops of the steam being extracted which can impair the ability to deliver the rated capacity of the power plant (Wang et al, 2012).

The potential environmental and social impacts of geothermal plants compare favorably to fossil fuel technologies as well as other types of renewable technologies. Land use for a geothermal power plant and related resettlements are limited compared to other technologies. Impacts on air quality through plumes and smells can in most cases be mitigated. Land subsidence has occurred in cases when reservoirs have been overdeveloped but can usually be mitigated by re-injecting the geothermal fluids back into the reservoir to keep up pressure necessary to sustain the production of steam.

### 7 Key questions

Whether a private sector company (e.g., Independent Power Producers-IPP) considers developing a geothermal project or investing in one, or whether a donor or Multilateral Developing Bank is considering supporting a project or financing it, there are always several basic questions to be asked:

1. For Independent Power Producers (IPP) the first question will be: Who are the previous IPPs operating geothermal power projects in the country and how successful have they been in their business?
2. Does the country have a clear and supportive legal and regulatory framework, allowing projects to be developed by IPPs?
3. How is geothermal data managed by the geological survey of the country and what data is available / accessible?
4. For a certain project, what exploration has been done so far and what are the results?
5. Has the availability of a geothermal resource been confirmed by drilling? If yes, were several test wells drilled, interference test done and wells tested for several months, to render reliable data about the potential?
6. Who will be the off-taker for the generated power and what is his financial standing?
7. Is a Power Purchase Agreement (PPA) with the off-taker available or what is required to get one signed?
8. Does the off-taker or government offer a fixed tariff for geothermal power? Is it high enough to sustain the operations?
9. What guarantees will be made available to ensure that the power producer will be paid according to the PPA?
10. Is the geothermal developer aware of the inherent risks of geothermal and does he know how to mitigate them?
11. Does the developer understand the project cycle, how long it takes, and what impact the time will have on his financing costs? Geothermal usually needs patient capital with low interest and extended grace period.
12. Does the developer have access to patient capital or other concessional funds / grants to develop the initial project phases?
13. Does the developer have in-house technical and financial capacity and a track record of geothermal or similar power projects?

14. Is the developer aware of the minimum system demand of the country and transmission capacity of the grid? Does he have access to all relevant data about the system? Does he understand the necessity of having access to reliable transmission and distribution systems?
15. If the project only focusing on power generation, or does it promote a more holistic approach including waste heat use for secondary industries, which could multiply the project's benefit for the country and especially the region?
16. Is the developer aware that a set of minimum 4 to 5 test wells will have to be drilled in order to receive exact geothermal data from the drillings?
17. Have exploration and drilling been planned and designed according to best international standards? If not and if the developer decides to abandon the project after (test-) drilling, all data will be worthless and the work will have to be repeated.
18. Has the project been planned with mitigation of resource risks in mind? After test drilling, will the developer first deploy a well head unit or small pilot plant, and then increase capacity in small increments of e.g. 25 or 50 MWe each? The potential of the reservoir should be scientifically confirmed, by long-term tested wells, before designing a full size power plant.
19. If more power is needed within a limited timeframe, has parallel development of multiple sites been considered? This helps prevent overdevelopment of a certain field and protects from loss of investment.

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